POSITIONING FOR COMPETITION AND UNCERTAINTY

RAMPP

Resource and Market Planning Program
RAMPP - 3

EXECUTIVE SUMMARY

APRIL, 1994

PACIFICORP

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"There is no subject, however complex, which, if studied with patience and intelligence, will not become more complex." — *Anonymous*

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RAMPP

PREPARING FOR THE FUTURE

Wouldn't it be nice to know the future?

For decades, utility planners have tried to predict it. By analyzing data, trends and projections, they've attempted to forecast future electricity demands and the resources available to meet them.

Now the emphasis has shifted. At PacifiCorp, the goal is not to pinpoint the future, but to prepare for whatever it may bring. The company explores a wide range of future possibilities using sophisticated computer models, to help decide what it should do now, given the uncertainties of the future.

The emphasis in resource planning has shifted in another way as well. While the company is still focused on making sure it will have enough resources to meet customer needs, neither electricity demand nor supply are seen as fixed quantities. Both can fluctuate according to changes in the market and industry, and with opportunities that become available. The company wants to grow in ways that will allow it to continue serving customers competitively.

THINKING STRATEGIC

The energy marketplace is changing dramatically. Deregulation, more alternative suppliers, new technology and changing customer needs are all contributing to a more competitive environment. In this new setting, the old rules of "franchised service territory" and "guaranteed customers" no longer apply. Options such as cogeneration, non-utility generation and purchasing from other suppliers are giving customers more choices than ever before.

To succeed in this competitive environment, PacifiCorp adheres to two main strategies:

- **Remaining a low-cost producer of electricity and energy services; and**
- **Providing high quality customer service that responds to customers' changing needs.**

In keeping with these two strategies, the company manages its power supply and demand and evaluates new resource alternatives based on five overall principles:

- **Minimize cost and retail price impact** — to help keep prices down.
- **Consider the tradeoff between cost and emissions** — to try to minimize both.
- **Provide reliable service** — which is essential for serving customers well.
- **Assure efficiency** — in both the operation of the company's system and the way in which customers use electricity, to assure high value for each energy dollar spent.
- **Maintain flexibility** — to be able to respond to changing circumstances. PacifiCorp maintains resource options that have short lead times and low capital costs and can be acquired in amounts that closely match growth.

By following these principles in its planning, the company can help assure cost-competitive, responsive service.

WHAT IS RAMPP?

In the same way it would be nice to know the future, it would be helpful to know the best route for getting there.

PacifiCorp's Resource and Market Planning Program provides general direction into the future, but allows the company to steer its own course as obstacles and opportunities arise. Rather than committing the company to a rigid resource plan for the next 20 years, RAMPP provides a process for deciding at any given time which way to go next. In this way, it gives PacifiCorp flexibility to respond to changing circumstances. The company can use RAMPP to evaluate specific resource and marketing opportunities as they develop.

In general, the RAMPP process:

- Provides a long-range plan and framework to guide the company in evaluating resource and market decisions; and
- Complies with regulatory commission requirements for integrated resource planning.

The regulatory commissions in Idaho, Montana, Oregon, Utah and Washington require the company to:

- Examine a range of forecasts for the energy needs of its customers;
- Consider all feasible alternatives for meeting those needs;
- Assess supply (new generation) and demand (customer efficiency) alternatives in a consistent manner;
- Assess the external costs of various resource alternatives;
- Describe a long-range plan and a shorter-term action plan for balancing supply and demand; and
- Prepare its plan with substantial public involvement.

PacifiCorp's RAMPP process and the reports documenting it meet all of these regulatory requirements. This report describes the results from RAMPP-3, the third cycle through the RAMPP process.

THE WORLD HAS BEEN CHANGING: DEVELOPMENTS SINCE RAMPP-2

A number of changes affecting both the content of RAMPP-3 and the process for developing it have occurred since RAMPP-2 was completed in May 1992. An overview of these changes follows:

Implementation of RAMPP-2 Action Plan

PacifiCorp has successfully implemented the RAMPP-2 action plan. It has pursued demand-side resources, renewable resources, peaking resources, cogeneration opportunities, system efficiencies and improvements as called for in the action plan. This includes implementation of the demand-side programs specified for 1992 and 1993; initiating development of two wind projects (one in Washington and one in Wyoming); involvement in two new cogeneration projects (James River and Hermiston); a capacity agreement with another utility (Southern California Edison); and additional resource-related actions.

Major Events

Key occurrences in the past two years include:

- **DSR Cost Recovery** — In 1993, the Oregon and Utah commissions adopted cost recovery mechanisms that will help equalize the earnings the company can achieve on demand-side resources and supply-side resources. Disincentives to acquiring DSR have included the fact that increased energy efficiency (through

DSR) reduces revenues, that DSR investments do not accrue an allowance for funds used during construction, and that DSR can only be acquired in small increments.

- **The Energy Policy Act of 1992** — Competition in the energy marketplace, already underway, increased with approval of the Energy Policy Act. The act established a new category of power producers, exempt wholesale generators (EWGs), and also expanded transmission access. Under the act, any utility or EWG can ask a utility to provide transmission service under certain conditions, and the utility must provide it.

- **Administrative Rules for the Clean Air Act Amendments** — PacifiCorp has reduced its thermal plant emissions since 1985 and therefore qualifies for a net surplus of SO2 allowances. A sale of these surplus allowances to Illinois Power is currently pending. The company's future sales of allowances will depend on the outcome of a lawsuit in New York dealing with allowance transactions and other Clean Air Act Amendment discussions.

- **Retail Competition** — Competition for retail sales is increasing as more and more customers — particularly industrial and commercial customers — investigate alternatives such as self-generation, fuel switching, changing to another provider such as public power, relocating or expanding to sites outside of PacifiCorp's service territory, cogenerating, buying power from another utility, or using new technologies. One particularly controversial form of retail competition, retail wheeling, is being debated at the state level. It would allow retail customers to require their local utility to transport power to them that the customer purchases from another utility or non-utility generation source. This would radically change the existing system, where each utility has an obligation to serve a defined area and is given an exclusive franchise for that area. If retail wheeling occurs, utilities that are low-cost producers will be best positioned to succeed.

- **Growth in Electricity Sales** — PacifiCorp's retail load increased by 1.1 percent in 1992; 2.1 percent in 1993. The RAMPP-2 forecast for 1993 was 1.7 percent load growth in the medium low case, and 3.1 percent in the medium high case.

- **BPA Peak Purchase Agreement** — PacifiCorp has negotiated a new 20-year peak purchase agreement with the Bonneville Power Administration that will allow the company to continue buying 1100 MW for peaking needs. Federal approval is pending. The 1100 MW purchase level represents a continuation from the company's previous contract with BPA, but is a reduction from the projection in RAMPP-2 for a purchase of 1400 MW by 1995.

- **BPA Rate Increase** — The Bonneville Power Administration increased the rates it charges PacifiCorp and other utilities as of Oct. 1, 1993. BPA has the option to further increase its rates in 1994 if necessary. PacifiCorp is most concerned about the effect BPA rate increases have on the residential exchange program, which benefits residential and small farm customers with a pass-through reduction in their prices in Washington, Oregon, Idaho and Montana. Each time BPA rates increase, the credit to customers is reduced and their prices increase. The 1993 BPA increase resulted in a 6.2 percent price increase for Oregon residential customers and an increase of 6.9 percent for Oregon small farm customers. Percentage increases for the other states were similar. BPA's increases also affect the price PacifiCorp must pay for power transmission over the north-south intertie.

- **Closing of Trojan** — Portland General Electric closed the 1100 MW Trojan Nuclear Plant in January 1993. PacifiCorp, which owned 2.5 percent of the plant, is replacing its 27 MW with firm power purchases.

CHANGES IN RAMPP METHODOLOGY

The RAMPP process has become more complex with each round of planning. Each RAMPP report has surveyed a wider range of future possibilities:

- **RAMPP-1**, completed in late 1989, focused mainly on the uncertainty of load growth;
- **RAMPP-2**, completed in early 1992, considered load uncertainty, but also different levels of gas pricing and uncertainties in resource performance;
- **RAMPP-3** tests the same variables analyzed in RAMPP-2, but also considers what would happen if the company followed different resource strategies (using more or less demand-side resources; more or less renewables; and more or less coal), and what happens if some key assumptions about the costs or characteristics of a specific resource are changed. RAMPP-3 also tests more environmental uncertainties.

A more complex model was used in the RAMPP-3 analyses for selecting and analyzing resources, a greater emphasis on external costs, greater recognition of geographic areas and transmission constraints, and the inclusion of transmission costs. The RAMPP-3 model included a capability for optimization to identify plans that minimize total costs for any specific combination of future conditions. It also integrated production costs with the selection of new resources over the next 20 years.

The complexity of the RAMPP-3 process and model are evident in the extent of its outcomes. Altogether, RAMPP-2 looked at 26 possible futures. It considered four levels of load forecasts, seven load uncertainties (e.g., if load growth is low at first and then suddenly increases), 10 sensitivities (including possible changes in gas prices, loss of resources, results from demand-side resources, amount of renewables used, etc.) and five environmental cases.

By contrast, RAMPP-3 looked at 155 possible futures — based on various levels of load growth, gas prices and resource strategies (different levels of DSR, any-coal or no-coal, and any-renewables or strategic-renewables); 29 sensitivities (which changed an input assumption, e.g., what if wind power can produce more energy than expected, what if coal prices are higher than expected, etc.); and 23 levels of environmental externalities (costs added to each resource based on emissions). Each one of these cases resulted in a unique least-cost resource plan.

The results from RAMPP-3 indicate that PacifiCorp can acquire supply- and demand-side resources for a broad range of future conditions that keep its electricity price increases at or below the expected level of inflation over the 20-year planning horizon.

PLANNING BASED ON UNCERTAINTY: LOOKING INTO THE FUTURE

Since the future is invariably unpredictable, PacifiCorp cannot know with any certainty what electricity demand will be and what new energy sources will best serve demand ten or twenty years from now. However, through the RAMPP process, the company can consider a broad range of possibilities and determine how it would respond in each case. By evaluating the pattern of these responses, the company can then determine a course of action that makes sense for the short-term and positions the company well for making future choices.

RAMPP-3 tests more possible futures than any of its predecessors, by varying levels of load growth, gas prices, resource strategies, input assumptions (sensitivities), and environmental factors.

Load Forecasts

RAMPP-3 considers five forecasts of customers' future electricity needs. The forecasts are based on various economic and demographic possibilities as well as end-use assumptions, historical information and other data. The five forecasts include load growth that is:

- **High (3.8%)**
- **Medium High (3.0%)**
- **Medium (2.1%)**
- **Medium Low (1.3%)**
- **Low (0.3%)**

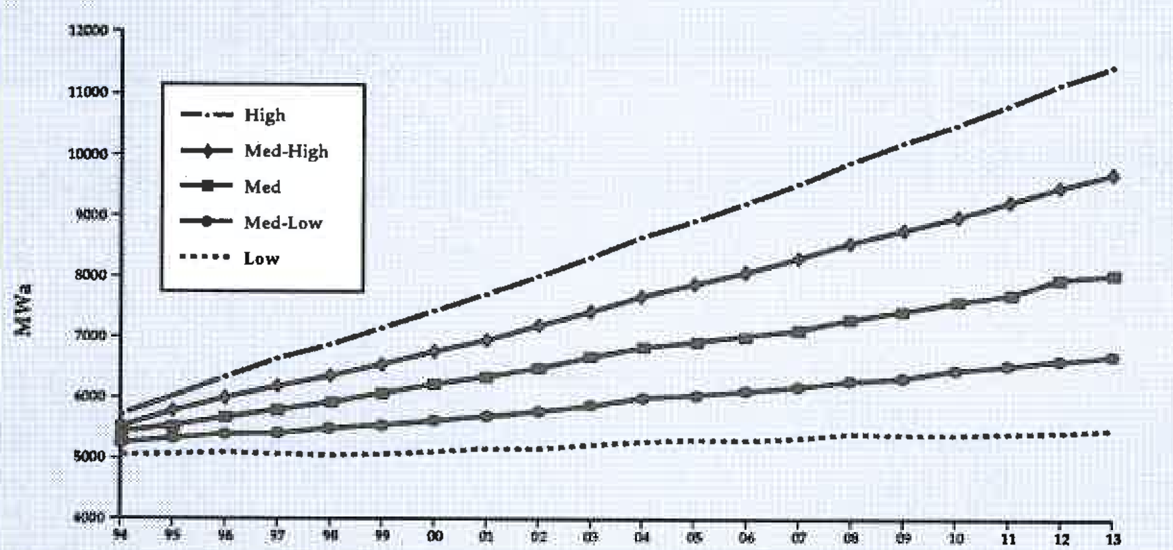
Growth between the medium low and medium high levels is considered very likely, based on a very large number of combinations of economic and demographic conditions. Growth at the highest and lowest levels is considered less likely, but was included to make the analysis of possible futures more all-inclusive.

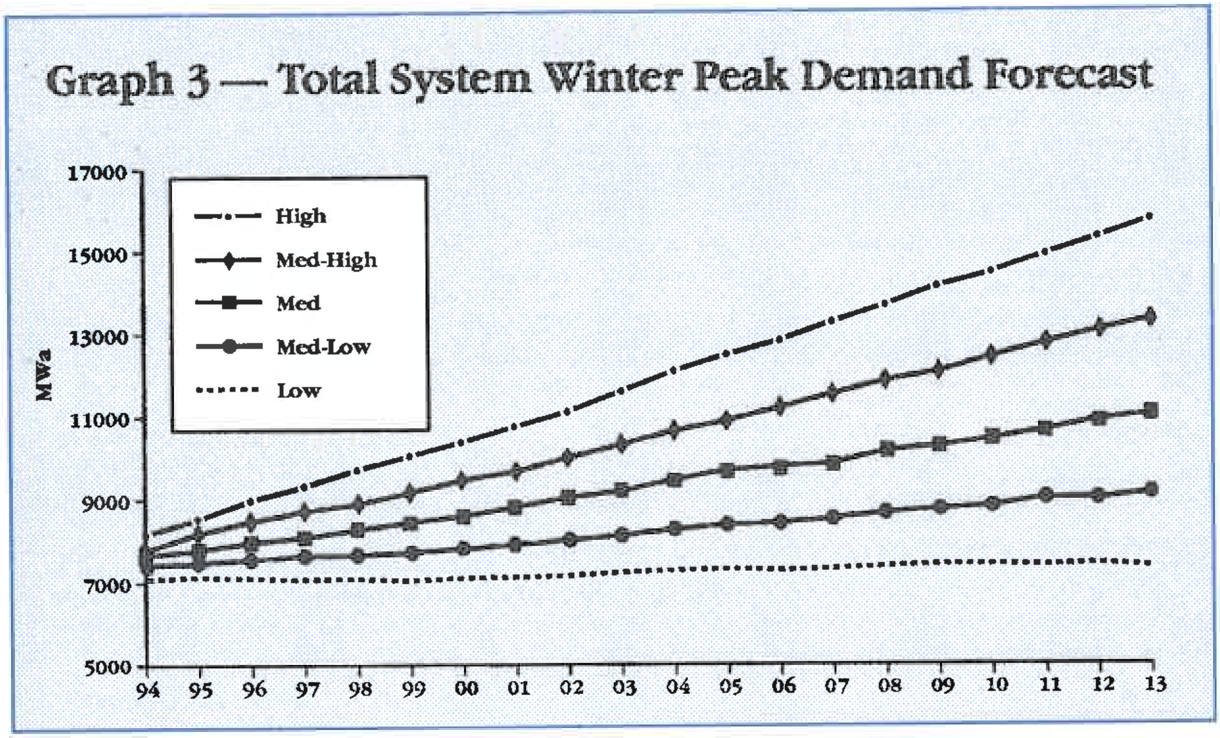
Table 1 shows the level of load growth associated with each forecast, as well as the annual energy (MWa) needed at the end of the planning period (2013) and the winter and summer peak loads at that time. Graph 2 charts the five levels of annual energy load growth for the next 20 years. Graph 3 shows the results for winter peak, and Graph 4, for summer peak.

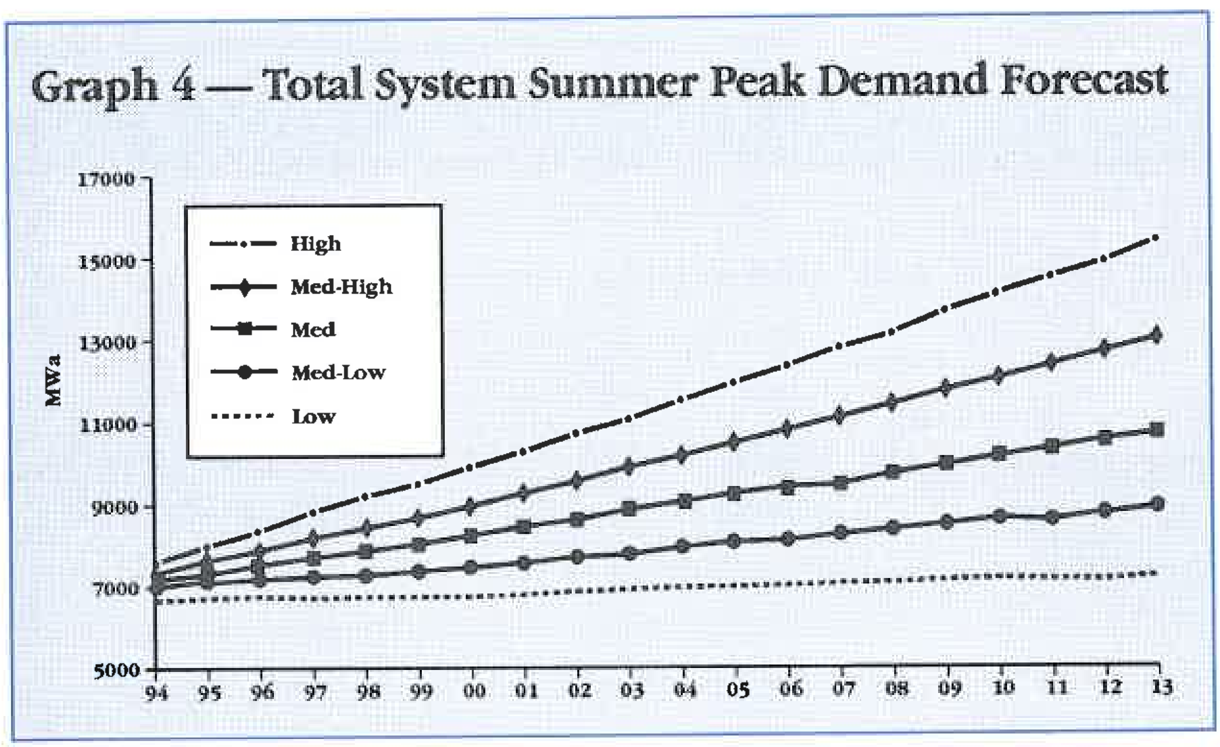
Table 1 — Key Forecast Information
Total System

	Energy				Winter Peaks				Summer Peaks			
Forecast	Avg. Annual Growth Rate %	Total MWa at 2013	Total MWa Added by 2013	Annual Avg. MWa Added	Avg. Annual Growth Rate %	Total MW at 2013	Total MW Added by 2013	Annual Avg. MW Added	Avg. Annual Growth Rate %	Total MW at 2013	Total MW Added by 2013	Annual Avg. MW Added
Low	0.33	5,373	328	16	0.33	7,504	449	22	0.35	7,194	460	23
Med-Low	1.26	6,621	1,397	70	1.26	9,277	1,969	98	1.29	8,894	1,922	96
Med	2.13	7,998	2,644	132	2.14	11,206	3,709	185	2.21	10,823	3,676	184
Med-High	3.02	9,624	4,151	208	2.99	13,488	5,782	289	3.09	13,037	5,731	287
High	3.75	11,381	5,725	286	3.72	15,949	7,975	399	3.84	15,456	7,906	395

Graph 2 — Total System Energy Forecast




Graph 3 — Total System Winter Peak Demand Forecast
17000
15000
13000
11000
9000
7000
5000
MWa
High
Med-High
Med
Med-Low
Low
94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12 13


Graph 4 — Total System Summer Peak Demand Forecast
17000
15000
13000
11000
9000
7000
5000
MWa
High
Med-High
Med
Med-Low
Low
94 95 96 97 98 99 00 01 02 03 04 05 06 07 08 09 10 11 12 13

Gas Prices

PacifiCorp, like most utilities in the country, expects natural gas to be one of the foremost fuel sources for new power generation in the future. Forecasts of future gas prices are therefore critical in estimating the cost of various resource plans.

RAMPP-3 used three gas price forecasts:

- **Low (1.7% real escalation)**
- **Medium (3.8% real escalation)**
- **High (5.6% real escalation)**

The forecasts were based on information about the long-term availability and pricing of gas supplies, including the costs for transportation and storage. Analysts agree that adequate gas resources currently exist in the United States to meet domestic demand at the current level for the next 60 to 70 years. PacifiCorp projects adequate reserves to meet increased demand well into the next century. By taking advantage of competition between natural gas producers in Canada and the United States and developing a mix of long- and short-term contract purchases, the company believes overall gas price escalation between the low and medium gas price forecasts is most likely.

The costs of transporting gas have become more competitive under Order No. 636 from the Federal Energy Regulatory Commission, which prohibits pipeline companies from continuing to sell gas to end-users, and instead requires them to function only as transporters of gas. With the increased competition, many large industrial, local distribution and electric utility companies have been able to reduce their costs for gas.

Gas price levels were considered independent of the load growth forecasts. RAMPP-3 tested each possible combination of load growth forecasts and gas price forecasts to create 15 unique futures.

Resource Strategies

After establishing the 15 load growth/gas price futures, RAMPP-3 tested a variety of resource strategies with the optimization model. Each resource strategy set parameters for acquiring a certain resource. These strategies were then tested against the possible futures.

For example: Let's say you began with a future case that assumed electricity load was growing at a medium rate, and so were gas prices. One resource strategy you might test would be: What would happen to the resource plan if the model was not allowed to choose any coal resources? Or, what if the model was allowed to select all of the demand-side resources that meet a high cost-effectiveness level? The model created a resource plan for various resource strategies after they were combined with specific load growth and gas price forecasts.

Altogether, the company tested, in different combinations, five strategies for demand-side resources, two for renewables, and two for coal. The resource strategies were as follows:

Demand-Side Resources

- **Low DSR:** Used a low level of cost-effectiveness for DSR (30 mills/kWh real levelized), with a slow ramp-up (or acceleration) rate;
- **Medium DSR:** Based cost-effectiveness (55 mills/kWh real levelized) on the avoided costs used in RAMPP-2 and the ramp-up rate in RAMPP-2;
- **Accelerated DSR:** Based cost-effectiveness on the avoided costs in RAMPP-2, but with an accelerated ramp-up rate;
- **High DSR:** Used a higher level of cost-effectiveness (70 mills//kWh real levelized) and an accelerated ramp-up rate;

- **Unconstrained DSR:** Used the RAMPP-2 cost-effectiveness level to develop initial programs, then added higher-cost measures and allowed the model to choose any or all of the DSR potential at any time. The model was allowed to add DSR immediately with no restrictions on ramp-up rate or the total selected in any one year. The unconstrained strategy was unrealistic in that it did not consider the startup time needed to acquire DSR from a given program.

Coal

- **Any-coal:** The model could select any amount (unconstrained) of new coal resources in the resource plan.
- **No-coal:** The model could not select any new coal resources.

Renewables

- **Any-renewables:** The model could select any amount (unconstrained) of new renewables.
- **Strategic-renewables:** The model was instructed to achieve a specific acceleration rate of renewables in the early years. It could then select any amount of additional renewables.

The DSR, coal, and renewable strategies (except unconstrained DSR) were combined with each other to produce

16 strategy alternatives. Unconstrained DSR was combined with "any-coal" and "any-renewables" to create a 17th, completely unconstrained case.

If all 17 of these strategy combinations were tested against all 15 futures, 255 model runs would have been required. To reduce this number and still achieve a good cross-representation, the company selected 103 cases for its base study plan. Table 5 shows the variables tested for each of these cases.

Table 5 — Base Study Plan

FUTURES		Load	L			ML			M			MH			H		
		Gas	LG	MG	HG	LG	MG	HG	LG	MG	HG	LG	MG	HG	LG	MG	HG
UNCONSTRAINED				X			X		X	X	X		X			X	
LD	AC	AR							X	X	X		X			X	
LD	AC	SR							X	X	X		X			X	
LD	NC	AR							X	X	X		X			X	
LD	NC	SR							X	X	X		X			X	
MD	AC	AR		X			X		X	X	X		X			X	
MD	AC	SR		X			X		X	X	X	X	X	X	X	X	X
MD	NC	AR		X			X		X	X	X		X			X	
MD	NC	SR		X			X		X	X	X	X	X	X	X	X	X
AD	AC	AR							X	X	X		X			X	
AD	AC	SR							X	X	X		X			X	
AD	NC	AR							X	X	X		X			X	
AD	NC	SR							X	X	X		X			X	
HD	AC	AR							X	X	X		X			X	
HD	AC	SR							X	X	X		X			X	
HD	NC	AR							X	X	X		X			X	
HD	NC	SR							X	X	X		X			X	
DSR	Coal	Renew															

STRATEGIES

DSR strategies:
- LD – use a low level of cost effectiveness for DSR with slower ramp-up rate
- MD – cost effectiveness based on RAMPP-2 avoided costs, and the ramp-up rate used in RAMPP-2
- AD – cost effectiveness based on RAMPP-2 avoided costs, but with an accelerated ramp-up rate
- HD – use a higher level of cost effectiveness, and an accelerated ramp-up rate

Coal strategies:
- NC – no coal plants
- AC – any coal plants

Renewable strategies:
- AR – any renewables
- SR – strategic renewables

Input Assumptions (Sensitivities)

To this point, the model had tested 103 possible combinations of load growth, gas prices and resource strategies (for combinations of DSR, coal and renewables), and produced a resource plan for each.

The company then moved beyond these base cases to consider a number of "what if's": What if one of the assumptions used in the base cases was changed? How would this affect the resource plan identified by the model? Each change in assumption created a different "sensitivity."

The input assumptions that were changed affected:

- **Load growth:** What if various factors reduced or increased growth slightly from the medium load growth case, or if electrification (of cars, industry, etc.) pushed electricity use above the high load growth case?
- **Resource acquisitions and transmission constraints:** What if other resource acquisitions were added to the portfolio, if certain technologies were converted, if transmission constraints were reduced, if a discount rate based on social benefits was applied, or if coal prices were higher?

- **Wholesale activities:** What if critical water levels rather than average water levels were assumed for hydro availability, if PacifiCorp's wholesale prices went up or down 20 percent, or if the wholesale market no longer offered opportunities for non-firm sales or purchases?

- **Renewable resources:** What if the costs of wind and geothermal power were different than assumed, or if the capacity or production levels associated with wind power changed?

The model considered all of these possible changes, and produced a resource plan for each.

Environmental Costs

Finally, the model considered the impact additional environmental costs would have on resource selections. Twenty-one environmental cases were tested, with various combinations of load growth, gas prices and DSR levels, but all using the any-coal and any-renewable strategies to provide the maximum range of choices. The environmental costs combined high and low values for NOx and total suspended particles with three values for CO_2. These were tested against selected future cases. Two additional cases restricted total CO_2 emissions to 1990 levels.

PORTFOLIO OF RESOURCES

PacifiCorp can choose from a number of resource alternatives to meet future electricity needs. The company's portfolio includes three categories of resources:

Existing System

Existing resources include those that are already on-line (thermal plants, hydro resources and power contracts) as well as system efficiency improvements and other changes the company knows will occur over the next 20 years.

PacifiCorp uses its coal plants to meet baseload needs, supplemented by hydro resources for daily, weekly and seasonal fluctuations in load. Coal generation meets about 82 percent of the company's energy requirements and provides 65 percent of the company's capacity; company-owned hydro represents 7 percent of energy requirements and 10 percent of capacity; and power purchases meet 11 percent of energy needs and 25 percent of capacity.

Planned system efficiencies, purchase contracts, and plant re-starts will add 918 MW of resources to PacifiCorp's existing system in the next five years. This does not include new (not net negotiated) purchased power, because the availability, price and terms of power purchase agreements are unpredictable. PacifiCorp takes advantage of opportunities to purchase power as they arise if those purchases are a more cost-effective resource choice than the alternatives.

Demand-Side Alternatives

PacifiCorp can also "create" additional resources by helping customers use energy more efficiently. Because energy efficiency programs reduce the demand for electricity, they are called demand-side measures. They result in saved energy, which can serve the same purpose as new sources of electricity.

In recent years, many of PacifiCorp's efficiency programs have used a financing mechanism called the Energy Service charge. Through this mechanism, the company finances a customer's initial costs for efficiency improvements, and the customer repays the company out of his or her energy savings through an Energy Service charge on the monthly bill.

The RAMPP-3 action plan used new financial standards to help the company rank DSR programs. These standards will allow the company to achieve DSR while still remaining price-competitive. They will also open up more possibilities for structuring DSR programs to better meet customers' individual needs. Options such as rebates or other financing approaches will be considered in addition to the Energy Service charge.

The company has reduced its estimates of the amount of energy efficiency savings that can be cost-effectively achieved over the next 20 years, compared with its projections in RAMPP-2. The potential savings have declined, mainly due to slower economic growth, improved building codes, and higher appliance efficiency standards. More experience and information have also clarified the costs and market potential for energy efficiency programs.

Supply-Side Alternatives

Supply-side resources include the vast array of new generating resources that can be added to the company's system. They include traditional as well as new technologies. The primary types of supply-side alternatives are coal-fired resources, natural gas-fired resources, cogeneration, wind, geothermal, solar power and pumped hydro storage.

RESULTS

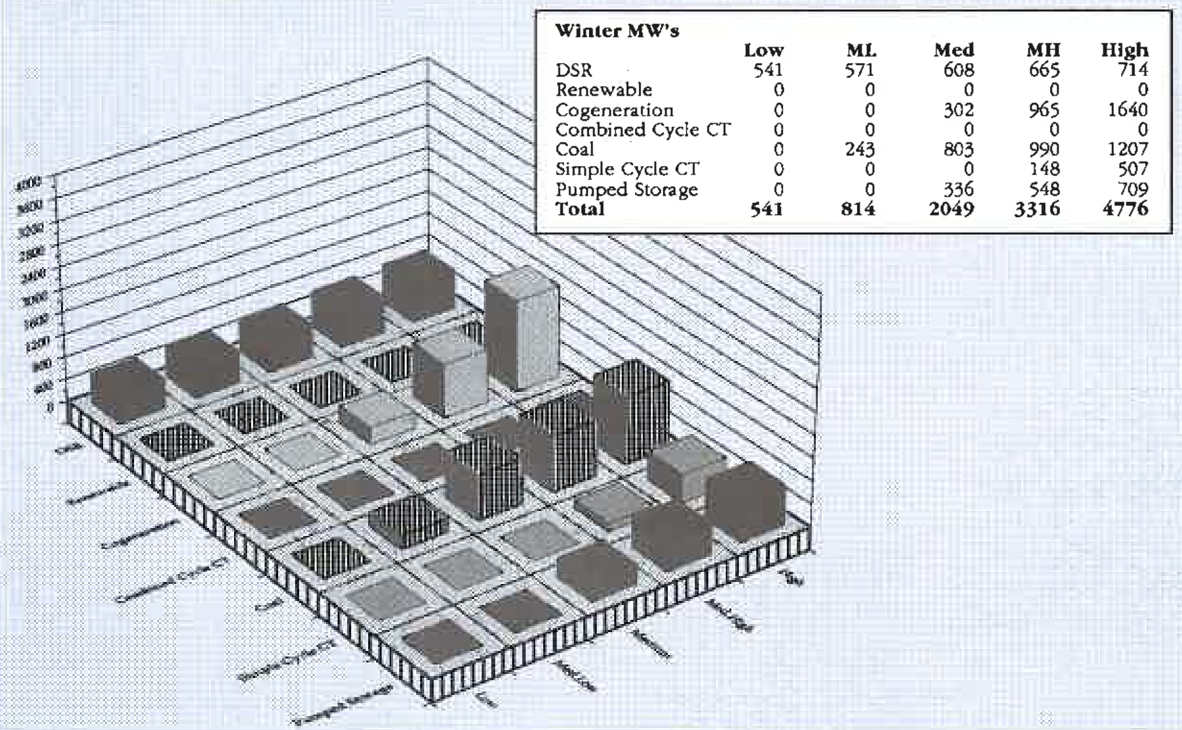
RAMPP-3 includes a resource plan for each of the 155 future cases. The resources in each plan were drawn from the company's portfolio.

Overall Findings

Taken together, the resource plans show that the company is well-positioned to respond to a broad range of possible futures. In every case, PacifiCorp has the flexibility and options it needs to economically meet customers' energy and capacity needs.

Graph 6 — Resource Additions by Load Level: 1994-2003

(Medium Gas Price, Medium DSR, Any-Coal, Any-Renewables)



Winter MW's	Low	ML	Med	MH	High
DSR	541	571	608	665	714
Renewable	0	0	0	0	0
Cogeneration	0	0	302	965	1640
Combined Cycle CT	0	0	0	0	0
Coal	0	243	803	990	1207
Simple Cycle CT	0	0	0	148	507
Pumped Storage	0	0	336	548	709
Total	**541**	**814**	**2049**	**3316**	**4776**

Graph 6 (for 1994 to 2003) and 7 (1994 to 2013) show the distribution of resource additions selected for each load growth level. Each figure assumes medium gas prices, medium DSR, and any-coal and any-renewables strategies.

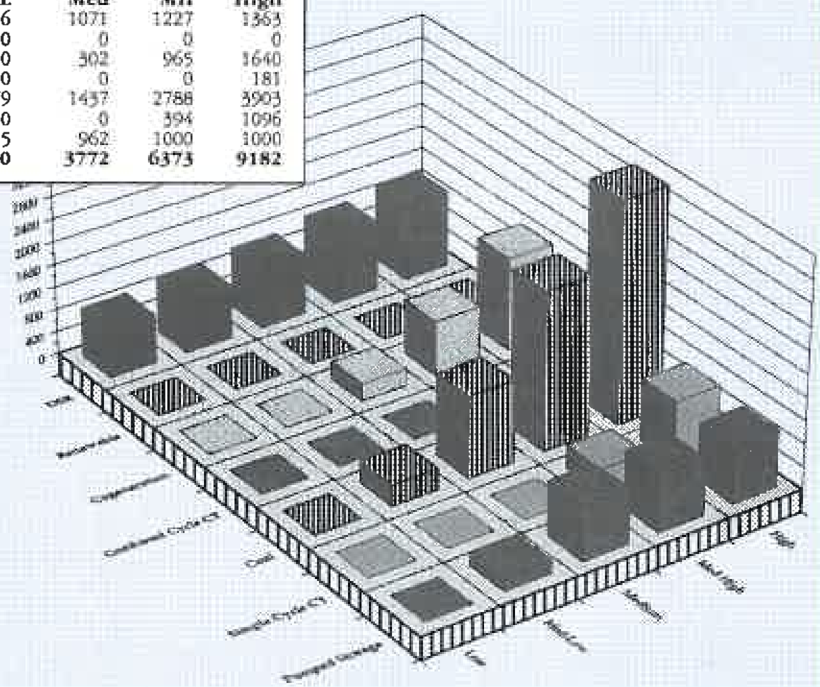
The results in the resource plans support two main conclusions:

PacifiCorp can meet new resource needs without having to increase prices greater than the expected level of inflation (3.4 percent).

Graph 7 — Resource Additions by Load Level: 1994-2013

(Medium Gas Price, Medium DSR, Any-Coal, Any-Renewables)

Winter MW's	Low	ML	Med	MH	High
DSR	864	956	1071	1227	1363
Renewable	0	0	0	0	0
Cogeneration	0	0	302	965	1640
Combined Cycle CT	0	0	0	0	181
Coal	0	379	1437	2788	3903
Simple Cycle CT	0	0	0	394	1096
Pumped Storage	0	235	962	1000	1000
Total	**864**	**1570**	**3772**	**6373**	**9182**



As load growth increased, customer prices in real terms generally stayed the same or decreased. The costs of new generating supplies are competitive with PacifiCorp's embedded costs. Therefore, the costs of acquiring additional resources do not exceed inflationary changes.

The fact that PacifiCorp can meet future electricity needs while keeping average prices in line with general inflation can help the company to maintain a competitive position as a low-cost producer.

Each supply- and demand-side alternative has its benefits and drawbacks; there is no single "best choice." RAMPP gives the company flexibility to make the right decision at the right time.

While new coal generation is the lowest-cost resource, it carries the risk of uncertain future taxes or restrictions on carbon dioxide emissions. Some clean coal technologies can reduce the CO2 risk, but the cost and performance of these are still being confirmed.

Cogeneration offers a shorter lead time than coal, but is dependent on negotiations with customers or other developers. Gas-fired resources carry the risk of uncertain prices in the future.

Renewable resources, such as wind and solar, are environmentally favorable, but are uncertain in terms of performance and ultimate cost. Demand-side resources present their own cost and performance uncertainties. In addition, DSR can have the effect of increasing average prices when total costs are recovered from a diminished volume of electricity sales.

Pumped storage resources can be particularly valuable for meeting peaking needs, but may be difficult to site.

The company must consider all of these factors in deciding which resources to pursue as needs and opportunities arise. RAMPP is a first step in making these decisions, but it is followed by extensive financial and operational analyses for specific projects and opportunities.

Baseload Resources

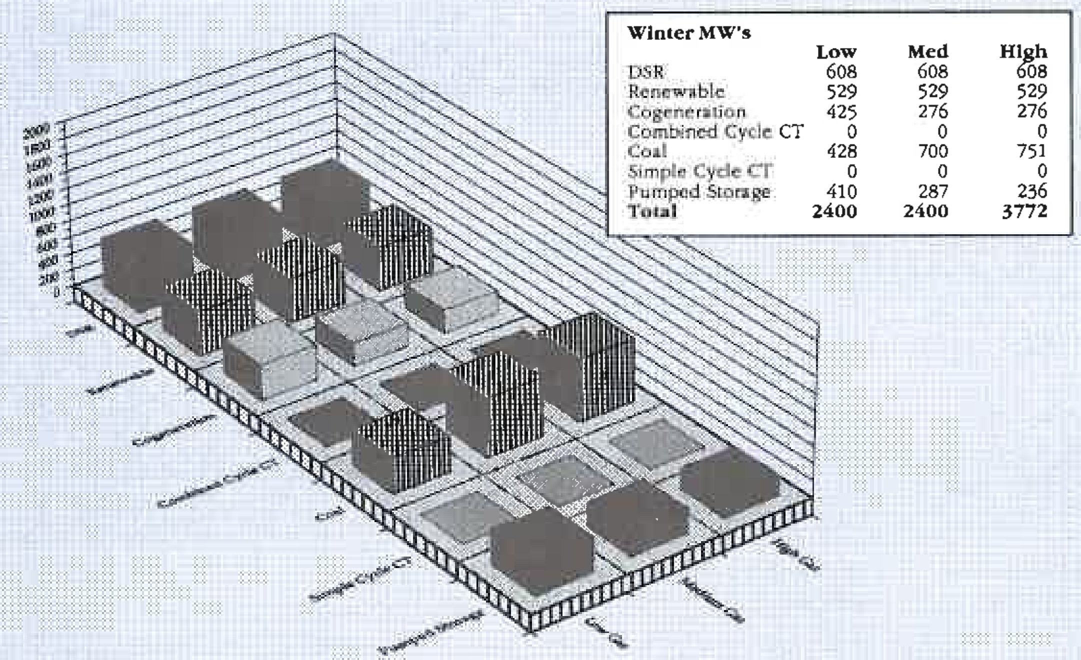
Assuming a medium level of load growth (2.1 percent per year), the company will need to add from 850 to 1,000 MW of baseload resources in the next 10 years. Coal and cogeneration were the least-cost choices for meeting baseload needs.

Peaking Resources

Assuming medium load growth, the company will need to add 200 to 500 MW of peaking resources in the next 10 years. The amount is higher under medium gas prices and lower under low gas prices. The RAMPP-3 model under-estimated the company's peak resource needs because it only recognized one season's peak (winter). Peaking needs are increasing as the company grows and manages its supply and demand in closer balance. Pumped storage or simple-cycle combustion turbines are the most cost-effective choices for meeting peaking needs.

Graph 8 — Resource Additions by Gas Price Level: 1994-2003

(Medium Load Growth, Medium DSR, Any-Coal, Strategic-Renewables)



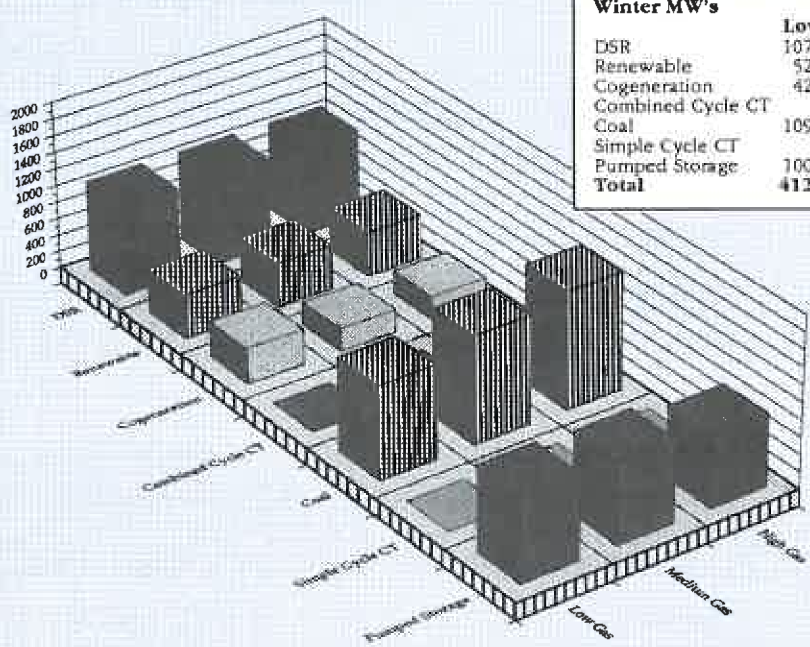
Winter MW's	Low	Med	High
DSR	608	608	608
Renewable	529	529	529
Cogeneration	425	276	276
Combined Cycle CT	0	0	0
Coal	428	700	751
Simple Cycle CT	0	0	0
Pumped Storage	410	287	236
Total	**2400**	**2400**	**3772**

Gas Prices

PacifiCorp believes gas prices are most likely to increase between the low and medium levels. Graphs 8 and 9 show the resource additions by gas price level for 1994-2003 and 1994-2013. Higher gas prices led the model to select more coal in the any-coal strategies and more wind resources under the no-coal constraint.

Graph 9 — Resource Additions by Gas Price Level: 1994-2013

(Medium Load Growth, Medium DSR, Any-Coal, Strategic-Renewables)



Winter MW's

	Low	Med	High
DSR	1071	1071	1071
Renewable	529	529	529
Cogeneration	425	276	276
Combined Cycle CT	0	0	0
Coal	1097	1274	1399
Simple Cycle CT	0	0	0
Pumped Storage	1000	973	848
Total	**4123**	**4123**	**4123**

Coal Strategy

Since coal was the least expensive new resource in the portfolio, the model mainly selected coal when allowed to. Cases that included new coal resulted in lower total costs and lower prices than those that did not.

Renewables Strategy

The company's strategic-renewables strategy caused total costs and customer prices to increase more than in the any-renewables strategy. However, the company is willing to sustain the small price impact in order to gain more experience with renewable technologies. The model's renewable resource selections would change only if there is a substantial improvement in the cost and performance of renewable resources. Under current cost assumptions, additional renewable resources are cost justified if gas prices are high and high environmental costs or constraints are imposed on new coal generation.

Regional Patterns

The geographical location of resource choices was most affected by the any-coal vs. no-coal strategies. New coal generation would be located in Utah and Wyoming; cogeneration from Oregon, Washington and California. Therefore, cases with the any-coal strategy had a higher percentage of their total resources in Utah, and cases with the no-coal strategy had a higher percentage of their total resources in the Pacific Northwest.

Coal Prices

Even if coal prices in Utah increased substantially, coal remained the least-cost resource. The Utah coal market has sufficient existing capacity for one or two units. The Wyoming coal market has sufficient capacity to allow for the additional of several new coal units.

Non-Firm Markets

The model consistently chose more non-firm sales for the company than non-firm purchases unless a CO2 tax of $25 or $40 per ton was introduced.

An assumption of critical rather than average water levels caused the company's costs and prices to increase. It reduced the amount of energy available from the existing system and from firm purchase contracts.

Changes in the price for non-firm sales had little effect on resource choices, but increased system costs and customer prices. A higher spot price caused the model to select about 90 MW more coal, and reduced costs and prices. Removing the non-firm market altogether caused utility costs, total resource costs and customer prices to increase. Because of the impact of non-firm prices, it is important that the company use a planning process that accurately reflects the non-firm market.

Environmental Adders

The addition of environmental costs or limits shifted the model's resource selections toward renewables and cogeneration, and from pulverized coal to coal gasification (a clean coal technology). Customer prices increased up to 20 percent for those cases that included environmental adders, versus their comparable non-adder cases.

Trade-off graphs showed which resource strategies best met the dual goals of lowering costs and lowering emissions. The no-coal strategy reduced emissions, but caused costs to increase from the any-coal strategy. Similarly, the strategic-renewables strategy reduced emissions, but cost more than the any-renewables approach. The company believes the cost of the strategic-renewables strategy may be necessary to gain experience with renewable technologies.

WHAT'S NEXT?

Based on the conclusions from RAMPP-3, PacifiCorp plans to take the following actions during the next two years:

- **Increase cost-effective demand-side acquisitions.** Achieve 40 MWa of cost-effective savings by the end of 1995.

- **Continue to pursue, if cost-effective, 200 MWa of renewable resources to be brought on line by 2001.**

- **Install 500 to 900 MW of cogeneration and/or combined cycle combustion turbines (CCCTs) by 2001, consistent with cost-effectiveness criteria.**

- **Evaluate clean coal technologies, such as gasification, and evaluate potential sites for new coal resources.**

- **Meet 150-200 MW of peaking needs by 2001 in addition to 150 MW of combustion turbines in Arizona.** More peaking resources may be required sooner. The company will seek to reduce those potential needs by pursuing peak management opportunities.

- **Implement pricing changes to further promote energy efficiency.**

- **Continue to improve the efficiency of the company's generation, transmission and distribution systems.**

- **Continue to test and demonstrate small-scale carbon offset projects.**

- **Develop improvements in the planning process for RAMPP-4.** The current schedule calls for the RAMPP-4 report to be completed by the end of 1995. It is expected to give more attention to competition, demand-side resources, renewables and the company's peaking needs.

FOR MORE INFORMATION

If you would like a copy of the full RAMPP-3 report, Positioning for Competition and Uncertainty, or additional copies of this Executive Summary, please call (503) 464-5620. Technical appendices are also available on the Load Forecasts, Demand-Side Resources, Modeling, and Public Process.

POSITIONING
FOR
COMPETITION
AND
UNCERTAINTY

RAMPP

Resource and Market Planning Program
RAMPP - 3

REPORT

APRIL, 1994

PACIFICORP

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APRIL, 1994

PACIFICORP

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INTRODUCTION

This report summarizes PacifiCorp's third Resource and Market Planning Program (RAMPP-3). It documents the internal and external process used by PacifiCorp to analyze future load growth, the ability of its existing power plants to meet customers' electric energy service needs, and the need for new resources, including new power plants and customer efficiency programs. The process described in this report:

1) Provides a long-range plan and framework to guide the company in evaluating resource and market decisions;

2) Complies with regulatory commission requirements for integrated resource planning (IRP).

RAMPP considers both resource and market conditions in evaluating future resource alternatives. The title of this report is "Positioning for Competition and Uncertainty." PacifiCorp selected that title because it reflects the company's goals in its resource acquisition activities: to position itself well for an uncertain future that will contain increasing competition. By positioning, the company intends to pursue activities that increase its future flexibility, shorten the lead time for future acquisitions, and allow it to respond quickly to market opportunities. To meet the competition, the company believes it will need to provide price and service levels that meet the customer's perception of a fair value. Overall, PacifiCorp's RAMPP aims at minimizing costs and risks to customers and society, and providing value to the company's shareholders.

See article by Pindyck

This report details the company's current planning information. It describes the assumptions, strategies and principles that will guide future supply and demand decisions. By using a process to guide decisions rather than following a pre-set plan, the company retains flexibility to respond to changing conditions. PacifiCorp uses the integrated resource plan and action plan to evaluate specific resource opportunities.

For more information on a particular issue or term, see the glossary or index at the end of this report. The glossary provides definitions for the various terms and abbreviations used throughout the report. The index provides a page reference for discussion of a particular issue or topic.

IRP REGULATORY REQUIREMENTS

Congress has increased interest in Integrated Resource Planning (IRP) by including a provision in the National Energy Policy Act of 1992 that mandates that all state regulatory commissions hold hearings on integrated resource planning for electric utilities.

This report, with the technical appendices, complies with regulatory commission requirements for integrated resource planning in Idaho, Montana, Oregon, Utah, and Washington. Guidelines established in those states require the company to:

- Examine a range of forecasts for electricity demand;
- Consider all feasible alternatives for balancing resource supply with electricity demand;
- Assess supply and demand alternatives in a consistent manner;
- Assess possible external cost effects as part of its evaluation of resource alternatives;
- Describe a credible long-range plan for balancing supply and demand and related uncertainties, and a short-range set of actions consistent with that long-range plan; and
- Prepare its plan with substantial public involvement.

Overall, the regulatory commissions support integrated resource planning as a way to help utilities: 1) conduct their planning openly with public involvement, and 2) let the Commissions know what process and principles the utility follows before it proposes specific actions. A separate chapter in this report details PacifiCorp's public involvement process. A separate appendix documents communication between the company and its public advisory group.

The RAMPP process at PacifiCorp involves several departments. They include Integrated Resource Planning, Power Planning, Demand-Side Policy and Strategy, Power Supply, Load Forecasting, Financial Planning, Pricing & Regulatory Affairs, Economic Regulation, Government Affairs, Distribution and Transmission Engineering, Fuels, and Wholesale Sales. These departments confer with others in the company when they need additional information. At meetings of the internal task force, the members discuss work progress, issues, and agenda items for the meetings of the RAMPP-3 Advisory Group (RAG). RAG includes representatives from public agencies and private groups.

RAMPP-3 ACTION PLAN SUMMARY

RAMPP-3 includes a new action plan for PacifiCorp for 1994 and 1995. The Action Plan chapter includes specific actions for 1994 and 1995, with more general actions for 1996 and 1997. These actions position the Company to provide electric service to customers at competitive prices in the face of a range of future load, resource, and market uncertainties.

The RAMPP Report documents the assumptions, analyses, and conclusions that lead to development of an action plan for the next two years. The action plan, described fully in the Action Plan chapter, contains the following items:

Demand-Side Resources:

1) Achieve 40 MWa of cumulative installed cost-effective demand-side savings by the end of 1995. During 1996 and 1997 acquire an additional cumulative 65 MWa of cost-effective demand-side savings.

Renewable Resources:

2) Continue with actions necessary to bring 200 MWa of renewable resources on line by 2001, if cost effective.

Baseload Resources:

3) Meet intermediate-term baseload requirements with installation of 500-900 MW of cogeneration and/or combined cycle combustion turbines (CCCTs) by 2001, consistent with cost-effectiveness criteria.
4) Evaluate clean coal technologies, such as gasification, and evaluate the feasibility of potential sites for new coal resources.

Peaking:

5) Meet 150-200 MW of peaking needs by 2001 in addition to 150 MW of simple cycle combustion turbines (SCCTs) in Arizona. Operational and resource uncertainties may require more peaking resources sooner.

Related Items:

6) Pursue peak management opportunities.
7) Implement pricing changes to promote economic and energy efficiency.
8) Continue to implement system efficiency improvements to the company's generation, transmission, and distribution systems.
9) Continue to test and demonstrate small-scale carbon offset projects.
10) Improve the RAMPP-4 process.

ORGANIZATION OF THE REPORT

This document is organized according to the sequence of activities used in preparing RAMPP-3. It first discusses policy matters, then identifies possible futures and a portfolio of possible resources. It then describes the analysis plan; the various resource plans selected for alternative futures, strategies, and sensitivities; conclusions from the analyses; and an action plan.

Chapter 2: Background discusses the company's strategic goals and planning principles, and milestones and changes since RAMPP-2.

Chapter 3: Futures discusses the load forecasts and alternative gas prices used to create different futures.

Chapter 4: Portfolio identifies the resource technology alternatives available to the Company. Included are three categories of resources: existing system, demand-side resources, and supply-side resources.

Chapter 5: Analysis Plan describes the approach the company used in analyzing the portfolio and resource strategies to arrive at an action plan.

Chapter 6: Illustrative Plans demonstrate how the Company would manage an efficient balance of resources to meet customers' future electric service needs under alternative strategies for different futures and under specified sensitivities.

Chapter 7: Environmental Analysis discusses the analysis work performed for environmental externalities. The chapter includes results using externality adders, and results of the multi-attribute trade-off analysis approach to considering emissions in resource planning.

Chapter 8: Renewable Analysis discusses PacifiCorp's activities to gain experience with renewable resources, barriers to renewable resources, and the results of the analysis on alternative renewable strategies and sensitivities.

Chapter 9: Questions and Answers provides a forum for a brief discussion of technical issues not developed elsewhere in the report.

Chapter 10: Public Process describes the role of the public advisory group and the meetings held between that group and company representatives.

Chapter 11: Conclusion summarizes the report and discusses the major lessons learned from the analysis.

Chapter 12: Action Plan identifies the specific actions the company plans to take in 1994 and 1995, and less specific goals for 1996 and 1997, to minimize future risks and prepare for likely levels of load growth.

Chapter 13: DSR Action Plan Detail provides the specifics, by customer sector, for the company's performance on the RAMPP-2 DSR action plan, and again by sector, the goals for the RAMPP-3 action plan. It also includes a section on the company's DSR financial standards and decision making.

Glossary defines the terms, abbreviations, and titles used in this report.

Index provides page references for various issues or topics in the report.

Technical Appendices include four documents with more detailed information on load forecasts, demand-side resources, modeling, and public process.

BACKGROUND

This chapter addresses three areas: first, the general context for RAMPP-3, including the Company's goals and planning principles; second, milestones since RAMPP-2 that have affected RAMPP-3; and third, improvements and changes to the process for RAMPP-3 since the previous IRP cycle.

ABOUT PACIFICORP

Through its Pacific Power and Utah Power divisions, PacifiCorp provides electricity and related energy services to 1.3 million customers in seven Western states: California, Idaho, Montana, Oregon, Utah, Washington, and Wyoming. Graph 2-1 shows the company's retail sales by customer class, and for residential and commercial, by end use. Almost half of retail sales are to industrial customers, about one fourth are to commercial, and about one fourth to residential. Commercial customers use electricity primarily for lighting and HVAC (heating, ventilation, and air conditioning). Residential customers use electricity for several purposes. The industrial sector contains a large number of end uses which do not lend themselves to a few categories.

According to the company's strategic plan:

> PacifiCorp's mission is to help our customers prosper in our economic system by satisfying their electric energy wants and needs with electricity, energy efficiency and other related value-added products and services. PacifiCorp can only do this by maintaining competitive prices and quality service for its customers, creating a favorable work environment for its employees, being a responsible steward of the natural environment, and in the end growing value for its shareholders.

The Company updates its strategic goals yearly, considering the company's growth opportunities; local, regional and national economic conditions; public policy trends; industry trends; and environmental issues. PacifiCorp's strategic goals cover four areas: Growth, Customer Service, Productivity and Cost Management, and the Environment. Pursuing all of the goals at once is a balancing act since actions in one arena may require a trade-off in another.

Goal 1: Growth How measure?

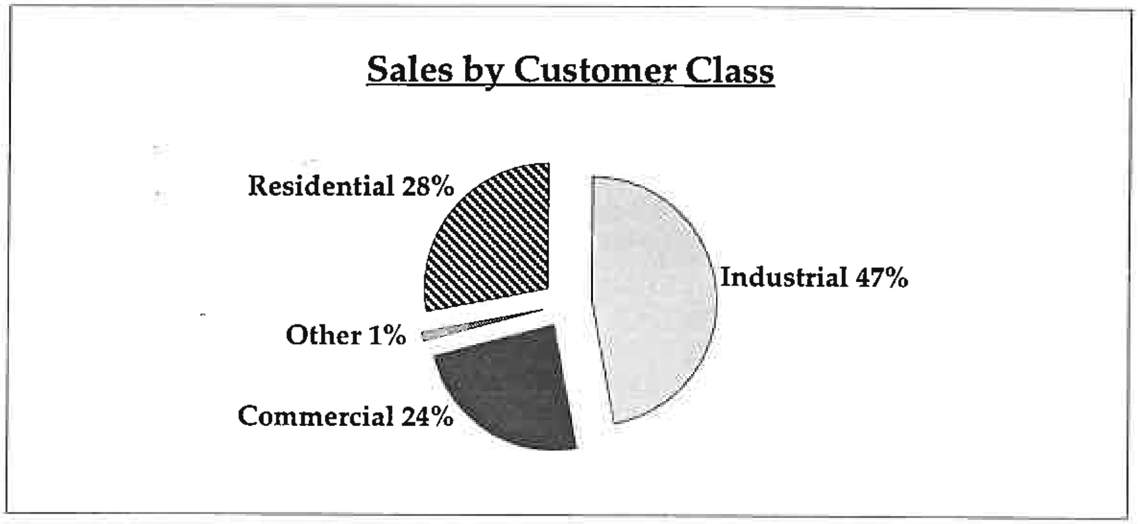
The growth goal focuses on the company's financial performance rather than on growth in kWh sales. The company believes that carefully planned and well-managed growth results in more efficient service and lower prices for customers and an opportunity for shareholders to earn a reasonable return on their investment. The 1993 growth goal is in term of return on assets, earnings available for common stock, and earning a superior return for shareholders.

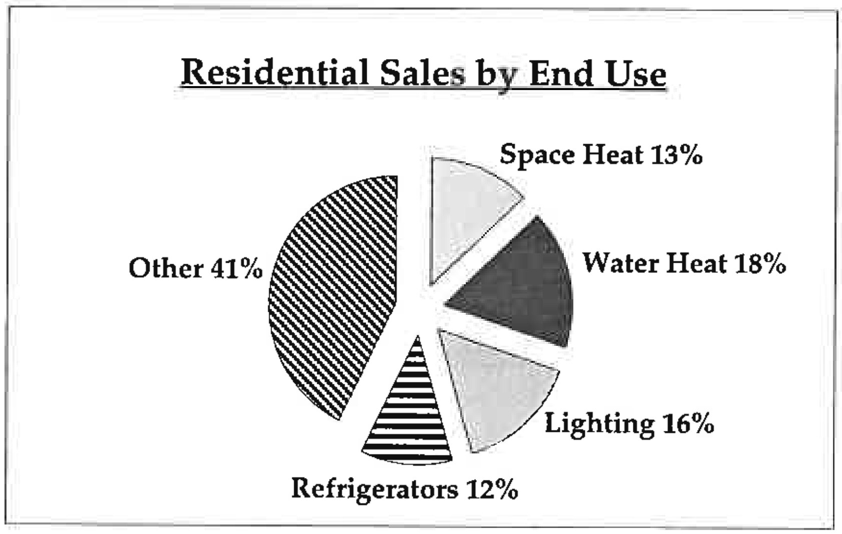
none of these include DSR

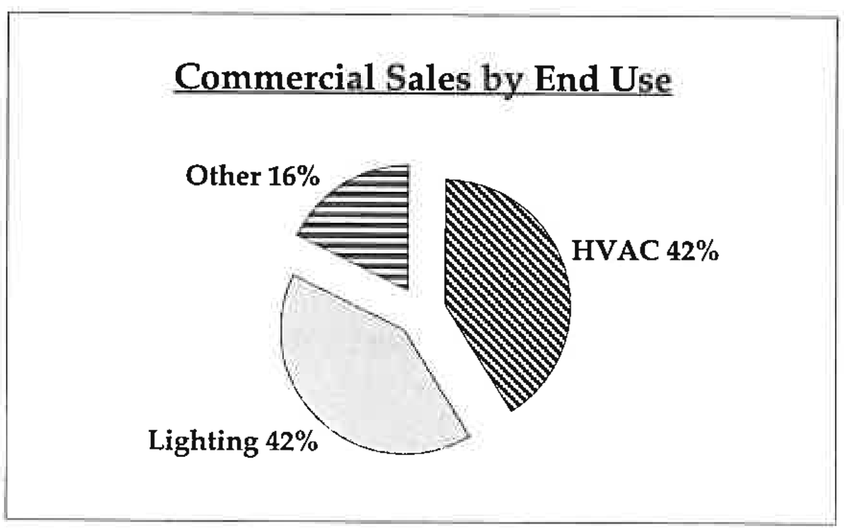
assets = rate base?

Sales Overview by Class and End Use (1993)

Graph 2-1







G2-01.sales overview

As an investor-owned corporation, the company must meet the expectations of its investors in order to secure financing in the competitive capital markets at reasonable costs.

The company's strategy does not rely on only one means of growth. A number of activities contribute to meeting the growth goal: expanded offerings of energy services, economic growth in the communities served by the company, and low-cost acquisitions of resources or assets. The company developed financial standards for new resource activities to be consistent with the growth goal. Those standards are intended to assure that new resource acquisitions do not impede earnings. For example, the standards include an internal rate of return measure (the DSR Action Plan Detail chapter includes a discussion of these standards and DSR decision making).

Goal 2: Customer Service

The customer service goal first aims at holding prices to a level that is highly competitive with other customer energy choices and, on average, keeping the controllable part of prices from rising as fast as inflation. The goal also calls for offering customers energy efficiency assistance, product and service options, a high level of reliability, and overall customer satisfaction. External non-controllable factors concern the company, such as the Bonneville Power Administration's (BPA) price increases and the reduction of the BPA residential exchange credit. A customer service orientation pervades all of the company's energy services activities. In some cases, "meeting customer needs" might mean improving an industrial customer's productivity through energy-efficient technologies; in other cases, it might mean improving a residential customer's energy efficiency.

hydro endow trans. endow

Goal 3: Productivity and Cost Management

PacifiCorp's overall strategy is to maintain its position as a low-cost producer of electricity. The company's low prices and extensive transmission network allow it to successfully compete in Western energy markets. PacifiCorp faces increasing competition from other energy suppliers including natural gas and oil companies, other electric utilities, cogenerators, suppliers of energy efficiency services, independent power producers, and brokers. The company's best means of competing effectively in both the retail and wholesale markets is through low operating costs and well-designed products and services that meet customer needs.

Goal 4: The Environment

PacifiCorp first introduced an environmental goal in its 1992 strategic plan. The goal, with initiatives for conservation, development of renewables, and testing CO_2 offsets, encourages the company to diversify its resources and make cost-effective environmental choices that benefit customers, shareholders and society at large. The National Energy Policy Act of 1992 and the continuing rulemaking on the Clean Air Act Amendments of 1990 reflect public concern over environmental issues. One part of the goal states that PacifiCorp will:

> "... begin staged development of renewable resources with a target of 50 megawatts by 1996, expanding to 200 average megawatts by 2001 if proven to be cost-effective with other company resource options."

This part of the goal will help position the company to acquire more renewables after 2001, if the early projects prove to be cost-effective resources. The challenge for PacifiCorp is to balance environmental activities with the need to continue providing low cost, high quality service to customers. To achieve this balance, the company must learn more about renewable resource development and its impact on the company's and region's power supply system.

PacifiCorp follows five key principles in managing power supply and demand and evaluating new resource alternatives. By using all five principles in developing and evaluating resource plans, the company can achieve balanced planning. The principles are:

Minimize cost and retail price impact. This is consistent with the Company's strategic goal of keeping prices to customers as low as possible.

Consider the tradeoff between cost and emissions. Minimizing resource costs as well as emissions is the principle behind the analysis in RAMPP-3. Finding the right balance between the two is a policy decision, so the company must first prepare objective information about the feasible choices.

Provide reliable service. This is essential for achieving a high quality of customer service. Customers rely on a dependable electricity supply for industrial processes, lighting, heating, and other uses.

Assure efficiency. Efficient resources are critical for keeping electricity prices down. Efficiency includes efficient operation of the Company's existing system, an efficient fit with other resource providers, and greater efficiency in the way customers use electricity.

Maintain flexibility. The company maintains a variety of resource options to be able to respond to changing circumstances. The options include those that are available in small amounts, have short lead times, and low capital costs. PacifiCorp uses the RAMPP process to guide resource and market decisions as conditions change and opportunities arise. The RAMPP-3 analysis tests the compatibility of alternative strategies under different future conditions.

In moving from the planning process to the action plan, the company needs to focus its decision making. From the strategic goals and the five key principles listed above, the company identified four considerations to use in determining what actions to take in the next two to four years. The goals in the RAMPP-3 action plan are intended to balance four considerations that partially conflict with one another:

- Reduce long-term total resource cost,
- Achieve equity among customers,
- Meet increasing competition in the electricity industry, and
- Reduce environmental emissions.

Some of these considerations can be analyzed quantitatively, others cannot. Some of these considerations conflict and some can be complementary. For example, reducing long-term total resource cost may conflict with meeting competition. Achieving equity among customers may be consistent with reducing environmental emissions. Reducing long-term total resource cost generally is consistent with reducing environmental emissions. The company based its action plan goals on its management's judgment regarding the impact of DSR and other resource acquisition levels on these factors.

DEVELOPMENTS SINCE RAMPP-2

Significant achievements and events in three areas affected the development of RAMPP-3. First, the company successfully implemented the RAMPP-2 action plan. The Action Plan chapter provides details of those accomplishments. Second, the company made some resource decisions since publication of RAMPP-2. Third, events outside the company's control have affected resource planning.

RAMPP-2 Action Plan Implementation

PacifiCorp has pursued demand-side, renewable, peaking, and cogeneration resources; system efficiencies; and RAMPP improvements as identified in the RAMPP-2 action plan. The company is on schedule in implementing the demand-side programs specified in the RAMPP-2 action plan for 1992 and 1993. Two wind projects are in the siting process, one in Washington and one in Wyoming. The company met some of its increased capacity needs through a capacity agreement with another utility. One cogeneration project, James River, is under construction. PacifiCorp will own only the steam turbine and generator for this project. Fuel supply is James River's responsibility; it will be a combination of gas and hog fuel. A second larger cogeneration project, Hermiston, is in the planning and permitting stage. The developer, U. S. Generating, is in the process of securing a long-term gas supply. The Action Plan chapter includes additional resource-related actions during 1992-1993, and details on all parts of the RAMPP-2 action plan performance.

Decisions Since RAMPP-2

Hermiston Cogeneration Project C1

PacifiCorp has signed a contract to acquire electricity from a 474 MW natural gas cogeneration plant in Hermiston, Oregon. U. S. Generating Company will finance, build and operate the project. Lamb-Weston's potato-processing plant will use the steam produced as a by-product of the generating process. PacifiCorp will have an option to own up to 50 percent of the generating plant once it begins operation. U. S. Generating must arrange for long-term gas supplies by mid-1994 to fulfill the terms of the contract. Construction should begin in 1994, with commercial operation by mid-1996. Although this project is not with a PacifiCorp industrial customer, the price is below the cost of cogeneration opportunities currently available with customers. The project is very competitive with coal, the least expensive supply-side technology available, and it provides power needed in the western part of the PacifiCorp system. A RAMPP-3 sensitivity tested its benefits to the system.

Southern California Edison Firm Capacity Purchase

PacifiCorp has entered into an agreement with Southern California Edison (SCE) to purchase low-cost capacity. Beginning October 1993, SCE began providing power to PacifiCorp from October through March for 10 years. Initially, PacifiCorp will purchase 222 MW with a capacity factor of zero to 100 percent, which means PacifiCorp can take as much as it needs each hour of the day. Optional increases of 100 MW will be available in January of both 1994 and 1995 to bring the total purchase to 422 MW. PacifiCorp has the option to extend the agreement in five year increments or to terminate the agreement early if SCE's fuel costs increase by 10 percent or more due to the California energy production tax. Because the agreement allows PacifiCorp to take power as needed, the company can use the power to back up existing resources, meet peaking requirements, or as a supplement to baseload generation if necessary.

The RAMPP-2 action plan step to add gas turbine power plants (SCCTs) started a search for the most cost-effective way to meet peaking needs. The SCE agreement delayed the company's schedule for construction of gas turbines and provides flexibility to meet winter loads. The SCE purchase has lower costs than the construction of gas turbines and presents fewer risks to both PacifiCorp and its customers.

Deseret Generation & Transmission Firm Purchase

PacifiCorp and Deseret G&T entered into a power purchase agreement in October of 1992. Delivery to PacifiCorp began in January 1993. The purchase provides PacifiCorp with 100 MW per month during the first three years of the five-year term, and 50 MW per month for the remaining two years of the contract. The Deseret purchase price was competitive compared to resource alternatives.

Colockum Exchange

PacifiCorp's original capacity and energy exchange agreement with the Colockum Transmission Company expired June 1993. In December 1992, both parties agreed to extend the agreement until June 2003. Under the agreement PacifiCorp provides equivalent firm energy to Colockum in exchange for 103 MW of capacity. The new agreement helps meet the Company's need for capacity, and the new agreement's price was competitive.

Western Area Power Administration Firm Sale II

The Western Area Power Administration (WAPA) II agreement is the second firm sale agreement between PacifiCorp and WAPA. Under this new agreement, PacifiCorp began delivering 75 MW to WAPA for a term of 20 years beginning in January, 1993. In addition to the revenues, the transaction provides PacifiCorp with additional low-cost access to intertie transmission facilities. The additional transmission scheduling rights include south-to-north access on the Intertie that helps to relieve the Company's transmission constraints in the Desert Southwest region. Through this sales agreement, PacifiCorp gains both a revenue source and valuable transmission access.

Eugene Water & Electric Board Firm Sale

PacifiCorp's sale to EWEB began in June, 1993. It is a 36 MW summer sale that extends for five years. The EWEB summer sale enables PacifiCorp to run its baseload thermal resources at a more consistent level year-round, and provides a source of revenue.

Through these various agreements, PacifiCorp added 322 MW to its system during 1992 and 1993.

Proposed Sale of Northern Idaho Service Territory

The company recently announced its intent to transfer ownership of all PacifiCorp electric properties in northern Idaho to Washington Water Power Company (WWP). The transfer affects about 9,300 customers. Several Bonner County communities are in the service area including Sandpoint, Priest River, Hope, East Hope, Clark Fork and Old Town. PacifiCorp has no generating plants or transmission lines in the area; it has relied on the Bonneville Power Administration and WWP to deliver power to the area because it is isolated from the rest of the PacifiCorp system. The company was facing the potential for substantial future rate increases to serve the area, whereas WWP can serve the customers at lower prices. The agreement is subject to regulatory review, including approval by the Idaho Public Utilities Commission and the Federal Energy Regulatory Commission. The two companies hope to close the agreement during the summer of 1994. Independent of the property sale, the company is also entering into two long-term power supply agreements with WWP: a 10 to 15 year 150 MW summer capacity purchase and a seasonal exchange (also three months, for 50 MW).

Major Events Affecting the Company's Business Environment

DSR Cost Recovery

The company has been working with its regulators to address disincentives that can occur with the acquisition of demand-side resources (DSRs) compared to supply-side resources (SSRs). The company's concern was its inability to earn the same authorized rate of return on DSRs as on SSRs. The adoption by Commissions of accounting treatment for DSR investments similar to that given SSR investments (capitalization and amortization over the life of the asset) removed a portion of the disincentives. However, even with these accounting changes, disincentives remained due to lost revenues created by DSR acquisition, lack of an accrual for AFUDC (allowance for funds used during construction) on DSR investment, and the fact that DSR is typically acquired in small increments. As a result of the last point, any given DSR acquisition is not only less likely to trigger a rate change request than an SSR, but may also require several rate change requests to accomplish the same result (cost recovery of the recent investments) as a single SSR rate change request would accomplish.

Last year the Oregon Public Utilities Commission (OPUC) and the Utah Public Service Commission (UPSC) adopted cost recovery mechanisms which will help equalize the earnings impacts of DSRs and SSRs. On December 21, 1993, the OPUC adopted a set of mechanisms for the period July 1, 1993, through December 31, 1995, allowing for 1) recovery of lost revenues, 2) delay of amortization of DSR program costs, and 3) accrual of carrying charges on DSR investments. The OPUC also adopted an incentive and penalty mechanism, which may allow the company to earn above its allowed rate of return for extraordinary DSR acquisition performance. On February 10, 1994, the UPSC adopted a mechanism for 1994 allowing for 1) accrual of lost revenues, and 2) accrual of carrying charges on DSR investments. The Utah mechanism will be a one-year experiment. The company is participating in a Utah collaborative to examine, among other issues, DSR cost recovery after 1994. The company regards these accounting and cost recovery changes to be a significant move toward equalizing the regulatory treatment of DSRs and SSRs.

The Energy Policy Act of 1992

The Energy Policy Act of 1992 has accelerated the trend toward an increasingly competitive energy marketplace. Major features of the act are the establishment of exempt wholesale generators (EWGs) and greater transmission access. The development of EWGs will expand the electric resource choices available to both utilities and major utility customers. Under the act, any utility or EWG can request a utility to provide transmission service under certain conditions, and the utility must provide it. New energy producers and opening of transmission access increase competition in the marketplace; these trends increase PacifiCorp's need to control costs and keep prices low.

Certain parts of the Act have been or are now being addressed in each of the seven states served by PacifiCorp. The act requires each state's regulatory commission to review the federal standards and issues related to least cost planning (LCP) and the development and control of independent power producers (IPPs) and EWGs. The states must make decisions on sections of the Energy Policy Act related to IPPs and EWGs by October, 1993 and LCP issues by October, 1995.

Administrative Rules for the Clean Air Act Amendments

Title IV of the 1990 Clean Air Act Amendments awards utilities SO2 allowances based on the emission ratings of their thermal plants. Each SO2 allowance gives the utility the right to emit one ton of sulfur dioxide. Phase I of the act requires the higher emitting plants to achieve the SO2 standards required in the Act by 1995 and Phase II requires all plants, including the lower emitting plants not included in Phase I, to comply by the year 2000. The Phase II standards are more stringent than those of Phase I.

Plants that have reduced their thermal plant emissions since 1985 will receive more allowances than needed to operate under the Phase II requirements, resulting in surplus allowances, which the owning utility can bank, sell, or trade. Plants that fall short of the Phase I emissions requirements can buy allowances from another utility. PacifiCorp's plants have a net surplus of allowances; PacifiCorp has sold some of them to Illinois Power (IP), pending final Environmental Protection Agency approval of IP's substitution plan.

Although markets exist for trading allowances, reconsideration of the CAAA administrative rules has temporarily stalled negotiations between utilities for allowance sales. The Environmental Protection Agency and other groups are concerned with a suit filed by the State of New York. The suit contends that the sale of allowances to Midwestern utilities allows those utilities to continue to emit pollutants that may cause acid rain in New York and other New England states. PacifiCorp's future allowance trading transactions will depend on the outcome of this lawsuit and related discussions.

Retail Competition

Competitive forces are relevant for both wholesale electricity markets and at the retail level. Passage of the Energy Policy Act increases the forces of competition in the industry. For PacifiCorp, with almost one half of its retail sales to industrial customers, competition is an immediate reality. Increasingly, retail customers pursue low-cost options for electric energy services. Alternatives such as self-generating, switching fuels, moving to other providers like public power, relocating or expanding to other sites, cogenerating, bypassing or finding technological alternatives are growing. This is particularly true of industrial and commercial customers who will look for the most competitive alternatives as they face global business competition. If the customer's local electric utility does not provide them the service that they want at the right price, they will find it from someone else.

The industry is focusing increasing attention on a form of retail competition known as retail wheeling. Retail wheeling would allow retail customers to require their local utility to transport power for the customer from another utility or non-utility generation source. Under the Energy Policy Act of 1992, the Federal Energy Regulatory Commission (FERC) cannot order retail wheeling. Therefore, debate on this issue has moved to state legislatures and public service commissions. The State of Nevada recently passed legislation allowing retail wheeling to serve a new business in the state to promote economic development. The New Mexico legislature has directed the state public service commission to produce a recommendation on retail wheeling issues within two years. The Michigan commission is considering a proposal for a retail wheeling experiment.

Retail wheeling changes the fundamental basis of existing retail electric service. Under the existing system, the utility has an obligation to serve, in return for an exclusive franchise to serve all retail customers in a defined area. If such a change occurs, those utilities that have best controlled their costs and prices will be in the most stable financial position. They will also be best positioned to provide low-cost service to the smaller core customers who have fewer electricity choices.

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Growth in Electricity Sales

PacifiCorp's retail load growth in 1992 energy sales was 1.1 percent actual, 2.6 percent temperature adjusted. For 1993, actual load growth in energy sales was 2.1 percent, 1.0 percent temperature adjusted. The RAMPP-2 forecast for 1993 was 1.7 percent load growth in the medium low case, and 3.1 percent in the medium high case.

think — is new agreement for 1400 MW? when will be signed?

BPA Peak Purchase Agreement

PacifiCorp's original agreement with the Bonneville Power Administration (BPA) for buying peak power expired in August, 1991. The parties signed an interim agreement to continue the purchase until a long-term agreement could be reached. The RAMPP-2 analyses assumed the re-negotiated capacity would increase from PacifiCorp's 1992 purchase level of 1100 MW to 1400 MW by 1995. However, the new 20-year agreement uses the 1992 level of 1100 MW. Therefore, RAMPP-3 also used the 1100 MW level. BPA must complete an environmental impact statement (EIS). Before the contract can be signed, the EIS must receive internal BPA approval, then it is reviewed through a National Environmental Policy Act process that includes public comment periods. Final approval is through the Department of Energy.

BPA Rate Increase

Effective October 1, 1993, the Bonneville Power Administration (BPA) increased the rates it charges to other utilities, including PacifiCorp. BPA also has the option of an additional interim increase in 1994, if operating conditions warrant it. These increases affect PacifiCorp operations directly as well as through their impact on the entire Pacific Northwest. Each utility faces different price effects, depending on the mix of BPA services used by the utility.

One of the company's main concerns is the effect of the BPA rate increase on the BPA residential exchange program. This program benefits residential and small farm customers with a pass-through reduction in their prices in the states of Washington, Oregon, Idaho, and Montana. Any BPA rate increase reduces the amount of the exchange. In some states, the BPA rate increase reduces the residential exchange benefits dramatically, which results in higher prices to PacifiCorp's residential and small farm customers in those states. For example, the impact of the October, 1993, increase on Oregon residential customers' bills is 6.2 percent, and the impact on small farm customers' bills is 6.9 percent. These impacts are typical for residential and small farm customers in PacifiCorp's other states that are also in the BPA exchange program.

In addition to the residential exchange, the October, 1993, rate increase affected all wheeling transactions on the north-south intertie and all other transactions using BPA's rate schedules. The intertie transmission rate increased by 48.1 percent, the energy transmission rate increased by 11.6 percent, and the firm capacity rate increased by 15.9 percent. For PacifiCorp, the greatest impacts will be in the peak power purchase and intertie wheeling transactions. Overall, BPA's total charges to PacifiCorp will increase by about 16 percent.

Share-The-Shortage Agreement

During the past three years, two concurrent processes have focused on how to manage a possible protracted energy shortage in the Pacific Northwest. One process resulted in a share-the-shortage agreement (Agreement); the other process involves government-initiated energy curtailment plans. While utilities plan for adequate resources to serve their loads, the potential for a protracted energy shortage still exists. Such a shortage could occur with a prolonged drought or severe operational constraints that greatly reduced hydroelectric capability, or an extended loss of major thermal resources or transmission facilities. The Agreement endeavors to alleviate the need for government-initiated curtailment when the normal open market fails to satisfy an energy shortage, and provides for an allocation and pricing scheme that allows the parties to receive reasonable compensation for lost revenues and increased costs during government-initiated curtailment. The Agreement identifies phases during a protracted energy shortage, during which utilities will offer voluntary sales of energy to the deficient utility, and then agree to pro-rata shares of any remaining deficit at an agreed-upon price. The Agreement helps resolve one of the planning uncertainties within the Northwest region.

Trojan Nuclear Power Plant

Portland General Electric (PGE) closed the 1100 MW Trojan Nuclear Plant in January 1993. PacifiCorp owned 2.5 percent of the plant, or 27 MW. PacifiCorp is replacing that generation through various purchases of firm power. PacifiCorp does not expect to sell any power to PGE to replace that company's lost generation.

Nevada Power sale change

RAMPP-2 included a firm 50 MW summer sale to Nevada Power (referred to as Nevada II). This sale was to begin in June 1992 and end in September 1996. However, the Nevada Commission did not approve the sale. Therefore, RAMPP-3 did not include the Nevada II sale in its load and resource assumptions.

RAMPP-3 IMPROVEMENTS SINCE RAMPP-2

RAMPP-3 includes improvements since RAMPP-2 in: 1) the model used for resource selection and analysis, 2) the analysis approach, 3) the delineation of geographic areas and transmission constraints, and 4) the inclusion of transmission costs. The model used for RAMPP-3 has capabilities that the RAMPP-2 model did not. These include an optimization algorithm to produce true "least-cost" resource plans, the integration of production costs with the selection of new resources over the entire 20-year planning horizon, and the recognition of geographic areas and transmission constraints.

RAMPP-2 used three separate models: first a capacity expansion model to select new resources under alternative futures, then a production cost model to calculate year-by-year costs of the system with the expanded capacity, and finally a financial model. The capacity expansion model used a simulation approach to select new resources, which could result in a resource plan that was not the true "least-cost" solution for a particular model run. The RAMPP-3 model used an optimization approach, which resulted in true "least-cost" solutions. It also integrated the production cost calculation with the capacity expansion process, so that the model selected resources based on their contribution to system costs throughout the planning horizon. The Analysis Plan chapter contains a fuller discussion of modeling issues. The Modeling Appendix contains sections describing the RAMPP-3 model, implementation and testing steps for it, and input files.

The model used for RAMPP-2 assumed that the PacifiCorp transmission system can move power from any generator to any load area at any time. Unfortunately, this was not an accurate reflection of PacifiCorp's system, but the modeling tools then available provided no alternative. The model for RAMPP-3 recognized multiple geographic areas and the transmission constraints among them. It also allowed PacifiCorp to identify resource needs and additions by geographic area.

The analysis approach in RAMPP-3 was more extensive and at the same time more focused on external costs compared to the approach used in RAMPP-2. RAMPP-2 considered external costs by including several sensitivity cases that assumed different levels of external costs. Many commissions and utilities use this method, known as the adders approach. RAMPP-3 used the adders approach as well as an additional one, so the reader can compare the two. The new approach is a multi-attribute trade-off analysis. It requires that alternative strategies be tested under alternative futures, and plotted, to determine which strategies best achieve the multiple goals of reducing system costs, prices, and emissions. The Analysis Plan chapter discusses this approach more fully.

RAMPP-2 did not include transmission costs. However, RAMPP-3 included transmission costs in two key ways. First, total costs for each new resource in the portfolio included the cost of integrating that resource into the local transmission grid. This better recognized the full cost of adding new resources. Second, PacifiCorp needs to upgrade and expand its transmission grid. Sensitivities in

RAMPP-3 analyzed how an expanded transmission grid would affect new resource additions.

After the model selected the resource plans, a separate analysis determined the financial impact of the plans on the cost of electricity, compared to the electricity price assumptions in the initial forecast. This "closes the loop" in the planning process by determining whether the new resource additions and resulting prices create a significant change in a key assumption: the load forecast. The company averaged the annual electricity prices from the medium load forecast runs in the base study plan and fed them back into the medium load forecast. The price changes were applied to each state and for each customer class in that state. The result was an increase in loads in the 20th year of the forecast period of 60 MWa compared to the initial forecast. This 60 MWa is 0.75 percent of the total load at the end of the 20 years. The difference in the medium-high loads compared to the medium loads in the 20th year of the forecast period was 1,626 MWa. Therefore, the company concluded that the intial price assumptions in the load forecasting process were sufficiently accurate; running the forecasts again in an iterative process with the new prices would have had an insignificant effect on the load forecast.

" flexibility analysis

FUTURES

Integrated resource planning helps a utility address the major uncertainties involved in preparing for customers' future electricity and energy service needs. The two main uncertainties for PacifiCorp in planning future electricity and energy service are load growth and gas prices. RAMPP-3 addressed these two uncertainties through the creation and analysis of many possible futures. In RAMPP-3, five load growth forecasts and three gas price forecasts created 15 alternative futures. RAMPP-3 used a cross-section of these futures to test alternative resource strategies.

The load forecasts represent the company's retail franchise business. In the past, that business was stable, with uncertainty primarily coming from regional and national economic trends. Increasing wholesale and retail competition, as described in the Background chapter, increases uncertainty for PacifiCorp's resource planning. For the five years ending in 1993, general business sales grew 2.1 percent annually on a temperature-adjusted basis. The comparable number for the last two years is 1.9 percent. Because the RAMPP forecasts are long-term forecasts, and these are short-term results, minor changes in the short-term results have little bearing on long-term growth rates.

RAMPP-3 addressed other uncertainties facing PacifiCorp, such as how the existing system will perform, cost of new resources, coal prices, variable hydro conditions, and external costs, through the use of sensitivities. The Analysis Plan chapter discusses the sensitivities.

LOAD FORECASTS

In resource planning, the first question to be addressed is, "How much power will customers need in the future?" This section describes the methodology used to develop five load forecasts of customers' future electricity needs. The load forecasts set boundaries for reasonable levels of future electricity consumption. They consider a number of economic and demographic possibilities that affect the level of load growth.

The RAMPP-3 process began with forecasts for every year from 1994 to 2013 based on 1992 temperature-adjusted actual data. RAMPP-3 used forecasts for each of nine zones served by the Company: Oregon, California, Utah, Washington and Montana as well two zones each in Idaho and Wyoming. Idaho and Wyoming each have one geographic area served by Utah Power and another area served by Pacific Power. Just before publication of RAMPP-3, the company agreed to sell its northern Idaho service territory, served by Pacific Power, to Washington Water Power. At that point, however, the company decided to not change the total forecast and re-do the analyses. The northern Idaho load is only 0.6 percent of the company's total system load.

The forecasting process uses information "inputs" and produces forecast "outputs." The forecasting model uses a range of values for certain variables to produce a range of forecasts. The range of forecasts for RAMPP-3 is large enough to accommodate reasonable variation in load levels that might occur.

Economic and demographic assumptions (such as employment, population and income for each zone) are major factors influencing electricity sales forecasts. The model combines demographic and economic forecasts for each zone with assumptions on the electricity needed to run electrical equipment (end-use information) in that zone, based on historical information and other data. The result of the process was a range of electricity sales forecasts for each zone.

The model created five forecasts for each zone: high, medium-high, medium, medium-low, and low. This report will sometimes use the following abbreviations:

Load Growth Level	Abbreviation	Growth Rate
High	H	3.8%
Medium-High	MH	3.0%
Medium	M	2.1%
Medium-Low	ML	1.3%
Low	L	0.3%

The high forecast for a given zone used high economic, demographic and other input factors. Similarly, the MH forecast used medium-high economic and demographic assumptions, and so on. The system wide forecast for each level (H, MH, M, ML and L) is the sum of the nine zone forecasts. For example, the high forecast for electricity sales system-wide is the sum of the high forecasts for all nine zones.

A very large number of combinations of economic and demographic conditions make any outcome between the MH and ML energy forecasts very likely. Load growth between the MH and high range, or between the ML and low range are less likely. Only a dramatic change in economic, demographic, or consumer choices and behaviors would produce load growth above the high or below the low forecast. The medium forecast is a forecast where the chances of under- or over-shooting it are roughly equal.

Electricity price is an important part of the forecasting model. The high forecast case assumed electricity prices will increase slightly more than the rate of inflation; the low forecast case assumed electricity prices will increase slightly less than the rate of inflation. The MH and ML forecasts assumed price increases at about the same as the level of inflation. After completing the RAMPP-3 analysis process, the company tested the accuracy of its initial price assumptions used in the load forecasts. By running the medium load forecast again, with the price results from RAMPP-3, the company determined that the intial price assumptions were within 0.75 percent of the initial load forecast. Therefore, running the forecasts again in an iterative process with the new prices would have had an insignificant effect on the load forecast.

The model did not reduce the high forecast nor increase the low forecast because of price elasticity (customer responses to price levels). That would have reduced the range of futures for planning. The Company believes that it is important to test the portfolio over a wide range of load growth levels. Although including price elasticity would make the forecast "more accurate," it would also decrease the range of forecasts.

The Company considered system losses (i.e., the efficiency in getting electricity from the generation source to the customer) before calculating the amount of energy required to meet peak levels of electricity need. The analysts divided annual energy into monthly amounts and then weekly, daily, and finally hourly loads using historical patterns of energy use. Adding up the zonal forecasts provided the hourly load forecast for the entire company. The maximum load for each month is the peak load for the company, and the zonal load at that time is the zonal coincident peak.

This methodology resulted in five forecasts for 1994-2013 with growth rates for energy of 0.3 percent in the low case, 1.3 percent in the ML case, 2.1 percent in the medium case, 3.0 percent in the MH case, and 3.8 percent in the high case. The winter and summer peak forecasts resulted in very similar growth rates for the five forecasts. The forecast was slightly higher in the early years than in the later years.

Table 3-1 shows the growth rates for energy over the forecast period, the average annual MWa added at the end of the planning period in 2013, and the average annual peak MW added for winter and summer. Annual energy requirements in 2013 ranged from 5,373 MWa in the low case to 11,381 MWa in the high case. The winter and summer coincidental peaks respectively ranged from 7,504 and 7,194 MW in the low case to 15,949 MW and 15,456 MW in the high case.

The Load Forecast Appendix includes, for each of the five forecasts, monthly coincidental peak and energy forecasts by state. The material below summarizes the methods used to develop these forecasts. The Load Forecast Appendix describes the methods in greater detail.

Input: The Variables

Economic and demographic assumptions are two key factors in determining forecasts of electricity usage. Absent other changes, usage of electricity usually increases as economic activity increases. However, several influences can change that parallel relationship, for example, changes in the price of electricity, the price and availability of competing fuels, changes in the nature of economic activity, the level of conservation and the replacement rate for buildings and energy-using appliances. The forecasts considered all of these variables.

Key Forecast Information

Total System

Table 3-1

Forecast	Energy				Winter Peaks				Summer Peaks			
	Avg. Annual Growth Rate %	Total MWa at 2013	Total MWa Added by 2013	Annual Average MWa Added	Avg. Annual Growth Rate %	Total MW at 2013	Total MW Added by 2013	Annual Average MW Added	Avg. Annual Growth Rate %	Total MW at 2013	Total MW Added by 2013	Annual Average MW Added
Low	0.33	5,373	328	16	0.33	7,504	449	22	0.35	7,194	460	23
Medium Low	1.26	6,621	1,397	70	1.26	9,277	1,969	98	1.29	8,894	1,922	96
Medium	2.13	7,998	2,644	132	2.14	11,206	3,709	185	2.21	10,823	3,676	184
Medium High	3.02	9,624	4,151	208	2.99	13,488	5,782	289	3.09	13,037	5,731	287
High	3.75	11,381	5,725	286	3.72	15,949	7,975	399	3.84	15,456	7,906	395

PacifiCorp used national economic and demographic assumptions from Data Resources Inc. (DRI), a national research company. DRI provides three possible forecasts for the national economy (optimistic, current trend and pessimistic). The model combined differing assumptions about regional economic growth with national assumptions to produce each of the five forecasts.

The third major factor in forecasting future electricity sales is anticipated consumer use: "What electrical appliances will customers want and how will they use them?" The Company predicted the level of use for each of its four customer segments: residential, commercial, industrial and "other."

Each customer segment uses electricity in specific ways; i.e., each has particular end uses for electricity. For example, residential customers use electricity primarily for space heating and water heating. Commercial customers mainly use electricity for lighting and heating/ventilation/air conditioning (HVAC). Industrial customers use it for processing.

To predict the overall level of future electricity use for any one customer segment, the Company looked at how the customers in that sector use electricity and how much electricity they use. Future usage depends on:

1) How many customers are currently equipped for each end use (the saturation level);

2) How many additional customers will be equipped for that end use in the future (the penetration level);

3) How much electricity that activity will consume;

4) How electricity consumption for that activity will change in the future.

Residential Load

In the residential sector, the Company predicted the anticipated consumer usage for 14 end uses of electricity: space heat, water heat, electric ranges, dishwashers, electric dryers, refrigerators, lighting, air conditioning, freezers, water beds, electric clothes washers, hot tubs, well pumps and residual uses. Air conditioning can be central, window or evaporative (swamp cooler).

For each end use, the Company looked first at saturation levels (the number of customers with that equipment) and how those saturation levels may change with demographic and economic changes. The model used company survey information to estimate the saturation level for each end use. Then the company determined the penetration level: given the economic and demographic future assumptions, how many new households are expected to adopt that end use in the future? In addition, how many houses which currently have that end use are demolished each year? The model estimated the demolition rate with historic information. The model also recognized that households replace some appliances several times before a home is demolished. The total number of customers for each end use were the sum of the new and existing customers using electricity for that end use.

The model also considered fuel switching. Surveys show that some electric space heating customers change fuels when they replace their space heater. Instead of replacing their electric furnace, they may instead install a gas furnace. After discussing this with the RAG participants, the group decided to apply fuel switching only to the ML and low forecasts to increase the total range of the forecasts.

The Company then looked at level of use. Historical information provided the basis for projections of energy usage for space heating, water heating, and appliances in existing homes. Accepted institutional, industry and engineering standards provided additional support.

The company used two additional factors in the space heating projections:

1) Availability of wood heat. In some parts of PacifiCorp's service territory (predominantly the Pacific Northwest), significant numbers of customers have both electric and wood heating (wood stoves) equipment. The company considered use of wood stoves instead of the installed electric heating equipment in projecting future consumption levels. The model assumed that income increased at each increasing level of load growth, and that with increased income, the use of wood heat decreased.

2) Model conservation or energy efficiency standards. If a state has energy standards, or is considering standards such as Oregon's model conservation standards, the company adjusted the projected space heat usage for that state. For states without model conservation standards, the company used the present energy standards.

The forecasting model assumed that most appliances will become more energy efficient over time, because of changes in government standards.

The result of all these calculations was the projected level of electricity usage expected from residential customers. This was the residential forecast used in developing the total system load forecast.

Commercial Load

The company projected commercial usage for each of 12 categories of commercial customers. Those categories were: communications, utilities, transportation; food stores; retail stores; restaurants; wholesale trade; lodging; schools; hospitals; other health services; offices; services; and miscellaneous. Growth in employment is the major determinant of increases in commercial energy use. Changes in employment drive changes in square footage, which is a major driver of commercial energy requirements.

The company forecasted the level of usage for seven end uses, based on kWh usage per square foot. The seven end uses were: space heating, water heating, space cooling, ventilation, cooking, lighting and miscellaneous uses. Saturation and level of use predicted future usage for each commercial end use.

The model estimated saturation levels and usage per square foot for each of the commercial end uses using data from commercial surveys, customer consumption data, and engineering estimates. Estimates of usage per square foot for existing buildings used 1990 data. Estimates of usage per square foot for new buildings used engineering models and assumed current practices.

The forecasted usage for the commercial sector considered how much conservation commercial customers will be performing on their own initiative, referred to as background conservation. This caused a reduction in the commercial forecast. The result of these calculations was a forecast of the kWh needed to serve commercial customers. That commercial forecast became part of the total system load forecast.

Industrial Load

PacifiCorp's industrial customers represent a large number of firms and industries. They are a mix of customers representing industries with widely divergent electricity consumption characteristics per unit of output. The company used 14 categories for the industrial customer segment: coal mining; oil and natural gas exploration; non-metallic mining; food processing; lumber and wood products; paper products; chemical products; petroleum refining; stone, clay and glass; primary metals; electric machinery; transportation equipment; a general manufacturing category; and other mining. The forecast for a given industrial segment did not identify end uses because industrial customers in each segment tend to use electricity in the same way, although individual plant processes may vary.

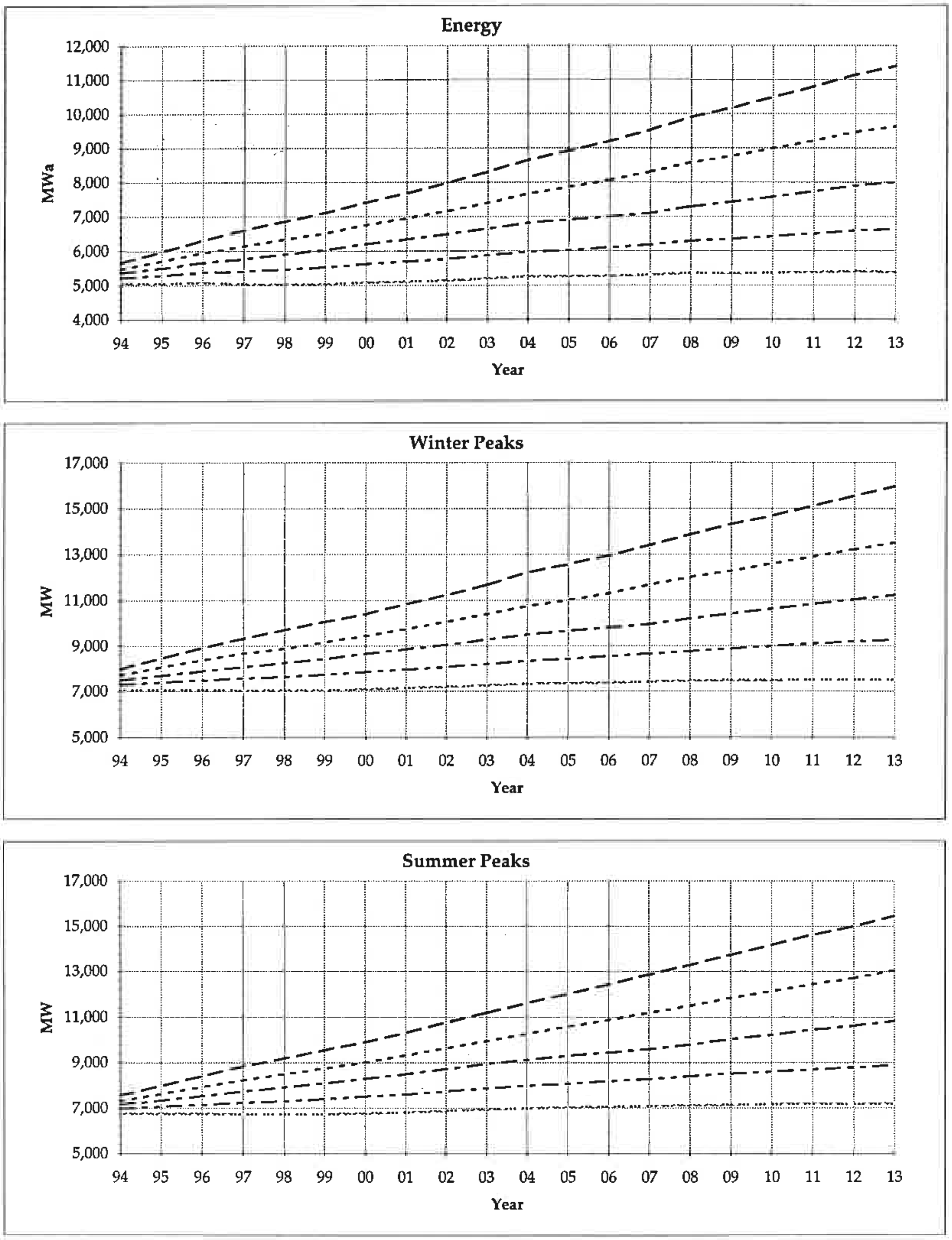
The company used employment as the foundation for the industrial energy forecasts. Estimates of electrical needs in the future used historical relationships between industrial consumption and employment for each industrial category.

As with the residential and commercial sectors, the forecast of how much energy industrial customers will need in the future considered how much conservation those customers will be performing on their own initiative. These calculations produced a forecast of the kWhs needed to serve industrial customers. That forecast was the level of industrial load used in developing the total system load forecast.

Forecasts of electricity usage for other smaller categories of customers (such as irrigation, highway lighting, street and area lighting, etc.) used methods similar to those used for the industrial customers.

Total System Energy, Winter and Summer Peaks Forecasts

Graph 3-2



High Growth — — — — — — Medium High Growth - - - - - - - - - - Medium Growth — - — - — - —
Medium Low Growth — - - — - - — Low Growth ....

G3-02.load forecast

Output: The Forecasts

Table 3-1 shows the low, ML, medium, MH, and high load growth projections for the system. The most probable future growth lies between the ML and MH forecasts. However, by broadening the range of forecasts to include higher and lower possibilities, the Company believes that there is little chance that future electricity consumption will lie outside the bounds of the high and low forecasts.

The company forecasted three projections for each of the five forecast levels (high, MH, medium, ML and low):

Annual energy sales (how many kWh the company expects to sell);

Winter peak sales (the highest level of demand projected for the winter months);

Summer peak sales (the highest level of demand projected for the summer months).

Graph 3-2 shows the five 20-year forecasts for energy, winter peak, and summer peak.

GAS PRICES

In RAMPP-2, about half of the new resources identified in the likely futures were gas-fired. In RAMPP-3 the contribution of gas-fired resources varied considerably, depending on the resource strategies used in each model run, but in all cases it was significant. Other utilities throughout the country are anticipating a strong reliance on gas-fired resources. Therefore, estimates of the future cost of natural gas will be critical in estimating the future costs of alternative resource plans.

RAMPP-3 used three gas price forecasts: low, medium, and high. Recent published studies provided information on long-term gas supply availability and pricing. The three basic components of delivered gas (burner tip) price are gas supply, transportation of the gas and storage. All three vary in price and rate of price increase depending on the geographic location and the type of application.

Most experts agree that the United States currently maintains sufficient gas resources in the lower 48 states to meet domestic demand at the current levels for 60 to 70 years. PacifiCorp and its consultants concluded that in-place reserves are sufficient to meet demand created by projected new construction of gas-fired generation in the western United States well into the next century.

The major sources of gas for the western part of PacifiCorp's service area are the provinces of British Columbia and Alberta in Canada and the Rocky Mountain region of the United States. Other sources of supply are accessible through interstate natural gas pipeline interconnections, but are not presently competitive in Northwest markets. Currently, consumers in the Pacific Northwest use more Canadian gas than domestic supplies. The eastern part of PacifiCorp's service area has access to additional domestic supplies through the interstate pipeline system.

PacifiCorp wants to take maximum advantage of the competitive forces that exist between natural gas supply regions in Canada and the United States through both long-term and short-term contract purchases from these competing production areas.

An increasingly competitive natural gas futures market and the associated financial derivatives products can benefit PacifiCorp by increasing future price certainty. Through a financial derivative, PacifiCorp can trade a floating price for a fixed price, which increases costs, but reduces risk. Natural gas pricing is extremely volatile, even more so than currencies, interest rates or base metals such as gold. Tools are now available to manage natural gas price risk in the same manner as businesses deal with interest rate or currency risk.

The pipeline systems that are currently of major interest to PacifiCorp are:

1. Questar pipeline connects with Northwest Pipeline, Colorado Interstate Gas (Coastal Corp. Subsidiary), and the Clay Basin Gas Storage Field (Questar) primarily to serve loads concentrated along the Wasatch Front in Utah. This pipeline is currently delivering gas to PacifiCorp's Gadsby Plant in Salt Lake City through a connection with Mountain Fuel Supply Company, the local distribution company. The tariffs on this system are "postage stamp," i.e. the rate for transporting the gas is the same regardless of the distance.

2. El Paso Natural Gas (El Paso) pipeline brings gas from Texas through New Mexico and Arizona to southern California. The El Paso system will deliver gas for the peaking resources being built under PacifiCorp's agreement with Arizona Public Service Company (APS). APS has major firm transportation agreements in place with El Paso, whose rates are mileage-based.

3. Pacific Gas Transmission (PGT) is a wholly owned subsidiary of Pacific Gas and Electric. Its system brings gas from Alberta to California markets. A connection of West Coast and Nova systems in Canada can deliver gas from northern British Columbia. The tariff for PGT is mileage based. Thus, there is a transportation price advantage for northern U.S. locations.

4. Northwest Pipeline (NWP) transports gas from British Columbia and Alberta to the Rocky Mountain areas. The PGT system connects to the Canadian system at the border. The NWP pipeline extends through the Rocky Mountain areas and connects to the Pacific Gas Transmission (PGT) system at Stanfield, in the northeastern part of Oregon, where the

NWP and PGT systems can exchange gas. Much of the transportation on the NWP system is through displacement, rather than physically moving the gas from receipt point to delivery point for each customer. This practice is common on most of the major pipeline systems. The rates on this system are also postage stamp.

A new order from the Federal Energy Regulatory Commission (FERC Order No. 636) prohibits the pipeline companies from continuing to sell gas to end users, such as large industrial, local distribution, and electric utility companies. The pipelines' function is now transportation only. The order requires that a very high percentage of the transportation rate that pipelines charge to transport gas must consist of the demand charge (based on the greatest amount of gas moved at any one time, rather than on how much total gas moves over the period of a day, week, or month). Therefore, it will be very expensive for a supplier to not have a fairly steady amount of gas being transported (a high transportation load factor).

If a customer has gas storage near the site of a generating resource, that customer can significantly improve its transportation load factor. There are a number of existing gas storage fields in the western United States, and several projects need development funding. There are two basic types of gas storage facilities: underground and liquefied natural gas (LNG). Underground storage requires compressing and pumping gas into existing depleted gas fields or aquifers. LNG facilities reduce gas volumes by 600 to 800 percent and then store the liquefied gas in special containers.

Existing gas storage facilities accessible to the PacifiCorp system include: (1) Clay Basin, on the eastern Utah/southern Wyoming border; (2) Jackson Prairie, in western Washington; (3) MacDonald Island and Los Medanos, in California on the PG&E system and directly accessible to PGT; (4) Big 4 and Playa Del Rey, in-ground storage on the SOCAL System and directly accessible to El Paso; and (5) Plymouth LNG Facility on the NWP System in south-central Washington. In addition, some proposed storage projects in the western United States may be of strategic interest to PacifiCorp, such as (1) Wild Goose storage, a depleted gas field in northern California accessible to the PG&E/PGT Systems; (2) Hog Back, a depleted gas storage field in north central Utah connected to both the NWP and Questar systems; (3) Mist Storage, a depleted gas field in western Oregon connected to Northwest Natural Gas; and (4) NWP Colorado storage field near Clay Basin. The company is studying LNG cost and operating characteristics to understand their feasibility in meeting requirements for peaking generation.

The capacity factor requirements in any proposed new gas supply contract will have a major impact on its price and availability. The Canadian Energy Board will not approve long-term export sales agreements with capacity factors of less than 60 percent. Canadian suppliers have indicated they are working towards 80 percent load factors. As in the United States, the reservation or demand charges on these contracts represents a major portion of the total cost of the gas. This strongly encourages high customer load factors in the agreements.

Gas Price Projections

In order to estimate future natural gas prices for planning purposes, PacifiCorp conducted a two-part study. The first step was determining a starting point for the price forecasts. The second step was a forecast of price increases in fixed real dollars. Five current major published reports(*) contain wellhead gas price projections through 2010.

The starting point for gas prices used the most recent gas price forecasts available and actual gas price history in PacifiCorp's service territory. This required developing a price that took advantage of the futures market. Futures trading of natural gas supply contracts began in April, 1990. The futures market uses gas contract pricing at Henry Hub, Louisiana, where several major U.S. pipelines connect. These contracts are traded on the New York Mercantile Exchange (NYMEX). For January through June, 1993, the company used the actual Henry Hub cash settlement prices. For the period from July through December 1993, the company used the NYMEX futures prices, as printed in the Gas Daily on June 23, 1993. The arithmetic average of these monthly prices was $2.19/MMbtu for 1993. In January 1994 the company calculated actual prices for 1993; they averaged $2.11 rather than the $2.19 estimated. This occurred after completing most of the analyses; it confirmed that the 1993 estimate was very close to actual prices.

A "basis differential" adjusted the estimates for PacifiCorp's service territory. This term means the difference between the Henry Hub price and the market index for a given area. PacifiCorp averaged the most recent six months of prices in the Rocky Mountain Index and the Canadian Index. The six-month Rocky Mountain Index was $1.85, and the six-month Canadian Index was $1.81, for an average of $1.83. The index from Henry's Hub for the same period was $2.05, for a basis differential of $0.22. When subtracted from $2.19, the PacifiCorp 1993 beginning price was $1.97. The company escalated this 1993 price to 1994 using the medium gas price real escalation rate of 3.78 percent and the RAMPP-3 inflation rate of 3.4 percent, resulting in a 1994 price of $2.11.

Table 3-3 shows growth rate projections for natural gas from various studies. PacifiCorp did not determine that any one of the projections was any more correct than another. The company grouped the growth rate projections into high, medium and low categories, and then averaged the growth rates in each of these three categories. The result was a high average real growth rate of 5.56

(*) --DRI/McGraw-Hill, 1992, Energy Review, Natural Gas Market Focus, Fall-Winter 1992-93, p. 25.
--Energy Information Administration, 1993, Annual Energy Outlook 1993, With Projections to 2010, Washington, D. C., p. 40.
--Gas Research Institute, 1992, Gas Research Insights, 1992 Edition, Baseline Projection of U. S. Energy Supply and Demand to 2010, Chicago, IL, p. 68.
--National Petroleum Council, 1992, The Potential for Natural Gas in the U. S., Summary, Washington, D. C., pp. 83 and 87.
--Northwest Power Planning Council, 1992, Status Report, the Implications of the Current Gas Price Outlook for Conservation Targets, Portland, OR, p. 13.

percent, medium of 3.78 percent, and low of 1.71 percent. The RAMPP-3 report uses the following abbreviations: LG for low gas price escalation assumptions, MG for medium gas price assumptions, and HG for high gas price assumptions.

Table 3-3 includes a standard financial hedge for January of 1993 as an example only. None of the calculations included the hedge, because the maximum term available is only about 10 years. However, the example may provide increased support for the low growth case, as the Northwest Power Planning Council's estimate was the only projection in that low growth range.

The bottom half of table 3-3 illustrates the effect of the calculated real dollar fixed price growth projections for low, medium and high growth cases as applied to the $2.11/MMBtu 1994 gas price starting point. The cost of new gas-fired resources in the portfolio included the regional pipeline transportation costs.

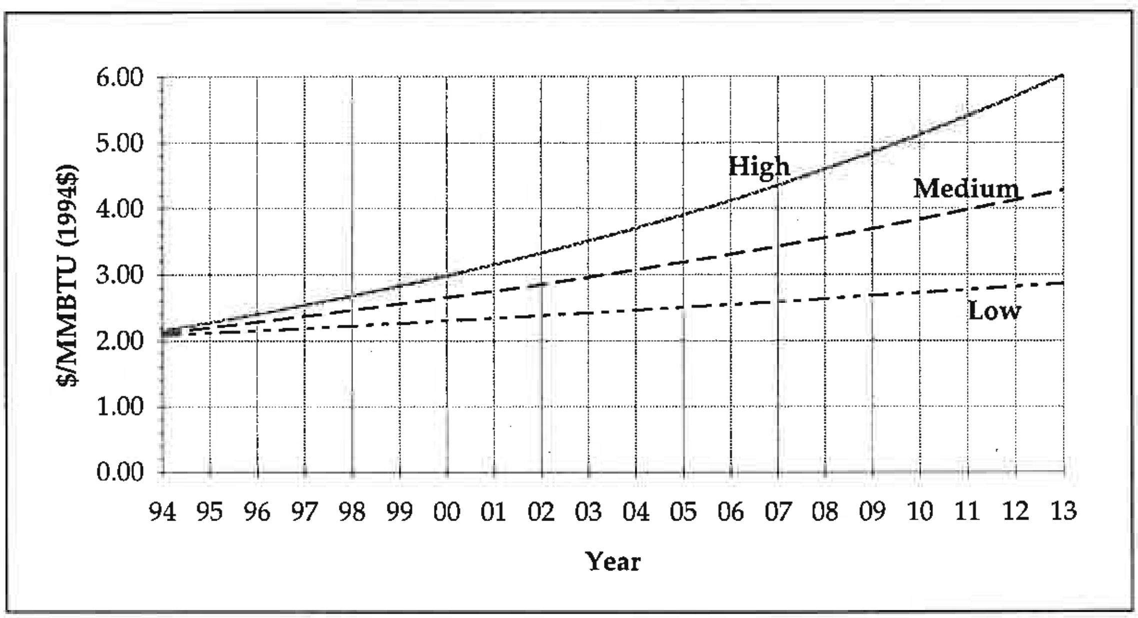
The load growth forecasts are independent of the three gas price levels; the gas prices were not fed back into the load forecasting model to create a different load forecast for each gas price level. All of the load growth forecasts assumed a medium gas price level. To incorporate gas price variability into the modeling process, the company combined each of the load growth forecasts with each of the gas price forecasts to create unique futures. The Analysis Plan chapter will discuss how the analysis used these futures to test alternative resource strategies.

Long Term Growth Rates for Natural Gas

Well Head Gas Pricing

Table 3-3

Projection	Annual Real Growth Rate 1993 - 2010	Average	
		Value	Level
Financial Hedge (10 years only)	1.30		
Northwest Power Planning Council - Low	1.71	1.71	Low
Northwest Power Planning Council - Med	3.17		
Energy Information Administration - Low	3.52		
DRI/McGraw Hill	3.85		
National Petroleum Council - Low	4.13		
Energy Information Administration - High	4.25	3.78	Medium
Gas Research Institute	5.23		
National Petroleum Council - Moderate	5.43		
Northwest Power Planning Council - High	6.02	5.56	High



T3-03.gas prices forecast

PORTFOLIO

PacifiCorp can choose from a number of resource alternatives to meet future electricity needs. Those alternatives fall into three categories: PacifiCorp's existing system, demand side resources (e.g., conservation or energy efficiency) and supply side resources (e.g., wind farms, coal plants, gas-fired combustion turbines, etc.). The chapter also discusses the company's transmission system and the discount rate used to compare resources in the portfolio.

EXISTING POWER SYSTEM

To determine how much additional resource it must acquire, the company first determined how much electricity it could produce from its existing power system. "Existing power system" refers to those PacifiCorp resources that are already on line, as well as changes the company knows will occur over the planning horizon.

RAMPP-3 included system efficiency improvements as part of the company's existing system, because PacifiCorp plans to pursue them as long as load growth remains within the medium-low to medium-high range. If load growth were to suddenly decrease, the company would re-evaluate its investments in a variety of areas, including efficiency improvements. The company will improve its thermal plants, hydro plants, transmission system, and distribution system. During 1994 and 1995, the company is planning projects to increase the available thermal capacity by 98 MW; no other improvements are cost effective over the 20-year planning horizon. The company is planning projects to increase the carrying capacity of the transmission and distribution system each year of the 20-year planning period, as shown on table 4-2. Each year for the first five years, the carrying capacity should increase by 7 MW.

The company currently meets its energy requirements with about 82 percent coal generation, 7 percent company-owned hydro, and 11 percent power purchases. About 65 percent of the company's capacity comes from company-owned thermal generating plants, 10 percent from hydro generation, and 25 percent from power purchases (mainly hydro-based). The company uses its peaking resources in all months of the year. The energy-return component of PacifiCorp's peaking contract with BPA allows the company to keep its coal plants running at relatively high capacity factors.

PacifiCorp's mix of thermal and hydro power contrasts with the Pacific Northwest's regional power system, where hydroelectric generation dominates. The company uses its coal plants for baseload needs and its hydro resources to respond to daily, weekly and seasonal load fluctuations. The company conducts maintenance on its thermal plants in the spring and fall, when loads are lower and inexpensive hydroelectric power is available from BPA.

Expected improvement and additions will add 918 MW of resources to the company's system in the next five years. The SCE contract will provide 422 MW through 2000, restarting Gadsby units 1 and 2 with natural gas will add 131 MW, new peaking combustion turbines Arizona will add 148 MW, the James River cogeneration project will add 52 MW, thermal plant reliability improvements will add 98 MW, and transmission and distribution efficiencies will add 67 MW. Some resources will provide less to the system over the 20 years, especially hydro resources and purchased power.

Tables 4-1, 4-2, and 4-3 show the components of the existing system, and expected changes over the 20-year planning horizon for energy, winter peak, and summer peak, respectively. The net energy resources in the existing system (Table 4-1) should decrease by 199 MWa over the 20-year planning horizon, but individual components will vary. For example, net thermal resources will increase, and transmission and distribution (T&D) efficiencies will increase. But, the hydro system will contribute less energy due to decreases in the amount of power the company can use from the Mid-Columbia hydro plants.

Capacity resources available to meet winter peak needs (Table 4-2) should decrease by 1,023 MW over the next 20 years. 417 MW of that decrease occurs in 2009, when the company expects to lose its rights to the Mid-Columbia hydro output. The expiration of other purchased power contracts will reduce capacity resources, particularly the SCE capacity purchase (422 MW) in 2002. The Bonneville Power Administration (BPA) peaking contract will remain at 1100 MW. This is a change from RAMPP-2, which assumed that the contract would ramp up to 1400 MW between 1992 and 1995. The company now believes that endangered species concerns and likely restrictions on usage of the federal hydro system make it prudent to diversify PacifiCorp's capacity resources through alternatives such as the SCE capacity purchase.

The resources available to meet the summer peak (Table 4-3) should decrease by 829 MW over the next 20 years. The loss of the Mid-Columbia hydro resource in 2009 accounts for 400 MW of that decrease.

As existing firm wholesale sales and purchase contracts expire, they change the amount of power available for retail customers. For example, firm wholesale sales decrease by 816 MW over the 20 years, decreasing the need for new resources for retail customers. Firm purchased power will decrease by 735 MW, increasing the need for new resources for retail customers. During the 20 years, the company expects to sign agreements for new wholesale power sales and purchases, but until those agreements are reached, the company cannot predict the availability, price and terms of such contracts. Therefore, purchased power is not in the RAMPP-3 portfolio. Rather, PacifiCorp takes advantage of purchased power opportunities to meet resource needs identified in RAMPP when such a purchased power opportunity provides more benefits at a lower cost to customers when compared to an alternative resource action.

Potential Energy of the Existing System (MWa)

Table 4-1

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Thermal Plants																				
Carbon 1,2	156	158	161	158	161	162	164	162	161	158	164	162	161	162	164	158	161	162	164	162
Centralia 1,2	583	583	572	572	583	583	583	583	572	572	583	583	583	583	572	572	583	583	583	583
Cholla 4	360	327	370	341	370	341	370	327	370	341	370	341	370	327	370	341	370	341	370	327
Colstrip 3,4	121	121	121	121	121	121	121	121	121	121	121	121	121	121	121	121	121	121	121	121
Craig 1,2	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138
Dave Johnston 1,2,3,4	690	682	693	686	685	674	690	682	693	686	685	674	690	682	693	686	685	674	690	682
Hayden 1,2	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63
Huntington 1,2	711	756	755	756	740	741	755	756	755	756	740	741	755	756	755	756	740	741	755	756
Hunter 1,2,3	862	913	905	886	900	891	895	913	905	886	900	891	895	913	905	886	900	891	895	913
Jim Bridger 1,2,3,4	1217	1217	1217	1217	1230	1229	1217	1217	1217	1217	1230	1229	1217	1217	1217	1217	1230	1229	1217	1217
Naughton 1,2,3	570	574	582	585	582	585	570	574	582	585	582	585	570	574	582	585	582	585	570	574
Wyodak	248	248	229	248	220	248	229	248	229	248	220	248	229	248	229	248	220	248	229	248
Gadsby 1,2,3	91	212	218	216	218	211	214	216	218	216	218	211	214	216	218	216	218	211	214	216
APS NEW CTs	0	0	0	0	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
James River	0	0	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51
Little Mountain	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Total Thermal	5819	6001	6084	6047	6094	6070	6092	6083	6107	6070	6097	6070	6089	6083	6110	6070	6094	6070	6092	6083
Renewables																				
Mid-Columbia	254	254	254	254	254	254	254	254	254	254	254	254	254	254	254	0	0	0	0	0
Hydro Pacific	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Hydro Utah	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Blundell Geothermal	19	18	19	19	18	19	19	18	19	19	18	19	19	18	19	19	18	19	19	18
Wind FC & Rtl Snake	0	0	0	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
Total Renewables	828	827	828	866	865	866	866	865	866	866	865	866	866	865	866	612	611	612	612	611
Purchased Power	374	370	173	137	89	82	72	57	52	58	70	70	70	70	70	70	70	70	70	83
SCE Capacity Purchase	13	18	18	18	18	18	18	18	0	0	0	0	0	0	0	0	0	0	0	0
Wind Capacity Purch. + 9																				
BPA Peaking Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Q.F. Contracts	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
T&D Efficiencies	4	9	13	17	22	26	30	35	39	41	44	46	49	51	54	56	59	61	64	64
Total Resources	7154	7339	7231	7200	7202	7176	7192	7172	7178	7150	7190	7167	7188	7184	7214	6923	6948	6928	6952	6955

T4-01.existing energy

Winter Capacity of the Existing System (MW)

Table 4-2

		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Thermal Plants																					
Carbon 1,2	173	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178
Centralia 1,2	622.2	638	638	638	638	638	638	638	638	638	638	638	638	638	638	638	638	638	638	638	638
Cholla 4	350	380	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390
Colstrip 3,4	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140
Craig 1,2	165	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Dave Johnston 1,2,3,4	750	772	772	772	772	772	772	772	772	772	772	772	772	772	772	772	772	772	772	772	772
Hayden 1,2	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Huntington 1,2	795	805	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855
Hunter 1,2,3	996	1003	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041
Jim Bridger 1,2,3,4	1387.2	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388
Naughton 1,2,3	700	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675
Wyodak	256	256	256	256	256	256	256	256	256	256	256	256	256	256	256	256	256	256	256	256	256
Gadsby 1,2,3		100	231	235	235	235	235	235	235	235	235	235	235	235	235	235	235	235	235	235	235
APS NEW CTs		0	0	0	0	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148
James River		0	0	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Little Mountain		13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Total Thermal	5813.4	6592	6821	6877	6877	7025	7025	7025	7025	7025	7025	7025	7025	7025	7025	7025	7025	7025	7025	7025	7025
	diff = 663 MW																				
Renewables																					
Mid-Columbia	1249	417	417	417	417	417	417	417	417	417	417	417	417	417	417	417	0	0	0	0	0
Hydro Pacific		882	882	882	882	882	882	882	882	882	882	882	882	882	882	882	882	882	882	882	882
Hydro Utah		50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Blundell Geothermal		22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Wind FC & Rtl Snake		0	0	0	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Total Renewables		1371	1371	1371	1384	1384	1384	1384	1384	1384	1384	1384	1384	1384	1384	1384	967	967	967	967	967
Purchased Power ~FIRM		560	549	342	291	290	265	241	233	226	206	197	197	197	147	147	147	147	147	147	147
SCE Capacity Purchase		322	422	422	422	422	422	422	422	0	0	0	0	0	0	0	0	0	0	0	0
BPA Peaking Purchase		1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100
O.F. Contracts		115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
T&D Efficiencies		7	14	21	28	35	42	49	56	63	67	71	75	79	83	87	91	95	99	103	103
Total Resources		10067	10392	10248	10217	10371	10353	10336	10335	9913	9897	9892	9896	9900	9854	9858	9445	9449	9453	9457	9457
Reserve Requirement		1332	1360	1367	1395	1422	1449	1472	1504	1536	1569	1570	1579	1599	1592	1628	1660	1680	1712	1728	1745
Available Resources		8735	9032	8881	8822	8949	8904	8864	8831	8377	8328	8322	8317	8301	8262	8230	7785	7769	7741	7729	7712

Summer Capacity of the Existing System (MW)

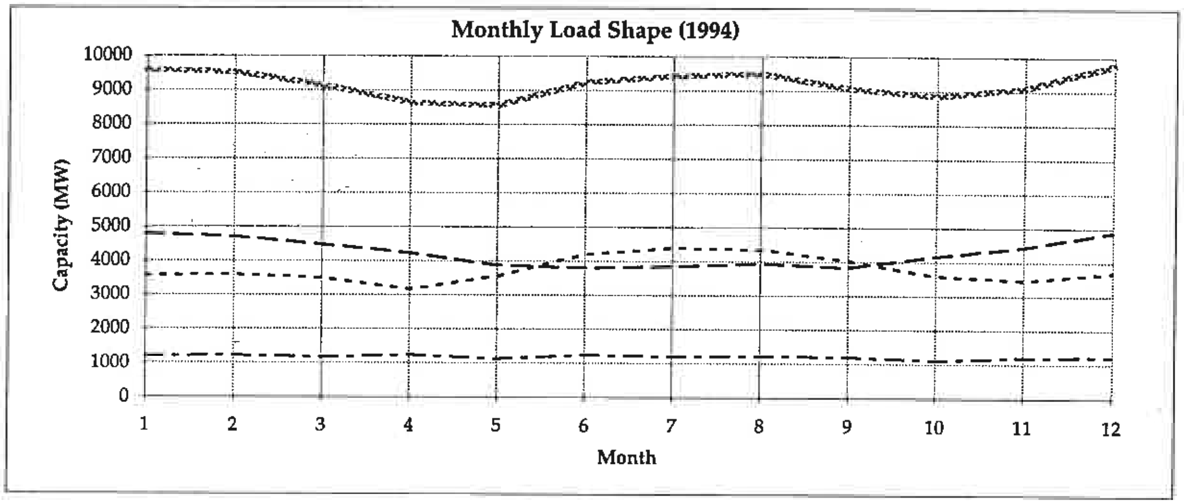
Table 4-3

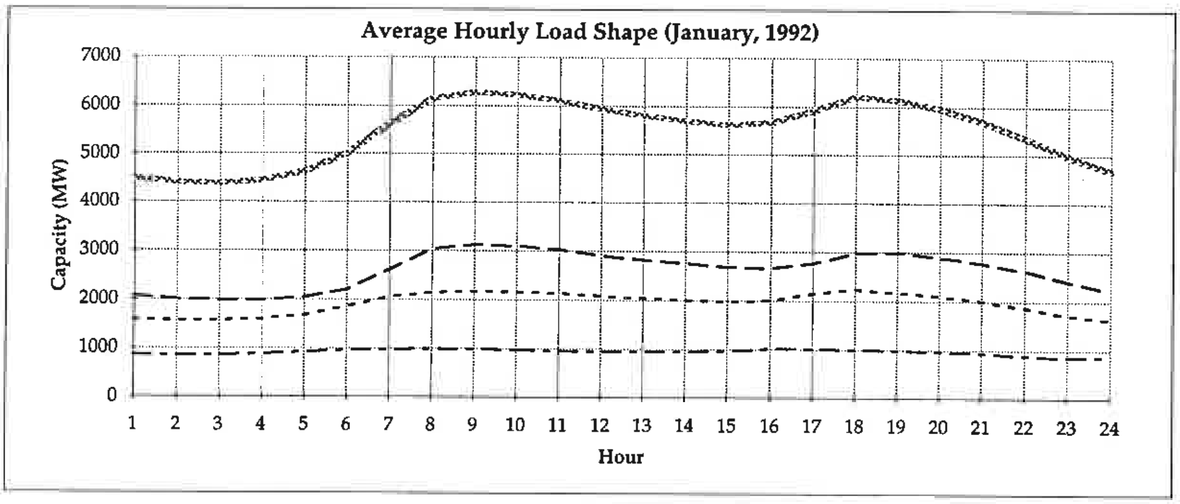
	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Thermal Plants																				
Carbon 1,2	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178	178
Centralia 1,2	638	638	638	638	638	638	638	638	638	638	638	638	638	638	638	638	638	638	638	638
Cholla 4	380	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390	390
Colstrip 3,4	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140
Craig 1,2	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Dave Johnston 1,2,3,4	772	772	772	772	772	772	772	772	772	772	772	772	772	772	772	772	772	772	772	772
Hayden 1,2	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Huntington 1,2	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855	855
Hunter 1,2,3	1003	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041	1041
Jim Bridger 1,2,3,4	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388	1388
Naughton 1,2,3	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675
Wyodak	256	256	256	256	256	256	256	256	256	256	256	256	256	256	256	256	256	256	256	256
Gadsby 1,2,3	231	235	235	235	235	235	235	235	235	235	235	235	235	235	235	235	235	235	235	235
APS NEW CTs	0	0	0	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148	148
James River	0	0	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Little Mountain	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Total Thermal	6773	6825	6877	7025	7025	7025	7025	7025	7025	7025	7025	7025	7025	7025	7025	7025	7025	7025	7025	7025
Renewables																				
Mid-Columbia 1127	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	0	0	0	0	0
Hydro Pacific	727	727	727	727	727	727	727	727	727	727	727	727	727	727	727	727	727	727	727	727
Hydro Utah	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Blundell Geothermal	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Wind FC & Rtl Snake	0	0	0	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
Total Renewables	1239	1239	1239	1252	1252	1252	1252	1252	1252	1252	1252	1252	1252	1252	1252	852	852	852	852	852
Purchased Power	532	521	314	263	162	137	113	105	83	78	69	69	69	69	69	69	69	69	69	69
SCE Capacity Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BPA Peaking Purchase	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100
O.F. Contracts	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115	115
T&D Efficiencies	7	14	21	28	35	42	49	56	63	67	71	75	79	83	87	91	95	99	103	103
Total Resources	9766	9814	9666	9783	9689	9671	9654	9653	9638	9637	9632	9636	9640	9644	9648	9252	9256	9260	9264	9264
Reserve Requirement	1324	1351	1370	1402	1428	1475	1497	1515	1549	1580	1578	1589	1608	1601	1634	1668	1686	1719	1730	1751
Available Resources	8442	8463	8296	8381	8261	8196	8157	8138	8089	8057	8054	8047	8032	8043	8014	7584	7570	7541	7534	7513

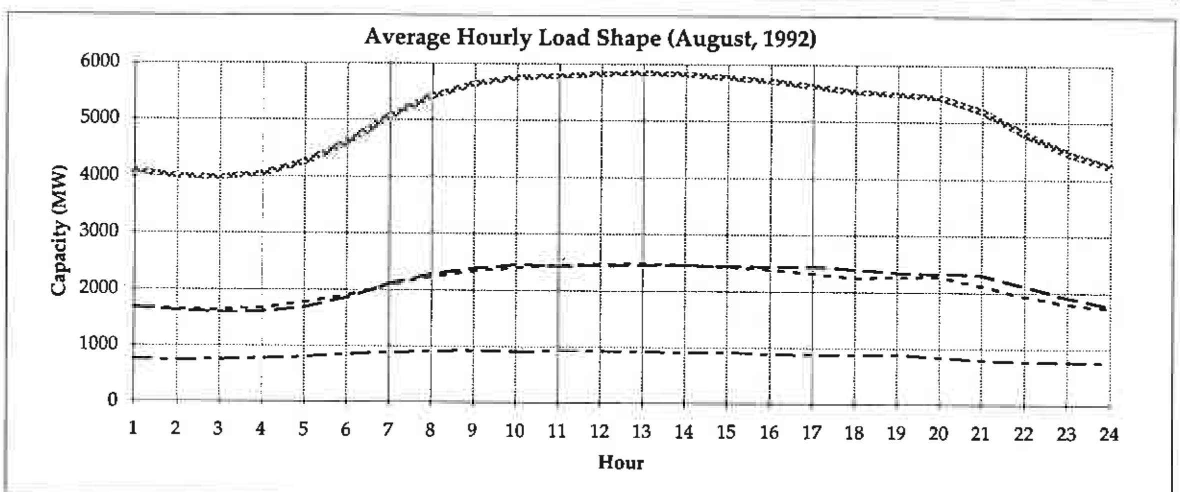
T4-03.existing summer

Monthly and Hourly Load Shapes

Graph 4-4







Note: wholesale sales are excluded from hourly load shapes.

Total System OWC Utah Wyoming

G4-04.load shapes

Load Characteristics

Graph 4-4 shows how the company's monthly load varies for the total system and for each of its three main load and resource areas. The Wyoming area's load is very flat across the months, the Utah area's load is higher in the summer months, and the OWC area (representing the western part of PacifiCorp's system) is higher in the winter months. The peaks in the OWC and Utah areas tend to offset each other, but PacifiCorp's total system load peaks in the winter. PacifiCorp can take advantage of the seasonal peak diversity between the winter peaking Northwest and the summer peaking Utah area through wholesale sales and seasonal resource acquisitions. Consequently, the system efficiently uses both winter and summer capacity resources. Since the recent purchase of winter capacity from Southern California Edison, PacifiCorp needs new resources to meet summer capacity needs sooner than it needs new resources to meet winter capacity needs.

Graph 4-4 also shows the average hourly load shape for January and August. PacifiCorp has a heavy load for about 16 hours each day starting around 6 a.m. and tapering off around 10 p.m. This is true for both the Northwest and Utah areas, although Wyoming loads are relatively flat throughout the day. The energy return requirements of PacifiCorp's peaking contract with BPA flattens the system load shape. For the company to achieve capacity benefits from peak management programs, loads must shift completely out of the 16-hour sustained peak period, and load reductions must be sustainable and predictable.

Reserve Requirements

All utilities must maintain a margin of resources above loads to assure reliable service in the event of generating unit outages, load fluctuations, or other unforeseen events. Utilities must meet both planning (long range) and operating (real time) reserve requirements.

Planning reserves for PacifiCorp follow the Pacific Northwest Coordination Agreement (PNCA) and the InterCompany Pool (ICP) reserve sharing agreements. The PNCA provides an efficient pooling arrangement by establishing requirements for planning reserve margins for participating Northwest utilities. First, the PNCA sets a reserve margin for the entire Northwest. They use a level of reliability that calls for only one weekday of failure to meet load in 20 years (a 5 percent probability of failing to meet one weekday peak load in a year). Then they allocate the regional reserve margin among participating utilities in the region.

The ICP analyzes reliability for utilities that connect with the Northwest region as defined by the PNCA. This includes utilities such as Idaho Power, Sierra Pacific Power and others. The ICP reserve analysis includes the reliability contribution of these utilities outside the Northwest. PacifiCorp's current ICP reserve allocation translates to a reserve margin of about 13 percent of peak load.

Operating reserve requirements use the Western System Coordinating Council (WSCC) and Northwest Power Pool (NWPP) guidelines. Operating reserves help assure day-to-day operating reliability. They allow system dispatchers to maintain scheduled frequency, meet load variations and replace generating capacity lost due to transmission and generator forced outages. The guidelines identify two types of operating reserves: spinning and non-spinning reserves. Spinning reserves must be from resources whose output can immediately increase to respond to load variations, typically from automatic generation control (AGC). This gives the utility the required regulating margin needed to follow the instantaneous load variations on the system. Non-spinning reserves must be responsive within 10 minutes. Units running at less than their maximum generating capacity and interruptible loads generally provide non-spinning reserves. Thus, a utility can use a unit's unused generating capability that can increase within 10 minutes as non-spinning reserves.

The WSCC requires its members to maintain minimum operating reserve as follows: sufficient spinning reserve to provide regulating margin, plus an additional amount of operating reserve equal to the sum of 5 percent of committed hydro generation and 7 percent of committed thermal generation (at least half of which must be spinning reserve).

Some generating units have restrictions on how quickly generation can increase or decrease, called the ramp rate. Ramp rates can reflect physical limits on parts of a thermal plant, or operating constraints on a river system. Quick-start resources can start cold and come up to a generating load within 10 minutes. Many hydro resources can be brought on line in a few minutes, as can some of the smaller simple-cycle combustion turbines. Other generation technologies cannot contribute fully to operating reserve due to ramp rate restrictions.

Scheduling and Dispatching

Each utility pre-schedules the operations of its resources, typically for the next business day and any holiday or weekend days that occur before the next regular business day. Some contracts with suppliers for purchased resources do not allow for variations from the pre-schedule, while others allow some changes up to 30 minutes before the dispatch hour. The schedule uses an estimate of expected loads and resource availability. Using these estimates, a utility schedules resources and transmission to meet requirements in the most economic way. A utility should notify others of a change at least two hours before the change is to occur. Modifications to the schedule occur as the day unfolds. Utilities may adjust their pre-schedule of operations due to unforeseen events such as load swings, transmission or generator forced outages, units coming back on line, changes by neighboring utilities, etc. Short-term non-firm purchases and sales arrangements occur with neighboring utilities as opportunities occur.

The ability to reliably forecast the output of a resource and the flexibility to make real-time changes in its use is quite valuable. If the utility cannot schedule a resource economically, and adjust the schedule when needed, that resource is less cost effective for the system.

DSM measure?

Resource Operability

Resources have different levels of real-time operability. A utility can modify generation levels within the limits of ramping rates, minimum and maximum generating capacity, and potential wear and tear on the power plant components. Simple cycle combustion turbines (SCCTs) can start and stop quite rapidly compared to power plants that use boilers. However, maintenance costs for SCCTs increase significantly as the number of starts increases.

Plants with expensive startup costs or slow ramping rates may have to keep running during low load periods if higher loads in the near future will require their full output. To be able to meet a future peak, a utility may have to "dump" output from expensive resources during off-peak hours in order to have enough cost-effective resources on line when it needs them. Fuel contracts may include requirements for minimum and maximum daily, seasonal, and annual use. However, a utility can pay more for flexibility in how much fuel it takes. Fuel suppliers usually give steady, high volume customers better deals than customers whose needs vary.

Hydro plants' reliable and dispatchable generation offers great operational flexibility. They can reach full output in a few minutes (versus several hours for plants that use boilers), providing peaking capacity, load following (with AGC), and operating reserve even if the plant is off-line. Hydro also provides shaping. Shaping refers to the ability of a resource to match the shape of loads being served. For example, a hydro unit can generate at maximum capacity during the heavy load hours of the day, backing down to lower generating levels as loads drop off. This effectively evens out the remaining load that other generating resources must meet, which allows base load resources to operate at full capability over more hours, enhancing efficiency. However, hydro plants may have operating constraints if variation in reservoir levels and river flow rates is limited. Non-power constraints such as downstream release requirements or reservoir fluctuation limits for fish protection can restrict operating flexibility.

Off-river pumped storage hydro units have hydro's operational advantages without the in-stream water restrictions. Pumped storage resources provide the maximum shaping capability, since they can generate at maximum capacity during heavy load hours, then switch to pumping the water back up to the higher reservoir during off-peak hours. Thus a 200 MW pumped storage unit can provide 200 MW of peak generation and fill in 200 MW of off-peak load.

Hydro System

The hydro projects owned and operated by PacifiCorp have a total nameplate rating of 1,015 MW, and are the largest renewable resource the company has. During the last 30 years, these projects produced an average of about 4.5 million MWh a year.

Several of PacifiCorp's hydro generating units will be due for relicensing by the Federal Energy Regulatory Commission (FERC) over the next 20 years. The

Electric Consumers Protection Act of 1986 requires FERC to give equal consideration to energy conservation, fish and wildlife protection, the enhancement and preservation of recreational opportunities and other aspects of environmental quality. The company assumed in RAMPP-3 that it will succeed in getting these resources relicensed, although the licenses may require reduced generating capability and/or reduced operational flexibility. Any loss of these low-cost resources would mean higher generation costs for the company and its customers. The relicensing process formally begins five and one half years before expiration of the license, but in reality the company prepares several studies in advance of the formal process. Upon relicensing, FERC issues new licenses, generally for a period of thirty years. The company's hydro units and their dates for relicensing are as follows: North Umpqua (185 MW) in 1997, Yale (130 MW) in 2002, Rogue (40 MW) in 2006, Swift (205 MW) in 2007, and Klamath (160 MW) in 2007, for a total of 720 MW. The company's estimates of the relicensing cost for these projects ranges from $46-to-$103/kW, which compares very favorably to the cost of new peaking resources. A simple cycle combustion turbine's capital costs are about $500/kW. Projected relicensing costs for specific plants are as follows: about $12 million for North Umpqua and $6.5 million for Yale. The company has not yet developed specific cost estimates for the other plants. The RAMPP-3 analyses include the projected relicensing cost in the financial model's inputs.

PacifiCorp is one of 15 generating utilities participating in the Pacific Northwest Coordination Agreement, along with the U.S. Bureau of Reclamation, the U.S. Army Corps of Engineers and the Bonneville Power Administration. This agreement helps optimize generation from the region's resources and protect all members using the system. It restricts the degree to which any member can draw down a particular reservoir, so that one member's use will not harm another member's reliance on hydro availability. PacifiCorp is currently participating in negotiations to extend the agreement beyond its 2003 expiration date.

Another agreement also affects PacifiCorp's hydro resources. In 1964, the United States and Canada agreed to share the cost and downstream benefits of building a number of hydroelectric dams in Canada. Canada sold its half of the downstream benefits to the United States under the Canadian Entitlement and Columbia Storage Power Exchange (CSPE). The U. S. must replace or return the power it purchases from Canada beginning in 1998. Negotiations are underway among Canada, BPA, non-federal owners of the Mid-Columbia hydro projects, and purchasers of power from those projects such as PacifiCorp to extend the purchase of benefits by U.S. parties.

Coal Plants

About 80 percent of PacifiCorp's power comes from its coal-fired plants, which have a total nameplate rating of more than 7,000 MW. Because PacifiCorp invested early in pollution controls at many of its plants, and because it has significant low-sulfur coal reserves, the company is among the cleanest coal-fired utilities in the country. PacifiCorp's plants are also some of the least expensive to operate. Three steam electric generating plants operated by PacifiCorp were among the seven least expensive to operate in 1992 in the United States, according to a survey released in September 1993 by the Utility Data Institute. Ratings used average expenses per net MWh. Of the plants operated by PacifiCorp, Dave Johnston ranked fourth, Wyodak sixth, and Huntington seventh in the survey. In addition, three other plants were in the 100 least expensive: Hunter at 36th, Jim Bridger at 43rd, and Carbon at 87th. Three plants in which PacifiCorp owns a share also were on the list: Colstrip at 17th, Hayden at 22nd, and Craig at 61st.

Plant Refurbishment

By 2013, many of PacifiCorp's hydro and thermal units will be 35 years or older. While 35 years is the commonly assumed useful life of such facilities for accounting purposes, PacifiCorp plans to maintain and extend the operating life of its generating plants as long as it is cost effective. Years of plant life do not predict operating capacity for PacifiCorp's plants. For example, two of the oldest plants, Dave Johnston and Carbon, have among the highest availability factors of any of the plants surveyed, at about 90 percent. Seven PacifiCorp thermal plants set generation records in 1992. The company has, through enhanced maintenance methods and other improvements, increased energy production at its existing power plants each year, delaying the need for new large generating stations. Table 4-5 shows the company's existing thermal plants and the operating availability for each plant.

Each component of a power plant has a different useful life. The company refurbishes and replaces individual components each year through periodic maintenance, both scheduled and unscheduled. Although power plants have some major components, such as the boiler and turbine generator, the company typically does not replace them as a single unit. Overhauling of boilers and turbines occurs on a regular maintenance cycle. A major overhaul for each plant occurs about every two years, other repairs or replacements of components occur as needed. Major component replacements occur over time if the replacement is cost effective. Those expenditures are currently very cost effective. Capital expenditures for ongoing refurbishment at the company's coal plants cost $7 to $11/kW for the system, based on annual capital expenditures of $60-90 million, divided by 6500 MW (the company's total coal installed capacity), times 80 percent (20 percent was for environmental compliance and other projects). Assuming the same level of expenditure occurred every year for a 35-year plant life (in real dollars), the present value amount would be about 45 percent of the sum of the nominal payments, or within a range of $110 to $175/kW. New resources currently cost a minimum of $500/kW. Because the cost of extending plant life is so low relative to new resource costs, RAMPP-3 included refurbishment and maintenance as part of known changes to the existing system rather than as resource choices in the portfolio. The company continues to evaluate these expenses, to assure that they remain cost effective relative to new resource choices.

Thermal Generating Resources

Steam Plants Using Coal

Table 4-5

	Plant		Unit	Net Capacity (MW)	Construction Date	Operating Equivalent Availability (Dec 92) Used in RAMPP-3	1993 Availability
1	Dave Johnston		1	105.0	1958	97.1	99.3
2	Dave Johnston		2	105.0	1960	95.4	98.5
3	Dave Johnston		3	220.0 750	1964	95.1	96.6
4	Dave Johnston		4	320.0	1972	93.7	90.2
5	Centralia	a	1	311.1	1971	96.5	85.0
6	Centralia	a	2	311.1 622.2	1972	97.2	88.5
7	Jim Bridger	a	1	346.8	1974	92.2	92.2
8	Jim Bridger	a	2	346.8	1975	94.7	95.7
9	Jim Bridger	a	3	346.8 1387.2	1976	95.6	92.7
10	Jim Bridger	a	4	346.8	1979	91.7	84.3
11	Wyodak	a		256.0	1978	97.4	98.8
12	Colstrip	a	4	70.0 140	1984	94.4	63.6
13	Colstrip	a	5	70.0	1986	98.7	73.5
14	Cholla	a	4	350.0	1981	96.1	96.6
15	Craig	a	1	82.5	1979	92.4	98.7
16	Craig	a	2	82.5 165	1980	87.8	97.4
17	Hayden	a	1	45.0	1965	77.8	98.7
18	Hayden	a	2	33.0 78	1976	85.6	98.8
19	Carbon		1	68.0 173	1954	98.4	93.3
20	Carbon		2	105.0	1957	97.9	96.1
22	Hunter		1	366.0	1978	90.2	97.5
23	Hunter	a	2	235.0 996	1980	82.9	93.3
24	Hunter	a	3	395.0	1983	93.2	96.1
25	Huntington		1	400.0 805	1977	95.7	94.3
26	Huntington		2	405.0	1974	93.2	96.0
27	Naughton	b	1	160.0	1963	94.5	90.8
28	Naughton	b	2	210.0 700	1968	96.7	94.9
29	Naughton		3	330.0	1971	83.2	79.4

Notes:

a PacifiCorp's portion only.

b In order to meet SO2 requirements, Naughton Units 1 and 2 will use supplemental gas firing beginning the second quarter of 1994.

BPA Entitlement Agreement

The RAMPP-2 portfolio included the BPA Entitlement Agreement as a 64 MWa resource. The model selected it for all of the resource plans. However, the company was unsure whether it could rely on the Agreement. It would provide energy and capacity primarily in the winter. The company's other sources for winter capacity, acquired since signing the Agreement, now diminish its value. PacifiCorp is now negotiating with BPA to determine if the company could exchange some of the winter capacity in the agreement for summer capacity, which would better meet system needs. When those negotiations determine the terms of a revised agreement, PacifiCorp will include the resource either in the existing system or in the portfolio of resources, depending on the terms of the agreement.

DEMAND-SIDE RESOURCE ALTERNATIVES

PacifiCorp has another option for responding to growth: helping customers use electricity more efficiently. Efficiency measures are demand-side resources (DSRs). Consumers do not want energy for its own sake; they want to use energy for specific purposes. For example, they want to heat their homes, light their offices, and operate their industrial machines. If they can do these things with less energy (greater efficiency), more energy will be available for other customers. Thus, saved energy can serve the same purpose as new sources of electricity.

PacifiCorp has long been an innovator in energy efficiency programs. In the late 1970's, the company's zero interest weatherization program helped residential customers overcome the financing hurdle for efficiency improvements. The Hood River Conservation Project provided a national model for what utility efforts can achieve. PacifiCorp and other suppliers weatherized an entire community. The company participated in Energy Edge to demonstrate the energy savings possible for new commercial buildings. Similarly, the Super Good Cents program promoted energy-efficient residential construction and the development of new building codes for efficiency.

Integrated resource planning compares demand-side resources (DSRs) and supply-side resources (SSRs). However, there are differences in acquisition. For SSRs, the utility pays all the costs, such as capital investment, fuel, and operation and maintenance expenses. The sum of these expenses is the total utility cost. If the company meets a resource need with purchased power, the cost incorporates these same cost components. However, for DSRs, the customer may pay some of the costs. For example, it might cost an extra $3000 to build an energy efficient house. Of that amount, the utility may pay a $2000 incentive, leaving the homeowner to pay the rest. The homeowner will be willing to do this because of the future energy savings. In some cases, there are non-energy benefits such as operational savings, or reduced maintenance costs associated with the conservation measures. The total resource cost (TRC) calculated for each DSR program included the utility cost of each DSR program, the amount the customer

Portfolio: Non-Cost Characteristics

Table 4-6

Description	MW Available in 1st Year or Plant Size	1st Year Available	Maximum MWa Available	Depreciation Life (years)	Tax Life (years)	Heat Rate (Btu/kWh) Incremental	Heat Rate (Btu/kWh) Average	Emissions (lbs/MMBTu) NOX	Emissions (lbs/MMBTu) CO2
OWC Appliance	2.28	1994	6.31						
UT Appliance	1.89	1994	5.23						
WY Appliance	0.39	1994	1.09						
UT Super Good Cents	0.02	1994	1.42						
WY Super Good Cents	0.02	1994	3.35						
OWC Super Good Cents	0.47	1994	23.75						
OWC Irrigation	0.42	1994	10.10						
UT Irrigation	0.60	1994	8.98						
OWC Industrial	0.30	1994	6.80						
WY Industrial	0.09	1994	6.48						
UT Industrial	0.27	1994	13.41						
Utah Coal	330	2001		45	20	8,595	10,300	0.45	204
UT Commercial Finanswer	1.40	1994	32.00						
WY Commercial Finanswer	0.03	1994	4.24						
OWC Commercial Finanswer	0.80	1994	34.02						
UT Commercial Retrofit	0.75	1994	82.33						
WY Commercial Retrofit	0.58	1994	15.84						
OWC Commercial Retrofit	1.75	1994	65.63						
Wyo Coal	330	2001		45	20	9,468	11,900	0.45	204
Utah IG CC	225	2001		35	20	6,330	9,058	0.03	202
Wyo IG CC	225	2001		35	20	6,420	9,192	0.03	202
Wyo FB Coal	150	2001		45	20	8,300	9,262	0.15	208
Utah FB Coal	150	2001		45	20	8,010	9,178	0.15	208
UT Finanswer 12,000	0.12	1994	21.62						
WY Finanswer 12,000	0.01	1994	5.07						
OWC Finanswer 12,000	0.24	1994	20.71						
OWC Cogeneration 1	160	1997	320	35	20	5,500	4,300	0.09	118
Utah Cogeneration 1	39	1997	39	35	20	5,500	4,300	0.09	118
OWC Cogeneration 2	470	1997	1,320	35	20	6,800	6,200	0.09	118
Utah Cogeneration 2	210	1997	420	35	20	6,800	6,200	0.09	118
OWC Pumped Storage	200	1998	500	50	20				
Utah Pumped Storage	200	1998	500	50	20				
Utah Combined Cycle CT	450	1998		35	20	5,250	7,518	0.09	118
OWC Combined Cycle CT	450	1998		35	20	5,250	7,518	0.09	118
Wyo Combined Cycle CT	450	1998		35	20	5,250	7,518	0.09	118
Utah Wind with Tax C	150	1997		20	5				
Wyo Wind with Tax C	150	1997		20	5				
OWC Residential Wx	3.43	1994	19.42						
UT Residential Wx	0.05	1994	0.47						
OWC Wind with Tax C	150	1997		20	5				
Utah Wind without Tax C	150	2000		20	5				
Wyo Wind without Tax C	150	2000		20	5				
OWC Wind without Tax C	150	2000		20	5				
OWC Geothermal	100	1998	300	30	20				
Utah Geothermal	100	1998	300	30	20				
UT Xtra Comml Measures	0.11	1994	18.77						
WY Xtra Comml Measures	0.01	1994	3.22						
OWC Xtra Comml Measures	0.08	1994	10.06						
OWC Water Heat Load Control	1.65	1994	15.96						
Utah Solar	100	1998		20	5				
Utah Simple Cycle CT	370	1998		30	15	10,545	11,336	0.09	118
Wyo Simple Cycle CT	320	1998		30	15	10,545	11,336	0.09	118
OWC Simple Cycle CT	370	1998		30	15	10,545	11,336	0.09	118

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Portfolio: Cost Components (in 1994 $)

Table 4-7

Description	Capital Cost: Unit Cost ($/kW)	Capital Cost: Transmission ($/kW)	Capital Cost: Payment Factor (%)	Capital Cost: Annual Payment ($/kW Year)	Fixed Cost: O&M ($/kW Year)	Fixed Cost: Expected Utilization Rate	Fixed Cost: Ttl. Capital & Fixed Cost (Mills/kWh)	Energy Cost in 1998: 1st Year (Cent/MMBTU)	Energy Cost in 1998: Levelized (Cent/MMBTU)	Energy Cost in 1998: Levelized (Mills/kWh)	Variable O&M (Mills/kWh)	TOTAL COST (Mills/kWh)
OWC Appliance	(113)		5.69	(6.44)		63%	(1.17)					(1.17)
UT Appliance	(108)		5.69	(6.14)		60%	(1.17)					(1.17)
WY Appliance	(108)		5.69	(6.14)		60%	(1.17)					(1.17)
UT Super Good Cents	2,322		5.81	134.89		84%	18.25					18.25
WY Super Good Cents	2,322		5.81	134.89		84%	18.25					18.25
OWC Super Good Cents	2,232		5.81	129.65		80%	18.55					18.55
OWC Irrigation	2,406		5.81	139.78		73%	21.75					21.75
UT Irrigation	2,389		5.81	138.74		73%	21.75					21.75
Utah Coal	1,795	60	8.32	154.34	28.40	92%	22.58	52.2	52.2	5.23	0.24	28.05
OWC Industrial	3,993		5.81	231.90		94%	28.30					28.30
WY Industrial	4,257		5.81	247.27		100%	28.30					28.30
UT Industrial	4,203		5.81	244.15		98%	28.30					28.30
UT Commercial Finanswer	2,601		5.48	142.50		54%	30.07					30.07
WY Commercial Finanswer	2,584		5.48	141.57		54%	30.11					30.11
OWC Commercial Finanswer	1,839		5.48	100.73		38%	30.27					30.27
UT Commercial Retrofit	2,677		5.48	146.64		55%	30.49					30.49
WY Commercial Retrofit	2,665		5.48	145.99		55%	30.49					30.49
OWC Commercial Retrofit	2,538		5.48	139.07		52%	30.50					30.50
Wyo Coal	1,942	60	8.32	166.57	28.40	90%	24.73	46.6	53.9	6.11	0.24	31.08
Utah IG CC	1,941	60	8.95	179.09	39.40	92%	26.99	52.2	52.2	4.50	1.00	32.50
Wyo IG CC	2,035	60	8.95	187.50	39.40	92%	28.03	46.6	53.9	4.72	1.00	33.75
Wyo FB Coal	2,355	60	8.32	200.89	32.20	92%	28.80	46.6	53.9	5.01	0.50	34.31
Utah FB Coal	2,454	60	8.32	209.16	32.20	92%	29.82	52.2	52.2	4.75	0.50	35.07
UT Finanswer 12,000	3,580		5.48	196.12		54%	41.39					41.39
WY Finanswer 12,000	3,556		5.48	194.83		54%	41.43					41.43
OWC Cogeneration 1	1,100		8.95	98.45	5.00	85%	13.89	289.8	492.6	27.09	0.50	41.49
OWC Finanswer 12,000	2,530		5.48	138.63		38%	41.66					41.66
Utah Cogeneration 1	1,293		8.95	115.72	5.00	85%	16.21	264.8	475.0	26.12	0.50	42.84
OWC Cogeneration 2	663	60	8.95	64.71	5.00	85%	9.36	289.8	492.6	33.50	0.50	43.36
Utah Cogeneration 2	779	60	8.95	75.09	5.00	85%	10.76	264.8	475.0	32.30	0.50	43.55
Utah Combined Cycle CT	742	60	8.95	71.78	10.00	80%	11.67	264.8	475.0	34.00	1.00	46.67
OWC Combined Cycle CT	687	60	8.95	66.86	10.00	80%	10.97	289.8	492.6	35.27	1.00	47.23
Wyo Combined Cycle CT	819	60	8.95	78.67	10.00	80%	12.65	264.8	475.0	34.00	1.00	47.66
OWC Pumped Storage	800		8.12	64.96	10.00	17%	50.11					50.11
Utah Pumped Storage	800		8.12	64.96	10.00	17%	50.11					50.11
Utah Wind with Tax C	750	212	9.84	94.66	9.50	36%	33.49	126.1	152.2	15.22	4.20	52.91
Wyo Wind with Tax C	750	212	9.84	94.66	9.50	36%	33.49	126.1	152.2	15.22	4.20	52.91
UT Residential Wx	6,180		5.78	356.95		73%	55.93					55.93
OWC Residential Wx	6,239		5.78	360.39		74%	55.93					55.93
OWC Wind with Tax C	805	120	9.84	91.02	9.50	28%	40.98	126.1	152.2	15.22	4.20	60.40
Utah Wind without Tax C	1,150	212	9.84	134.02	9.50	36%	46.15	126.1	152.2	15.22	4.20	65.57
Wyo Wind without Tax C	1,150	212	9.84	134.02	9.50	36%	46.15	126.1	152.2	15.22	4.20	65.57
OWC Wind without Tax C	1,120	120	9.84	122.02	9.50	28%	53.62	126.1	152.2	15.22	4.20	73.04
OWC Geothermal	2,076	120	8.95	196.54	58.00	90%	32.29	220.4	415.0	41.50	1.00	74.78
Utah Geothermal	2,076	120	8.95	196.54	58.00	90%	32.29	220.4	415.0	41.50	1.00	74.78
UT Xtra Comml Measures	5,573		5.48	305.34		39%	88.41					88.41
WY Xtra Comml Measures	5,573		5.48	305.34		39%	88.41					88.41
OWC Xtra Comml Measures	7,366		5.48	403.56		52%	88.50					88.50
OWC Water Heat Load Control	7,177		5.66	406.55		42%	111.06					111.06
Utah Solar	4,283	120	9.84	433.26	49.40	40%	137.74					137.74
Utah Simple Cycle CT	518	60	9.16	52.94	21.80	5%	170.65	269.8	480.0	50.61	3.50	224.76
Wyo Simple Cycle CT	571	60	9.16	57.80	21.80	5%	181.73	269.8	480.0	50.61	3.50	235.85
OWC Simple Cycle CT	479	60	9.16	49.37	35.76	5%	194.37	255.8	458.6	48.36	3.50	246.22

Note: some numbers changed since last draft

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pays, and the non-energy benefits the customer receives. However, the TRC does not include lost revenues -- revenues the company no longer receives due to lower energy sales after DSR implementation.

Table 4-6 shows the non-cost characteristics of each resource option for both demand-side and supply-side resources. Table 4-7 shows the cost components for each resource technology. Both tables rank the resources by total resource cost.

End Use

For RAMPP-3, PacifiCorp prepared a detailed analysis of the cost and possible energy and capacity savings for specific end uses in each customer segment. The models relied heavily on methods developed by the Northwest Power Planning Council. The company adjusted models of prototype buildings to match the characteristics and consumption patterns of PacifiCorp customers. The computer models estimated the amount of savings possible from specific conservation measures and the potential savings in industrial facilities.

Cost Ceilings

Cost effectiveness limits the potential energy and capacity savings of DSRs. The company used three cost levels to determine alternative demand-side strategies: a low level of demand side resource, with a 30 mills/kWh ceiling; a middle level, with a 55 mills/kWh ceiling; and a high level, with a 70 mills/kWh ceiling. The program development process for each level included all demand-side measures that cost less than the appropriate cost-effectiveness ceiling. The average cost of a program is less than the ceiling, because the program includes low cost measures in combination with measures costing up to the ceiling. The company then added administrative costs to each program.

Use of a cost effective ceiling does not mean the company will have to pay all costs of demand-side resources. In many cases, the company can reduce utility cost by sharing costs or redistributing benefits among program participants.

Energy Service Charge Approach

Typical conservation programs have one negative side effect: even though they are a low-cost way to secure additional resources, they can cause customer's prices to increase. Participants in conservation programs usually see their electricity prices go up, but their lower usage after installation of energy efficiency equipment causes their bills to go down. Customers who do not participate in DSR programs see their prices and bills increase. Therefore, DSR programs do not result in an even distribution of benefits across all customers.

PacifiCorp prefers a goal of ensuring that the beneficiary pays for demand-side measures. An Energy Service Charge (ESc) is one way to recover the costs of efficiency measures from customers who benefit from them. The ESc mechanism finances the cost of the efficiency measures as a loan from PacifiCorp or through other commercial financing sources. As customers repay the loans, non-participants benefit from avoided price increases. The primary goal of efficiency programs remains to capture the demand-side resource while minimizing the price impact on non-participants. PacifiCorp believes it can acquire the resource through demand-side programs and use the ESc to redistribute benefits. The company can adjust the level of the ESc, when necessary, to assure that it is not limiting acquisition of the demand-side resource.

Program Design

One concern with RAMPP-2 was whether the deployment rate for demand-side programs was optimal. RAMPP-3 explored the timing of demand-side programs with unconstrained-DSR model runs of the integration model. In an unconstrained-DSR model run, the integration model selected the least cost amount of DSRs without regard to the logistics of implementation.

The unconstrained-DSR model runs produced a set of program implementations that were not feasible. For example, the run suggested PacifiCorp implement all of its industrial program within one year because the program is low cost. In reality, the company cannot implement a program of that magnitude in such a short time, nor are all customers likely to participate within a narrow time period. The model did not select residential weatherization until late in the planning horizon with little ramp-up. Program designers must develop an actual deployment rate that considers both optimal and feasible deployment. Actual program designs recognize that programs require a ramp-up period.

The RAMPP-3 portfolio of resources offered to the integration model included nine DSR programs: Appliance, Super Good Cents, Irrigation, Industrial, Commercial FinAnswer, Commercial Retrofit, FinAnswer 12,000, Residential Weatherization, and Extra Commercial Measures. The Extra Commercial Measures provided a package of higher cost measures for commercial buildings. The model did not select this group of demand-side measures because its costs were too high compared to other demand-side and supply-side resource choices. A tenth DSR choice provided to the model was Water Heat Load Control in OWC as a pure capacity program. The model did not select that DSR option because less expensive capacity resources were available.

Each DSR program had a specified amount of resource in each year of the 20-year planning horizon, according to the ramp rate for the program. The amount of resource (energy and capacity savings) for a particular program varied depending on the demand-side strategy and the load forecast. The savings anticipated from each DSR program did not include the amount of background conservation assumed in the forecast.

The Demand-Side Appendix contains details on program development, program design, and resource estimates.

Changes Since RAMPP-2

The economic environment and energy market place have changed significantly since RAMPP-2. The potential for energy and capacity savings through efficiency over the next 20 years fell mainly due to slower economic growth. The medium load growth forecast rate for RAMPP-3 was lower than the medium-high load growth forecast rate for RAMPP-2. In addition, new legislative codes and appliance efficiency standards reduced the need for several utility programs, especially in the residential market. Finally, recent program experience provided more accurate information on program costs and potential for market penetration. The company adjusted assumptions for demand-side resource development in RAMPP-3 to reflect these changes.

SUPPLY-SIDE RESOURCE ALTERNATIVES

This section describes each of the technologies in the supply-side portfolio by geographic area -- OWC, Wyoming, and Utah. The OWC area includes Oregon, Washington, and California load areas, the company's hydro plants in the western states, and the Centralia coal-fired plant. The Wyoming area includes only the eastern Wyoming service area, and the Dave Johnston and Wyodak coal-fired plants. The Utah area includes loads within Utah, southern Idaho, and southwestern Wyoming, and several coal-fired plants, the Gadsby gas-fired plant, and Utah hydro.

The company used in-house cost estimates or research on generic plant costs. Costs include financing costs during construction (AFUDC), fuel transportation and storage, and are in January 1994 dollars. Heat rates are on an average annual basis. A plant's heat rate is the amount of btu's of input energy required to produce one kWh of output, thus lower heat rates are better. Plant costs differ between the regions mainly because of elevation. For combustion turbine-based options in particular, elevation affects output and capacity. The company assumed an elevation of 2,000 feet for plants in the OWC area, 4,500 feet for the Utah area, and 7,000 feet for Wyoming. Variations in coal quality between Utah and Wyoming resulted in different heat rates and emissions. Natural gas transportation costs also varied between areas.

Table 4-7 shows the total costs that were input into the model. Those costs include the total capital costs (including transmission integration) as well as the fixed O&M, variable O&M, and fuel costs. For supply-side resources, these total costs are consistent with the definition of total resource costs.

Coal-Fired Resources

The portfolio included three types of coal fired resources: pulverized, integrated gasification combined cycle, and fluidized bed. The most economical location for a coal plant is either Utah or Wyoming because of proximity to coal supplies and to existing plants that have room for expansion. The portfolio tables (table 4-6 and 4-7) include six entries for coal-fired plants (each of three technologies in two areas). The total costs for all new coal resources include the current selling price of $160/ton for SO2 allowances, which translates to $.0013/kWh assuming Hunter 2 heat rates, 85 percent plant utilization, and 90 percent SO2 removal rates.

Greater accuracy argued for separate resource entries on the portfolio table and in the model inputs for plants at existing sites and plants at new sites. However, two other factors argued for more limited entries. First, the company tried to limit the number of entries to reduce the clock time required for each model run. Second, RAMPP is a study using generic technologies; if and when the company decides to build a coal plant, the costs for the specific site would be carefully analyzed and compared to other resource alternatives. Existing sites would have several advantages over a new site due to existing fuel supply contracts, coal handling facilities, transmission and cost advantages. Each table entry is an average of costs. Each potential coal unit in Utah is an average of the costs for a fourth unit at the Hunter site, a small generic plant (location unknown) and a large generic plant (location unknown). Each potential coal unit in Wyoming is an average of the costs for a second unit at the Wyodak site, a small generic plant (location unknown) and a large generic plant (location unknown).

Fixed - costs.

The heat rate for Wyoming coal is higher than for Utah coal, because Wyoming coal typically has a higher moisture content. In addition, Wyoming coal has a lower heat content (8,500 btu vs 11,500 btu), and the Wyodak site includes an air-cooled condenser, which penalizes the heat rate by approximately 10 percent. Utah coal's capital cost is less than Wyoming coal's capital cost for three reasons: some of the design, construction, and procurement for Hunter 4 had started before it was canceled, and therefore the cost to complete Hunter 4 would be less than a grassroots coal plant; Utah coal does not include an air-cooled condenser, like Wyodak, which costs $100/kW more; and Utah coal's costs include less AFUDC because Hunter 4 could be completed one year sooner than plants in other locations.

Conventional pulverized coal plants use a steam boiler that burns coal. The technology meets all emission control requirements for particulate removal, achieves 90 percent removal of sulfur dioxide (SO2), and includes low-nitrogen oxide (NOx) burners. This technology is mature and reflects the company's current power plants. PacifiCorp would examine the cost effectiveness of other coal technologies at existing sites before adding any new units using pulverized coal technology.

Integrated gasification combined-cycle (IGCC) plants burn gas from pulverized coal. The coal goes into a gasifier where it reacts with steam and oxygen to produce an intermediate gas. After the gas passes through a cooling section, the process removes nitrogen and almost 99 percent of the sulfur compounds. The clean gas burns in a combustion turbine. The hot exhaust gases generate steam in heat recovery boilers. The steam drives a steam turbine generator.

Low pollution levels are the major advantage of an IGCC plant. Total emissions decline because the heat rate for combustion turbines is less than the heat rate for a pulverized coal resource. The heat rate for a pulverized coal plant is 11,900, but only 9,192 for an IGCC plant, resulting in fewer pounds of coal required per kWh produced, thus lower emissions per kWh. IGCC equipment can be added to natural gas-fired combustion turbines if gas prices rise enough to make it economical. The IGCC plant used to develop the RAMPP-3 cost estimate is an oxygen-blown Destec gasifier combined with a GE 7F combined-cycle equipment similar to the Public Service of Indiana (PSI) project being built in Terre Haute, Indiana.

Fluidized bed coal plants use crushed coal with limestone to provide electrical generation without using sulfur dioxide (SO2) scrubbers). The calcium in the limestone captures most of the sulfur released from the coal during combustion. Atmospheric fluidized bed combustion (AFBC) uses air to suspend the coal during combustion. The technology includes a conventional steam cycle very similar to a pulverized coal plant. The use of AFBC can result in the use of a wider variety of coals at lower levels of NOx emissions than a comparable pulverized coal boiler. AFBC plants have gained a measure of commercial acceptance in the 50-175 MW size range.

Construction lead times for a new coal plant would be four to five years from permit approval, depending on weather. Permitting would require at least three years, or only two years if the plant would be at an existing site. New coal resources carry certain risks. There is potential coal price uncertainty, uncertainty of the clean coal technologies, and uncertainty over a future environmental tax or emission limit. 6-8 yrs LEAD T.

Utilities design baseload coal-fired resources to operate at or near full load to maximize operating and fuel efficiencies and minimize maintenance costs. Cycling between stable minimum and maximum load levels occurs during surplus or off-peak times. If the unit is on line, equipped for AGC and not fully loaded, the remaining capacity can qualify for spinning reserve. Depending on the ramp rate of a particular unit (usually 3 to 4 MW per minute), part of that capacity can also qualify as operating reserve. Ramp rates from a cold start to full load are generally 6 to 12 hours.

PacifiCorp monitors the coal market for reserves, long-term contracts and spot purchases, to evaluate the most cost-effective fuel strategy for existing and new plants. The company developed a coal price and a forecast escalation rate for two regions: the Powder River Basin area of Wyoming and the Carbon/Emery County area of Utah. Graph 4-8 shows the price stream for those two areas, and a higher coal price for the Utah area, used in some sensitivities. The coal requirement for a unit in either region would be 1 to 1.5 million tons per year.

At the time the coal price estimates for RAMPP-3 were prepared, the coal markets were reasonably stable and both had substantial coal available from existing mines. The company used spot pricing for future cost estimates. The company expected prices to remain flat in real terms, that is, to increase only at the level of inflation in Utah and to increase modestly in Wyoming. The 1993 coal price for the Powder River Basin area of $7.20/ton (included $4.00/ton transportation) assumed a new coal plant would be at the Wyodak or Dave

why not average of plant at existing site & greenfield plant at unknown location

Johnston plants or somewhere in between. The 1993 coal price for the Carbon/Emery County area of Utah of $12.00/ton (included $1.60/ton transportation) assumed a new coal plant would be located at or near the Hunter or Huntington plant sites. These coal prices resulted in a 47 cents/mmbtu cost in Wyoming, and a 52 cents/mmbtu cost in Utah. Again why not average of prices

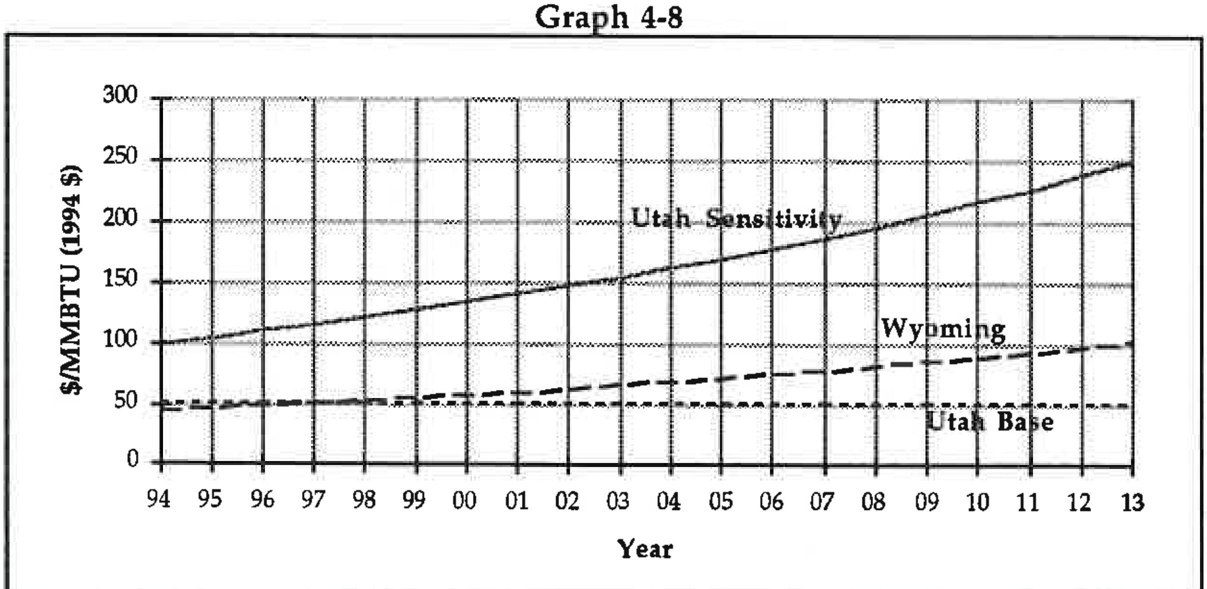
After the major analysis work for RAMPP-3 was finished, the coal market began to change. The Wyoming market is experiencing increased demand from midwestern utilities, but these new market pressures are expected to be ? temporary. Adding to Wyoming coal supplies requires only more trucks and more people. Sufficient coal supplies in Utah at the $0.52/mmbtu price are available for only one additional unit (about 1.5 million tons). The coal required by additional units would require additional capital investment in coal mining facilities. The Utah coal price is really a step function. The coal price for a second unit would increase by about 50 percent, and the coal price for additional units would probably double, to $1.06/mmbtu.

The cases in the base study plan that allowed new coal plants added from a few hundred to almost 4,000 MW of new coal plants. It was not feasible to re-do all of the any-coal runs to include the step-function coal price for Utah. The Analysis Plan chapter describes five sensitivities the company used to explore the impact of coal price uncertainty in the Utah area. The sensitivities doubled the Utah coal price, to $1.06/MMbtu. RAMPP-4 will use a step function for coal prices for new coal units.

Table 4-8 shows the escalation of coal prices under the three assumptions. The Wyoming prices have 0.9 percent real annual escalation; the Utah base prices have zero percent real annual escalation; the Utah sensitivity prices have 4.95 percent real escalation.

Gas Prices

Graph 4-8



Gas-Fired Resources

The total price for each gas-fired resource varied in the different model runs, depending on which gas price forecast was used for that model run. Siting of new natural gas-fired generation facilities will depend partly on accessibility to gas transportation and competitive gas markets. PacifiCorp will evaluate gas storage as a way to increase transportation load factors, peaking capabilities, and the company's ability to take advantage of seasonal variations in gas prices.

Gas prices consist of five different components: commodity cost is the cost of the actual gas at the wellhead (addressed in the futures chapter); shrinkage and taxes include the pipeline charges to operate compression equipment and various taxes (5 percent of the commodity charge); transportation is the fee the pipeline company charges to move the gas from the wellhead to the user's site (varies by area and assumed utilization); storage is the cost incurred to store gas for later use (varies by area and assumed utilization); and injection and withdrawal charges for injecting or withdrawing gas from underground storage (varies by area). The company used the following cost estimates by area:

Gas Price Components by Geographic Area
Table 4-9

	East-Side	West-Side
Transportation	$0.20/mmbtu	$0.45/mmbtu
Storage demand	$2.8 million*	$1.6 million**
Transportation demand		$3.5 million**
Storage injection/withdrawal	$0.05/mmbtu	$0.11/mmbtu

* For a 135 MW unit operating at a 20% capacity factor
**For a 147 MW unit operating at a 20% capacity factor

The East-side area should not experience transportation demand charges, because of the availability of more pipelines.

The portfolio included two types of natural gas-fired resources: simple cycle combustion turbines (SCCTs) for peaking, and combined-cycle combustion turbines (CCCTs) for baseload generation. Cogeneration also typically uses natural gas, but a separate section discusses its characteristics.

An SCCT burns fuel (natural gas) in the presence of compressed air. The resulting gas mixture, at an elevated temperature, expands through a power turbine. The power turbine turns both the compressor (used to generate the compressed air) and an electric generator. SCCT technology is mature and commercially available. Construction lead times are about two years with another two years needed for the necessary permits. Environmental impact is low, with the greatest problem being nitrogen oxide (NOx) emissions, but control technologies are available.

The advantages of SCCTs include low capital cost and flexible load shaping capability (i.e., they can respond easily to fluctuations in electrical load). The main disadvantages of an SCCT are its high heat rate (requires more fuel to produce one kWh of electricity than does a coal plant, for example) and uncertainty over the future cost of natural gas. Because of higher fuel costs, utilities typically use SCCTs to provide peaking power only. They typically do not have capacity factors (the ratio of time they operate to the amount of time they could operate) of more than 15 to 20 percent, and may operate at capacity factors below 5 percent. The low capacity factor creates the need for some form of standby fuel, storage, or firm gas transportation contracts. Once an SCCT unit is on line, it has some flexibility to operate between minimum and maximum load.

Increased efficiency results from adding a heat recovery steam generator to a combustion turbine and creating a combined-cycle system, called a combined cycle combustion turbine (CCCT). Added equipment to gasify coal would enable the equipment to use coal, if natural gas becomes too expensive. The system would then be an integrated gasification combined cycle (IGCC) plant. The discussion of coal resources, above, includes the IGCC system.

CCCT technology is mature and commercially available. Siting, permitting, and construction lead times are similar to those of the simple cycle machines. CCCTs require a water source since they use cooling towers as a part of the steam turbine cycle. The main problem with CCCTs is the uncertainty of natural gas prices. Steam injection or dry low-NOx burner technology can control NOx emissions.

The use of the combined cycle greatly improves the heat rate of the plant and makes natural gas cost effective for baseload generation. While there are operating efficiencies and maintenance considerations similar to other baseload plants, the CCCT can respond quickly to short-term load requirements, and offers spinning and operating reserve subject to ramping limitations. Cold start ramping to full load generally takes about two hours.

Cogeneration

PacifiCorp identifies opportunities for cogeneration through two distinct channels. The first is through its operating divisions' routine contact with industrial customers; the second through solicited and unsolicited contacts with resource developers by the company's power systems planning and resource acquisitions groups. Following the initial contact at a customer's site, PacifiCorp conducts an engineering analysis of the production process and its associated cogeneration potential. When the customer's plans allow for installation of an economical cogeneration system based on thermal matching of the generation and process needs, PacifiCorp usually enters into more detailed discussions.

Resource developers provide cogeneration opportunities, typically at sites other than PacifiCorp customers. The company evaluates these opportunities as it receives them, and then compares them to other resource opportunities in an on-going competitive process.

The cogeneration resources identified through these evaluations consist of a large variety of projects. They vary in technology, fuel type and efficiency. Technologies typically include back pressure steam turbines, combustion turbines with heat recovery steam cycles, and combined cycles with combustion turbines and steam turbines. While all of the viable cogeneration projects have efficiency advantages over the same project configured without cogeneration, the closer the cogeneration cycle matches the thermal needs of the production process, the higher the overall cycle efficiency. At any time, the company has numerous, viable projects to compare to its resource needs.

The portfolio included Cogeneration 1 and Cogeneration 2 in each of two regions, OWC and Utah. Cogeneration 1 represents units with relatively high capital costs and low heat rates, such as a back pressure steam turbine or small combustion turbine unit, and a high percentage of thermal matching. Cogeneration 2 represents units with relatively low capital costs and higher heat rates, typically large CCCT configurations, with varying amounts of process steam extraction from the steam portion of the cycle. The process steam usage is the distinguishing difference between the Cogeneration 2 units and the non-cogeneration CCCT units discussed above under Gas-Fired Resources.

Actual costs and performance of cogeneration resources are very site specific depending on the steam and heat requirements at the host site, existing equipment at the site, fuel, and emissions control regulations. The costs for the cogeneration options are from internal estimates that used vendor prices for major equipment, primarily the gas turbine generator. In the case of the small units, the cost assumed an aeroderivitive gas turbine such as the General Electric LM-6000. The cost for the large unit assumed an industrial frame gas turbine such as the GE or Westinghouse "F" technology units. The base cost assumed sea level installation in the OWC area; costs for Utah were altitude adjusted.

The marketplace influences the price PacifiCorp must pay for cogenerated power. Each customer can negotiate a price for the potential power output that is competitive with what they could get from any other interested buyer in the marketplace. In addition, the customer's choice of fuel and its forecasted price will often strongly influence the negotiated price. The Company has little control over when it can bring cogeneration on line and dispatch it, because the customer's processing needs drive production of cogenerated power.

The value of a particular cogeneration project to PacifiCorp's system depends in part on the company's system at the time and the location of the project. If sufficient flexible resources already exist on PacifiCorp's system, then the cost per MWh of the cogeneration project becomes more important. If there is a need for flexible resources, a resource with a low cost but without flexibility would have less value. The company carefully weighs the need for flexibility on a system and area basis before committing to any particular cogeneration project.

Wind

Wind generates electricity by turning turbines attached to a generator. A typical wind energy system is a "farm" of many turbines. Wind turbine technology has changed significantly over the last 13 years and is now entering its third generation of development and testing. Systems in the 50 to 500 kW range are a proven technology. Advantages of wind power include size flexibility, minimum environmental impact, no fuel cost and a short lead time for construction.

Current costs reflect contracts with Kenentech Windpower for wind farms in Washington and Wyoming. The portfolio separately identifies costs for wind resources that would qualify for federal tax credits and those that would not. To be eligible for the 1.5 cent/kWh production credit under the 1992 National Energy Policy Act, the project must be in service before July 1, 1999. The project's eligibility would last for ten years. For eligible wind projects the credit results in a $315/kW (25 percent) reduction in capital cost in OWC, from $1,240 to $925; and a $400/kW (29 percent) reduction in capital costs in UTA and WYO areas, from $1,362 to $962. The tax credit is a function of the capacity factor, which is higher in UTA and WYO, thus wind located in those areas has a higher credit.

The quality of a wind resource, and therefore its cost, is very site-specific. The primary consideration for site selection is local meteorology, elevation, topography and terrain. The best sites for wind farms are in wind corridors, such as canyons or valleys, high plains or plateaus, or on high elevation ridges. A 50 MW wind farm is the minimum practical size. The most important factor for a successful wind farm is a consistently strong wind. The average wind speed must be more than 14 mph for a site to be acceptable. Since the wind power produced is proportional to wind velocity cubed, a small increase in wind speed will significantly increase energy output.

Disadvantages of wind power include a low capacity factor, variable wind at most sites, and potential aesthetic impacts of large numbers of wind machines on the landscape. Wind that peaks at about the same time as the system load peaks is desirable. If the daily and annual peak of the wind resource complements the utility's peak, the power produced by the wind farm has greater value.

Wind is the most difficult resource to schedule without disrupting existing resources, and requires additional reserves from other resources to offset its output variations. Because wind velocity varies, wind turbines do not provide predictable capacity (or reserves) to the system. As wind forecasting techniques improve, wind power should become a more flexible resource for the utility.

Geothermal

Heat from the earth has generated electricity for many years at various locations around the world. Flashed steam plants use geothermal fluids that are hot enough to flash to steam when raised to the surface and partially depressurized. This steam drives a steam turbine generator. Binary cycle plants use geothermal fluids that are too cool to produce useful amounts of steam. In these plants the geothermal fluid vaporizes a secondary working fluid having a low boiling point. The secondary working fluid drives a turbine generator. Both flashed steam and binary cycle units are commercially available. Continuous operation of a geothermal plant as a baseload unit allows the purchasing utility to derive maximum benefit from the investment and steam contract, but cycling is possible.

Geothermal facilities require only about 24 to 36 months for construction. However, confirming the quantity and quality of a geothermal resource is a difficult, expensive and risky business. Actual energy costs for geothermal power will vary considerably from site to site. Costs vary according to fluid temperatures (and related thermal efficiencies), fluid chemistry, reservoir depth, and the conversion technology used. The options in the portfolio assumed that PacifiCorp would not be the developer of the steam resource.

The long-term reliability of the working fluid can also be uncertain. The steam resource at Pacific Gas & Electric's Geyser Plants is diminishing. According to the May 1993 issue of Geothermal Resources Council Bulletin, the Geysers is experiencing rapidly declining steam resources and serious productivity declines due to over-development in the 1980s. While geothermal energy is attractive from an environmental point of view, a limited number of sites are available.

The PacifiCorp service area includes three to four potential geothermal sites. Geothermal developers are investigating several known geothermal resources in Oregon and Northern California. Another likely site for future development would be the Roosevelt steam field in Utah, the site of PacifiCorp's Blundell plant. The company signed the current 30-year contract for steam for the Blundell plant in January of 1991. PacifiCorp does not hold any geothermal leases in the area. Companies that do hold such leases could drill new wells for steam and develop additional plants there, or sell the steam to PacifiCorp.

Solar Power

Thermal energy conversion can convert energy from the sun into electricity (solar heat makes steam that then drives a generator). Photovoltaic (PV) systems can also convert solar energy into electricity. In PV systems, sunlight falls on a semiconductor surface, usually made of silicon, and directly produces an electrical current. Although PV costs have declined dramatically, they are generally not competitive with other supply alternatives. PV systems are an economical choice for providing low levels of power to remote locations, where transmission costs can be extremely high. Because PV's costs as a central-station generating plant are still very high, the portfolio does not include PV. The RAMPP-3 action plan addresses four company projects that will provide experience with PV technology.

Thermal solar systems can potentially meet bulk power needs of a utility system. In a solar thermal system, a fluid heated by solar energy drives a heat engine. Solar thermal systems are a commercial product. There are three basic solar thermal power plant technologies: 1) dish systems, 2) parabolic trough, and 3) central receiver. Although the technology for dish systems is not yet commercially viable, it is one of the most promising solar thermal resources. A parabolic dish concentrator focuses sunlight on a receiver at the focal point of the dish, producing very high temperatures. PacifiCorp submitted two proposals to the Department of Energy (DOE) to participate in the financing and operation of sterling dish projects. The DOE selected one project for final negotiation, and contract discussions are underway.

The solar resource costs used in the RAMPP-3 portfolio used the LS-3 parabolic trough system technology. The LS-3 technology is mature and commercially available through a Belgian firm located in Israel called SOLEL. The system uses gas-fired boilers or oil heaters to generate power during the night or in overcast periods. The hybridization allows a utility to dispatch these plants like a thermal unit. Sandia and Bechtel/PG&E studies provided the cost data. Some of the best solar sites in the United States are located in Utah. The RAMPP-3 portfolio included only Utah sites for solar resources.

Development efforts such as Solar II suggest that central receiver/molten salt plants could be the technology that will provide high value energy at the lowest cost of any bulk power renewable resource in the 2000-2010 time frame. Such a system can provide dispatchable energy from thermal energy stored in molten salt. Energy storage allows the plant to have an annual capacity factor of 40 to 60 percent, compared to 25 percent for other solar technologies when not using a backup fossil fuel.

Solar II is a test facility for the central receiver/molten salt technology. The $39 million project is being jointly funded by the U.S. DOE and a consortium of utilities, including PacifiCorp. PacifiCorp's participation in Solar II will allow the company direct access to cost and performance data and will help to foster development and commercialization of this technology. Southern California Edison is acting as the project sponsor, and will operate the facility.

The cost estimates in the portfolio do not include tax credits for solar resources because current tax credits will probably not apply in the early 2000's when solar resources should become cost competitive. The Energy Policy Act permanently extended the investment tax credit, but utilities do not qualify for it.

Pumped Hydro Storage

Pumped hydro uses low-cost off-peak electricity to pump water to an upper reservoir. When the utility needs power, it discharges water through a reversible pump-turbine to a lower reservoir, producing electricity. The lower reservoir can be above ground, or underground if a suitable underground cavern or reservoir is available. This technology is mature with many facilities now in operation throughout the world, but its costs are very site specific. Costs in table 4-7 reflect preliminary proposals made to PacifiCorp for pumped hydro sites in the company's service territory. These sites are not on rivers, which would remove fish concerns in the siting process. The 100 MW size reflects PacifiCorp's share of a future project rather than the total size of a facility.

Two pumped storage projects in the Pacific Northwest region reflect current interest in this technology. PacifiCorp is not a partner in either project. Energy Storage Partners out of Minneapolis is developing the Lorella project near Olene, Oregon. The project developers are now seeking the necessary permits and marketing the power. The location of the project near the Pacific Intertie and two major substations at the Oregon/California border would enable the project to sell power to Oregon in winter and California in summer. Albert Rim Hydroelectric Associates of Greenville, South Carolina, is developing a second project in south central Oregon. Environmental concerns may arise with this project because of its potential impact on the local area's land and wildlife.

Pumped storage is a peak management resource that can significantly improve the efficiency and flexibility of a system that has low-cost, off-peak generation available. Pumped storage provides peaking capacity, load following, firming for other resources, highly reliable and dispatchable generation and energy storage. Pumped storage, if ideally located, could enhance the cost effectiveness of the Company's existing thermal resources by providing a use for generation during hours when there would otherwise be less need to run the plants. This would result in more even and constant usage of the thermal plants, increasing their efficiency and decreasing their deterioration. Pumped storage units can provide spinning reserve if properly equipped, and can provide operating reserves, even if off-line, since they can start up in minutes.

TRANSMISSION SYSTEM

The transmission system linking Wyoming, Utah and the Pacific Northwest allows the company to take advantage of the load and resource diversities between the Pacific Northwest and Rocky Mountain and Desert Southwest areas. By taking advantage of these interconnections and diversities, the company can increase system operating efficiencies beyond those already achieved by the Utah Power/Pacific Power merger. However, the transmission system has capacity constraints that limit the flow of power between certain load and resource areas. Planning for resource additions must recognize these limitations.

The PacifiCorp electric system operates within the Western Systems Coordinating Council (WSCC) interconnected transmission network. The WSCC began in 1967 to provide for the coordination of transmission system operation and planning among the member systems. The WSCC interconnected systems include the Western states, western Canada, and a portion of northwestern Mexico.

The member systems' transmission within the WSCC operate electrically as one network. Physical limits of the interconnected member systems and contractual and ownership rights of the members constrain the movement of power across and through the WSCC system. Various WSCC committees determine transfer capabilities between major load and resource areas by examining thermal capabilities, voltage constraints, and transient behavior during disturbances. The monitoring, reinforcement, and expansion of this transmission network is the major work of the WSCC Planning Committees.

The WSCC transmission network transfers firm and non-firm power from one region to another. The network is becoming more and more constrained as members have had to site resources far from their load centers, and firm- and non-firm power sales between utilities increase. Many lines and paths operate at or near their recognized capabilities. The nature of electrical networks is such that operating one path at high levels can cause problems in other paths. Most member utilities now find themselves in the same position: cheap surplus transmission is no longer available. When load requires more capacity, it will often require new expensive transmission lines.

PacifiCorp has enough transmission capacity in each geographic area to serve the loads in these areas. However, transmission constraints limit transfer of power between these areas. At present, existing generating resource capability on the east side of the system could meet additional west side requirements if more transmission capacity were available. The company is evaluating its short- and long-term transmission requirements and capabilities, and is developing a long-term transmission plan to increase east-to-west capacity. This transmission evaluation work will enable the company to better identify the appropriate geographic locations for specific transmission resources. If available when RAMPP-4 requires it, RAMPP-4 will include information from the new long-term transmission plan.

The RAMPP-3 portfolio added to the cost of each resource additional dollars for transmission to connect the future resource to the system grid. The estimates were generic in nature, independent of resource type, and included costs for a susbstation, transmission line, and a transmission switching station. These costs do not include additional equipment necessary to upgrade transmission facilities to move power from one geographic area to another PacifiCorp load area. The cost to upgrade transmission between areas could affect the choice and timing of cost-effective resource additions. Table 4-7 shows the generic intra-area interconnection cost.

1) Resources such as coal, IGCC, SCCT, CCCT were assumed to be over 400 MW and within 50 miles of existing transmission with a cost of $60/kW.

2) Wind and geothermal sites in the OWC area were assumed to be 200 MW or smaller and 50 miles minimum from existing transmission for a connection cost of $120/kW.

3) Wind sites in Utah and Wyoming were also assumed to be 200 MW or smaller and, as demonstrated by PacifiCorp's Foote Creek project, in very remote locations relative to the company's transmission facilities, for a connection cost of $212/kW.

Transmission and Distribution Efficiencies

Transmission and distribution efficiencies are a resource to the company, in that they can increase the amount of power available to serve customers. Currently, losses throughout the transmission and distribution system average 10 percent, and load forecasts assume this historic loss level will continue. The company uses three criteria for selecting projects to reduce line losses:

1) *Total cost of ownership over life of equipment.* This includes the purchase and installation of new distribution and substation transformers and new conductors, adjusted by the value of loss savings over a 30-year life.

2) *Number of years until positive cash flow.* This applies to categories such as reconductoring, installation of capacitors, and conversions to higher voltage levels. The value of loss savings should exceed annual revenue requirement in five years or less.

3) *Personnel constraints.* Reswitching, phase balance, and conservation voltage reduction (CVR) have low costs but require extensive study efforts to identify specific projects. Because PacifiCorp's system is geographically dispersed, the company focuses on a different geographic area each year to identify specific projects. Adding additional personnel to be able to identify more projects each year would increase costs and make fewer projects cost effective.

PacifiCorp annually evaluates and ranks potential projects. The company considers the following categories of costs for potential projects: distribution and transmission system transformers, use of larger primary conductors on new mainline feeder construction, use of larger secondary conductors on new installations, reconfiguring selected feeder systems to reduce loading on heavily loaded portions and better use lightly loaded circuits, installation of additional capacitor banks on selected feeders with high reactive loadings, balancing feeder loading between phases, and equipment at transmission substations to reduce losses. The only item not related to system loss reduction is conservation voltage reduction (CVR). This item represents an estimated reduction in customer usage from a small reduction in feeder voltage levels. About 90 percent of the listed CVR resource is customer load reduction, while about 10 percent is system loss reduction due to the load reduction.

DISCOUNT RATE

A discount rate determined the real levelized cost of resources, which provides a way to compare resources that have different cost structures and different lifetimes. The company used its after-tax incremental cost of capital as the discount rate for RAMPP-3. Cost of capital represents the return required by all investors, including debt holders, preferred shareholders and common shareholders. Each group of investors requires a return that compensates them for the level of risk they have assumed by investing in the company. Each company's cost of capital varies according to its capital structure (percentage of capital provided by debt, preferred stock, and common stock), the return required by each investment group, and its tax rate. Therefore, a weighted average incremental cost of capital must consider the cost for each component of the capital structure and the amount of each component.

In regulatory proceedings the company uses a hypothetical capital structure that reflects an electric utility of comparable credit ratings (i.e., "A" rated). An A rating, under current market conditions, enables the company to obtain low-cost capital and ready access to capital markets. Recent regulatory commission proceedings have accepted this approach to determining PacifiCorp's capital structure.

The capital structure used in RAMPP-3, and stipulated in several jurisdictions, provides an efficient balance of debt and equity for a low overall cost of capital:

	Capital Structure	Cost	Weighted Cost	
Debt	49%	8.99%	4.41%	
Preferred	6%	8.93%	0.54%	
Equity	45%	12.20%	5.49%	10.13
Total	100%		10.43%	

The cost of equity is based on the results using three methods: Capital Asset Pricing Model, Risk Premium Model, and Discounted Cash Flow Model. The cost of debt is based on the historical spread of returns on A-rated utility bonds over AA-rated utility bonds. This spread is then added to future projected yields on AA bonds, as provided by Data Resources, Inc., to predict future yields on A-rated utility bonds. The same methodology is applied to historical returns on AA-rated utility bonds versus baa-rated utility preferred stock to predict future costs of preferred stock.

This capital structure is also representative of other A-rated utilities in the Salomon 100 group. These A-rated utilities include companies rated between A+ and A- by both Moody's and Standard & Poor's. A 45 percent equity ratio is the minimum level consistent with an ongoing A rating. Because of increased competition and risk in the industry, several rating agencies believe the electric utility industry needs to increase the equity component of its capital structure. Therefore, the equity ratio will likely increase rather than decrease over time.

Using a "nominal" discount rate to compute "real" levelized cost ?!

To calculate a real levelized cost for each resource shown in Table 4-7, the company used a discount rate of 8.8 percent. The 8.8 percent discount rate is simply the company's 10.43 percent incremental rate of return with the debt component expressed on an after-tax basis. Using a tax rate of 36.91 percent applied to the debt cost, the after-tax cost of capital used in RAMPP-3 was 8.81 percent. The 10.43 percent rate used the pre-tax cost of debt. The cost of preferred and common stock was expressed on an after-tax basis in both cases.

RAMPP-3 used an average of the expected cost of capital for the utility over a 20-year RAMPP planning period. When analyzing investments today, the company would use today's cost of capital rather than a 20-year average. In either case, however, the cost of capital is incremental.

To calculate an annual payment on capital costs (also called the capital carrying charge) for each resource, the company first calculated the year-by-year capital revenue requirements for the particular resource, including the company's rate of return, recovery of capital (depreciation), and income taxes. This stream of year-by-year revenue requirements was then present valued using the 8.81 percent discount rate. Next, another stream of annual payments was created which increase at the rate of inflation each year and has the same present value as the stream of year-by-year revenue requirements. The company used a long-run inflation assumption of 3.4 percent in this step. To calculate the real levelized capital carrying charge (the annual payment found in the third column of table 4-7), the company calculated the ratio of the first-year payment to the present value total of the second annual stream. The annual payment on capital costs varies by resource because of varying book lives and tax treatment.

The company believes that new resource acquisitions will not significantly alter its capital structure, because the company will issue new debt or new equity as needed to maintain a capital structure that meets the above goals. The company is not asking its state regulatory commissions for a premium for purchased power at this time because of purchased power's potential impact on rating agencies' perception of the company's capital structure. If conditions should change such that the company at a later time believes that prudent resource actions justify such a premium, it will notify the commissions and make such an application.

Some argue that evaluation of an investment should use the cost of debt rather than the cost of capital if financing for that project would be with debt rather than equity. (The cost of debt is generally lower and provides a tax deduction.) However, financing with only debt would use up some of the company's ability to issue new low-cost debt in the future, which would make the next project more expensive. At some point, the company will need to issue equity in order to maintain its lowest overall capital structure. Too much debt in the capital structure would increase the financial risk of the company, and require the company to compensate investors with higher returns on their debt and equity investments. Alternatively, a greater amount of equity would reduce the company's financial risk and its incremental debt costs, but the larger amount of equity would increase the weighted average cost of capital.

An issue in integrated resource planning is whether the levelization process to compare resources should use a social discount rate. A common social discount rate, and the one requested by the public advisory group for a sensitivity analysis, is three percent real, or about 6.5 percent nominal. This 6.5 percent rate compares to a company incremental after-tax cost of capital of 8.8 percent nominal. Table 4-10 shows the ranking of resources using a social discount rate for levelization, rather than the company's cost of capital. The social discount rate changed the ranking very little. To test the impact of the new ranking of resources, a sensitivity used the cost of resources from table 4-10. The Illustrative Plans chapter discusses the results of that sensitivity. Table 4-11 shows the ranking of resources in the portfolio under both the company's discount rate and the social discount rate.

The calculation of a levelized cost for each resource technology provides the relative cost of the different technologies. It is an initial tool to compare resource alternatives, and an initial idea of how the model will select resources. Table 4-7 can also provide insight into how much lower a given resource's cost must be before it is competitive compared to the alternatives. Utah pulverized coal was the least expensive at a real levelized total cost of 28 mills/kWh, followed by Wyoming pulverized coal at 31 mills/kWh, Utah IGCC coal at 32 mills/kWh, and Wyoming IGCC coal at 34 mills/kWh. Under the coal price sensitivities, the real levelized cost of Utah pulverized coal increased to 38 mills/kWh and Utah IGCC coal increased to 41 mills/kWh. After coal, the next most cost-effective supply-side resource technology was cogeneration, which fell in a range of 42 to 44 mills/kWh. Thus, cogeneration costs would have to decrease by about 13 mills to be competitive with coal. CCCTs' costs were 47 to 48 mills/kWh. Wind plants using the federal tax credit cost 53 mills/kWh. Thus wind costs with the tax credit would have to decrease by about 25 mills/kWh to be competitive with coal, or about 10 mills/kWh to be competitive with cogeneration.

The cost estimates in Table 4-7 used an assumed capacity factor. The modeling process itself provided a much better comparison, because it used a capacity factor for each resource based on how the model would operate that resource. The model picked resources on price, which provides useful information to the company, but management makes its decisions on other criteria as well, such as resource operability and fit with the existing system. Also, the costs of resources presented in this chapter reflect generic technologies. The actual costs which PacifiCorp would incur in acquiring a certain resource are highly site specific and may be more or less than the estimates used in the resource planning model.

Portfolio: Using Social Discount Rate (3.0% real)

Table 4-10

	Capital Cost				Fixed Cost			Energy Cost in 1998				
Description	Unit Cost ($/kW)	Trans-mission ($/kW)	Payment Factor (%)	Annual Payment ($/kW Year)	O&M ($/kW Year)	Expected Utilization Rate	Ttl. Capital & Fixed Cost (Mills/kWh)	1st Year (Cent/ MMBTU)	Levelized (Cent/ MMBTU)	Levelized (Mills/ kWh)	Variable O&M (Mills/kWh)	TOTAL COST (Mills/kWh)
OWC Appliance	(113)		3.92	(4.44)		63%	(0.80)					(0.80)
UT Appliance	(108)		3.92	(4.23)		60%	(0.80)					(0.80)
WY Appliance	(108)		3.92	(4.23)		60%	(0.80)					(0.80)
UT Super Good Cents	2,322		4.08	94.75		84%	12.82					12.82
WY Super Good Cents	2,322		4.08	94.75		84%	12.82					12.82
OWC Super Good Cents	2,232		4.08	91.07		80%	13.03					13.03
UT Irrigation	2,389		4.08	97.46		73%	15.27					15.27
OWC Irrigation	2,406		4.08	98.19		73%	15.27					15.27
UT Commercial Finanswer	2,601		3.61	93.90		54%	19.81					19.81
WY Commercial Finanswer	2,584		3.61	93.28		54%	19.84					19.84
OWC Industrial	3,993		4.08	162.90		94%	19.88					19.88
WY Industrial	4,257		4.08	173.69		100%	19.88					19.88
UT Industrial	4,203		4.08	171.50		98%	19.88					19.88
OWC Commercial Finanswer	1,839		3.61	66.37		38%	19.94					19.94
UT Commercial Retrofit	2,677		3.61	96.63		55%	20.09					20.09
WY Commercial Retrofit	2,665		3.61	96.20		55%	20.09					20.09
OWC Commercial Retrofit	2,538		3.61	91.63		52%	20.09					20.09
Utah Coal	1,795	60	7.13	132.26	28.40	92%	19.85	52.2	52.2	5.23	0.24	25.32
UT Finanswer 12,000	3,580		3.61	129.23		54%	27.27					27.27
WY Finanswer 12,000	3,556		3.61	128.38		54%	27.30					27.30
OWC Finanswer 12,000	2,530		3.61	91.34		38%	27.45					27.45
Wyo Coal	1,942	60	7.13	142.74	28.40	90%	21.71	46.6	53.9	6.11	0.24	28.06
Utah IG CC	1,941	60	7.96	159.28	39.40	92%	24.55	52.2	52.2	4.50	1.00	30.05
Wyo FB Coal	2,355	60	7.13	172.15	32.20	92%	25.25	46.6	53.9	5.01	0.50	30.76
Wyo IG CC	2,035	60	7.96	166.76	39.40	92%	25.47	46.6	53.9	4.72	1.00	31.19
Utah FB Coal	2,454	60	7.13	179.25	32.20	92%	26.12	52.2	52.2	4.75	0.50	31.38
OWC Cogeneration 1	1,100		7.96	87.56	5.00	85%	12.43	289.8	492.6	27.09	0.50	40.02
Utah Cogeneration 1	1,293		7.96	102.92	5.00	85%	14.49	264.8	475.0	26.12	0.50	41.12
OWC Cogeneration 2	663	60	7.96	57.55	5.00	85%	8.40	289.8	492.6	33.50	0.50	42.40
Utah Cogeneration 2	779	60	7.96	66.78	5.00	85%	9.64	264.8	475.0	32.30	0.50	42.44
OWC Pumped Storage	800		6.84	54.72	10.00	17%	43.27					43.27
Utah Pumped Storage	800		6.84	54.72	10.00	17%	43.27					43.27
Utah Combined Cycle CT	742	60	7.96	63.84	10.00	80%	10.54	264.8	475.0	34.00	1.00	45.54
OWC Combined Cycle CT	687	60	7.96	59.46	10.00	80%	9.91	289.8	492.6	35.27	1.00	46.18
Wyo Combined Cycle CT	819	60	7.96	69.97	10.00	80%	11.41	264.8	475.0	34.00	1.00	46.42
Utah Wind with Tax C	750	212	9.31	89.56	9.50	36%	31.85	126.1	152.2	15.22	4.20	51.27
Wyo Wind with Tax C	750	212	9.31	89.56	9.50	36%	31.85	126.1	152.2	15.22	4.20	51.27
UT Residential Wx	6,180		5.78	356.95		73%	55.93					55.93
OWC Residential Wx	6,239		5.78	360.39		74%	55.93					55.93
OWC Wind with Tax C	805	120	9.31	86.12	9.50	28%	38.98	126.1	152.2	15.22	4.20	58.40
Utah Wind without Tax C	1,150	212	9.31	126.80	9.50	36%	43.83	126.1	152.2	15.22	4.20	63.25
Wyo Wind without Tax C	1,150	212	9.31	126.80	9.50	36%	43.83	126.1	152.2	15.22	4.20	63.25
OWC Wind without Tax C	1,120	120	9.31	115.44	9.50	28%	50.94	126.1	152.2	15.22	4.20	70.36
OWC Geothermal	2,076	120	8.61	189.08	58.00	90%	31.34	220.4	415.0	41.50	1.00	73.84
Utah Geothermal	2,076	120	8.61	189.08	58.00	90%	31.34	220.4	415.0	41.50	1.00	73.84
UT Xtra Comml Measures	5,573		5.48	305.34		39%	88.41					88.41
WY Xtra Comml Measures	5,573		5.48	305.34		39%	88.41					88.41
OWC Xtra Comml Measures	7,366		5.48	403.56		52%	88.50					88.50
OWC Water Heat Load Control	7,177		5.66	406.55		42%	111.06					111.06
Utah Solar	4,283	120	9.31	409.92	49.40	40%	131.08					131.08
Utah Simple Cycle CT	518	60	8.30	47.97	21.80	5%	159.30	269.8	480.0	50.61	3.50	213.41
Wyo Simple Cycle CT	571	60	8.30	52.37	21.80	5%	169.34	269.8	480.0	50.61	3.50	223.46
OWC Simple Cycle CT	479	60	8.30	44.74	35.76	5%	183.78	255.8	458.6	48.36	3.50	235.64

T4-10.potential social-DR

Portfolio: Impact of Discount Rate

Table 4-11

Ranked Using Company's Cost of Capital

Description	Payment Factor (%)	Capital & Fixed Cost (Mills/kWh)	Levelized Energy Cost (Mills/kWh)	TOTAL COST (Mills/kWh)
OWC Appliance	5.69	(1.17)		(1.17)
UT Appliance	5.69	(1.17)		(1.17)
WY Appliance	5.69	(1.17)		(1.17)
UT Super Good Cents	5.81	18.25		18.25
WY Super Good Cents	5.81	18.25		18.25
OWC Super Good Cents	5.81	18.55		18.55
OWC Irrigation	5.81	21.75		21.75
UT Irrigation	5.81	21.75		21.75
Utah Coal	8.32	22.58	5.23	28.05
OWC Industrial	5.81	28.30		28.30
WY Industrial	5.81	28.30		28.30
UT Industrial	5.81	28.30		28.30
UT Commercial Finanswer	5.48	30.07		30.07
WY Commercial Finanswer	5.48	30.11		30.11
OWC Commercial Finanswer	5.48	30.27		30.27
UT Commercial Retrofit	5.48	30.49		30.49
WY Commercial Retrofit	5.48	30.49		30.49
OWC Commercial Retrofit	5.48	30.50		30.50
Wyo Coal	8.32	24.73	6.11	31.08
Utah IG CC	8.95	26.99	4.50	32.50
Wyo IG CC	8.95	28.03	4.72	33.75
Wyo FB Coal	8.32	28.80	5.01	34.31
Utah FB Coal	8.32	29.82	4.75	35.07
UT Finanswer 12,000	5.48	41.39		41.39
WY Finanswer 12,000	5.48	41.43		41.43
OWC Cogeneration 1	8.95	13.89	27.09	41.49
OWC Finanswer 12,000	5.48	41.66		41.66
Utah Cogeneration 1	8.95	16.21	26.12	42.84
OWC Cogeneration 2	8.95	9.36	33.50	43.36
Utah Cogeneration 2	8.95	10.76	32.30	43.55
Utah Combined Cycle CT	8.95	11.67	34.00	46.67
OWC Combined Cycle CT	8.95	10.97	35.27	47.23
Wyo Combined Cycle CT	8.95	12.65	34.00	47.66
OWC Pumped Storage	8.12	50.11		50.11
Utah Pumped Storage	8.12	50.11		50.11
Utah Wind with Tax C	9.84	33.49	15.22	52.91
Wyo Wind with Tax C	9.84	33.49	15.22	52.91
UT Residential Wx	5.78	55.93		55.93
OWC Residential Wx	5.78	55.93		55.93
OWC Wind with Tax C	9.84	40.98	15.22	60.40
Utah Wind without Tax C	9.84	46.15	15.22	65.57
Wyo Wind without Tax C	9.84	46.15	15.22	65.57
OWC Wind without Tax C	9.84	53.62	15.22	73.04
OWC Geothermal	8.95	32.29	41.50	74.78
Utah Geothermal	8.95	32.29	41.50	74.78
UT Xtra Comml Measures	5.48	88.41		88.41
WY Xtra Comml Measures	5.48	88.41		88.41
OWC Xtra Comml Measures	5.48	88.50		88.50
OWC Water Heat Load Control	5.66	111.06		111.06
Utah Solar	9.84	137.74		137.74
Utah Simple Cycle CT	9.16	170.65	50.61	224.76
Wyo Simple Cycle CT	9.16	181.73	50.61	235.85
OWC Simple Cycle CT	9.16	194.37	48.36	246.22

Ranked Using Social Discount Rate (3.0% real)

Description	Payment Factor (%)	Capital & Fixed Cost (Mills/kWh)	Levelized Energy Cost (Mills/kWh)	TOTAL COST (Mills/kWh)
OWC Appliance	3.92	(0.80)		(0.80)
UT Appliance	3.92	(0.80)		(0.80)
WY Appliance	3.92	(0.80)		(0.80)
UT Super Good Cents	4.08	12.82		12.82
WY Super Good Cents	4.08	12.82		12.82
OWC Super Good Cents	4.08	13.03		13.03
UT Irrigation	4.08	15.27		15.27
OWC Irrigation	4.08	15.27		15.27
UT Commercial Finanswer	3.61	19.81		19.81
WY Commercial Finanswer	3.61	19.84		19.84
OWC Industrial	4.08	19.88		19.88
WY Industrial	4.08	19.88		19.88
UT Industrial	4.08	19.88		19.88
OWC Commercial Finanswer	3.61	19.94		19.94
UT Commercial Retrofit	3.61	20.09		20.09
WY Commercial Retrofit	3.61	20.09		20.09
OWC Commercial Retrofit	3.61	20.09		20.09
Utah Coal	7.13	19.85	5.23	25.32
UT Finanswer 12,000	3.61	27.27		27.27
WY Finanswer 12,000	3.61	27.30		27.30
OWC Finanswer 12,000	3.61	27.45		27.45
Wyo Coal	7.13	21.71	6.11	28.06
Utah IG CC	7.96	24.55	4.50	30.05
Wyo FB Coal	7.13	25.25	5.01	30.76
Wyo IG CC	7.96	25.47	4.72	31.19
Utah FB Coal	7.13	26.12	4.75	31.38
OWC Cogeneration 1	7.96	12.43	27.09	40.02
Utah Cogeneration 1	7.96	14.49	26.12	41.12
OWC Cogeneration 2	7.96	8.40	33.50	42.40
Utah Cogeneration 2	7.96	9.64	32.30	42.44
OWC Pumped Storage	6.84	43.27		43.27
Utah Pumped Storage	6.84	43.27		43.27
Utah Combined Cycle CT	7.96	10.54	34.00	45.54
OWC Combined Cycle CT	7.96	9.91	35.27	46.18
Wyo Combined Cycle CT	7.96	11.41	34.00	46.42
Utah Wind with Tax C	9.31	31.85	15.22	51.27
Wyo Wind with Tax C	9.31	31.85	15.22	51.27
UT Residential Wx	5.78	55.93		55.93
OWC Residential Wx	5.78	55.93		55.93
OWC Wind with Tax C	9.31	38.98	15.22	58.40
Utah Wind without Tax C	9.31	43.83	15.22	63.25
Wyo Wind without Tax C	9.31	43.83	15.22	63.25
OWC Wind without Tax C	9.31	50.94	15.22	70.36
OWC Geothermal	8.61	31.34	41.50	73.84
Utah Geothermal	8.61	31.34	41.50	73.84
UT Xtra Comml Measures	5.48	88.41		88.41
WY Xtra Comml Measures	5.48	88.41		88.41
OWC Xtra Comml Measures	5.48	88.50		88.50
OWC Water Heat Load Control	5.66	111.06		111.06
Utah Solar	9.31	131.08		131.08
Utah Simple Cycle CT	8.30	159.30	50.61	213.41
Wyo Simple Cycle CT	8.30	169.34	50.61	223.46
OWC Simple Cycle CT	8.30	183.78	48.36	235.64

T4-11.discount rate impact

ANALYSIS PLAN

This chapter explains the method of analysis used in RAMPP-3: multi-attribute trade-off analysis (MATO). The chapter describes the overall approach, the model used to select the new resources, and the geographic areas and transmission capabilities among them used in the modeling and analysis. It then addresses the issues of peak versus energy planning, and critical versus average water planning.

MULTI-ATTRIBUTE TRADE-OFF ANALYSIS

Electric utilities tend to use one of three approaches to integrated resource planning. The first involves trial resource plans created by utility planners that they test against alternative futures through a production cost model and a financial model. A resource plan identifies the resource technologies needed to meet future load growth, and the size and timing of those additions. The testing of trial plans helps determine which plan minimizes costs under the most futures, and which plan minimizes risk for the utility and its customers. The best performing trial plan becomes the preferred plan. However, the trial plan approach provides no assurance that any of the trial plans is a true least-cost solution to the resource planning problem. PacifiCorp used the trial plan approach for its first integrated resource plan, RAMPP-1.

The second approach to integrated resource planning uses a capacity expansion model to create a discrete resource plan for each specific future and sensitivity. A simulation or optimization model makes the new resource selections to expand the utility's capacity. The model also calculates the production costs over the entire 20-year planning horizon. A financial module determines the cost of the entire resource plan, and the overall retail price impact and other financial results. The utility typically runs a few base cases and some sensitivities through the model. PacifiCorp used this approach with a simulation model for its second integrated resource plan, RAMPP-2.

The third approach to integrated resource planning is multi-attribute trade-off analysis (MATO). PacifiCorp is using this approach for RAMPP-3.

The MATO approach tests many possible resource strategies against many possible futures. Resource strategies put restrictions on certain resource acquisition activities, for example one resource strategy might set a low level of cost effectiveness for DSR, and another might remove coal from the portfolio of resources. One possible future would be medium-low load growth, while another would anticipate medium-high load growth. A set of strategies combined with a set of futures creates a unique case. In the MATO approach, the model creates a resource plan for each case.

A multi-attribute approach measures the performance of each resource plan on a number of measures, including system costs, emissions, and prices. The company used these performance measures to compare how the different strategies perform over the range of alternative futures. The analyst can plot the results from the resource plans on a graph. Typically the plot will show a financial measure (price, or utility cost, or total resource cost) on one axis, and emissions on the other. A MATO approach allows other formats to display the performance measures of the resource plans, such as utility costs on one axis and customer prices on the other. The analyst can identify those plans with the lowest costs and emissions, as well as the strategies that led to the more favorable plans. The goal is to identify the strategies that lead to resource plans that minimize both costs and emissions.

Integrated resource planning can address issues either through strategies or sensitivities. Strategies address the most critical issues facing the company and its customers. For RAMPP-3, the three most critical issues were the amount and implementation rate of DSR, the amount of new coal resources to include in a new resource plan, and the amount of new renewable resources to include. Sensitivity analyses addressed other issues raised by the company's public advisory group. The trade-off approach provides a much fuller analysis than a sensitivity. Therefore, it addressed the three critical issues through alternative strategies.

Alternative DSR strategies allowed the company to investigate the impact of alternative levels of DSR on utility costs and customer prices. Using DSR to meet customers' energy service needs decreases total utility costs and total resource costs, but increases average prices. DSR lowers total bills for participants, but increases bills for non-participants. The company evaluates the trade-off between prices and total costs to determine appropriate levels of DSR, rather than relying on any simple rate impact measure (RIM) or total resource cost (TRC) test. A set level of cost effectiveness can help determine the amount of DSR in a resource plan by providing a cut-off point for DSR measures. DSR program development does not consider measures that cost more than the cost effectiveness level. The discussion of demand-side resources in the Portfolio chapter and the Demand-Side Appendix explain this process. The lower the cost-effectiveness level, the lower the amount of DSR included in that DSR strategy, and the lower the amount of DSR in the cases which used that DSR strategy. Four alternative strategies explored possibilities for acquiring demand-side resources:

Strategy **LD** (Low DSR): a low level (30 mills/kWh) of cost effectiveness for DSR with a slow ramp-up rate.

Strategy **MD** (Medium DSR): a higher cost effectiveness (55 mills/kWh) based on RAMPP-2 avoided costs, and the ramp-up rate used in RAMPP-2.

Strategy **AD** (Accelerated DSR): cost effectiveness (55 mills/kWh) based on RAMPP-2 avoided costs, but with an accelerated ramp-up rate.

Strategy **HD** (High DSR): a higher level of cost effectiveness (70 mills/kWh), and an accelerated ramp-up rate.

The company developed and tested an additional DSR strategy, **U D** (Unconstrained DSR) to meet the request of the company's public advisory group. Strategy UD used the RAMPP-2 cost effectiveness level to develop programs, then added additional higher cost measures to the portfolio, and allowed the model to select any or all of the DSR potential at any time. Strategy UD allowed the model to add DSR immediately, with no restrictions on ramp-up rate feasibility or the total that the model could select in any one year. It did not realistically consider the company's ability to deliver the resource quickly. Combining the UD strategy with the AC (any-coal) and AR (any-renewables) created a truly unconstrained run for each load growth level.

The second major strategy area involved new coal resources. The company recognizes that there are national environmental concerns about coal-fired generation. At the same time, the company recognizes that coal is a very cost-effective new resource. Given the continuing debate over global warming and whether or to what degree coal plants are a contributor, PacifiCorp believes it is not prudent to eliminate coal as a future possibility. Two alternative strategies examined the role of new coal resources in planning:

Strategy **AC** (Any-Coal): the model can select any amount of new coal in the resource plan. This is an unconstrained strategy.

Strategy **NC** (No-Coal): the model cannot select new coal resources.

The third strategy issue was the amount of new renewable resources to include in resource plans. Two alternatives examined new renewable resources.

Strategy **AR** (Any-Renewables): the model can select any amount of new renewables. It imposes no minimum nor maximum limit on the selection of new renewables. This is an unconstrained strategy.

Strategy **SR** (Strategic-Renewables): the model must achieve a specific acceleration of renewables in the early years. The model can then select any amount of additional new renewable resources.

Sixteen combinations of the strategy alternatives were possible:

LD Cases	MD Cases	AD Cases	HD Cases
LD AC AR	MD AC AR	AD AC AR	HD AC AR
LD AC SR	MD AC SR	AD AC SR	HD AC SR
LD NC AR	MD NC AR	AD NC AR	HD NC AR
LD NC SR	MD NC SR	AD NC SR	HD NC SR

Base Study Plan

Table 5-1

FUTURES		Load	L			ML			M			MH			H		
		Gas	LG	MG	HG	LG	MG	HG	LG	MG	HG	LG	MG	HG	LG	MG	HG
UNCONSTRAINED				X			X		X	X	X		X			X	
STRATEGIES: DSR	Coal	Renew															
LD	AC	AR							X	X	X		X			X	
LD	AC	SR							X	X	X		X			X	
LD	NC	AR							X	X	X		X			X	
LD	NC	SR							X	X	X		X			X	
MD	AC	AR		X			X		X	X	X		X			X	
MD	AC	SR		X			X		X	X	X	X	X	X	X	X	X
MD	NC	AR		X			X		X	X	X		X			X	
MD	NC	SR		X			X		X	X	X	X	X	X	X	X	X
AD	AC	AR							X	X	X		X			X	
AD	AC	SR							X	X	X		X			X	
AD	NC	AR							X	X	X		X			X	
AD	NC	SR							X	X	X		X			X	
HD	AC	AR							X	X	X		X			X	
HD	AC	SR							X	X	X		X			X	
HD	NC	AR							X	X	X		X			X	
HD	NC	SR							X	X	X		X			X	

DSR strategies:

- LD - use a low level of cost effectiveness for DSR with slower ramp-up rate
- MD - cost effectiveness based on RAMPP-2 avoided costs, and the ramp-up rate used in RAMPP-2
- AD - cost effectiveness based on RAMPP-2 avoided costs, but with an accelerated ramp-up rate
- HD - use a higher level of cost effectiveness, and an accelerated ramp-up rate

Coal strategies:

- NC - no coal plants
- AC - any coal plants

Renewable strategies:

- AR - any renewables
- SR - strategic renewables

The 17th combination contained UD, AC, and AR (the completely unconstrained case). Combining five different load growth forecasts (low, medium low, medium, medium high, and high) with three different gas price forecasts (low, medium, and high) resulted in fifteen possible futures. Using all of these futures to test the strategies would have required 15 x 17 model runs, or 255. Therefore, the company used only some of the futures to test the strategies. Table 5-1 shows the base study plan of 103 cases. The following table summarizes that by showing the number of cases within each future.

Summary of Base Study Plan
Table 5-2

	Gas Prices		
Load Growth	**LG**:Low	**MG**: Medium	**HG**: High
L: Low		5	
ML: Medium-Low		5	
M: Medium	17	17	17
MH: Medium-High	2	17	2
H: High	2	17	2

ENVIRONMENTAL CASES

Twenty-one cases used environmental cost adders, with alternative load growth, gas price, and DSR levels, but all using the any-coal (AR) and any-renewable (AR) strategies, to give the model maximum flexibility in its selection of new resources. The adder levels followed the guidelines established in the Oregon Commission's Order from UM 424 from their proceeding on externality issues. Combining the high and low values for NOx and total suspended particles (TSP) with three values for CO2 created six levels of adders. The UM 424 low and high values for external costs are $2000 and $5000 per ton for NOx emissions, and $2000 and $4000 per ton for TSP emissions. The three values for CO2 are $10, $25, and $40 per ton. The company tested these six combinations against alternative futures, resulting in 21 cases. Six environmental cases used future M (medium load growth) and MD (medium DSR). The second six used M (medium load growth) but HD (high DSR). The third six used MH (medium-high load growth) and MD (medium DSR). An additional three cases used M (medium load growth) but HG (high gas) with MD (medium DSR) to test the impact of adders with high gas prices. Each adder case used the adders for both resource selections and system dispatch. Two additional cases required the model to respect 1990 CO2 emission limits.

Carbon Emissions Limit The model must find a mix of resources that limits carbon emissions below the level of carbon emissions that current PacifiCorp resources emitted in 1990. Two sensitivities met this requirement. The first one used medium DSR, and the second used high DSR. Both used the any-coal and any-renewable strategies.

An additional analysis provides information on environmental dispatch, as required by the Oregon Commission's Order on UM 424.

Environmental Dispatch The company used the results of the environmental adder cases to determine the 1994 system operating cost and emissions when dispatch assumed that the operating cost of each resource included the different levels of externality adders.

The Environmental Analysis Chapter discusses the results of these cases and the environmental dispatch information.

SENSITIVITIES

Sensitivities are unique cases in addition to the base study plan and environmental cases. Each sensitivity used a specified set of strategies and input assumptions under one future to create a unique resource plan. Sensitivities addressed several areas: load growth, the portfolio and transmission limits (including specific recent resource acquisitions), coal prices, the non-firm market, and renewable resources. All of the sensitivities used the medium load growth (**M**) and medium gas prices (**MG**) future unless otherwise noted. Most of the sensitivities used the medium DSR strategy (**MD**). The coal and renewable strategies varied by the sensitivity.

Load Sensitivities

Three sensitivities tested the impact of alternative levels of load growth. Although the load forecast provided a broad range of future load possibilities, other load futures could occur. Three sensitivities addressed the potential impact of actions that would alter load growth.

Load Reduction This sensitivity assumed that rate design, changes in customers' fuel choices, or other influences would reduce load somewhat from the medium load growth level, but remain above the medium-low level.

Increased Sales To test the impact of the company's marketing and economic development activities on load and resource needs, this sensitivity assumed more growth than the medium load growth case, but less than the medium-high growth level.

Electrification This assumed a load growth level above the high load growth case due to electric cars and industrial electrification technology.

Portfolio and Transmission Sensitivities

The next group of sensitivities altered the input assumptions used for the portfolio of resources and transmission constraints. The company has taken recent resource acquisition actions that have altered other resource decisions. To better understand the impact of those actions, sensitivities determined if the model would have selected those resources.

SCE Peaking Contract The bae study plan included the SCE contract in the existing system. This sensitivity assumed that the existing system did not include the SCE peaking contract; instead it assumed that the portfolio included the SCE contract as a potential resource. The model could determine when to add it to the PacifiCorp system. This sensitivity complies with a requirement in the Utah Public Service Commission order that acknowledged RAMPP-2.

Hermiston Cogeneration Opportunity The company is currently proceeding with steps to acquire power from a large (474 MW) cogeneration project near Hermiston, Oregon. The base study plan did not include Hermiston in either the existing system or the portfolio of available resources. Two sensitivities placed the Hermiston project in the portfolio, and the model could determine when to add it to the PacifiCorp system. One sensitivity used the any-coal strategy, and one used the no-coal strategy, to determine how the model would treat the Hermiston project under both conditions.

Any coal

IGCC Conversion This sensitivity allowed a combined cycle combustion turbine to convert into a plant using a clean coal technology -- integrated gasification combined cycle (IGCC), which allows it to switch fuels from gas to coal, but with emission levels closer to gas's than to coal's.

No coal

IGCC Treated as Gas The company used two sensitivities to determine the cost competitiveness of IGCC compared to other resources if IGCC were the only coal technology available. The company used the no-coal strategy, so it would not select pulverized coal, but allowed the model to select IGCC by classifying it as gas for this test. The first of two sensitivities simply allowed to model to select IGCC but no other coal technology. The second also lowered the cost of IGCC by 20 percent.

Transmission Capacity Upgrades The model cannot select between a generating capacity resource and a transmission upgrade. The company is exploring the possibility of model code modifications to add this capability for RAMPP-4. To test the impact of higher transmission capacity on the need for new resources by geographic area, two sensitivities used reduced transmission constraints between geographic areas. The first one increased the BRI-to-OWC path from 1500 MW to 1800 MW at a generic cost of $300/kW. The second one increased the UTAH-to-OWC path from 90 MW to 690 MW at a generic cost of $300/kW. (See Map 5-4 on page 84). These two transmission upgrades would be the most beneficial, and the company is currently negotiating with other utilities for these upgrades.

Social Discount Rate This sensitivity tested the impact of a social discount rate on the model's selection of resources. The social discount rate was 6.5 percent nominal, or 3.0 percent real. The discount rate used in the rest of the cases was 8.8 percent nominal, or 5.22 percent real. Table 4-10 in the Portfolio chapter shows the calculation of costs for each resource using the social discount rate for the levelization step. This sensitivity used costs from that table for each resource in the portfolio.

Coal Price Sensitivities

Five sensitivities tested the impact of a higher Utah coal price on the model's resource choices, system costs, and prices. After the major analysis work for RAMPP-3 was finished, the coal market began to change. The Wyoming market is experiencing increased demand from midwestern utilities, but these new market pressures are expected to be temporary. Sufficient coal supplies in Utah at the $0.52/mmbtu price are available for only one additional unit (about 1.5 million tons). The coal required by additional units would require additional capital investment in coal mining facilities. The Utah coal price is really a step function; it varies by the amount of coal plants built. The sensitivities doubled the price of Utah coal from that used in the base cases. The five sensitivities tested the higher coal prices under medium load growth assuming each of the three gas price levels, and under medium-high and high load growth assuming medium gas prices.

Non-Firm Market Sensitivities

Assumptions regarding the wholesale non-firm market, for both sales and purchases, can have a dramatic impact on resource plans. Non-firm markets are dependent on hydrologic and weather conditions, variations in natural gas and oil prices, and forced outages or other regional load conditions.

Critical Water This assumed hydro availability from critical water levels, rather than average water levels. RAMPP-3 planning assumed average water levels. The company wanted to test whether using critical water assumptions would significantly change resource selections or alter the level of costs.

Wholesale Sales Price Wholesale prices can be difficult to forecast. Two cases tested the sensitivity of the results to this input, which can affect the total costs of the system, and thus customer prices. One assumed a 20 percent increase in the price PacifiCorp can charge for power on the wholesale market. The other assumed a 20 percent decrease.

Availability of Wholesale Market Two sensitivities altered the availability of the wholesale market, to determine the impact of the market on utility costs. One allowed the model to make no non-firm sales. The other allowed no non-firm sales or purchases.

Renewable Resource Sensitivities

Seven sensitivities analyzed renewable resources more completely. The Renewable Analysis chapter discusses the results of these sensitivities.

Reduced Cost of Wind The company first lowered the capital cost of wind by 20 percent, to determine if that would increase its cost competitiveness and result in the model selecting it under an any-renewables strategy. It did not. By incrementally increasing the cost reduction, the company determined that a capital cost reduction of $600 would be necessary for wind to start replacing other resources in model selections. Therefore, this sensitivity assumed the capital cost of wind to be $600 less than the base case assumption.

O&M Escalation for Geothermal Almost all of the O&M costs for geothermal are due to the cost of the steam or hot water. The base assumption for RAMPP-3 for geothermal O&M costs was that they would escalate at the same rate as do gas prices. Therefore, the rate varied in the studies, depending on the gas escalation assumption for that model run. To test the impact of this assumption, a sensitivity lowered the O&M real escalation rate to zero.

O&M Escalation for Wind Vendor information for wind resources' O&M escalation ranged from zero to 2.5 percent real escalation. A factor of 1.25 percent real escalation was the base assumption for RAMPP-3. The actual real escalation of O&M costs for wind is another area of uncertainty. Two sensitivities test the impact of the range. One used zero real escalation, and one used 2.5 percent real escalation.

Capacity Factor for Wind The single largest uncertainty related to wind is the capacity that a wind resource can provide at the time of the system peak demand. It is a function of both the strength of the wind and the performance of the wind turbine equipment. If wind velocity were constant during the day, average generation would be a good extimate of expected capacity at the time of system peak. However, wind velocity varies through the day. The RAMPP-3 assumption was that wind's peak contribution was 90 percent of its average level of generation. Two sensitivities tested the impact of this assumption. The first sensitivity assumed a 20 percent increase in wind's contribution at the time of system peak. The second sensitivity assumed that wind's peak contribution was equal to its average winter generation. Under the winter assumption, for wind in the OWC area the capacity factor was 19 percent. For wind in the WYO and UTA areas the capacity factor was 59 percent. (See Table 5-5 on page 85)

Wind Energy Production A sensitivity determined how much wind strength and/or wind technology would have to improve before wind would become competitive with other gas-fired resources. The model began selecting additional wind resources if the assumption were raised by 35 percent. Therefore, this sensitivity assumed that the wind turbines can generate 35 percent more energy per kW of installed capacity.

MODEL

Computer models have made resource planning easier, but more complex. As computers have become faster and more sophisticated, the expectations of the industry and regulators have also increased. Utility planners are continually looking for better computer systems and models to manage an increasingly complex process. Computerized utility resource planning models must capture the essence of the decision making process of utility management, but they must also make compromises to simplify the problem.

Utilities use two basic types of computer models in developing their least cost plans: simulation models and optimization models. Most of the models used for resource planning fall into one of these categories.

Simulation models start with the construction of a model of the utility's generating system, often including system operation and performance on an hourly basis. The model can then analyze the effects of alternative input assumptions on the generating system. These alternatives address major uncertainties (load growth, fuel costs, hydroelectric availability, generating unit forced outage, etc.) in a very direct way. The models simulate uncertainty by taking successive "random draws" from probability distributions of different levels of load growth, different fuel costs, different water levels for hydro resources, etc. Simulation models can determine which resources to add to the system, and when, but they do not provide the optimal least cost solution. However, many of the electric utility simulation models now have algorithms that try to mimic the optimal resource selection logic of linear programming models. Simulation models excel at examining the system in small time increments.

Optimization models use an algorithm based on mathematical programming techniques. Mathematical programming is a group of disciplines including linear, nonlinear, integer, and dynamic programming that attempts to determine the minimum or maximum value of a function or equation, given one or more constraints. For electric utilities using optimization models for generation expansion planning, the model selects the timing and quantity of future resources to minimize costs. The value of such techniques is that the solution is the single best or optimal alternative, given a set of input assumptions.

Linear programming models are by far the most common type of optimization models used by electric utilities for developing generation expansion models. The basic structure for linear programming (and all forms of mathematical programming) includes:

a) Some objective which must be achieved, such as minimizing the present value of future capital and operating costs;

b) Simultaneous management of a large number of inputs such as fuel, and outputs such as capacity in kW and energy in kWh;

c) The variables interact and may conflict with each other.

Electric utilities usually use minimizing the present value of future capital and operating costs for an objective function. This will be subject to a wide variety of constraints, including minimum operating levels and certain ramp rates for conservation programs.

Results from an optimization model are optimal only if all of the forecasted data used in the model is correct. The load forecast, fuel cost escalation, resource cost estimates and resource operating levels must all occur as projected in the model, for the result to be the true optimal solution. Simulation models have similar limitations. Since simulation models deal with uncertainties, such as weather, carbon tax, global warming, and gas availability, their results are estimates subject to statistical error.

Resource planning models help utility management and staff place the risk, uncertainties and complexities of generating resource selection and operation within an organized and well-structured view of the planning environment. They can then take a comprehensive look at alternative resource strategies.

However, there are limitations on the answers resource planning models can provide utilities, commissions and the general public. Quantitative computer models cannot provide all the information and analysis senior management needs for resource acquisition decisions. They also cannot substitute for the experience and judgment of decision makers. Even with useful and valuable input, senior management must ultimately make the resource decisions.

Models Available to PacifiCorp for RAMPP-3

PacifiCorp received comments on RAMPP-2 from the public utility commissions in three of the seven states in which PacifiCorp serves retail customers. Order No. 93-206, issued February 12, 1993, included the Oregon Public Utilities Commission (OPUC) comments. The Utah Public Service Commission (UPSC) comments, issued June 1, 1993, are from in Docket No. 90-2035-01. The Washington Utilities and Transportation Commission (WUTC) comments were in a letter to PacifiCorp, rather than a formal order. All of the commissions stated that PacifiCorp's RAMPP-2 process met the substantive and procedural requirements of their least-cost planning guidelines.

Each commission provided recommendations for PacifiCorp to incorporate in RAMPP-3. Several related to the resource planning model. Because RAMPP-2 did not use an optimization model, there was no assurance that each resource plan was truly least cost for the input assumptions. After RAMPP-2, PacifiCorp staff began looking for a new model for RAMPP-3. Most utilities would be able to choose from the large number of models that are available commercially.

However, PacifiCorp needed a more customized model that considers the unique planning needs of a system with substantial hydro resources and geographic diversity. Company-owned hydroelectric resources represent only 10 percent of PacifiCorp's resource base. However, the company has significant purchased hydro from the Mid-Columbia system, and from BPA to meet capacity needs.

The wholesale market accounts for 20 to 25 percent of PacifiCorp's energy sales. The wholesale market is a major part of the company's business and further complicates resource planning. PacifiCorp, more than other utilities, must consider the large size and geographic dispersion of its service territory and the associated transmission requirements. These unique characteristics limit the modeling choices available to PacifiCorp.

The company looked for four specific capabilities in its new model: 1) the ability to recognize transmission limits between regions; 2) some form of optimization algorithm to provide the logic for resource selection; 3) integration of the dispatch and operating costs of new resources with selection of those new resources; and 4) a well documented and well maintained model. A fifth requirement -- using probability to test certain variables -- was impossible to meet. Commercially available models do not yet provide resource optimization along with probabilistic treatment of certain variables.

PacifiCorp contacted utilities and model vendors to find an integrated planning model with the four capabilities identified above. After evaluating several models, only a few met all four requirements. The company acquired the last two models for testing:

a. Develop a customized resource planning model
b. Pro-Screen/Pro View from Energy Management Associates (EMA)
c. Power Marketing Decision Analysis Model (PMDAM)
d. Integrated Planning Model (IPM) from ICF Resources, Inc.

The first option for PacifiCorp was developing its own resource planning model using staff and consultants. Such individualized models can take two to three years to develop and test, and are much more expensive than commercially available models. The company decided not to develop its own model for RAMPP-3 primarily because of time constraints.

ProScreen and ProView are two modules of an integrated model marketed by EMA. It uses a dynamic programming algorithm to develop a "least cost plan" for a utility. ProScreen could not handle multiple regions and transmission constraints when evaluated by PacifiCorp.

The Power Marketing Decision Analysis Model (PMDAM) is a decision model that uses probabilistic simulation techniques to model the West Coast utility market. The database includes information on every operating and planned power plant in the West Coast area and all existing transmission agreements. PacifiCorp acquired the model for testing. Although it could adequately represent PacifiCorp's system, it did not produce consistent solutions, and its documentation and support were inadequate for RAMPP-3 modeling needs.

ICF Resources, Inc. developed the Integrated Planning Model (IPM). ICF is a consulting firm that has been marketing resource planning models and doing environmental analysis work for more than 15 years. ICF developed the first generation expansion model for the Northwest Power Planning Council in the early 1980's. IPM is a linear programming-based model with the ability to handle a utility with several discrete regions and associated transmission constraints. The model dispatches resources to meet system demand and energy requirements, and contains limited logic to model hydroelectric resources. IPM satisfied all the criteria PacifiCorp established for the new resource planning model, and became the model for RAMPP-3. The Modeling Appendix contains the model evaluation and implementation process used by the company to prepare for the modeling process.

IPM's Representation of the PacifiCorp System

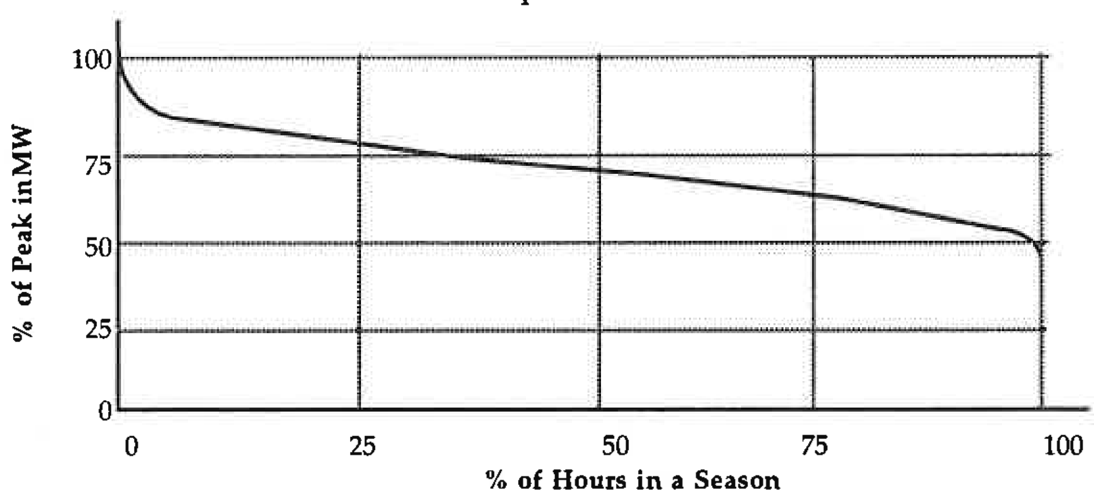
IPM minimizes the present value of total resource costs. When the financial model calculates total utility cost, it removes the customer costs and benefits from the total resource cost output of the IPM model. To include end effects of resources chosen in the first 20 years, PacifiCorp chose to minimize costs over a period of 50 years. Each model run recognizes the impact of end effects when selecting new resources for the 20-year planning horizon. End effects occur because some technologies last longer than others.

The company required the model to solve (select new resources for) only 14 of the years. If each model run solved for every year of the 20 years, plus additional years to recognize end effects, the result would be an exceedingly large modeling problem. Each model run required from 1 hour (using an initial solution from another run) to 20 hours for an initial solution on a DEC Alpha workstation. The model solved for every year from 1994 through 2001, then the following specific years, 2003, 2006, 2009, 2013, 2022, and 2036. However, the model calculated utility costs for every calendar year, using the resource selections from the nearest solution year to calculate production costs. The calculation of costs for the year 2005 used the resources in place in 2006. The calculation for the year 2007 also used the resources in place in 2006. Approximations on one side balanced approximations on the other side.

IPM is a load duration curve model. Such models first sort hourly loads from highest to lowest. The model then overlays resource output from lowest to highest cost so that the model operates the least expensive resources during the most hours, and operates the most expensive resources only during the high load hours. As load increases during the day, plants with the lowest operating costs would operate first, followed by plants with increasing operating costs. As load decreases during the day, plants with the highest operating costs would stop generating first. This simplifying assumption allows a quick solution to the problem of when to dispatch which resource when calculating the production costs for the system. However, this simplifying assumption also removes recognition of several dispatching requirements. For example, the operation of a resource in the previous hour may limit its level of generation in the current hour, and each thermal plant has ramp rate restrictions (how much a unit's output can increase or decrease within one hour). A utility's operation and maintenance costs and unit efficiency depend in part on how it operates each generating unit, especially how often a unit goes on- and off-line or cycles from its maximum-to-minimum or minimum-to-maximum output. Dispatch based on load duration curve does not recognize these restrictions or costs. A load duration curve solution to the dispatch problem also tends to over-utilize pumped storage, peak-energy exchanges, and hydro resources with limited storage capability.

IPM uses load duration curves for its data on how much electricity the system needs to produce. Load duration curves show a utility's hourly loads, generally for one year, in descending order. Graph 5-3 shows such a load duration curve. In IPM, a separate curve inputs the data for each season. The seasons are as follows: December, January, and February; March, April, and May; June, July, and August; and September, October, and November. This seasonal designation reflects the seasonal variation in customer loads on the system, in both shape and magnitude, as well as the pattern of hydroelectric generation on the Columbia river system. The company divided each season's load duration curve into eight areas for handling by IPM.

Load Duration Curve
Graph 5-3



Linear programming models assume that new generating units come in infinitely divisible units. Model results may call for adding 37 MW of cogeneration to the system, or 203 MW of coal in a particular year. Management must determine the actual size and timing of resource additions using information from the model results. Recent changes in the structure of the electric utility industry have made it increasingly possible for utilities to acquire shares of units.

All computer models must make simplifying assumptions to produce results in a reasonable amount of computation time. Modeling of the resource expansion decision is especially complex, because the model must consider resource operations and costs over a long time period (20 to 50 years). In order to solve a problem of this magnitude, an expansion planning model must make many simplifying assumptions. Some of these simplifying assumptions result in compromises for calculating annual production costs. Simplifying assumptions in the RAMPP-3 analyses included a simplified transmission network, and resource operation on a seasonal basis rather than hourly.

Modeling the expansion planning decision presents additional challenges when the model uses a single calculation for both production costs and new resource additions. Assumptions which are appropriate for determining expected production costs, such as average hydro conditions and significant access to non-firm purchase and sale markets, are inconsistent with standard expansion planning assumptions because the expansion planning problem must consider system reliability. Capacity expansion assuming average hydro and significant access to non-firm markets could threaten system reliability. Typical resource expansion analysis assumes critical hydro availability and little or no access to non-firm markets, because these resources and markets are uncertain. For example, a model which assumes significant access to the non-firm market will tend to select more peaking resources and fewer baseload resources, compared to an assumption of restricted access, because the model assumes that the utility can purchase energy easily. However, PacifiCorp assumed average hydro conditions and significant access to non-firm markets in RAMPP-3 to assure greater accuracy of the financial results.

A consequence of this tension between the needs of a resource expansion model and a production costing model is that management must evaluate the resource expansion results with an understanding of the necessary compromises.

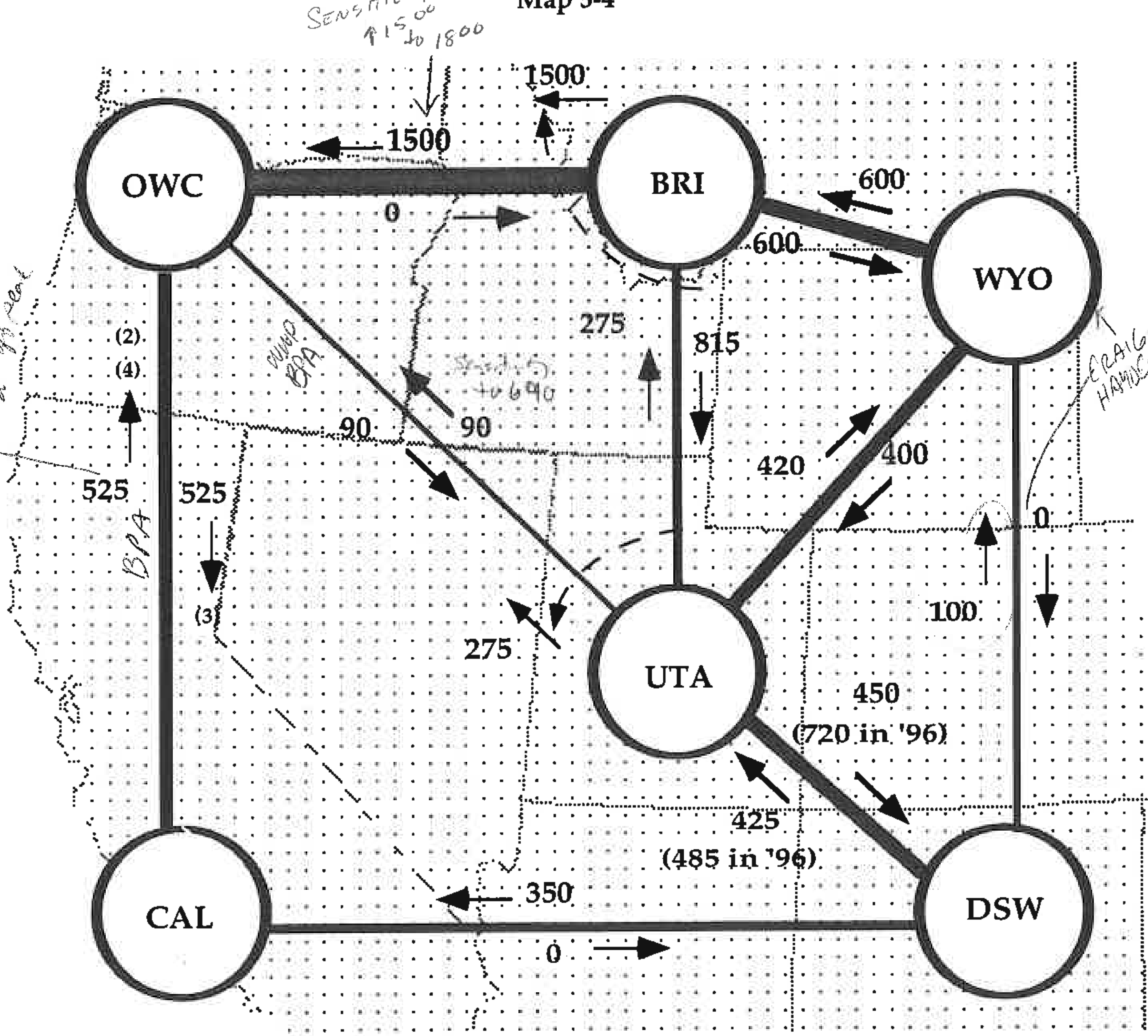
GEOGRAPHIC AREAS AND THE TRANSMISSION SYSTEM

The IPM model recognizes transmission limits between geographic areas of a utility's system. For modeling, the company divided the system into geographic areas, with loads and resources identified for each area. The number of areas evaluated is a trade-off between precision and time available for model runs. PacifiCorp tested several alternatives in determining the number of areas to use for RAMPP-3. A configuration of six geographic areas accurately represents the system and still keeps model run time reasonable.

Map 5-3 shows the six regions. Table 5-4 shows the assignment of the company's loads and resources to the six areas. They include three load and resource centers; two resource centers without load areas; and one purely market driven region that offers both buying and selling opportunities. The three load centers are OWC, UTA and WYO. OWC includes the company's Oregon, Washington, California, and Montana load areas. The resources assigned to OWC are the

Geographic Areas and Transfer Capabilities (MW)

Map 5-4



(1) Transfer Capabilities (MW) are Pacificorp's inter-regional transfer capabilities utilized in RAMPP -3 Studies.

(2) 525 MW modeled as 260MW off-peak capability in selected studies.

(3) Subject to change depending on final Non-Federal-Participation allocation or long term contract discussions.

(4) Subject to change depending on final Non-Federal-Participation allocation or long term contract discussions and final S to N Pacific Intertie rating.

(5) In studies, the total of the UTA to BRI and the UTA to OWC paths is limited to the capability of the UTA to BRI path.

Sales and Resources by Geographic Areas (1994)

Table 5-5

	aMW	Winter Peak	Summer Peak
OWC			
SALES	2,395	3,940	2,992
Oregon	1,674	2,740	2,046
Washington	492	812	653
North Idaho	32	62	34
Montana	100	157	102
California	98	169	157
RESOURCES	1,216	2,469	2,348
Cholla 4	360	380	380
Craig 1,2	138	166	166
Hydro Utah	55	50	90
Hydro Pacific	500	882	727
BPA Peaking Purchase		0	0
Purchased Power	150	991	985
SCE Capacity Purchase	13	0	0
UTAH			
SALES	2,365	2,550	3,201
Utah	1,590	2,009	2,462
Interruptibles	299		
South Idaho	228	250	466
Southwest Wyoming	248	291	274
RESOURCES	8,922	10,111	10,292
Centralia 1,2	583	638	638
Hunter 1,2,3	862	1003	1003
Jim Bridger 1,2,3,4	1217	1388	1388
Wyodak	248	256	256
Wind FC & Rtl Snake	0	0	0
APS NEW CTs	0	0	0
Blundell Geothermal	19	22	22
Total Thermal	5819	6592	6773
Purchased Power	174	212	212

	aMW		Winter Peak		Summer Peak	
WYOMING						
SALES		**892**		**1,007**		**954**
East Wyoming	892		1,007		954	
RESOURCES		**1,081**		**1,617**		**1,566**
Hayden 1,2	63		78		78	
Gadsby 1,2,3	91		100		231	
Purchased Power	927		1,439		1,257	
BRIDGER						
SALES		**0**		**0**		**0**
RESOURCES		**570**		**675**		**675**
Naughton 1,2,3	570		675		675	
CALIFORNIA						
SALES		**0**		**0**		**0**
RESOURCES		**0**		**0**		**0**
	0		0		0	
DSW						
SALES		**0**		**0**		**0**
RESOURCES		**1,522**		**1,717**		**1,781**
Colstrip 3,4	121		140		140	
Dave Johnston 1,2,3,4	690		772		772	
Huntington 1,2	711		805		855	
Purchased Power b	0		0		14	

Note: a. Return during off-peak
b. Off-peak purchases
Energy amounts are after forced outage and maintenance

T5-05.sales/resource by region

Centralia and Colstrip coal-fired plants, the Pacific Power and mid-Columbia hydro resources, the BPA peaking contract, and other purchased power contracts.

UTA is the geographic area for loads within Utah, southern Idaho, and southwestern Wyoming. The UTA area includes the Carbon, Huntington, Hunter, and Naughton coal-fired plants, the Blundell geothermal plant, the Gadsby gas-fired plant, Utah hydro, and purchased power contracts. The WYO area includes only the eastern Wyoming service area. WYO includes the Dave Johnston and Wyodak coal-fired plants and some purchased power.

The three other areas help represent the company's use of the transmission system, but do not include loads. The two resource regions are Bridger (BRI) and the Desert Southwest (DSW). The Bridger area includes the Jim Bridger coal-fired plant, and allows the model to recognize that the plant's location and nearby transmission connections with Idaho Power impose constraints on the system. The DSW and California (CAL) areas allow the model to consider how the company buys and sells secondary non-firm power to minimize utility costs. DSW represents the Cholla, Craig and Hayden thermal plants, and power sales contracts in the Desert Southwest region, including the Colorado market. CAL represents the purchase and sale of power between PacifiCorp and the California and Nevada utilities.

The OWC area has a winter peak with surplus summer capacity while the Utah area peaks in the summer and has surplus winter capacity. These two areas complement each other's capacity needs well. The Wyoming area shows little seasonal diversity in its loads.

To recognize PacifiCorp's purchase and sales activity in the non-firm markets, the model assumptions include access to three regionally diverse wholesale markets. These three markets are the Pacific Northwest, the Desert Southwest (Utah, Four Corners and Palo Verde inter-connections), and California (through the Intertie). The company used the price features unique to each region, differentiated by season and time of day. Market prices escalate through time consistent with the gas price escalation used for the particular model run. The company used historical trends for price and power availability in each of the wholesale markets. The California market capacity is large, but transmission limitations severely restrict market access.

Map 5-3 shows the transmission paths among the six regions. The transfer constraints are either the official published transfer capabilities recognized by WSCC, or the amount of contract rights PacifiCorp has from other utilities. The map shows the transfer constraint in both directions for each path. The constraints differ directionally due to the nature of their placement within the Western Systems Coordinating Council (WSCC) grid, and the location of loads along the paths. Usually a path with a large load at the sending end has a larger capability than one with a large load at the receiving end. The OWC-to-Bridger path is zero west-to-east, because PacifiCorp has no east-bound transfer capability across the Idaho Power Company system. By agreement with Idaho

this is backwards
maybe not - maybe I'm
wrong

Power Company, PacifiCorp can transfer 1500 MW east-to-west. The OWC-to-Utah path allows for 90 MW of transfer through contractual arrangements with BPA and Washington Water Power. The OWC-to-CAL path currently allows for 525 MW of transfer through contractual arrangements with Bonneville.

The map includes a simultaneous limit between two paths, BRI-to-OWC and BRI-to-UTA, shown as a dotted line on the map with 1500 MW at the head of the arrow. Both lines together can simultaneously carry no more than 1500 MW. A second simultaneous limit occurs between the UTA-to-BRI and the UTA-to-OWC paths. Their simultaneous limit is 275 MW.

The Bridger-to-Wyoming path can transfer 600 MW. The 815 MW of transfer capability on the Bridger-to-Utah path is by contractual arrangements to provide firm transmission services on this path for other entities. Some 275 MW of capacity is available for the company to move power from Utah to Bridger.

The Utah-to-Wyoming path is 420 MW eastbound, and 400 MW westbound. The Utah-to-DSW path is 450 MW eastbound in 1994, consisting of the Four Corners-Pinto 345 kV line with a north-to-south transfer capability of 550 MW. PacifiCorp provides 100 MW of firm transmission service to Arizona Public Service Company. After completion of the Glen Canyon-Navajo interconnection in 1995, this transfer path will be 720 MW. The Utah-to-DSW path is 425 MW westbound, which will increase to 485 MW in 1996.

The Wyoming-to-DSW path is zero going south because PacifiCorp has no transfer capability on this path in that direction. However, PacifiCorp has rights to transfer 100 MW from the Craig plant north to Dave Johnston as part of the Craig and Hayden resource acquisitions.

The CAL-to-DSW path is zero going east, but PacifiCorp has 350 MW of rights going west. PacifiCorp has the right to deliver Cholla's resource to Palo Verde.

The IPM model dispatches existing resources and adds additional generating resources to meet loads in a manner that inter-area flows are within these limits. The model first looks to existing resources within an area to meet load needs, then available resources from other areas that can move over the transmission network, and then adds resources in a manner that respects the transfer limits.

PEAK VERSUS ENERGY PLANNING

A utility's resource planning may be energy-focused or capacity-focused, depending on the nature of its system. Resource planners in the Pacific Northwest have traditionally focused on energy, due to the 33,000 MW of capacity available from the region's federal hydro system. Hydro-dominated utilities focus their resource planning on energy, because they can shape almost all energy production to match hourly load requirements, especially within daily-to-weekly time frames. Hydro plants provide shaping by generating when load requirements are greatest and storing water in reservoirs when they are lower. This shaping allows planners in the Northwest to assess new resource requirements based on fairly simple comparisons of energy loads and resources.

Before the merger between Pacific Power and Utah Power, Pacific Power's planning followed this regional pattern. The capacity contract with BPA, plus the company's owned and purchased hydro, were sufficient to shape energy production into hours of need. This allowed the company to operate its thermal plants as baseload units (run at high capacity around the clock) for maximum efficiency. However, Utah Power was a more traditional thermal-based utility. A thermal-based utility usually focuses on capacity in resource planning, because the utility cannot shape most of its energy production to meet peaking requirements. Utah Power added new resources to meet peak capacity requirements, cycled thermal plants (reduced generation during lower load periods) to follow daily and seasonal changes in system requirements, and used purchased power to help meet peak loads.

The merged company falls between the hydro- and thermal-based. Thermal resources dominate the combined company. However, energy requirements affect the economics of different new resource options. Hydro generation meets 8 to 10 percent of total energy needs. For peaking, owned and purchased hydro is 13 percent of total generating capacity. Adding BPA peaking capacity brings the total to 24 percent.

As a result, capacity requirements are the primary driver in planning new resource additions for PacifiCorp. Peaking resources meet short term capacity and energy requirements caused by heavy load conditions and major forced outages. Peaking resources can also meet other needs: reduce transmission bottlenecks, protect against the risk of reduced peaking available from hydro and contract resources, and provide regulating margin or load following service.

A comparison of energy loads and resources is valid only if energy production can match daily and seasonal variations in demand. An annual energy "surplus" on paper does not guarantee that PacifiCorp's system will have sufficient generation to meet all load requirements. PacifiCorp cannot shape all of its generation into the hours needed, and foresees a decreasing ability to shape generation. The BPA peaking contract at 1100 MW is not increasing; the company's hydro resource base is not growing; and constraints on capacity from the federal hydro system will increase, primarily due to fish concerns. The company's transmission system and geographical load diversity limit the use of resources under certain conditions. The company's total off-peak thermal energy surplus is about 1400 GWh (160 MWa). About 850 GWh (100 MWa) is in the eastern portion of PacifiCorp's system. Transmission constraints prevent the full utilization of that potential energy in areas that need it.

The IPM model required the company to identify one season's peaking needs as the driver for resource selections. Since winter peaks will continue to be higher than summer peaks throughout the 20-year planning horizon, the company selected the winter season. However, the Company's internal load & resource analysis indicates that summer capacity needs are more immediate, because the company has winter capacity coming on-line in the next few years (through the SCE capacity purchase). Because the model only considered winter peak requirements, the model results inadequately reflected the company's immediate summer peaking needs, and may underestimate the amount of peaking resources needed. Seasonal capacity purchases can be an efficient way to meet near-term summer capacity needs. The company is working with the model vendors to change the model code so that in RAMPP-4 it will be able to recognize, and add resources to meet, both the winter and summer peaks.

CRITICAL VERSUS AVERAGE WATER PLANNING

Critical versus average water assumptions affect energy planning, but not capacity planning. The amount of stream flow generally has little effect on generating capacity. However, the amount of stream flow, and thus the annual hydro generation, in the Pacific Northwest region can vary widely, depending on rainfall and snow pack accumulation.

Planners in the Pacific Northwest usually categorize production capability under low-precipitation conditions as firm energy. Any stream flow and resulting generation above that level is non-firm energy. Using this worst-case level of energy production from hydro resources when assessing the need for new resource additions is critical water planning. Planning on critical hydro energy means there is a very low probability that actual hydro generation will be less than expected in a given year. Average water planning assumes a higher level of energy production from hydro plants based on average stream flow. Planning on average hydro would mean that about half the time actual hydro generation would be less than expected. When a utility bases its planning on average hydro conditions, it must assume it can purchase non-firm power for a reasonable price whenever the hydro system produces less than the average amount of energy.

For hydro-based utilities, the use of critical versus average water planning assumptions is very important, since most of their energy comes from hydro resources. Hydro accounts for 62 percent of total Northwest regional energy production, most of it from the federal hydro system (Columbia and Snake rivers). The Northwest hydro system's energy generation based on average water levels is 16,600 MWa, whereas its energy generation based on critical water (assuming worst case stream flows) is 12,500 MWa (33 percent less).

Storage of water behind dams for later release partially offsets the variation in annual stream flows. However, the Columbia River has limited storage capability. The total storage available in Columbia river system dams represents only 25 percent of the annual stream flows in an average year. This limited storage causes significant variation in energy output on the Columbia River system, which affects the price for power bought and sold between utilities. This variation can also complicate computer modeling for resource planning.

The Pacific Northwest Coordination Agreement (PNCA) provides for the coordinated planning and operation of Northwest generating resources to meet loads. This coordination is the result of a regulation that optimizes operation of hydro generating resources for given stream flow conditions. The regulation considers flood control reservoir limits, minimum flow targets, and recreation, irrigation, navigation, and fish release requirements.

The critical hydro regulation operates the coordinated system from full reservoirs to empty over a 4 year period, using actual stream flow data from 1928 to 1932, the driest 4 year period of historical record. The median hydro regulation operates the coordinated system from full reservoirs back to full over a one year period, using average historical stream flows.

PacifiCorp is a party to reserve sharing agreements (PNCA and ICP) that require a showing of sufficient resources to cover loads and reserves assuming hydro generating capability based on critical hydro conditions. The NWPPC also uses the critical hydro standard in their regional planning.

PacifiCorp's integrated resource planning process assumed average hydro conditions. Hydro is a small part of the company's energy resources. The energy difference for PacifiCorp's system between critical and average hydro is only about 145 MWa, less than two percent of 1993 firm energy loads. Additionally, the company depends on an additional 30 MWa from the May/June/July fish flush from Bonneville, for a total impact of about 175 MWa. A sensitivity tested the impact of this planning assumption, by changing the hydro assumption from average water used in the base study plan to critical water. This sensitivity enabled the company to determine the difference in resource requirements and costs. The Illustrative Plans chapter discusses this sensitivity.

PacifiCorp decided to use average water planning for RAMPP-3 because the difference in energy availability between critical and average stream flow assumptions is only about 145 MWa (175 with the spring/summer fish flush power), and the use of critical water assumptions would distort the annual production costs. Under critical water planning, the model would have to buy 145 to 175 MWa of power each year to make up the deficit compared to average water, which would artificially increase PacifiCorp's production costs for each year.

ILLUSTRATIVE PLANS

The first step in the analysis was preparation of a separate model run for each of 155 cases. The 155 cases fall into three categories: 103 cases in the base study plan, 23 cases using environmental adders and carbon limits, and 29 sensitivity cases. This chapter discusses the resource selections made by the model for each case and the financial consequences of those selections. The financial results include the costs of operating the existing system and the additional capital and operating costs of new resources. The model used several strategies to minimize total costs, including its selection of particular new resources, annual dispatch of the new resources, annual dispatch of resources in the existing system, use of provisions in firm contracts, use of the non-firm sales market, and use of the non-firm purchase market.

The Environmental Analysis chapter discusses the environmental cases. The results and conclusions in this chapter do not consider the impact of environmental costs on resource choices. The Renewable Analysis chapter discusses results of the renewable strategy alternatives and the renewable sensitivities.

The base study plan included cases for each of the five load growth levels (low, medium-low, medium, medium-high, and high) under low, medium, and high gas price assumptions. Table 6-1 shows the cases in the base study plan, and the case number for each.

This chapter describes findings on load growth and gas price uncertainties, DSR strategy, and coal strategy. It explains results of the various cases on gas-fired baseload resources and peaking resources. It also discusses non-environmental sensitivities, such as changing the assumptions regarding the non-firm market for power. Finally, this chapter discusses regional patterns of resource choices.

LOAD GROWTH

The following discussion describes the results of the five load growth levels when gas price escalation is medium (3.78 percent real annual increase). The next section, Gas Prices, discusses the runs using low and high gas prices. Two tables show results for each level of load growth and gas price escalation. The first table summarizes the first 10 years of resource selections including both capacity in MW and energy in MWa. The company relied heavily on the 10-year results in developing the action plan. The second table for each load and gas price escalation level summarizes 20 years of resource selections, and provides information regarding system needs and total resources for the 20th year,

Base Study Plan with Case Numbers

Table 6-1

FUTURES		Load	L			ML			M			MH			H		
		Gas	LG	MG	HG	LG	MG	HG	LG	MG	HG	LG	MG	HG	LG	MG	HG
UNCONSTRAINED				1			6		11	28	45		64			85	
LD	AC	AR							12	29	46		65			86	
LD	AC	SR							13	30	47		66			87	
LD	NC	AR							14	31	48		67			88	
LD	NC	SR							15	32	49		68			89	
MD	AC	AR		2			7		16	33	50		69			90	
MD	AC	SR		3			8		17	34	51	62	70	81	83	91	102
MD	NC	AR		4			9		18	35	52		71			92	
MD	NC	SR		5			10		19	36	53	63	72	82	84	93	103
AD	AC	AR							20	37	54		73			94	
AD	AC	SR							21	38	55		74			95	
AD	NC	AR							22	39	56		75			96	
AD	NC	SR							23	40	57		76			97	
HD	AC	AR							24	41	58		77			98	
HD	AC	SR							25	42	59		78			99	
HD	NC	AR							26	43	60		79			100	
HD	NC	SR							27	44	61		80			101	
DSR	Coal	Renew															

(STRATEGIES)

DSR strategies:

- LD - use a low level of cost effectiveness for DSR with slower ramp-up rate
- MD - cost effectiveness based on RAMPP-2 avoided costs, and the ramp-up rate used in RAMPP-2
- AD - cost effectiveness based on RAMPP-2 avoided costs, but with an accelerated ramp-up rate
- HD - use a higher level of cost effectiveness, and an accelerated ramp-up rate

Coal strategies:

- NC - no coal plants
- AC - any coal plants

Renewable strategies:

- AR - any renewables
- SR - strategic renewables

Table 6-2

Low and Medium-Low Load Growth and Medium Gas Price

Resource Selections by 10th Year (2003)

	Load	Low				Medium Low			
	DSM	medium				medium			
	Coal	any		no		any		no	
	Renewable	any	strat	any	strat	any	strat	any	strat
	Case #	2	3	4	5	7	8	9	10
	Winter Peak Capacity in 2003 (MW)								
1	Native Load	7,255	7,255	7,255	7,255	8,194	8,194	8,194	8,194
2	Firm Sales	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195
3	Reserve Requirement	1,186	1,186	1,186	1,186	1,323	1,323	1,323	1,323
4	**Total Requirements**	**9,636**	**9,636**	**9,636**	**9,636**	**10,712**	**10,712**	**10,712**	**10,712**
5	Existing Generation	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582
6	Firm Purchases	317	317	317	317	317	317	317	317
7	New Resources								
8	DSR	541	541	541	541	571	571	571	571
9	Renewable	0	529	0	529	0	529	0	529
10	Cogeneration	0	0	0	0	0	0	0	0
11	Combined Cycle CT	0	0	0	0	0	0	0	0
12	Coal	0	0	0	0	243	38	0	0
13	Peaking Resources	0	0	0	0	0	27	243	65
14	**Total Resources**	**10,440**	**10,969**	**10,440**	**10,969**	**10,713**	**11,064**	**10,713**	**11,064**
	Annual Energy in 2003 (MWa)								
15	Native Load	5,183	5,183	5,183	5,183	5,855	5,855	5,855	5,855
16	Pump Storage/Peak Return	306	306	306	306	306	314	364	322
17	Firm Sales	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410
18	Non-Firm Sales	690	744	690	744	463	469	426	462
19	**Total Requirements**	**7,589**	**7,643**	**7,589**	**7,643**	**8,034**	**8,048**	**8,055**	**8,049**
20	Existing Generation	6,902	6,802	6,902	6,802	7,051	7,060	7,137	7,075
21	Firm Purchases	363	360	363	360	364	364	370	364
22	Non-Firm Purchases	32	13	32	13	85	94	193	109
23	New Resources								
24	DSR	307	307	307	307	325	325	325	325
25	Renewable	0	177	0	177	0	178	0	178
26	Cogeneration	0	0	0	0	0	0	0	0
27	Combined Cycle CT	0	0	0	0	0	0	0	0
28	Coal	0	0	0	0	223	34	0	0
29	Peaking Resources	0	0	0	0	0	6	45	12
30	**Total Resources**	**7,604**	**7,659**	**7,604**	**7,659**	**8,048**	**8,062**	**8,070**	**8,063**

T6-02.grand.l-ml.10yrs

emission levels, and utility costs. In addition, three-dimensional bar charts for some of the cases show the 10- and 20-year new resource choices.

Table 6-2 shows new resource selections under low and ML load growth for the first 10 years of the 20-year planning horizon. The first section shows the results in winter capacity (MW), and the second section shows the results in energy (MWa). Line 1 shows the native load (retail load) requirements in the 10th year of the planning horizon. It reflects the system retail load after 10 years of load growth at the specified growth rate. Line 2 shows power requirements for firm sales in the 10th year. This includes only those sales whose contracts extend for at least 10 years from 1994 (RAMPP-3 includes no new firm sales). Line 3 shows reserve requirements based on 15 percent of the native load and firm sales requirements, after reductions due to DSR. Line 4 adds the three previous lines to determine total requirements for existing and new resources. The remaining lines in this section itemize the existing and new resources. Line 5 shows the available capacity from the existing system, adjusted for known changes. Line 6 shows firm purchases from existing contracts that extend for at least 10 years. RAMPP-3 adds no new firm purchases to the system during the 20 years. Lines 8 through 13 show the new resources added in each model run by general categories: DSR, renewable, cogeneration, combined cycle CT (CCCT), coal, and peaking resources. Line 14 indicates the total resource amounts.

The next section of the table shows annual energy output in MWa. Line 15 indicates the native load in the 10th year of the planning horizon. Line 16 shows the amount of energy needed for the company to meet the energy return requirements in its peaking contract with BPA (included under existing resources) and the energy needed for pumped storage resources added to the system. Line 17 indicates firm sales. The next line shows the amount of non-firm sales in the 10th year that the model made for each case. Added together, these four categories represent the total requirements for that year (line 19). Line 20 shows the amount of energy the model had the existing system produce, followed on line 21 by the amount of non-firm purchases the model made for that year. Lines 24 through 29 show the amount of energy the model produced from the new resources. Line 30 shows the total resources available to serve the system's energy needs.

Table 6-3 summarizes 20 years of resource selections. The first two sections of this table, as in the 10-year table, show model run results for winter peak capacity in MW and for energy in MWa. The next section indicates emission levels, with CO_2 shown on line 31 and NOx shown on line 32. The Modeling Appendix shows TSP emission amounts.

The last section of the table shows the financial results from each case. Line 33 shows the net present value (NPV) of 50 years of annual revenue requirements, in millions of dollars. Although this is a 20-year resource plan, the financial outputs, to include end effects, used a 50-year NPV. Line 34 shows the real levelized cost in mills/kWh, that is the price customers would pay per kWh if the company charged all customers on a kWh basis (no basic or demand charge) and prices did not vary by state or customer class (pricing ignored allocation

Low and Medium-Low Load Growth and Medium Gas Price

Resource Selections, Emissions and Financial Results

	Load	Low				Medium Low			
	DSM	medium				medium			
	Coal	any		no		any		no	
	Renewable	any	strat	any	strat	any	strat	any	strat
	Case #	2	3	4	5	7	8	9	10
	Winter Peak Capacity in 2013 (MW)								
1	Native Load	7,504	7,504	7,504	7,504	9,277	9,277	9,277	9,277
2	Firm Sales	437	437	437	437	437	437	437	437
3	Reserve Requirement	1,062	1,062	1,062	1,062	1,314	1,314	1,314	1,314
4	**Total Requirements**	9,003	9,003	9,003	9,003	11,028	11,028	11,028	11,028
5	Existing Generation	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196
6	Firm Purchases	262	262	262	262	262	262	262	262
7	New Resources								
8	DSR	864	864	864	864	956	956	956	956
9	Renewable	0	529	0	529	0	529	0	529
10	Cogeneration	0	0	0	0	0	0	0	0
11	Combined Cycle CT	0	0	0	0	0	0	0	0
12	Coal	0	0	0	0	379	170	0	0
13	Peaking Resources	0	0	0	0	235	267	615	437
14	**Total Resources**	10,322	10,851	10,322	10,851	11,028	11,380	11,028	11,380
	Annual Energy in 2013 (MWa)								
15	Native Load	5,373	5,373	5,373	5,373	6,620	6,620	6,620	6,620
16	Pump Storage/Peak Return	305	305	305	305	373	382	424	413
17	Firm Sales	841	841	841	841	841	841	841	841
18	Non-Firm Sales	1,036	1,064	1,036	1,064	617	618	446	556
19	**Total Requirements**	7,555	7,583	7,555	7,583	8,451	8,461	8,331	8,430
20	Existing Generation	6,735	6,589	6,735	6,589	6,979	6,990	7,063	7,034
21	Firm Purchases	335	333	335	333	386	386	429	420
22	Non-Firm Purchases	0	0	0	0	152	157	212	180
23	New Resources								
24	DSR	498	498	498	498	548	548	548	548
25	Renewable	0	177	0	177	0	179	0	179
26	Cogeneration	0	0	0	0	0	0	0	0
27	Combined Cycle CT	0	0	0	0	0	0	0	0
28	Coal	0	0	0	0	348	156	0	0
29	Peaking Resources	0	0	0	0	53	60	93	85
30	**Total Resources**	7,568	7,597	7,568	7,597	8,466	8,476	8,345	8,446
	Average Annual Emissions in 1994-2013 (1000 tons)								
31	CO_2	54,226	53,488	54,226	53,488	57,215	56,205	56,136	55,863
32	NOx	122	121	122	121	129	127	127	126
	Financial Results with End Effects to 2043								
	50-year Utility Cost								
33	NPV at 8.8% (million $)	38,040	38,791	38,040	38,791	41,419	41,939	41,582	41,984
34	Real Levelized (mills/kWh)	50.07	51.06	50.07	51.06	47.02	47.61	47.21	47.66
	50-year Total Resources Cost								
35	NPV at 8.8% (million $)	39,310	40,061	39,310	40,061	42,760	43,280	42,923	43,325
36	Real Levelized (mills/kWh)	48.63	49.56	48.63	49.56	45.80	46.36	45.98	46.41

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issues and cost of service by customer class). Therefore, the reader should not compare price, as used in the following discussion, with a current price on any tariff. The reader should use price as a way to compare one plan to another, and as an indication of the ability of different resource plans to minimize price increases. The next two lines show NPV and real levelized unit costs for total resource costs. Total resource costs include utility cost and the customer's costs and non-energy benefits of DSR measures. The NPV of total utility costs tends to be lower than the NPV of total resource costs because the latter includes more costs. However, the real levelized mills/kWh of the utility cost tends to be higher than the real levelized mills/kWh of total resource costs because the calculation of real levelized mills/kWh of total resource costs uses total energy services as the divisor. Total energy services is a larger number than kWh sales because it includes the energy saved from DSR measures.

Low and Medium-Low Load Growth

Five cases examined resource planning under each of the two lowest load growth levels -- low and medium-low (ML). One was the completely unconstrained run (unconstrained DSR, any-coal and any-renewable strategies). Tables 6-17 and 6-18 on pages 117 and 118 show the 10- and 20-year resource selections for the unconstrained cases. The other four for each load growth level used the medium DSR level and the four combinations of coal and renewable strategies (any-coal with any-renewables, any-coal with strategic-renewables, no-coal with any-renewables, and no-coal with strategic-renewables).

Low load growth assumed an annual growth rate of 0.3 percent. Under low load growth, no new supply-side resource additions occurred in the next 10 years. Over the 20-year planning horizon, the model added only 17 MW of DSR in the unconstrained run (see Table 6-18). The system experienced excess capacity. The forced addition of DSR or renewable resources, as in the runs using LD, MD, AD, HD, or SR strategies (see Table 6-1), increased the excess capacity: reserve margins increased to as much as 36 percent. The model minimized production costs by running existing units less, and sold excess power on the non-firm market whenever possible. Utility costs and total resource costs were the lowest for any of the load growth levels, but prices (real levelized cost in mills/kWh) were the highest, because the embedded system would be under-utilized if load growth suddenly dropped to a very low level.

Medium-low load growth assumed annual load growth of 1.25 percent, and resulted in 1,397 MWa and 1,969 peak MW of additional load at the end of 20 years. In the early years, the model ran existing units less and made high levels of annual non-firm sales to minimize net production costs. It began adding new resources (pumped storage and up to 424 MW of coal) only after 2000. Under the no-coal strategy, the model used more energy from the company's firm purchase contracts than under the any-coal strategy. Utility costs and total resource costs were slightly higher than under low load growth, but prices were lower, reflecting greater use of the embedded system.

Under the medium DSR strategy, moving from low to ML load growth, on average, increased the NPV of utility cost by $3,315 million, decreased real levelized prices by 3.19 mills/kWh, and increased the NPV of total resource cost by $3,387 million.

Medium Load Growth

The medium load growth cases assumed annual load growth of 2.1 percent, which resulted in additional load of 1,281 MWa and 1,776 peak MW by the end of 10 years, and 2,644 MWa and 3,709 peak MW by the end of the 20-year planning period. Seventeen runs tested the strategy combinations under medium load growth. The first was an unconstrained run, followed by four sets of four runs each using the four combinations of coal and renewable strategies. Each of the four sets used a different DSR strategy: low, medium, accelerated, or high.

Table 6-4 shows resource additions in the first 10 years. The model selected DSR, strategic renewables (where applicable), cogeneration, coal (where applicable), and pumped storage. If the strategies were medium DSR and any-coal, the new resources were about 300 MW of cogeneration and 700 to 800 MW of coal, for a total of 1,000 to 1,100 MW of baseload resources. If the strategies were medium DSR and no-coal, the new resources were 850 to 1,050 MW of cogeneration. Under medium load growth, the company would face significant new baseload requirements in the next 10 years (850 to 1,100 MW). Under the medium DSR strategy, the model also added about 350 to 400 MW of peaking resources. The company heavily weighted these 10-year results for medium load growth in developing the action plan. These results indicate that the action plan should include items to acquire cogeneration as soon as possible, evaluate coal technologies and siting, and pursue the acquisition of peaking resources.

Table 6-5 shows new resources added after 20 years. Under medium load growth, the model selected cogeneration, coal, and pumped storage to meet new system needs. Cogeneration entered the new resource plan at its earliest available date, 1997. The amount of cogeneration chosen depended heavily on the coal strategy (more cogeneration under no-coal), the DSR strategy (more cogeneration under less DSR), and the renewable strategy (slightly more cogeneration under any-renewables). The model relied heavily on coal as a resource in the any-coal cases, from 1,260 to 1,900 MW, beginning in 2001, the earliest it was available given its lead time. By the end of 20 years, new resource plans included the maximum amount of pumped storage (1000 MW). In the no-coal cases, the model added 400 to 820 MW of combustion turbines for peaking.

Utility costs and total resource costs were higher for medium load growth than for medium-low load growth, but prices were lower, reflecting greater use of the embedded system. Under medium DSR, moving from ML to medium load growth, on average, increased the NPV of utility cost by $5,112 million, decreased real levelized prices by 0.74 mills/kWh, and increased the NPV of total resource cost by $5,336 million.

Table 6-4

Medium Load Growth and Medium Gas Price

Resource Selections by 10th Year (2003)

	DSM	low				medium				accelerated				high			
	Coal	any		no		any		no		any		no		any		no	
	Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
	Case #	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44
	Winter Peak Capacity in 2003 (MW)																
1	Native Load	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273
2	Firm Sales	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195
3	Reserve Requirement	1,528	1,528	1,528	1,528	1,479	1,479	1,479	1,479	1,470	1,470	1,470	1,470	1,452	1,452	1,452	1,452
4	**Total Requirements**	**11,996**	**11,996**	**11,996**	**11,996**	**11,947**	**11,947**	**11,947**	**11,947**	**11,938**	**11,938**	**11,938**	**11,938**	**11,920**	**11,920**	**11,920**	**11,920**
5	Existing Generation	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582
6	Firm Purchases	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317
7	New Resources																
8	DSR	284	284	284	284	608	608	608	608	670	670	670	670	786	786	786	786
9	Renewable	0	529	0	529	0	529	0	529	0	529	0	529	0	529	0	529
10	Cogeneration	402	347	1,324	1,114	302	276	1,058	864	227	180	994	805	180	134	929	735
11	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Coal	912	819	0	0	803	700	0	0	809	719	0	0	792	698	0	0
13	Peaking Resources	500	471	490	522	336	287	383	399	333	293	375	386	264	226	307	323
14	**Total Resources**	**11,997**	**12,348**	**11,997**	**12,348**	**11,948**	**12,299**	**11,948**	**12,299**	**11,939**	**12,290**	**11,939**	**12,290**	**11,921**	**12,272**	**11,921**	**12,272**
	Annual Energy in 2003 (MWa)																
15	Native Load	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634
16	Pump Storage/Peak Return	434	432	433	442	394	389	405	413	395	391	404	411	375	372	387	393
17	Firm Sales	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410
18	Non-Firm Sales	508	511	485	491	488	507	461	475	486	499	464	478	472	490	455	470
19	**Total Requirements**	**8,986**	**8,987**	**8,962**	**8,977**	**8,926**	**8,940**	**8,910**	**8,932**	**8,925**	**8,934**	**8,912**	**8,933**	**8,891**	**8,906**	**8,886**	**8,907**
20	Existing Generation	7,077	7,053	7,140	7,140	7,069	7,053	7,141	7,138	7,070	7,048	7,140	7,136	7,058	7,037	7,136	7,131
21	Firm Purchases	364	364	364	364	364	364	364	364	364	364	364	364	364	364	364	364
22	Non-Firm Purchases	104	87	115	107	97	71	108	111	90	74	107	109	92	81	108	114
23	New Resources																
24	DSR	175	175	175	175	348	348	348	348	404	404	404	404	448	448	448	448
25	Renewable	0	177	0	178	0	178	0	178	0	178	0	178	0	178	0	178
26	Cogeneration	345	297	1,085	921	260	236	887	725	200	156	835	675	163	122	780	619
27	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Coal	836	750	0	0	735	641	0	0	741	659	0	0	726	640	0	0
29	Peaking Resources	100	98	99	106	68	64	77	83	69	66	76	82	53	51	63	68
30	**Total Resources**	**9,000**	**9,001**	**8,977**	**8,991**	**8,941**	**8,954**	**8,925**	**8,947**	**8,939**	**8,948**	**8,926**	**8,948**	**8,905**	**8,921**	**8,899**	**8,922**

Medium Load Growth and Medium Gas Price

Resource Selections, Emissions and Financial Results

	DSM	low				medium				accelerated				high			
	Coal	any		no		any		no		any		no		any		no	
	Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
	Case #	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44
	Winter Peak Capacity in 2013 (MW)																
1	Native Load	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206
2	Firm Sales	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437
3	Reserve Requirement	1,667	1,667	1,667	1,667	1,586	1,586	1,586	1,586	1,581	1,581	1,581	1,581	1,551	1,551	1,551	1,551
4	**Total Requirements**	**13,310**	**13,310**	**13,310**	**13,310**	**13,229**	**13,229**	**13,229**	**13,229**	**13,224**	**13,224**	**13,224**	**13,224**	**13,194**	**13,194**	**13,194**	**13,194**
5	Existing Generation	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196
6	Firm Purchases	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262
7	New Resources																
8	DSR	526	526	526	526	1,071	1,071	1,071	1,071	1,106	1,106	1,106	1,106	1,303	1,303	1,303	1,303
9	Renewable	0	529	0	529	0	529	0	529	0	529	0	529	0	529	0	529
10	Cogeneration	402	347	1,610	1,318	302	276	1,180	948	227	180	1,148	924	180	134	1,032	854
11	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Coal	1,925	1,799	0	0	1,437	1,274	0	0	1,463	1,319	0	0	1,406	1,262	0	0
13	Peaking Resources	1,000	1,004	1,717	1,831	962	973	1,520	1,574	970	984	1,513	1,559	848	860	1,402	1,402
14	**Total Resources**	**13,311**	**13,662**	**13,311**	**13,662**	**13,230**	**13,581**	**13,230**	**13,581**	**13,224**	**13,575**	**13,224**	**13,575**	**13,195**	**13,546**	**13,195**	**13,546**
	Annual Energy in 2013 (MWa)																
15	Native Load	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998
16	Pump Storage/Peak Return	460	461	492	481	455	447	460	449	445	435	457	447	437	430	445	445
17	Firm Sales	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841
18	Non-Firm Sales	517	521	379	330	456	467	313	294	429	424	312	297	418	413	296	305
19	**Total Requirements**	**9,816**	**9,821**	**9,710**	**9,650**	**9,750**	**9,753**	**9,612**	**9,582**	**9,713**	**9,698**	**9,608**	**9,583**	**9,694**	**9,682**	**9,580**	**9,589**
20	Existing Generation	6,761	6,750	7,085	7,088	6,914	6,911	7,087	7,090	6,896	6,882	7,087	7,090	6,894	6,879	7,091	7,089
21	Firm Purchases	346	348	442	442	375	381	442	442	374	376	442	442	375	380	442	442
22	Non-Firm Purchases	153	153	245	261	152	152	266	269	154	154	267	269	154	154	272	269
23	New Resources																
24	DSR	318	318	318	318	613	613	613	613	638	638	638	638	718	718	718	718
25	Renewable	0	179	0	179	0	179	0	179	0	179	0	179	0	179	0	179
26	Cogeneration	366	315	1,448	1,191	275	252	1,068	858	210	167	1,040	837	167	125	938	774
27	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Coal	1,764	1,648	0	0	1,317	1,168	0	0	1,341	1,209	0	0	1,289	1,157	0	0
29	Peaking Resources	122	123	186	184	119	111	150	145	115	107	147	142	110	104	132	132
30	**Total Resources**	**9,830**	**9,834**	**9,724**	**9,663**	**9,765**	**9,766**	**9,626**	**9,596**	**9,728**	**9,712**	**9,621**	**9,597**	**9,707**	**9,696**	**9,594**	**9,603**
	Average Annual Emissions in 1994-2013 (1000 tons)																
31	CO_2	63,320	62,494	59,304	58,807	61,972	61,102	58,589	58,130	61,752	60,915	58,422	57,963	61,372	60,533	58,231	57,766
32	NO_x	141	140	129	129	139	137	129	128	138	137	129	128	138	136	129	128
	Financial Results with End Effects to 2043																
	50-year Utility Cost																
33	NPV at 8.8% (million $)	47,195	47,681	47,742	48,224	46,337	46,802	46,894	47,338	46,327	46,809	46,834	47,270	46,067	46,549	46,563	46,970
34	Real Levelized (mills/kWh)	45.73	46.20	46.26	46.73	46.13	46.59	46.68	47.12	46.42	46.90	46.93	47.37	46.50	46.99	47.01	47.42
	50-year Total Resources Cost																
35	NPV at 8.8% (million $)	48,099	48,586	48,647	49,128	47,903	48,368	48,460	48,903	47,784	48,266	48,291	48,727	47,789	48,271	48,285	48,691
36	Real Levelized (mills/kWh)	45.28	45.74	45.79	46.25	45.09	45.53	45.62	46.04	44.98	45.44	45.46	45.87	44.99	45.44	45.45	45.84

T6-05.grand.m.mg.20yrs

Table 6-6

Medium High Load Growth and Low, Medium and High Gas Prices

Resource Selections by 10th Year (2003)

	Gas	Low		Medium																High	
	DSM	medium		low				medium				accelerated				high				medium	
	Coal	any	no	any		no		any		no		any		no		any		no		any	no
	Renewable	strat	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
	Case #	62	63	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82
	Winter Peak Capacity in 2003 (MW)																				
1	Native Load	10,382	10,382	10,382	10,382	10,382	10,382	10,382	10,382	10,382	10,382	10,382	10,382	10,382	10,382	10,382	10,382	10,382	10,382	10,382	10,382
2	Firm Sales	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195
3	Reserve Requirement	1,637	1,637	1,691	1,691	1,691	1,691	1,637	1,637	1,637	1,637	1,619	1,619	1,619	1,619	1,608	1,608	1,608	1,608	1,637	1,637
4	**Total Requirements**	**13,214**	**13,214**	**13,268**	**13,268**	**13,268**	**13,268**	**13,214**	**13,214**	**13,214**	**13,214**	**13,196**	**13,196**	**13,196**	**13,196**	**13,185**	**13,185**	**13,185**	**13,185**	**13,214**	**13,214**
5	Existing Generation	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582
6	Firm Purchases	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317
7	New Resources																				
8	DSR	665	665	301	301	301	301	665	665	665	665	780	780	780	780	858	858	858	858	665	665
9	Renewable	529	529	0	529	300	529	0	529	300	529	0	529	0	529	0	529	0	529	529	529
10	Cogen	1,555	1,898	1,162	1,089	2,060	1,986	965	895	1,845	1,770	934	872	1,880	1,685	899	835	1,836	1,651	801	1,341
11	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Coal	232	0	990	923	0	0	990	895	0	0	977	859	0	0	967	852	0	0	996	0
13	Peaking Resources	686	576	917	881	911	905	696	684	707	704	608	609	639	656	563	565	594	601	676	1,133
14	**Total Resources**	**13,566**	**13,566**	**13,269**	**13,621**	**13,470**	**13,620**	**13,215**	**13,566**	**13,416**	**13,566**	**13,198**	**13,549**	**13,198**	**13,549**	**13,187**	**13,538**	**13,187**	**13,538**	**13,566**	**13,566**
	Annual Energy in 2003 (MWa)																				
15	Native Load	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390	7,390
16	Pump Storage/Peak Return	428	423	463	469	456	456	445	452	441	446	447	454	443	436	439	447	439	435	476	425
17	Firm Sales	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410
18	Non-Firm Sales	475	485	521	526	487	484	518	524	482	485	522	525	478	480	520	523	476	482	534	389
19	**Total Requirements**	**9,703**	**9,708**	**9,784**	**9,795**	**9,743**	**9,740**	**9,763**	**9,776**	**9,723**	**9,731**	**9,769**	**9,779**	**9,721**	**9,716**	**9,759**	**9,770**	**9,715**	**9,717**	**9,810**	**9,614**
20	Existing Generation	7,063	7,037	7,100	7,091	7,143	7,140	7,091	7,085	7,136	7,136	7,085	7,085	7,141	7,132	7,085	7,084	7,141	7,130	7,114	7,182
21	Firm Purchases	364	364	364	364	364	364	364	364	364	364	364	364	364	364	364	364	364	364	364	392
22	Non-Firm Purchases	128	108	133	107	130	118	110	98	114	110	106	93	125	109	103	92	123	108	85	224
23	New Resources																				
24	DSR	380	380	189	189	189	189	380	380	380	380	445	445	445	445	480	480	480	480	380	380
25	Renewable	178	178	0	177	105	177	0	177	105	178	0	177	0	178	0	177	0	178	177	178
26	Cogen	1,288	1,559	967	896	1,693	1,633	810	746	1,524	1,461	777	725	1,549	1,395	751	695	1,515	1,366	659	1,144
27	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Coal	212	0	907	845	0	0	907	820	0	0	895	788	0	0	886	781	0	0	913	0
29	Peaking Resources	105	96	139	139	134	134	117	120	114	117	112	117	112	110	105	110	107	106	132	128
30	**Total Resources**	**9,718**	**9,722**	**9,799**	**9,809**	**9,758**	**9,755**	**9,778**	**9,790**	**9,737**	**9,745**	**9,783**	**9,793**	**9,736**	**9,732**	**9,774**	**9,783**	**9,729**	**9,731**	**9,824**	**9,628**

T6-06 grand mb 10yrs

Medium High Load Growth and Low, Medium and High Gas Prices

Resource Selections, Emissions and Financial Results

	Gas	Low		Medium																High	
	DSM	medium		low				medium				accelerated				high				medium	
	Coal	any	no	any		no		any		no		any		no		any		no		any	no
	Renewable	strat	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
	Case #	62	63	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82
	Winter Peak Capacity in 2013 (MW)																				
1	Native Load	13,488	13,488	13,488	13,488	13,488	13,488	13,488	13,488	13,488	13,488	13,488	13,488	13,488	13,488	13,488	13,488	13,488	13,488	13,488	13,488
2	Firm Sales	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437
3	Reserve Requirement	1,905	1,905	2,004	2,004	2,004	2,004	1,905	1,905	1,905	1,905	1,891	1,891	1,891	1,891	1,866	1,866	1,866	1,866	1,905	1,905
4	**Total Requirements**	15,830	15,830	15,929	15,929	15,929	15,929	15,830	15,830	15,830	15,830	15,816	15,816	15,816	15,816	15,791	15,791	15,791	15,791	15,830	15,830
5	Existing Generation	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196
6	Firm Purchases	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262
7	New Resources																				
8	DSR	1,227	1,227	566	566	566	566	1,227	1,227	1,227	1,227	1,320	1,320	1,320	1,320	1,482	1,482	1,482	1,482	1,227	1,227
9	Renewable	529	529	0	529	300	529	0	529	300	529	0	529	0	529	0	529	0	529	529	3,999
10	Cogen	1,555	2,099	1,162	1,089	2,099	2,099	965	895	2,099	2,099	934	872	2,099	2,099	899	835	2,099	2,099	801	1,341
11	Combined Cycle CT	0	553	0	0	916	835	0	0	570	494	0	0	642	481	0	0	565	413	0	0
12	Coal	1,839	0	2,951	2,834	0	0	2,788	2,649	0	0	2,788	2,653	0	0	2,740	2,608	0	0	2,841	0
13	Peaking Resources	1,574	2,316	1,792	1,805	2,792	2,794	1,394	1,424	2,378	2,375	1,317	1,336	2,298	2,282	1,213	1,232	2,188	2,163	1,326	2,571
14	**Total Resources**	16,182	16,182	15,929	16,281	16,130	16,280	15,831	16,182	16,032	16,182	15,817	16,168	15,817	16,168	15,792	16,143	15,792	16,144	16,182	18,595
	Annual Energy in 2013 (MWa)																				
15	Native Load	9,623	9,623	9,623	9,623	9,623	9,623	9,623	9,623	9,623	9,623	9,623	9,623	9,623	9,623	9,623	9,623	9,623	9,623	9,623	9,623
16	Pump Storage/Peak Return	492	491	468	473	528	525	468	468	512	509	468	467	501	507	468	466	495	511	457	426
17	Firm Sales	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841
18	Non-Firm Sales	491	321	487	482	300	298	469	466	304	303	460	463	291	308	460	463	294	321	462	179
19	**Total Requirements**	11,447	11,276	11,419	11,419	11,292	11,287	11,401	11,398	11,280	11,276	11,392	11,394	11,256	11,279	11,392	11,393	11,253	11,296	11,383	11,069
20	Existing Generation	6,866	7,048	6,671	6,655	7,092	7,094	6,653	6,656	7,095	7,095	6,651	6,649	7,092	7,096	6,654	6,651	7,091	7,096	6,549	7,048
21	Firm Purchases	336	399	336	338	442	442	338	340	442	442	339	341	442	442	339	340	442	442	332	429
22	Non-Firm Purchases	152	292	153	150	266	264	151	152	265	263	151	152	266	261	152	153	269	264	153	234
23	New Resources																				
24	DSR	694	694	349	349	349	349	694	694	694	694	718	718	718	718	795	795	795	795	694	694
25	Renewable	179	179	0	179	105	179	0	179	105	179	0	179	0	179	0	179	0	179	179	1,273
26	Cogen	1,372	1,946	1,041	981	1,930	1,930	871	809	1,928	1,925	844	789	1,933	1,925	813	756	1,932	1,927	725	1,223
27	Combined Cycle CT	0	515	0	0	847	772	0	0	527	457	0	0	594	444	0	0	524	381	0	0
28	Coal	1,685	0	2,705	2,597	0	0	2,554	2,428	0	0	2,555	2,431	0	0	2,511	2,390	0	0	2,604	0
29	Peaking Resources	179	219	180	185	274	272	154	156	239	236	149	151	226	229	142	144	215	226	162	182
30	**Total Resources**	11,462	11,291	11,434	11,434	11,306	11,303	11,415	11,413	11,295	11,290	11,406	11,409	11,270	11,294	11,406	11,407	11,268	11,311	11,398	11,083
	Average Annual Emissions in 1994-2013 (1000 tons)																				
31	CO2	64,142	60,987	67,982	67,214	61,888	61,736	66,937	66,106	61,205	61,076	66,745	65,861	61,334	60,886	66,498	65,621	61,186	60,758	66,443	59,828
32	NOx	139	130	149	148	131	131	147	146	131	131	147	145	131	131	147	145	131	130	147	130
	Financial Results with End Effects to 2043																				
	50-year Utility Cost																				
33	NPV at 8.8% (million $)	52,410	52,682	53,278	53,767	54,588	54,811	52,290	52,785	53,449	53,664	52,137	52,627	53,125	53,504	51,930	52,423	52,886	53,257	53,043	56,461
34	Real Levelized (mills/kWh)	45.75	45.99	45.27	45.69	46.39	46.58	45.65	46.08	46.66	46.85	45.80	46.23	46.67	47.00	45.88	46.32	46.73	47.06	46.31	49.29
	50-year Total Cost																				
35	NPV at 8.8% (million $)	54,176	54,448	54,241	54,730	55,552	55,774	54,056	54,551	55,215	55,430	53,711	54,202	54,699	55,078	53,859	54,352	54,815	55,186	54,809	58,227
36	Real Levelized (mills/kWh)	44.78	45.01	44.84	45.24	45.92	46.10	44.68	45.09	45.64	45.82	44.40	44.80	45.21	45.53	44.52	44.93	45.31	45.62	45.30	48.13

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Medium-High Load Growth

Medium-high load growth (3.0 percent) added 4,151 MWa and 5,782 peak MW to the total system load. The general pattern of resource selections resembled that for medium load growth, only more of the same resources and sooner. Table 6-6 shows resource additions in the first 10 years. Under medium DSR, the model added about 1,800 to 1,900 MW of new baseload resources, and about 700 MW of new peaking resources.

Table 6-7 shows resource additions after 20 years. Under a no-coal strategy, the model added the full amount of available cogeneration, 2,099 MW. Under the any-coal strategy, the model added from 834 to 1,162 MW of cogeneration. Thus the medium-high runs added from 618 to 1,245 MW of cogeneration in addition to the amount in the medium load growth runs. Additional gas-fired baseload resources in the form of CCCTs began appearing in 2006 in the no-coal cases. In the any-coal cases, the model added from 1,608 to 2,951 MW of coal. All cases used the maximum amount of pumped storage available (1,000 MW). However, under MH load growth, the model added from 100 to 150 MW more pumped storage in the first 10 years compared to medium load growth. The higher load growth required more combustion turbines for peaking. This began in the first 10 years. Over the next 10 years MH load growth called for 213 to 1,133 MW of additional SCCTs over the amount needed for medium load growth. The possibility of higher load growth reinforced the company's belief it should begin acquiring cogeneration resources immediately. MH load growth required 1500 to 2000 MW of additional baseload resources beyond the requirements of medium load growth, and 450-800 MW of additional peaking resources.

Utility costs and total resource costs were higher for MH than medium load growth, but real prices were slightly lower. This indicates that load growth above the current level can occur without price increases greater than inflation. Under medium DSR, moving from medium to MH load growth, on average, increased the NPV of utility cost by $6,204 million, decreased real levelized prices by 0.32 mills/kWh, and increased the NPV of total resource cost by $6,404 million. In the any-coal cases, new coal resources displaced as much as 261 MWa of more expensive existing resources. Also, up to 41 MWa of dispatchable firm purchases were also displaced. These combined actions caused the NPV of utility cost to increase, but price to decrease. The no-coal runs added more expensive resources, thus they were not able to lower prices as much as the any-coal runs.

High Load Growth

High load growth (3.75 percent) added 5,725 MWa and 7,975 peak MW of load. This doubled the system. The pattern of resource selections resembled that for medium and MH load growth, only more resources and sooner. Table 6-8 shows new resources after 10 years. Under medium DSR, resource plans included about 1,700 to 2,100 MW of new baseload resources, and 1,200 to 1,400 MW of peaking resources.

Table 6-8

High Load Growth and Low, Medium and High Gas Prices

Resource Selections by 10th Year (2003)

		Gas	Low		Medium																High	
		DSM	medium		low				medium				accelerated				high				medium	
		Coal	any	no	any		no		any		no		any		no		any		no		any	no
		Renewable	strat	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
		Case #	83	84	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100	101	102	103
	Winter Peak Capacity in 2003 (MW)																					
1	Native Load		11,658	11,658	11,658	11,658	11,658	11,658	11,658	11,658	11,658	11,658	11,658	11,658	11,658	11,658	11,658	11,658	11,658	11,658	11,658	11,658
2	Firm Sales		1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195
3	Reserve Requirement		1,821	1,821	1,880	1,880	1,880	1,880	1,821	1,821	1,821	1,821	1,797	1,797	1,797	1,797	1,787	1,787	1,787	1,787	1,821	1,821
4	**Total Requirements**		**14,674**	**14,674**	**14,733**	**14,733**	**14,733**	**14,733**	**14,674**	**14,674**	**14,674**	**14,674**	**14,650**	**14,650**	**14,650**	**14,650**	**14,640**	**14,640**	**14,640**	**14,640**	**14,674**	**14,674**
5	Existing Generation		9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582
6	Firm Purchases		317	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317
7	New Resources																					
8	DSR		714	714	318	318	318	318	714	714	714	714	873	873	873	873	938	938	938	938	714	714
9	Renewable		529	529	0	529	300	529	0	529	300	529	0	529	300	529	0	529	300	529	529	950
10	Cogen		1,889	2,099	1,640	1,640	2,099	2,099	1,640	1,640	2,099	2,099	1,640	1,620	2,099	2,099	1,640	1,605	2,099	2,099	1,517	2,099
11	Combined Cycle CT		0	473	0	0	625	558	0	0	424	399	0	0	388	323	0	0	358	293	0	96
12	Coal		684	0	1,342	1,167	0	0	1,207	1,052	0	0	1,168	1,032	0	0	1,151	1,025	0	0	1,320	0
13	Peaking Resources		1,311	1,312	1,536	1,533	1,695	1,683	1,215	1,192	1,440	1,387	1,071	1,049	1,294	1,279	1,013	997	1,248	1,235	1,047	1,550
14	**Total Resources**		**15,026**	**15,026**	**14,734**	**15,086**	**14,936**	**15,085**	**14,675**	**15,026**	**14,876**	**15,026**	**14,651**	**15,002**	**14,852**	**15,002**	**14,642**	**14,993**	**14,843**	**14,993**	**15,026**	**15,308**
	Annual Energy in 2003 (MWa)																					
15	Native Load		8,288	8,288	8,288	8,288	8,288	8,288	8,288	8,288	8,288	8,288	8,288	8,288	8,288	8,288	8,288	8,288	8,288	8,288	8,288	8,288
16	Pump Storage/Peak Return		429	425	481	488	429	433	480	495	426	429	484	492	427	428	479	488	427	428	517	441
17	Firm Sales		1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410
18	Non-Firm Sales		434	434	453	472	400	405	485	499	411	430	494	506	428	428	497	507	430	429	549	406
19	**Total Requirements**		**10,561**	**10,557**	**10,632**	**10,658**	**10,527**	**10,536**	**10,663**	**10,692**	**10,535**	**10,557**	**10,676**	**10,696**	**10,553**	**10,554**	**10,674**	**10,693**	**10,555**	**10,555**	**10,764**	**10,545**
20	Existing Generation		7,088	7,095	7,142	7,139	7,157	7,155	7,134	7,132	7,154	7,151	7,128	7,120	7,152	7,151	7,128	7,118	7,153	7,151	7,123	7,198
21	Firm Purchases		363	363	364	364	364	364	364	364	364	364	364	364	364	364	364	364	364	364	364	395
22	Non-Firm Purchases		183	192	157	159	213	211	144	133	216	202	137	126	206	199	130	125	205	199	106	214
23	New Resources																					
24	DSR		409	409	202	202	202	202	409	409	409	409	482	482	482	482	512	512	512	512	409	409
25	Renewable		178	178	0	178	105	178	0	177	105	178	0	177	105	178	0	177	105	178	177	326
26	Cogen		1,587	1,765	1,374	1,378	1,779	1,777	1,358	1,358	1,780	1,772	1,352	1,333	1,776	1,771	1,348	1,318	1,777	1,772	1,214	1,774
27	Combined Cycle CT		0	431	0	0	561	500	0	0	376	353	0	0	343	286	0	0	317	259	0	85
28	Coal		627	0	1,229	1,069	0	0	1,106	964	0	0	1,070	946	0	0	1,055	939	0	0	1,210	0
29	Peaking Resources		140	138	178	184	161	163	164	169	146	144	157	161	138	138	151	157	135	136	177	159
30	**Total Resources**		**10,575**	**10,571**	**10,647**	**10,673**	**10,542**	**10,550**	**10,678**	**10,706**	**10,550**	**10,573**	**10,691**	**10,711**	**10,567**	**10,569**	**10,688**	**10,709**	**10,569**	**10,570**	**10,779**	**10,560**

Table 6-9

High Load Growth and Low, Medium and High Gas Prices

Resource Selections, Emissions and Financial Results

	Gas	Low		Medium																High	
	DSM	medium		low				medium				accelerated				high				medium	
	Coal	any	no	any		no		any		no		any		no		any		no		any	no
	Renewable	strat	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
	Case #	83	84	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100	101	102	103
	Winter Peak Capacity in 2013 (MW)																				
1	Native Load	15,949	15,949	15,949	15,949	15,949	15,949	15,949	15,949	15,949	15,949	15,949	15,949	15,949	15,949	15,949	15,949	15,949	15,949	15,949	15,949
2	Firm Sales	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437
3	Reserve Requirement	2,253	2,253	2,367	2,367	2,367	2,367	2,253	2,253	2,253	2,253	2,230	2,230	2,230	2,230	2,210	2,210	2,210	2,210	2,253	2,253
4	**Total Requirements**	18,639	18,639	18,753	18,753	18,753	18,753	18,639	18,639	18,639	18,639	18,616	18,616	18,616	18,616	18,596	18,596	18,596	18,596	18,639	18,639
5	Existing Generation	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196
6	Firm Purchases	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262
7	New Resources																				
8	DSR	1,363	1,363	604	604	604	604	1,363	1,363	1,363	1,363	1,519	1,519	1,519	1,519	1,654	1,654	1,654	1,654	1,363	1,363
9	Renewable	529	529	0	529	300	529	0	529	300	529	0	529	300	529	0	529	300	529	658	5,450
10	Cogeneration	1,889	2,099	1,640	1,640	2,099	2,099	1,640	1,640	2,099	2,099	1,640	1,640	2,099	2,099	1,640	1,640	2,099	2,099	1,640	2,099
11	Combined Cycle CT	273	2,474	367	320	2,871	2,798	181	133	2,444	2,353	154	103	2,405	2,330	129	77	2,311	2,238	0	366
12	Coal	3,030	0	4,149	4,020	0	0	3,903	3,766	0	0	3,924	3,780	0	0	3,862	3,720	0	0	4,106	0
13	Peaking Resources	2,449	3,068	2,537	2,535	3,623	3,618	2,096	2,103	3,177	3,189	1,922	1,938	3,036	3,032	1,856	1,871	2,977	2,971	1,863	3,672
14	**Total Resources**	18,992	18,992	18,754	19,105	18,955	19,105	18,640	18,992	18,841	18,992	18,617	18,968	18,818	18,968	18,597	18,949	18,799	18,949	19,088	22,409
	Annual Energy in 2013 (MWa)																				
15	Native Load	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380	11,380
16	Pump Storage/Peak Return	505	534	479	480	576	572	471	471	562	558	470	464	559	554	470	465	554	551	451	496
17	Firm Sales	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841
18	Non-Firm Sales	430	342	511	519	335	336	503	493	312	304	502	492	308	307	497	493	303	303	531	142
19	**Total Requirements**	13,156	13,097	13,211	13,220	13,132	13,129	13,195	13,185	13,095	13,083	13,193	13,177	13,088	13,082	13,188	13,179	13,078	13,075	13,203	12,859
20	Existing Generation	6,763	7,023	6,547	6,534	7,085	7,085	6,554	6,543	7,079	7,079	6,539	6,528	7,078	7,078	6,550	6,542	7,079	7,079	6,350	7,060
21	Firm Purchases	335	379	338	338	442	442	338	332	442	442	334	332	442	442	334	333	442	442	330	429
22	Non-Firm Purchases	162	260	135	140	230	227	154	153	235	236	153	153	240	238	153	153	254	248	157	266
23	New Resources																				
24	DSR	769	769	379	379	379	379	769	769	769	769	802	802	802	802	868	868	868	868	769	769
25	Renewable	179	179	0	178	105	179	0	178	105	179	0	179	105	179	0	179	105	179	209	1,739
26	Cogeneration	1,697	1,910	1,444	1,444	1,902	1,900	1,451	1,450	1,910	1,910	1,453	1,453	1,914	1,910	1,454	1,457	1,917	1,917	1,459	1,935
27	Combined Cycle CT	254	2,299	341	298	2,636	2,568	168	124	2,246	2,161	143	96	2,209	2,139	120	72	2,124	2,055	0	331
28	Coal	2,776	0	3,802	3,684	0	0	3,576	3,451	0	0	3,596	3,464	0	0	3,539	3,409	0	0	3,763	0
29	Peaking Resources	244	294	240	240	367	364	200	200	324	321	189	184	311	308	184	181	305	302	181	352
30	**Total Resources**	13,178	13,113	13,226	13,235	13,146	13,144	13,210	13,200	13,109	13,098	13,208	13,191	13,102	13,096	13,201	13,192	13,093	13,090	13,217	12,880
	Average Annual Emissions in 1994-2013 (1000 tons)																				
31	CO_2	69,465	64,276	73,566	72,542	65,268	65,111	72,120	71,171	64,502	64,350	71,856	70,918	64,285	64,122	71,623	70,701	64,157	63,994	71,878	62,368
32	NO_x	149	133	159	157	134	134	156	154	134	134	156	154	133	133	155	154	133	133	156	132
	Financial Results with End Effects to 2043																				
	50-year Utility Cost																				
33	NPV at 8.8% (million $)	58,639	59,049	59,980	60,428	61,809	62,024	58,788	59,243	60,508	60,733	58,519	58,982	60,250	60,469	58,255	58,722	59,984	60,201	59,903	65,092
34	Real Levelized (mills/kWh)	45.04	45.35	44.88	45.21	46.25	46.41	45.15	45.50	46.47	46.64	45.23	45.59	46.57	46.74	45.23	45.59	46.57	46.74	46.01	49.99
	50-year Total Cost																				
35	NPV at 8.8% (million $)	60,535	60,945	61,013	61,461	62,841	63,056	60,684	61,139	62,404	62,629	60,269	60,731	62,000	62,218	60,687	61,154	62,416	62,633	61,799	66,988
36	Real Levelized (mills/kWh)	44.11	44.41	44.46	44.79	45.80	45.95	44.22	44.55	45.48	45.64	43.92	44.26	45.18	45.34	44.23	44.57	45.49	45.64	45.04	48.82

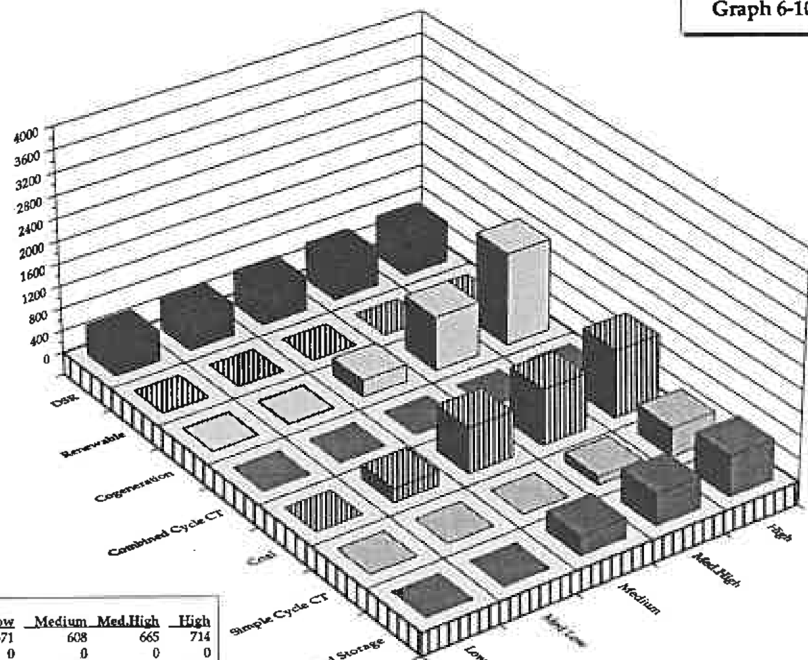
T6-09.grand.h.20yrs

Graph 6-10

Resource Additions by Load Level:

(Medium Gas Price, Medium DSR, Any-Coal, Any-Renewables)

1994-2003

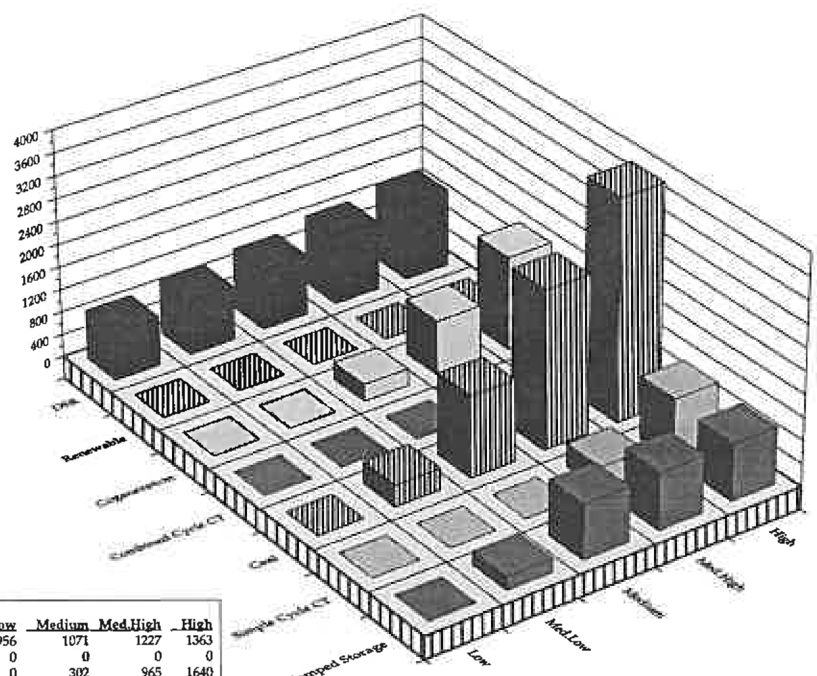


Winter MW's	Low	Med.Low	Medium	Med.High	High
DSR	541	571	608	665	714
Renewable	0	0	0	0	0
Cogeneration	0	0	302	965	1640
Combined Cycle CT	0	0	0	0	0
Coal	0	243	803	990	1207
Simple Cycle CT	0	0	0	148	507
Pumped Storage	0	0	336	548	709
Total	541	814	2049	3316	4776

Resource Additions by Load Level:

(Medium Gas Price, Medium DSR, Any-Coal, Any-Renewables)

1994-2013



Winter MW's	Low	Med.Low	Medium	Med.High	High
DSR	864	956	1071	1227	1363
Renewable	0	0	0	0	0
Cogeneration	0	0	302	965	1640
Combined Cycle CT	0	0	0	0	181
Coal	0	379	1437	2788	3903
Simple Cycle CT	0	0	0	394	1096
Pumped Storage	0	235	962	1000	1000
Total	864	1570	3772	6373	9182

Table 6-9 shows new resources after 20 years. As under MH load growth, the model added the full amount of available cogeneration, 2,099 MW, under a no-coal strategy. The model added 1,640 MW of cogeneration in all of the any-coal cases. From 2,238 to 2,871 MW of CCCTs beginning in 2001 or 2003 helped meet system needs in the no-coal cases. In the any-coal cases, coal met from 3,720 to 4,149 MW of new resource needs beginning in 2001. The plans included the maximum amount of pumped storage -- from 500 to 800 MW in the first 10 years, and the full 1,000 MW by 2013. SCCTs grew to a maximum of 2,623 MW. Under the any-coal strategy, the model selected fewer SCCTs.

Utility costs and total resource costs were higher in the high load growth than the medium-high cases, but prices were about the same, again indicating that load growth can occur without price increases greater than inflation. Under medium DSR, moving from MH to high load growth, on average, increased the NPV of utility cost by $6,771 million, decreased real levelized prices by 0.37 mills/kWh, and increased the NPV of total resource cost by $6,901 million.

Graph 6-10 provides a summary of the new resource selections for all five load growth levels by resource category under the medium DSR, any-coal and any-renewables strategies for 10 years and for 20 years. In the first 10 years, the graph shows that for the low growth case, the only resource addition was DSR. In the ML case, the only resource additions were DSR and a little coal. Under medium load growth, the resource plans included DSR, cogeneration, coal, and pumped storage. In MH and high, the resource plans followed the same pattern as medium growth, with more of each resource and the addition of a few SCCTs. After 20 years, the graph shows higher stacks for the same resource technologies.

GAS PRICES

Each case assumed one of three real escalation rates for gas prices: low at 1.71 percent real growth per year, medium at 3.78 percent, and high at 5.56 percent. Table 6-1 shows the cases for each gas price escalation level. Medium load growth used all of the strategy combinations under each of the three gas price escalation levels. Low and medium-low load growth used only medium gas price escalation. Medium-high and high load growth used medium gas price escalation for all of the strategy combinations. In addition, MH and high load growth used low and high gas price escalation for a few strategy combinations.

Tables 6-11 and 6-12 show the cases using low gas price escalation with medium load growth. Tables 6-13 and 6-14 show the cases using high gas prices escalation with medium load growth. Tables 6-6, 6-7, 6-8, and 6-9 show the effect of low and high gas prices under MH and high load growth. Changing the gas price escalation did not dramatically change the resources selected. Lower gas price escalation increased the model's reliance on gas-fired resources. Higher gas price escalation reduced the model's reliance on gas-fired resources, and increased its reliance on coal resources.

Medium Load Growth and Low Gas Price

Resource Selections by 10th Year (2003)

	DSM	low				medium				accelerated				high			
	Coal	any		no		any		no		any		no		any		no	
	Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
	Case #	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
	Winter Peak Capacity in 2003 (MW)																
1	Native Load	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273
2	Firm Sales	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195
3	Reserve Requirement	1,528	1,528	1,528	1,528	1,479	1,479	1,479	1,479	1,470	1,470	1,470	1,470	1,452	1,452	1,452	1,452
4	**Total Requirements**	**11,996**	**11,996**	**11,996**	**11,996**	**11,947**	**11,947**	**11,947**	**11,947**	**11,938**	**11,938**	**11,938**	**11,938**	**11,920**	**11,920**	**11,920**	**11,920**
5	Existing Generation	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582
6	Firm Purchases	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317
7	New Resources																
8	DSR	284	284	284	284	608	608	608	608	670	670	670	670	786	786	786	786
9	Renewable	0	529	0	529	0	529	0	529	0	529	0	529	0	529	0	529
10	Cogeneration	636	582	1,457	1,238	478	425	1,225	1,038	460	396	1,160	971	390	324	1,095	906
11	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Coal	598	468	0	0	564	428	0	0	520	395	0	0	504	399	0	0
13	Peaking Resources	580	587	357	399	399	410	216	225	390	400	210	221	341	334	141	152
14	**Total Resources**	**11,997**	**12,348**	**11,997**	**12,348**	**11,948**	**12,299**	**11,948**	**12,299**	**11,939**	**12,290**	**11,939**	**12,290**	**11,921**	**12,272**	**11,921**	**12,272**
	Annual Energy in 2003 (MWa)																
15	Native Load	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634
16	Pump Storage/Peak Return	416	425	391	401	401	404	358	361	399	402	356	360	388	386	340	343
17	Firm Sales	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410
18	Non-Firm Sales	478	484	487	489	474	477	469	481	473	476	471	483	462	467	463	476
19	**Total Requirements**	**8,938**	**8,953**	**8,922**	**8,934**	**8,919**	**8,925**	**8,871**	**8,886**	**8,916**	**8,922**	**8,871**	**8,887**	**8,894**	**8,897**	**8,847**	**8,863**
20	Existing Generation	7,069	7,062	7,036	7,039	7,058	7,050	7,037	7,031	7,058	7,049	7,037	7,032	7,058	7,042	7,034	7,033
21	Firm Purchases	363	364	364	364	364	364	364	364	364	364	364	364	364	364	364	364
22	Non-Firm Purchases	178	182	105	104	177	179	90	86	176	176	89	85	187	180	89	83
23	New Resources																
24	DSR	175	175	175	175	348	348	348	348	404	404	404	404	448	448	448	448
25	Renewable	0	178	0	178	0	178	0	178	0	178	0	178	0	179	0	178
26	Cogeneration	527	481	1,191	1,015	395	352	1,006	851	380	328	952	796	325	270	899	742
27	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Coal	548	429	0	0	517	392	0	0	476	362	0	0	462	366	0	0
29	Peaking Resources	92	98	66	74	74	76	40	43	72	74	39	42	63	62	26	28
30	**Total Resources**	**8,951**	**8,968**	**8,936**	**8,948**	**8,933**	**8,939**	**8,885**	**8,900**	**8,931**	**8,935**	**8,885**	**8,901**	**8,907**	**8,911**	**8,861**	**8,877**

T6-11.grand.m.lg.10yrs

Table 6-12

Medium Load Growth and Low Gas Price

Resource Selections, Emissions and Financial Results

	DSM	low				medium				accelerated				high			
	Coal	any		no		any		no		any		no		any		no	
	Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
	Case #	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
	Winter Peak Capacity in 2013 (MW)																
1	Native Load	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206
2	Firm Sales	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437
3	Reserve Requirement	1,667	1,667	1,667	1,667	1,586	1,586	1,586	1,586	1,581	1,581	1,581	1,581	1,551	1,551	1,551	1,551
4	**Total Requirements**	**13,310**	**13,310**	**13,310**	**13,310**	**13,229**	**13,229**	**13,229**	**13,229**	**13,224**	**13,224**	**13,224**	**13,224**	**13,194**	**13,194**	**13,194**	**13,194**
5	Existing Generation	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196
6	Firm Purchases	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262
7	New Resources																
8	DSR	526	526	526	526	1,071	1,071	1,071	1,071	1,106	1,106	1,106	1,106	1,303	1,303	1,303	1,303
9	Renewable	0	529	0	529	0	529	0	529	0	529	0	529	0	529	0	529
10	Cogeneration	636	582	1,936	1,679	478	425	1,544	1,341	460	396	1,513	1,306	390	324	1,404	1,195
11	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Coal	1,474	1,315	0	0	1,222	1,097	0	0	1,201	1,087	0	0	1,124	1,006	0	0
13	Peaking Resources	1,216	1,253	1,391	1,470	1,000	1,000	1,156	1,182	1,000	1,000	1,147	1,176	919	926	1,030	1,061
14	**Total Resources**	**13,311**	**13,662**	**13,311**	**13,662**	**13,230**	**13,581**	**13,230**	**13,581**	**13,224**	**13,575**	**13,224**	**13,575**	**13,195**	**13,546**	**13,195**	**13,546**
	Annual Energy in 2013 (MWa)																
15	Native Load	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998
16	Pump Storage/Peak Return	444	442	493	483	428	427	483	477	427	427	480	476	425	425	477	476
17	Firm Sales	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841
18	Non-Firm Sales	476	467	489	465	427	430	464	452	420	420	464	452	383	377	455	441
19	**Total Requirements**	**9,759**	**9,748**	**9,821**	**9,787**	**9,694**	**9,696**	**9,786**	**9,768**	**9,686**	**9,686**	**9,783**	**9,767**	**9,647**	**9,641**	**9,771**	**9,756**
20	Existing Generation	6,915	6,905	7,010	7,012	6,926	6,915	7,011	7,006	6,929	6,914	7,011	7,007	6,934	6,920	7,009	7,005
21	Firm Purchases	336	341	370	372	342	345	382	374	342	346	383	376	347	349	385	380
22	Non-Firm Purchases	167	175	243	249	186	179	257	265	186	179	257	268	190	184	269	277
23	New Resources																
24	DSR	318	318	318	318	613	613	613	613	638	638	638	638	718	718	718	718
25	Renewable	0	179	0	179	0	179	0	179	0	179	0	179	0	179	0	179
26	Cogeneration	566	517	1,725	1,505	425	378	1,389	1,200	409	352	1,362	1,169	347	288	1,267	1,073
27	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Coal	1,351	1,205	0	0	1,120	1,006	0	0	1,101	996	0	0	1,030	922	0	0
29	Peaking Resources	121	121	169	166	96	96	148	144	96	96	145	144	94	94	136	138
30	**Total Resources**	**9,773**	**9,761**	**9,835**	**9,801**	**9,708**	**9,710**	**9,799**	**9,781**	**9,700**	**9,700**	**9,795**	**9,781**	**9,660**	**9,654**	**9,784**	**9,770**
	Average Annual Emissions in 1994-2013 (1000 tons)																
31	CO_2	62,332	61,386	59,351	58,902	61,259	60,366	58,736	58,274	60,997	60,120	58,574	58,103	60,614	59,788	58,380	57,903
32	NO_x	138	136	129	129	136	135	128	128	136	134	128	128	135	134	128	128
	Financial Results with End Effects to 2043																
	50-year Utility Cost																
33	NPV at 8.8% (million $)	47,167	47,664	47,188	47,692	46,379	46,878	46,406	46,901	46,334	46,837	46,361	46,857	46,096	46,598	46,112	46,612
34	Real Levelized (mills/kWh)	45.70	46.18	45.72	46.21	46.17	46.67	46.20	46.69	46.43	46.93	46.46	46.95	46.53	47.04	46.55	47.05
	50-year Total Resources Cost																
35	NPV at 8.8% (million $)	48,071	48,568	48,092	48,596	47,945	48,444	47,971	48,467	47,791	48,295	47,818	48,315	47,818	48,320	47,834	48,333
36	Real Levelized (mills/kWh)	45.25	45.72	45.27	45.75	45.13	45.60	45.16	45.63	44.99	45.46	45.01	45.48	45.01	45.49	45.03	45.50

T6-12.grand.m.lg.20yrs

Table 6-11 shows new resources selected assuming low gas price escalation and medium load growth for the first 10 years. Under medium DSR, significant baseload and peaking requirements remained, but the resource mix shifted to more cogeneration and less coal.

Table 6-12 shows the resources selected under low gas price escalation and medium load growth after 20 years. Over the 20-year period, low gas price escalation increased the amount of cogeneration selected by about 200 to 300 MW over that for medium gas price escalation. Under low gas price escalation, the model selected from 250 to 400 MW less coal than under medium gas price escalation. Gas price escalation had no effect on the amount of renewables selected. Pumped storage additions contributed about 100 MW less for the first 10 years under low gas price escalation compared to medium gas price escalation. However, by the end of 20 years, the plans included all 1,000 MW of pumped storage regardless of gas price escalation. In all of the no-coal cases, the amount of additional cogeneration selected was exactly equal to the decrease in SCCTs selected. The model used the additional baseload capacity to increase non-firm sales, displace existing high cost generation, displace high cost dispatchable firm purchases, and displace peaking resources. In all of the any-coal cases, the model selected less coal and more SCCTs and cogeneration. Under low gas prices and any-coal, the model decreased non-firm sales, increased existing generation, displaced high cost dispatchable firm purchases, and reduced pumped storage. In all cases, total energy requirements declined for the any-coal cases and increased for the no-coal cases. Utility costs, real levelized customer prices, and total resource costs were lower with lower gas price escalation.

Lower gas prices under medium-high or high load growth resulted in no significant resource changes compared to the resources selected under medium gas prices.

Table 6-13 shows new resource choices for medium load growth assuming high gas prices for the first 10 years. Under medium DSR, more coal and less cogeneration met baseload needs in the any-coal strategy cases; renewables and cogeneration met baseload needs in the no-coal strategy cases.

Table 6-14 shows the results for high gas prices after 20 years. The plans included less gas-fired resources and more renewables, as one might expect. The model selected less cogeneration and more renewable resources under high gas prices than under medium gas prices. Higher gas prices reduced the amount of cogeneration, but the effect varied widely. Under high DSR, there was almost no impact on cogeneration, but under low DSR the model selected less cogeneration under high gas prices. Higher gas prices caused the model to select slightly more coal in the any-coal cases, but never more than 160 additional MW. High gas prices had the greatest impact on the selection of renewables in the no-coal cases. High gas prices caused the model to select from 2,111 to 3,207 MW of renewables, compared to none under medium gas prices. Higher gas prices had almost no impact on the selection of pumped storage. From 60 to 130 MW of

Table 6-13

Medium Load Growth and High Gas Price

Resource Selections by 10th Year (2003)

	DSM	low				medium				accelerated				high			
	Coal	any		no		any		no		any		no		any		no	
	Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
	Case #	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61
	Winter Peak Capacity in 2003 (MW)																
1	Native Load	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273
2	Firm Sales	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195
3	Reserve Requirement	1,528	1,528	1,528	1,528	1,479	1,479	1,479	1,479	1,470	1,470	1,470	1,470	1,452	1,452	1,452	1,452
4	**Total Requirements**	**11,996**	**11,996**	**11,996**	**11,996**	**11,947**	**11,947**	**11,947**	**11,947**	**11,938**	**11,938**	**11,938**	**11,938**	**11,920**	**11,920**	**11,920**	**11,920**
5	Existing Generation	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582
6	Firm Purchases	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317
7	New Resources																
8	DSR	284	284	284	284	608	608	608	608	670	670	670	670	786	786	786	786
9	Renewable	0	529	1,200	529	0	529	1,066	529	0	529	1,050	529	0	529	1,050	529
10	Cogeneration	365	299	388	498	160	276	359	436	160	160	320	337	160	133	320	320
11	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Coal	990	885	0	0	924	751	0	0	927	758	0	0	893	741	0	0
13	Peaking Resources	459	452	1,054	1,138	357	236	743	827	282	274	715	854	183	184	581	738
14	**Total Resources**	**11,997**	**12,348**	**12,825**	**12,348**	**11,948**	**12,299**	**12,675**	**12,299**	**11,939**	**12,290**	**12,654**	**12,290**	**11,921**	**12,272**	**12,637**	**12,272**
	Annual Energy in 2003 (MWa)																
15	Native Load	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634
16	Pump Storage/Peak Return	434	437	422	419	401	375	418	418	388	386	414	410	360	360	418	408
17	Firm Sales	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410
18	Non-Firm Sales	521	516	376	327	477	518	430	372	493	501	433	358	497	498	443	372
19	**Total Requirements**	**8,999**	**8,997**	**8,842**	**8,790**	**8,922**	**8,937**	**8,892**	**8,834**	**8,925**	**8,931**	**8,891**	**8,812**	**8,901**	**8,902**	**8,905**	**8,824**
20	Existing Generation	7,097	7,069	7,175	7,187	7,070	7,036	7,164	7,174	7,050	7,037	7,162	7,178	7,036	7,020	7,160	7,179
21	Firm Purchases	363	363	405	437	364	364	396	419	363	364	391	421	364	364	391	416
22	Non-Firm Purchases	68	68	234	251	88	54	213	224	63	69	209	229	62	72	188	225
23	New Resources																
24	DSR	175	175	175	175	348	348	348	348	404	404	404	404	448	448	448	448
25	Renewable	0	177	388	179	0	178	356	179	0	178	352	179	0	178	352	179
26	Cogeneration	303	246	358	452	146	229	327	398	145	138	289	313	145	114	287	297
27	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Coal	907	811	0	0	847	688	0	0	850	694	0	0	818	679	0	0
29	Peaking Resources	100	102	121	123	74	54	103	107	64	62	98	103	42	42	94	96
30	**Total Resources**	**9,013**	**9,011**	**8,855**	**8,804**	**8,936**	**8,951**	**8,906**	**8,848**	**8,939**	**8,946**	**8,905**	**8,826**	**8,915**	**8,917**	**8,920**	**8,839**

T6-13.grand.m.hg.10yrs

Medium Load Growth and High Gas Price

Resource Selections, Emissions and Financial Results

	DSM	low				medium				accelerated				high			
	Coal	any		no		any		no		any		no		any		no	
	Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
	Case #	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61
	Winter Peak Capacity in 2013 (MW)																
1	Native Load	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206
2	Firm Sales	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437
3	Reserve Requirement	1,667	1,667	1,667	1,667	1,586	1,586	1,586	1,586	1,581	1,581	1,581	1,581	1,551	1,551	1,551	1,551
4	**Total Requirements**	**13,310**	**13,310**	**13,310**	**13,310**	**13,229**	**13,229**	**13,229**	**13,229**	**13,224**	**13,224**	**13,224**	**13,224**	**13,194**	**13,194**	**13,194**	**13,194**
5	Existing Generation	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196
6	Firm Purchases	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262
7	New Resources																
8	DSR	526	526	526	526	1,071	1,071	1,071	1,071	1,106	1,106	1,106	1,106	1,303	1,303	1,303	1,303
9	Renewable	0	529	3,207	2,840	0	529	2,412	2,080	0	529	2,424	2,346	0	529	2,122	2,111
10	Cogeneration	365	299	388	498	160	276	359	436	160	160	320	337	160	133	320	320
11	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Coal	1,930	1,808	0	0	1,595	1,399	0	0	1,565	1,428	0	0	1,454	1,331	0	0
13	Peaking Resources	1,032	1,042	1,988	1,961	945	848	1,626	1,623	935	895	1,618	1,609	820	793	1,476	1,463
14	**Total Resources**	**13,311**	**13,662**	**15,568**	**15,284**	**13,230**	**13,581**	**14,926**	**14,668**	**13,224**	**13,575**	**14,926**	**14,856**	**13,195**	**13,546**	**14,679**	**14,655**
	Annual Energy in 2013 (MWa)																
15	Native Load	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998
16	Pump Storage/Peak Return	456	457	409	409	445	451	409	408	442	446	406	406	427	441	403	403
17	Firm Sales	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841
18	Non-Firm Sales	492	488	234	256	398	531	254	263	405	453	252	263	423	452	243	257
19	**Total Requirements**	**9,787**	**9,784**	**9,482**	**9,504**	**9,682**	**9,821**	**9,502**	**9,510**	**9,686**	**9,738**	**9,497**	**9,508**	**9,689**	**9,732**	**9,485**	**9,499**
20	Existing Generation	6,759	6,746	7,049	7,053	6,842	6,866	7,056	7,064	6,850	6,837	7,054	7,060	6,866	6,857	7,055	7,059
21	Firm Purchases	346	348	431	434	363	377	435	437	365	371	434	436	377	381	435	436
22	Non-Firm Purchases	153	151	228	232	151	152	230	237	151	151	230	233	152	154	232	233
23	New Resources																
24	DSR	318	318	318	318	613	613	613	613	638	638	638	638	718	718	718	718
25	Renewable	0	179	975	889	0	179	733	657	0	179	743	729	0	179	658	666
26	Cogeneration	331	273	359	457	149	252	333	401	149	149	298	314	149	124	298	298
27	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Coal	1,769	1,657	0	0	1,462	1,282	0	0	1,434	1,308	0	0	1,333	1,219	0	0
29	Peaking Resources	125	126	136	135	116	114	117	116	113	118	114	113	107	113	104	103
30	**Total Resources**	**9,801**	**9,797**	**9,496**	**9,518**	**9,695**	**9,835**	**9,517**	**9,524**	**9,700**	**9,751**	**9,511**	**9,522**	**9,702**	**9,745**	**9,499**	**9,513**
	Average Annual Emissions in 1994-2013 (1000 tons)																
31	CO_2	63,527	62,640	57,339	57,783	62,174	61,344	57,136	57,482	62,012	61,089	56,999	57,226	61,653	60,721	56,940	57,144
32	NO_x	142	140	128	128	140	137	128	128	139	137	128	128	138	137	128	128
	Financial Results with End Effects to 2043																
	50-year Utility Cost																
33	NPV at 8.8% (million $)	47,153	47,652	50,053	49,925	46,403	46,607	48,541	48,474	46,305	46,687	48,469	48,534	45,945	46,381	48,015	48,106
34	Real Levelized (mills/kWh)	45.69	46.17	48.50	48.37	46.19	46.40	48.32	48.25	46.40	46.78	48.57	48.63	46.38	46.82	48.47	48.56
	50-year Total Resources Cost																
35	NPV at 8.8% (million $)	48,057	48,557	50,957	50,829	47,969	48,173	50,107	50,039	47,762	48,144	49,926	49,992	47,667	48,103	49,737	49,827
36	Real Levelized (mills/kWh)	45.24	45.71	47.97	47.85	45.16	45.35	47.17	47.11	44.96	45.32	47.00	47.06	44.87	45.28	46.82	46.91

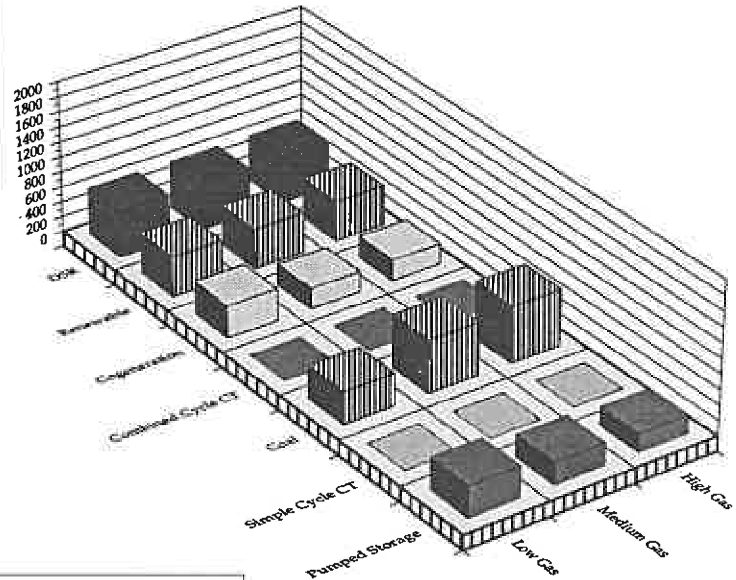
T6-14.grand.m.hg.20yrs

Graph 6-15

Resource Additions by Gas Price Level:

(Medium Load Growth, Medium DSR, Any-Coal, Strategic-Renewables)

1994-2003



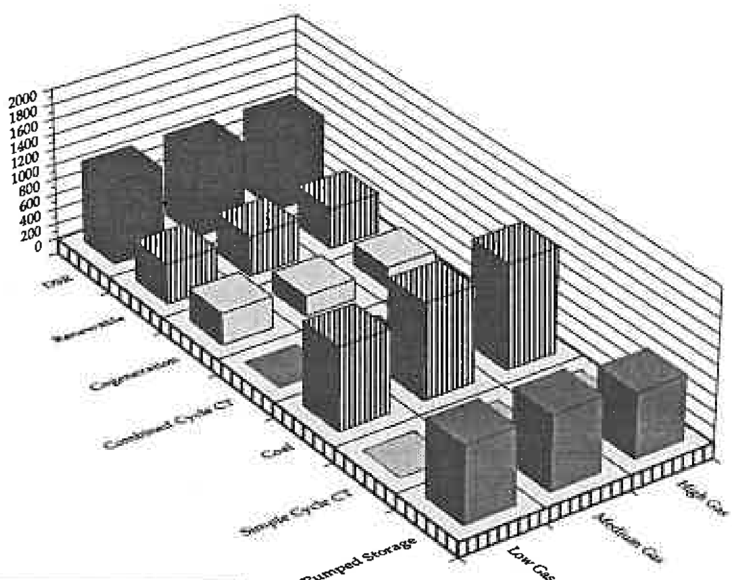
Winter MW's

	Low Gas	Medium Gas	High Gas
DSR	608	608	608
Renewable	529	529	529
Cogeneration	425	276	276
Combined Cycle CT	0	0	0
Coal	428	700	751
Simple Cycle CT	0	0	0
Pumped Storage	410	287	236
Total	2400	2400	2400

Resource Additions by Gas Price Level:

(Medium Load Growth, Medium DSR, Any-Coal, Strategic Renewables)

1994-2013



Winter MW's

	Low Gas	Medium Gas	High Gas
DSR	1071	1071	1071
Renewable	529	529	529
Cogeneration	425	276	276
Combined Cycle CT	0	0	0
Coal	1097	1274	1399
Simple Cycle CT	0	0	0
Pumped Storage	1000	973	848
Total	4123	4123	4123

additional SCCTs met peaking needs in the high gas price escalation cases (because of the high amount of renewables).

Under MH load growth, higher gas prices reduced the amount of cogeneration selected from 2,099 MW to 1,340 MW. Higher gas prices also reduced the selection of CCCTs to zero, and dramatically increased the amount of renewables to 3,999 MW. Slightly more SCCTs met peaking needs under high gas prices than medium gas prices.

Under high load growth, higher gas prices had no effect on cogeneration; decreased CCCTs from 2,353 MW under medium gas prices to 366 MW; increased renewables to 5,450 MW; and increased SCCTs by about 500 MW compared to medium gas prices. High gas prices had a slight impact on utility cost, causing the cost to decrease in the any-coal cases and increase in the no-coal cases. In the any-coal cases, the model avoided the high gas prices by selecting coal instead of gas-fired resources. In the no-coal cases, the model had to select more renewable resources, which raised utility costs.

Graph 6-15 summarizes the new resource selections according to type of resource and gas price escalation under medium load growth for 10 and 20 years. Under medium load growth, as gas prices increased, less cogeneration and more coal met baseload needs.

Under medium DSR and assuming low gas prices, moving from medium to MH load growth, on average, increased the NPV of utility cost by $5,905 million, decreased real levelized prices by 0.56 mills/kWh, and increased the NPV of total resource cost by $6,105 million. Again under medium DSR and assuming low gas prices, moving from MH to high load growth increased the NPV of utility cost by $6,298 decreased real levelized prices by 0.68 mills/kWh, and increased the NPV of total resource cost by $6,428 million. Under medium DSR and assuming high gas prices the NPV of utility cost increases for each level of load growth increase was about $1.5 billion more, and real levelized prices increased rather than decreasing as under low or medium gas prices.

One result, unexpected and seemingly inconsistent with an optimization model, required a second look at the detailed output. Under medium load growth and an any-coal strategy, the model tended to produced a lower total utility cost under medium gas prices compared to low gas prices, and a lower total utility cost under high gas prices compared to medium gas prices, all else remaining the same. However, all else did not remain the same. Under higher gas prices, the model also used higher prices for non-firm sales and purchases. The following table shows the relevant information for one of these seemingly inconsistent results:

Results by Gas Price Level: Cost and Non-Firm Transactions
Table 6-16

Gas Prices	Medium Case #34 M.MG.MD.AC.SR	High Case #51 M.HG.MD.AC.SR
Total Utility Cost	46,802	46,607
Non-firm sales	467	531
Non-firm purchases	152	152

Because of the higher price for non-firm sales, the model made more sales each year, which provided sufficient revenue to lower the total utility cost. The model also made other adjustments to minimize costs when gas prices increased. These adjustments included changing the resource mix, dispatching gas units less, adjusting non-firm transactions, and adjusting pumped-storage usage.

The company believes the most likely future range for gas prices is between the low and medium assumptions used in RAMPP-3; therefore the company relied heavily on the resource selections under low and medium gas price escalations in developing the action plan. The model's selection of cogeneration and peaking resources reinforced the need to include them in the action plan. Low gas prices would result in only slightly lower utility and total resource costs compared to medium gas prices. There was almost no change in real prices.

DSR STRATEGIES

Four levels of demand-side resources (DSR) tested alternative DSR strategies. In addition, one unconstrained DSR option allowed the model to select the amount and timing of DSR. The financial model results show how the four DSR strategies would affect utility costs and customer prices.

Table 6-17 shows the 10-year results of the unconstrained DSR assumption for seven futures: one for each load growth level using medium gas prices, and two additional ones using low and high gas prices under medium load growth. Table 6-18 shows the 20-year results for the same cases. Most of the DSR comes on in the first 10 years. Since these runs all used completely unconstrained strategies, the resource plans for all the cases consisted of DSR, cogeneration, some peaking, and primarily coal. Table 6-18 includes emissions data for each run, but not financial data. The assumptions required to calculate the financial results would have been inconsistent with the goals of the unconstrained run. The financial model used an assumed cost per kWh for the DSR. That cost depends on the amount of DSR developed each year. A high amount of DSR in each year would result in a very high cost per kWh, but such high costs would have resulted in the model selecting much less DSR. Rather than devote the considerable time and energy required to perform the necessary iterations to find the right price and annual unconstrained DSR amounts, the public advisory

Table 6-17

Unconstrained Resource Strategies for All Load Growth Levels

Resource Selections by 10th Year (2003)

	Load	Low	Medium Low	Medium			Medium High	High
	Gas	Medium	Medium	Low	Medium	High	Medium	Medium
	Case #	1	6	11	28	45	64	85
	Winter Peak Capacity in 2003 (MW)							
1	Native Load	7,255	8,194	9,273	9,273	9,273	10,382	11,658
2	Firm Sales	1,195	1,195	1,195	1,195	1,195	1,195	1,195
3	Reserve Requirement	1,266	1,295	1,440	1,444	1,441	1,589	1,756
4	**Total Requirements**	**9,716**	**10,684**	**11,908**	**11,912**	**11,909**	**13,166**	**14,609**
5	Existing Generation	9,582	9,582	9,582	9,582	9,582	9,582	9,582
6	Firm Purchases	317	317	317	317	317	317	317
7	New Resources							
8	DSR	13	757	869	841	860	981	1,144
9	Renewable	0	0	0	0	0	0	0
10	Cogeneration	0	0	453	192	96	811	1,599
11	Combined Cycle CT	0	0	0	0	0	0	0
12	Coal	0	25	363	767	876	972	1,027
13	Peaking Resources	0	0	320	210	176	500	936
14	**Total Resources**	**9,912**	**10,681**	**11,905**	**11,909**	**11,906**	**13,163**	**14,606**
	Annual Energy in 2003 (MWa)							
15	Native Load	5,183	5,855	6,634	6,634	6,634	7,390	8,288
16	Pump Storage/Peak Return	306	306	383	368	357	436	485
17	Firm Sales	1,410	1,410	1,410	1,410	1,410	1,410	1,410
18	Non-Firm Sales	525	449	464	477	475	523	508
19	**Total Requirements**	**7,424**	**8,020**	**8,891**	**8,889**	**8,876**	**9,759**	**10,691**
20	Existing Generation	7,023	7,082	7,070	7,046	7,024	7,074	7,131
21	Firm Purchases	364	364	364	364	364	364	364
22	Non-Firm Purchases	45	105	181	68	63	87	131
23	New Resources							
24	DSR	8	459	523	501	509	587	681
25	Renewable	0	0	0	0	0	0	0
26	Cogeneration	0	0	375	174	87	669	1,307
27	Combined Cycle CT	0	0	0	0	0	0	0
28	Coal	0	23	333	703	803	891	942
29	Peaking Resources	0	0	60	48	40	101	151
30	**Total Resources**	**7,440**	**8,033**	**8,905**	**8,903**	**8,889**	**9,774**	**10,706**

T6-17.grand.unc.10yrs

Table 6-18

Unconstrained Resource Strategies for All Load Growth Levels

Resource Selections and Emissions

	Load	Low	Medium Low	Medium			Medium High	High
	Gas	Medium	Medium	Low	Medium	High	Medium	Medium
	Case #	1	6	11	28	45	64	85
	Winter Peak Capacity in 2013 (MW)							
1	Native Load	7,504	9,277	11,206	11,206	11,206	13,488	15,949
2	Firm Sales	437	437	437	437	437	437	437
3	Reserve Requirement	1,189	1,321	1,580	1,577	1,577	1,891	2,228
4	**Total Requirements**	**9,130**	**11,035**	**13,223**	**13,220**	**13,220**	**15,816**	**18,614**
5	Existing Generation	9,196	9,196	9,196	9,196	9,196	9,196	9,196
6	Firm Purchases	262	262	262	262	262	262	262
7	New Resources							
8	DSR	17	908	1,112	1,128	1,128	1,318	1,533
9	Renewable	0	0	0	0	0	0	0
10	Cogeneration	0	0	453	192	96	903	1,640
11	Combined Cycle CT	0	0	0	0	0	0	133
12	Coal	0	424	1,201	1,547	1,628	2,823	3,919
13	Peaking Resources	0	242	996	892	907	1,311	1,926
14	**Total Resources**	**9,475**	**11,031**	**13,220**	**13,216**	**13,216**	**15,812**	**18,610**
	Annual Energy in 2013 (MWa)							
15	Native Load	5,373	6,620	7,998	7,998	7,998	9,623	11,380
16	Pump Storage/Peak Return	305	375	426	456	439	468	470
17	Firm Sales	841	841	841	841	841	841	841
18	Non-Firm Sales	724	618	395	433	371	456	502
19	**Total Requirements**	**7,243**	**8,454**	**9,660**	**9,728**	**9,649**	**11,388**	**13,193**
20	Existing Generation	6,880	6,978	6,936	6,904	6,853	6,666	6,549
21	Firm Purchases	336	392	344	370	363	337	335
22	Non-Firm Purchases	31	152	187	154	152	152	153
23	New Resources							
24	DSR	10	503	607	593	593	696	813
25	Renewable	0	0	0	0	0	0	0
26	Cogeneration	0	0	403	179	89	816	1,454
27	Combined Cycle CT	0	0	0	0	0	0	124
28	Coal	0	388	1,100	1,417	1,492	2,587	3,592
29	Peaking Resources	0	55	95	124	122	148	189
30	**Total Resources**	**7,257**	**8,468**	**9,673**	**9,741**	**9,663**	**11,402**	**13,208**
	Average Annual Emissions in 1994-2013 (1000 tons)							
31	CO_2	56,918	57,827	60,866	61,812	61,911	66,448	71,083
32	NOx	115	116	136	139	139	147	154

T6-18.grand.unc.20yrs

group agreed that financial results for the unconstrained model runs were not necessary.

The amount of DSR included in each of the base study plan cases varied by load growth level and DSR strategy. The following table shows the 20-year amounts of DSR in MW, beginning with the unconstrained cases.

MW of Demand-Side Resource Added by DSR Strategy and Load Growth
Table 6-19

Load Growth	Unconstrained	Low	Medium	Accelerated	High
Low	17		864		
ML	908		956		
Medium	1,128	526	1,071	1,106	1,303
MH	1,318	566	1,227	1,320	1,482
High	1,553	604	1,363	1,519	1,654

The model selected a total amount of DSR in the unconstrained cases that fell between the accelerated and high DSR strategies. The amount of DSR almost doubled from the low to the medium strategies, and increased by smaller amounts in the accelerated and high strategies. The following table shows DSR as a percentage of new resources for each of the DSR strategies by load growth level. It indicates that the medium DSR strategy would meet 28 percent of new resource needs under medium load growth, about double the amount in the low DSR strategy, and only one percentage point lower than the amount in the accelerated strategy.

DSR as Percentage of Total New Resources
Table 6-20

Level of DSR Load Growth	Low (LD)	Medium (MD)	Accelerated (AD)	High (HD)
Low		100		
Medium-low		61		
Medium	14	28	29	35
Medium-high	9	19	21	23
High	6	15	17	18

The company used a separate financial analysis to determine the amount of DSR to include in the action plan for the next two to four years. The financial analysis prioritized DSR programs based on their internal rate of return and cost comparison to avoided costs, and examined their cumulative potential price impact. The DSR Action Plan Detail chapter includes an explanation of the financial analysis methodology. The amounts derived from the financial analysis are very close to the medium DSR level.

The amount of DSR affected the amount of other resources chosen. The lower DSR cases added more of the other resources than did the higher DSR cases. The higher the DSR level, the lower the total utility cost or total resource cost. However, the DSR strategies had a price impact in the reverse direction. This is because a higher DSR level reduces the amount of total sales the utility makes, and thus fewer kWhs must carry the total system costs, increasing the cost per kWh. The higher the DSR level, the higher the price to customers. For example, Table 6-5 shows that under medium load growth with medium gas prices, any-coal and strategic-renewables, the real levelized price to customers would be 46.20 mills/kWh under low DSR, 46.59 under medium DSR, 46.90 under accelerated DSR, and 46.99 under high DSR. The same patterns held with low and high gas prices, or with MH or high load growth.

The following table shows the average cost difference from one DSR strategy to the next, plus the difference between the medium and the high strategies. These were calculated by averaging the net present value (NPV) of utility cost and total resource cost, or averaging the levelized mills/kWh (price) over all the load growth, gas price, and strategy combinations in the base study plan.

Average Cost Increase by DSR Level
Table 6-21

	NPV Utility Cost $ millions	Price Mills/kWh	NPV Total Resource Cost $ millions
From LD to MD	(1,030)	0.33	(300)
From MD to AD	(109)	0.21	(242)
From AD to HD	(278)	0.06	88
From MD to HD	(387)	0.27	(154)

This table shows that higher levels of DSR decrease utility cost and total resource cost. Increasing levels of DSR cause consistent price increases to customers. The next table shows the percentage impact of moving from one DSR strategy to another under each of the three measures.

Percentage Change in Cost Measures by DSR Strategy
Table 6-22

	NPV Utility Cost % change	Price % change	NPV Total Resource Cost % change
From LD to MD	-2.0	0.7	-0.5
From MD to AD	-0.2	0.5	-0.4
From AD to HD	-0.6	0.1	0.1
From MD to HD	-0.8	0.6	-0.3

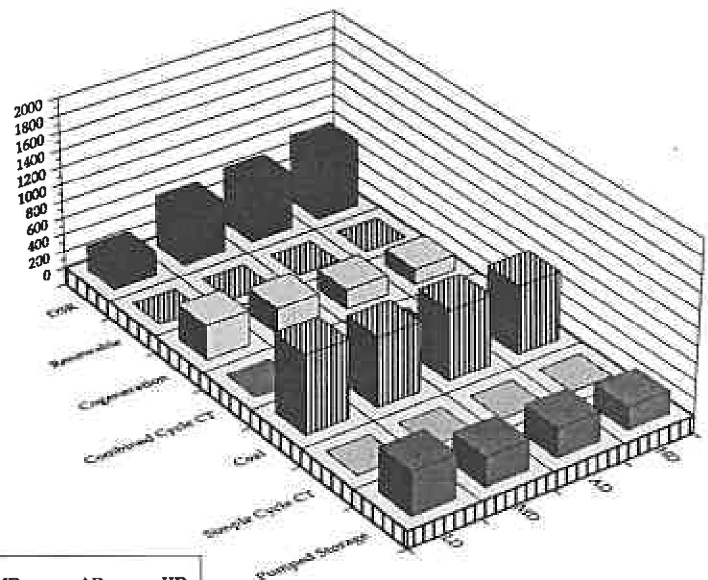
Graph 6-23 summarizes the new resource selections by category and DSR level under medium load growth for 10 and 20 years. Each of the resource categories selected under low DSR gradually decreased as the amount of DSR increased.

Resource Additions by DSR Levels:

(Medium Load Growth, Medium Gas Price, Any-Coal, Any-Renewables)

1994-2003

Graph 6-23



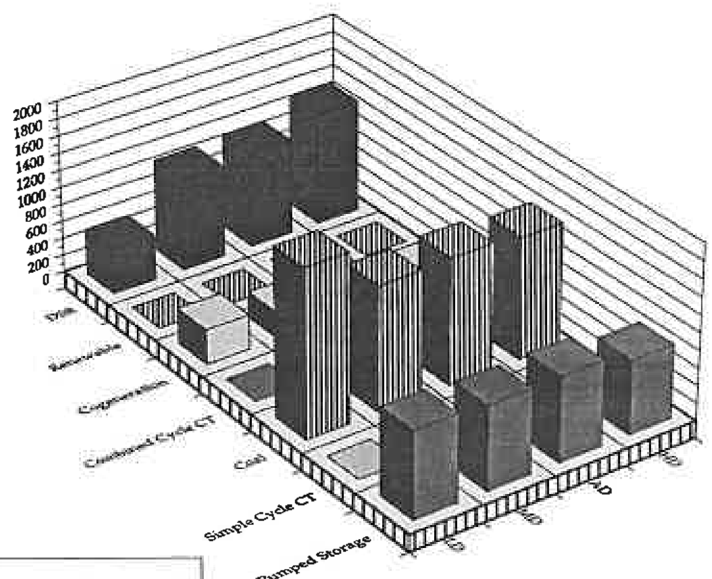
Winter MW's

	LD	MD	AD	HD
DSR	284	608	670	786
Renewable	0	0	0	0
Cogeneration	402	302	227	180
Combined Cycle CT	0	0	0	0
Coal	912	803	809	792
Simple Cycle CT	0	0	0	0
Pumped Storage	500	336	333	264
Total	2098	2049	2040	2022

Resource Additions by DSR Levels:

(Medium Load Growth, Medium Gas Price, Any-Coal, Any-Renewables)

1994-2013



Winter MW's

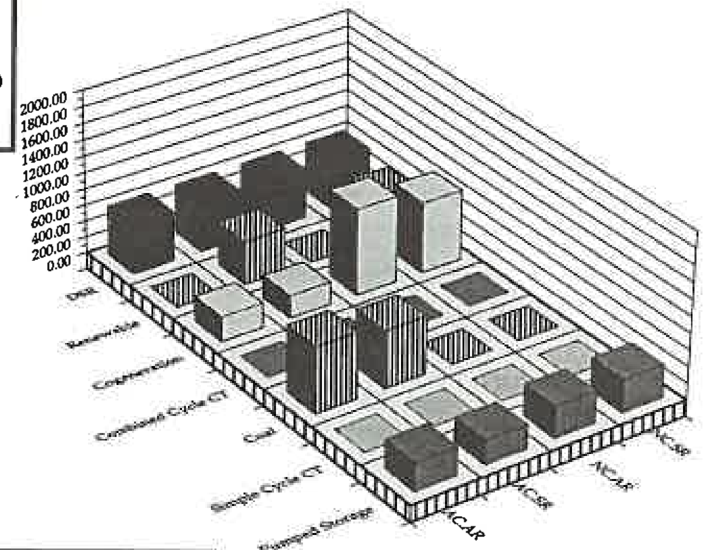
	LD	MD	AD	HD
DSR	526	1071	1106	1303
Renewable	0	0	0	0
Cogeneration	402	302	227	180
Combined Cycle CT	0	0	0	0
Coal	1925	1437	1463	1406
Simple Cycle CT	0	0	0	0
Pumped Storage	1000	962	970	848
Total	3853	3772	3766	3737

Graph 6-24

Resource Additions by Coal/Renewable Strategies:

(Medium Load Growth, Medium Gas Price, Medium DSR)

1994-2003

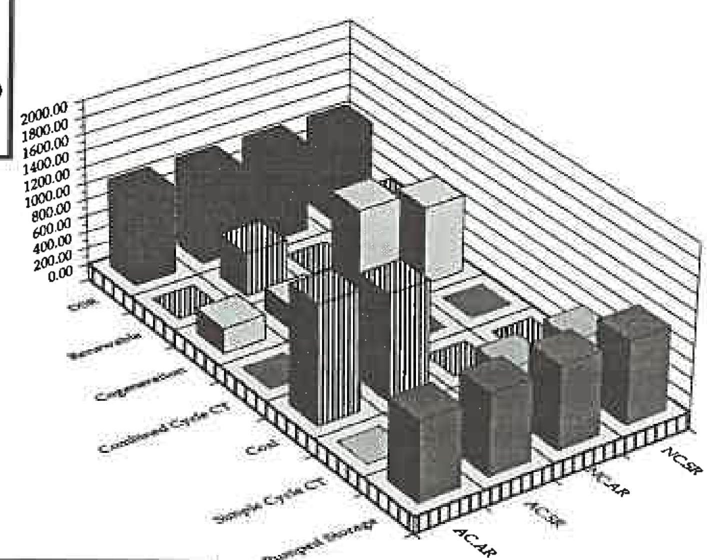


Winter MW's	AC.AR	AC.SR	NC.AR	NC.SR
DSR	608	608	608	608
Renewable	0	529	0	529
Cogeneration	302	276	1058	864
Combined Cycle CT	0	0	0	0
Coal	803	700	0	0
Simple Cycle CT	0	0	0	0
Pumped Storage	336	287	383	399
Total	2049	2400	2049	2400

Resource Additions by Coal/Renewable Strategies:

(Medium Load Growth, Medium Gas Price, Medium DSR)

1994-2013



Winter MW's	AC.AR	AC.SR	NC.AR	NC.SR
DSR	1071	1071	1071	1071
Renewable	0	529	0	529
Cogeneration	302	276	1180	948
Combined Cycle CT	0	0	0	0
Coal	1437	1274	0	0
Simple Cycle CT	0	0	520	574
Pumped Storage	962	973	1000	1000
Total	3772	4123	3772	4123

COAL STRATEGIES

The different cases also tested two coal strategies, any-coal and no-coal. These strategy alternatives had a dramatic impact on resource selections in almost all of the runs, because coal was the least expensive supply-side resource on the table of levelized costs. Therefore, under any-coal, the model always selected coal when the system needed additional resources, beginning in 2001, the first year it was available. During the first 10 years under medium load growth the model added at least 400 MW of coal under low gas prices, at least 700 MW under medium gas prices, and only slightly more under high gas prices. By the end of 20 years, resource plans under any-coal included from 1,000 to 1,930 MW of coal. Under MH load growth and medium gas prices, the model selected at least 850 MW of coal in the first 10 years, and at least 2,600 MW by the end of 20 years. Under high load growth, the model selected at least 1,000 MW in 10 years and at least 3,700 MW in 20 years. Under the any-coal strategy, the model relied heavily on coal.

The emissions benefits of the no-coal strategy over the any-coal strategy were about a five percent reduction in CO_2 emissions (based on the four cases using medium load growth, medium gas prices, and medium DSR).

The average cost difference between all of the any-coal and comparable no-coal cases shows the cost to the utility system and to customers of one coal strategy versus the other. The no-coal strategy increased the average NPV of 50 years of revenue requirement by $967 million, and increased levelized customer prices by an average of 0.87 mills/kWh.

Graph 6-24 shows new resource choices by coal strategy under medium load growth. The graph includes four cases: the any-coal and no-coal under both the any-renewables and the strategic-renewables strategies. It shows that the model substituted cogeneration for coal to meet baseload requirements under the no-coal (NC) strategy.

BASELOAD GAS-FIRED RESOURCES

The coal strategy and gas price escalation assumptions affected the amount of gas-fired resources chosen. Coal and cogeneration were the two top choices for meeting baseload requirements. The model selected cogeneration first because it had a shorter lead time. However, as soon as coal was available (beginning in 2001), the model selected coal over cogeneration in the any-coal cases because of coal's lower price. All of the medium load growth cases under medium gas prices selected cogeneration, usually in 1997, the earliest it was available. The any-coal strategy reduced the amount of cogeneration to only 134 to 402 MW (all in the first 10 years). The no-coal strategy added more cogeneration, most of it in the first 10 years. The no-coal resource plans included from 854 to 1,610 MW of cogeneration over the entire 20 years. Lower gas prices resulted in more gas-fired resources, and higher gas prices reduced the amount of gas-fired resources.

Only the MH and high load growth cases using the no-coal strategy included CCCTs. These runs first exhausted the supply of cogeneration resources; after cogeneration the next most cost-effective choice was CCCTs.

PEAKING RESOURCES

All of the cases added peaking resources during the first 10 years except under low and ML load growth. They added additional amounts in the second 10 years. Medium load growth required at least 200 MW of pumped storage in the first 10 years, and almost all of the 1,000 MW maximum by the end of 20 years. Medium-high load growth required at least 500 MW of pumped storage in the first 10 years, and the full 1,000 MW by the end of 20 years. The pattern for high load growth was the same as for MH. Medium load growth did not need additional peaking resources from SCCTs, unless high gas prices added more renewables, which in turn required more peaking resources. The renewables selected were wind, which contribute little to the reserve margin, requiring more peaking resources that could meet the reserve margin requirements of the model. Medium-high load growth required up to 300 MW of SCCTs in the first 10 years, and up to 1,800 MW by the end of 20 years. The high load growth cases added a wide range of SCCT amounts, from 267 to 1,177 MW in the first 10 years, and from 871 to 2,623 MW by the end of 20 years.

The company relied heavily on these peaking resource results in developing the action plan. Under all load growth futures except low and ML, the model added peaking resources in the next 10 years. The company also recognized that the IPM model, by using winter peak, may in some years understate the amount of peaking resources needed to meet the reserve requirement. Other studies using hourly simulation modeling indicate that in the next five years, the system will need summer peaking resources before winter peaking resources. The SCE capacity contract alleviated immediate winter peaking needs, but it does not provide power in the summer. The Company will carefully examine summer capacity needs and options (exchanges, purchases, new resources, or transmission) to find cost-effective solutions to summer capacity problems.

SENSITIVITIES

Sensitivities tested input assumptions in several areas: seven on renewable resources (discussed in the Renewable Analysis chapter), three on load levels, nine on the portfolio of resources and transmission constraints, five on coal prices, and five on the non-firm markets.

Load Levels

Although the load forecast provided a broad range of future possibilities, other load futures could occur. Three sensitivities helped broaden the analysis of how additional load growth futures would affect resource planning. All of these cases used medium DSR strategy, no-coal, and strategic-renewables. Table 6-25

Load Level Sensitivities

(Using Medium Gas Price, Medium DSR, No-Coal and Strategic-Renewables)

Resource Selections by 10th Year (2003)

	Load Level	Medium Low	Reduced Load	Medium	Economic Development	Medium High	High	Electrification
	Case #	10	201	36	202	72	93	203
	Winter Peak Capacity in 2003 (MW)							
1	Native Load	8,194	8,259	9,273	9,678	10,382	11,658	10,951
2	Firm Sales	1,195	1,195	1,195	1,195	1,195	1,195	1,195
3	Reserve Requirement	1,323	1,327	1,479	1,540	1,637	1,821	1,715
4	**Total Requirements**	**10,712**	**10,781**	**11,947**	**12,413**	**13,214**	**14,674**	**13,861**
5	Existing Generation	9,582	9,582	9,582	9,582	9,582	9,582	9,582
6	Firm Purchases	317	317	317	317	317	317	317
7	New Resources							
8	DSR	571	608	608	608	665	714	714
9	Renewable	529	529	529	529	529	529	529
10	Cogeneration	0	50	864	1,247	1,770	2,099	2,099
11	Combined Cycle CT	0	0	0	0	0	399	0
12	Coal	0	0	0	0	0	0	0
13	Peaking Resources	65	47	399	482	704	1,387	972
14	**Total Resources**	**11,064**	**11,133**	**12,299**	**12,765**	**13,566**	**15,026**	**14,213**
	Annual Energy in 2003 (MWa)							
15	Native Load	5,855	5,976	6,634	6,906	7,390	8,288	7,782
16	Pump Storage/Peak Return	322	320	413	435	446	429	448
17	Firm Sales	1,410	1,410	1,410	1,410	1,410	1,410	1,410
18	Non-Firm Sales	462	445	475	494	485	430	466
19	**Total Requirements**	**8,049**	**8,151**	**8,932**	**9,245**	**9,731**	**10,557**	**10,106**
20	Existing Generation	7,075	7,109	7,138	7,133	7,136	7,151	7,153
21	Firm Purchases	364	364	364	364	364	364	364
22	Non-Firm Purchases	109	113	111	104	110	202	140
23	New Resources							
24	DSR	325	348	348	348	380	409	409
25	Renewable	178	178	178	178	178	178	178
26	Cogeneration	0	43	725	1,033	1,461	1,772	1,744
27	Combined Cycle CT	0	0	0	0	0	353	0
28	Coal	0	0	0	0	0	0	0
29	Peaking Resources	12	11	83	100	117	144	133
30	**Total Resources**	**8,063**	**8,166**	**8,947**	**9,260**	**9,745**	**10,573**	**10,121**

T6-25.grand.load.10yrs

Table 6-26

Load Level Sensitivities

(Using Medium Gas Price, Medium DSR, No-Coal and Strategic-Renewables)

Resource Selections, Emissions and Financial Results

	Load Level / Case #	Medium Low 10	Reduced Load 201	Medium 36	Economic Development 202	Medium High 72	High 93	Electrification 203
	Winter Peak Capacity in 2013 (MW)							
1	Native Load	9,277	9,967	11,206	12,081	13,488	15,949	17,867
2	Firm Sales	437	437	437	437	437	437	437
3	Reserve Requirement	1,314	1,400	1,586	1,717	1,905	2,253	2,541
4	**Total Requirements**	11,028	11,804	13,229	14,235	15,830	18,639	20,845
5	Existing Generation	9,196	9,196	9,196	9,196	9,196	9,196	9,196
6	Firm Purchases	262	262	262	262	262	262	262
7	New Resources							
8	DSR	956	1,071	1,071	1,071	1,227	1,363	1,363
9	Renewable	529	529	529	529	529	529	529
10	Cogeneration	0	98	948	1,653	2,099	2,099	2,099
11	Combined Cycle CT	0	0	0	0	494	2,353	3,686
12	Coal	0	0	0	0	0	0	0
13	Peaking Resources	437	1,000	1,574	1,875	2,375	3,189	4,062
14	**Total Resources**	11,380	12,156	13,581	14,587	16,182	18,992	21,197
	Annual Energy in 2013 (MWa)							
15	Native Load	6,620	7,195	7,998	8,586	9,623	11,380	12,584
16	Pump Storage/Peak Return	413	410	449	500	509	558	577
17	Firm Sales	841	841	841	841	841	841	841
18	Non-Firm Sales	556	295	294	346	303	304	331
19	**Total Requirements**	8,430	8,741	9,582	10,273	11,276	13,083	14,333
20	Existing Generation	7,034	7,085	7,090	7,093	7,095	7,079	7,078
21	Firm Purchases	420	441	442	442	442	442	442
22	Non-Firm Purchases	180	263	269	258	263	236	218
23	New Resources							
24	DSR	548	613	613	613	694	769	769
25	Renewable	179	180	179	179	179	179	179
26	Cogeneration	0	91	858	1,502	1,925	1,910	1,887
27	Combined Cycle CT	0	0	0	0	457	2,161	3,377
28	Coal	0	0	0	0	0	0	0
29	Peaking Resources	85	83	145	201	236	321	399
30	**Total Resources**	8,446	8,755	9,596	10,287	11,290	13,098	14,349
	Average Annual Emissions in 1994-2013 (1000 tons)							
31	CO_2	55,863	56,220	58,130	58,130	61,076	64,350	58,130
32	NO_x	126	127	128	128	131	134	128
	Financial Results with End Effects to 2043							
	50-year Utility Cost							
33	NPV at 8.8% (million $)	41,984	43,872	47,338	49,720	53,664	60,733	62,582
34	Real Levelized (mills/kWh)	47.66	48.50	47.12	47.09	46.85	46.64	43.45
	50-year Total Resources Cost							
35	NPV at 8.8% (million $)	43,325	45,438	48,903	51,286	55,430	62,629	64,478
36	Real Levelized (mills/kWh)	46.41	47.22	46.04	46.05	45.82	45.64	42.69

T6-26.grand.load.20yrs

Illustrate why price is not good indicator— avg bills ↑ → ratemaking consequ. elec. Our tariff may be different to assume no cross subsidies

MC < AC
So with each additional unit produced prices and revenue ↑

this looks very questionable

↑ avg. bills will so was ...

shows these three cases at 2003, along with comparison cases using the same strategy combinations and gas prices. Table 6-26 shows results for the same cases at 2013. The NPV of utility cost and TRC show a continuous pattern of increase from the lowest load growth on the table to the highest load growth. However, the prices do not show the same continuous pattern. The lowest prices result from the highest load -- the electrification case. The highest prices result from the reduced load sensitivity (case #201). The draft report had very different results from these. The company discovered an error in the calculation of the load levels in the financial model, which was corrected.

The first load level sensitivity, case #201, assumed load growth of 1.68 percent, between the ML at 1.26 percent and the medium at 2.13 percent. This reduced level from the medium forecast might occur from aggressive pricing designs or changes in customers' fuel choices. Case #201 assumed the same number of customers and the same level of DSR as in the medium load growth. The load growth followed the ML path for the first 10 years, and increased during the second 10 years. The load in 2003 was only about 60 MW more than ML. Thus, the only resources needed in the first 10 years were 50 MW of cogeneration and 47 MW of peaking resources. Table 6-23 shows the results after 20 years. Resources added included only DSR, the strategic renewables, 98 MW of cogeneration, and 1,000 MW of peaking resources. The early reduction in loads caused the NPV of utility cost and total resource cost to decline markedly from the medium load growth level. However, the lower load caused prices to increase above that of any of the other cases on the table.

The second load growth sensitivity, case #202, assumed load growth of 2.41 percent, between the medium at 2.13 percent and the MH at 3.02 percent. The company created this sensitivity to mimic what might occur from economic development activities. It also assumed the same level of DSR as in medium load growth, but increased the number of customers. After 10 years, the medium load growth case had 1,487,000 customers whereas this case had 1,569,000. Its load remained about midway between the medium and MH for the entire 20 years. After 10 years load was 405 MW higher than medium load growth, and 704 MW less than MH. The resource choices were the same as for medium and MH (cogeneration and peaking resources); the amounts added fell between the amounts added for those two load growth levels. The financial results show a NPV of utility cost and TRC between the medium and MH comparison cases, but with prices about the same as for the medium load growth.

The third load growth sensitivity assumed load growth higher than the high load forecast, as might occur if electrification became more common, for example, through the use of electric cars and certain industrial electrification technologies. Case #203 used the same number of customers and DSR from the high load forecast. The load growth rate was 4.48 percent, higher than the high at 3.75 percent. However, in the first 15 years its load was between the MH and high, and only during the last five years was its load higher than the high load growth case. To meet the higher load, the model added additional CCCTs and some additional peaking resources. The NPV of utility costs and total resource costs increased somewhat over the high load growth, but customer prices decreased.

Table 6-27

Portfolio/Transmission Sensitivities

Resource Selections by 10th Year (2003)

Run against	#35		#33		#36 M.MG.MD.NC.SR					#33 M.MG.MD.AC.AR		
Sensitivity	m.mg md.nc.ar	Hermiston as Potential Unit	m.mg md.ac.ar	Hermiston as Potential Unit	m.mg md.nc.sr	SCE as Potential Unit	CCCT to IGCC	IGCC avail when No Coal	IGCC avail when No Coal: Low IGCC Cost	Transmission: From Bridger to OWC +300MW	Transmission: From Utah to OWC +600MW	Real Discount Rate at 3%
Case #	35	212	33	213	36	211	222	223	224	231	232	241
Winter Peak Capacity in 2003 (MW)												
1 Native Load	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273
2 Firm Sales	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195
3 Reserve Requirement	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479
4 **Total Requirements**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**
5 Existing Generation	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582
6 Firm Purchases	317	317	317	317	317	317	317	317	317	317	317	317
7 New Resources												
8 DSR	608	608	608	608	608	608	608	608	608	608	608	608
9 Renewable	0	0	0	0	529	529	529	529	529	0	0	0
10 Cogeneration	1,058	560	302	0	864	865	276	290	276	149	0	302
Hermiston		472		472								
11 Combined Cycle CT	0	0	0	0	0	0	1	0	0	0	0	0
12 Coal & IGCC	0	0	803	721	0	0	643	572	693	924	924	916
13 Peaking Resources	383	409	336	247	399	398	343	401	294	368	517	222
14 **Total Resources**	**11,948**	**11,948**	**11,948**	**11,948**	**12,299**	**12,299**	**12,299**	**12,299**	**12,299**	**11,948**	**11,948**	**11,948**
Annual Energy in 2003 (MWa)												
15 Native Load	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634
16 Pump Storage/Peak Return	405	417	394	376	413	413	397	407	389	400	430	371
17 Firm Sales	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410
18 Non-Firm Sales	461	417	488	376	475	476	496	485	501	494	482	512
19 **Total Requirements**	**8,910**	**8,878**	**8,926**	**8,796**	**8,932**	**8,933**	**8,937**	**8,936**	**8,934**	**8,938**	**8,956**	**8,927**
20 Existing Generation	7,141	7,139	7,069	7,045	7,138	7,138	7,076	7,097	7,055	7,106	7,136	7,028
21 Firm Purchases	364	364	364	364	364	364	364	364	364	363	364	364
22 Non-Firm Purchases	108	102	97	47	111	110	94	110	73	87	179	57
23 New Resources												
24 DSR	348	348	348	348	348	348	348	348	348	348	348	348
25 Renewable	0	0	0	0	178	178	178	178	178	0	0	0
26 Cogeneration	887	477	260	0	725	727	238	256	238	128	0	254
Hermiston		431		428								
27 Combined Cycle CT	0	0	0	0	0	0	1	0	0	0	0	0
28 Coal & IGCC	0	0	735	661	0	0	584	519	629	847	847	840
29 Peaking Resources	77	87	68	55	83	83	71	78	64	73	96	50
30 **Total Resources**	**8,925**	**8,947**	**8,941**	**8,947**	**8,947**	**8,947**	**8,952**	**8,950**	**8,948**	**8,952**	**8,970**	**8,941**

Portfolio/Transmission Sensitivities

Resource Selections, Emissions and Financial Results

Run against		#35		#33	#36 M.MG.MD.NC.SR					#33 M.MG.MD.AC.AR		
		Hermiston as Potential Unit		Hermiston as Potential Unit		SCE as Potential Unit	CCCT to IGCC	IGCC avail when No Coal		Transmission		Real Discount Rate at 3%
Sensitivity	m.mg md.nc.ar		m.mg md.ac.ar		m.mg md.nc.sr				Low IGCC Cost	From Bridger to OWC +300MW	From Utah to OWC +600MW	
Case #	35	212	33	213	36	211	222	223	224	231	232	241
Winter Peak Capacity in 2013 (MW)												
1 Native Load	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206
2 Firm Sales	437	437	437	437	437	437	437	437	437	437	437	437
3 Reserve Requirement	1,586	1,586	1,586	1,586	1,586	1,586	1,586	1,586	1,586	1,586	1,586	1,586
4 Total Requirements	13,229	13,229	13,229	13,229	13,229	13,229	13,229	13,229	13,229	13,229	13,229	13,229
5 Existing Generation	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196
6 Firm Purchases	262	262	262	262	262	262	262	262	262	262	262	262
7 New Resources												
8 DSR	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071
9 Renewable	0	0	0	0	529	529	529	529	529	0	0	0
10 Cogeneration	1,180	1,103	302	472	948	948	276	290	276	149	0	302
11 Combined Cycle CT	0	0	0	0	0	0	1	0	0	0	0	0
12 Coal & IGCC	0	0	1,437	1,575	0	0	1,169	1,169	1,369	1,645	1,825	1,564
13 Peaking Resources	1,520	1,598	962	654	1,574	1,574	1,077	1,064	878	907	875	834
14 Total Resources	13,230	13,230	13,230	13,230	13,581	13,581	13,580	13,581	13,581	13,230	13,230	13,230
Annual Energy in 2013 (MWa)												
15 Native Load	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998
16 Pump Storage/Peak Return	460	447	455	444	449	449	452	452	443	466	481	449
17 Firm Sales	841	841	841	841	841	841	841	841	841	841	841	841
18 Non-Firm Sales	313	278	456	618	294	294	415	427	503	519	606	511
19 Total Requirements	9,612	9,564	9,750	9,901	9,582	9,582	9,706	9,718	9,785	9,824	9,926	9,799
20 Existing Generation	7,087	7,091	6,914	6,828	7,090	7,090	6,953	6,954	6,881	6,934	6,970	6,861
21 Firm Purchases	442	442	375	353	442	442	389	389	373	363	387	365
22 Non-Firm Purchases	266	271	152	130	269	269	154	154	152	157	159	152
23 New Resources												
24 DSR	613	613	613	613	613	613	613	613	613	613	613	613
25 Renewable	0	0	0	0	179	179	179	179	179	0	0	0
26 Cogeneration	1,068	1,017	275	439	858	858	252	265	252	139	0	275
27 Combined Cycle CT	0	0	0	0	0	0	1	0	0	0	0	0
28 Coal & IGCC	0	0	1,317	1,443	0	0	1,060	1,060	1,242	1,507	1,673	1,434
29 Peaking Resources	150	144	119	109	145	145	119	118	108	126	138	114
30 Total Resources	9,626	9,578	9,765	9,914	9,596	9,596	9,720	9,732	9,799	9,838	9,939	9,813
Average Annual Emissions in 1994-2013 (1000 tons)												
31 CO_2	58,589	57,364	61,972	60,860	58,130	57,414	58,320	60,110	60,466	62,637	62,907	62,260
32 NO_x	129	128	139	137	128	128	128	127	127	141	142	139
Financial Results with End Effects to 2043												
50-year Utility Cost		1136		1005		16 million						
33 NPV at 8.8% (million $)	46,894	45,758	46,337	45,332	47,338	47,354	46,040	47,096	46,561	46,205	46,115	46,319
34 Real Levelized (mills/kWh)	46.68	45.55	46.13	45.13	47.12	47.14	45.83	46.88	46.35	46.00	45.91	46.11
50-year Total Resources Cost						17 mill.						
35 NPV at 8.8% (million $)	48,460	47,323	47,903	46,898	48,903	48,920	47,606	48,662	48,127	47,771	47,680	47,885
36 Real Levelized (mills/kWh)	45.62	44.55	45.09	44.15	46.04	46.05	44.82	45.81	45.31	44.97	44.88	45.08

? How do firm purchases change? NC → then purchased YES

coal + non-firm sales ↑

T6-28.grand.misc.20yrs

Because of the model's ability to add resources which do not cause costs to increase faster than inflation, higher load growth can reduce prices because it allows costs to be spread over a larger number of kWhs.

Portfolio and Transmission

Nine sensitivities changed the portfolio of available resources or the transmission system. Tables 6-27 and 6-28 show the 10- and 20-year results, respectively, with the appropriate comparison cases from the base study plan.

The first two sensitivities, cases #212 and #213, added the Hermiston cogeneration project to the portfolio to allow the model to select it if cost effective compared to other resources in the portfolio. One sensitivity used the any-coal strategy, and one used the no-coal strategy, to determine how the model would treat the Hermiston project under both conditions. Both sensitivities selected Hermiston over the years 1996 to 2000. The Hermiston input data used an availability date of 1996 (consistent with current plans), ahead of the availability of any other cogeneration resources. The model selected some of the Hermiston resource in 1996 because no other large resources were available that early. However, the model continued to select more of the Hermiston resource in 1997 through 2000, indicating that it was a more cost-effective choice than any of the other cogeneration available in 1997. The financial results indicated that the addition of Hermiston to the system would reduce the NPV of utility costs, the NPV of TRC, and customer prices over their comparison cases without the Hermiston option. Both sensitivity cases selected Hermiston amounts as follows:

MW of Hermiston Project Selected
Table 6-29

	1996	1997	1998	1999	2000
Case #212 (any-coal)	115.1	186.9		118.1	51.9
Case #213 (no-coal)	115.1	186.9		118.1	51.9

The next sensitivity, case #211, removed the SCE peaking contract from the existing system and placed it in the portfolio, which allowed the model to select it when needed. Tables 6-24 and 6-25 include a column for this sensitivity, which is useful for the financial information, but it is not informative for new resource choices. Because the SCE contract expires after seven years, it does not show up in 2003 or 2013. Table 6-30 shows the year-by-year results. The model did not have to respect the contract terms for the SCE Agreement. It selected 322 MW of the contract in 1994, another 62 MW in 1995, and the final 38 MW in 1996. Then in 2001 through 2003 it removed the contract from system resources (consistent with the contract). The financial results are almost the same as in the comparison case using the SCE contract as part of the existing system. The small differences are because the model selected only parts of the contract each year from 1994 through 1996. Changing the SCE contract from an existing resource to a potential resource (where the model could select it) caused no price impact until 2003, when the contract expires.

Case # 211

SCE Modeled as a Potential Unit

Annual Incremental Winter Capacity (MW) of Resource Additions

Table 6-30

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C				29.0	36.0	45.0							110.0
	OWC Wind without Tax C							29.0	29.0					58.0
	OWC Geothermal								13.0					13.0
O	OWC Cogen 1						44.3	70.2	160.0	45.5				320.0
W	OWC Cogen 2				275.6				68.1	162.5	29.6	53.6		589.4
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											12.1	487.9	500.0
	SCE Winter	322.0	62.3	37.7					(322.0)	(100.0)				0.0
	Total	**346.4**	**87.3**	**61.8**	331.1	**72.8**	135.3	**152.7**	1.8	**177.2**	111.9	**134.9**	554.3	2167.5
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.2
	Utah Wind with Tax C				29.0	36.0	45.0							110.0
	Utah Wind without Tax C							29.0	29.0					58.0
	Utah Geothermal								12.0					12.0
	Utah Solar													
U	Utah Cogen 1								39.0					39.0
T	Utah Cogen 2													
A	Utah Combined Cycle CT													
H	Utah CC CT Convert													
	Utah Coal													
	Utah IG CC													
	Utah FB Coal													
	Utah Simple Cycle CT											574.0		574.0
	Utah Pumped Storage								146.0	251.5		102.5		500.0
	Total	**8.9**	**10.1**	**14.1**	48.1	**56.1**	70.1	**55.2**	252.5	302.2	74.6	**742.6**	48.5	1683.0
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	103.9
W	Wyo Wind with Tax C				29.0	36.0	45.0							110.0
Y	Wyo Wind without Tax C							29.0	29.0					58.0
O	Wyo Combined Cycle CT													
M	Wyo CC CT Convert													
I	Wyo Coal													
N	Wyo IG CC													
G	Wyo FB Coal													
	Wyo Simple Cycle CT													
	Total	**1.8**	**1.2**	**3.9**	34.0	**42.2**	49.9	35.3	35.4	**12.5**	19.1	**19.1**	17.7	271.9
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable				87.0	108.0	135.0	87.0	112.0					529.0
O	Cogen				275.6		44.3	70.2	267.1	208.0	29.6	53.6		948.4
T	Combined Cycle CT													0.0
A	Coal													0.0
L	Simple Cycle CT											574.0		574.0
	Pumped Storage								146.0	251.5		114.6	487.9	1000.0
	SCE Winter	322.0	62.3	37.7					(322.0)	(100.0)				0.0
	Total	**357.1**	**98.6**	**79.8**	413.2	**171.1**	255.3	**243.2**	289.7	**491.9**	205.6	**896.6**	620.5	4122.6

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	658	649	445	394	395	375	351	344	317	312	262	262
	New Resources	322	384	422	785	893	1072	1229	1432	1792	1821	2564	3051
L	**Total Resources**	**10068**	**10355**	**10249**	**10581**	**10843**	**11004**	**11144**	**11347**	**11691**	**11722**	**12010**	**12509**
&													
R	Reserves	1210	1350	1236	1371	1444	1405	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.0	13.7	15.0	15.6	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

T6-30.sce.cap_add

Case #222 added an option to the portfolio under which the model could convert a CCCT into a plant using a clean coal technology -- integrated gasification combined cycle (IGCC), which allows it to switch fuels from gas to coal, but with emission levels closer to gas's than to coal's. A no-coal case was the basis for this sensitivity, so that the model would not select other coal. Under a no-coal strategy, the model could not select pulverized coal, but by classifying IGCC as gas, the model could select the IGCC. The model did not select IGCC when the conversion possibility was not part of the model inputs. These constraints and opportunities for case #222 caused to model to select 643 MW of IGCCs by the end of 10 years (between 2001 and 2003), and 1,169 MW by the end of 20 years. In 2000 the model built 70 MW of CCCTs, which it converted to IGCC in 2001. From that point on, it built only IGCCs to meet baseload requirements. To compensate, it selected less cogeneration and less peaking resources. This option reduced the NPV of utility cost and TRC, and reduced the real levelized mills/kWh by 1.29 mills compared to the equivalent case without the conversion option.

when was converted IGCC built?

Two additional sensitivities allowed the model to select the IGCC technology under a no-coal strategy, cases #223 and #224. The model could not select pulverized coal, but it was allowed to select IGCC coal if it was the cost effective choice. Neither included a conversion option, the model selected the IGCC technology directly. Case #223 used the same cost assumptions for IGCC as the rest of the cases; case #224 also lowered the costs of IGCC by 20 percent. Without the cost reduction, the model replaced some cogeneration with IGCC; with the cost reduction it added slightly more IGCC resources. Case #223 lowered average annual CO2 emissions by about three percent compared to its comparison any-coal case. The no-coal option lowered emissions about five percent. These results indicate that clean coal technologies have the potential to take advantage of low coal costs while producing fewer emissions.

Comparison case would decrease by 1.6%

when is comparison AC case?

not comparable cases - IGCC includes BR, case 33 doesn't

emissions look higher on page 156

The company wanted to test the impact of higher transmission capacity on the need for new resources according to geographic area. The IPM model did not have the capability of selecting between a generation resource and a transmission upgrade. The company is exploring model code changes to add this capability for RAMPP-4. Cases #231 and #232 changed the transmission constraints between geographic areas. Case #231 increased the path from the BRI area to the OWC area from 1500 MW to 1800 MW at a generic cost of \$300/kW. Case #232 increased the path from the UTA area to the OWC area from 90 MW to 690 MW at a generic cost of \$300/kW. These two cases are the most beneficial upgrades to the company, and the company is currently negotiating for them. The comparison case is #33, also shown on tables 6-27 and 6-28. Increasing the path from Bridger to OWC decreased new cogeneration in OWC by about 150 MW and increased new coal in Utah by about 200 MW. Increasing the path from Utah to OWC stopped the model from picking cogeneration in OWC; the model instead picked about 400 MW more of coal in Utah than it did in the comparison case. These transmission upgrades also reduced costs and prices. These sensitivities reinforced the company's belief that the two transmission upgrades are worth pursuing.

The last sensitivity on tables 6-27 and 6-28 altered the discount rate used to levelize costs for the entire portfolio, from a discount rate based on the company's incremental after-tax cost of capital (5.22 percent real, 8.8 percent nominal) to a discount rate based on a social cost of capital (3 percent real, 6.5 percent nominal). Case #241 used the real levelized cost of each resource assuming the social discount rate, and the medium DSR strategy with the unconstrained coal and renewable strategies. The company chose the medium DSR strategy, to be consistent with the other sensitivities, and consistent with the company's preferred DSR level, although a higher DSR level could become more cost competitive with other resource choices using the social discount rate. The model added slightly more coal and slightly less peaking resources. The impact on costs and prices was minimal. Thus, using a social discount rate would not cause a noticeable shift in resource selections.

By constraining DSR this result is meaningless — still picked no more renewables

Coal Prices

Table 6-31 shows the 20-year results for five sensitivities which used a higher price for Utah coal. After reviewing comments on the draft report from several parties questioning the coal prices used by the company in the RAMPP-3 analyses, the company reviewed its assumptions. After the major analysis work for RAMPP-3 was finished, the coal market began to change. The Wyoming market is experiencing increased demand from midwestern utilities, but these new market pressures are expected to be temporary. Sufficient coal supplies in Utah at the $0.52/mmbtu price are available for only one additional unit (about 1.5 million tons). The coal required by additional units would require additional capital investment in coal mining facilities. The Utah coal price is really a step function. The coal price for a second unit would increase by about 50 percent, and the coal price for additional units would probably be double the $0.52/mmbtu price. To test the impact of higher Utah coal prices, the company added five sensitivities which doubled the Utah coal price. Three sensitivities used medium load growth, one for each of the three gas price levels. One sensitivity used MH load growth with medium gas prices, and one used high load growth with medium gas prices.

Table 6-32 shows the incremental additions of coal, cogeneration, and peaking resources in MW by year and region. It indicates that the model switched to Wyoming coal until it met a transmission constraint, and then it began adding coal in Utah, but continued to add Wyoming coal to meet Wyoming load growth. In each case, the model selected less coal than the comparison case (with the base Utah coal price assumption). To compensate, the model selected more cogeneration and more SCCTs. The reduction in coal varied, from about 400 MW in the medium load growth cases with medium or high gas prices, to about 600 MW in the other cases.

between 400-600 MW less selected

The cost and price impact of the increased coal price assumption was to increase both, but not to the level of the no-coal cases. The differential in the real levelized mills/kWh between the any-coal and the no-coal cases using the base coal price assumption was about 0.5 mills; the new coal price reduced that differential by about half. Coal remained the least cost option. Thus these

Table 6-31

Coal Price Sensitivities 272

Resource Selections, Emissions and Financial Results 273

Run against		#16		#33		#50		#69		#90
Load Growth	m.lg	Medium	m.mg	Medium	m.hg	Medium	mh.mg	Medium High	h.mg	High
Gas Price	md.ac.ar	Low	md.ac.ar	Medium	md.ac.ar	High	md.ac.ar	Medium	md.ac.ar	Medium
Case #	16	261	33	261	50	261	69	261	90	261
Winter Peak Capacity in 2013 (MW)										
1 Native Load	11,206	11,206	11,206	11,206	11,206	11,206	13,488	13,488	15,949	15,949
2 Firm Sales	437	437	437	437	437	437	437	437	437	437
3 Reserve Requirement	1,586	1,586	1,586	1,586	1,586	1,586	1,905	1,905	2,253	2,253
4 **Total Requirements**	13,229	13,229	13,229	13,229	13,229	13,229	15,830	15,830	18,639	18,639
5 Existing Generation	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196
6 Firm Purchases	262	262	262	262	262	262	262	262	262	262
7 New Resources										
8 DSR	1,071	1,071	1,071	1,071	1,071	1,071	1,227	1,227	1,363	1,363
9 Renewable	0	0	0	0	0	0	0	0	0	0
10 Cogeneration	478	931	302	399	160	235	965	1,280	1,640	1,889
11 Combined Cycle CT	0	0	0	0	0	0	0	0	181	197
12 Coal & IGCC	1,222	628	1,437	1,044	1,595	1,400	2,788	1,988	3,903	3,168
13 Peaking Resources	1,000	1,142	962	1,257	945	1,066	1,394	1,878	2,096	2,565
14 **Total Resources**	13,230	13,230	13,230	13,230	13,230	13,230	15,831	15,831	18,640	18,640
Annual Energy in 2013 (MWa)										
15 Native Load	7,998	7,998	7,998	7,998	7,998	7,998	9,623	9,623	11,380	11,380
16 Pump Storage/Peak Return	428	471	455	437	445	454	468	461	471	479
17 Firm Sales	841	841	841	841	841	841	841	841	841	841
18 Non-Firm Sales	427	434	456	322	398	376	469	382	503	367
19 **Total Requirements**	9,694	9,744	9,750	9,598	9,682	9,669	11,401	11,307	13,195	13,067
20 Existing Generation	6,926	6,995	6,914	6,990	6,842	6,917	6,653	6,956	6,554	6,826
21 Firm Purchases	342	368	375	412	363	375	338	381	338	351
22 Non-Firm Purchases	186	229	152	157	151	154	151	152	154	153
23 New Resources										
24 DSR	613	613	613	613	613	613	694	694	769	769
25 Renewable	0	0	0	0	0	0	0	0	0	0
26 Cogeneration	425	839	275	366	149	216	871	1,146	1,451	1,677
27 Combined Cycle CT	0	0	0	0	0	0	0	0	168	184
28 Coal & IGCC	1,120	576	1,317	957	1,462	1,283	2,554	1,822	3,576	2,890
29 Peaking Resources	96	138	119	117	116	126	154	172	200	232
30 **Total Resources**	9,708	9,757	9,765	9,611	9,695	9,683	11,415	11,323	13,210	13,081
Average Annual Emissions in 1994-2013 (1000 tons)										
31 CO_2	61,259	59,873	61,972	61,335	62,174	62,155	66,937	65,679	72,120	70,685
32 NO_x	136	132	139	137	140	139	147	143	156	152
Financial Results with End Effects to 2043										
50-year Utility Cost										
33 NPV at 8.8% (million $)	46,379	46,466	46,337	46,656	46,403	46,721	52,290	52,907	58,788	59,932
34 Real Levelized (mills/kWh)	46.17	46.26	46.13	46.45	46.19	46.51	45.65	46.19	45.15	46.03
50-year Total Resources Cost										
35 NPV at 8.8% (million $)	47,945	48,032	47,903	48,222	47,969	48,287	54,056	54,673	60,684	61,828
36 Real Levelized (mills/kWh)	45.13	45.22	45.09	45.39	45.16	45.46	44.68	45.19	44.22	45.06

Coal Price Sensitivities

Incremental Winter Capacity (MW) of Resource Additions

Table 6-32

Future		1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
Medium Load Growth with Low Gas Price	**Base Case: #16**										
	Utah Coal						563.9	29.6	614.0	14.9	1222.4
	Wyo Coal										0.0
	Cogeneration	302.0		118.1	57.8						477.9
	Peaking				38.7	142.5	217.6		128.3	472.9	1000.0
	Case: #271										
	Utah Coal										0.0
	Wyo Coal							29.6	587.8	10.7	628.1
	Cogeneration	302.0		118.1	96.6	142.5	271.4				930.6
	Peaking						510.0		154.4	477.2	1141.6
Medium Load Growth with Medium Gas Price	**Base Case: #33**										
	Utah Coal					142.5	660.0	29.6	578.3	26.5	1436.9
	Wyo Coal										0.0
	Cogeneration	302.0									302.0
	Peaking			118.1	96.6		121.5		163.9	461.4	961.5
	Case: #272										
	Utah Coal								78.3		78.3
	Wyo Coal					24.3	534.8	29.6	284.7	92.3	965.7
	Cogeneration	302.0		97.1							399.1
	Peaking			20.9	96.6	118.2	246.7		379.3	395.6	1257.3
Medium Load Growth with High Gas Price	**Base Case: #50**										
	Utah Coal					264.0	660.0	29.6	541.4	100.0	1595.0
	Wyo Coal										0.0
	Cogeneration	160.0									160.0
	Peaking		118.8	141.2	96.6				200.9	387.9	945.4
	Case: #273										
	Utah Coal								425.5		425.5
	Wyo Coal					142.5	562.8	29.6	139.8	99.3	974.0
	Cogeneration	235.3									235.3
	Peaking		43.6	141.2	96.6		218.7		177.0	388.5	1065.6
Medium High Load Growth with Medium Gas Price	**Base Case: #69**										
	Utah Coal					330.0	660.0	437.2	884.0	476.3	2787.5
	Wyo Coal										0.0
	Cogeneration	630.0	187.0	147.7							964.7
	Peaking		169.6	98.4	183.6		244.7		265.2	432.0	1393.5
	Case: #274										
	Utah Coal								637.0	249.3	886.3
	Wyo Coal						547.2	282,7	109.1	162.4	1101.4
	Cogeneration	767.0	73.7	198.2	183.5	57.4					1279.8
	Peaking		145.9	47.9		178.7	451.6	154.4	403.2	496.5	1878.2
High Load Growth with Medium Gas Price	**Base Case: #90**										
	Utah Coal					330.0	660.0	823.5	990.0	818.0	3621.5
	Wyo Coal						216.6			64.6	281.2
	Cogeneration	630.0	630.0	271.8	108.2						1640.0
	Peaking		679.4	37.4	135.8	17.1	345.7		416.0	464.3	2095.7
	Case: #275										
	Utah Coal							414.6	771.1	676.9	1862.6
	Wyo Coal					65.2	660.0	237.9	125.7	216.4	1305.2
	Cogeneration	879.0	630.0	190.6	189.4						1889.0
	Peaking		430.4	118.7	54.6	281.9	562.2	170.9	472.1	474.0	2564.8

T6-32.coal price.mw

sensitivities did not alter the company's conclusions from the base analyses that coal is a least-cost choice, but carries some environmental risks, which the IGCC clean coal technology may help mitigate.

Wholesale Non-Firm Markets

PacifiCorp's ability to use the non-firm market is very beneficial to customers. Revenue from those sales reduces the total system costs, which reduces the total amount of revenue that must be recovered from retail customers. Therefore, accurate estimation of non-firm market activity is important in understanding the financial impacts of alternative futures, strategies, and sensitivities.

PacifiCorp has the transmission and shaping capabilities needed to transform low-value off-peak energy into a high-value on-peak product. PacifiCorp assumes the non-firm markets will track natural gas prices because non-firm energy is a substitute for expensive thermal generation. In general, low gas prices reduce non-firm prices, while high gas prices increase non-firm prices. In each case, the company used the same beginning prices for non-firm sales and purchases, but varied the escalation rate to match the three gas price escalation rates (1.71 percent real escalation for low, 3.78 percent real escalation for medium, and 5.56 percent real escalation for high). The prices varied by on- versus off-peak, by season (winter, spring, summer, or fall), and by region. Other factors which affect non-firm prices are water conditions (wet years have lower non-firm prices, dry years have higher non-firm prices) and heavy plant outages, which raise prices due to increased market demand.

Assumptions about the wholesale non-firm market related to both buying and selling can have a dramatic impact on the model's resource choices. Different sensitivities changed the input assumptions about the wholesale market itself, and the company's involvement in it. Table 6-33 shows the amount of non-firm sales and purchases made by the model in the 10th year (2003) and in the 20th year (2013) across different load growth levels. Table 6-34 shows the same information across different sensitivities. The model's ability to use the non-firm markets cannot accurately mimic the company's day-to-day operations within the marketplace. However, the model's ability to use the non-firm markets allows for a better representation of the true costs of alternative load growth levels, gas price levels, resource strategies, and sensitivity cases.

Consistently, the model made more sales than purchases, reflecting the company's low price structure relative to other utilities in the marketplace. The exception to this pattern was the externality adder cases with a CO_2 adder of $25 or $40/ton; in those cases, the model restricted its non-firm sales activity and made more purchases. This is due to the input assumption using the adders for a CCCT for all non-firm purchases; at the higher adder levels the total cost of purchases were less than the total cost of producing from the company's coal plants. Gas price level had little impact on the level of sales or purchases, probably because it altered both the purchase and sales prices. Under the any-coal strategy, with output from more coal plants available, the model made more sales. Under the no-coal strategy, the model made more purchases. Both of these

Average Non-Firm Sales and Purchases in 2003 and 2013
(Medium DSR, Accross Load Growth and Gas Price Levels)

Table 6-33

Coal Strategy	Case Numbers	Non-Firm Sales 2003	Non-Firm Sales 2013	Non-Firm Purchases 2003	Non-Firm Purchases 2013
Medium Gas Price					
Low Load Growth					
Any-Coal	2, 3	717	1050	23	0
No-Coal	4, 5	717	1050	23	0
Medium-Low Load Growth					
Any-Coal	7, 8	466	618	90	155
No-Coal	9, 10	444	501	151	196
Medium Load Growth					
Any-Coal	33, 34	498	462	84	152
No-Coal	35, 36	468	304	110	268
Medium-High Load Growth					
Any-Coal	69, 70	521	468	104	152
No-Coal	71, 72	484	304	112	264
High Load Growth					
Any-Coal	90, 91	492	498	139	154
No-Coal	92, 93	421	308	209	236

Coal Strategy	Case Numbers	Non-Firm Sales 2003	Non-Firm Sales 2013	Non-Firm Purchases 2003	Non-Firm Purchases 2013
Low Gas Price					
Medium Load Growth					
Any-Coal	16, 17	476	429	178	183
No-Coal	18, 19	475	458	88	261
Medium-High Load Growth					
Any-Coal	62	475	491	128	152
No-Coal	63	485	321	108	292
High Load Growth					
Any-Coal	83	434	430	183	162
No-Coal	84	434	342	192	260
High Gas Price					
Medium Load Growth					
Any-Coal	50, 51	498	465	71	152
No-Coal	52, 53	401	259	219	234
Medium-High Load Growth					
Any-Coal	81	534	462	85	153
No-Coal	82	389	179	224	234
High Load Growth					
Any-Coal	102	549	531	106	157
No-Coal	103	406	142	214	266

T6-33.n/ S&P,load-gas

Non-Firm Sales and Purchases in 2003 and 2013

(For Sensitivity and Environmental Adder Cases)

Table 6-34

Cases	Case Number	Non-Firm Sales 2003	Non-Firm Sales 2013	Non-Firm Purchases 2003	Non-Firm Purchases 2013
Sensitivity Cases, Medium DSR					
Hermiston w/ NC	212	472	278	102	271
Hermiston w/ AC	213	512	618	47	130
SCE as potential	211	476	294	110	269
CCCT to IGCC	222	496	415	94	154
IGCC w/ NC	223	485	427	110	154
IGCC low cost w/ NC	224	501	503	73	152
Transm Bridger 300	231	494	519	87	157
Transm Utah 600	232	482	606	179	159
Critical water	251	374	287	57	56
Non-firm $ lower	252	375	252	79	57
Non-firm $ higher	253	653	546	179	169
No non-firm sales	254	0	0	87	47
No non-firm S/P	255	0	0	0	0

Cases	Case Number	Non-Firm Sales 2003	Non-Firm Sales 2013	Non-Firm Purchases 2003	Non-Firm Purchases 2013
Environmental Adder Cases					
Medium DSR					
Low NOx, Low CO2	301	348	416	239	171
Low NOx, Med CO2	302	0	382	364	238
Low NOx, High CO2	303	0	156	578	342
High NOx, Low CO2	304	183	523	347	169
High NOx, Med CO2	305	0	428	538	341
High NOx, High CO2	306	0	45	656	334
High DSR					
Low NOx, Low CO2	307	343	342	239	173
Low NOx, Med CO2	308	0	379	364	248
Low NOx, High CO2	309	0	156	597	344
High NOx, Low CO2	310	171	449	347	190
High NOx, Med CO2	311	0	407	542	345
High NOx, High CO2	312	0	65	652	334
Limited Carbon Sensitivity Cases					
Carbon Limit, Med DSR	322	0	65	365	365
Carbon Limit, High DSR	323	32	68	365	365

Wholesale Market Sensitivities

Resource Selections by 10th Year (2003)

	Run against		#33 M.MG.MD.AC.AR				
	Sensitivity	m.mg md.ac.ar	Critical Water Condition	Change Non-Firm Sales Price Lower	Change Non-Firm Sales Price Higher	No Non-Firm Sales	No Non-Firm Sales or Purchases
	Case #	33	251	252	253	254	255
	Winter Peak Capacity in 2003 (MW)						
1	Native Load	9,273	9,273	9,273	9,273	9,273	9,273
2	Firm Sales	1,195	1,195	1,195	1,195	1,195	1,195
3	Reserve Requirement	1,479	1,479	1,479	1,479	1,479	1,479
4	**Total Requirements**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**
5	Existing Generation	9,582	9,554	9,582	9,582	9,582	9,582
6	Firm Purchases	317	317	317	317	317	317
7	New Resources						
8	DSR	608	608	608	608	608	608
9	Renewable	0	0	0	0	0	0
10	Cogeneration	302	454	271	302	235	302
11	Combined Cycle CT	0	0	0	0	0	0
12	Coal	803	798	764	884	334	421
13	Peaking Resources	336	216	405	255	871	718
14	**Total Resources**	**11,948**	**11,948**	**11,948**	**11,948**	**11,948**	**11,948**
	Annual Energy in 2003 (MWa)						
15	Native Load	6,634	6,634	6,634	6,634	6,634	6,634
16	Pump Storage/Peak Return	394	367	403	381	315	316
17	Firm Sales	1,410	1,410	1,410	1,410	1,410	1,410
18	Non-Firm Sales	488	374	375	653	0	0
19	**Total Requirements**	**8,926**	**8,785**	**8,822**	**9,078**	**8,359**	**8,360**
20	Existing Generation	7,069	6,894	7,046	7,074	7,055	7,017
21	Firm Purchases	364	330	364	364	363	369
22	Non-Firm Purchases	97	57	79	179	87	0
23	New Resources						
24	DSR	348	348	348	348	348	348
25	Renewable	0	0	0	0	0	0
26	Cogeneration	260	391	224	260	195	246
27	Combined Cycle CT	0	0	0	0	0	0
28	Coal	735	732	701	810	306	386
29	Peaking Resources	68	47	75	58	18	8
30	**Total Resources**	**8,941**	**8,799**	**8,837**	**9,092**	**8,372**	**8,374**

T6-35.grand.wholesale.10yrs

Table 6-36

Wholesale Market Sensitivities

Resource Selections, Emissions and Financial Results

	Run against	#33 M.MG.MD.AC.AR					
	Sensitivity	m.mg md.ac.ar	Critical Water Condition	Change Non-Firm Sales Price: Lower	Change Non-Firm Sales Price: Higher	No Non-Firm Sales	No Non-Firm Sales or Purchases
	Case #	33	251	252	253	254	255
	Winter Peak Capacity in 2013 (MW)						
1	Native Load	11,206	11,206	11,206	11,206	11,206	11,206
2	Firm Sales	437	437	437	437	437	437
3	Reserve Requirement	1,586	1,586	1,586	1,586	1,586	1,586
4	**Total Requirements**	**13,229**	**13,229**	**13,229**	**13,229**	**13,229**	**13,229**
5	Existing Generation	9,196	9,168	9,196	9,196	9,196	9,196
6	Firm Purchases	262	262	262	262	262	262
7	New Resources						
8	DSR	1,071	1,071	1,071	1,071	1,071	1,071
9	Renewable	0	0	0	0	0	0
10	Cogeneration	302	454	271	302	235	318
11	Combined Cycle CT	0	0	0	0	0	0
12	Coal	1,437	1,422	1,430	1,532	1,465	1,357
13	Peaking Resources	962	852	1,000	866	1,000	1,026
14	**Total Resources**	**13,230**	**13,230**	**13,229**	**13,230**	**13,230**	**13,230**
	Annual Energy in 2013 (MWa)						
15	Native Load	7,998	7,998	7,998	7,998	7,998	7,998
16	Pump Storage/Peak Return	455	445	433	446	392	372
17	Firm Sales	841	841	841	841	841	841
18	Non-Firm Sales	456	287	252	546	0	0
19	**Total Requirements**	**9,750**	**9,571**	**9,524**	**9,831**	**9,231**	**9,211**
20	Existing Generation	6,914	6,746	6,859	6,895	6,658	6,710
21	Firm Purchases	375	342	356	369	332	341
22	Non-Firm Purchases	152	56	57	169	47	0
23	New Resources						
24	DSR	613	613	613	613	613	613
25	Renewable	0	0	0	0	0	0
26	Cogeneration	275	415	240	281	187	252
27	Combined Cycle CT	0	0	0	0	0	0
28	Coal	1,317	1,303	1,310	1,404	1,343	1,243
29	Peaking Resources	119	110	103	114	69	69
30	**Total Resources**	**9,765**	**9,585**	**9,537**	**9,845**	**9,247**	**9,228**
	Average Annual Emissions in 1994-2013 (1000 tons)						
31	CO_2	61,972	62,118	61,477	62,415	59,229	59,498
32	NO_x	139	139	138	139	133	133
	Financial Results with End Effects to 2043						
	50-year Utility Cost						
33	NPV at 8.8% (million $)	46,337	47,273	46,768	45,723	47,152	47,164
34	Real Levelized (mills/KWh)	46.13	47.06	46.56	45.52	46.94	46.95
	50-year Total Resources Cost						
35	NPV at 8.8% (million $)	47,903	48,838	48,334	47,288	48,718	48,730
36	Real Levelized (mills/KWh)	45.09	45.97	45.50	44.52	45.86	45.87

coal patterns accentuated under higher gas prices. The model made more sales under the portfolio sensitivities: Hermiston with the any-coal strategy, the CCCT conversion to IGCC case, the IGCC case under no-coal, the IGCC case under no-coal with lower costs, and the two transmission sensitivities. Each of these modifications to the portfolio would increase the company's ability to use the wholesale marketplace to reduce retail prices.

Table 6-35 shows the 10-year results for the non-firm market sensitivities; table 6-36 shows the 20-year results. The first sensitivity, case #251, changed the hydro stream flow assumption to critical water. Critical water levels would significantly reduce the amount of non-firm power available from BPA and decrease the amount of energy available from PacifiCorp's system. RAMPP-3 planning assumed average water levels. By the 10th year under critical water, the existing system and power available from Bonneville during May/June/July for the fish flush provided about 175 MWa less energy than was available under an average water assumption. The model was able to use 34 MWa less from firm purchase contracts. Non-firm purchases decreased by 40 MWa and non-firm sales increased by 114 MWa compared to the average water case. By the 20th year, non-firm purchases decreased by 96 MWa and non-firm sales increased by 169 MWa compared to the average water case. To compensate, the model selected about 150 MW more cogeneration, which provided 131 more MWa of energy. As expected, an assumption of critical water raised utility cost and prices. However, it is not an accurate reflection of normal operations for PacifiCorp. The company uses the non-firm market for both sales and purchase opportunities, which on average are at an average water level, to lower total system costs and reduce retail prices.

Four sensitivities tested the effect of the wholesale market on resource choices. Two altered the price on the market: case #252 reduced the non-firm sales price by 20 percent; case #253 increased it by 20 percent. A reduced price had very little effect on resource choices, but it increased system costs and customer prices. A higher price caused the model to select about 90 MW more of coal than the comparison case, and reduced costs and prices. These sensitivities illustrate the importance of using reasonably accurate estimates of prices on the non-firm market in the RAMPP-3 modeling process.

The other two wholesale market sensitivities altered the availability of the non-firm market. Case #254 did not allow any non-firm sales to occur. Case #255 allowed neither non-firm sales nor purchases. With no non-firm sales, the model selected slightly less cogeneration. Case #255 removed both sales and purchases from the non-firm market. This caused the model to add less coal. Both cases caused utility costs, TRC, and customer prices to be higher. The lesson for PacifiCorp is that the IRP process must use a model that can recognize and use the non-firm market as the company does for daily operations to accurately reflect system costs.

Building Cogen
for non-firm sales?

REGIONAL PATTERNS

Table 6-37 shows the regional distribution of new resources for the medium load growth case after 20 years. The company prepared this and the following table 6-38 to summarize the regional detail provided by the IPM model. Although the regional detail did not directly impact development of the action plan, the company found the detail useful to help focus its demand-side program activity, and to clarify the east-side-coal versus west-side-cogeneration resource choices. All of the results in the tables used the any-renewable strategy; table 6-37 breaks out the results by coal strategy, DSR strategy, and gas price escalation. The regional distribution of new resources in the higher load growth cases followed the same pattern. Three factors influenced the regional distribution of new resources: coal strategy, level of DSR, and gas prices. New coal resources are in Utah and Wyoming; most of the new cogeneration is in OWC. The table shows the amount of coal added in Utah (most of which would be added in Wyoming with higher Utah coal prices), the amount of cogeneration added in OWC, and the amount of other resources added in each of the three load and resource areas.

The most influential factor in the distribution of new resources between OWC and Utah was the coal strategy. The any-coal strategy selected 62 percent of new resources (coal) in Utah. The no-coal strategy selected 57 percent of new resources (cogeneration) in OWC. Cogeneration in OWC was the new resource of choice under no-coal, because its price was slightly lower than was the price for cogeneration in Utah. The amount of new resources in Wyoming remained at 3 percent (except in the low DSR cases and the coal price sensitivity cases).

The second factor affecting the regional distribution of new resources was the DSR strategy. The amount of DSR in OWC tripled from the low to the high DSR strategies, whereas the amount of DSR in Utah only doubled. This meant more resources came from OWC in the higher DSR cases. However, the impact was not nearly as dramatic as it was for the coal strategies.

The third factor was gas prices. Under higher gas prices, the model selected more renewables; under the any-coal strategy with higher gas prices, the model selected more coal. Thus a higher gas price escalation caused more resources selections in Utah.

Another way to look at the question is to examine the regional distribution of resources in 1994 compared to the distribution in 2013 after 20 years of additions, as shown on table 6-38. In 1994, 53 percent of the company's generating resources are in the OWC region, 36 percent in Utah, and 11 percent in Wyoming. In 2013 the distribution varies by case, but there is a consistent swing toward Utah, making Utah's and OWC's shares about equal. As Table 6-38 shows, Utah will probably increase its share of the company's total resources from 36 percent to somewhere between 40 and 50 percent. OWC's share will probably decrease from 53 percent to somewhere between 40 and 50 percent, and Wyoming's share will decrease slightly. The exact percentage share for each region will depend primarily on how much new coal comes on line versus alternative resources.

Regional Patterns for New Resource Additions
MW Added by 2013

Table 6-37

Coal Strategy	med load • med gas • med DSR • any renewables			
	any coal		no coal	
OWC				
Cogen	302		1067	
Other	1039		1077	
OWC Total	*1341*	*36%*	*2145*	*57%*
Utah				
Coal	1437		0	
Other	890		1523	
Utah Total	*2327*	*62%*	*1523*	*40%*
Wyo				
Wyo Total	*104*	*3%*	*104*	*3%*
Total	3772		3772	

DSR Strategy	med load • med gas • any coal • any renewables					
	low DSR		med DSR		high DSR	
OWC						
Cogen	402		302		180	
Other	755		1039		1072	
OWC Total	*1157*	*30%*	*1341*	*36%*	*1252*	*34%*
Utah						
Coal	1925		1437		1406	
Other	731		890		964	
Utah Total	*2656*	*69%*	*2327*	*62%*	*2370*	*63%*
Wyo						
Wyo Total	*41*	*1%*	*104*	*3%*	*115*	*3%*
Total	3853		3772		3737	

Gas Price Esc	med load • med DSR • any coal • any renewables					
	low gas		med gas		high gas	
OWC						
Cogen	478		302		160	
Other	1077		1039		1023	
OWC Total	*1555*	*41%*	*1341*	*36%*	*1183*	*31%*
Utah						
Coal	1222		1437		1595	
Other	890		890		890	
Utah Total	*2112*	*56%*	*2327*	*62%*	*2485*	*66%*
Wyo						
Wyo Total	*104*	*3%*	*104*	*3%*	*104*	*3%*
Total	3772		3772		3772	

T6-37.regional pattern for new

Regional Distribution of Resources at 1994 and 2013 (%)

Table 6-38

		New Resource Additions by 2013				Total Resources by 2013			
		by Region			Total	by Region			Total
Scenario	Case #	OWC	UTA	WYO	Additions	OWC	UTA	WYO	Resource
Existing Resources in 1994		52.81	35.99	11.20	100.0				
Existing Resources in 2013		46.02	42.65	11.34	100.0				
M.LG.MD.AC.AR	16	41.23	56.01	2.76	100.0	44.65	46.46	8.89	100.0
M.LG.MD.AC.SR	17	40.83	52.57	6.60	100.0	44.44	45.66	9.90	100.0
M.LG.MD.NC.AR	18	63.17	34.07	2.76	100.0	50.91	40.20	8.89	100.0
M.LG.MD.NC.SR	19	60.28	33.12	6.60	100.0	50.35	39.75	9.90	100.0
M.MG.MD.AC.AR	33	35.54	61.70	2.76	100.0	43.03	48.08	8.89	100.0
M.MG.MD.AC.SR	34	36.54	56.86	6.60	100.0	43.14	46.96	9.90	100.0
M.MG.MD.NC.AR	35	56.86	40.38	2.76	100.0	49.11	42.00	8.89	100.0
M.MG.MD.NC.SR	36	52.58	40.82	6.60	100.0	48.01	42.09	9.90	100.0
M.HG.MD.AC.AR	50	31.35	65.89	2.76	100.0	41.84	49.27	8.89	100.0
M.HG.MD.AC.SR	51	33.51	59.89	6.60	100.0	42.22	47.88	9.90	100.0
M.HG.MD.NC.AR	52	44.02	45.84	10.13	100.0	45.29	43.82	10.89	100.0
M.HG.MD.NC.SR	53	43.28	50.28	6.44	100.0	45.05	45.36	9.60	100.0

ENVIRONMENTAL ANALYSIS

RAMPP-3 examined the environmental impacts of resource planning in three ways: through cases that used external cost adders, sensitivities that limited CO2 emissions, and graphs showing trade-offs, based on results of the model runs in the base study plan. This chapter ends with a discussion of system dispatch assuming environmental cost adders and an environmental insurance analysis.

EXTERNAL COST ADDER CASES

Twenty-one cases tested various levels of external costs under alternative load growth and DSR assumptions. The company used the adder amounts in the final order from an Oregon Public Utility Commission proceeding on external costs, UM 424. The order established low externality cost values of $2,000/ton for NOx and $2,000/ton for TSP, and high values of $5,000/ton for NOx and $4,000/ton for TSP, and three levels for CO2 ($10, $25, and $40 per ton). Combining the low and high values for NOx and TSP with the three values for CO2 produced six different adder levels.

The company used the six external cost combinations with the assumptions for case #33 (medium load growth, medium gas prices, medium DSR), case #41 (medium load growth, medium gas prices, high DSR), and case #69 (medium-high load growth, medium gas, medium DSR). In addition, at the request of the public advisory group, three of the adder combinations also used case #50 (medium loads, high gas prices, and medium DSR). The following table shows the case numbers for the 21 cases using adders:

Environmental Adder Case Numbers
Table 7-1

Comparison Case		AC AR M.MG.MD (# 33)	M.MG.HD (# 41)	M.HG.MD (# 50)	MH.MG.MD (# 69)
Load Growth		Medium	Medium	Medium	Medium-Hi
Gas Prices		Medium	Medium	High	Medium
DSR Strategy		Medium	High	Medium	Medium
Low NOx/TSP	Low CO2	#301	#307	#313	#316
	Med CO2	302	308	314	317
	High CO2	303	309	315	318
High NOx/TSP	Low CO2	304	310		319
	Med CO2	305	311		320
	High CO2	306	312		321

All of the adder cases used the any-coal and any-renewable strategies, to give the model maximum flexibility in selecting resources. Each of these cases used the adders for both selecting resources and dispatching power. However, calculations of production costs, total utility costs, and total resource costs ignored the adders. Thus, the IPM model selected new resources as if the adders were real, but the financial model operated as if the company did not have to pay the adder costs. Tables 7-2 and 7-3 summarize the results of these 21 cases, as well as comparable cases without the adders, for the first 10 years, and two cases using carbon emission limits. Tables 7-4 and 7-5 show the results after 20 years for the 23 cases. Overall, when faced with resource prices that included the adders, the model selected more renewables and more cogeneration, and switched from pulverized coal to coal gasification.

For the first six cases (with medium load growth, medium gas prices, and medium DSR) Case #33 was the non-adder comparison case. Case #33 (without adders) included DSR, cogeneration, pulverized coal, and peaking resources. Case #301 used the lowest level of adders. The model added slightly more cogeneration, and switched from pulverized coal to a clean coal technology -- integrated gasification combined cycle (IGCCs). The MW section of the tables divides coal into two categories, pulverized and IGCC, to highlight the switch from pulverized to IGCC at the lower adder levels. Case #302, with higher adders, started relying on renewables and cogeneration to replace some of the IGCCs. Case #303, with a \$40/ton CO2 adder, relied on extensive renewables (4,350 MW of wind installed, about 1,460 MW effective capacity), and cogeneration, and no peaking resources, probably because pumped storage requires more off-peak, carbon-producing generation and the SCCTs produce carbon as well. When the CO2 adder was \$40/ton, the model met its reserve requirement by adding non-peaking resources that would not produce carbon. When the NOx and TSP adders were higher (cases #304, #305, and #306), the model used more cogeneration and IGCC coal to replace peaking resources.

The 20-year tables show CO2 and NOx emission levels, because these two had a major impact on the model's resource selections. The tables do not include TSP amounts because they did not influence the model's choices. The Modeling Appendix includes information on TSP emissions. CO2 and NOx emission amounts decreased as adder amounts increased. In addition, NOx emissions were lower in the higher load growth cases than in the medium load growth cases, everything else remaining equal, because the model added more new resources for higher load growth. This gave the model more generation options to choose from in meeting load. New resources that emit less NOx could replace generation from existing coal plants. Utility costs as well as customer prices increased. At the highest level of adders, levelized customer prices were about 10 mills (or about 20 percent) higher than in the non-adder comparison case.

The second six cases used medium load growth and medium gas prices, but high rather than medium DSR. Case #41 was the non-adder comparison case. Resource selections followed the same pattern as with the first set of adder cases; however, the model chose slightly less of each technology because more DSR was

Table 7-2

Environmental Cost Adder Sensitivities
Resource Selections in 10th Year (2003)

	Run against		#33 M.MG.MD.AC.AR							#41 M.MG.HD.AC.AR					
	NOx & TSP		Low			High				Low			High		
	CO2		Low	Med	High	Low	Med	High		Low	Med	High	Low	Med	High
	Case #	33	301	302	303	304	305	306	41	307	308	309	310	311	312
	Winter Peak Capacity in 2003 (MW)														
1	Native Load	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273
2	Firm Sales	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195
3	Reserve Requirement	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,452	1,452	1,452	1,452	1,452	1,452	1,452
4	**Total Requirements**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**	**11,920**	**11,920**	**11,920**	**11,920**	**11,920**	**11,920**	**11,920**
5	Existing Generation	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582
6	Firm Purchases	317	317	317	317	317	317	317	317	317	317	317	317	317	317
7	New Resources														
8	DSR	608	608	608	608	608	608	608	786	786	786	786	786	786	786
9	Renewable	0	0	900	2,550	0	900	2,550	0	0	900	2,550	0	900	2,550
10	Cogeneration	302	438	1,052	1,301	462	1,241	1,683	180	320	939	1,066	320	1,076	1,609
11	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Coal IGCC	0	593	92	0	924	0	0	0	582	0	0	902	0	0
13	Coal Pulverized	803	0	0	0	0	0	0	792	0	0	0	0	0	0
14	Peaking Resources	336	410	0	0	55	0	0	264	333	0	0	14	0	0
15	**Total Resources**	**11,948**	**11,948**	**12,551**	**14,358**	**11,948**	**12,648**	**14,740**	**11,921**	**11,921**	**12,524**	**14,302**	**11,921**	**12,661**	**14,844**
	Annual Energy in 2003 (MWa)														
16	Native Load	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634
17	Pump Storage/Peak Return	394	354	306	306	306	306	306	375	349	306	306	306	306	306
18	Firm Sales	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410
19	Non-Firm Sales	488	348	0	0	183	0	0	472	343	0	0	171	0	0
20	**Total Requirements**	**8,926**	**8,746**	**8,350**	**8,350**	**8,533**	**8,350**	**8,350**	**8,891**	**8,736**	**8,350**	**8,350**	**8,521**	**8,350**	**8,350**
21	Existing Generation	7,069	6,730	5,803	4,911	6,114	5,537	4,479	7,058	6,732	5,890	5,010	6,153	5,586	4,453
22	Firm Purchases	364	471	471	471	471	471	470	364	471	471	471	471	471	468
23	Non-Firm Purchases	97	239	364	578	347	538	656	92	239	364	597	347	542	652
24	New Resources														
25	DSR	348	348	348	348	348	348	348	448	448	448	448	448	448	448
26	Renewable	0	0	316	845	0	316	845	0	0	316	845	0	316	845
27	Cogeneration	260	397	979	1,211	430	1,154	1,566	163	298	874	992	298	1,001	1,497
28	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Coal	735	537	83	0	838	0	0	726	528	0	0	818	0	0
30	Peaking Resources	68	37	0	0	0	0	0	53	33	0	0	0	0	0
31	**Total Resources**	**8,941**	**8,759**	**8,364**	**8,363**	**8,548**	**8,364**	**8,363**	**8,905**	**8,750**	**8,363**	**8,363**	**8,535**	**8,365**	**8,363**

T7-02,3.grand.adders.10yrs

Table 7-3

Environmental Cost Adder Sensitivities (cont.) and Limited Carbon Sensitivities
Resouce Selections by 10th Year (2003)

	Run against		#50 M.HG.MD.AC.AR				#69 MH.MG.MD.AC.AR						#33 M.MG MD.AC.AR		#41 M.MG HD.AC.AR	
	NOx & TSP		Low				Low			High						
	CO2		Low	Med	High		Low	Med	High	Low	Med	High				
	Case #	50	313	314	315	69	316	317	318	319	320	321	33	322	41	323
	Winter Peak Capacity in 2003 (MW)															
1	Native Load	9,273	9,273	9,273	9,273	10,382	10,382	10,382	10,382	10,382	10,382	10,382	9,273	9,273	9,273	9,273
2	Firm Sales	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195
3	Reserve Requirement	1,479	1,479	1,479	1,479	1,637	1,637	1,637	1,637	1,637	1,637	1,637	1,479	1,479	1,452	1,452
4	**Total Requirements**	**11,947**	**11,947**	**11,947**	**11,947**	**13,214**	**13,214**	**13,214**	**13,214**	**13,214**	**13,214**	**13,214**	**11,947**	**11,947**	**11,920**	**11,920**
5	Existing Generation	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582
6	Firm Purchases	317	317	317	317	317	317	317	317	317	317	317	317	317	317	317
7	New Resources															
8	DSR	608	608	608	608	665	665	665	665	665	665	665	608	608	786	786
9	Renewable	0	150	1,350	3,150	0	0	922	2,550	300	922	2,550	0	1,256	0	900
10	Cogeneration	160	205	244	359	965	1,378	1,758	2,099	1,437	2,099	2,099	302	363	180	394
11	Combined Cycle CT	0	0	0	0	0	0	0	305	0	0	530	0	0	0	0
12	Coal IGCC	0	698	675	126	0	675	335	0	1,083	249	0	0	0	0	0
13	Coal Pulverized	924	0	0	0	990	0	0	0	0	0	0	803	0	792	0
14	Peaking Resources	357	500	113	0	696	598	256	0	33	0	0	336	674	264	545
15	**Total Resources**	**11,948**	**12,060**	**12,888**	**14,142**	**13,215**	**13,215**	**13,835**	**15,518**	**13,416**	**13,835**	**15,743**	**11,948**	**12,800**	**11,921**	**12,524**
	Annual Energy in 2003 (MWa)															
16	Native Load	6,634	6,634	6,634	6,634	7,390	7,390	7,390	7,390	7,390	7,390	7,390	6,634	6,634	6,634	6,634
17	Pump Storage/Peak Return	401	384	306	299	445	350	306	306	306	304	306	394	306	375	306
18	Firm Sales	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410
19	Non-Firm Sales	477	352	141	0	518	399	0	0	256	0	0	488	0	472	32
20	**Total Requirements**	**8,922**	**8,780**	**8,491**	**8,343**	**9,763**	**9,549**	**9,106**	**9,106**	**9,362**	**9,104**	**9,106**	**8,926**	**8,350**	**8,891**	**8,382**
21	Existing Generation	7,070	6,818	6,077	5,627	7,091	6,646	5,642	4,610	5,754	5,252	4,354	7,069	6,414	7,058	6,432
22	Firm Purchases	364	471	471	471	364	471	471	471	471	471	464	364	471	364	471
23	Non-Firm Purchases	88	237	347	474	110	216	364	577	347	514	632	97	365	92	365
24	New Resources															
25	DSR	348	348	348	348	380	380	380	380	380	380	380	348	348	448	448
26	Renewable	0	36	424	988	0	0	321	845	105	321	845	0	426	0	316
27	Cogeneration	146	191	227	334	810	1,187	1,636	1,953	1,337	1,953	1,951	260	338	163	364
28	Combined Cycle CT	0	0	0	0	0	0	0	284	0	0	493	0	0	0	0
29	Coal	847	633	612	114	907	612	303	0	982	226	0	735	0	726	0
30	Peaking Resources	74	60	0	0	117	51	2	0	0	0	0	68	3	53	0
31	**Total Resources**	**8,936**	**8,794**	**8,505**	**8,356**	**9,778**	**9,562**	**9,120**	**9,120**	**9,376**	**9,118**	**9,119**	**8,941**	**8,364**	**8,905**	**8,397**

Environmental Cost Adder Sensitivities
Resource Selections, Emissions and Financial Results

	Run against	#33 M.MG.MD.AC.AR							#41 M.MG.HD.AC.AR						
	NOx & TSP		Low			High				Low			High		
	CO2		Low	Med	High	Low	Med	High		Low	Med	High	Low	Med	High
	Case #	33	301	302	303	304	305	306	41	307	308	309	310	311	312
	Winter Peak Capacity in 2013 (MW)														
1	Native Load	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206
2	Firm Sales	437	437	437	437	437	437	437	437	437	437	437	437	437	437
3	Reserve Requirement	1,586	1,586	1,586	1,586	1,586	1,586	1,586	1,551	1,551	1,551	1,551	1,551	1,551	1,551
4	**Total Requirements**	**13,229**	**13,229**	**13,229**	**13,229**	**13,229**	**13,229**	**13,229**	**13,194**	**13,194**	**13,194**	**13,194**	**13,194**	**13,194**	**13,194**
5	Existing Generation	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196
6	Firm Purchases	262	262	262	262	262	262	262	262	262	262	262	262	262	262
7	New Resources														
8	DSR	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,303	1,303	1,303	1,303	1,303	1,303	1,303
9	Renewable	0	0	900	4,350	0	900	4,836	0	0	900	4,253	0	900	4,747
10	Cogeneration	302	438	1,052	1,301	462	1,241	1,683	180	320	939	1,066	320	1,076	1,609
11	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Coal IGCC	0	1,262	563	0	2,088	1,163	0	0	1,145	518	0	1,950	1,061	0
13	Coal Pulverized	1,437	0	0	0	0	0	0	1,406	0	0	0	0	0	0
14	Peaking Resources	962	1,000	789	0	150	0	0	848	968	680	0	163	0	0
15	**Total Resources**	**13,230**	**13,230**	**13,833**	**16,180**	**13,230**	**13,833**	**17,048**	**13,195**	**13,195**	**13,798**	**16,080**	**13,195**	**13,798**	**17,117**
	Annual Energy in 2013 (MWa)														
16	Native Load	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998
17	Pump Storage/Peak Return	455	422	326	305	306	305	305	437	420	326	305	305	305	305
18	Firm Sales	841	841	841	841	841	841	841	841	841	841	841	841	841	841
19	Non-Firm Sales	456	416	382	156	523	428	45	418	342	379	156	449	407	65
20	**Total Requirements**	**9,750**	**9,677**	**9,547**	**9,300**	**9,668**	**9,572**	**9,189**	**9,694**	**9,601**	**9,544**	**9,300**	**9,593**	**9,551**	**9,209**
21	Existing Generation	6,914	6,826	6,447	5,232	6,139	5,663	4,606	6,894	6,853	6,473	5,373	6,188	5,778	4,619
22	Firm Purchases	375	443	443	443	443	443	443	375	443	443	443	443	443	443
23	Non-Firm Purchases	152	171	238	342	169	341	334	154	173	248	344	190	345	334
24	New Resources														
25	DSR	613	613	613	613	613	613	613	718	718	718	718	718	718	718
26	Renewable	0	0	316	1,477	0	316	1,647	0	0	316	1,443	0	316	1,616
27	Cogeneration	275	402	977	1,207	424	1,154	1,560	167	298	873	992	298	1,001	1,492
28	Combined Cycle CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Coal	1,317	1,145	510	0	1,894	1,055	0	1,289	1,039	470	0	1,769	962	0
30	Peaking Resources	119	92	17	0	1	0	0	110	90	17	0	1	0	0
31	**Total Resources**	**9,765**	**9,691**	**9,561**	**9,314**	**9,682**	**9,585**	**9,204**	**9,707**	**9,614**	**9,557**	**9,313**	**9,607**	**9,564**	**9,222**
	Average Annual Emissions in 1994-2013 (1000 tons)														
32	CO2	61,972	57,164	48,839	39,193	54,754	45,453	36,847	61,372	56,659	48,495	39,370	54,356	45,312	36,424
33	NOx	139	119	103	82	109	93	76	138	119	104	84	109	93	75
	Financial Results with End Effects to 2043														
	50-year Utility Cost														
34	NPV at 8.8% (million $)	46,337	46,980	49,155	54,757	47,901	50,884	56,529	46,067	46,668	48,805	54,156	47,526	50,446	56,310
35	Real Levelized (mills/kWh)	46.13	46.77	48.93	54.51	47.68	50.65	56.27	46.50	47.11	49.27	54.67	47.98	50.93	56.84
	50-year Total Resources Cost														
36	NPV at 8.8% (million $)	47,903	48,545	50,721	56,322	49,467	52,449	58,095	47,789	48,390	50,527	55,878	49,248	52,168	58,032
37	Real Levelized (mills/kWh)	45.09	45.70	47.75	53.02	46.57	49.37	54.69	44.99	45.55	47.56	52.60	46.36	49.11	54.63

T7-04,5.grand.adders.20yrs

Table 7-5

Environmental Cost Adder Sensitivities (cont.) and Limited Carbon Sensitivities
Resource Selections, Emissions and Financial Results

	Run against		#50 M.HG.MD.AC.AR				#69 MH.MG.MD.AC.AR						#33 M.MG MD.AC.AR		#41 M.MG HD.AC.AR	
	NOx & TSP		Low				Low			High						
	CO2		Low	Med	High		Low	Med	High	Low	Med	High				
	Case #	50	313	314	315	69	316	317	318	319	320	321	33	322	41	323
	Winter Peak Capacity in 2013 (MW)															
1	Native Load	11,206	11,206	11,206	11,206	13,488	13,488	13,488	13,488	13,488	13,488	13,488	11,206	11,206	11,206	11,206
2	Firm Sales	437	437	437	437	437	437	437	437	437	437	437	437	437	437	437
3	Reserve Requirement	1,586	1,586	1,586	1,586	1,905	1,905	1,905	1,905	1,905	1,905	1,905	1,586	1,586	1,551	1,551
4	**Total Requirements**	**13,229**	**13,229**	**13,229**	**13,229**	**15,830**	**15,830**	**15,830**	**15,830**	**15,830**	**15,830**	**15,830**	**13,229**	**13,229**	**13,194**	**13,194**
5	Existing Generation	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196
6	Firm Purchases	262	262	262	262	262	262	262	262	262	262	262	262	262	262	262
7	New Resources															
8	DSR	1,071	1,071	1,071	1,071	1,227	1,227	1,227	1,227	1,227	1,227	1,227	1,071	1,071	1,303	1,303
9	Renewable	0	150	1,350	6,461	0	0	922	5,550	300	922	5,852	0	3,922	0	3,152
10	Cogeneration	160	205	244	359	965	1,378	1,758	2,099	1,437	2,099	2,099	302	363	180	394
11	Combined Cycle CT	0	0	0	0	0	0	0	305	0	0	530	0	0	0	0
12	Coal IGCC	0	1,531	1,315	126	0	2,392	2,055	58	2,941	2,678	646	0	0	0	0
13	Coal Pulverized	1,454	0	0	0	2,788	0	0	0	0	0	0	1,437	0	1,406	0
14	Peaking Resources	945	926	732	192	1,394	1,375	1,030	888	669	66	0	962	1,054	848	1,000
15	**Total Resources**	**13,089**	**13,342**	**14,170**	**17,667**	**15,831**	**15,831**	**16,451**	**19,585**	**16,032**	**16,451**	**19,811**	**13,230**	**15,868**	**13,195**	**15,306**
	Annual Energy in 2013 (MWa)															
16	Native Load	7,998	7,998	7,998	7,998	9,623	9,623	9,623	9,623	9,623	9,623	9,623	7,998	7,998	7,998	7,998
17	Pump Storage/Peak Return	445	441	382	316	468	445	338	332	331	305	305	455	298	437	302
18	Firm Sales	841	841	841	841	841	841	841	841	841	841	841	841	841	841	841
19	Non-Firm Sales	398	411	465	415	469	457	468	146	495	477	58	456	65	418	68
20	**Total Requirements**	**9,682**	**9,691**	**9,686**	**9,570**	**11,401**	**11,366**	**11,270**	**10,942**	**11,290**	**11,246**	**10,827**	**9,750**	**9,202**	**9,694**	**9,209**
21	Existing Generation	6,842	6,773	6,596	5,756	6,653	6,586	6,075	5,265	5,962	5,119	4,453	6,914	6,092	6,894	6,224
22	Firm Purchases	363	443	443	443	338	443	443	443	443	443	439	375	443	375	443
23	Non-Firm Purchases	151	147	145	201	151	138	237	350	153	315	312	152	365	154	365
24	New Resources															
25	DSR	613	613	613	613	694	694	694	694	694	694	694	613	613	718	718
26	Renewable	0	36	424	2,116	0	0	321	1,898	105	321	1,970	0	1,361	0	1,107
27	Cogeneration	149	191	227	334	871	1,220	1,623	1,949	1,260	1,942	1,944	275	338	167	365
28	Combined Cycle CT	0	0	0	0	0	0	0	284	0	0	464	0	0	0	0
29	Coal	1,462	1,389	1,193	113	2,554	2,169	1,864	52	2,667	2,426	565	1,317	0	1,289	0
30	Peaking Resources	116	113	61	9	154	132	28	22	20	0	0	119	4	110	1
31	**Total Resources**	**9,695**	**9,704**	**9,701**	**9,584**	**11,415**	**11,381**	**11,284**	**10,956**	**11,305**	**11,261**	**10,841**	**9,765**	**9,216**	**9,707**	**9,223**
	Average Annual Emissions in 1994-2013 (1000 tons)															
32	CO2	62,174	58,071	52,348	42,884	66,937	60,910	52,964	41,914	57,222	48,955	40,218	61,972	50,086	61,372	50,117
33	NOx	140	120	108	93	147	120	103	84	107	90	79	139	111	138	111
	Financial Results with End Effects to 2043															
	50-year Utility Cost															
34	NPV at 8.8% (million $)	46,403	47,064	48,710	54,401	52,290	53,168	55,297	61,341	54,454	57,305	62,697	46,337	50,849	46,067	50,060
35	Real Levelized (mills/kWh)	46.19	46.85	48.49	54.16	45.65	46.41	48.27	53.55	47.54	50.03	54.73	46.13	50.62	46.50	49.83
	50-year Total Resources Cost															
36	NPV at 8.8% (million $)	47,969	48,630	50,276	55,967	54,056	54,934	57,063	63,107	56,220	59,071	64,463	47,903	52,415	47,789	51,626
37	Real Levelized (mills/kWh)	45.16	45.78	47.33	52.69	44.68	45.41	47.17	52.16	46.47	48.83	53.29	45.09	49.34	44.99	48.60

added to the system. Emissions followed the same pattern as with the first set of adder cases, although emissions for each comparable case were slightly lower, again because of more DSR. Utility costs were lower for each of the high DSR cases than the comparable medium DSR cases, while levelized customer prices were higher.

The next three cases (#314, 315, and 316) assumed medium load growth, high gas prices, and medium DSR. They included only the low adder amounts for NOx and TSP combined with each of the three levels of CO2 adders. High gas prices, together with the adders, caused an earlier and increased reliance on renewable resources and less cogeneration. Emissions were slightly higher for these cases than for medium gas prices. why?

The last six cases (#316 through #321) assumed MH load growth, with medium gas prices and medium DSR. The model selected more of each category of resources than it had for comparable cases under medium load growth. Emissions for CO2 were higher when load growth was MH, but NOx emissions were the same or lower. Utility costs and levelized customer prices were higher for the medium-high than for the medium load growth cases, as expected.

These analyses indicate that new resources can affect the level of future CO2 and NOx emissions, but choices which reduce emissions come at a noticeable cost to customers. One way or another, we pay

CASES WITH CO2 LIMITS

Two sensitivities tested the effect of CO2 emission limits on resource planning. Both required the model to add resources, and adjust operation of the existing system, to keep CO2 emissions below their 1990 level. Both sensitivities used medium load growth with medium gas prices, and the unconstrained coal and renewable strategies (any-coal and any-renewables). The first one used the medium DSR strategy, and the second one used the high DSR strategy. Tables 7-3 and 7-5 show the medium DSR case #322 with its companion case #33 without CO2 limits, and the high DSR case #323 with its companion case #41 without CO2 limits.

The CO2 limits had four primary (direct) effects on the model: 1) new renewables (and additional peaking resources) replaced new coal; 2) reduced generation from the existing system; 3) reduced non-firm sales with increased non-firm purchase; and 4) higher costs for the utility, customers, and society. A higher amount of DSR tended to reduce these effects. If carbon limits were to be imposed, the company would examine the potential impacts of higher DSR levels to mitigate the price impact on customers.

To meet the CO2 limitation requirement, the model had to reduce generation from the existing system's coal plants, and replace it with non-firm purchases. The emissions used for non-firm purchases assumed a CCCT, which has lower CO2 emissions than a coal plant. In 2003 the model reduced generation from the

price of non-firm purchase would ↑

Case Numbers and Utility Cost

Table 7-6

Future Load	Future Gas Price	DSR Strategy	Case Numbers (Coal & Renewable Strategy) AC.AR	AC.SR	NC.AR	NC.SR	NPV Utility Cost in $M (Coal & Renewable Strategy) AC.AR	AC.SR	NC.AR	NC.SR
Low	Medium	Medium	2	3	4	5	38,040	38,791	38,040	38,791
Medium-Low	Medium	Medium	7	8	9	10	41,419	41,939	41,582	41,984
Medium	Low	Low	12	13	14	15	47,167	47,664	47,188	47,692
Medium	Low	Medium	16	17	18	19	46,379	46,878	46,406	46,901
Medium	Low	Accelerated	20	21	22	23	46,334	46,837	46,361	46,857
Medium	Low	High	24	25	26	27	46,096	46,598	46,112	46,612
Medium	Medium	Low	29	30	31	32	47,195	47,681	47,742	48,224
Medium	Medium	Medium	33	34	35	36	46,337	46,802	46,894	47,338
Medium	Medium	Accelerated	37	38	39	40	46,327	46,809	46,834	47,270
Medium	Medium	High	41	42	43	44	46,067	46,549	46,563	46,970
Medium	High	Low	46	47	48	49	47,153	47,652	50,053	49,925
Medium	High	Medium	50	51	52	53	46,403	46,607	48,541	48,474
Medium	High	Accelerated	54	55	56	57	46,305	46,687	48,469	48,534
Medium	High	High	58	59	60	61	45,945	46,381	48,015	48,106
Medium-High	Low	Medium		62		63		52,410		52,682
Medium-High	Medium	Low	65	66	67	68	53,278	53,767	54,588	54,811
Medium-High	Medium	Medium	69	70	71	72	52,290	52,785	53,449	53,664
Medium-High	Medium	Accelerated	73	74	75	76	52,137	52,627	53,125	53,504
Medium-High	Medium	High	77	78	79	80	51,930	52,423	52,886	53,257
Medium-High	High	Medium		81		82		53,043		56,461
High	Low	Medium		83		84		58,639		59,049
High	Medium	Low	86	87	88	89	59,980	60,428	61,809	62,024
High	Medium	Medium	90	91	92	93	58,788	59,243	60,508	60,733
High	Medium	Accelerated	94	95	96	97	58,519	58,982	60,250	60,469
High	Medium	High	98	99	100	101	58,255	58,722	59,984	60,201
High	High	Medium		102		103		59,903		65,092

Run Against	NOx & TSP Level	Case Numbers (CO2 Level) Low	Medium	High	NPV Utility Cost in $M (CO2 Level) Low	Medium	High
M.MG.MD.AC.AR	Low	301	302	303	46,980	49,155	54,757
	High	304	305	306	47,901	50,884	56,529
M.MG.HD.AC.AR	Low	307	308	309	46,668	48,805	54,156
	High	310	311	312	47,526	50,446	56,310
M.HG.MD.AC.AR	Low	313	314	315	47,064	48,710	54,401
MH.MG.MD.AC.AR	Low	316	317	318	53,168	55,297	61,341
	High	319	320	321	54,454	57,305	62,697

Average Annual CO2 and NOx Emissions

Table 7-7

Case Numbers				Average CO2 Emission (1000 tons)				Average NOx Emission (1000 tons)			
Coal & Renewable Strategy				Coal & Renewable Strategy				Coal & Renewable Strategy			
AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR
2	3	4	5	54,226	53,488	54,226	53,488	122	121	122	121
7	8	9	10	57,215	56,205	56,136	55,863	129	127	127	126
12	13	14	15	62,332	61,386	59,351	58,902	138	136	129	129
16	17	18	19	61,259	60,366	58,736	58,274	136	135	128	128
20	21	22	23	60,997	60,120	58,574	58,103	136	134	128	128
24	25	26	27	60,614	59,788	58,380	57,903	135	134	128	128
29	30	31	32	63,320	62,494	59,304	58,807	141	140	129	129
33	34	35	36	61,972	61,102	58,589	58,130	139	137	129	128
37	38	39	40	61,752	60,915	58,422	57,963	138	137	129	128
41	42	43	44	61,372	60,533	58,231	57,766	138	136	129	128
46	47	48	49	63,527	62,640	57,339	57,783	142	140	128	128
50	51	52	53	62,174	61,344	57,136	57,482	140	137	128	128
54	55	56	57	62,012	61,089	56,999	57,226	139	137	128	128
58	59	60	61	61,653	60,721	56,940	57,144	138	137	128	128
	62		63		64,142		60,987		139		130
65	66	67	68	67,982	67,214	61,888	61,736	149	148	131	131
69	70	71	72	66,937	66,106	61,205	61,076	147	146	131	131
73	74	75	76	66,745	65,861	61,334	60,886	147	145	131	131
77	78	79	80	66,498	65,621	61,186	60,758	147	145	131	130
	81		82		66,443		59,828		147		130
	83		84		69,465		64,276		149		133
86	87	88	89	73,566	72,542	65,268	65,111	159	157	134	134
90	91	92	93	72,120	71,171	64,502	64,350	156	154	134	134
94	95	96	97	71,856	70,918	64,285	64,122	156	154	133	133
98	99	100	101	71,623	70,701	64,157	63,994	155	154	133	133
	102		103		71,878		62,368		156		132

	NOx &	Average CO2 Emission (1000 tons)			Average NOx Emission (1000 tons)		
	TSP	CO2 Level			CO2 Level		
Run Against	Level	Low	Medium	High	Low	Medium	High
	Low	57,164	48,839	39,193	119	103	82
M.MG.MD.AC.AR	High	54,754	45,453	36,847	109	93	76
	Low	56,659	48,495	39,370	119	104	84
M.MG.HD.AC.AR	High	54,356	45,312	36,424	109	93	75
M.HG.MD.AC.AR	Low	58,071	52,348	42,884	120	108	93
	Low	60,910	52,964	41,914	120	103	84
MH.MG.MD.AC.AR	High	57,222	48,955	40,218	107	90	79

Case Numbers and Total Resource Cost

Table 7-8

Future		DSR	Case Numbers				NPV Total Resource Cost in $M			
			Coal & Renewable Strategy				Coal & Renewable Strategy			
Load	Gas Price	Strategy	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR
Low	Medium	Medium	2	3	4	5	39,310	40,061	39,310	40,061
Medium-Low	Medium	Medium	7	8	9	10	42,760	43,280	42,923	43,325
Medium	Low	Low	12	13	14	15	48,071	48,568	48,092	48,596
Medium	Low	Medium	16	17	18	19	47,945	48,444	47,971	48,467
Medium	Low	Accelerated	20	21	22	23	47,791	48,295	47,818	48,315
Medium	Low	High	24	25	26	27	47,818	48,320	47,834	48,333
Medium	Medium	Low	29	30	31	32	48,099	48,586	48,647	49,128
Medium	Medium	Medium	33	34	35	36	47,903	48,368	48,460	48,903
Medium	Medium	Accelerated	37	38	39	40	47,784	48,266	48,291	48,727
Medium	Medium	High	41	42	43	44	47,789	48,271	48,285	48,691
Medium	High	Low	46	47	48	49	48,057	48,557	50,957	50,829
Medium	High	Medium	50	51	52	53	47,969	48,173	50,107	50,039
Medium	High	Accelerated	54	55	56	57	47,762	48,144	49,926	49,992
Medium	High	High	58	59	60	61	47,667	48,103	49,737	49,827
Medium-High	Low	Medium		62		63		54,176		54,448
Medium-High	Medium	Low	65	66	67	68	54,241	54,730	55,552	55,774
Medium-High	Medium	Medium	69	70	71	72	54,056	54,551	55,215	55,430
Medium-High	Medium	Accelerated	73	74	75	76	53,711	54,202	54,699	55,078
Medium-High	Medium	High	77	78	79	80	53,859	54,352	54,815	55,186
Medium-High	High	Medium		81		82		54,809		58,227
High	Low	Medium		83		84		60,535		60,945
High	Medium	Low	86	87	88	89	61,013	61,461	62,841	63,056
High	Medium	Medium	90	91	92	93	60,684	61,139	62,404	62,629
High	Medium	Accelerated	94	95	96	97	60,269	60,731	62,000	62,218
High	Medium	High	98	99	100	101	60,687	61,154	62,416	62,633
High	High	Medium		102		103		61,799		66,988

Run Against	NOx & TSP Level	Case Numbers			NPV Total Resource Cost in $M		
		CO2 Level			CO2 Level		
		Low	Medium	High	Low	Medium	High
M.MG.MD.AC.AR	Low	301	302	303	48,545	50,721	56,322
M.MG.MD.AC.AR	High	304	305	306	49,467	52,449	58,095
M.MG.HD.AC.AR	Low	307	308	309	48,390	50,527	55,878
M.MG.HD.AC.AR	High	310	311	312	49,248	52,168	58,032
M.HG.MD.AC.AR	Low	313	314	315	48,630	50,276	55,967
MH.MG.MD.AC.AR	Low	316	317	318	54,934	57,063	63,107
MH.MG.MD.AC.AR	High	319	320	321	56,220	59,071	64,463

T7-08.case #/trc

existing system by about 600 MW, in 2013 by 800 to 900 MW. Non-firm purchases increased by about 250 MW, which did not vary by year or DSR strategy. The requirement to limit CO2 emissions to 1990 levels would likely result in non-coal utilities increasing their generation to sell to utilities that have a high percentage of their generation coming from coal.

High DSR worth 1/2 billion

Limiting CO2 emissions to 1990 levels increased the NPV of utility costs by $4.5 billion under medium DSR and by $4 billion under high DSR. The limits increased the NPV of total resource costs by $4.5 billion under medium DSR and $3.8 billion under high DSR. The levelized effect on real customer prices would be 4.5 mills/kWh (about 10 percent increase) under medium DSR and 3.3 mills/kWh (about 7 percent increase) under high DSR. $.0033/kWh

The company prepared three tables (7-6, 7-7, and 7-8) which summarize emissions, total utility cost, TRC, and case numbers for the base study plan and the externality adder cases. They show the emissions versus cost trade-offs in numerical form. The next section shows the equivalent information in graphical form.

TRADE-OFF GRAPHS

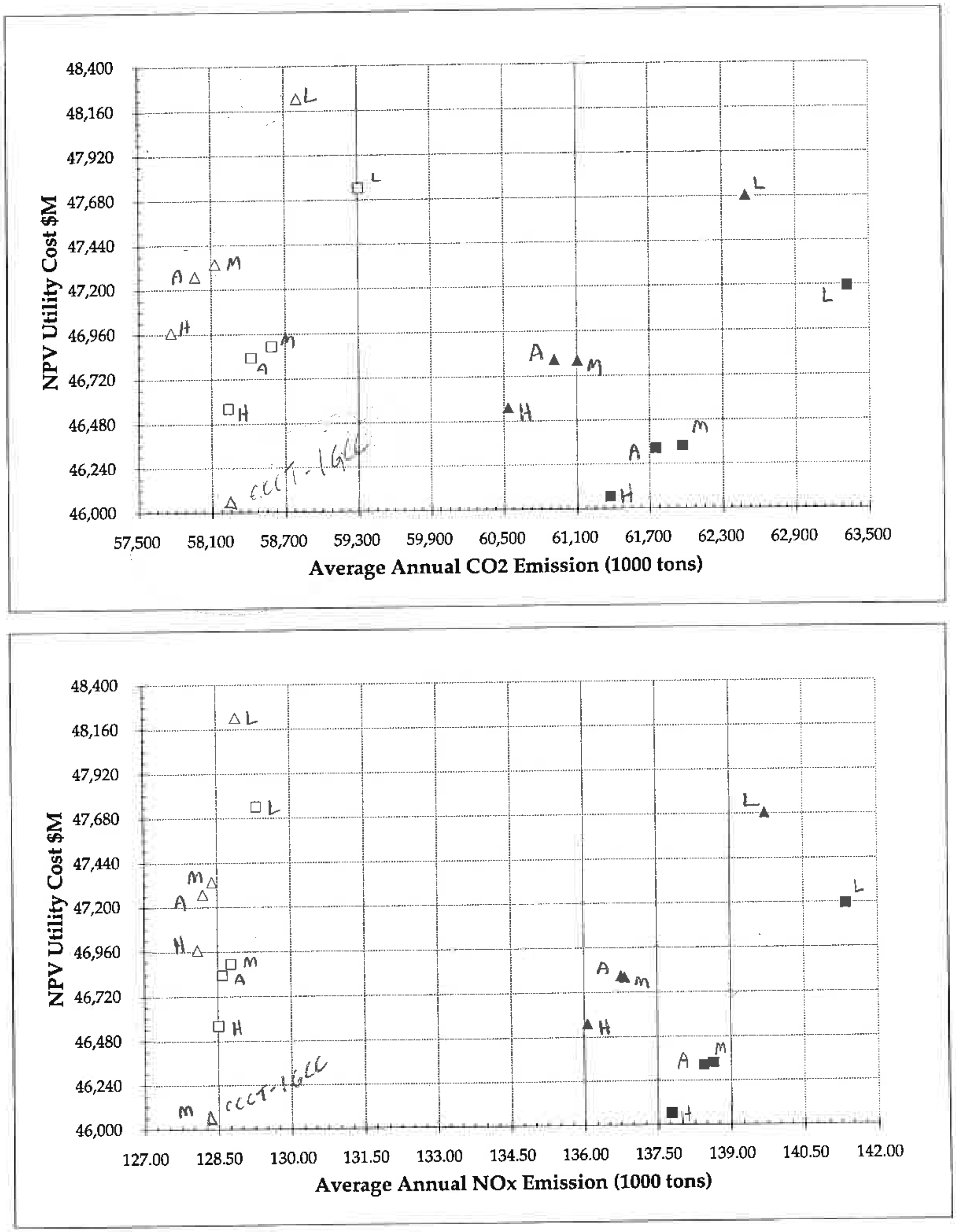
The following graphs show the trade-off between emissions and financial results assuming medium load growth and medium gas prices. The graphs compare NOx and CO2 emissions with three financial results (utility cost, customer price, and total resource cost). The same patterns occurred in the cases with lower gas prices or with higher load growth. The graphs illustrate:

Graph 7-9: Utility Cost, CO2 and NOx Emissions
Graph 7-10: Price, CO2 and NOx Emissions
Graph 7-11: Total Resource Cost, CO2 and NOx Emissions

The symbols on the graphs indicate coal and renewable strategies. Four points on each graph have the same symbol. There are four black squares, four white squares, four black triangles, and four white triangles. For example, the four white squares represent results for the NC.AR combination (no-coal and any-renewables). Each set of four points using the same symbol represents results from the four DSR strategies. For each set of four points using the same symbol, the lowest point on the utility and total resource cost graphs represents the high DSR case, the next highest point represents the accelerated DSR case, then medium DSR, and the highest represents the low DSR case. This is because higher levels of DSR reduce total utility costs and total resource costs. On the price graphs the opposite pattern occurs: the lowest of the four white squares represents low DSR, the next highest medium DSR, then accelerated DSR, and the highest represents the high DSR case. This is because higher levels of DSR increase prices to customers. The same patterns repeat for each set of four symbols. Not so / 1st varies

Utility Cost, CO2 and NOx Emissions
(Medium Load Growth, Medium Gas Price)

Graph 7-9

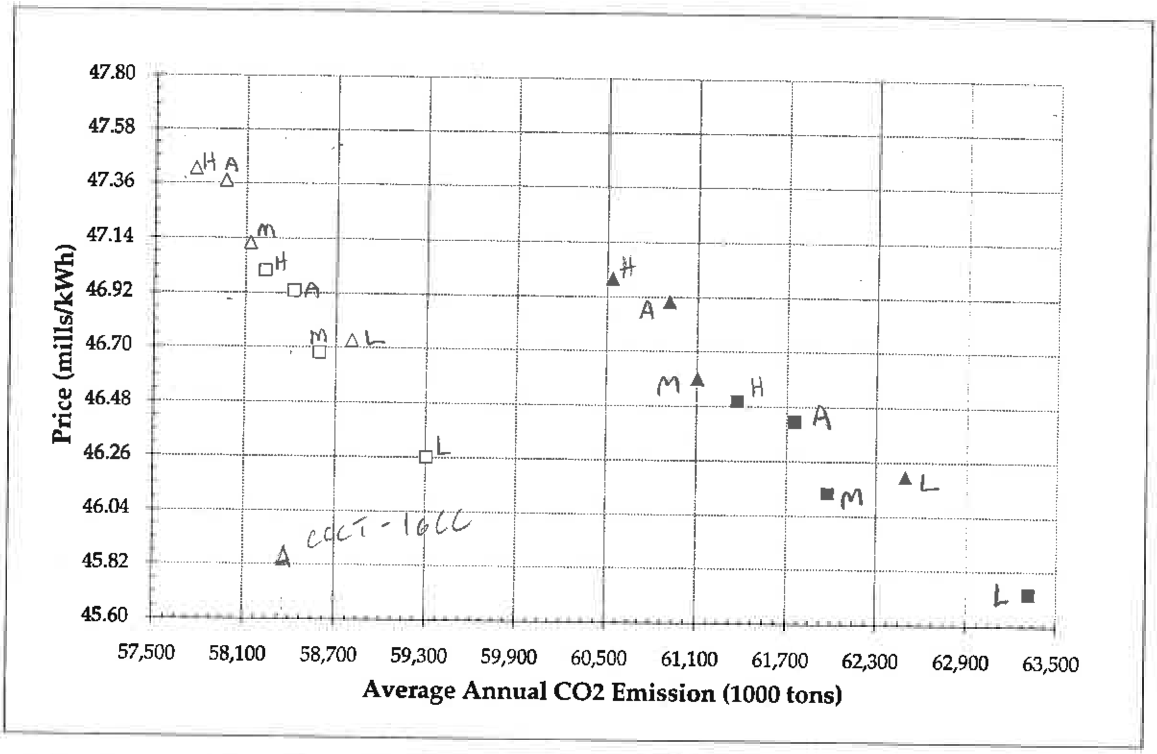


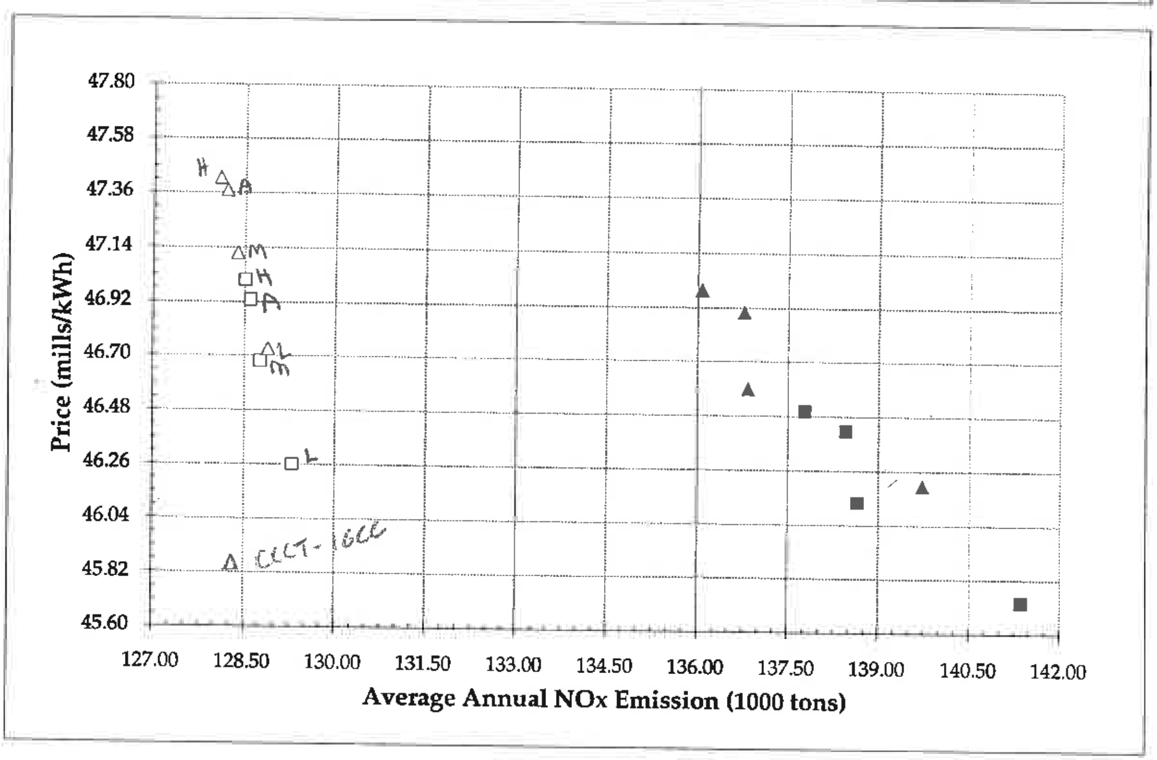
□ No-Coal & Any-Renewables
■ Any-Coal & Any-Renewables
△ No-Coal & Strategic-Renewables
▲ Any-Coal & Strategic-Renewables

G7-09.utility/emiss

Price, CO2 and NOx Emissions
(Medium Load Growth, Medium Gas Price)

Graph 7-10



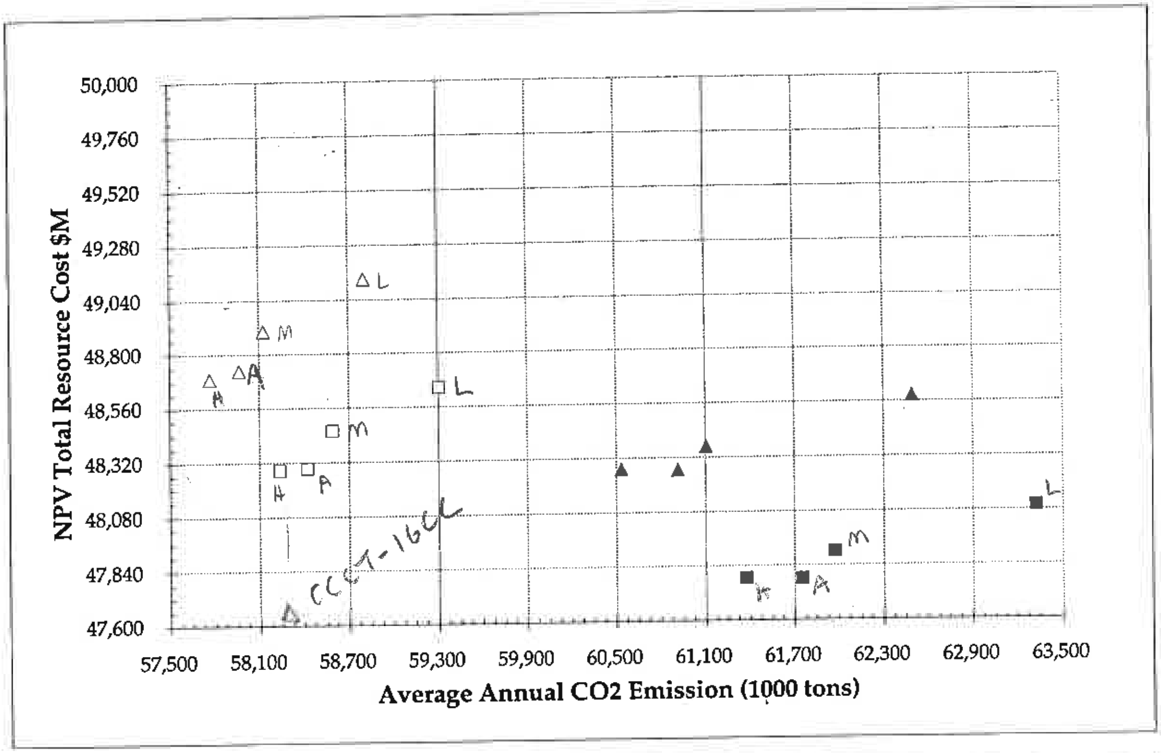


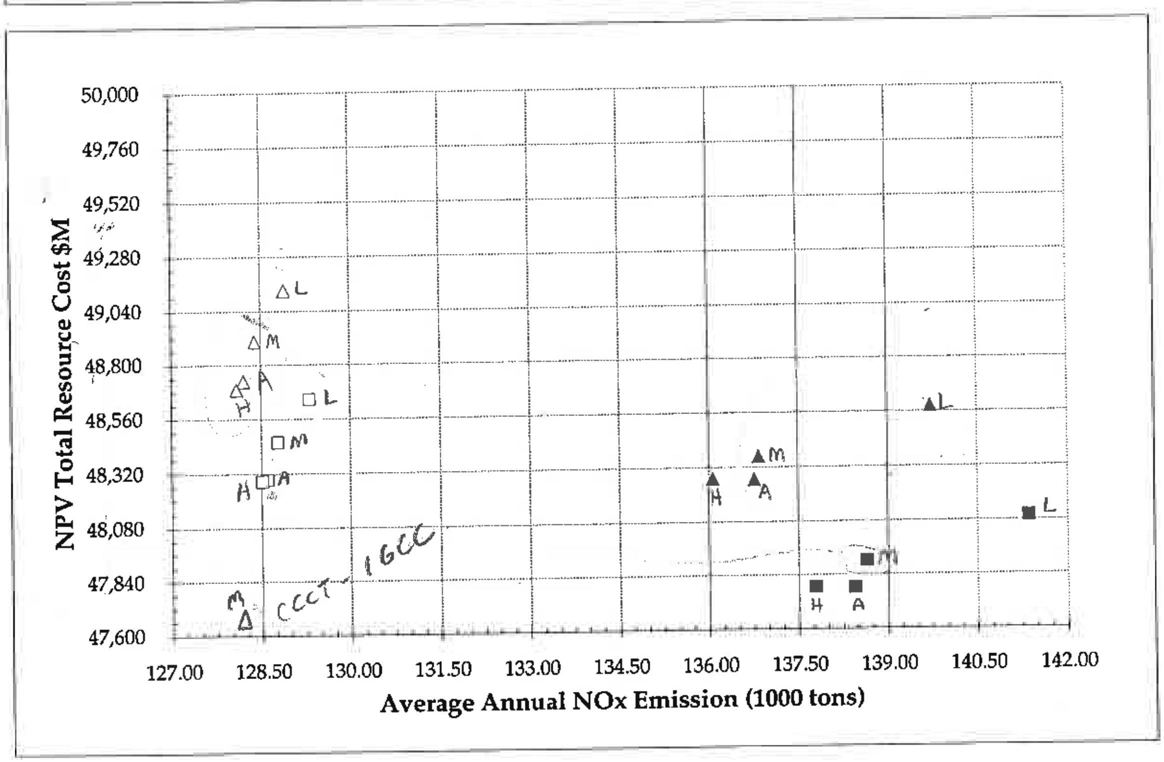
□ No-Coal & Any-Renewables
■ Any-Coal & Any-Renewables
△ No-Coal & Strategic-Renewables
▲ Any-Coal & Strategic-Renewables

G7-10.price/emiss

Total Resource Cost, CO2 and NOx Emissions
(Medium Load Growth, Medium Gas Price)

Graph 7-11





□ No-Coal & Any-Renewables
■ Any-Coal & Any-Renewables
△ No-Coal & Strategic-Renewables
▲ Any-Coal & Strategic-Renewables

All of the graphs show that no-coal is a lower-emission strategy than any-coal, and that any-renewables is a lower-cost strategy than strategic-renewables. The goal, however, is to find the combination of strategies that yields the solution of both lowest costs and lowest emissions.

Graph 7-9 shows that the most favorable combination, for both emissions and utility cost, is the NC.AR strategies (no-coal, any-renewables). Although the NC.SR combination (no-coal, strategic-renewables) yields lower emissions, it does so at a higher cost. The AC.AR and AC.SR combinations have lower costs, but significantly higher emissions. Graph 7-11 shows total resource cost with CO2 and NOx emissions. The points follow a similar pattern as they do for the utility cost graph (7-9). Graph 7-10, comparing price and CO2 and NOx emissions, also shows that the most favorable combination is NC.AR. The lowest points on Graph 7-10, from lowest price upward, are as follows:

any-coal, any-renewables, low DSR (black square);
any-coal, any-renewables, medium DSR (black square);
any-coal, strategic-renewables, medium DSR (black triangle); and
no-coal, any-renewables, low DSR (white square).

Moving from the lowest black square to the lowest white square (from any-coal to no-coal) reduced CO2 emissions by 5 percent, and increased prices by 1 percent. Moving from the lowest black square to the lowest black triangle (from any-renewables to strategic-renewables) decreased emissions by 1 percent, and increased prices by 1 percent. Moving from any-coal to no-coal resulted in the same customer price impact as moving from any-renewables to strategic-renewables, but the coal strategy change resulted in a greater emissions reduction. In spite of this, the company believes it is more important at this time to pursue the strategic-renewables strategy to gain needed experience. Coal gasification provides a potential method to achieve some of the same benefits of the no-coal strategy with little customer price impact. If the only coal technology the any-coal strategy could use were coal gasification, the emissions would be lower with a slightly higher cost.

Another way to evaluate the emissions versus financial trade-off is to determine how much emissions decrease as real levelized customer prices increase. In all cases, the percentage reduction in emissions was greater than the percentage increase in price, although the price impact was sometimes quite large. Table 7-12 shows the percentage change in emissions with the percentage change in real levelized customer prices for each of the externality adder cases, compared to the appropriate non-adder case. Compared to Case #33 (medium load growth, medium gas prices, and medium DSR), a 7.8 percent decrease in CO2 emissions could occur with a 1.4 percent increase in real levelized prices to customers. A 40.5 percent decrease in CO2 emissions would raise prices by 22.0 percent. For each of the cases, the percentage reduction in CO2 and NOx resulted in increases in real levelized customer prices. Similar relationships held under each of the other cases.

Changes in Emissions and Customer Prices

Table 7-12

	CO2 Decrease		NOx Decrease		Price Increase
	from Base Case	relative to Price Change	from Base Case	relative to Price Change	from Base Case
	(%)	(ratio)	(%)	(ratio)	(%)
Base case:	**Case #33 - M.MG.MD.AC.AR**				
Case #301	7.8%	5.6	13.8%	10.0	1.4%
Case #304	11.6%	3.5	21.2%	6.3	3.4%
Case #302	21.2%	3.5	25.4%	4.2	6.1%
Case #305	26.7%	2.7	33.3%	3.4	9.8%
Case #303	36.8%	2.0	40.6%	2.2	18.2%
Case #306	40.5%	1.8	45.3%	2.1	22.0%
Base case:	**Case #41 - M.MG.HD.AC.AR**				
Case #307	7.7%	5.9	13.5%	10.3	1.3%
Case #310	11.4%	3.6	20.6%	6.5	3.2%
Case #308	21.0%	3.5	24.8%	4.2	6.0%
Case #311	26.2%	2.7	32.4%	3.4	9.5%
Case #309	35.8%	2.0	39.3%	2.2	17.6%
Case #312	40.7%	1.8	45.4%	2.0	22.2%
Base case:	**Case #50 - M.HG.MD.AC.AR**				
Case #313	6.6%	4.6	13.8%	9.6	1.4%
Case #314	15.8%	3.2	22.6%	4.5	5.0%
Case #315	31.0%	1.8	33.2%	1.9	17.3%
Base case:	**Case #69 - MH.MG.MD.AC.AR**				
Case #316	9.0%	5.4	18.7%	11.2	1.7%
Case #319	14.5%	3.5	27.5%	6.6	4.1%
Case #317	20.9%	3.6	30.1%	5.2	5.7%
Case #320	26.9%	2.8	38.9%	4.1	9.6%
Case #318	37.4%	2.2	42.8%	2.5	17.3%
Case #321	39.9%	2.0	46.7%	2.3	19.9%

Table 7-13

Results of Environmental Dispatch using Externality Adders (1994)

to minimize emissions

Run against	#33 M.MG.MD.AC.AR							#41 M.MG.HD.AC.AR						
NOx & TSP		Low			High				Low			High		
CO2		Low	Med	High	Low	Med	High		Low	Med	High	Low	Med	High
Case #	33	301	302	303	304	305	306	41	307	308	309	310	311	312
Existing Generation (MWa)														
Renewable	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Hydro	809	809	809	809	809	809	809	809	809	809	809	809	809	809
Cogeneration	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle CT	4	5	9	9	9	9	9	4	5	9	9	9	9	9
Oil/Gas Fired	45	32	91	91	57	91	91	45	32	91	91	57	91	91
Coal	5,577	4,948	4,540	4,141	4,708	4,262	4,134	5,575	4,938	4,524	4,126	4,698	4,247	4,118
Simple Cycle CT	0	0	2	231	0	235	238	0	0	2	230	0	234	238
Pumped Storage	312	312	310	309	306	308	312	312	312	311	309	307	309	311
Total Generation	6,776	6,134	5,790	5,620	5,919	5,743	5,622	6,774	6,124	5,775	5,604	5,908	5,728	5,606
Non-Firm Transactions (MWa)														
Non-Firm Purchases	128	364	618	663	485	663	663	118	364	618	663	481	663	663
Non-Firm Sales	420	87	0	0	0	0	0	424	94	0	0	0	0	0
Emissions (1000 tons)														
CO2	54,170	47,978	44,216	41,138	45,716	42,367	41,106	54,160	47,880	44,045	40,985	45,596	42,202	40,949
TSP	138.6	119.4	103.4	82.4	109.2	92.5	75.8	137.8	119.1	103.6	83.6	109.4	93.1	75.2
NOx	11.0	10.1	8.8	6.8	9.2	7.8	6.1	11.0	10.0	8.8	7.0	9.2	7.9	6.1
Utility Cost														
Operating Revenues ($M)	2,135	2,177	2,227	2,328	2,209	2,304	2,327	2,132	2,174	2,226	2,326	2,206	2,302	2,326
Cost in mills/kWh	47.8	48.8	49.9	52.2	49.5	51.6	52.2	47.9	48.9	50.0	52.3	49.6	51.7	52.3
Total Resource Cost														
Total Resource Cost ($M)	2,139	2,181	2,232	2,332	2,213	2,308	2,332	2,137	2,179	2,231	2,331	2,212	2,307	2,331
Cost in mills/kWh	47.8	48.7	49.8	52.1	49.4	51.5	52.1	47.7	48.7	49.8	52.1	49.4	51.5	52.1

T7-13,14.adders dispatch

Table 7-14

Results of Environmental Dispatch (cont.) using Externality Adders (1994)

Run against		#50 M.HG.MD.AC.AR				#69 MH.MG.MD.AC.AR					
NOx & TSP		Low				Low			High		
CO2		Low	Med	High		Low	Med	High	Low	Med	High
Case #	50	313	314	315	69	316	317	318	319	320	321
Existing Generation (MWa)											
Renewable	23	23	23	23	23	23	23	23	23	23	23
Hydro	809	809	809	809	809	809	809	809	809	809	809
Cogeneration	0	0	0	0	0	0	0	0	0	0	0
Combined Cycle CT	4	5	9	9	5	5	9	9	9	9	9
Oil/Gas Fired	45	32	91	91	52	32	91	91	61	91	91
Coal	5,577	4,948	4,540	4,141	5,602	5,008	4,659	4,253	4,788	4,377	4,253
Simple Cycle CT	0	0	2	231	0	0	1	238	0	237	238
Pumped Storage	312	312	311	312	312	312	310	312	298	306	311
Total Generation	6,776	6,134	5,791	5,622	6,809	6,194	5,908	5,742	5,994	5,859	5,741
Non-Firm Transactions (MWa)											
Non-Firm Purchases	128	364	618	663	170	364	619	663	521	663	663
Non-Firm Sales	420	87	0	0	376	29	0	0	0	0	0
Emissions (1000 tons)											
CO_2	62,331	47,978	44,216	41,138	54,453	48,557	45,372	42,269	46,515	43,522	42,278
TSP	139.7	120.4	108.0	93.3	147.5	119.9	103.1	84.4	106.9	90.1	78.5
NOx	11.1	10.1	9.1	7.9	11.3	10.0	8.7	6.8	8.9	7.4	6.2
Utility Cost											
Operating Revenues ($M)	2,135	2,177	2,227	2,328	2,175	2,216	2,258	2,360	2,246	2,335	2,358
Cost in mills/kWh	47.8	48.8	49.9	52.2	47.7	48.7	49.6	51.8	49.3	51.3	51.8
Total Resource Cost											
Total Resource Cost ($M)	2,139	2,181	2,232	2,332	2,179	2,221	2,263	2,364	2,250	2,339	2,362
Cost in mills/kWh	47.8	48.7	49.8	52.1	47.7	48.6	49.5	51.7	49.2	51.2	51.7

ENVIRONMENTAL DISPATCH

Tables 7-13 and 7-14 show the operating results for 1994 from dispatching PacifiCorp's system using environmental cost adders. The company increased the operating cost of all resources by the amount of the adders in each of the 21 environmental cost adder cases.

The primary effects for PacifiCorp were an increase in non-firm purchases, a decrease in non-firm sales, a decrease in emissions, and an increase in total utility costs. Non-firm purchases in 1994 in the non-adder case were only 128 MWa. That increased as the adder amount increased, between a range of 364 and 663 MWa. Using adders for environmental dispatch would only reduce emissions for the region if all utilities used the same adder values, and all utilities used a gas-fired plant as the marginal unit that supported all non-firm sales.

Non-firm sales by PacifiCorp in 1994 were 420 MWa in the non-adder case, but zero in all the adder cases except for the lowest adder amounts, when the model made 87 MWa of non-firm sales. This change greatly added to the total utility costs, because normally the company can profitably sell excess generation on the non-firm market, using that revenue to reduce prices to all retail customers.

Under these assumptions, PacifiCorp's emissions decreased in each adder case. While PacifiCorp's emissions are predicted to decrease in these cases, it is not possible to conclude from this analysis whether regional emissions as a whole would increase or decrease from the use of adders, or that overall environmental quality would improve. Aside from the changes in non-firm transactions that are embedded in the results, there are inter-regional changes in generation that could have positive or negative environmental consequences, but that are not reflected in the total company CO2 and NOx emission decreases described above. For example, higher levels of adders caused the SCE peaking generation to be used more heavily for energy, displacing some of the company's coal generation. The fact that the increased generation is most likely from CTs located in the Southern California air basin raises the concern that net environmental impairment could increase in a future with adders.

Total utility costs for 1994 increased from \$2.14 billion to a high of \$2.33 billion in the highest adder case. The 1994 price to customers averaged increases from the non-adder case ranging from 0.8 mills/kWh to 4.2 mills/kWh.

ENVIRONMENTAL INSURANCE

environmental dispatch?

For purposes of risk analysis, the company calculated the amount of avoidable environmental tax (looking on the adder as a potential environmental tax). It is avoidable by reconfiguring the generating system (using existing coal plants less and selecting new resources with lower emissions). The avoidable environmental tax is the difference between the level of environmental tax from system expansion which does not consider the environmental tax (a non-adder model run), and the level of environmental tax from a re-configured system expansion which does consider the environmental tax (an adder model run). The company calculated the total environmental tax for each model run by taking a net present value of each year's tax.

The company also calculated an insurance cost associated with avoiding environmental taxes. The insurance cost is the difference between the total utility cost from system expansion which does not consider the environmental tax (a non-adder model run), and the total utility cost from a re-configured system expansion which does consider the environmental tax (an adder model run). In the adder model runs, the model built and operated a more expensive system, but that system avoided more environmental taxes. Thus the re-configuring of the system can be considered insurance, since the higher cost from a different system expansion may avoid or mitigate a potential future expense (the environmental tax).

resource selection based on cost of adder

Tables 7-15 and 7-16 show that it would cost the company about \$40 to insure against \$100 in potential environmental taxes. The \$40/\$100 ratio is fairly constant across all levels of adders and across different load growth levels, gas prices, and DSR levels, with slightly higher insurance costs under higher gas prices and higher load growth.

by reconfiguring - means resource selection but econ. dispatch

Another strategy that the company could select would be a flexible response to the possible environmental tax. The company could select the same "environmental" resources as in adder case #301, but dispatch the resources without the environmental tax until a tax was in place. The company prepared case #324 to evaluate the cost of implementing this flexible response. Case #324 is case #301 (low NOx/TSP and low CO2 adders with medium DSR) with non-environmental dispatch. Case #325 is case #307 (low NOx/TSP and low CO2 adders with high DSR) with non-environmental dispatch. Cases #324 and #325 provide the impact of minimizing the tax by only reconfiguring the system (while operating the system as if the adders or environmental tax were not in effect). Table 7-17 shows the results of these two additional cases. It compares the non-environmental runs (cases #33 and 41) with the environmental runs (cases #301 and 307) and the flexible response runs (cases #324 and #325). Cases #33, 301, and 324 used medium DSR; cases #41, 302, and 325 used high DSR.

In millions of dollars, case #33 had a 50-year NPV utility cost of \$46,337; case #324 had a cost of \$46,763, for an additional cost over case #33 of \$426. Case #301 had a cost of \$46,980, for an additional cost over case #33 of \$643. Thus selecting new resources using adders while dispatching the system using actual costs increases total costs by \$426, but selecting new resources with adders and dispatching with adders costs \$643. The flexible response of selecting new resources using adders, but not immediately dispatching them using adders, would allow the company to spend only \$426 as insurance. Then, if an environmental tax were imposed, the company could switch from a non-environmental dispatch to an environmental dispatch. This strategy lowered the insurance cost from \$643 million (case #301) to \$426 million (case #324) for a savings of \$217 million. The results for case #325 using high DSR provided similar results.

Table 7-15

Environmental Cost Adder Cases

Environmental Tax Insurance

environmental reconfiguration based on cost of resources w/tax

Run against NOx & TSP		#33 M.MG.MD.AC.AR							#41 M.MG.HD.AC.AR					
NOx & TSP		Low			High				Low			High		
CO2		Low	Med	High	Low	Med	High		Low	Med	High	Low	Med	High
Case #	33	301	302	303	304	305	306	41	307	308	309	310	311	312
Energy Sales and Generation (MWa)														
1 Load and Pump Storage	9,294	9,261	9,165	9,144	9,145	9,144	9,144	9,276	9,259	9,165	9,144	9,144	9,144	9,144
2 Non-Firm Sales	456	416	382	156	523	428	45	418	342	379	156	449	407	65
3 Existing Resources	7,289	7,269	6,890	5,675	6,582	6,106	5,049	7,269	7,296	6,916	5,816	6,631	6,221	5,062
4 Non-Firm Purchases	152	171	238	342	169	341	334	154	173	248	344	190	345	334
5 New Resources	2,324	2,251	2,433	3,297	2,931	3,138	3,821	2,284	2,145	2,393	3,153	2,786	2,998	3,826
Average Annual Emissions in 1994-2013 (1000 tons)														
6 CO2	61,972	57,164	48,839	39,193	54,754	45,453	36,847	61,372	56,659	48,495	39,370	54,356	45,312	36,424
7 NOx	139	119	103	82	109	93	76	138	119	104	84	109	93	75
8 TSP	11	10	9	7	9	8	6	11	10	9	7	9	8	6
Cost of Environmental Adder "Tax" (million $)														
50-year NPV														
9 - Comparison Case		17,367	34,953	52,540	25,624	43,211	60,797		17,222	34,642	52,062	25,430	42,850	60,270
10 - Environmental Adder Case		15,726	27,951	33,537	21,378	31,568	35,593		15,606	27,786	33,766	21,304	31,565	35,280
11 Savings of 50-year NPV from the Comparison Case		1,641	7,002	19,002	4,246	11,643	25,204		1,616	6,856	18,296	4,126	11,285	24,990
Financial Results with End Effects to 2043 (million $)														
50-year Utility Cost NPV														
12 - Comparison Case	46,337	46,337	46,337	46,337	46,337	46,337	46,337	46,067	46,067	46,067	46,067	46,067	46,067	46,067
13 - Environmental Adder Case		46,980	49,155	54,757	47,901	50,884	56,529		46,668	48,805	54,156	47,526	50,446	56,310
14 Incremental Utility Cost due to Altered New Resource Choices		643	2,818	8,420	1,564	4,547	10,192		601	2,739	8,089	1,459	4,380	10,243
50-year Total Resources Cost NPV														
15 - Comparison Case	47,903	47,903	47,903	47,903	47,903	47,903	47,903	47,789	47,789	47,789	47,789	47,789	47,789	47,789
16 - Environmental Adder Case		48,545	50,721	56,322	49,467	52,449	58,095		48,390	50,527	55,878	49,248	52,168	58,032
17 Incremental Total Resource Cost due to Altered New Resource Choices		643	2,818	8,420	1,564	4,547	10,192		601	2,739	8,089	1,459	4,380	10,243
Insurance Cost per $100 of Potential Tax ($)														
18 Utility cost (Line 14 / Line 11)		39	40	44	37	39	40		37	40	44	35	39	41
19 Total Resource Cost (Line 17 / Line 11)		39	40	44	37	39	40		37	40	44	35	39	41

T7-15,16.Insurance summary

For every $1, $.39 saved

Table 7-16

Environmental Cost Adder Cases (cont.)
Environmental Tax Insurance

	Run against		#50 M.HG.MD.AC.AR				#69 MH.MG.MD.AC.AR					
	NOx & TSP		Low				Low			High		
	CO2		Low	Med	High		Low	Med	High	Low	Med	High
	Case #	50	313	314	315	69	316	317	318	319	320	321
	Energy Sales and Generation (MWa)											
1	Load and Pump Storage	9,284	9,280	9,221	9,155	10,932	10,909	10,802	10,796	10,795	10,769	10,769
2	Non-Firm Sales	398	411	465	415	469	457	468	146	495	477	58
3	Existing Resources	7,205	7,216	7,039	6,199	6,991	7,029	6,518	5,708	6,405	5,562	4,892
4	Non-Firm Purchases	151	147	145	201	151	138	237	350	153	315	312
5	New Resources	2,339	2,341	2,517	3,184	4,273	4,214	4,529	4,898	4,747	5,384	5,637
	Average Annual Emissions in 1994-2013 (1000 tons)											
6	CO_2	62,174	58,071	52,348	42,884	66,937	60,910	52,964	41,914	57,222	48,955	40,218
7	NOx	140	120	108	93	147	120	103	84	107	90	79
8	TSP	11	10	9	8	11	10	9	7	9	7	6
	Cost of Environmental Adder "Tax" (million $)											
	50-year NPV											
9	- Comparison Case		17,447	35,093	52,740		17,367	34,953	52,540	25,624	43,211	60,797
10	- Environmental Adder Case		15,894	29,722	36,341		15,606	27,786	33,766	21,304	31,565	35,280
11	Savings of 50-year NPV from the Comparison Case		**1,553**	**5,371**	**16,399**		**1,761**	**7,167**	**18,773**	**4,320**	**11,645**	**25,517**
	Financial Results with End Effects to 2043 (million $)											
	50-year Utility Cost NPV											
12	- Comparison Case	46,403	46,403	46,403	46,403	52,290	52,290	52,290	52,290	52,290	52,290	52,290
13	- Environmental Adder Case		47,064	48,710	54,401		53,168	55,297	61,341	54,454	57,305	62,697
14	Incremental Utility Cost due to Altered New Resource Choices		**661**	**2,307**	**7,998**		**878**	**3,007**	**9,051**	**2,164**	**5,015**	**10,407**
	50-year Total Resources Cost NPV											
15	- Comparison Case	47,969	47,969	47,969	47,969	54,056	54,056	54,056	54,056	54,056	54,056	54,056
16	- Environmental Adder Case		48,630	50,276	55,967		54,934	57,063	63,107	56,220	59,071	64,463
17	Incremental Total Resource Cost due to Altered New Resource Choices		**661**	**2,307**	**7,998**		**878**	**3,007**	**9,051**	**2,164**	**5,015**	**10,407**
	Insurance Cost per $100 of Potential Tax ($)											
18	Utility cost (Line 14 / Line 11)		43	43	49		50	42	48	50	43	41
19	Total Resource Cost (Line 17 / Line 11)		43	43	49		50	42	48	50	43	41

Environmental Cost Adder Cases

Environmental Tax Insurance in Low NOx & TSP / Low CO2 Case

Table 7-17

Economic flexing to respond.

		No Adder Case	Adder Case #301		No Adder Case	Adder Case #307	
			Regular Dispatch	Envir. Dispatch		Regular Dispatch	Envir. Dispatch
	Case #	33	324	301	41	325	307
	Energy Sales and Generation (MWa)						
1	Load and Pump Storage	9,294	9,291	9,261	9,276	9,287	9,259
2	Non-Firm Sales	456	493	416	418	423	342
3	Existing Resources	7,289	7,369	7,269	7,269	7,390	7,296
4	Non-Firm Purchases	152	155	171	154	167	173
5	New Resources	2,324	2,275	2,251	2,284	2,167	2,145
	Average Annual Emissions in 1994-2013 (1000 tons)						
6	CO_2	61,972	60,696	57,164	61,372	60,178	56,659
7	NOx	139	128	119	138	128	119
8	TSP	11	11	10	11	11	10
	Cost of Environmental Adder "Tax" (million $)						
	50-year NPV						
9	- Comparison Case	17,367			17,222		
10	- Environmental Adder Case		16,626	15,726		16,498	15,606
11	Savings of 50-year NPV from the Comparison Case		**741**	**1,641**		**724**	**1,616**
	Financial Results with End Effects to 2043 (million $)						
	50-year Utility Cost NPV						
12	- Comparison Case	46,337			46,067		
13	- Environmental Adder Case		46,763	46,980		46,288	46,668
14	Incremental Utility Cost due to Altered New Resource Choices		**426**	**643**		**221**	**601**
	50-year Total Resources Cost NPV						
15	- Comparison Case	47,903			47,789		
16	- Environmental Adder Case		48,309	48,545		48,009	48,390
17	Incremental Total Resource Cost due to Altered New Resource Choices		**407**	**643**		**221**	**601**
	Insurance Cost per $100 of Potential Tax ($)						
18	Utility cost (Line 14 / Line 11)		57	39		30	37
19	Total Resource Cost (Line 17 / Line 11)		55	39		30	37

T7-17.insurance dispatch

COMPARISON OF ADDERS AND MULTI-ATTRIBUTE TRADE-OFF

Adders have become the most common way to analyze the impact of external costs on utility resource planning and find resource plans which lower emissions. PacifiCorp wanted to try an approach which would provide information about alternative ways to lower both emissions and costs. The multi-attribute trade-off approach (MATO) offered that possibility. The MATO approach can identify resource strategies which lead to a solution of lower emissions with lower costs. The adders approach identifies a resource plan which would minimize emissions by minimizing system costs assuming a specified level of adders, but it does not address whether an alternative resource plan would lead to similar or lower emissions with lower total costs. However, by using six alternative levels of adders the company could examine the trade-off between cost and environmental performance. This approach to the use of adders demonstrated the benefit of not beginning the analysis with a pre-determined adder level.

RAMPP-3 used both the adders and the MATO approaches, and both provided useful information, but each had its limitations. However, the company believes the limitations of the adders approach are inherent to that methodology, whereas the limitations of the MATO approach were primarily a function of how it was applied in RAMPP-3.

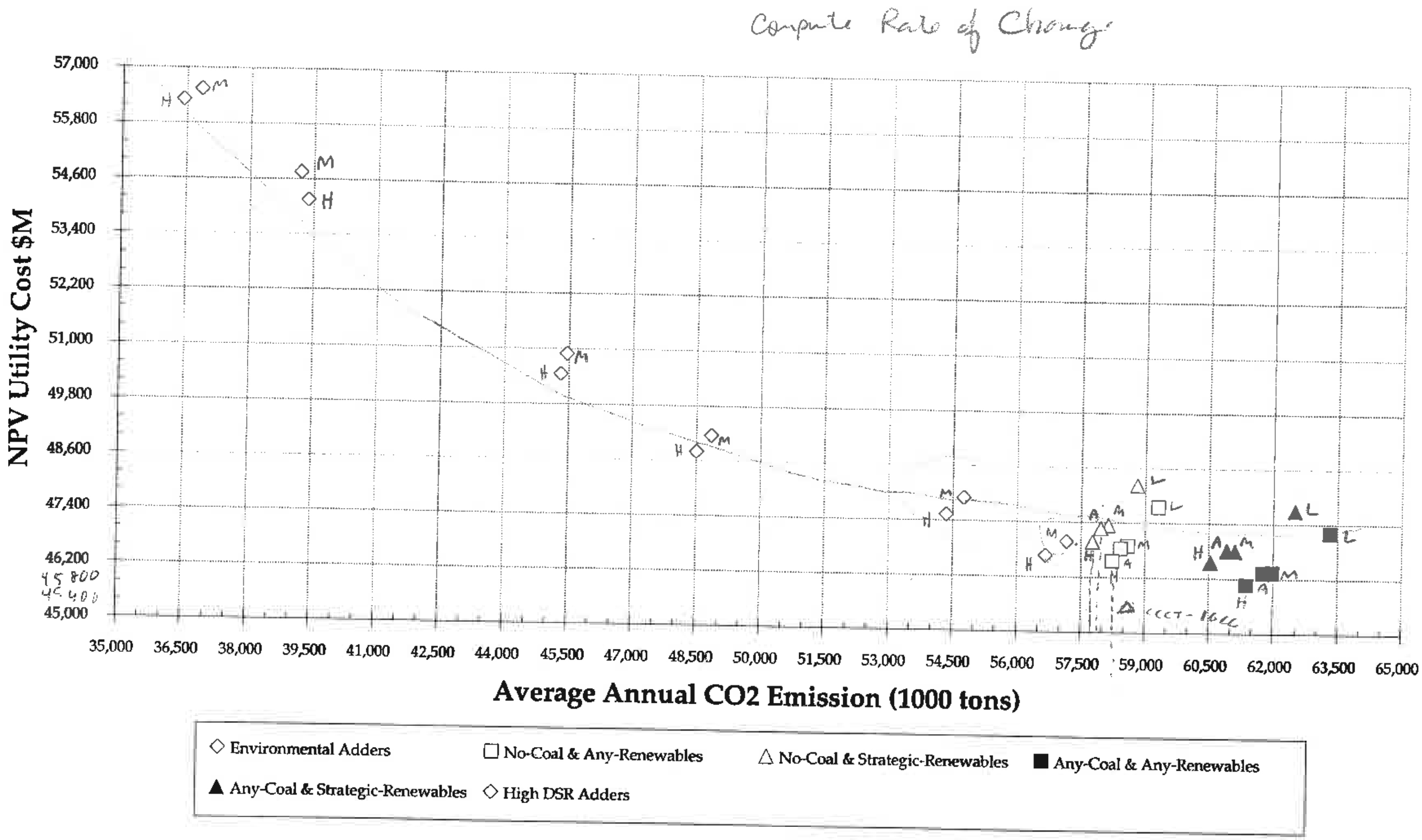
One way to compare the results from the two approaches is to add points from the adder cases to a trade-off graph. Beginning with the utility cost/CO2 graph (the top half of Graph 7-9), Graph 7-18 adds two sets of six adder cases. All of the cases on Graph 7-18 used medium load growth and medium gas prices. One set of six adder cases used medium DSR and one set of six used high DSR. The adder cases with medium DSR are slightly higher on the cost axis than the comparable adder cases using high DSR. The adder cases extend to a much higher cost level and to a much lower emission level, thus compressing the base study plan cases from the MATO analysis into the bottom right hand corner. The 24 cases do not produce a curve. They produce more of a straight line from the upper left corner to the lower right corner of the graph.

Of special interest are four cases which fall in the low-cost area, two from the adders cases and two from the MATO analysis. Case #301 is the lowest cost case from the adders set using medium DSR. Case #307 is the lowest cost case from the adders set using high DSR. Case #43 from the MATO analysis was a no-coal, any-renewables case with high DSR (the lowest white square). Case #44 from the MATO analysis was a no-coal, strategic-renewables case with high DSR (the lowest white triangle). All achieved similar cost levels and similar emission levels, but arrived there by different means, as shown on Table 7-19. Cases #43 and #44 could not use IGCC coal, since they were no-coal cases, so they had to rely on additional cogeneration to minimize costs. A combination of IGCC coal with some cogeneration can achieve very similar cost and emission results compared to all or almost-all cogeneration.

Utility Cost and CO2 Emissions

Environmental Adders Versus Medium Load Medium Gas Cases

Graph 7-18



G7-18 adders trade-off

Resource Additions After 20 Years: MATO vs Adders
Table 7-19

Case #	43	44	301	307
DSR	1,303	1,303	1,071	1,303
Renewables		529		
Cogeneration	1,032	854	438	320
IGCC Coal			1,262	1,145
Peaking Resources	1,402	1,402	1,000	968
CO2 Emissions	58,231	57,766	57,164	56,659
NPV Utility Cost	46,563	46,970	46,980	46,668

PacifiCorp learned an important lesson from the MATO versus adders analyses in RAMPP-3. The successful use of MATO depends on the strategies selected and the alternatives for each strategy. If PacifiCorp's use of the MATO approach had incorporated a wider variety of resource strategies and a different specification of alternatives for each strategy, the results would have been more informative.

Duh!!!!!! See pg 35-39 of Public Process Tech. Appdx

RAMPP-3 tested three strategies: DSR, coal and renewables. It didn't test alternative levels of cogeneration (a major contributor to lowered emissions and reduced costs). RAMPP-3 included no strategy to meet peaking needs. It is possible that distinguishing between pumped storage and SCCTs as peaking resource strategies would have produced meaningful results.

The alternatives within each strategy also limited the results from the MATO analysis. The coal strategy included only two alternatives: any-coal and no-coal, without distinguishing between pulverized and IGCC technologies and without distinguishing, for example, a limit of only one or two new coal units. It also only tested only two renewable strategies: any-renewables and strategic-renewables. In most of the cases the any-renewables strategy resulted in fewer renewable additions than the strategic-renewables strategy, but in some cases it resulted in more renewable additions. Therefore, its results were not linear.

The company intends to refine the MATO approach for RAMPP-4, to test more strategies, to refine the alternatives for the strategies, and to do the MATO analysis in a more focused way (fewer cases under each strategy) to keep the entire study plan of a manageable size.

See PC response pp 41-43!!!

RENEWABLE ANALYSIS

The Portfolio chapter describes three types of renewable resources: wind, geothermal, and solar. This chapter discusses what PacifiCorp is currently doing to gain experience with these renewable resources. It also explains the primary barriers to renewable resource development and results of the model runs for the two renewable strategies and the renewable sensitivity studies.

The main attraction of renewable resources is that nature continually replenishes the energy source, as opposed non-renewable resources, that use fossil fuels. The company wants to gain improved understanding and experience with renewable resources at the commercial stage to reduce cost and operational uncertainties; help the renewables industry to understand and address cost and operational issues; learn from other utilities that are developing renewable resources on a larger scale due to higher avoided costs; and gain these benefits without having to make large investments.

PACIFICORP'S ACTIONS

Integrated resource planning does not provide a way to determine whether purchasing or building renewable energy is more beneficial to the company's customers. It is difficult to define and compare the costs and benefits associated with each renewable resource project, because those costs and benefits depend on the specific project and the specific site. The company tries to address the trade-offs on a case-by-case basis in contract negotiations and project development discussions.

PacifiCorp's approach to gaining experience with renewables is to join with other utilities to invest in larger projects, so each utility gains operating experience with the technology. PacifiCorp is participating in joint wind and solar projects, including a wind farm in southwest Washington, a Wyoming wind farm, and the Solar II project in California. The company is also participating in four photovoltaic (PV) projects. The Background and Action Plan chapters of the report provide a discussion of these projects and their technologies.

The company is gaining experience with a range of photovoltaic (PV) applications and technologies. PV devices have been used for several years on company facilities to power remote telemetry and repeater equipment and aircraft warning beacons on transmission structures, where they have proven to be cost effective. Besides these niche, off-grid applications, the company has initiated several remote and grid-connected PV demonstrations, with the objective of gaining practical and technical experience and testing the economics of such applications. In 1993, the company developed guidelines that encourage

PV applications where they are a cost effective alternative to new grid connections. The guidelines identify line extension requests that could be more economically served by isolted PV systems. When the company receives such extension inquiries, the company informs the customer of the PV alternative and provides information on possible consultant and vendor sources. By tracking such requests, the company will over time be able to evaluate its potential role as a supplier of such services as well.

projects?

The company does not yet have the experience and knowledge it needs to make large-scale renewable resource commitments; however, increased experience should reduce the uncertainties and resolve some of the issues related to renewables. Currently, the unique characteristics of renewable resources present significant uncertainties that the integrated resource planning process cannot fully address. Experience with the initial prects can provide the knowledge necessary to reduce these uncertainties. Often these issues are operational and not easily quantified; they are therefore difficult to test and evaluate with a capacity expansion planning model.

In addition to directly participating in projects, the company participates in a number of regional and national processes and forums dealing with renewable issues. Such groups as Portland General Electric's Renewable Resource Collaborative Work Group, the OPUC's UM 550 proceeding, and ongoing efforts such as the Northwest Advisory Council for Wind Energy, the OSU Wind Research Cooperative and EEI's Renewables Committee are part of this activity. These groups help to define the role of the utility, regulatory agencies, and developers with respect to renewable resource development, and share technical and resource planning information.

At

The company's most up-to-date source of information is developers. PacifiCorp is continuously evaluating proposals from developers. Any any point in time, the company typically has on-going conversations with from five to ten developers about specific project proposals. The company's current projects and its ongoing discussions with developers have influenced its views regarding the value of a Green RFP.

Green RFP

Included in the company's strategic goals are targets for renewable resource acquisition: 200 MWa by 2001 if the early projects prove to be cost-effective resources. A Green RFP or Renewable Set-Aside in an open RFP is one possible approach to meeting this acquisition goal. Another approach is to take advantage of opportunities to acquire renewable resources at competitive prices through negotiations with developers who approach the company with unsolicited projects. PacifiCorp has been successfully using the second approach to acquire renewable resources and has no plans for a Green RFP or Renewable Set-Aside. Should the company find it difficult to identify cost-effective renewable resource opportunities through unsolicited prosals, then a Green RFP or Renewable Set-Aside may be appropriate.

The company's actions to acquire experience with a range of renewable resource technologies will provide the benefits that may be gained through a Green RFP or Renewable Set-Aside in an open RFP. One of those benefits is understanding the marketplace (price, terms, availability, etc.) for renewable resources. Developers continually approach PacifiCorp with proposals for specific projects, often projects which they have submitted to other utilities in a formal bidding process or in an unsolicited process. A second benefit is gaining operating experience with renewable technologies. The two wind projects in which the company is participating (Columbia Hills in Washington and Foote Creek in Wyoming), participation in Solar II, and photovoltaic projects now being installed on buildings within PacifiCorp's service territory are providing that experience. PacifiCorp does not believe a Green RFP or Renewable Set-Aside would provide experience that would be any more valuable than the experiences being gained through the current unsolicited bidding process and the current renewable resource projects.

Until the company gains experience with the two current wind projects, acquiring more wind resources does not appear to be a likely course of action. PacifiCorp is in discussions with several geothermal developers. Solar resources are the most expensive of the renewable technologies, and the company's participation in Solar II and four current photovoltaic projects are exploring the solar technologies which have the best potential fit with the company's system.

PacifiCorp has assessed what its role should be in fostering technological and other advances that deliver customer benefits. The company concluded that it must closely track technological developments and actively foster the commercialization of appropriate advances. Basic research and development (R&D), best performed by the manufacturers of power-generating equipment, develops new technologies and products to the point of demonstrated technological feasibility. PacifiCorp then applies the technology into commercially viable operations by solving the myriad and challenging technological, institutional, communication and control, and integration problems of moving an emerging technology from the stage of demonstrated feasibility to the stage of commercial viability.

PacifiCorp believes its current approach balances two sometimes competing goals. One goal is to diversify the company's resource mix with more renewable resources; the second goal is to keep prices as low as possible to meet the competitive marketplace. By using a competitive process where renewables must compete against each other and against a broader standard, the company is better able to balance these competing issues. what standard?

what is this competitive process?

In the development of renewable generation, the company's objectives are to demonstrate renewable generation alternatives to confirm their commercial readiness, confirm actual operating cost and performance characteristics, address system integration issues, and assess environment benefits. All of these objectives can be met through the company's current process of taking advantage of unsolicited, but frequent and varied, opportunities to acquire competitive renewable resources, gaining needed experience with each technology, and then

is wholesale

what are the targets?

moving forward with those technologies which prove to be cost effective in price and operations. PacifiCorp is developing its renewable targets within its strategic planning and IRP processes. This gives the company the flexibility needed to adjust those targets as market conditions and technology change.

BARRIERS TO USING RENEWABLE RESOURCES

Based on its own experience and knowledge, PacifiCorp has identified some key concerns about renewable resources. The main barriers for the company in developing renewable resources are: 1) higher cost than other technologies, 2) more uncertain costs than other technologies, 3) energy production that depends on the local seasonal and daily weather, and 4) siting difficulties. Other barriers include inadequate valuation of non-price factors, especially the lack of fuel price risk and environmental benefits of renewables. PacifiCorp will make an effort to improve the modeling of non-price factors, such as fuel price risk and environmental impacts, in RAMPP-4.

Higher Cost than Other Technologies

Renewable resources generally cost more than other technologies. In the RAMPP-3 portfolio of resources, wind resources were the most cost competitive renewable resource. With the pre-2000 tax credit, the real levelized cost of wind in Utah was 55 mills/kWh, and 63 mills/kWh in OWC, compared to pulverized coal resources in the 29 to 32 mills/kWh range, and cogeneration in the 45 to 48 mills/kWh range. Table 8-1 shows the cost of supply-side resources with no adders, and then with the six levels of adders used in the Environmental Analysis chapter. Backup for Table 8-1 is available in the Modeling Appendix. With the addition of sufficiently high environmental costs (the highest of the six adder levels), wind with the federal tax credit became the least expensive of the supply-side resources in the portfolio. This comparison, of course, ignores the obvious but difficult-to-quantify differences in value between intermittent and dispatchable resources. Without adders, geothermal resources under base RAMPP-3 assumptions had a real levelized cost of 81 mills/kWh, which did not become competitive even if the highest level of environmental cost adders. Solar resources are not yet cost competitive with or without adders in the range used in RAMPP-3.

Industry experts expect the costs of all renewable technologies to decline in the next few years, for two reasons: technological advances and 2) economies of scale as utilities increase renewable resource acquisitions. The federal government will increase its spending on renewable energy research by 36 percent in fiscal 1994, to $347 million. The wind industry has been developing new technology to reduce the costs of wind-powered generation and is marketing that technology to utilities. The amount of commercial power generated from wind is now about 2,500 MW worldwide, and growing. Makers of solar thermal and PV equipment are continuing to improve their technologies. Perhaps RAMPP-4 or RAMPP-5 will reorder resources based on a lower cost for some of the renewable technologies.

Impact of Environmental Adders on Portfolio Costs (in 1994$)

Table 8-1

Description	Total Resource Cost (Mills/kWh)	Low NOx and TSP CO2 Low	Low NOx and TSP CO2 Medium	Low NOx and TSP CO2 High	High NOx and TSP CO2 Low	High NOx and TSP CO2 Medium	High NOx and TSP CO2 High
Utah Coal	28.05	42.93	58.27	73.61	49.85	65.19	80.52
Wyo Coal	31.08	47.93	65.30	82.67	55.76	73.13	90.50
Utah IG CT	32.50	41.51	54.55	67.60	41.96	55.01	68.05
Wyo FB Coal	34.31	45.49	59.97	74.44	47.72	62.20	76.67
Utah FB Coal	35.07	46.02	60.20	74.37	48.21	62.38	76.56
OWC Cogeneration 1	41.49	45.25	50.11	54.98	46.01	50.87	55.74
Utah Cogeneration 1	42.84	46.60	51.46	56.33	47.36	52.22	57.09
OWC Cogeneration 2	43.36	48.00	54.02	60.04	48.94	54.96	60.98
Utah Cogeneration 2	43.55	48.19	54.21	60.23	49.13	55.15	61.17
Utah Combined Cycle	46.67	51.56	57.90	64.23	52.55	58.88	65.22
OWC Combined Cycle	47.23	52.12	58.46	64.79	53.11	59.44	65.78
Wyo Combined Cycle	47.66	52.55	58.89	65.22	53.54	59.87	66.21
Utah Wind with Tax C	52.91	52.91	52.91	52.91	52.91	52.91	52.91
Utah CC CT Convert	53.64	58.53	64.87	71.20	59.52	65.85	72.19
OWC CC CT Convert to IGCC?	53.64	58.53	64.87	71.20	59.52	65.85	72.19
Wyo CC CT Convert to IGCC?	55.23	60.12	66.46	72.79	61.11	67.44	73.78
OWC Wind with Tax C	60.40	60.40	60.40	60.40	60.40	60.40	60.40
Utah Wind without Tax C	65.57	65.57	65.57	65.57	65.57	65.57	65.57
Wyo Wind without Tax C	65.57	65.57	65.57	65.57	65.57	65.57	65.57
OWC Wind without Tax C	73.04	73.04	73.04	73.04	73.04	73.04	73.04
Utah Geothermal	74.78	74.78	74.78	74.78	74.78	74.78	74.78

? $/Δ trans constraints?

T8-01.portfolio w/adders

More Uncertain Costs than Other Technologies

Uncertain costs are a barrier to the purchase of a technology. However, more experience over time with each technology will reduce the cost uncertainty. The number of utilities that are getting involved in renewable resource projects is growing, and they will be sharing the results of their experiences with one another. PacifiCorp stays well-informed of other utilities' experience with renewable technologies.

Energy Production Depends on Weather

Wind and solar energy are intermittent power sources. They produce electricity only when the wind blows or the sun shines. As a result, they are not dispatchable (they cannot be turned on when needed if the wind isn't blowing or the sun isn't shining), unlike traditional fossil-fueled resources. However, the Solar II project in southern California may be able to demonstrate the feasibility of storing solar energy during on-peak sunshine hours for use during off-peak hours. The degree to which wind or solar power is available when customer loads are higher can mitigate their non-dispatchability. Solar is the most compatible for meeting daily peaks because people use electricity most during daylight hours. Solar also provides the best match for seasonal peaks in summer-peaking areas. Wind is best for winter peaking areas. PacifiCorp is studying the issues involved in matching an intermittent resource with the company's loads to better understand how to maximize the benefits to the system of the different renewable technologies.

Low-cost energy storage technology would make these resources more dispatchable by providing greater reserve capabilities. If special equipment can store the electrical output for use when the utility system needs it, it won't matter when the wind blows or the sun shines. Storage methods such as batteries, compressed air and hydrogen are all under development by various firms in the energy industry.

Utilities are becoming increasingly interested in studying resource needs and resource alternatives for specific sites. For example, photovoltaic (PV) resources can provide electricity for remote sites, where line extensions to connect a customer to the utility grid would be very expensive. PV may also become cost effective as an alternative to upgrading distribution equipment when load grows in a particular area. Utilities are giving more consideration to the costs of accommodating pockets of load growth on the distribution grid. The Action Plan chapter provides examples of PacifiCorp's use of PVs.

Siting Difficulties

Renewable resources can be difficult to site, mainly because of environmental and aesthetic concerns. Siting of wind plants must minimize bird mortality from contact with the blades of the machines. Wind plants also need to avoid areas where their operation would threaten rare or endangered species or interfere with bird migratory patterns. Wind farms, solar facilities, and geothermal equipment can also present visual barriers to scenic areas. They need to avoid areas with pre-emptive uses, such as parks, wilderness and scenic areas, and sacred sites. Rangeland or other open areas may allow multiple uses.

Non-Price Factors

For sound resource planning, it is important to give adequate value to non-price factors. Factors other than price are qualitative rather than quantitative and are therefore difficult to measure. Non-price factors include how much a resource avoids fuel price risk, contributes to resource diversity, and reduces environmental impacts.

Avoidance of fuel risk is one of the most valuable characteristics of renewable resources. Wind and solar resources have high capital costs but no fuel costs. Once built, there is no risk of fuel cost increases. The price of some fossil fuels can fluctuate, and utilities may be forced to raise their prices to recover unexpected increases. Nevertheless, the high capital cost of renewable resources presents a high risk to utilities, because almost all of the resource's costs occur in the first year. This exposes the utility to more capital carrying costs and exposes customers to a greater price impact.

Resource diversity is important in resource planning, because it can reduce some of the risks facing utilities. If one technology becomes more expensive or begins performing poorly, a utility can rely more on plants that use other technologies. However, diversity carries costs of its own. Each utility tends to have one technology that is the least expensive for it, due to geographic position and resource availability. The utility will probably have its resource mix heavily weighted in that technology because of its low-cost advantages. More use of renewables would increase a utility's resource diversity, but often at a cost that would make the utility's product more expensive.

Including environmental impacts in the planning process increases the relative benefits of renewable resources over fossil-fueled resources. RAMPP-3 includes environmental impacts in two ways: first by comparing emissions with various financial measures for different resource strategies, and second by adding externality cost adders to the operating cost of each new resource. The Environmental Analysis chapter describes the results of these analyses. The company used the results of the environmental analyses in developing the action plan, which calls for investigation of the IGCC clean coal technology and staged development of renewable resources.

The IRP process and regulatory proceedings are useful forums to address renewable resource planning issues. PacifiCorp will continue to learn more about renewable resources through participation in various groups, meetings, and conferences, and through direct participation in projects. The company's environmental goal and its desire to acquire cost-effective resources to reduce future price risk for customers provide incentives for developing renewable resources and including them in future resource planning.

MODEL ANALYSIS RESULTS

The analysis plan provides two types of information about renewable resources. First, the strategy alternatives of any-renewables and strategic-renewables provide information on the cost and price impacts of early renewable projects. Second, three sensitivities altered the input assumptions for renewable resources.

Renewable Strategies

The company developed two renewable strategies from its environmental goal (develop 200 MWa of renewable resources by 2001 if proven to be cost-effective with other company resource options). The two renewable strategies tested the impact of early renewable development on emissions, utility costs, customer prices, and total resource costs.

Half of the runs in the base study plan used the any-renewables strategy, and half used the strategic-renewables strategy. The any-renewables strategy allowed the model to select renewables if they were cost effective compared to other resources. The strategic-renewables strategy required the model to add a specific amount of renewable resources each year through 2001 to meet the company's strategic goal targets. This strategy also did not allow the model to add any additional renewable resources during those years. Thus, for the first eight years, all of the strategic-renewable cases have exactly the same amount added -- 529 MW. This 529 MW of installed capacity, plus the Washington and Wyoming wind projects, results in 200 MWa of renewable resources by 2001 as called for in the environmental goal. The existing system includes the Foote Creek and Columbia Hills projects in Wyoming and Washington, respectively. Therefore, the financial results for both strategies include the costs for these two projects.

When the model selected renewables, it always selected wind, because it was the only renewable resource which became cost competitive with the other supply-side alternatives under any of the cases. Because wind resources have a low availability factor, the company assumes it can rely on about 300 MW if installed capacity is 1,000 MW. Thus, 1000 MW of wind resources compares with 300 MW of coal resources.

For medium or higher load growth, the model added wind resources in the any-renewables cases only under a no-coal strategy. Under medium load growth, the model added wind only if the case used high gas prices; then it added from 2,100 to 3,200 MW of wind resources. With no-coal and high gas prices, renewables were the only alternative. Under medium-high load growth with no-coal, the model selected 4,000 MW of wind with high gas prices. Under high load growth with no-coal, the model selected 5,450 MW of wind with high gas prices. These cases resulted in higher utility costs and total resource costs because of the high gas prices and the selection of the more expensive wind resources.

The strategic-renewables strategy reduced emissions by only about one percent in the medium load growth, medium gas price, medium DSR cases. In spite of this low emissions reduction, the company believes that renewable resources have other benefits, such as resource diversity and lack of fuel price risk which increase their potential value to the system.

To determine the cost to the utility, customers, and society of following the strategic-renewables strategy, the company calculated the average cost difference between all of the any-renewables cases and all of the strategic-renewables cases. For utility cost, the average difference in NPV of 50 years of revenue requirement was $397 million. For the medium load growth with medium gas cases, the difference was slightly greater. Under medium DSR and any-coal, the difference in NPV of 50 years of revenue requirement between the any-renewables and the strategic renewables was $465 million, under medium DSR and no-coal the difference was $443 million, under high DSR and any-coal the difference was $482 million, and under high DSR and no-coal the difference was $406 million. For real levelized customer prices, the average difference was 0.38 mills/kWh, meaning customers would pay an average of 0.83 percent more under strategic-renewables than under any-renewables.

1% price increase

Table 8-2 shows the annual average nominal mills/kWh that would result from different renewable strategies and different DSR strategies under medium load growth, medium gas prices, and a no-coal strategy, and at the end, the real levelized mills/kWh over the entire 50 year period:

Nominal Mills/kWh by Renewable and DSR Strategies
Table 8-2

	Any-Renewables Medium DSR	Strategic-Renewables Medium DSR	Any-Renewables High DSR
1994	47.8	47.8	47.9
1995	49.8	49.8	50.2
1996	50.4	50.4	51.0
1997	50.9	51.0	51.9
1998	52.2	52.6	52.8
1999	53.9	54.8	54.5
2000	55.2	56.3	55.8
2001	56.4	57.9	56.9
2013	90.2	91.2	90.7
Real Levelized	45.6	47.1	47.0

The real levelized price impact of the strategic-renewables strategy (over the any-renewables strategy) is almost the same as the real levelized price impact of the high DSR strategy (over the medium DSR strategy), but the real levelized price masks timing differences. For the first five years, the strategic-renewables strategy has less of a price impact than does the high DSR strategy, and then it

Table 8-3

Renewables Sensitivities

Resource Selections by 10th Year (2003)

	Run against	#35 M.MG.MD.NC.AR							
				Geothermal	Wind				
			Lower Renewable Cost	0% inflation Rate on O & M	Inflation Rate on O & M		Reserve Contribution		20% More Energy
	Sensitivity	m.mg md.nc.ar			0%	2.5%	1.2 times Higher	Set to Winter	
	Case #	35	261	262	263	264	265	266	267
	Winter Peak Capacity in 2003 (MW)								
1	Native Load	9,273	9,273	9,273	9,273	9,273	9,273	9,273	9,273
2	Firm Sales	1,195	1,195	1,195	1,195	1,195	1,195	1,195	1,195
3	Reserve Requirement	1,479	1,479	1,479	1,479	1,479	1,479	1,479	1,479
4	**Total Requirements**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**	**11,947**
5	Existing Generation	9,582	9,582	9,582	9,582	9,582	9,582	9,582	9,582
6	Firm Purchases	317	317	317	317	317	317	317	317
7	New Resources								
8	DSR	608	608	608	608	608	608	608	608
9	Renewable	0	1,350	0	0	0	0	300	493
10	Cogeneration	1,058	510	913	1,058	1,058	1,058	922	833
11	Combined Cycle CT	0	0	0	0	0	0	0	0
12	Coal	0	0	0	0	0	0	0	0
13	Peaking Resources	383	521	528	383	383	383	342	386
14	**Total Resources**	**11,948**	**12,888**	**11,948**	**11,948**	**11,948**	**11,948**	**12,071**	**12,219**
	Annual Energy in 2003 (MWa)								
15	Native Load	6,634	6,634	6,634	6,634	6,634	6,634	6,634	6,634
16	Pump Storage/Peak Return	405	418	407	405	405	405	395	405
17	Firm Sales	1,410	1,410	1,410	1,410	1,410	1,410	1,410	1,410
18	Non-Firm Sales	461	468	425	461	461	461	457	493
19	**Total Requirements**	**8,910**	**8,930**	**8,876**	**8,910**	**8,910**	**8,910**	**8,896**	**8,942**
20	Existing Generation	7,141	7,133	7,151	7,141	7,141	7,141	7,135	7,124
21	Firm Purchases	364	367	368	364	364	364	364	364
22	Non-Firm Purchases	108	144	162	108	108	108	116	116
23	New Resources								
24	DSR	348	348	348	348	348	348	348	348
25	Renewable	0	424	0	0	0	0	105	233
26	Cogeneration	887	436	776	887	887	887	773	693
27	Combined Cycle CT	0	0	0	0	0	0	0	0
28	Coal	0	0	0	0	0	0	0	0
29	Peaking Resources	77	92	84	77	77	77	69	77
30	**Total Resources**	**8,925**	**8,943**	**8,889**	**8,925**	**8,925**	**8,925**	**8,911**	**8,955**

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Table 8-4

Renewables Sensitivities

Resource Selections, Emissions and Financial Results

	Run against	#35 M.MG.MD.NC.AR							
				Geothermal	Wind				
			Lower	0% inflation	Inflation Rate		Reserve Contribution		20%
		m.mg	Renewable	Rate	on O & M		1.2 times	Set to	More
	Sensitivity	md.nc.ar	Cost	on O & M	0%	2.5%	Higher	Winter	Energy
	Case #	35	261	262	263	264	265	266	267
	Winter Peak Capacity in 2013 (MW)								
1	Native Load	11,206	11,206	11,206	11,206	11,206	11,206	11,206	11,206
2	Firm Sales	437	437	437	437	437	437	437	437
3	Reserve Requirement	1,586	1,586	1,586	1,586	1,586	1,586	1,586	1,586
4	**Total Requirements**	13,229	13,229	13,229	13,229	13,229	13,229	13,229	13,229
5	Existing Generation	9,196	9,196	9,196	9,196	9,196	9,196	9,196	9,196
6	Firm Purchases	262	262	262	262	262	262	262	262
7	New Resources								
8	DSR	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071
9	Renewable	0	2,058	246	0	0	0	300	493
10	Cogeneration	1,180	510	913	1,180	1,180	1,180	1,032	931
11	Combined Cycle CT	0	0	0	0	0	0	0	0
12	Coal	0	0	0	0	0	0	0	0
13	Peaking Resources	1,520	1,593	1,541	1,520	1,520	1,520	1,491	1,548
14	**Total Resources**	13,230	14,690	13,230	13,230	13,230	13,230	13,353	13,501
	Annual Energy in 2013 (MWa)								
15	Native Load	7,998	7,998	7,998	7,998	7,998	7,998	7,998	7,998
16	Pump Storage/Peak Return	460	427	451	460	460	460	453	443
17	Firm Sales	841	841	841	841	841	841	841	841
18	Non-Firm Sales	313	297	312	313	313	313	293	319
19	**Total Requirements**	9,612	9,563	9,602	9,612	9,612	9,612	9,585	9,601
20	Existing Generation	7,087	7,071	7,087	7,087	7,087	7,087	7,091	7,079
21	Firm Purchases	442	435	442	442	442	442	442	442
22	Non-Firm Purchases	266	255	269	266	266	266	269	267
23	New Resources								
24	DSR	613	613	613	613	613	613	613	613
25	Renewable	0	608	234	0	0	0	105	233
26	Cogeneration	1,068	467	826	1,068	1,068	1,068	937	842
27	Combined Cycle CT	0	0	0	0	0	0	0	0
28	Coal	0	0	0	0	0	0	0	0
29	Peaking Resources	150	128	144	150	150	150	143	138
30	**Total Resources**	9,626	9,576	9,615	9,626	9,626	9,626	9,600	9,615
	Average Annual Emissions in 1994-2013 (1000 tons)								
31	CO_2	58,589	57,231	58,338	58,589	58,589	58,589	58,279	58,012
32	NO_x	129	128	129	129	129	129	129	128
	Financial Results with End Effects to 2043								
	50-year Utility Cost								
33	NPV at 8.8% (million $)	46,894	47,078	47,139	46,894	46,894	46,894	47,018	47,056
34	Real Levelized (mills/KWh)	46.68	46.86	46.93	46.68	46.68	46.68	46.81	46.84
	50-year Total Resources Cost								
35	NPV at 8.8% (million $)	48,460	48,643	48,705	48,460	48,460	48,460	48,584	48,621
36	Real Levelized (mills/KWh)	45.62	45.79	45.85	45.62	45.62	45.62	45.74	45.77

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reverses. From 1999 onward, the strategic-renewables strategy has the greater price impact. However, the company made its decision to pursue the strategic-renewables approach on more than an initial five-year price advantage over the high DSR approach. The benefits of the strategic-renewables strategy include confirming renewable resources' cost effectiveness and operating conditions to be positioned for greater acquistion should conditions warrant.

Renewable Sensitivities

To further analyze renewable resources, the company performed seven sensitivities, shown on Tables 8-3 and 8-4. Four sensitivities addressed costs, and three addressed performance characteristics. All of these sensitivities used medium load growth, medium gas prices, medium DSR, no-coal and any-renewables strategies. The no-coal strategy was necessary to prevent the model from selecting coal, the lowest cost resource, to meet resource needs.

The first renewable sensitivity addressed a future reduction in the cost of wind. The company first reduced the cost of wind by 20 percent. This had no effect on resource choices; the cost differential was not large enough to make wind less expensive than cogeneration. The company determined that the capital cost of wind plants, in addition to the tax credit, would have to decrease by $600 for wind to be less expensive than cogeneration. The first sensitivity, case #261, therefore reduced the capital cost of wind by $600. Table 8-5 shows the costs of wind including the tax credit and the $600 reduction.

Capital Costs of Wind
Table 8-5

	OWC	UTA	WYO
Initial Capital Cost	$1,120	$1,150	$1,150
Transmission	120	212	212
Total	$1,240	$1,362	$1,362
Tax Credit	($315)	($400)	($400)
Capital Cost with Tax Credit	$925	$962	$962
Sensitivity Credit	$600	$600	$600
Capital Cost for Case #261	$325	$362	$362

Under this assumption, the model selected 1,350 MW of wind during the first 10 years, and 2,058 by the end of 20 years, and reduced the amount of cogeneration selected This increased costs and prices very little, because of the assumption of very inexpensive wind.

The next three renewable sensitivities addressed the inflation rate used for O&M costs, one for geothermal resources and two for wind. In order to accomplish this, the company used a modeling convenience of splitting the variable O&M expense between that category and the fuel category. This allowed the model to see part of the O&M expense increasing faster than inflation. Case #262 used a zero inflation rate for O&M costs of geothermal resources. In all the other cases geothermal O&M costs increased with the gas price assumption used in that case. Since the company modeled geothermal acquisition as a purchase, the logical conclusion was that geothermal prices would track competitive market conditions, and the driver of energy markets is likely to be natural gas prices. Therefore, the company modeled gas O&M costs to follow gas prices. With gas price inflation on O&M, the model selected no geothermal in the comparison case. With no inflation the model selected 246 MW of geothermal, but not until the 2009-2013 time period. This increased the NPV of utility cost and TRC slightly, and real levelized mills/kWh by 0.25 mills.

Cases #263 and #264 altered the inflation rate for O&M costs on wind resources. Case #263 used a zero rate, and case #264 used a 2.5 percent rate. All the other runs used 1.25 percent, the middle of the range of estimates available from developers. Neither of these had any effect on resource selections.

The final three renewable sensitivities altered various performance characteristics. Cases #265 and #266 addressed the largest uncertainty related to wind -- the capacity contribution that wind can provide at the time of the system peak demand. It is a function of both the strength of the wind and the performance of the wind turbine equipment. The RAMPP-3 assumption was that wind's peak contribution was about 90 percent of its average level of generation. If wind velocity were constant during the day, average generation would be a good estimate of expected peak contribution. However, ongoing studies indicate very little correlation between system peak and maximum generation from wind resources. Therefore, the company assumed that wind's contribution at the time of system peak was 90 percent of its average level of generation. To test the sensitivity of results to this assumption, the company first increased it by 20 percent, case #265, but that had no impact on resource choices. The company next altered wind's peak contribution to its average winter generation. Under the winter assumption, the capacity factor for wind in the OWC area was 19 percent. For wind in the WYO and UTA areas the capacity factor was 59 percent. Under this assumption the model selected 300 MW of wind in the first 10 years, but no more during the second 10 years. It had almost no impact on costs or prices.

The last sensitivity addressed the amount of energy available from wind resources. Case #267 assumed that wind plants can produce 35 percent more energy per kW of wind turbines than assumed in the base cases. The company arrived at this percentage after testing increasing amounts until the model began selecting more wind. With the 35 percent increase in energy output, the model selected 493 MW of wind, all during the first 10 years. The cost and price impacts were minimal.

The company drew two primary conclusions from the renewable sensitivities. First, they indicated that the renewable industry needs to lower costs significantly before renewable resources will be cost-competitive with other supply-side technologies (due to initial costs, O&M costs, and operating characteristics). Second, they indicated that if the company erred in the renewable input assumptions used for the base study plan, those errors would have to be quite large to affect modeling results. The company recognizes that the renewable industry is in a development stage, and the input assumptions for RAMPP-3 will need to be carefully revisited for the next IRP process.

QUESTIONS AND ANSWERS

Members of the company's public advisory group requested that the company provide responses to several issues and questions which may arise from the RAMPP analyses, but which the RAMPP analyses do not directly answer. Therefore, this chapter discusses those issues and questions. The company recognizes that these answers did not receive the same level of review and discussion in RAG meetings as did the RAMPP inputs and analyses, and that the answers provided may not apply to all states.

What is the relationship between the wholesale marketplace and RAMPP?

Retail electric operations are the core of PacifiCorp's business. PacifiCorp plans and acquires its resources based on retail needs. However, its wholesale operations play an important role in allowing the company to efficiently use its power system and reduce the cost burden on retail customers. The company bases its wholesale sales decisions on the benefits they can provide to retail customers.

The company has years of experience in selling bulk power to other utilities and power distributors. The merger between Pacific Power and Utah Power positioned PacifiCorp very well for wholesale activity. PacifiCorp's diverse service area, with both winter and summer peaking, enhances the company's wholesale business opportunities. The company has interconnections with more than 50 other utilities in four regions: the Pacific Northwest, California, Rocky Mountain region, and the Desert Southwest. Over the next two to four years, all of these regions except the Rocky Mountain area will probably require additional resources. As a result of new transmission access through Palo Verde, and additional transmission access through an agreement with Arizona Public Service Company, PacifiCorp has more flexibility to reach the southern California markets. However, competition for existing wholesale markets should remain intense in all regions.

Wholesale sales currently represent about one-fourth of PacifiCorp's total electric sales. PacifiCorp has two types of wholesale sales: "regular sales for resale" (about 8 percent of PacifiCorp's wholesale sales) and "special sales" (about 92 percent of PacifiCorp's wholesale sales). Regular sales for resale, also known as tariff or requirements sales, are firm sales to other utilities served directly off PacifiCorp's own power system and are within PacifiCorp's service area. Special sales are to other electric utilities outside the company's service area. Special sales may be either non-firm or firm. Non-firm sales are available on an hour-by-hour basis depending on the availability of resources, and may be interrupted under certain conditions.

Firm special sales represent 70 percent of all wholesale sales for PacifiCorp. Firm sales provide a reliable source of power to the purchaser; the seller may not interrupt or curtail most sales. They can be short- or long-term, or cover specific seasons. Short-term sales are usually one year or less. Long-term sales may cover 15 to 30 years, although in many long-term agreements the parties may mutually agree to terminate the agreement before the contract term expires.

Selling power on the wholesale market helps the company meet its revenue requirements, which reduces the cost burden on retail customers. PacifiCorp uses the "revenue credit" regulatory treatment to lower retail revenue requirements. This means the company first assigns all capital costs and expenses to the retail jurisdictions, including the costs of serving wholesale load. The company deducts wholesale revenues from total costs to determine the revenues needed from retail customers.

Long-term wholesale contracts also provide stable revenues should an economic downturn affect retail and short-term wholesale sales. PacifiCorp signs long-term contracts with major utilities on a take-or-pay capacity basis. Such contracts are not susceptible to fluctuations in local economies.

Wholesale sales also benefit PacifiCorp's retail customers by allowing the company to capture supply-side resources as they become available on the market. Since it is difficult to time resource acquisitions to exactly match retail load, wholesale sales can provide flexibility to more efficiently utilize resources when they become available. The Company can acquire resources needed for future retail loads and use them for wholesale sales until needed for retail loads. By purchasing supply-side resources as they become available on the market, PacifiCorp can pay a lower price than it would have to pay for a corresponding resource in the future. In this way the Company is able to capture an economic resource ahead of its needs and hold it for the future benefit of its retail customers.

Because PacifiCorp plans and acquires its resources based on retail needs, RAMPP-3 included only existing wholesale sales. The model used data on the price and term for each contract. When an existing sale is scheduled to terminate, it was no longer included as firm load in RAMPP-3. PacifiCorp does not project new wholesale sales; it is too difficult to forecast the size and type of sales that might occur. Instead PacifiCorp makes wholesale sales as opportunities arise that will maximize the efficiency of its system and complement its retail sales.

PacifiCorp stays attuned to wholesale sales opportunities through frequent contacts with other utilities. It also evaluates other utilities' requests for proposals when they openly solicit power from the wholesale market.

How does RAMPP consider acquisitions?

The RAMPP portfolio did not include acquisitions of existing resources, such as from another utility, as potential resources. Each acquisition is unique, so no model can be "typical." Acquisition of a generating plant is often part of a multi-faceted agreement that includes a wholesale sale, transmission arrangements or power exchange agreements. Acquisitions cannot be projected years in advance, which is required for long-range planning. PacifiCorp uses the RAMPP framework to evaluate potential acquisitions. RAMPP provides the basis for avoided costs, which the company uses to analyze the cost effectiveness of any potential acquisition.

The company also analyzes both the regulated and unregulated emissions from any potential acquisition. Craig units 1 and 2 both have surplus SO2 allowances from the Clean Air Act Amendments, at expected capacity factors, while Hayden units 1 and 2 and Cholla unit 4 are deficit. The Company intends to meet these allowance deficits with part of its surplus from other units. This leaves a substantial company-wide surplus available for other purposes.

As for carbon dioxide emissions, the company has adopted a strategic goal calling for continued investigation and testing of cost-effective strategies to offset future increases in carbon dioxide emissions. The four offset pilot projects discussed in this chapter involve planting trees to sequester carbon. The company also is exploring other methods of offsetting emissions, such as recovery of coal bed methane. The company's first small-scale pilot projects suggest carbon may be sequestered in trees for a cost of about $2/ton of carbon.

PacifiCorp continues to monitor all emissions from its fossil fuel generating plants, and will continue to consider the impact of increased emissions when evaluating whether to acquire additional plants.

How has the Company used competitive bidding to acquire a portion of its resources?

Competitive bidding is a process required, in different forms, by several of the states served by PacifiCorp. Bidding for resources is one method the company may use to review and compare resources. The bidding process also provides resource developers with an opportunity to assess opportunities within the market. PacifiCorp issued its first Request for Proposals (RFP) in October 1991 for both supply-side and demand-side resources. The company received 48 proposals ranging from combustion turbines (21 percent) to cogeneration (65 percent) to renewables (14 percent). In June of 1992, the company selected two supply-side resource proposals and three demand-side resource proposals for final contract negotiations. The five proposals totaled 12 MW. One of the supply-side projects is currently selling energy to the company, and is in negotiations to sell capacity. The other supply-side project is negotiating to determine the contract terms. The first demand-side project is a residential multi-family program to wrap water heaters and pipes and install low-flow showerheads in two states. The project completed its work in Washington, and began work in Utah. The second program is commercial lighting retrofit in Utah, which is now auditing buildings; installation will occur in 1994-1995. The third is retrofit of large commercial buildings in Utah, which is in the final phases of contract negotiations. Plans are for installation in 1994-1996.

This experience allowed the company to examine resource acquisitions and priorities from a different perspective. PacifiCorp learned that competitive bidding works best when a utility is as specific as possible about its resource needs. The RFP also revealed several non-price factors that an evaluation should consider. In some cases, non-price factors may be even more important than cost. For example, one important non-price factor is the location of the potential resource. For a multi-state utility such as PacifiCorp, resource location is critically important. Other non-price factors in evaluating the RFP proposals include environmental factors, the experience of the developer in successfully bringing a project on line, and fuel supply security.

PacifiCorp did not create a new resource market or expand the existing one by issuing an RFP. A number of the proposals were from developers who had previously approached the company. A broad range of developers continues to approach PacifiCorp outside the formal bidding process. PacifiCorp learned that competitive bidding can help the company develop guidelines for evaluating future supply- and demand-side resource acquisitions and provide a benchmark against which the company can measure its own programs. Bidding requirements should be flexible and suited to the specific needs of each utility. PacifiCorp is working with state regulators to encourage the adoption of bidding requirements that are compatible with a multi-state territory.

PacifiCorp plans to issue another RFP after completing the RAMPP-3 report. The company will use what it learned from the first RFP process and from the RAMPP-3 analysis to define resource needs. The company intends to solicit for 50 MW in its next RFP. However, PacifiCorp will not limit its resource acquisition to proposals submitted in response to an RFP. The company will continue to evaluate all resource opportunities as they arise.

Within 90 days following submission of the company's IRP with the regulatory commissions, PacifiCorp plans to file its RFP with the Oregon, Washington and Utah Commissions for their review. The schedule ordered by the Washington Utilities and Transportation Commission (WUTC) allows 60 days for comments and an additional 30 days to submit their recommendations to PacifiCorp. Within another 30 days PacifiCorp would formally seek solicitations. Assuming the final IRP is submitted in mid-April, PacifiCorp would be seeking solicitations with its formal RFP by mid-November 1994. This schedule does not appear to conflict with that required in any other states in which PacifiCorp serves. The WUTC has recently completed a rulemaking proceeding to modify its competitive bidding rules. The result of that rulemaking resolved most of the major differences between the Oregon and Washington rules. (Utah does not yet have formal competitive bidding rules). The remaining major RFP conflict among the state regulations is whether to combine or separate the demand-side and supply-side bids. The WUTC requires that they be combined, while the Oregon Commission has ordered them to be separate.

How are the RAMPP results used in the development of avoided costs?

RAMPP-3 medium load growth, resource cost data, and resource assumptions were used to develop avoided costs, adjusted for known changes since the RAMPP inputs were finalized for modeling work.

The company created a load and resource plan using the RAMPP-3 data on loads and existing resources to identify periods of resource sufficiency (no additional deferrable resources are needed to meet forecasted capacity and energy needs) and to identify the potentially avoidable resources when new deferrable resources are required. The existing resources from the RAMPP-3 analyses included 1) demand-side resources which represent the company's commitment to the development of programmatic conservation; 2) upgrades to existing thermal, hydro, transmission and distribution systems which are part of the company's long-range maintenance and life extension programs; 3) a 1992 agreement that allows the company to build and own a 50 MW cogeneration facility at James River Corporation's pulp and paper mill in Camas, Washington; 4) a 150 MW simple cycle combustion turbine built by the company in Arizona in accordance with existing contracts; and 5) two wind projects in Washington and Wyoming. For RAMPP-3, known changes since the inputs were finalized for modeling work included: 1) a wholesale sale to the City of Redding, 2) a power purchase contract with US Generating Company for power from the Hermiston project, 3) a generic summer capacity purchase, 4) the Idaho irrigation load control program, and 5) gas prices between the medium and low RAMPP-3 forecasts.

Under medium load growth PacifiCorp would not require any new deferrable resources to satisfy either winter peak or total energy load until 1999. Thus the avoided cost calculations can be broken into two distinct periods. The short run is a period of winter capacity and total energy sufficiency (1994 - 1998) in which the avoided costs are based on the marginal production cost of existing resources plus the cost of purchasing summer capacity. Summer capacity additions are necessary beginning in 1994. The summer capacity component of avoided cost prices was based on a generic three-month summer capacity purchase. This purchase matches the company's intention to purchase power to meet any system capacity shortfalls until the load and resource balance analysis indicates a need for additional energy resources and capacity resource requirements in both winter and summer. The price assumed for the summer capacity purchase is consistent with the company's SCE winter capacity purchase.

The long run for avoided costs is a period in which new resources are required to provide both summer and winter capacity and energy to meet the company's loads (1999 and beyond). Avoided costs during the long-run period are based on the cost of a combined cycle combustion turbine. A combined cycle combustion turbine was selected as the measure of avoided cost beginning in 1999 because it provides both capacity and energy, is deferrable, and its cost is easily defined.

Has PacifiCorp considered using different load decrements in the calculation of avoided costs?

Currently, to calculate avoided costs, PacifiCorp reduces assumed load growth by 50 MW, and analyzes the impact of that 50 MW reduction on resource costs. In the past, PacifiCorp calculated avoided costs for different load decrements; the results were very close to avoided costs using a 50-MW decrement.

How has PacifiCorp addressed the problem of using avoided costs from a previous IRP for determining a DSR cost effectiveness level in the current IRP?

PacifiCorp calculates avoided costs using the best information currently available. The level of cost effectiveness for DSR measures in the current RAMPP uses avoided costs from the previous RAMPP. Avoided costs in the previous RAMPPs have been very similar, reflecting only evolutionary changes. The Company's avoided cost methodologies since the time of the first RAMPP have been very similar. The method has evolved over time to reflect the specific resources which were avoidable and the specific types of avoidable resource needs faced by the Company -- capacity needs and energy needs. The changes in avoided costs mainly reflect evolutionary changes in the Company itself such as acquisition of resources, development of new load forecasts including new wholesale sales, changes in gas price forecasts, and changes in other resource costs for owned resources and for purchased power. The repeated iterations of a RAMPP process that would be necessary for a convergence of an output and an input avoided cost would be prohibitively time consuming. In addition, the impact of converging the two would be small. Therefore, the company feels it is not in the best interest of its customers or shareholders to expend the time and resources necessary for converging the two avoided costs.

How does the RAMPP process take into account the issues associated with Clean Air Act compliance?

Congress addressed sulfur dioxide (SO_2) emissions under Title IV (Acid Rain) provisions of the 1990 Clean Air Act Amendments (CAAA). By the year 2000, the CAAA permanently caps SO_2 emissions at 8.9 million tons per year from fossil-fired plants, which is a 10 million ton reduction (or approximately 50 percent) from 1980 levels. The CAAA also requires a 2 million ton reduction in oxides of nitrogen (NO_x). The CAAA creates SO_2 allowances, allocated to each electric generating unit in the United States, which are tradable and salable commodities. Each allowance constitutes a federal authorization to emit one ton of SO_2 per year. The CAAA bases a plant's allowances on that plant's emissions from 1985-1987 and classifies each plant as Phase I or Phase II, depending on their level of SO_2 emissions. The industry refers to utilities like PacifiCorp, which own only

Phase II plants, as Phase II utilities; Phase I utilities own Phase I plants. Phase I is the period 1995 - 1999; Phase II begins in 2000. Phase I plants are all east of the Mississippi River. A utility may use Phase I allowances in the 1995-1999 time frame or bank them for use during Phase II. Phase I plants will require the greatest amount of emission reductions using the most intensive and costly measures. The utilities that own these plants must develop an optimum compliance strategy.

Because their plants are cleaner operating, Phase II utilities already comply with Phase I requirements. Phase II utilities must have sufficient sulfur dioxide emission allowances to operate their thermal generating units beginning in the year 2000. Each utility must monitor emissions from each generating unit to assure that actual emissions do not exceed their allocated allowances. PacifiCorp is a Phase II utility, due primarily to the use of lower-sulfur coal and pollution-control equipment. PacifiCorp and other western utilities use coal with a sulfur content that can be as much as six times less than that of eastern and midwestern coal. Additionally, PacifiCorp customers have paid over $700 million to install SO2 scrubbers to reduce emissions at the company's plants.

current?

Except as associated with Phase I substitution transactions as discussed below, PacifiCorp will not receive annual allowances until Phase II. Starting in the year 2000, the company expects to receive about 180,000 allowances each year. Operation of the company's generating plants will require more than 143,000 allowances. This will leave some 37,000 surplus Phase II allowances. If the company receives adequate allowances to operate its system at fairly high capacity, as expected, it will not have to develop a compliance plan or undertake expensive compliance actions. New equipment to continuously monitor emissions at each plant will require some additional expense, and some technologies for reducing nitrogen oxide emissions as necessary to meet Title IV NOx standards.

is this cost included in incremental

The CAAA provides a substitution option. A Phase I utility can contract with a Phase II utility to substitute allowances in one time period for those in another. PacifiCorp applied for an allocation of Phase I substitution allowances for an allowance sale to Illinois Power. The agreement is subject to the Environmental Protection Agency's approval of the substitution plan for Illinois Power.

PacifiCorp's first use of its allowances will be to support operation of its thermal system, including future additions to the system. It will retain a reasonable cushion of surplus allowances to accommodate potential changes in the operation of its units and to protect against unforeseen contingencies. The company will market any remaining surplus allowances.

Some parties have questioned whether the company should reduce production at some of its generating plants to be able to sell additional allowances. If the company were to reduce production at a generating plant to free up allowances to sell, the market price for those allowances would have to be greater than the cost of acquiring replacement power. Only then would such a strategy benefit PacifiCorp customers. The price for surplus allowance will develop from market conditions, including the cost to prospective purchases of bringing their systems into compliance, auctions of allowances, and the development of futures markets. The current market price for SO2 allowances appears to be about $160 per ton of SO2 emissions, which translates to about 0.13 mills/kWh, or less than $0.005/kWh. The cost of all new coal-fired resources includes this cost, which the company would incur either as an opportunity cost (fewer allowances available to sell) or as a direct cost (the need to acquire additional allowances). The cost of new resources or purchased power is about $0.04 to $0.06 per kWh. Thus the cost of acquiring replacement power is at least 10 times the what the company would gain by decreasing production at its current coal plants and selling more allowances. The company will periodically reassess its strategy as the allowance market develops.

How is the company using pilot projects to explore methods of offsetting CO_2 emissions from its plants?

As part of the company's environmental goal, PacifiCorp is testing strategies to offset emissions of carbon dioxide (CO_2). While the scientific jury is still out on how carbon emissions may affect climate, the company believes it is prudent to begin exploring low-cost ways to offset CO_2 emissions. The company's demonstration projects will be useful in developing policies for using carbon offsets as a cost-effective way to counter the emissions of greenhouse gases.

Other offset techniques under consideration include recycling coal ash and recovering methane from mines. PacifiCorp has retained the services of an outside consultant to assist in the technical evaluation of the current projects and to help in the evaluation of future offset opportunities. PacifiCorp recognizes that offsets such as those achieved through forestry are only one component of an overall carbon strategy that includes renewable resource development and helping customers conserve energy.

Two projects are currently underway, and two additional projects are under development:

Rural Reforestation in Oregon.

PacifiCorp is working with the Oregon Department of Forestry (ODF) to assist non-industrial landowners plant trees on private lands currently covered with grass or light brush. Under an agreement with the landowners, PacifiCorp provides 75 percent of the landowner's costs for site preparation and planting for those who agree not to harvest for 45 years. For landowners willing to agree not to harvest for 65 years, PacifiCorp pays 100 percent of the landowner's up front costs. Through this project, landowners planted approximately 200 acres in the 1992 - 93 planting season, and another 400 acres in the 1993-94 planting season. The company estimates that the cost of carbon sequestration in this project is about $2 per ton of carbon. PacifiCorp is dedicating a total of $200,000 to this pilot project for plantings last season and this season.

Shade Tree Planting.

PacifiCorp, in partnership with a non-profit organization called TreeUtah, is planting shade trees in eight different neighborhoods around the Salt Lake valley. The project tests the use of urban trees to offset carbon emissions in two ways: by absorbing carbon and reducing cooling load by shading homes, thereby reducing fossil fuel generating needs. The trees (about 1,400) are being planted around houses and multifamily dwellings to achieve maximum benefit in reducing both cooling and heating requirements. With the assistance of work underway by the U. S. Forest Service, PacifiCorp will monitor the success of the delivery mechanism and determine the carbon benefit. Evapotranspiration from a tree, which reduces the "heat island effect," and shade from a tree make up over 90% of an urban tree's carbon benefit. The remainder is from actual carbon sequestration as the tree grows. The cost of carbon sequestration in Salt Lake is $15 to $30 per ton. PacifiCorp has dedicated $100,000 to this pilot project.

Reforestation of Fire-Damaged Lands in Eastern Washington

In 1991, fire damaged over 50,000 acres of privately owned forested land in northeastern Washington and western Idaho. The fire depleted most of the seed stock. As a result, natural pine regeneration is unlikely on all but about 10,000 acres. PacifiCorp's carbon offset project will plant trees on the fire-damaged lands in this region. The project will be conducted in cooperation with the Upper Columbia Resource Conservation and Development Area, which is a federally supported organization assisting private landowners with reforestation and forest management. The pilot project includes a long-term management plan that allows thinning at regular intervals and establishes an on-going cycle of forest regeneration. PacifiCorp will pay 75 percent of the landowners' site preparation and planting costs, so the carbon offset cost will be approximately $1.75 per ton of carbon. PacifiCorp will be contributing $50,000 to this pilot project.

Forestation in the Saratov Region of Russia

PacifiCorp has joined forces with EPA, Oregon State University, and the Environmental Defense Fund to work with the Russian forest service to plant currently unplanted lands in Russia's Saratov District. The Saratov district is approximately 1,000 kilometers southeast of Moscow. At least 500,000 acres of state-owned land are in need of planting for soil protection and other purposes. These lands have not previously been forested, nor will any tree growth be likely without some form of assistance. PacifiCorp, in partnership with the Russian Forest Service, will plant pine, ash, larch, and birch trees in the area. The U. S. Environmental Projection Agency, through cooperative agreements, is providing additional technical and financial support. The newly planted trees will not be cut for a minimum of 80 years. Although the new trees have a slow growth rate, the project is very cost effective due to the extremely low costs of implementation and oversight. The total project cost should be $15 - $20 per acre, with a resulting carbon cost of $0.60 per ton of carbon. PacifiCorp will contribute $50,000 to the pilot project.

The company's pilot projects will test the cost effectiveness of a variety of offset techniques and explore a variety of contractual arrangements for implementing the projects. The Clinton Administration's Climate Action Plan contains voluntary programs to limit greenhouse gas emissions. The President's plan encourages carbon offsets, including forestry projects. An accounting system registering activities that limit CO2 emissions is under development by the Administration, as required under the Energy Policy Act of 1992. These guidelines are likely to include rules for registering forestry projects as well as other offsets.

Is fuel switching included in the company's portfolio?

PacifiCorp believes that public policies should encourage the efficient use of all fuels rather than promoting one fuel over another, and evaluations of fuel switching must incorporate the competitive marketplace and overall energy efficiency. To incorporate fuel switching into the analysis within RAMPP-3, one of the sensitivities assumed a reduced load level, below the medium load growth level, due to usage level changes on the customer side of the meter such as would occur from rate design changes or fuel switching. The company is addressing the issue of fuel switching more directly in changes to its Hassle-Free Program.

The Oregon Public Utility Commission's (OPUC) Order No. 93-206, which acknowledged RAMPP-2, included two provisions related to fuel switching. First, the commission said "Pacific should offer customers the choice of high efficiency electric or gas replacement water heaters in its Hassle Free program if customers have gas space heat." The company has implemented this directive. PacifiCorp worked with OPUC staff and representatives of Oregon's three local gas distribution companies to develop a new option for the Hassle-Free program. The option will allow Hassle-Free customers with residential gas service to choose either a new high-efficiency electric water heater or an equivalent cash payment. The cash applies to the purchase and installation of a high-efficiency gas water heater. OPUC staff and all three gas utilities support the change.

The company extensively analyzed fuel switching in conjunction with its RAMPP-2 activity. It found that fuel switching was not cost effective in most applications after the installation of less costly efficiency measures. A further study of fuel switching was ordered by the Oregon Commission. However, subsequent discussions with the OPUC staff confirmed that they did not see the need for an additional study.

How does RAMPP incorporate rate design?

Comments on RAMPP-2 included a concern that price design alternatives be considered for promoting energy efficiency and peak reduction. As a pricing policy objective, the company will promote economic and energy efficiency by proposing service and price packages which:

- Better reflect costs by season, time of use and customer characteristics
- Increase differentiation of utility services and customer segments to provide additional service and price options to customers
- Consider the competition -- what are the customer's alternatives to standard utility price and service packages
- Consider the customer's perception of the company's services being provided to customers

The company has developed a number of pricing proposals for promoting energy efficiency and achieving peak reduction. Some of these proposals can begin soon, while others should be a part of a general rate case filing. Any rate design proposals would be supported by analysis presented in the general rate case.

Any discussion of energy efficiency and price design should recognize that the design of prices must meet and balance a number of objectives. As paraphrased from Bonbright's work, Principles of Public Utility Rates, these objectives are as follows: encourage economic use, simplicity, revenue requirement recovery, revenue stability, gradualism of changes, cost of service reflection, and lack of unfair discrimination. The company has linked price design with the RAMPP process in two ways. First, integrated resource planning and rate design come together in the ratemaking process. The first step is the development of avoided costs from the RAMPP studies. One of the primary inputs for the company's marginal cost studies is avoided costs. The marginal cost studies provide guidance for rate design. The role of a price signal is to neither encourage nor discourage consumption, but to provide customers with information about the costs of providing the service, so they can decide to buy and consume electricity when the value they place on electricity is greater than its relevant marginal costs. With appropriate price signals, customers may instead choose to install energy efficiency measures.

Second, the action plan links price design with the RAMPP process. The RAMPP-3 action plan includes specific pricing plans developed from a 1993 peak management study. One is more time-of-day pricing for irrigation and large industrial customers. Currently in the Pacific Division, only demand charges for large industrial customers are differentiated by time of day. In the Utah Division only some of the industrial tariffs are time-differentiated. Greater use of time-of-day pricing would provide appropriate price signals to customers. The company's energy costs for off-peak periods are lower than for on-peak periods. The prices charged during off-peak versus on-peak hours would reflect this variation in the company's costs.

Another pricing action is to develop a capacity credit, roughly based on the company's avoided capacity cost, for customers willing and able to be curtailed during periods chosen by the company. This capacity credit would apply to additional requests for interruptible-type power and serve as a replacement for existing interruptible service upon expiration of existing contracts. While requests for interruptible service are common, the company has consistently declined to offer traditional interruptible service to additional customers. The company's non-spinning reserves serve the traditional interruptible contracts. Those contracts have 85 percent guaranteed availability, and provide an opportunity for the customer to buy short-term service at higher prices during periods of economic interruption. A capacity credit would be a different product. A standard tariff would offer the capacity credit. This would also require a contract between PacifiCorp and the customer. Ultimately, the capacity credit offering could be structured in many different ways, including the payment of a credit only upon interruption. It would provide a low-cost, lower-value service alternative for customers with flexible service requirements. The company will be exploring many alternatives with customers to develop services that meet customer needs at prices acceptable to participating customers.

How does the RAMPP process deal with interruptible load?

The load forecasts include the company's contract obligations to provide energy resources to interruptible customers. However, the load forecasts do not include the capacity needs of interruptible customers.

How has PacifiCorp included decoupling in the RAMPP analysis?

Decoupling is being addressed through other regulatory forums. PacifiCorp believes this approach should continue. Decoupling is currently being discussed in separate forums in Oregon and Utah.

Can the company improve the accuracy of its conservation load factor?

Yes. The Company plans more load research over the next few years to reduce uncertainties in its conservation load factor estimates. Conservation load factors help determine cost-effectiveness limits for conservation by converting dollars/kW to mills/kWh. The amount of peak saved depends on the type of measure and how likely it is to affect usage during peak hours.

To accurately measure the peak savings benefits of conservation, the definition of a peak period needs to reflect the PacifiCorp system. Most utilities measure peak savings on only one day of the year. For PacifiCorp, capacity is important during all months of the year for load following, scheduling of maintenance for thermal plants, and completing firm wholesale sales. The company needed a way to reflect this year-round peaking pattern in developing conservation load factors.

The conservation load factor of 1.212 for residential weatherization comes from Hood River Project data. This is one of the few studies that measured peak capacity savings during different times of the year. Hood River data indicate that after weatherization, customers reduced their energy consumption by an average of 14 percent a year. However, peak load savings were not as high since weatherization typically does not include improvements in HVAC equipment and appliances.

For residential new construction, the company is using a conservation load factor of 1.00. This comes from BPA's End-use Load and Consumer Assessment Program (ELCAP) study of energy savings in new buildings. Independent computer modeling using Department of Energy models developed the 0.6 conservation load factor for commercial buildings. Since the BPA analysis provided only energy savings, these models estimated demand savings. The aggregate conservation load factor ranged from 0.6 to 0.8.

What is the company doing to measure actual energy and capacity savings from DSR programs?

PacifiCorp launched three load studies in 1993. These studies collect data on four major DSR programs: new residential construction, residential retrofit, commercial and industrial retrofit, and commercial and industrial new construction. Evaluations of DSR irrigation programs will use historical data on time of use for irrigation.

For residential new construction, in 1993 the company installed equipment on 160 homes: 80 customers' homes as a control group, and 80 customers' homes participating in the Super Good Cents Project in Oregon. All of the homes had total load recorders. In addition, in 1994 the company will install additional equipment on 30 of the 160 sites -- 15 in each customer group -- to monitor water heating use, space heating use and indoor temperature. The study will continue through the 1994-95 heating season. Data from the study will help estimate the impact on load shape of new construction programs.

For residential retrofit, in 1994 the company will install about 65 total load recorders on customers' homes in Oregon and Washington who are participating in the Home Comfort retrofit program. These will be customers who have previously had load recorders on their homes. This will enable the company to obtain data on load shape both before and after the retrofit. This study will run through 1995. Data obtained from this load study along with historical data on load shape will help estimate the impacts on peaks for retrofit programs.

In 1993 and 1994, special equipment will monitor total load shape of 120 commercial and industrial buildings in the Energy FinAnswer programs. Equipment is now on about 50 buildings; the rest must await completion of new buildings. In addition, historical load shape data available in the load research system will identify candidates for Energy FinAnswer programs. For irrigation, load shape data from irrigation load studies in Idaho are available for evaluation of irrigation programs. As these demand-side programs begin in other jurisdictions, more load monitoring may be needed.

load research data now available in Utah as well.

Has the company investigated peak management as a follow-up to RAMPP-2?

Yes. The company completed a peak management report in November of 1993. Peak management allows a utility to modify the shape of its load curve to benefit both the utility and the customer. The dual objectives of peak management are to reduce utility cost and provide customers with value. Both demand- and supply-side activities can meet these objectives.

The report summarized the company's current and past peak management activities and outlined future plans. Current and past activities include the company's capacity purchase from Bonneville Power Administration that provides 1100 MW of power during peak loads and the return of an equivalent amount of energy when loads are low. The merger between Pacific Power and Utah Power saved the company the equivalent of a 400 MW power plant. In addition, the company's industrial interruptible customers provide 438 MW of peak management with another 80 to 100 MW available from interruptible irrigation customers. The company also uses time-of-day pricing to manage peak loads.

A company survey of 30 utilities concerning their peak management experiences concluded that the appropriate peak management strategy is unique to each utility and must consider the load profile of the utility to ensure the load shape modifications occur at the time and place of need. Load shape changes can result from reducing peak period demands, increasing the load factor, moving energy demand to different times and seasons, increasing off-peak energy sales, and promoting energy efficiency. Successful peak management must also appeal to customers. Many utilities use pilot programs to gauge customer response. Direct contact with customers can also provide meaningful information.

The most common peak management activities undertaken by the utilities surveyed included time-of-day prices and interruptible options for industrial customers. Direct control of appliances was also a frequently used strategy. Newer technologies such as thermal storage and "real time" pricing occurred less frequently.

Peak management between customer classes is a trade-off between economies of scale associated with large customers and the larger number of residential customers who can tolerate interruptions of power and change lifestyle habits. The most frequently encountered strategy for residential customers was direct load control of air conditioners and water heaters. For commercial customers, many utilities were focusing on energy conservation to reduce peak. For industrial customers, interruptible pricing was the most frequently used strategy. Even the most popular strategies did not work for all utilities. Some reported problems with customers who receive benefits from programs but who would have taken the same action absent those benefits (free riders) and customer comfort. Conclusions were: 1) the peak management strategy for each utility is unique and depends upon system operating characteristics and customer base; 2) successful programs are ones that are cost effective and that customers respond to; 3) companies that have made a long-term commitment to pursue peak management report the most success; 4) pilot programs frequently determine the feasibility of a particular strategy; and 5) many utilities are focusing future efforts on energy efficiency, which reduces energy and peak demand, while maintaining existing cost effective peak management programs and eliminating non-cost effective programs.

Development of recommended courses of action for PacifiCorp required review of the system daily and seasonal load shapes, resource operating characteristics, operational requirements and transmission constraints. The results from this analysis show that:

> The daily load shape indicates a heavy load period of 16 hours. Capacity is important during all months of the year but in the near term, reductions or shifts in Utah summer peaks are more valuable.
>
> Peak reductions need to be predictable and dispatchable to fit with existing hydro and purchased shaping resources.
>
> Instantaneous peak reduction (real time load control) could have value in reducing load following requirements met by thermal resources.
>
> Utilities fully load transmission lines in the West. Shifting load to off peak would exacerbate the transmission limits in the West. In the Utah Division, there are transmission bottlenecks. Peak management in the Utah area could reduce these bottlenecks.
>
> Local area benefits (at the level of the feeder, substation or city) from peak management merit greater study.

The company's peak management strategy will involve a combination of supply side and demand side activities, including system efficiency improvements, consideration of generation resources with dynamic operating benefits, and demand side programs and pricing options. Discussing options with customers can yield useful suggestions. Evaluations of peak management strategies will use the following success criteria: 1) maximize net present value to customers, 2) acceptable to customers, 3) benefits exceed costs from a utility perspective, 4) risks can be effectively managed, and 5) the measure allows for future flexibility to modify, expand or eliminate the program.

The action plan for RAMPP-3 includes several items from the peak management study.

Has the company evaluated the costs and benefits of its economic development activities?

Customers and the communities served by Utah Power and Pacific Power directly benefit from PacifiCorp's economic development efforts through job creation, increases in personal income, net tax revenues to state and local governments, and local economic stability. The company's commitment to economic development comes from a belief that the customers and communities served must prosper and meet their economic and competitive challenges for PacifiCorp to prosper. The Company's economic development activities are a vital part of PacifiCorp's overall business objectives.

At both Pacific Power and Utah Power the approach to economic development is to work in partnership with local communities, states, and other interests, to assist in the development and implementation of plans, strategies and programs that achieve mutual economic development objectives within the local economy. This involves working with local communities on their development efforts, assisting existing business in their expansion efforts, providing information about industrial sites, infrastructure, transportation, etc., to businesses considering relocation. All of these efforts help communities stabilize and diversify local economies to maintain jobs and enhance local services.

The community development activities focus on assisting local communities to improve economic well-being through increased economic diversification and enhanced employment opportunities. The services include facilitating and organizing community development groups, assisting in the development and implementation of community plans, assisting select communities in outreach efforts such as trade show participation and marketing materials, and assisting communities in identifying resources to use in economic development efforts.

Industrial development activities target recruitment and siting of new businesses that will add jobs for communities within the Company's service territory. PacifiCorp prepares comprehensive proposals to assist potential new customers with every aspect of the siting process. These activities may include assistance in obtaining appropriate financing; securing adequate infrastructure; energy efficiency service options; utility service to the site; and helping with land and use zoning issues, licenses and permits necessary to facilitate the location effort.

The business retention and expansion activities involve maintaining an active public and private sector networking capability to assist new or existing business in arranging financing for job creation, provide market research, provide feasibility analysis to pinpoint opportunities for job creation, provide project evaluation, and perform industry specific economic research.

The cost for providing all community development services was approximately $1.7 million in 1993. About 59 percent was for community development and 41 percent for business retention, expansion, and attraction. Much of the cost was for informational assistance to customers before they move into the service territory and assistance in helping existing customers improve profitability and expand. The Company provides no rate discounts to influence a relocation decision.

The Utah Economic Development Task Force provided a report to the Public Service Commission of Utah on October 7, 1993, "The Treatment of Economic Development Expenses in Setting Prices in Utah." The report concluded that the Company's economic development efforts, in partnership with state, regional and local organizations, benefit customers by diversifying and improving the long-term stability of the local economy. In addition, the task force found that many of the services and activities performed by the Economic Development Department, such as price comparison, information regarding electric service capabilities, etc., are consistent with good customer service.

The task force found that supporting and facilitating the creation, retention, expansion, and attraction of businesses benefits existing customers by helping to influence new customers in decisions regarding their electric service requirements and installation of demand-side measures. The company informs new and existing customers of energy efficiency program offerings. This provides the customer with an opportunity to improve their competitive position and the company with an opportunity to acquire cost effective demand side resources. The task force acknowledged that while these activities may result in an increase in the demand for electricity, the Company's participation in economic development will better position it to plan for and manage such growth.

Depressed local economies tend to have high vacancy rates, abandoned commercial space, and closed industrial sites. Utility plant in service is very much under-utilized in these communities, therefore bring business in and keeping existing business helps to revitalize the community and reduce the overall cost to provide customers with electric service.

The State of Oregon recognizes the importance of a strong and diverse economy and has established specific measurable objectives to improve the livability of the state and provide economic opportunities for all Oregonians. The Oregon Benchmarks for the Economy, created by the Oregon Legislature, summarizes the significance of a healthy and diverse economy:

> "A prosperous, diverse economy is important for Oregon's future in at least three ways. First, a healthy economy provides job opportunities for individual Oregonians. Second, businesses and individuals working in such an economy provide the revenues to fund schools, recreational and cultural attractions, public facilities and services. Third, the individual opportunities created by a healthy economy can reduce the rate of unemployment and poverty, reducing the costs of social service programs."

The three key benchmarks for measuring economic progress are per capita income, regional employment growth, and industrial growth and diversification. Most job creation in communities served by Pacific Power over the last decade has been in the non-manufacturing sector and represents lower real wages. The state encourages a strong partnership with private sector business, such as PacifiCorp, to assist Oregon's rural communities in improving their economic future.

The Utah Department of Revenue estimates that every job created provides a net tax revenue to the state of $2,800 per year. Diversified economies are more resilient to dislocation and societal costs that can result when cutbacks and shutdowns occur in a local community. The curtailment or shut-down of a major industry adversely affects the economic health of a community. This occurred throughout the timber-dependent communities of the Northwest. Communities in Utah and Wyoming that are dependent on single industries such as oil and gas or military installations are also vulnerable. Plant closures, job losses and indirect economic impacts have occurred in many of the communities served by PacifiCorp. In some cases the closures have resulted in the loss of above average per capita wages and left the local economy without an industrial base. PacifiCorp's economic development efforts help stabilize these economies.

One of the sensitivities tested the impact of increased load growth from economic development on customer prices and system costs. That sensitivity, which included the cost of the company's economic development program and the additional capital cost for new distribution equipment required to serve additional customers, indicated that economic development would not result in increased prices to customers.

What about additional personnel

PUBLIC PROCESS

PacifiCorp's refers to its IRP public advisory group as the RAMPP Advisory Group (RAG). A separate appendix in this report details two types of written communication between the company and the public advisory group: letters during RAMPP-3 and written comments on the draft report. During the course of the RAMPP-3 process, the company invited participants to write letters to the company whenever there was a topic on which they wanted a written response. RAG participants took advantage of this opportunity thirteen times. The letters tended to be about the company's decision-making process, demand-side resources, and the analysis plan for RAMPP-3. The Public Process Appendix includes the letters from the participants and the company's response to each. In addition, two oral questions received written responses, which are included, and one letter (from the Industrial Energy Consumers) did not request a response.

After the company issued the draft report, RAG participants and other interested parties had an opportunity to provide written comments to the company. The Public Process Appendix includes the company's written response to each of the inquiry items included in each of those letters, as well as a document which includes all of the comments the participants made on the draft report at a special two-day RAG meeting devoted to parties' comments on the draft report. All of the items from the letters and special RAG meeting totaled 311. The response to each item includes: whether the report or an appendix was changed from the draft version; if there was a change, where the reader can find the change; if there was not a change, why not; and often the response includes some additional information about the topic.

PacifiCorp began using a public advisory group during the development of RAMPP-1 (during 1988 and 1989). The company re-convened that group for RAMPP-2 (during 1990, 1991 and 1992), and again for RAMPP-3 (during 1992, 1993 and 1994). While some of the participating individuals have changed, there has been little change in the organizations represented. The major difference has been the addition of representation from more of the states in which PacifiCorp provides service. Utah public agencies and customer groups began sending representatives during RAMPP-2. Idaho, Montana, and Wyoming agencies began sending representatives during RAMPP-3. In order to include more Utah representatives in the RAMPP-3 technical subgroup meetings, the subgroup used the company's video-conference facilities in Portland and Salt Lake City for most of their meetings. In this way, more Utah representatives could "meet" with parties in Portland by way of video.

PacifiCorp considers the public group's role to be one of providing advice and counsel on the planning process, rather than finding a collaborative consensus on the actual plan. Some parties would prefer a collaborative process, and expressed this preference at RAG meetings. However, the company believes its senior management is responsible for decision-making.

Senior management participated more in RAMPP-3 than in previous RAMPP processes. Officers attended RAG meetings to provide an opportunity for RAG participants to hear from and question company officers. Mike Henderson, then vice president of Community and Energy Services, spoke on demand-side resource strategy. Chuck Adams, then senior vice president of Fuels and Power Supply, spoke on the company's coal plant strategy. Dennis Steinberg, vice president of System Development, spoke on the company's implementation of the RAMPP-2 action plan, again on the company's strategic plan, and again on the company's DSR standards with Dan Spalding, senior vice president of the company's financial area. Harry Haycock, senior vice president and Chief Engineer, spoke on the company's strategy for improving the efficiency of its transmission and distribution systems. Tom Imeson, vice president of Communication and Government Affairs, spoke on the company's CO2 strategy.

PARTICIPANTS

Participants in the RAMPP-3 Advisory Group included public agency personnel, private groups, and customer representatives. Following is a list of the groups and individuals represented in the RAG:

Bonneville Power Administration
Community Energy Project (representing residential customers)
Drazen-Brubaker (representing industrial customers)
Idaho Public Utilities Commission
Industrial Customers of Northwest Utilities
Montana Department of Natural Resources and Conservation
Montana Public Service Commission
Northwest Conservation Act Coalition
Northwest Natural Gas Company
Northwest Power Planning Council
Oregon Department of Energy
Oregon Public Utilities Commission
Portland General Electric
Solar Energy Association of Oregon
Utah Association of Industrial Energy Users
Utah Committee of Consumer Services
Utah Division of Energy
Utah Division of Public Utilities
Utah Public Service Commission
Washington Office of Attorney General
Washington State Energy Office
Washington Utilities and Transportation Commission
Wyoming Public Service Commission
Ruthine Hepburn (representing residential customers)

The company tried to increase customer participation in the RAG for RAMPP-3. Solicitation for greater industrial involvement resulted in participation by the Industrial Customers of Northwest Utilities. In addition, the company recruited two residential customers through the company's local service office in northeast Portland. The addition of more customer representation would improve the public advisory process by providing a wider variety of opinions and positions to consider in the RAMPP process.

RAG MEETINGS

Twelve all-day RAG meetings reviewed RAMPP-3 inputs and analyses before the company issued the draft report. Following is a list of the RAMPP-3 RAG meetings:

October 2, 1992	10 a.m. - 3 p.m.	RAG
November 5, 1992	2 p.m. - 4 p.m.	Technical Subgroup
November 6, 1992	10 a.m. - 3 p.m.	RAG
December 10, 1992	2 p.m. - 4 p.m.	Technical Subgroup
December 11, 1992	10 a.m. - 3 p.m.	RAG
January 28, 1993	2 p.m. - 4 p.m.	Technical Subgroup
January 29, 1993	10 a.m. - 3 p.m.	RAG
March 11, 1993	8 a.m. - 4 p.m.	Technical Subgroup
March 12, 1993	10 a.m. - 3 p.m.	RAG
April 9, 1993	9 a.m. - 1 p.m.	RAG
April 9, 1993	1 p.m. - 4 p.m.	Technical Subgroup
April 29, 1993	8 a.m. - 4 p.m.	Technical Subgroup
April 30, 1993	9 am. - 3 p.m.	RAG
June 3, 1993	1 p.m. - 4 p.m.	Technical Subgroup
June 4, 1993	10 a.m. - 3 p.m.	RAG
July 30, 1993	10 a.m. - 3 p.m.	RAG
September 10, 1993	10 a.m. - 3 p.m.	RAG
October 29, 1993	10 a.m. - 3 p.m.	RAG
December 16, 1993	10 a.m. - 3 p.m.	Technical Subgroup
December 17, 1993	10 a.m. - 3 p.m.	RAG
February 17, 1994	10 a.m. - 3 p.m.	Technical Subgroup
February 18, 1994	10 a.m. - 3 p.m.	RAG

Subgroups of the RAG also met to discuss specific topics more fully. Those groups addressed:

Demand-Side Resources
Forecasting
Model Testing
Study Plan

CONTRIBUTIONS OF RAG

Before each RAG meeting the company mailed out the material to be presented at the meeting. At each meeting the company presented methods, analysis and findings to the group. The meetings provided an opportunity for the participants to contribute their comments and concerns about work in progress. In this way, the group could raise issues and discuss them, and the company could incorporate the group's input into the plan. The company was able to produce better analyses and reports with the information and suggestions provided by the group.

The mailing prior to each RAG meeting also included detailed minutes from the previous meeting. These generally were 20-30 pages. The minutes enabled parties who were not able to attend a particular meeting to stay current with RAMPP-3 progress. They also allowed other parties, who were not able to regularly attend RAG meetings, to keep up with the issues addressed, and provide input.

At the first meeting of the RAG for the RAMPP-3 process, the group discussed lessons learned from RAMPP-2 and how to create a better RAMPP-3. Two key suggestions from several members called for more involvement by senior management in the RAG meetings and better explanation of company policies and decisions. The company implemented both suggestions. As described above, senior management participated in several of the RAG meetings. The RAMPP report includes more documentation of decision making.

The introductory chapter includes a discussion of the milestones and major decisions since RAMPP-2, and the basis for those decisions. The Conclusion chapter provides a link between the analyses and the company's decisions for the action plan. The DSR Action Plan Detail chapter contains a section on the financial standards the company used to make its decisions on the amount of DSR to include in the action plan.

As RAMPP-3 progressed, the company relied on considerable input from the RAG participants in the development of the RAMPP-3 process, report and appendices. This occurred through RAG meetings, private conversations with RAG members, letters from RAG members, and written comments on the draft report and appendices. The contribution of the RAG is most evident in the analysis plan and documentation of input assumptions.

The RAG participants helped the company identify three basic elements of the analysis plan: strategy alternatives, sensitivities, and model runs (which cases would use which futures).

The company initially proposed three strategy alternatives for demand side resources, based on high, medium, and low cost-effectiveness levels. RAG participants felt that ramp rates were equally significant, and so the company added a fourth DSR strategy, based on the medium cost effectiveness level but with an accelerated ramp rate in the early years, which became the Accelerated DSR strategy.

The company initially proposed a set of sensitivities, expanding on the sensitivities used in RAMPP-2. RAG participants called for additional sensitivities in several areas. For example, they requested two load sensitivities, which the company added: first, load growth that would reflect marketing and economic development activities, and second, load growth that would reflect changes in rate design and fuel switching. Both tested the price and system cost impacts of these efforts. They also requested some of the portfolio sensitivities. Since the company used average water for the base assumption in RAMPP-3, RAG participants made sure that one of the sensitivities used critical water. Since the non-firm markets are an essential element in PacifiCorp's normal operations, the group requested sensitivities on that market, leading to the reduced-price and increased-price sensitivities on the non-firm market. As a result of the written comments that questioned the company's coal price assumptions for new coal resources, the company re-examined its coal price assumptions, and realized the changing coal markets required additional sensitivities. Five coal price sensitivities were added to the analysis plan after issuing the draft report and receiving the parties' written comments.

The company initially proposed model runs for each future based on all the combinations of demand-side, renewable, and coal strategies. The renewable and coal strategies included an unconstrained option, but the demand-side strategies did not. An unconstrained option means that the model has no constraints or requirements that force it to add certain resources, or restrict it from adding any particular resources. The model was free to add resources only as they were the most cost-effective choice. The RAG participants felt strongly that a full analysis required an unconstrained demand-side strategy, to provide a basis of comparison against the other demand-side cases. As a result, the company added an unconstrained DSR strategy. When combined with the unconstrained coal and renewable strategies (any-coal and any-renewables), it provided a totally unconstrained run for each future.

The company initially proposed 12 environmental adder cases, using two combinations of load growth, gas prices, and DSR strategy. The group requested that the analysis plan include nine additional cases, six using a third combination of load growth, gas prices, and DSR strategy, and a final set of three cases using a fourth combination.

The advisory group helped the company identify the specific model runs to do out of the set of 255 potential cases using all of the strategy combinations in all of the futures. The group identified 103 cases to limit the study plan to a manageable size, yet provide a useful set of information.

As a result of the written comments on the draft report, the company added additional material to better document input assumptions. These comments resulted in an additional item in the Questions and Answers chapter on avoided cost, a new section in the DSR Action Plan Detail chapter which addresses the company's decision making on DSR, a new paragraph in the Action Plan chapter which addresses the difference between RAMPP planning and the company's acquisition decisions, a different placement of the Conclusion chapter before the Action Plan chapter, a re-writing of the Conclusion chapter to provide a bridge between the analyses and the action plan, and additional explanation in numerous other places in the report and appendices. The largest area of additional information was in documenting DSR assumptions and inputs. The DSR draft Appendix was larger and more complete than the appendix for RAMPP-2; the additional suggestions from the written comments should allow readers to find the information they need.

Overall, PacifiCorp is proud of its RAG process. It has improved the RAMPP-3 process and product (Report and Appendices). The IRP requirement to include public involvement has resulted in greater documentation of assumptions and inputs, and provided useful information to all parties, both inside and outside the company.

CONCLUSIONS

This conclusion chapter addresses four areas: 1) the objective criteria the company used in designing the RAMPP-3 study and evaluating the results, 2) the information used as inputs, 3) what the company learned from RAMPP-3, and 4) a brief note on plans for PacifiCorp's fourth IRP, RAMPP-4.

OBJECTIVE CRITERIA

Any discussion of objective criteria must begin with PacifiCorp's mission statement from its strategic plan:

> PacifiCorp's mission is to help our customers prosper in our economic system by satisfying their electric energy wants and needs with electricity, energy efficiency and other related value-added products and services. PacifiCorp can only do this by maintaining competitive prices and quality service for its customers, creating a favorable work environment for its employees, being a responsible steward of the natural environment, and in the end growing value for its shareholders.

The overriding strategic focus for PacifiCorp is to maintain its position as a low cost producer of electricity for its 1.3 million customers in 7 western states. Therefore, PacifiCorp's IRP goals are to minimize prices and risks to customers, minimize costs and risks to society, and provide value to shareholders.

who is the competition in Utah?

The RAMPP-3 report title -- Positioning for Competition and Uncertainty -- reflects these concerns. This title represents the company's intent to position itself for an uncertain future that will contain increasing competition. By positioning, the company intends to pursue activities that maintain its future flexibility, shorten the lead time for future acquisitions, and allow it to respond quickly to market opportunities. To meet the competition, the company believes it will need to provide both price and service levels that meet the customer's perception of fair value.

from whom?

PacifiCorp believes that balanced planning results from considering multiple criteria. Least cost is a worthwhile goal, but least cost can be defined in various ways, and if viewed in too narrow a sense, can lead to unwise decisions. Viewing least cost in a broad perspective can result in wiser decisions. The company has adopted a broader perspective in achieving a least cost goal. It considers five criteria in its integrated resource planning process:

- Minimize cost and retail price impact,
- Consider the tradeoff between cost and emissions,
- Provide reliable service,
- Assure efficiency, and
- Maintain flexibility.

The company used its strategic goals and the five criteria listed above to focus on four considerations in developing the goals in the RAMPP-3 action plan. This is a balancing act, because all four considerations are important yet they partially conflict with each other:

- Reduce long term total resource cost,
- Achieve equity among customers,
- Meet increasing competition in the electricity industry, and
- Reduce environmental emissions.

Some of these considerations can be analyzed quantitatively, others cannot. The company based its action plan goals on its management's judgment regarding the impact of DSR and other resource acquisition levels on these considerations.

Competition is an increasing reality for electric utilities. For PacifiCorp, with almost one half of its retail sales to industrial customers, and up to one quarter of its total sales to wholesale customers, competition is an immediate reality. Passage of the Energy Policy Act has increased the forces of competition in the industry, both at the retail level and at the generation level. The company's low prices and extensive transmission network allow it to compete in Western energy markets. However, competition from other energy suppliers including natural gas and oil companies, other electric utilities, cogenerators, suppliers of energy efficiency services, independent power producers, and brokers requires the company to control costs and keep prices as low as possible.

The Energy Policy Act facilitated the entry of brokers -- a new breed of player -- in the market, which has increased competitive forces even more. Brokers don't own assets and don't carry reserves; they rely on non-firm power from utilities, taking on the risk they will be able to provide firm service to buyers. They don't have to meet any regulatory requirements for retail customers, nor do they have to meet FERC requirements to base their prices on costs. They base their prices on the market. Their impact is to reduce the market price for wholesale power for all sellers. This will push wholesale prices down, which will increase the need to keep PacifiCorp's costs as low as possible, and will reduce the benefit from wholesale sales that the company will be able to provide to its retail customers.

RAMPP provides some essential tools to help the company meet the competition, by identifying relative costs and benefits of alternative resource acquisition strategies, and by providing a framework and benchmark against which to compare opportunities that occur. The company was able to use the RAMPP-2 framework and benchmark to take advantage of significant opportunities, such as the SCE peaking contract and the Hermiston cogeneration project. These transactions will result in lower cost service to retail customers. RAMPP-3 should provide an equally useful framework and benchmark for future opportunities.

While the company tried to be as clear and explicit as possible in applying the objective criteria described above, it is also important to recognize that management must use its collective judgment to balance objectives, draw conclusions, plan for action, and evaluate opportunities. The company tried to be as clear as possible in describing how and where it exercised that judgment in developing the action plan.

INPUTS AND ASSUMPTIONS

Before performing the analyses, the company determined a range of load growths, a range of gas price forecasts, the ability of the existing system to meet retail customers' growing power needs, a portfolio of new resources to meet customers' needs as they exceed the existing system's capability, and analysis tools (models) to combine these inputs and produce usable results.

Five load growth forecasts covered a range of average annual load growth of energy consumption over the next 20 years from 0.3 percent to 3.75 percent. The medium load growth case, at 2.1 percent, approximates recent actual load growth experienced by the company. The company expects growth to be between the medium-low at 1.3 percent and the medium-high at 3.0 percent, but does not rule out the possibility of higher or lower growth conditions.

Three natural gas price escalation rates covered a likely range from a low of 1.7 percent real annual escalation, medium of 3.8 percent, and high of 5.6 percent. Inflation was assumed to average 3.4 percent over the RAMPP-3 planning horizon. The company's goal is to take advantage of competitive forces in the natural gas markets, such as siting a plant near two pipelines, and maximizing the load factor of deliveries, to minimize the cost. The RAMPP-3 analysis included the individual gas cost components for gas-fired resources, including the commodity cost, transportation charges, transportation demand charges, storage demand charges, and storage injection and withdrawal charges.

In developing the action plan, the company relied on results from more than one load forecast level and more than one gas escalation rate. Based on recent history and current economic projections, the company believes that load growth will fall between the medium-low and medium-high, and probably closer to the medium. Therefore, the company weighed the results of the medium-low, medium and medium-high load growth forecast cases more heavily than the results of the low and high cases in developing the action plan. Based on recent experience in the natural gas market, the company also believes it is more likely that gas prices will be in the low-to-medium range. Therefore, the company weighed the results of the low and medium gas escalation cases more heavily than the results of the high gas cases in developing the action plan.

The portfolio of resources available to meet retail customers' power needs consisted of the existing system, demand-side resources, and supply-side resources. The company believes the existing system will lose 1,023 MW of resources over the 20-year planning horizon, but gain 918 MW through known additions, changes, and upgrades. Nine demand-side programs and major supply-side technologies provided a wide range of choices to the model. The major supply-side resource technologies were pulverized and IGCC coal, cogeneration, CCCTs, wind, and SCCTs or pumped storage for peaking. Total costs included transmission needed to interconnect a new resource to the system, but not the cost of expanding the transmission system to move power between geographic areas. This latter cost could affect the choice and timing of cost-effective resource additions..

Supply Side #'s

The portfolio information provides the relative cost of the different technologies. Utah and Wyoming pulverized coal was the least expensive at a real levelized total cost of 28 to 31 mills/kWh. IGCC coal would cost between 32 and 34 mills/kWh. Under coal price sensitivities that doubled the price of coal in the Utah area, Utah pulverized coal price increased to 38 mills and Utah IGCC coal price increased to 41 mills/kWh. The next most cost effective resource choice was cogeneration, which fell in a range of 42 to 44 mills/kWh. Thus, cogeneration costs would have to decrease by about 13 mills/kWh to be competitive with coal. CCCTs' costs were 47 to 48 mills/kWh. Wind plants using the federal tax credit cost 53 mills. Thus wind costs would have to decrease by about 25 mills/kWh to be competitive with coal. The model picked resources on price, which provides useful information to the company, but management makes its decisions on other criteria as well, such as resource operability, fit with the existing system, and future uncertainties and risks.

An optimization model provided a mathematical least cost plan for each of the cases included in the analysis. The capacity expansion model selected new resources after calculating the system operating cost through the study period with and without each of the potential new resource additions. A financial model then used a revenue requirements approach to calculate the utility system costs, total resource costs, and mills/kWh for each of the cases.

The analysis plan for RAMPP-3 consisted of 155 cases; for each case the model created a unique least-cost resource plan. The analysis plan included 103 cases in the base study plan which tested five load growth levels, three gas price levels, four demand-side resource strategies, two coal resource strategies, and two renewable resource strategies. An additional 23 cases tested the impact of environmental cost adders and carbon limits. Additional sensitivity cases (29) tested input assumptions for resources in the portfolio, transmission constraints, coal prices, and the non-firm market. The optimization model had to meet transmission constraints among six geographic areas representing the PacifiCorp system. The company tested each of these resource planning uncertainties on new resource choices, utility costs, customer prices, total resource costs, and emission levels.

WHAT THE COMPANY LEARNED FROM RAMPP-3

RAMPP-3 created 155 least cost plans. Since RAMPP-3 used an optimization model, each of the runs created a least cost plan for that set of input assumptions and constraints. It is impossible to identify which of the 155 is "the least cost plan." Each of them is a least cost plan for its particular combination of load growth, gas price, demand-side strategy, renewable strategy, coal strategy, and other input assumptions.

Regional Patterns and Transmission

The biggest influence on resource choices was the any-coal versus no-coal strategy choice. Coal (picked in the any-coal cases) is in Utah or Wyoming, cogeneration (picked in the no-coal cases) is in OWC. Therefore, cases with the any-coal strategy had a higher percentage of their total resources in Utah or Wyoming, and cases with the no-coal strategy had a higher percentage of their total resources in OWC. Higher levels of DSR moved the distribution toward OWC (more DSR in OWC). Higher gas prices moved the distribution toward Utah (because the model selected more coal). Transmission is increasingly constrained as utilities grow and wholesale transactions increase. To test the impact of these constraints, the analysis included two sensitivities that expanded the capacity of two key paths (from Wyoming to OWC and from Utah to OWC). These cases added less cogeneration and more coal, increased the system's non-firm sales, and decreased non-firm purchases. Both transmission sensitivities lowered customer prices. The company is continuing to pursue these upgrades.

Load Growth

As load growth increased, customer prices in real terms generally stayed constant or decreased, indicating that the company can meet the new resource needs caused by load growth with price increases that are no greater than inflation (inflation assumed to be 3.4 percent). Three sensitivities expanded the analysis of load growth uncertainties. The results from these sensitivities indicate that higher load growth can lead to lower prices. The company has worked for a long time to be a low-cost provider. RAMPP-3 confirmed that those efforts are paying off.

The finding that load growth leads to lower retail customer prices in RAMPP-3 is contrary to the findings about load growth from RAMPP-2. It is true that coal price assumptions in RAMPP-3 were lower than they were in RAMPP-2, but the RAMPP-3 no-coal cases also showed lower retail customer prices than RAMPP-2. The company believes there are three reasons for the lower price results in RAMPP-3.

First, modeling techniques in RAMPP-2 did not include an optimization model, so resource additions did not always exactly match the reserve margin requirement (they often exceeded it), resulting in excess additions and thus higher costs than optimally necessary for some years. RAMPP-3 used an optimization model that added only the exact amount of resource needed, regardless of whether it was only a portion of a plant. This removed any lumpiness from resource additions, lowering the costs for many of the years. Second, the company recognized that significantly more inexpensive cogeneration was potentially available from industrial customers when preparing the RAMPP-3 input assumptions than was the case with RAMPP-2. In RAMPP-2 only 400 MW of inexpensive cogeneration was available to the model (39 mills in 1991$); 1,000 MW of more expensive cogeneration (60 mills in 1991$); and 1,400 MW of very expensive cogeneration (79 mills in 1991$). However, in RAMPP-3, 2,099 MW of inexpensive cogeneration was available (42-45 mills in 1994$). Thus in RAMPP-2 the model only had 400 MW of inexpensive cogeneration, whereas in RAMPP-3 it had 2,099 MW of inexpensive cogeneration. The model did not have to turn to the next more expensive resource as soon with RAMPP-3. Third, fuel price assumptions changed, causing generally lower costs for RAMPP-3. The beginning coal price in RAMPP-3 was lower than it was in RAMPP-2, but the escalation rates were about the same. The beginning price for natural gas was about the same in both studies, but the escalation rate was lower in RAMPP-3 than in RAMPP-2.

Gas Prices

Changing the gas price escalation from one case to another did not dramatically change the resources selected. Under lower gas prices the model selected more cogeneration and less coal, and made more non-firm sales and purchases to minimize system costs. Higher gas price escalation reduced the model's use of gas-fired resources and increased its use of coal resources and wind. Higher gas prices in the no-coal cases also caused fewer non-firm sales, and fewer non-firm purchases. PacifiCorp's access to the non-firm markets improves its ability to respond to gas price uncertainty. That access may also help stabilize retail pricing. The real levelized mills/kWh (the best predictor of customer prices) showed little variation by gas price level. Therefore, it appears the company can manage its resource activities to minimize retail price risk from gas price uncertainty.

Resource Choice

Do risks cancel out?

The RAMPP-3 model runs indicated the company needs additional resources in 1994 and 1996 (without the Hermiston project). However, the earliest year new supply-side additions from the portfolio could come on-line would be 1997. To meet these resource needs, there is no guaranteed best-choice resource. Every resource has its pros and cons. Demand-side resources carry the risk of uncertain performance and an uncertain ultimate cost of demand-side resource acquisition. Gas-fired resources carry the risk of uncertain gas prices in the future. Cogeneration carries the risks of uncertain negotiations with customers or other developers and uncertain gas prices. Coal resources carry the risk of uncertain future taxes or restrictions on carbon dioxide emissions. Clean coal technologies, which can reduce the carbon dioxide risk, carry the risk of a new, not thoroughly proven technology. Renewable resources carry the risk of uncertain performance and ultimate cost. Pumped storage resources carry the risk of potential siting difficulties. All new supply-side resources carry siting risks. The company's management must weigh each of these risks against the anticipated benefits of each resource in making its ultimate decisions. Those decisions often depend on the opportunities that become available to the company, and typically require much more extensive financial and operational analysis than can be accomplished within RAMPP. RAMPP provides a first step in a careful analysis and evaluation process the company uses before making an acquisition. RAMPP provides the framework and benchmark against which the company evaluates resource opportunities.

Peaking Resources

PacifiCorp's immediate capacity needs make capacity requirements the primary driver in planning new resource additions. The RAMPP-3 model provided an incomplete analysis of capacity additions because it required the company to select one season as the peak period. The company used winter, since the winter peak remains higher than the summer peak throughout the 20-year planning horizon. However, PacifiCorp has peaking needs in both winter and summer. The model in RAMPP-4 will be able to add resources to meet either winter or summer peaks. This added capability will enable the company in RAMPP-4 to significantly improve its analysis of peaking needs and the fit of alternative resources to meet those needs.

The analysis included a sensitivity to test whether the model would select the SCE contract for a peaking resource, if allowed to. In fact, the model confirmed its cost effectiveness as a peaking resource.

The RAMPP-3 model runs indicated that the company will need peaking resources as early as 1999, although the model selected few peaking resources between 1994 and 2001. More detailed site-specific capacity studies performed outside the RAMPP process using an hourly production cost model identified summer peaking needs as soon as 1997 or 1998. The RAMPP-3 study assumptions under-estimated the company's peaking needs because 1) it based them on winter peaks, and the company has more immediate summer peaking needs; and 2) the model used baseload resources to meet the margin requirement because it relied heavily on non-firm markets to sell excess energy made available by the baseload resources.

The following table shows the model's resource additions in MW for peaking resources assuming what the company believes are the most likely futures: medium load growth, low and medium gas prices, medium DSR, strategic-renewables, and an additional case with the lowest level of adders. The adder case used medium load growth, medium gas prices, and any-coal. The peaking resources added were simple cycle combustion turbines (SCCTs) and pumped storage.

Peaking Resource Additions by Year (MW)
Table 11-1

Medium Load, Medium DSR	Case	1997	1998	1999	2000	2001	2003
Low gas, any-coal	17					56	428
Low gas, no-coal	19						248
Med gas, any-coal	34			44	70		173
Med gas, no-coal	36						398
Low adders	301				78		332

Under medium load growth, the company needs to add from 248 to 484 MW of peaking resources in the next 10 years. The model added more under a no-coal strategy, and less under an any-coal strategy. Either pumped storage or SCCTs would meet peaking needs in a cost-effective manner. To develop the peaking item in the action plan, the company reviewed peaking needs by 2001, recognizing that the model logic underestimated summer peaking needs. Although the model only selected 56 to 114 MW from 1994 through 2001, a more realistic assessment (based on an analysis using a detailed hourly production cost model) would require a total of 300 to 350 MW of peaking resources by 2001.

During the course of the RAMPP-3 process, the company prepared a peak management report. That report identified peak management approaches that have worked for other utilities, the peak management efforts currently underway at PacifiCorp, and areas for expansion or improvement. The action plan contains several items as a result of the peak management report effort.

Demand-Side Resource Strategy

The RAMPP-3 analyses provided the information necessary for the company to evaluate the price versus total resource cost trade-off. The company's financial analysis allowed it to prioritize demand-side resources, and arrive at an action plan acquisition level that is very close to the medium DSR strategy tested in RAMPP-3. DSR as a percentage of all new resource additions under a medium DSR strategy would be 61 percent under medium-low load growth, 26 percent under medium, and 19 percent under medium-high. Higher amounts of DSR led to a slightly lower total utility cost and total resource cost (TRC) levels, but also led to higher prices. There is a utility cost versus price, or a TRC versus price, trade-off. The DSR Action Plan Detail chapter provides a discussion of this analysis.

Baseload Resources

Under medium load growth, the company needs to add from 350 to 600 MW of baseload resources by 2001, and from 850 to 1,000 MW by 2003 (in the next ten years). Coal and cogeneration were the model's resources of choice to meet baseload needs. Table 11-2 shows the coal and cogeneration resources added to meet baseload needs. The numbers in brackets indicate coal added.

Coal and Cogeneration Resource Additions by Year (MW)
Table 11-2

Medium Load, Medium DSR	Cogen by 2001	[Coal] by 2001	Total baseload	[Coal]/Cogen Added 2003	Total by 2003
Low gas, any-coal	425		425	[428]	853
Low gas, no-coal	481		481	557	1,038
Med gas, any-coal	276	[91]	367	[609]	976
Med gas, no-coal	481		481	383	864
Low adders	438	[142]	580	450	1,060

The model selected coal if there were no restrictions on its ability to select coal resources. The model selected cogeneration until coal would be available (not until 2001 due to its lead time). Under medium-low load growth (and medium gas prices), the model added between zero and 223 MW of baseload resources in the next ten years. Under medium-high load growth (and medium gas prices), the model added up to 1,600 MW of baseload resources in the next ten years. This provides a range from zero to 1,600 MW. A narrower range, from 850 to 1,000 MW, is a target on which the company should focus. Although there is always risk that acquisition levels will be too small or too large, because of load growth uncertainty, focusing actions on a range of 850 to 1,000 MW of baseload additions in the next ten years is a reasonable strategy.

Coal Strategy

Coal was the least expensive new resource in the portfolio. Therefore, the model selected primarily coal when allowed to. These cases resulted in lower total costs and lower prices compared to cases that did not allow new coal resources. Without environmental adders, the model selected pulverized coal; with environmental adders, the model selected coal gasification (IGCC). The IGCC sensitivities provided additional support for the potential cost effectiveness of a clean coal technology. The company believes that further study is appropriate to identify potential sites, firm up cost estimates, evaluate changes in the coal market, and evaluate the alternative coal technologies.

The RAMPP-3 analysis included new coal plants in Wyoming and Utah. After the major analysis work for RAMPP-3 was finished, the coal market began to change. The Wyoming market is experiencing a temporary increase in demand. In Utah sufficient coal supplies at the $0.52/mmbtu price are available for only one new coal-fired unit. The coal required for additional new units would require additional capital investment in coal mining facilities. The coal price for additional units would be up to double the base study plan assumption (up to $1.06/mmbtu) for future new coal in Utah, which raised the real levelized cost of Utah pulverized coal from 29 to 38 mills/kWh. Five sensitivities used this higher Utah coal price. They confirmed the least-cost advantages of coal, even with the higher Utah coal price.

Cogeneration

The model selected cogeneration to meet new resource needs in all of the resource plans except the low and medium-low load growth cases. Most of the resource plans showed cogeneration coming on-line the earliest year it was available (1997). By 2001, the model added significant amounts of cogeneration under conditions the company regards as likely -- medium load growth, medium DSR amounts, and addition of the strategic-renewable resources. By 2003, the model had added even larger amounts. In the medium-high load growth cases the model added significantly more cogeneration. The model selected a large amount of cogeneration in 1997, none in 1998, and then varying amounts in 1999 through 2003. Table 11-3 shows results the company relied on most heavily in developing the cogeneration action item. It added less cogeneration in the any-coal cases, knowing it could add less expensive coal beginning in 2001.

Cogeneration Resource Additions by Year (MW)
Table 11-3

Medium Load, Medium DSR	1997	1998	1999	2000	2001	2003
Low gas, any-coal	276		44	70	35	
Low gas, no-coal	276		44	70	91	557
Med gas, any-coal	276					
Med gas, no-coal	276		44	70	91	383
Low adders	302		118	18		

The company determined that it should immediately pursue a range of cogeneration additions. The exact amount should depend on the opportunities that are available over the next few years. The range of cogeneration additions by 2001 for these five cases was from 276 to 481 MW; the range of baseload additions by 2001 was from 367 to 580 MW. The range of cogeneration additions by 2003 was 481 to 1,038; the range of baseload additions by 2003 was 853 to 1,038.

In developing a range of cogeneration acquisition for the action plan, the company considered the ranges listed above, tempered by its recent experience in the cogeneration market. Opportunities develop in sizes that don't always match a utility's exact requirements from a least cost plan. The company believes it is important to have the flexibility necessary to take advantage of opportunities, such as the Hermiston cogeneration project, which lowered total costs and customer prices. The company adopted a range beginning at 500 MW. This is consistent with a known expected resource acquisition (the Hermiston project), and is easily defended by the range of baseload additions required to meet anticipated load growth by 2001. The company adopted a top of the range for cogeneration additions in the action plan at 900 MW, which is above the top of the ranges for cogeneration and total baseload additions by 2001, and slightly below the top of the ranges for cogeneration and total baseload additions by 2003.

The top of the range by 2001 was 481 MW for cogeneration and 580 MW for total baseload; the top of the range by 2003 was 1,038 MW for cogeneration and 1,060 MW for total baseload. This gives the company the flexibility it needs to take advantage of potential opportunities, which don't come in the exact sizes specified by a model's resource additions. The 500 to 900 MW range adopted for the action plan includes the Hermiston project.

Renewables Strategy

The company's strategic-renewable strategy caused total costs and customer prices to be higher than under an any-renewables strategy. Under most conditions, the any-renewables strategy resulted in no renewable resource additions. The company believes a small price impact is justified to acquire experience with renewable technologies. Several sensitivities determined that if the company's base assumptions about renewable resource costs and operating characteristics were inaccurate, the errors would have to be quite large to alter the model's resource selections. The renewable sensitivities indicated that the renewable industry needs to advance significantly before renewable resources will be cost-competitive (due to initial costs, O&M costs, and operating characteristics). At the same time, renewable resources contributed heavily in the cases with high gas prices and a no-coal strategy, and in the environmental adders cases when CO_2 adders were $25/ton or higher. The strategic-renewables actions can position the company to pursue the higher level of renewables should future conditions require it. Those future conditions could be higher gas prices with restrictions on new coal resources.

Portfolio Sensitivities

The sensitivities provided some valuable lessons regarding the portfolio input assumptions. The Hermiston sensitivities indicated that the Hermiston project lowers system costs and customer prices compared to a resource plan without it. The SCE sensitivity confirmed that the contract was a wise decision. The IGCC sensitivities confirmed that a clean coal technology can bring many of the benefits of low-cost coal while mitigating some of the environmental risks. The transmission sensitivities confirmed the value of expanding the company's transmission capacity from the eastern to the western part of the system.

Coal Price Sensitivities

Five sensitivities doubled the price of coal for new coal plants in Utah. The model switched from Utah coal to Wyoming coal, until it hit a transmission constraint, and then began adding Utah coal. Even with the coal price increase, Utah coal was still less expensive than any other supply-side technology. The coal price sensitivities did not alter the company's conclusion that coal is the least-cost supply-side technology.

Non-firm Market Sensitivities

The company successfully uses the non-firm markets to buy and sell power, using the savings and revenues to reduce the total revenue requirement for retail customers, and thereby reducing customers' retail prices. Consistently, the model made more sales than purchases (unless the case included a CO2 tax of $25 or $40/ton), reflecting the company's low price structure relative to other utilities in the marketplace. Neither load growth nor gas price escalation had much impact on the model's activity in the non-firm markets. The any-coal strategy resulted in more sales; the no-coal strategy resulted in more purchases, accentuated under higher gas prices. The Hermiston, IGCC, and transmission sensitivities increased the system's ability to use the non-firm market. In the environmental adder cases the model made fewer sales and more purchases, because the adder assumption for purchases used a CCCT's emissions, whereas the company's sales had an adder for coal's emissions.

Non-firm lower prices

Sensitivities on the non-firm market helped clarify the importance of non-firm sales and purchases in model selections. Under critical water, the existing system provided about 225 to 230 MWa less energy and the company was able to use about 30 MWa less from firm purchase contracts. The model selected about 150 MW more cogeneration and made fewer non-firm sales and purchases, for a net reduction of 92 MWa of generation. An assumption of critical water raised utility cost and prices. The company decided to use average water assumptions for RAMPP-3 so that the financial model would produce reasonable results. Another sensitivity showed that a reduced price for the non-firm market had very little effect on resource choices, but it increased system costs and customer prices. A higher price caused the model to select about 90 MW more coal and reduced costs and prices. These sensitivities illustrate the importance of using reasonably accurate estimates of prices on the non-firm market. With no non-firm sales, the model selected slightly less cogeneration. With no non-firm sales or purchases, the model added less coal. Removing the non-firm market caused utility costs, TRC, and customer prices to be higher. The lesson for PacifiCorp is that the IRP process must use a model that can recognize and use the non-firm market as the company does for daily operations to accurately reflect the system's use of the non-firm market to minimize system costs and minimize customers' retail prices. With no rate cases, there is no impact.

By how much?

Environmental Adders

The use of environmental adders or limits moved resource choices toward renewables, toward cogeneration, and from pulverized coal technology to coal gasification. Resource plans using the adders caused customer prices to increase up to 10 mills/kWh (20 percent) over the comparable non-adder case. The trade-off graphs indicated which resource strategies best met the dual goals of lowering costs and lowering emissions (no-coal and any-renewables). The no-coal strategy reduced emissions but increased costs compared to the any-coal strategy. Likewise, the strategic-renewables strategy reduced emissions but increased costs compared to the any-renewables strategy. However, the company believes the strategic-renewables approach can position the company to acquire additional renewable resources if the costs and performance demonstrate that wind or other renewable technologies are cost effective compared to available alternatives. The results of the adder cases depended heavily on the assumption about adders for non-firm purchases (based on the emissions of a CCCT). Because the model could alter its use of the non-firm market, the assumption about the purchase price on the non-firm market influenced the model's choice of new resources, and both of these in turn influenced the financial results.

Public Process

The company used a public advisory group throughout the development of RAMPP-3, holding 13 meetings and additional sub-group meetings for more focused discussion of specific issues. The two most beneficial aspects of the public advisory group's participation were their questions and discussion at RAG meetings and their written comments on the draft report. Discussion at RAG meetings helped the company develop modeling inputs and the analysis plan that provided a richer analysis. Written comments on the draft report enabled the company to correct and modify analyses and add needed explanation to several parts of the report.

Price Impacts

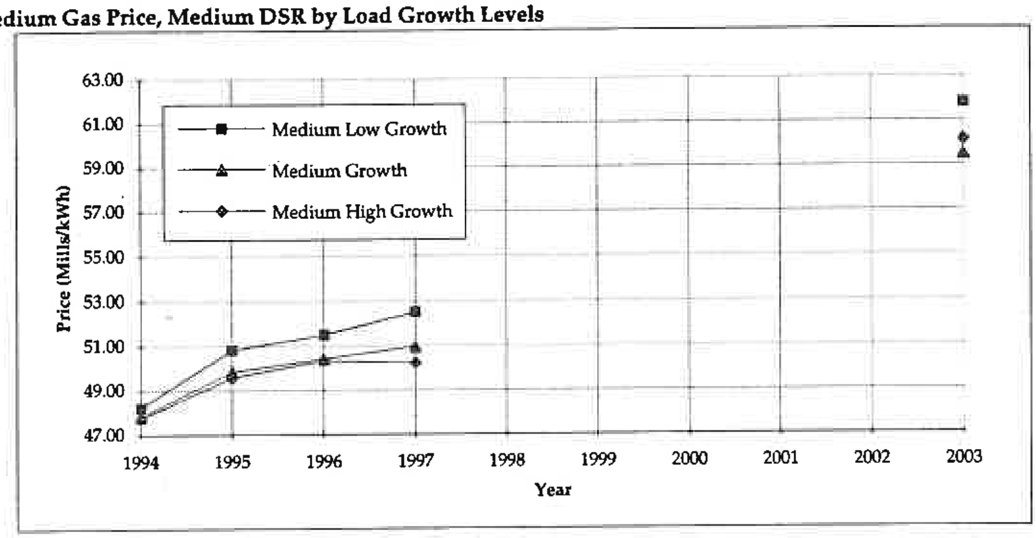
In this discussion, the term price signifies the mills/kWh of total utility cost provided in the financial results for each of the cases. The mills/kWh from the financial results is an average over all states and all customer classes. It ignores allocation and class cost of service issues. Graph 11-4 shows the year-by-year mills/kWh (price) in nominal dollars for 1994 through 1997, and then 2003, for selected cases. The first graph shows price impacts across three load growth levels. It shows that higher load growth results in lower prices. The second graph shows price impacts across gas price levels. It shows no significant price impact for the first four years, and a small effect by 2003, indicating the company's ability to manage its costs in the face of gas price uncertainty. The third graph shows price impacts across DSR levels. It shows that lower levels of DSR result in lower prices. Overall, prices in real dollars in RAMPP-3 tended to decline in the early years of the study until 2006, then tended to increase until 2013, and then decline slowly.

Table 11-5 shows the 50-year real levelized mills/kWh and the average annual nominal dollar mills/kWh for each of the first four years of the study plan, plus the 10th and 20th years: 1994, 1995, 1996, 1997, 2003, and 2013. This allows comparison of patterns for real levelized mills/kWh results (an average 50-year result) with patterns for the more immediate year-by-year nominal dollar impacts of alternative futures, strategies, and sensitivities. Under medium load growth (the first set of numbers on Table 11-5), annual nominal price increases between 1994 and 1997 averaged 4 percent 1994-1995, then one percent each year thereafter, for a total nominal price increase between 1994 and 1997 of 6.7 percent. A one-mill price difference from one strategy to another would cause a

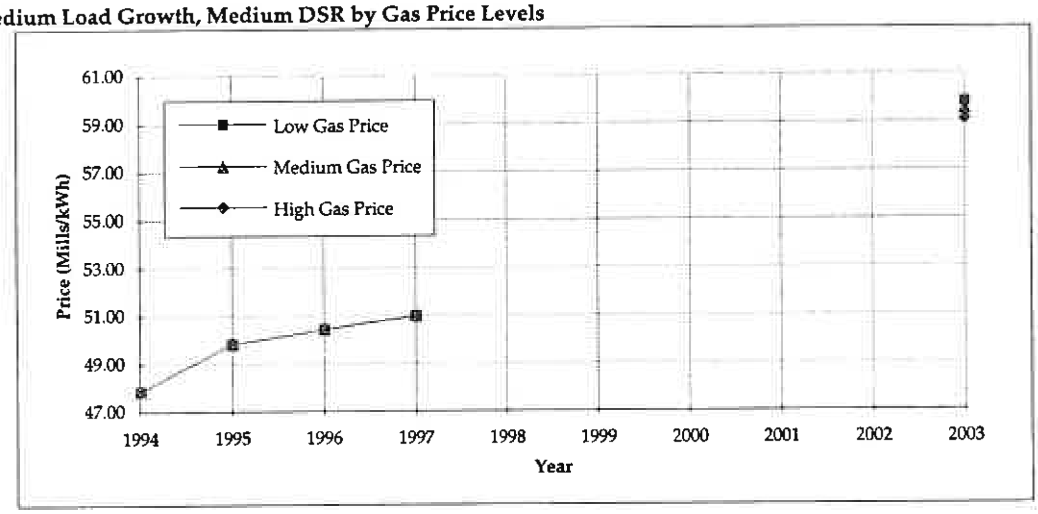
Yearly Norminal Prices (Mills/kWh)
(for Any-Coal & Strategic-Renewable Cases)

Graph 11-4

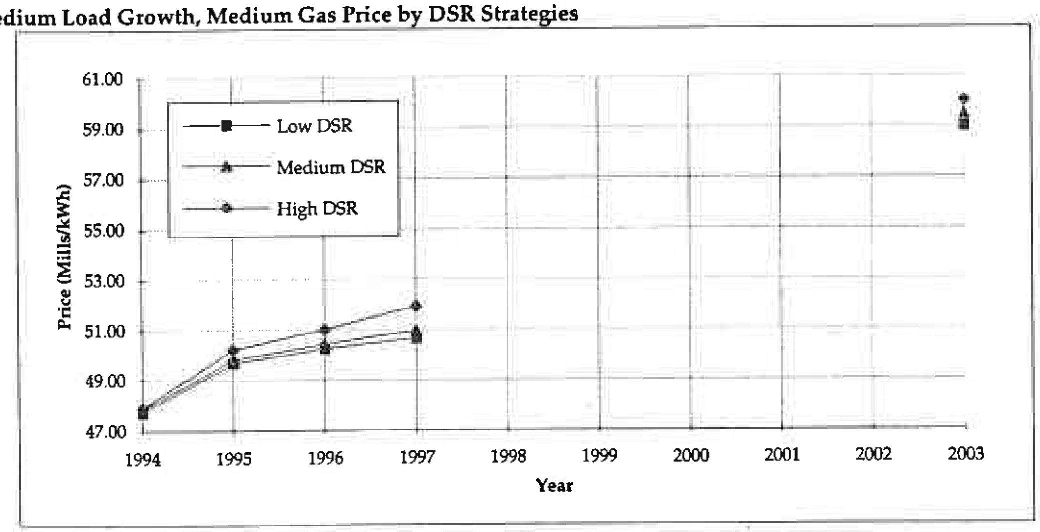
Medium Gas Price, Medium DSR by Load Growth Levels



Medium Load Growth, Medium DSR by Gas Price Levels



Medium Load Growth, Medium Gas Price by DSR Strategies



G11-4.yearly price

Yearly Norminal Prices (Mills/kWh)

(by Load Growth, Gas Price and DSR)

Table 11-5

Coal & Renewable Strategy	Case Number	Real Levelized Mills/kWh	Average Mills/kWh 1994	1995	1996	1997	2003	2013
Medium Gas Price, Medium DSR								
Medium Load Growth								
Any-Coal & Any-Renewable	**33**	**46.13**	**47.8**	**49.8**	**50.4**	**50.9**	**57.8**	**89.5**
Any-Coal & Strategic-Renewable	**34**	**46.59**	**47.8**	**49.8**	**50.4**	**51.0**	**59.5**	**90.3**
No-Coal & Any-Renewable	**35**	**46.68**	**47.8**	**49.8**	**50.4**	**50.9**	**59.4**	**90.2**
No-Coal & Strategic-Renewable	**36**	**47.12**	**47.8**	**49.8**	**50.4**	**51.0**	**60.8**	**91.2**
Medium-Low Load Growth								
Any-Coal & Any-Renewable	7	47.02	48.2	50.8	51.5	52.4	58.9	89.4
Any-Coal & Strategic-Renewable	8	47.61	48.2	50.8	51.5	52.5	61.8	90.3
No-Coal & Any-Renewable	9	47.21	48.2	50.8	51.5	52.4	59.5	90.8
No-Coal & Strategic-Renewable	10	47.66	48.2	50.8	51.5	52.5	61.9	90.7
Medium-High Load Growth								
Any-Coal & Any-Renewable	69	45.65	47.7	49.6	50.3	50.2	58.9	87.8
Any-Coal & Strategic-Renewable	70	46.08	47.7	49.6	50.3	50.2	60.2	88.8
No-Coal & Any-Renewable	71	46.66	47.7	49.6	50.3	50.0	60.3	89.6
No-Coal & Strategic-Renewable	72	46.85	47.7	49.6	50.3	49.9	61.3	90.1
Medium Load Growth								
Medium Gas Price, Low DSR								
Any-Coal & Any-Renewable	29	45.73	47.7	49.7	50.3	50.6	57.6	87.7
Any-Coal & Strategic-Renewable	30	46.20	47.7	49.7	50.3	50.7	59.0	88.6
No-Coal & Any-Renewable	31	46.26	47.7	49.7	50.3	50.6	58.9	88.7
No-Coal & Strategic-Renewable	32	46.73	47.7	49.7	50.3	50.7	60.5	89.9
Medium Gas Price, High DSR								
Any-Coal & Any-Renewable	41	46.50	47.9	50.2	51.0	51.8	58.3	89.9
Any-Coal & Strategic-Renewable	42	46.99	47.9	50.2	51.0	51.9	60.0	90.8
No-Coal & Any-Renewable	43	47.01	47.9	50.2	51.0	51.9	59.8	90.7
No-Coal & Strategic-Renewable	44	47.42	47.9	50.2	51.0	51.9	61.4	91.4
Low Gas, Medium DSR								
Any-Coal & Any-Renewable	16	46.17	47.8	49.8	50.4	50.9	57.8	90.2
Any-Coal & Strategic-Renewable	17	46.67	47.8	49.8	50.4	51.0	59.8	91.0
No-Coal & Any-Renewable	18	46.20	47.8	49.8	50.4	50.9	58.9	88.7
No-Coal & Strategic-Renewable	19	46.69	47.8	49.8	50.4	51.0	60.7	89.7
High Gas, Medium DSR								
Any-Coal & Any-Renewable	50	46.19	47.8	49.8	50.4	51.1	58.1	88.6
Any-Coal & Strategic-Renewable	51	46.40	47.8	49.8	50.4	51.0	59.1	88.5
No-Coal & Any-Renewable	52	48.32	47.8	49.8	50.4	51.2	61.5	94.6
No-Coal & Strategic-Renewable	53	48.25	47.8	49.8	50.4	51.0	61.3	95.3

T11-5.yearly prices,base

Yearly Norminal Prices (Mills/kWh)
(for Sensitivity and Environmental Adder Cases)

Table 11-6

Cases	Case #	Run against Case #	Real Levelized Mills/kWh	Average Mills/kWh 1994	1995	1996	1997	2003	2013
Medium Gas Price									
Medium Load Growth, Medium DSR									
Any-Coal & Any-Renewable	**33**		**46.13**	**47.8**	**49.8**	**50.4**	**50.9**	**57.8**	**89.5**
Any-Coal & Strategic-Renewable	**34**		**46.59**	**47.8**	**49.8**	**50.4**	**51.0**	**59.5**	**90.3**
No-Coal & Any-Renewable	**35**		**46.68**	**47.8**	**49.8**	**50.4**	**50.9**	**59.4**	**90.2**
No-Coal & Strategic-Renewable	**36**		**47.12**	**47.8**	**49.8**	**50.4**	**51.0**	**60.8**	**91.2**
Medium Load Growth, High DSR									
Any-Coal & Any-Renewable	**41**		**46.50**	**47.9**	**50.2**	**51.0**	**51.8**	**58.3**	**89.9**
Hermiston w/ NC	212	35	45.55	47.8	49.8	49.9	50.3	57.1	88.0
Hermiston w/ AC	213	33	45.13	47.8	49.8	49.9	50.3	55.8	85.1
SCE as potential	211	36	47.14	47.8	49.8	50.4	51.0	61.9	91.0
CCCT to IGCC	222	36	45.83	47.8	49.8	50.4	51.0	59.2	87.1
IGCC w/ NC	223	36	46.88	47.8	49.8	50.4	51.0	60.5	91.1
IGCC low cost w/ NC	224	36	46.35	47.8	49.8	50.4	51.0	60.4	88.8
Transm Bridger 300	231	33	46.00	47.8	49.8	50.4	51.1	58.3	88.8
Transm Utah 600	232	33	45.91	47.8	49.8	50.4	51.4	58.2	87.9
Critical water	251	33	47.06	48.8	50.8	51.4	51.9	59.3	91.1
Non-firm $ lower	252	33	46.56	48.3	50.3	50.9	51.4	58.7	90.9
Non-firm $ higher	253	33	45.52	47.1	49.1	49.7	50.1	57.0	87.0
No non-firm sales	254	33	46.94	48.7	50.7	51.1	51.8	59.7	91.3
No non-firm S/P	255	33	46.95	48.8	50.8	51.1	51.8	59.9	91.1
Wind cost less $600/kw	261	35	46.86	47.8	49.8	50.4	51.1	59.2	91.3
Geothermal 0% inflation	262	35	46.93	47.8	49.8	50.4	50.9	59.4	91.2
Wind 0% inflation	263	35	46.68	47.8	49.8	50.4	50.9	59.4	90.2
Wind 2.5% inflation	264	35	46.68	47.8	49.8	50.4	50.9	59.4	90.2
Wind Res Marg 1.2	265	35	46.68	47.8	49.8	50.4	50.9	59.4	90.2
Wind Res Marg Winter	266	35	46.81	47.8	49.8	50.4	50.9	59.7	90.5
Wind 35% more energy	267	35	46.84	47.8	49.8	50.4	51.1	60.0	90.4
Low NOx, Low CO2	301	33	46.77	48.8	50.9	51.4	51.8	59.4	89.9
Low NOx, Med CO2	302	33	48.93	49.9	52.1	52.5	55.1	65.9	89.1
Low NOx, High CO2	303	33	54.51	52.2	54.7	55.4	56.5	77.0	106.1
High NOx, Low CO2	304	33	47.68	49.5	51.7	52.0	52.5	61.3	90.7
High NOx, Med CO2	305	33	50.65	51.6	53.9	54.5	55.9	69.2	92.7
High NOx, High CO2	306	33	56.27	52.2	54.8	55.5	57.4	79.5	111.6
Carbon limit, Med DSR	322	33	50.62	48.4	50.7	51.7	52.4	64.4	102.7
Carbon limit, High DSR	323	41	49.83	48.3	50.5	51.0	51.9	62.8	101.0

T11-6.yearly prices,sen

2.2 percent price impact over and above the price impact caused by normal load growth and inflation. The company is concerned about seemingly small mill differences because they would add to price impacts.

Under medium-low load growth, the price would be higher than under medium load growth (the second set of numbers on Table 11-5), and the impact occurs immediately. The higher price was caused by under-utilization of existing resources. After 20 years, loads and resources were in balance and the price difference disappeared. Under medium-high load growth, prices would decrease by 0.1 mills (compared to medium load growth) in each of the first three years; the difference would reach one mill by 20 years.

Low DSR (the fourth set of numbers on Table 11-5) would reduce prices by 1997 by only 0.3 mills. High DSR (the fifth set of numbers on Table 11-5) caused a 0.4 mill real levelized impact, which reached a nominal price difference of 0.9 mill in 1997. By 1997 prices would be almost 2 percent higher under high DSR than they would be under medium DSR. DSR's small levelized impact masks a larger immediate price impact to customers.

Low gas prices caused a small levelized price savings, but no price savings during the first four years, 0.5 mill by 2003, and by 2013 it varied from 0.7 to 1.5 mills. High gas prices generally caused a levelized impact of 0.1 to 1.7 mills. The annual impacts began in 1997 and remained small due to assumptions that higher gas prices would cause non-firm sales prices to increase, and the company's ability to use the non-firm markets.

[illegible] gas - [illegible] firm prices

The sensitivity cases, shown on Table 11-6, had varying results. Allowing the Hermiston cogeneration project into the portfolio caused levelized prices to decrease compared to a companion case without Hermiston. The yearly price reduction effects began in 1996. The model selected the SCE contract, though not in the same quantities and yearly increments as specified in the contract. Changing the SCE contract from an existing resource to a potential resource (where the model could select it) caused no price impact until 2003, when the contract expires.

The IGCC cases had no price impact until 2003, after that all of them caused prices to decrease compared to their companion cases that allowed no coal resource additions. The transmission cases lowered levelized prices, but did not begin to have an impact until 1997.

The lowest levelized and immediate prices (in 1994-1997) would result from higher load growth, lower gas prices, lower DSR, the any-coal strategy, the any-renewables strategy, Hermiston added to the system, IGCC as an available technology, implementing the transmission upgrades, and having a non-firm market with high sales prices and low purchase prices. Some of these factors the company has little control over, but the company can try to match its DSR investments to levels that limit price impacts, try to take advantage of coal's low costs, perhaps through the IGCC technology, and implement the transmission upgrades.

RAMPP-4

The company will begin preparing its next IRP, RAMPP-4, in the next few months. New information and changes that have occurred since beginning the analysis for RAMPP-3 will allow the company to update its integrated resource planning efforts. The current schedule calls for completing and publishing the final RAMPP-4 report by the end of 1995.

It has been said: "There is no subject, however complex, which, if studied with patience and intelligence, will not become more complex." RAMPP-4 will be more complex than RAMPP-3. PacifiCorp intends to refine the MATO analysis approach and increase its ability to analyze DSR, peaking needs, and uncertainty.

ACTION PLAN

This chapter describes the company's progress in meeting the action plan goals in RAMPP-2, as well as the new action plan for RAMPP-3. The next chapter provides detail on the DSR portion of the RAMPP-2 action plan and the new RAMPP-3 action plan. The action plan for RAMPP-2 used the information and analysis available when RAMPP-2 was prepared. It was a guide rather than a blueprint for specific actions. In implementing the plan, the company adhered to its principles more than the precise words of each action item. In other words, the company followed the intent of the plan while allowing itself flexibility to respond to changing conditions. While action plans emphasize the importance of acquiring the cheapest resource first, the company also considers other factors such as the value of learning more about new technologies (as with renewables).

While some utilities include long-term purchased power in their portfolio of resources, PacifiCorp did not include purchases from other utilities or developers in the RAMPP-3 portfolio. The company's first integrated resource plan, RAMPP-1, did include substantial amounts of long-term purchased power. Since then, PacifiCorp's experience in the IRP process and in the wholesale market led the company to conclude that purchased power opportunities over the planning horizon are not predictable. It is difficult, if not impossible, to predict availability, price, terms and conditions for a purchased power arrangement two or more years in advance. These opportunities are uncertain until a specific negotiation is well under way, or in some cases until contract signing. Therefore, PacifiCorp decided to exclude purchased power from its RAMPP-3 portfolio, but continues to use purchased power opportunities to acquire competitively priced resources. PacifiCorp will pursue power purchases that offer more benefits to customers than other resource choices. Following is a fuller discussion of how the company analyzes purchased power compared to resources it would build itself.

- use IRP to analyze purchased power contracts.

Three options are available to PacifiCorp as a means to acquire resources: build and own, buy as a turnkey project (someone else builds the plant, and when it is ready to operate, the company purchases it), or purchased power. Each has its own advantages and disadvantages. The first criterion for PacifiCorp in deciding among these three options is the cost of the resource. During the resource acquisition process, PacifiCorp analyzes cost information on specific options. Various other factors also affect the cost of a resource, whether built by a utility or a non-utility developer. For example, a developer or utility may have a standard plant design for a particular technology, so their respective cost may be lower for that technology. Also, developers currently require a higher rate of return for their projects than do utilities, but developers also can use a higher proportion of debt in their capital structure, which lowers their overall cost of capital.

Another major criterion for PacifiCorp is risk. PacifiCorp assesses development, siting, financial and regulatory risks for each specific project. For example, PacifiCorp's approach to wind plants is to purchase them as turnkey projects with guarantees, which leaves the development risk with the developer.

A third criterion in PacifiCorp's choice between building and owning (or turnkey) versus purchasing the power may be the effect on the company's capital structure and perceptions by the investment community. Owning avoids the potential for credit rating agencies to reduce the utility's credit rating for increased levels of power purchases. Related to this concern is the opportunity to earn a return on an owned, rate-based investment, while purchased power offers no earnings potential.

One of the advantages of utility ownership is control of the operations, maintenance, and improvement of the resource. This avoids the risk that an independent power producer (IPP) could allow project output to degrade, while the utility still has an obligation to serve. A second advantage of utility ownership is integration with the utility system, which allows for dispatchability and more flexibility in response to load fluctuations. Utility ownership also brings the ability to secure a very long-term resource, whereas most purchased power contracts last considerably less time than a power plant. When the contract terminates, the utility must secure replacement resources.

An advantage of purchased power is reducing the risks associated with operations, fuel price, financial, technological and regulatory treatment. A second advantage is the potential to tailor the agreement to match emerging loads over time. PacifiCorp evaluates these aspects of any purchased power arrangement relative to its costs and benefits in making any decision to use purchased power to meet some of its resource needs.

PERFORMANCE ON RAMPP-2 ACTION PLAN

The company successfully achieved its RAMPP-2 action plan. The following discussion lists each step from the RAMPP-2 action plan, and then describes the actions the company took to achieve the goals from that step.

1. **Continue to increase the amount of demand side acquisitions. Achieve 27 MWa of savings by the end of 1993.**

Overall, the company is on schedule in implementing the demand-side resource programs specified in the RAMPP-2 action plan, and expects results to show it has been on target in achieving its 1993 energy savings goals. The following table shows the goals and actual MWa savings for all demand-side projects completed or for which the company has a signed contract with the customer.

DSR Action Plan Goals and Actual for 1992 and 1993 (Signed Basis)

Program Area	MWa Goal	MWa Savings	Variance
Residential Weatherization	4.7	2.4	(2.3)
New Residential	2.0	5.0	3.0
Commercial Retrofit	4.6	0.5	(4.1)
New Commercial	7.8	7.0	(0.8)
Industrial & Irrigation	7.3	5.4	(1.9)
Appliance	0.8	6.9	6.1
Competitive Bid		1.1	1.1
Total	27.2	28.3	1.1

Nearly simultaneously with the RAMPP-2 planning effort the company developed a strategic goal of 170 MWa of DSR acquistion over the next five years (1992 through 1996). The 170 MWa goal most closely reflects the medium-high load growth forecast from RAMPP-2 and an additional acquisition of DSR from an accounting of all conservation that would be captured by 1996. For example, it included 40 MWa of background conservation. There was an additional assumed acquisiton of 13 MWa from a competitive bidding initiative above and beyond the program activity included in RAMPP-2. Once adjusted for the background conservation and the additional bidding initiative, the net resource delivered under the strategic goal (170 MWa less 40 and less 13 equals 117 MWa) roughly equaled the program activity in the RAMPP-2 medium-high load growth case. The RAMPP-3 medium load growth at 2.1 percent is lower than the RAMPP-2 medium-high load growth at 2.9 percent. This change reduced the program activity by 17 MWa (to 100 MWa). In addition, improvements in state building codes and appliance efficiency standards and already-installed DSR reduced the amount of program activity for RAMPP-3. These changes reduced the program activity by 25 MWa (to 75 MWa). This 75 MWa can be compared to the 69 MWa goal in the RAMPP-3 action plan DSR for 1994-1996 of 69 MWa (40 during 1994 and 1995, and 29 during 1996), for a reduction of 6 MWa in program variance from the 170 MWa strategic goal.

2. **Determine actions needed in 1992 and 1993 to have 125 MW of wind capacity (40 MW effective capacity) in operation by 1996-97, and pursue those identified actions.**

The company has contracted for two wind generation projects, one in Washington and one in Wyoming. PacifiCorp is participating with Portland General Electric and Puget Power on a 50 MW, 140-turbine project in the Columbia Hills region of Washington's Klickitat County, near Goldendale. The parties signed a contract on February 14, 1994. Kenentech Windpower will develop and construct the $40 to 50 million project. PacifiCorp will own 37.5 percent, or about 19 MW. Construction should begin in 1995 with production starting in 1996. In August of 1993 Kenentech Windpower decided to move the proposed project from Rattlesnake Ridge in Washington's Benton County to neighboring Klickitat County because the former site was on the Department of Energy's Hanford Reservation, where the project would have to clear land use restrictions, various Native American issues and environmental concerns. Permitting should be quicker at the new site.

PacifiCorp has also contracted with Kenentech Windpower for a 50 MW plant in Carbon County, Wyoming. Kenentech Windpower will build the plant with PacifiCorp as the principal owner. The Eugene Water and Electric Board, Tri-State Generation and Transmission Association, and Public Service Company of Colorado are also considering participating. If each of these companies participates to the full level of their preliminary request, the project will become 70.5 MW. The steady winds of Wyoming offer 30 to 50 percent more energy potential than sites in the Pacific Northwest. BPA will buy 25 MW of the output and PacifiCorp and the other owners will take some of the output for their own customers. PacifiCorp will get 25 MW for its own use. The project offers opportunities for staged development: PacifiCorp could expand its involvement if the initial project is cost-effective and successful. If transmission limitations are overcome, sufficient wind towers at the Wyoming site could produce several hundred MW. The project should begin producing power in 1996.

3. **Sign confidentiality agreements for one or more potential sites to analyze the feasibility of bringing 50 MW of geothermal capacity on line by 1998.**

PacifiCorp and Calpine Corporation have had an ongoing series of discussions for developing a geothermal project near Glass Mountain, California. Calpine desires to construct a plant with a rating of at least 130 MW for commercial operation starting in 1998. PacifiCorp would purchase up to 100 MW from the plant for 30 years, if arrangements can be made with Calpine. In addition, PacifiCorp is considering other opportunities with developers for other geothermal plants under development.

4. **Determine the cost and performance of utility-scale solar energy resources through participation in the Solar II demonstration project.**

Solar II is a 10 MW test project in the Mojave Desert east of Barstow, California. An array of mirrors reflects solar energy to a central receiver; the heat turns salt into a molten state. The heat produces steam that in turn drives a turbine generator. This is the first major solar development to use molten salt storage as part of its technology. Molten salt has a greater capacity than water for collecting and storing heat, and will provide dispatchable solar energy. The 10 project participants include PacifiCorp, the U. S. Department of Energy, Southern California Edison, Pacific Gas & Electric, Salt River Project, Sacramento Municipal Utility District, and Arizona Public Service. PacifiCorp is contributing $1.25 million to the project. The project should operate from 1995 to 1998. The objective of the project is to move molten salt technology toward commercial-sized plants (100-200 MW) by the year 2010.

In addition, PacifiCorp intends to participate, along with the state of Utah, in a 100 kW photovoltaic (PV) technology demonstration at the Dangling Rope Marina on a remote arm of Lake Powell in the Glen Canyon National Recreation

Area. A federal Department of Energy grant will fund the project. The marina, owned by the National Park Service, currently barges in 65,000 gallons of diesel fuel each year to run the facility's electric generators. The one-acre solar array, coupled with inverters and a deep-cycle lead acid battery system, will reduce diesel fuel use to 10,000 gallons per year. The permanent facility will provide information on the construction and operating economies of PV systems.

The company has also begun three other PV projects in cooperation with Ascension Technology of Waltham, Massachusettes. Each involves installation of PV equipment to provide 5 kW of peak output. The project will help the company better understand how well PVs perform in specific settings and how they can fit into the power system. The sites are a PacifiCorp district office/service center in Moab, Utah; a PacifiCorp service center in Laramie, Wyoming; and a community college building in Bend, Oregon. The PV potential at these sites represents the solar prospects of three key states in PacifiCorp's system. Partial funding of this project by the Environmental Protection Agency will reduce the cost of the equipment in half, to only about $5 per watt. Installation should be complete by early 1994, with full operation beginning by mid-1994. Ascension will monitor the performance of each system, and will evaluate the performance data with PacifiCorp. The project will operate for one year, after which PacifiCorp will own all the equipment and can choose to continue, alter, or discontinue the project. Three rotating shadowband pyronometers will be installed at each site to monitor temperature and provide data support for the PV systems. At the end of the study year, PacifiCorp will move them to other potential PV sites.

5. **Initiate siting, permitting, and procurement for up to 450 MW of SCCTs. Operational and resource uncertainties may require more CTs. Seek permits which allow some of the SCCTs to be converted to CCCTs units if needed.**

The company removed the word procurement from this action plan item, per the Oregon Public Utilities Commission Order acknowledging RAMPP-2. After reviewing its options for meeting peaking needs, the company took advantage of a window of opportunity to acquire the needed peaking resources more cost-effectively through a capacity contract with another utility. PacifiCorp signed an agreement with Southern California Edison to buy up to 422 MW of capacity between October 15 and March 15 each year over the next seven years. Beginning this October, the Company will have 222 MW available on an as-needed, around-the-clock basis. By October 1995 an additional 200 MW will be available. RAMPP-2 identified a need for additional peaking resources by the mid-1990s and this contract provides those resources at a lower cost than other alternatives. The SCE agreement delays the company's schedule for construction of gas turbines. It also provides flexibility for PacifiCorp to meet winter loads. SCE is a summer peaking utility and has gas-fired generation available during the winter months. PacifiCorp, a winter peaking utility, can use this capacity as needed to meet either peaking or baseload requirements. Using the assumptions current at the time of the purchase, the following is a comparison of levelized SCE Winter Capacity Purchase costs with corresponding simple cycle combustion turbine costs. The figures are shown for capacity factors from 10 to 20 percent, consistent with peaking resource usage. They are expressed in $/MWH:

Capacity Factor	SCE Winter Purchase	Simple Cycle CT
10%	$92	$169
15%	$82	$129
20%	$76	$109

6. **Implement the decision to acquire 150 MW of peaking resources in Arizona Public Service Company's service area. Determine whether CTs or renewable resources are more cost effective. Initiate siting, permitting and procurement.**

The company prepared a report to the Arizona Corporation Commission which evaluated the relative costs and benefits of simple-cycle combustion turbines (SCCTs) and renewables to meet peaking needs. The analysis showed that SCCTs were the more cost-effective choice. The company is now pursuing the construction of 150 MW of SCCTs consistent with its contracts with the Arizona Public Service Company. The companies signed a construction agreement for the SCCTs in April of 1993. Work has begun to determine the site for the plant. The agreement calls for a best-efforts schedule for commercial operation by the end of 1996. The facility will be entirely financed and owned by PacifiCorp, but will be built, maintained and operated by APS. Customers of both companies will share the electric output of the plants.

7. **Sign intent agreements and pursue contract negotiations with industrial customers to achieve up to 300 MWa of cogeneration on-line by 1997. Build in options to accelerate or delay construction to allow for load growth uncertainty.**

PacifiCorp signed a contract to acquire electricity from a 474 MW natural gas cogeneration plant that U.S. Generating Company plans to build in Hermiston, Oregon. U.S. Generating will finance, build and operate the project. Lamb-Weston will use the steam produced as a by-product of the generating process as a heat source in its potato processing plant adjacent to the power plant site. PacifiCorp will have an option to own up to 50 percent of the generating plant once it begins operation, as well as the flexibility to schedule the amount of actual power produced, based on customer needs. U.S. Generating must arrange for long-term gas supplies for the plant by mid-1994 to fulfill the terms of the contract. Construction should begin in 1994, with commercial operation by mid-1996. The project is midway between a major substation and the intersection of two major natural gas pipelines: Northwest Pipeline and Pacific Gas Transmission (PGT).

The Umatilla Electric Co-op's transmission lines will transfer power from the generating plant to a Bonneville Power Administration substation; BPA will wheel the power to a PacifiCorp substation near Eugene, Oregon. The Oregon Department of Energy (ODOE) issued a proposed order recommending approval of a site certificate for the project. ODOE set several conditions on the site certificate, including a $5 million early plant retirement fund, fish and wildlife mitigation, and landscaping. The project includes construction of a 4.5 mile pipeline to connect with PGT, and upgrading 12 miles of transmission line, for which BPA must complete an environmental impact statement.

PacifiCorp also signed a contract to build a 50 MW cogeneration project at the James River paper mill in Camas, Washington. PacifiCorp will own the generation facilities and pay a royalty to James River for use of the steam. The contract for steam royalties extends for 20 years. The $60 million facility will use steam produced for the paper-making process to drive an electric turbine-generator. It should begin operating in late 1995. The project provides PacifiCorp with a highly efficient source of generation near the Portland metropolitan area. It will have a heat rate of 4,381 btu's per kWh, compared to 5,500-8,000 btu's per kWh for typical cogeneration projects. The low heat rate makes it about twice as efficient as a conventional utility thermal plant. PacifiCorp is pursuing other cogeneration opportunities as well.

8. **Identify at least one potential pumped storage site and determine the feasibility and cost- effectiveness of the technology.**

Pumped storage may fit well with PacifiCorp's existing system. It would be particularly beneficial for the eastern part of the company's service area because it would provide a flexible resource for load shaping. Pumped storage could efficiently use off-peak power by using it to provide on-peak power. This would allow the thermal units to operate more evenly, which would decrease wear and maintenance requirements on the units.

Working with project developers, PacifiCorp has identified several potential sites for pumped storage units in the Northwest and Utah. No negotiations have begun. However, analysis indicates the company should continue to evaluate possibilities for pumped storage with developers.

9. **Identify where transmission upgrades could enhance resources and proceed where such upgrades are cost effective.**

Each year the company completes transmission projects to meet load growth or reliability needs. These projects also provide savings in transmission losses. Other projects provide loss savings alone. The company recognizes transmission losses as part of the total cost of owning conductors and transformers. PacifiCorp selects equipment based on the sum of the purchase price plus the amount of losses over the expected life of the equipment. This applies to all transmission and distribution equipment, but the following examples apply to the two largest expense categories: conductors and transformers.

The largest conductors are part of the transmission system. Because PacifiCorp's service area is so widespread, transmission is a major consideration in all power transactions. The company is improving its transmission capabilities through transmission access agreements as well as the upgrading and construction of transmission lines.

One of the transmission constraints facing PacifiCorp is a limited ability to transport power from the desert Southwest to the Pacific Northwest. To alleviate this problem, PacifiCorp signed a 20-year agreement with Southern California Edison (SCE) for off-peak firm transmission service from Palo Verde to the California-Oregon border. SCE will provide 78 MW of off-peak transmission service through 1993, increasing to 260 MW for the rest of the contract. From mid-April to mid-June each year, SCE will use the transmission capacity itself. The agreement provides an additional path to the Pacific Northwest for power from PacifiCorp's Cholla #4 unit and other Arizona resources. It also provides a path out of the desert Southwest for other power transactions. To facilitate the SCE transmission agreement, PacifiCorp obtained additional south-to-north AC intertie rights from BPA, as discussed below.

PacifiCorp has negotiated various transmission arrangements with Bonneville during 1993, which have increased PacifiCorp's south-to-north transfer rights by 182 MW on the Pacific AC intertie. In addition, PacifiCorp acquired south-to-north transfer rights on the Pacific DC intertie. These Pacific DC intertie rights commenced January 1, 1994, for 100 MW and increase to 200 MW on January 1, 1995, and remain at 200 MW thereafter until the Pacific AC intertie facilities are removed from service. These additional rights, combined with PacifiCorp's existing intertie rights, provide the company with a total of 782 MW of south-to-north intertie scheduling rights.

In southern Oregon, the company improved transmission and lowered losses through the installation of a 500 KV transmission line from Eugene to Medford. The new line, a joint venture with the Bonneville Power Administration, joins with the California Oregon Transmission Project (COTP), forming the third AC intertie. The entire project provides a 4800 MW transfer capability between the Northwest and California regions. It is part of the Third AC plan of service, jointly adding 1600 MW of transfer capacity to the Pacific AC Intertie. Southern Oregon now has greater access to resources because of its connection to a stronger interstate transmission grid. The company completed the Eugene to Dixonville part of the line in late 1992, and the remaining part, Dixonville to Medford in November of 1993. This section increased the southern Oregon system import capability to 1875 MW. Part of this project included PacifiCorp's adding 500 kV series capacitors to the existing 500 kV Intertie north of Malin.

It is sometimes possible to minimize losses by reconfiguring the system. An extreme example was the 1993 installation of series reactors on the Carbon-Spanish Fork transmission path in Utah (near the Carbon thermal plant). The path consists of two parallel transmission lines, one of which had much lower losses. The new reactors forced the current flow onto the lower-loss line, thereby saving energy and capacity. Balancing the flows between the two lines increased the transfer capability of the two lines by about 100 MW. The new equipment resulted in energy savings of 5.7 mills/kWh over the facility life, and had a first-year cost of 10 mills/kWh.

In 1991 the company installed a 115 kV line between the Troutdale and Cully substations in Oregon. A wire size of 795 MCM would have been sufficient to carry the required current on this 10 mile line; however, consideration of losses favored the installation of a 1272 MCM conductor. The cost per kWh of losses saved was 12.7 mills/kWh over the life of the circuit. The cost of the first year's energy savings was 22.3 mills/kWh.

Power correction can also reduce losses. For example, the company installed 4800 kVAR of capacitors in Corvallis in 1992, resulting in a loss savings of 12 mills/kWh over the expected capacitor life, at a cost of 21 mills/kWh for the first year.

PacifiCorp recently signed an agreement with General Electric and Cooper Power Systems to purchase distribution transformers with ultra-efficient, amorphous metal cores. The transformers will reduce losses within the transformer by 70 percent compared to losses with the traditional steel cores. Over the course of the three-year partnership, the company expects to triple its use of these efficient transformers.

PacifiCorp continues to study its transmission and distribution system to find opportunities to cost-effectively reduce losses and increase efficiency.

10. Explore new or expanded modeling solutions for RAMPP-3.

As soon as RAMPP-2 was completed, the company began searching for a new model to use for RAMPP-3. After establishing criteria for the new model and testing the two best alternatives, the company selected the Integration Planning Model (IPM) from ICF Resources for RAMPP-3. The Analysis Plan chapter discusses that process.

11. Continue to implement system efficiency improvements as identified in RAMPP-1 and included in the existing system for RAMPP-2.

In 1992 and 1993, PacifiCorp gained additional resources through efficiency improvements on its generation, transmission and distribution systems. Increasing the efficiency of the equipment added one MW to the hydro system. Ten additional MW were through efficiency improvements, including conservation voltage reduction.

Carbon Offsets. Although the company did not have a specific action item from RAMPP-2 regarding carbon offsets, PacifiCorp has investigated low-cost techniques for offsetting carbon emissions. The company has two ongoing projects and has committed to two more pilot projects. The Questions and Answers chapter discusses these projects in more detail. In general they are:

1) Reforestation in southern Oregon, which resulted in the planting of 200 acres in the 1992-1993 season, and will result in 300 more in the 1993-1994 season.
2) Shade tree planting in Salt Lake City, in partnership with the non-profit TreeUtah in eight urban neighborhoods.
3) Reforestation in eastern Washington, in which the company is helping to pay for the replanting of privately-owned lands that have been damaged by fire.
4) Forestation in the Saratov district of Russia on lands which have not been previously forested.

The offset efforts will explore a variety of contractual arrangements for implementing projects, and test the cost effectiveness of different offset methods before making any large-scale commitment. PacifiCorp will continue to explore other offset techniques and will pilot test those that appear most promising.

The RAMPP-3 action plan, discussed below, is an updating of the RAMPP-2 action plan. The amount of resource to be acquired in each item in the RAMPP-3 plan should not be added together with the amount of the resource in the comparable item from the RAMPP-2 plan. The RAMPP-3 plan replaces and updates the RAMPP-2 amounts.

RAMPP-3 ACTION PLAN

We used to ask, what will the future be? Now we ask, what are the things we need to do now, whatever the future brings? We used to ask, will we have enough resources? Now we ask, are there any good opportunities out there? The wealth of information provided by the RAMPP process helps the company approach the future more proactively.

PacifiCorp developed its RAMPP-3 action plan after analyzing the results of the base study plan, environmental adders and sensitivity analyses, input from the RAMPP Advisory Group, and applying the judgment of company management. RAMPP-3 prepared 155 least cost plans for 155 different views of the future. None of those 155 is the company's "preferred plan." Instead, the company approached the task of developing an action plan by looking for consistent elements in the 155 resource plans, to arrive at action items that were consistent with a lot of the cases, especially actions that were consistent with the most likely cases: those with load growth between the medium-low and medium-high, and those with gas prices between the low and medium escalation rates. The company paid more attention to the 10-year results than the 20-year results in developing the action plan. The RAMPP-3 report title, Positioning for Competition and Uncertainty, reflects a theme that is the basis for many of the items in the action plan. PacifiCorp is positioning itself for an uncertain future by taking actions which are consistent with the most likely futures and provide flexible options for a wide range of futures.

While load growth and gas prices are critical uncertainties, other uncertainties also require a flexible action plan, especially industry changes from possible deregulation and restructuring. These industry changes require the company to be very sensitive to competitive pressures, and to focus its resource strategies on actions which will allow it to maintain its competitive positioning in both the short and long run. Other uncertainties include governmental action on environmental issues. The company recognizes that continuing concerns over environmental consequences of electric utility generation may lead to federal legislation. The company's renewable activities, as well as its carbon offset projects, should help the company contribute factual information to that debate and position the company to respond with the most economical choices, whatever policies emerge.

Did docs & mitigate the potential costs w/ assoc. environ. tax.

The RAMPP-3 action plan identifies actions that will position the company for the next 20 years. The analyses show that the company can use a broad range of alternative resources to meet future needs, but the actual amount and timing of new resources will depend on how the future unfolds and what opportunities become available. PacifiCorp believes that with the portfolio of resource options identified in RAMPP-3, it can manage situations that arise in the forecast cases as well as those outside them. For example, if the future brings very low load growth, the flexibility built into some of the resource options would allow the company to maintain reasonable levels of resources and sell any surplus through its access to other markets. If load growth is significantly greater than expected, the company could accelerate the siting and construction of some resources to sustain a modest period of higher-than-expected growth without dramatic retail price impacts. These short-notice resources include SCCTs and some renewable resources.

The company created the action plan in a step-wise process:

- Step 1: Identify actions for the resource strategies
  - a: How much DSR
  - b: How much renewables
  - c: How much coal
- Step 2: Identify actions to meet baseload requirements
- Step 3: Identify actions to meet peaking requirements
- Step 4: Identify other activities to complement steps 1-3

Step 1 determined the resources needed in each of the three resource strategy areas: DSR, renewables, and coal. For DSR, the primary criteria used in determining the level of activity over the next two to four years were internal financial standards, including an internal rate of return standard, an avoided cost standard, and a price impact check. The price impact check is a look at the incremental price impact of the total of DSR activity compared to a supply-side only plan. PacifiCorp management found the cumulative impact of less than 1 percent to be acceptable. The DSR Action Plan Detail chapter contains a discussion of the financial analysis of DSR programs and how the company used that analysis in developing the DSR action plan.

The next resource strategy area considered was renewable resources. For renewables, the company decided to pursue some initial projects which would position it to acquire more renewables if the early projects are cost effective. The company will evaluate the cost effectiveness of the early projects by examining their performance characteristics (including reliability, maintenance costs, integration with the system, impact on other resources, etc.)

The last resource strategy area considered in step 1 was coal resources. For coal, the company decided the appropriate next step would be a feasibility study which would enable it to make a decision regarding whether, where, and what type of new coal resources to build. The company recognizes that coal is the least-cost resource in many of the least cost plans created in RAMPP-3, but there are risks and constraints associated with coal.

The second step determined the actions needed over the next two years to meet baseload requirements, given the demand-side, renewable, and coal actions already identified. The most cost-effective supply-side resource choice after coal was cogeneration, and the Hermiston cogeneration project is the most cost-effective immediate opportunity. How the rest of the identified range of acquisition are filled will depend less on the RAMPP analyses and more on actual opportunities that become available.

The third step determined the actions needed to meet peaking requirements. The acquisitions identified in the action plan should enable the company to make better informed decisions as opportunities arise to acquire or build resources to meet peaking needs.

The fourth step determined the actions needed to complement the other areas. These arose from the company's effort in 1993 to compile its Peak Management Report, continuing efforts to identify pricing actions which would be consistent with RAMPP planning, and continuing with efficiency activities.

The company can meet the action plan objectives in a variety of ways. The company could build and own the resource; a developer could build the resource and the company own it; the company could acquire the power through a bidding process; or the company could purchase power through an arrangement with another supplier. The company plans to issue another request for proposals (RFP) to begin a bidding process after RAMPP-3, and anticipates that the bids in that RFP could meet some of the resource needs identified in this action plan. The beginning of this chapter provides a discussion of how the company evaluates purchased power opportunities.

Before the company takes any acquistion actions, it first performs detailed analyses of the specific opportunity, including its consistency with the current RAMPP plan, location-specific transmission and distribution facilities, the capital and operating cost estimate for the particular project, the fuel supply arrangements for the project, comparison of those costs with the most recent data to update avoided costs, comparison of those costs with other specific projects under review, the project's potential impact on the company's capital structure and any need for financing, and its impact on the hourly operation of the system during different seasons and during both peak and off-peak times. Senior management reviews all of these analyses before making an acquisition decision. RAMPP cannot provide all the detailed information management needs to make an acquisition decision. RAMPP provides a snapshot look at generic technologies at generic plant locations. RAMPP must 1) use broad area transmission constraints, 2) rely on generic costs, 3) freeze modeling inputs at one point in time within each two-year planning cycle, 4) and RAMPP cannot evaluate hourly impacts of generic resources. Therefore, RAMPP provides the framework and a beginning point for the detailed analyses that management needs for its acquisition decisions.

In developing a RAMPP action plan or making an acquisition decision, the company also considers potential cost recovery issues. While regulation allows for recovery of prudent investments that are "used and useful," issues remain which have an impact on the company's ability to achieve full recovery. The company's largest concern is the impact on price levels. The company takes very seriously the changes which are making the business environment more competitive. This has led to a strong commitment to be a low-cost producer and to keep retail prices competitive. The market may preclude higher prices even if the regulatory commissions were willing to allow prices high enough to provide for full cost recovery. An additional issue is the uncertainty surrounding cost recovery for unproven technologies such as renewable resources. For example, in acquiring these new technologies, the company relies on information that is available today when, in fact, the future may mean a shorter than anticipated life. For such resources, it may be appropriate to relax "used and useful" standards so that unexpectedly short lives do not preclude full cost recovery. Finally, there are issues raised by PacifiCorp's multi-jurisdictional operations. To the extent that commissions in different jurisdictions adopt conflicting standards for cost recovery, a resource that is eligible for full cost recovery in one state may not necessarily be accepted for full cost recovery by other jurisdictions.

The RAMPP-3 action plan is for two years, 1994 and 1995; in some areas it also includes broader steps for 1996 and 1997.

1) Continue to increase the amount of demand-side acquisitions consistent with cost and price impact criteria. Achieve 40 MWa of cumulative installed cost-effective savings by the end of 1995. By the end of 1997 acquire an additional cumulative 65 MWa of demand-side acquisitions, if cost effective.

Financial standards guide PacifiCorp's demand-side and supply-side resource activity. All resource acquisitions must meet these financial standards, which focus on meeting low-cost resource objectives and equity concerns.

During the second half of 1993, the company clarified its standards for investment in new resources to create greater consistency in the evaluation of DSR compared to other investment opportunities, achieve greater upper management consensus and commitment, and improve the process of developing DSR programs to be consistent with both RAMPP goals and company policies. The clarification process resulted in standards for evaluating DSR programs that are consistent with the standards used in evaluating other investment decisions of the company, including those relating to supply-side resources. These standards are two: first, the internal rate of return for the DSR program must exceed 9 percent; second, the DSR program costs must meet an avoided cost standard, which includes lost revenues. Once the programs are identified that pass these two tests, the package is evaluated for its impact on retail prices. PacifiCorp's management accepts a 1 percent cumulative price impact for 1994 through 1998, over what would result from an alternative supply-side resource plan. The next chapter, DSR Action Plan Detail, provides a discussion of the financial standards and the company's use of them to determine the DSR goals to include in the RAMPP-3 action plan.

The amount of identified DSR that met the financial standards for 1994 through 1998 -- 143 MWa -- compares favorably to the 152 MWa identified for that period in the medium DSR case for RAMPP-3. The company expects to identify additional DSR opportunities that meet the standards. Therefore, the new resource analyses in RAMPP-3 that assumed medium DSR are a valuable benchmark to use in anticipating future resource needs. The current difference, only 9 MWa, will not affect any other resource acquisition decisions in the next two years (before the company develops the next RAMPP action plan).

The company will also modify programs where necessary to mitigate price impacts. In all programs, the company will continue to maximize the amount of the participating customer's contribution to minimize non-participant price impacts.

The level of demand-side resources identified in the action plan assumed a medium level of load growth (2.1 percent annual growth). If load growth varies from that expectation, the company may need to adjust the amount of demand-side and supply-side acquisitions, but it is unlikely that in the next two years load growth will depart sufficiently to justify any significant change in resource acquisition activities. The more likely course of action would be incorporation of the new load growth data into the next RAMPP planning process, which will begin shortly after publication of RAMPP-3.

The action plan for DSR would not change significantly in the first two years under different growth scenarios, other than with an increase in lost opportunity new construction programs. As the load growth increases, there tends to be more DSR available through the new construction market.

2) Continue with actions necessary to have 200 MWa of renewable resources on line by 2001, if cost effective.

PacifiCorp's strategic plan includes an environmental goal, which calls for the staged development of renewable resources beginning with 50 MW by 1996, and expanding to 200 MWa by 2001 if proven to be cost effective compared to other resource options. To know whether these projects are cost effective, the company needs operating experience. That experience will reveal if there are fluctuations in output and how those fluctuations affect PacifiCorp's system. Experience will also reveal how wind plants affect the system use of other resources for load following, how they affect the local transmission and/or distribution system, how they perform under severe weather conditions, and whether there are problems with community acceptance. The company needs to learn how to deal with any operating problems that may develop. In addition, equipment costs should decline from technological improvements over the next few years; if those improvements don't occur, wind will be a less desirable resource. To gain the needed experience, the company is proceeding rapidly with current and planned projects, consistent with the RAMPP-2 action plan.

a) Bring the SW Washington and Foote Creek, Wyoming, wind projects on-line by 1996. The company's share of the output will be 56 MW (19 MWa). PacifiCorp assumed half of the share released by Idaho Power in addition to its previous commitment. The consortium of project developers in the Wyoming project, including PacifiCorp, is also selling 25 MW to the Bonneville Power Administration. Kenentech Windpower will construct the wind plant.

b) During 1996 and 1997, evaluate the cost-effectiveness and performance of the southwest Washington and Wyoming wind projects, and determine through continuing communication with wind developers the cost-effectiveness and performance of other wind projects in North America.

c) If these early projects confirm the cost-effectiveness of wind, pursue agreements in 1996 and 1997 with wind developers for an additional 40-50 MW of wind resources to be on-line by 1999. PacifiCorp has an option to purchase additional windplant from Kenentech at the SW Washington site.

d) Consistent with cost-effectiveness criteria, pursue agreements with developers to have 50-100 MW of geothermal resources on-line by 1998.

e) Continue to participate in the Solar II demonstration project to determine the cost effectiveness and performance of utility-scale solar energy.

f) Continue to participate in the Dangling Rope Marina photovoltaic project in Utah. The company will help install photovoltaic equipment to reduce the marina's need for diesel fuel to power its equipment.

g) By mid-1994, finish installing photovoltaic equipment on three buildings in PacifiCorp's service territory to better understand the operation and economics of direct generation from smaller dispersed photovoltaic units.

h) Identify targeted geographic areas with constrained transimission and distribution capacities. Evaluate general and specific opportunities to use direct load control and distributed generation technologies as a cost-effective means to resolve costraints.

i) Determine any unique considerations associated with various levels of renewable resources for integrating them into the company's system.

3) Meet baseload requirements with installation of 500-900 MW of cogeneration and/or combined-cycle combustion turbines (CCCTs) by 2001, consistent with cost-effectiveness criteria.

The company determined that it should pursue a range of cogeneration additions, given the range of additions made by the model across different cases that the company regards as likely, and to provide the company with the flexibility it needs to take advantage of low-cost opportunities that may arise in the next two years. Actual load growth during the next two years could cause a revision in these amounts for the action plan in RAMPP-4. The company will build in options to accelerate or delay construction to allow for load growth uncertainty.

a) Proceed with the Hermiston project according to the terms of the agreements.

b) Continue to evaluate cogeneration options with industrial customers in both the Utah and Pacific divisions. Reach agreements to develop projects or to secure options where cost-effective.

c) Continue to evaluate cogeneration and CCCTs with independent developers. Reach agreements to develop projects or to secure options where cost effective.

4) Evaluate clean coal technologies such as gasification, and evaluate the feasibility of potential sites for new coal resources.

Evaluating clean coal technologies and potential sites for using them will help the company better understand whether coal is a viable resource option for the future. Because clean coal technologies can reduce future environmental risks, the company recognizes the need to better understand clean coal technologies. Several gasification demonstration projects in progress or under development indicate the work occurring in this area. In addition, the company needs to evaluate the coal market and how changes in that market may impact current and future prices for coal required at new plants. At this point, the company does not need to make coal acquisitions that might prove costly or irrevocable. Instead the company plans to conduct further studies to better understand coal's benefits and risks, reduce the lead time for bringing coal resources on line, and assure flexibility in the future.

5) Meet 150-200 MW of peaking needs by 2001 in addition to the APS SCCTs (see item a), for a total of 300-350 MW. Operational and resource uncertainties may require the company to acquire more peaking resources sooner.

In addition to the Arizona SCCTs, the company could meet peaking needs through additional SCCTs, purchased power, pumped storage, and/or other peak management options (see action item 6). The amount and mix of peaking resources the company will need will depend on load growth, market conditions, the resource characteristics of the company's current system, the mix of other resources added to the system, fuel supply logistics and costs, environmental concerns and overall economics.

a) Complete construction of 150 MW of SCCTs in Arizona Public Service Company's service area to be on-line by the end of 1996.

Following are the alternatives the company will explore to meet peaking needs. The company does not expect to acquire new resources from all of these possibilities. In the two year action plan time frame the company plans to prepare detailed analyses of SCCTs and pumped storage sites, under alternative timing schedules and alternative locations. The company will initiate permitting and procurement, if required by timing, for the selected resource, whether it is a SCCT, pumped storage or other.

b) Identify at least two pumped storage sites and determine their feasibility and cost. If these projects are cost-effective, proceed with obtaining siting permits and equipment in 1996 and 1997.

c) Identify potential sites for up to 300 MW of SCCTs. If these projects are cost-effective, proceed with obtaining siting permits and equipment during 1995 to 1997.

d) Pursue opportunities to purchase power that provides peaking benefits and are more cost-effective than building or acquiring peaking resources.

e) Analyze the relative value of alternative peaking resources. The RAMPP research provides initial insights into peaking resource requirements. The company will apply detailed system simulation tools to specify and analyze peaking needs and how to best meet those needs.

6) Pursue peak management opportunities.

Demand-side and supply-side strategies can modify the shape of the company's load curve to reduce costs and increase value to the customer. Strategies can include reducing peak period demands, increasing the system load factor, and moving energy usage to different times and seasons to modify the system load factor. In October 1993 the Company completed a study of peak management that included a survey of 30 utilities across the United States and Canada, a review of the company's current and past peak management activities, and a review of system resources and operating characteristics. After reviewing the study and its results, the company recommended the following steps:

a) Consider pumped storage as a possible peaking option.

b) Continue the new amorphous core transformer program, under which the company acquires lower-loss transformers. Evaluate and implement, as appropriate, the use of larger conductors, reconfiguration of selected feeders and the installation of additional capacitor banks.

c) In the next general rate case filing in each state, offer standard tariff time-of-day differentiated prices for industrial customers of over 1 MW for both demand and energy. This will provide appropriate price signals to customers consistent with the company's costs and may help increase the company's system load factor.

d) Evaluate the costs and benefits of alternative levels of service quality, and develop various services that meet customer needs at prices acceptable to participating customers.

e) Promote the current option for time-of-day service to electric space and water heating customers in Utah.

f) Determine how residential customers respond to better data on their power usage through a pilot project in Portland, Oregon. This will help the company better understand how customers use information on real-time energy uses.

g) Continue to offer current options for irrigation load control in Idaho and Utah. In the next general rate case filing in each state, offer time-of-day service for irrigation customers.

h) Identify targeted geographic areas with constrained transmission and distribution capacities. Evaluate the possibility of using direct load control.

7) **Implement pricing changes to further promote economic and energy efficiency.**

a) In future general rate case filings in Montana and Utah, eliminate declining block energy price structures for residential customers by increasing energy charges.

b) In future general rate case filings, implement price design changes which better reflect costs and assist customers to improve the efficiency of their use of electric power.

8) Continue to increase system efficiency through improvements to the company's current generation, transmission, and distribution systems.

Additional system efficiencies are possible in all parts of PacifiCorp's system. The company plans to improve the reliability of its thermal plants in 1994 and 1995 to realize an additional 98 MW of capacity. Scheduled efficiency improvements to the transmission and distribution systems will gain 7 MW of capacity over the next two years and an additional 14 MW by 1997.

9) Continue to test and demonstrate small-scale carbon offset projects.

Carbon offsets, along with conservation activities and the use of renewable resources, help reduce the company's carbon emissions. Pilot offset projects will help the company identify reliable and cost-effective techniques for offsetting carbon emissions before making any major investment. PacifiCorp is participating in four offset projects that test a variety of techniques for offsetting carbon.

a) Reforest fire-damaged land in eastern Washington and western Idaho.

b) Work in cooperation with the US Environmental Protection Agency to forest unplanted lands in the Sartov region of Russia.

c) Plant shade trees in Salt Lake City neighborhoods with the assistance of the TreeUtah organization.

d) Help non-industrial landowners in Oregon plant under-stocked lands through a partnership with the Oregon Department of Forestry.

10) Improve the RAMPP process for use in RAMPP-4.

a) Implement feasible process improvements identified in the RAMPP-3 regulatory acknowledgment review.

b) Improve the company's ability to evaluate capacity needs in the RAMPP analysis.

c) Add to the IPM model's abilities so that it can recognize, and add resources to meet, both winter and summer peaks.

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DSR ACTION PLAN DETAIL

This chapter provides detail on the company's DSR activities. The first section describes the company's performance in implementing its RAMPP-2 demand side resource acquisition plan for 1992 and 1993. The second section lists and describes by sector the company's plans for DSR activity in the next few years.

1992-1993 DSR ACTION PLAN PERFORMANCE DETAIL

The action plan for 1992 and 1993 called for continued increase in the amount of demand-side resource acquisition. The action plan called for 27 MWa of savings by the end of 1993. The following table shows the goals and actual savings by program area for all projects that have signed an Energy Service Charge contract for 1992 and 1993. Overall, the Company is on schedule in implementing the demand-side resource programs and achieving the energy savings specified in the RAMPP-2 action plan.

DSR Action Plan Goals and Actual for 1992 and 1993 (Signed Basis)
Table 13-1

Program Area	MWa Goal	MWa Savings	Variance
Residential Weatherization	4.7	2.4	(2.3)
New Residential	2.0	5.0	3.0
Commercial Retrofit	4.6	0.5	(4.1)
New Commercial	7.8	7.0	(0.8)
Industrial & Irrigation	7.3	5.4	(1.9)
Appliance	0.8	6.9	6.1
Competitive Bid		1.1	1.1
Total	27.2	28.3	1.1

New Residential Buildings

Super Good Cents and Manufactured Housing (MAP) programs continue to achieve extraordinary penetration rates and capture significant lost opportunity resources beyond existing codes in the residential new construction market.

Super Good Cents promotes new residential energy efficiency improvements which exceed the existing state building energy code requirement. This program was changed in early 1992 because several states revised their building codes to be equivalent to Super Good Cents.

The company participates in the Manufactured Acquisition Program (MAP) administered by Bonneville Power Administration which provides incentives to all Pacific Northwest manufacturers of mobile homes for the construction of electrically heated manufactured homes to Super Good Cents standards, achieving effectively a 100 percent penetration rate for all electric manufactured homes located within Pacific's service territory.

PacifiCorp has worked with state building code officials and others toward improving energy requirements under the residential building codes. Oregon and Washington have changed their residential building code energy standards to be equivalent to the Model Conservation Standards (MCS). California already has building codes in place that are equal to MCS. The process to improve the energy building codes in Montana is underway.

The following are RAMPP-2 action steps related to new residential buildings, and the company's progress on those activities:

Action Step: Expand the Super Good Cents program to all states. Achieve a 25 percent participation rate in Montana in 1992 and 40% in 1993; achieve a 10 percent rate in Utah and Wyoming in 1992 and a 25 percent rate in 1993.

> Progress: The Super Good Cents program was expanded to Wyoming in late 1992. The program is now available in all states except Utah. The program achieved a 16 percent participation rate in Montana in 1992 and 20 percent in 1993; it achieved a 15 percent rate in Wyoming in 1993.

Action Step: Extend the Long-Term Super Good Cents program to Oregon, Washington, Idaho, and California, and include efficient appliances in the program. The goal was to achieve a penetration rate in Oregon-Washgton-Idaho of 15 percent in 1992 and 25 percent in 1993; achieve a rate in California of 10 percent in 1992 and 20 percent in 1993.

> Progress: The long term Super Good Cents program was extended to Oregon, Washington, Idaho, and Montana. The shell energy improvement standards were increased in early 1992 to exceed the revised codes in these states. In addition to shell measures, the efficient Heat Pumps (6.8 to 7.4 HSPF), water heaters (EF .89 to .93), low flow showerhead and aerators, and solar water heater appliances are included within the program. The program has not yet been extended to California. Incremental savings are presently being reviewed to determine if the company will file a tariff in the near future in California. The program achieved penetration rates of 46 percent in 1992 and 66 percent in 1993 in the four western states.

Action Step: Achieve more than 85 percent penetration of efficient mobile homes in the Northwest market by 1994. Support a regional program to encourage manufacturers to produce energy efficient mobile homes, and extend the program to Utah, Wyoming, and California. Support strong HUD standards.

> Progress: In 1992 PacifiCorp joined other Northwest Utilities to provide incentives to Northwest manufacturers of electrically heated mobile homes to build to Super Good Cents standards. Currently there are 23 manufacturers

involved in this program, 18 of which are located within the region. The program achieved a 49 percent penetration rate in 1992 (transition year) and 100 percent penetration rate in 1993. The program has been extended to the states of Oregon, Washington, Idaho, Montana, and California.

Action Step: Support incorporation of Model Conservation Standards into local codes in Idaho and Montana.

Progress: PacifiCorp has met periodically with state and local officials regarding the energy efficiency standards and has put together a package for Montana which includes an upgrade of the C.A.B.O. model energy code now in effect toward MCS levels. Financial assistance for limited income entry-level home buyers, a low-interest mortgage pool for those buyers, and enhanced compliance were also included in the package. In Idaho, work toward upgrading the code to MCS levels with state-wide compliance is on hold pending results of a pilot project involving the City of Boise.

Action Step: Study effectiveness of code enforcement efforts in Northwest. Work with Utah agencies to assure implementation of efficiency measures in new building code enforcement.

Progress: The company has been involved in the recent commercial code change processes in Oregon and Washington, serving on the technical working group sub-committees that crafted code language, as well as assisting with training, education and implementation efforts. Major changes in commercial codes are expected to be approved in Oregon in 1995, and are taking effect in Washington this year. The Energy FinAnswer programs sponsored by the company preceeded these code changes. These programs were designed to increase the participation of architects, engineers, owners, developers, contractors, suppliers and others engaged in the design and construction of commercial buildings. The new state codes will incorporate the more popular and cost-effective elements of the company's energy efficiency programs. The company has continuously updated its energy efficiency programs to reflect code revisions. The company will revise its current programs in Oregon and Washington to account for the new state energy codes for commercial construction.

The company has actively assisted in code training and education related efforts, but does not believe it is in the best interests of the company or its ratepayers to be in the business of code enforcement. Code enforcement, by law, is the responsibility of local building code jurisdictions. In the case of Washington, however, the state's public and private electric utilities are coordinating with local jurisdictions to provide resources for code enforcement over the next three years. The program covers plans review and inspections at 100 percent reimbursement to the permit holder for the first year and a half after the new code is implemented, followed by a 50 percent reimbursement for the remaining year and a half. A third party Special Inspector Program has been set up to facilitate ease and timeliness in the implementation of the new commercial code. It is a temporary program to allow the local jurisdictions time to get a self-funded system in place.

Action Step: Incorporate solar access, solar water heating and passive cooling site design into the Super Good Cents program.

Progress: Solar site design and solar water heating measures have been incorporated within the program.

Action Step: Evaluate savings potential from new efficient appliances, such as ventilation heat pump water heater.

Progress: PacifiCorp is actively involved with field testing of energy saving appliances. A test of three unique heat pumps in single family homes was completed in 1993. The three heat pumps in Oregon are a high efficiency heat pump with a scroll compressor, a variable speed heat pump and a ground coupled heat pump. As a control, there is one standard air source heat pump in Oregon and one zonal baseboard system with a split system air conditioner in Yakima, Washington. All five homes have been monitored for performance over one year and the final data is available. Two ventilation heat pump water heaters were tested. The first one completed was installed in Grants Pass, Oregon to deliver water heating only. Test results, which show a seasonal COP of about 2.4, were analyzed in September 1993. The second unit is providing both hot water and space heating. Since this home was not occupied for about 9 months during the test, a second year of monitoring is being conducted in 1994. The Home Comfort program in Yakima, Washington will be testing the energy savings for showers. The equipment was installed by Delta T in late 1993.

A competitive bid contractor has installed domestic hot water (DHW) measures in Washington apartments and 20 of these were monitored. Both the DHW savings and savings from occupancy based thermostat on baseboard space heaters were measured. The DHW measures saved about 1,000 kwh per year, close to the estimated amount. However, the thermostat did not show any statistically valid energy savings.

The Washington competitive bid contractor began installing DHW measures in apartments in Utah late in 1993. A monitoring study will identify average water use and water heating energy use in apartments. Energy monitoring meters have been installed in 75 apartment units, with 16 of those also having water volume monitoring meters installed to collect water usage information. Measurements are occuring for 60 days before installation and for 60 days post installation. The data is expected to be completely collected by the end of April 1994.

Existing Residential Buildings

In the past the company relied primarily on existing low-interest loan programs and low income equity programs as mechanisms for achieving residential weatherization. Within the last two years PacifiCorp has increased support for community-based weatherization (including low income) and developed new and innovative approaches to residential weatherization. In Washington and California, the Home Comfort program has been launched and a similar program is being piloted in Oregon for launch in 1994. The Washington and California programs are designed to achieve higher rates of customer participation (defined as having an audit and receiving instant savings measures) than previously achieved through other residential weatherization programs. The higher participation rate is achieved through increased public promotion of energy efficiency and the use of new house-tightening and energy auditing technologies. These action steps have been taken to build capability to offer wide-spread programs which would compliment existing weatherization programs and provide updated auditing techniques, new financing mechanisms (Energy Service Charge and 3rd party financing), and new retrofit technologies. PacifiCorp is also examining areas in the Utah Division which have relatively high percentages of electric space heat homes for potential targeted weatherization offerings.

The following are RAMPP-2 action steps related to residential retrofit, and the company's progress on those activities:

Action Step: Develop and test a retrofit weatherization program in Washington. Operate a weatherization program that achieves 3,000 audits and 1,500 weatherizations per year. This program will verify that the activity levels assumed in future plans are achievable. Verify that customers can be persuaded to participate in numbers anticipated. Investigate alternative approaches, such as competitive bidding.

> Progress: The Home Comfort program has been launched in Washington. In 1993, over 3,140 homes were audited and approximately 612 Energy Service Charge agreements were signed. Of those homes, 450 were weatherized by year-end 1993.
>
> A competitive bid project has also been completed in Washington. A contract was awarded in early 1993 to provide low flow showerheads, tank and pipe wraps, and faucet aerators to multi-family dwellings. The contractor installed measures in about 7,025 units and installed savings to date are estimated at approximately 8,608 MWh. In late 1993, the contractor began installing measures in multi-family units in Utah.
>
> In addition to investigating competitive bidding in Washington, the company's community-based program has pioneered unit pricing which avoids the administrative burden of multiple bids per household.

Action Step: Operate a weatherization program that offers enhanced audits and instant measures as a means of increasing customer acceptance of full weatherization. Achieve the following numbers of full weatherization participants per year:

Full Weatherization Participants
Table 13-2

STATE	1992 Goal	1993 Goal
Oregon	0	1,300
California	150	250
Washington	933	1,552
Utah	0	300

Progress: PacifiCorp's weatherization program, Home Comfort, which offers enhanced audit and instant measures is being offered state-wide in Washington and California. Program results are shown in the table below:

Home Comfort Program Results
Table 13-3

State	1992 Actual		1993 Actual	
	Signed ESC	Completed	Signed ESC	Completed
California	57	9	437	375
Washington	90	30	612	450
Total	147	39	1049	825

PacifiCorp also offers low interest loans, rebates, and low income grants for weatherization of electrically heated homes. Results are shown in the following tables:

Weatherization Programs
Table 13-4

STATE	1992 Homes Weatherized	1993 Homes Weatherized
Oregon	940	1,074
Washington	63	32
Montana	8	7
Idaho	27	56
Total	1,038	1,169

Low-Income Program
Table 13-5

STATE	1992 Homes Weatherized	1993 Homes Weatherized
Oregon	473	528
Washington	319	416
California	108	329
Montana	38	54
Idaho	52	47
Utah	66	286
Total	1,056	1,660

In Oregon, PacifiCorp is currently piloting a new weatherization program called Super Good Cents Home Improvement, which takes lessons learned from the Home Comfort program and capitalizes on the name familiarity of SGC in Oregon to obtain high levels of participation. The residential retrofit program in Oregon will be offered state-wide in early 1994. The program was piloted in 1993 with approximately 215 homes audited. The primary audit was a self audit completed by the customer and returned to the company for analysis. In one area, audits were completed by company energy services representatives.

Action Step: Test a pilot program for pay-for-performance bidding for low-income weatherization in Oregon. Achieve full weatherization of 2,000 homes by end of 1994.

Progress: A contract has been signed with ECONS, Inc. The low income weatherizations will begin in first quarter 1994 and it is expected that 1,000 homes will be weatherized under the contract by the end of 1994.

Action Step: Demonstrate feasibility of using Energy Service charge to operate residential programs while minimizing impact on non-participants.

Progress: The Energy Service Charge, which provides financing for incremental measure costs, is offered to customers participating in the Washington and California Home Comfort programs who elect to have the recommended measures installed. Through participant satisfaction surveys the company found that the availability of financing was rated as "Very Important" in the decision to participate in the Home Comfort Program by over 90 percent of the survey respondents.

Action Step: Incorporate new means of achieving potential savings, such as recovery of heat duct losses, into the weatherization program. Demonstrate a methodology to accurately estimate and measure savings for quality control, cost assignment and documentation of program benefits.

Progress: Duct sealing and blower door assisted weatherization is incorporated into the Home Comfort program, and special training is provided to weatherization contractors. Effectiveness of the new techniques was not considered in the program evaluation.

Action Step: Achieve proportional participation by low-income customers in residential weatherization. Support full weatherization of 3,000 homes through community energy groups.

Progress: In 1992 and 1993, 2,716 low income occupied homes were weatherized; 1,056 in 1992 and 1,660 in 1993.

Residential Appliances

The company has pursued several initiatives to facilitate the transformation of the electric appliance market to more energy efficient units over the last two years.

Programmatic efforts have focused on electric water heater efficiency standards that exceed common installation practices for water heater replacement and new installations. Two programs assist in accomplishing this transformation. In the replacement market, the company offers an electric water heater replacement insurance program for residential customers called Hassle Free Guarantee. Approximately 4,250 electric water heaters are replaced each year under the program with a .93 efficient water heater, compared to the .89 efficiency units typically installed. For the new construction market installations of .93 or higher efficiency electric water heaters receive an incentive under the Super Good Cents program. Water heater appliance incentives have been in place in the Super Good Cents program since early 1992. Both of these programs have moved the market to more efficient electric water heating installations. Many dealers keep the highly efficient units in inventory for prompt installation in new or replacement situations.

In July of 1993 PacifiCorp joined 25 other utilities nationally in a joint effort to advance the technology and manufacture of super energy efficient refrigerators. The Super Efficient Refrigerator Program, Inc. (SERP) is a non-profit corporation formed by public and private utilities throughout the United States. SERP will provide incentives to Whirlpool to develop and distribute over 250,000 Refrigerators/Freezers nationally that are at least 25% to 50% more efficient than the 1993 federal standards. PacifiCorp has committed approximately $1 million to the program and will begin receiving delivery of super efficient refrigerators in our service territory sometime in first quarter 1994.

In August 1993, the company offered a free showerhead kit, which included a 2.0 GPM showerhead and faucet aerators, to Oregon single family residential electric water heating customers (approximately 240,000 customers). Through December 1993, over 101,000 requests for the kit were received, and over 15,700 second showerheads were requested. Approximately 30,000 customers sent back their old showerheads. This represents 6.01 MWa of savings installed in 1993 on an annualized basis.

The following are RAMPP-2 action steps related to residential appliances, and the company's progress on those activities:

Action Step: Rely on improved standards as the preferred way to achieve savings. Participate in joint projects with other utilities. Investigate manufacturer incentives, such as "Golden Carrot", as a model for future upgrading of appliance efficiency.

> Progress: PacifiCorp not only was a founding member of the Golden Carrot committee which became SERP, but is also an active member of the Western

Utilities Consortium which is working on similar programs for other appliances such as heat pump water heaters and horizontal axis washing machines.

Action Step: Upgrade efficiency of water heaters installed under the "Hasslefree Water Heater Program". Achieve installation of 8,000 efficient water heaters. Include installation of low-flow showerhead in all installations.

Progress: System-wide approximately 60,000 customers participate in the Hassle Free water heater replacement program. The efficiency standard was upgraded to .93 since RAMPP 2. Approximately 3,798 water heaters were replaced in 1992 and 4,258 water heaters were replaced in 1993, surpassing the 8,000 replacement goal. Low flow showerheads are installed under the program with customer approval.

Action Step: Join a national utility program providing incentives to manufacturers to produce super-efficiency refrigerators. Participate in "Golden Carrot" award for efficient refrigerators to the extent that is cost-effective for the company.

Progress: PacifiCorp joined SERP in 1992.

Action Step: Continue support for Northwest Regional Appliance Efficiency Group. Seek market transformation toward leading-edge energy efficiency technology through joint utility programs that encourage customers to purchase more efficient models.

Progress: A company representative attends quarterly meetings of the NWREAL (Northwest Residential Efficient Appliance and Lighting) Group.

Action Step: Continue to participate in BPA's Blue Clue program encouraging high-efficiency appliances.

Progress: Blue Clue pamphlets are available in Pacific Division field offices and customer service representatives provide this information to customers when asked.

Action Step: Evaluate customer preferences and available products for alternative cooling appliances in Utah. The purpose is to determine which evaporative cooling products will receive customer acceptance as potential replacements for air conditioning.

Progress: A contract task order was approved in August, 1993 for a consultant to conduct a theoretical analysis of residential cooling system options. The approach will include a review of housing types, an evaporative cooling equipment survey, an analysis of electrical energy savings versus conventional refrigerated systems using a detailed computer model (DOE2.1), and finally a full life cycle cost comparison. Four system combinations will be analyzed: heat pump, gas/DX, gas/direct evaporative, and gas/indirect/direct evaporative. The four systems are being evaluated for three home types: premium, medium, and existing. A fifth system, an existing gas furnace with a new add-on heat pump, is being evaluated for the existing home only. A premium home is a custom built home with 3,000 SF on two stories plus a conditioned basement constructed to the current energy code. A medium home is a new tract home with 1,400 SF in one story plus a conditioned basement constructed to current energy code. The existing home is 3,000 SF plus a conditioned basement, with R-38 ceiling insulation, brick walls with R-0 insulation, and single pane wood windows. The study period was extended from the original January 15 deadline to allow time for analysis of the additional home types. The final report should be completed by March, 1994.

Existing Commercial Buildings

PacifiCorp continues to make progress in developing the capability to acquire Demand-side Resources in existing small and large commercial buildings.

The following are RAMPP-2 action steps related to existing commercial buildings, and the company's progress on those activities:

Action Step: Pilot a program to retrofit 10 to 25 large commercial buildings in Salt Lake City and Portland. Achieve a savings of 2.0 MWa by 1994.

Progress: Currently under the Energy FinAnswer tariff 32 major remodel projects have been done or are in the pipeline. These projects represent 1.6 million square feet of commercial floor space and annual savings estimated at 17,884 MWH or 2.0 MWa. A major retrofit/remodel program was tariffed in Oregon beginning in November 1993. The program had not been offered because of company concerns regarding cost recovery, specifically lost revenues of DSM investments. Cost recovery is in place in Oregon, and in Utah the company received an order which addressed the treatment of DSR expenditures and lost revenues.

Action Step: Expand Pacific Environments program from Albany, Oregon to include small businesses in Corvallis, Oregon. Develop marketing techniques to persuade existing customers to pursue retrofit.

Progress: The Pacific Environments program is no longer promoted by the company. The lessons learned from this program were incorporated into an Oregon state-wide large commercial program targeting lost opportunity remodels and includes lighting measures and HVAC tune-ups at customer discretion. This program was approved and tariffed in November 1993 with the program currently underway in Oregon.

Action Step: Focus on limited geographic areas to ease program development. Develop management tools to effectively implement and manage large commercial programs. Verify appeal of programs to the market.

Progress: The program under development will focus on areas with larger buildings where most of the least-cost opportunities exist in this sector. The company expects many of the buildings participating in this program to be in the Portland area and medium sized cities served by Pacific Power in the rural areas of Oregon (i.e. Medford, Corvallis, etc.). Market research and trade ally surveys show that there is a significant demand for a commercial lighting program, especially in the remodel stage. Although certain customers may desire a lighting-only approach, efforts to date have been to obtain depth of savings at each facility. In the long term it is strongly felt that a depth of measure approach will yield the greatest reduction in the need for future power plant, transmission and distribution upgrades.

Action Step: Improve ability to effectively market programs to small businesses. Operate pilot in Oregon. Achieve savings of 0.4 MWa by 1994.

Progress: The Pacific Environments program was offered in Albany, Oregon. In the three years the program was offered, over 90 commercial buildings were audited and 26 commercial buildings participated in the program by installing recommended measures. This represents about 0.1 MWa in savings. The lessons learned from this program have been used to develop the new construction small facility program (Energy FinAnswer 12,000) and will be used in the development of a prescriptive program for retrofit/remodel of small commercial facilities, to include unit pricing, prescriptive audit, and low administrative costs. The program is in the RAMPP 3 action plan.

Action Step: Develop "standard package" offers for small businesses to minimize the costs of operating the program.

Progress: This approach has been successfully employed in the 12,000 program for new commercial construction, small facility program, and will be used as a model for the next phase which is an existing building program targeted at small facilities.

Action Step: Demonstrate the degree to which the Energy Service Charge can reduce the impact on non-participants.

Progress: Participants who receive funding through a commercial program Energy Service charge repay 100 percent of the measure cost. The utility (and ultimately the ratepayer) bears the remaining costs which include program development, administration, building energy auditing, commissioning, savings verification, and interest subsidy costs to carry the loan. These costs typically add an additional 20 to 30 percent onto the costs which the utility must absorb. For a 30 percent or greater rebate program the utility would bear a higher percentage of the costs than the participants and therefore the impact on the non-participants would be much higher.

Action Step: Develop a way to commission buildings and verify that energy conservation measures are working.

Progress: The Energy FinAnswer commissioning will take place for the commercial remodel program when it is implemented in Oregon beginning in 1994. Protocalls which were developed and refined since 1991 will be used.

Action Step: Demonstrate a methodology to accurately estimate and measure savings for purposes of quality control, cost assignment, and documentation of program benefits.

Progress: Short term end-use monitoring under the Pacific Environments program provided significantly more accurate savings estimates. Short-term measurements in a commercial retrofit program help to increase the energy auditors' knowledge of energy use at the site. They also quantify and verify achieved energy savings which are otherwise obscured by occupancy changes at the site. The company will monitor a sample of buildings under the new Commercial FinAnswer remodel program to verify savings using this method.

Commercial New Construction

The company has been very successful in developing programs to capture lost opportunities in commercial construction. The Energy FinAnswer, which targets new large commercial and major remodels, and the Energy FinAnswer 12,000, which is a prescriptive approach in the small commercial market, have both been developed, implemented, and enhanced over the last two years.

The following are RAMPP-2 action steps related to new commercial construction, and the company's progress on those activities:

Action Step: Expand program to capture lost opportunities as soon as possible. Target most important segments for immediate attention. Review results to ensure that company is on track to achieving 85 percent penetration by 1995.

Progress: The Energy FinAnswer program is available in all seven states served by Pacific Power and Utah Power. The program is exceeding market penetration goals in all states except Utah and Wyoming.

Action Step: Operate Energy FinAnswer in all states by 1993. Achieve the following participation rates in new construction:

Energy Financer Program Participation
Table 13-6

State	1992 Goal	1993 Goal
Oregon	35%	45%
Utah, California, Washington, Idaho	22%	35%
Montana, Wyoming	--	20%

Progress: The Energy FinAnswer has tariffs in all seven states served by PacifiCorp. The program achieved the following participation rates based on installed and proposed MWH savings as a percent of total potential MWH savings for buildings constructed during the period:

Energy Financer Program Performance
Table 13-7

State	1992 Penetration Rate Installed MWh	1993 Penetration Rate Installed MWh
California	13%	11%
Idaho	37%	20%
Montana	0%	0%
Oregon	74%	126%
Utah	10%	24%
Washington	32%	61%
Wyoming	0%	8%
Total	27%	44%

Action Step: Develop "standard package" offers for small businesses to minimize program operation cost.

Progress: The Energy FinAnswer 12,000 program, for commercial buildings whose construction lend themselves to prescriptive measures such as buildings under 12,000 square feet and all size warehouses, was developed and launched in 1992. The program provides customers with a list of qualifying measures, the funding provided and dollar savings associated with their installation. The customer selects between "Better" or "Best" options and signs an Energy Services Contract. Conservation payments are made upon inspection of properly installed measures. The program is tariffed in all states except California, which is currently filed and awaiting commission approval. In 1992, 15 projects signed ESc contracts with estimated savings of 354 MWh, and 10 projects completed installation of measures for savings of 295 MWh. In 1993, 95 projects signed ESc's for estimated savings of 3,057 MWh and 71 projects installed measures for savings of 1,942 MWh.

Action Step: Develop methodology to commission buildings and verify that energy conservation measures are operating.

Progress: A full methodology for commissioning was developed in preparation for the launching of The Energy FinAnswer in May of 1991. At that time we held a two-day workshop to train about a dozen commissioning agents from across the Pacific and Utah Power service areas.

In subsequent years the commissioning protocol has been further refined, additional commissioning agents have been trained, and "veteran" commissioning agents have attended refresher courses. In 1993 our original handbook was significantly improved by the addition of substantial portions of text to supplement materials that had previously been presented in outline format.

The commissioning process includes the following steps: gather basic project information and meet with the building owner and primary contractors to establish the full scope of commissioning work; write a commissioning plan and specific tests to be carried out; work with owner's contractors to document equipment start-up; carry out equipment functional performance tests; coordinate operations and maintenance training for building staff; prepare a commissioning report. To ensure quality and consistency when working with a large number of commissioning agents, a commissioning technical coordinator reviews all work products and provides guidance to commissioning agents.

Action Step: Demonstrate the degree to which energy service charge can reduce the impact on non-participants.

Progress: Participants who receive funding through a commercial program Energy Service charge repay 100 percent of the measure cost. The utility (and ultimately the ratepayer) bears the remaining costs which include program development, administration, building energy modeling, commissioning, savings verification, and interest subsidy costs to carry the loan. These costs typically add an additional 20 to 30 percent onto the costs which the utility must absorb. For a 30 percent or greater rebate program the utility would bear a higher percentage of the costs than the participants and therefore the impact on the non-participants would be much higher.

Action Step: Demonstrate a methodology to accurately estimate savings for purposes of quality control, cost assignment, and documentation of program benefits.

Progress: The company's experience with savings verification has come from retrofit DSM programs where real billing data exists before and after the ECMs are installed. This is true for residential, commercial and industrial programs. There has been very little experience with verifying energy savings in new construction. In every case some form of engineering estimate has been made during design, prior to installation of ECMs. Most often some form of computer model is used to estimate energy usage before and after ECM installation. However, in very few cases has any systematic approach been attempted to re-estimate the energy savings after the homes or buildings are constructed. The added modeling and analysis more than doubles the administrative cost for each building in the study. And because there is still no "real" before billing data, the re-assessment can never be more than a second estimate based on existing "efficient" building.

However, PacifiCorp has started down this savings verification "re-estimation" path for new commercial construction following the trail started by BPA in the Energy Edge program. The goal is to develop a low-cost savings verification method for commercial buildings. Phase Zero began by proving that short term (two to four week) end-use monitoring could replace very expensive long term end-use monitoring. In Phase One, completed in November 1993, the methodology was developed and tested on two buildings. In Phase Two thirty additional buildings will go through the full scale savings verification process. The results will be used to 1) revise guidelines for the design stage energy estimates, 2) revise the program design for savings verification in new commercial construction, 3) improve the performance of new buildings with proper selection and better commissioning of new energy efficient equipment, and 4) revise the methodology for savings verification to fit the needs of the program. Some of the techniques can be applied in retro-fit commercial and possibly in industrial programs. Hopefully, only the best ECM equipment will be recommended, buildings will be commissioned to operate at their best possible performance, and low-cost methods will become very accurate at estimating actual savings within program and customer parameters.

Code compliance studies for commercial energy code in Washington and Oregon were completed in 1992. A compliance support package is under development for implementation in Washington in 1994, with evaluation scheduled for 1995. Success there will guide development of a similar package for Oregon's new commercial code, effective in July 1995.

Industrial Sector

PacifiCorp continues to develop its ability to acquire demand-side resources in the industrial sector. In 1992 the company developed the Industrial Energy FinAnswer program, an experimental energy service for industrial customers. The program is tariffed in California, Oregon, Utah, and Washington. It provides the customer with a free analysis of electric energy efficiency opportunities in target technology areas, specifically lighting, air compressors, refrigeration, and motors. The company offers funding for energy efficiency improvements from an engineering study of the facility. Irrigation FinAnswer, targeting electrically powered pumps and irrigation systems, is being piloted in California. The program started in 1992 and includes a complete irrigation systems analysis including water management and irrigation scheduling training. Energy efficiency measure recommendations can be funded and repayed by the customer through an energy service charge.

The following are RAMPP-2 action steps related to the industrial sector, and the company's progress on those activities:

Action Step: Develop high market penetration for targeted high potential niches. Identify key market segments for saturation ("blitz") marketing. Expand program offerings from successful segments to other opportunities.

Progress: Efforts in the industrial sector initially focused on lighting, motors, air compressor systems, and refrigeration systems. They are easier to analyze, and customers are not likely to change to new technologies which affect their production processes until they see how successful the other efficiency measures are within the plant. Most of the projects are process oriented.

Action Step: Achieve 4.6 MWa of efficiency savings from the industrial sector. Identify key market segments for saturation marketing. Expand program offerings from successful segments.

Progress: The market segments are primarily Food Products and Forest Products companies. The savings impact for 39 projects completed to date is estimated at 34,933 MWh annually or 4.0 MWa.

Action Step: Develop Energy Partners program in all states. Achieve the following participation per year:

Energy Partners Program Goals
Table 13-8

State	1992 MWa Savings Goals	1993 MWa Savings Goals
Oregon	1.0	1.0
California	0.1	0.1
Washington	--	0.6
Utah	0.7	1.1
Total	1.8	2.8

Progress: In 1992 the Industrial Energy FinAnswer program targeted industrial customers (in the four states in which program is tariffed) whose monthly demand was over 500 KW, to limit the market in order to serve participants adequately. The 498 customers targeted represented about 90 percent of the market. The program was offered to 60 of these customers which represented 12 percent of the target market. To date, eighteen customers have signed Energy Service Contracts to implement the recommended energy conservation measures and accept company funding. In addition, 23 customers have used their own funding to implement the recommeded measures. The MWa savings on a signed contract and on a completed basis for 1992 and 1993 are shown in the following table:

Industrial Energy FinAnswer Program Performance
Table 13-9

STATE	1992 MWa Signed ESC	SAVINGS Completed	1993 MWa Signed ESC	SAVINGS Completed
Oregon	1.2	0.0	1.3	1.8
California	0.0	0.0	0.1	0.1
Washington	0.3	0.0	0.2	0.3
Utah	1.2	1.3	0.4	0.5
Total	2.7	1.3	2.0	2.7

Action Step: Continue development of an industrial sector database to improve assessments of resource cost and availability.

Progress: Some progress has been made on collection of data which improves our assessment of resource cost and availability in this sector. PacifiCorp will support a database of industrial audits being prepared by Oregon State University.

Action Step: Demonstrate feasibility of using energy service charge to distribute efficiency benefits to all customers. Provide opportunities for participants to benefit from up-front financing in exchange for sharing savings with other customers.

Progress: The shared savings concept was dropped in early 1992 because of non-acceptance by the market and the company turned to a more conventional loan based Energy Service Charge approach to finance incremental energy efficiency improvements. This approach has been very successful and is expected to gain acceptance in the future.

Action Step: Develop programs across specific segments of industrial customers, offering technologies such as efficient air compressors, ammonia refrigeration or efficient motors.

Progress: Technologies which affect Controlled Atmosphere with an emphasis on fan cycling has received much interest from customers. In addition, adjustable speed drive applications on dry kilns has proved to be an important offering for lumber processors.

Action Step: Develop pilot irrigation program in California. Achieve 1,500 MWH by 1994.

Progress: The Irrigation Energy FinAnswer was developed for the California Irrigation market. It provides a complete irrigation systems analysis and water management and irrigation scheduling training. In 1993, ESc agreements were signed for seven irrigation projects worth approximately 234 MWh of savings.

DSR FINANCIAL STANDARDS AND DECISION MAKING

The goals in the RAMPP-3 action plan are intended to balance four considerations that partially conflict with one another:

Rate Design Issue

- Reduce long term total resource cost,
- Achieve equity among customers,
- Meet increasing competition in the electricity industry, and
- Reduce environmental emissions.

Some of these considerations can be analyzed quantitatively, others cannot. The company based its DSR action plan goals on management's judgment regarding the impact of DSR acquisition levels on these factors. The purpose of this section is to describe the factors and reasoning that lead to the particular DSR goals in the RAMPP-3 action plan.

DSR Strategies

RAMPP models analyzed four DSR strategies: Low, Medium, Accelerated, and High. The models also analyzed a fifth case which allowed the model to select amounts of DSR unconstrained by practical or business considerations. The Analysis Plan chapter describes these strategies. For the base case, Tables 6-5 and 6-12 provide information about the long-term total resource costs (TRC) of the four DSR strategies:

Compari / long term to short term - should use
some component

TRC (50-Year NPV in $Millions) Under Alternative DSR Strategies
(Medium Load and Strategic Renewables)
Table 13-10

	Low DSR	Medium DSR	Accelerated DSR	High DSR
Low Gas Price				
Any-Coal	48,568	48,444	48,295	48,320
No-Coal	48,596	48,467	48,315	48,333
Medium Gas Price				
Any-Coal	48,586	48,368	48,266	48,271
No-Coal	49,128	48,903	48,727	48,691
Average	48,720	48,546	48,401	48,404

Each strategy produced 50-year NPV of TRC results that are within 1 percent of each other. The accelerated DSR strategy achieved the lowest TRC NPV.

TRC and Price Impacts Under Alternative DSR Strategies
Table 13-11

	Low DSR	Medium DSR	Accelerated DSR	Change: Medium to Accelerated
Average TRC (50-Year NPV in Millions $)	48,720	48,546	48,401	-145 million REAL
? nominal Average Price in 1997 Mills/kWh	46.2 ~~50.7~~	46.8 ~~51.0~~	47.1 ~~51.9~~	~~0.9~~ .3
TRC Compared to Low DSR		-0.36%	-0.65%	-0.30%
Price Compared to Low DSR		.013% ~~0.6%~~	.019% ~~2.4%~~	~~1.8%~~ .006% REAL LEVELIZED
Ratio: Price/TRC Impact		1.7	3.7	6.0
		.036	.029	.02

Table 13-11 shows a comparison of TRC and price impacts across DSR strategies. The TRC of the accelerated strategy was 0.30 percent lower than the TRC of the medium DSR strategy and 0.65 percent lower than the TRC of the low DSR strategy. The accelerated DSR strategy has higher near term price impacts, however. Compared to the medium DSR strategy, the accelerated strategy increased near-term prices by 1.8 percent. This is in addition to the 6 percent increase in nominal prices that would be justified from 1994 through 1998 in the medium load forecast case. The negative impact on near term prices is six times larger than the positive impact on long-term TRC. Clearly there are diminishing returns to large DSR programs and the accelerated strategy is past the point of diminishing returns. The company is concerned about this and other policy factors discussed later in this section of the report. The company's subsequent financial analysis was based on the medium DSR strategy of RAMPP.

Financial Analysis Of DSR

The company analyzed the internal rate of return (IRR) of DSR programs consistent with analyses of other investment opportunities. Appendix J of the Demand-Side Appendix contains details of the methodology and an example for an industrial program. The IRR analysis examined the cash flows associated with investments in DSR programs. Costs included the original capital costs and associated taxes. Costs also included reductions in retail sales revenue because they occur with the investment in DSR. Benefits included avoided power costs, line losses, ESc revenue from program participants, and an additional 15 percent to cover other unquantified benefits.

The analysis did not include as a benefit revenue from general increases in the price of electricity to pay for the programs. The ability to recover the costs of a program in retail prices does not justify an otherwise uneconomic program. The company conducts both demand-side and supply-side acquisition analyses using this same assumption. Structuring the analysis in this way emphasizes the impact of programs on non-participants and helps ensure that programs will not have undue equity impacts.

Co does ? not look at revenue when analyzing supply side investments?

Programs must produce an IRR of 9 percent to pass the IRR test. This is consistent with the criteria used to analyze generating resources and other capital investments. The company plans to undertake programs that pass the IRR test as well as mandated programs (such as those for low income customers) and existing lost opportunity programs (such as Super Good Cents).

The company concluded that DSR programs that pass the IRR test would increase prices by slightly less than 1 percent from 1994 through 1998, compared to the case with no DSR programs. This 1 percent impact was acceptable to PacifiCorp management. The 1 percent price "rule" did not limit the DSR goals; instead, it resulted from the analysis of planned programs. The company has not determined that price impacts of slightly more than 1 percent would be unreasonable. However, larger DSR programs, like the accelerated strategy which increases prices approximately 3 percent, do not appear to produce commensurate benefits.

document, nominal or real

prices? Is this nominal or real?

Comparison of Financial and TRC Results

Table 13-12 compares the results of the company's financial analysis with the results of the TRC test and the lessons from the unconstrained model runs.

Results of DSR Financial and TRC Analyses
Table 13-12

Program	IRR Test	TRC Test	Lessons from Unconstrained Run
New Residential	Fails	Passes	Lost opportunity
Existing Residential	Fails	Passes	Not selected until 2003
Appliances	Fails	Passes	Acquire when technologies are commercially available
Existing Commercial	Passes	Passes	Acquire in 1996
New Commercial	Marginally failed	Passes	Lost opportunity
Industrial	Passes	Passes	Acquire immediately

Pilot should be rolled out now.

Residential programs fail the IRR test because they create large lost revenues and because they tend to be higher in cost than commercial and industrial programs. Weatherization of existing residences is not economic under the TRC test for approximately 10 years, by which time system costs will likely have escalated in relation to these programs.

The impact of the IRR test on the resource plan is modest. Results indicate that 143 MWa of DSR from existing programs is consistent with the IRR test and can be acquired in the next five years. The medium DSR strategy would acquire 152 MWa. The RAMPP-3 action plan contains significant actions even in sectors that "fail" the IRR test, and important existing programs are continued. Other actions are aimed at cutting cost and developing alternative approaches such as codes and standards. The company is focusing additional efforts to develop new program initiatives that meet the IRR test.

Policy Factors

Some customers won't participate in a utility's DSR programs. A recent well-documented case involves IBM Corporation. IBM built a modern energy-efficient facility to build electronic components in the service territory of a utility with limited DSR programs and low retail prices. Almost immediately, the utility began an aggressive DSR program and raised retail prices. IBM paid for its own efficiency improvements and now is paying for the efficiency improvements of other customers. It is disadvantaged compared to other makers of electronic components world-wide. This example is indicative of equity opt out options

effects on non-participants, particularly those who for various reasons have undertaken efficiency improvements on their own.

The equity impact of a large DSR program can be mitigated by cutting program cost or by requiring payments from participants. PacifiCorp has been a leader in developing such program designs. The company's energy service charge programs recover a substantial portion -- but not all -- of their costs from participants. Requiring participants to pay the full cost of programs would substantially diminish participation, particularly in the residential and commercial sectors. The RAMPP-3 action plan states that the company will continue to work toward reducing the costs of its DSR programs.

The company is not following a strict "no losers" test. That test requires that DSR programs produce no upward pressure on price. Instead, DSR programs must produce net benefits that are commensurate with their price impacts. The financial and other standards balance price impacts with the benefits of DSR. please demonstrate with empirical analysis

I don't

PacifiCorp believes that increased competition for retail customers is likely. Many of PacifiCorp's largest customers compete against low-cost foreign suppliers. If a change in regulatory policy can reduce cost and improve the competitiveness of a large spectrum of American industry, such policy changes seem likely to occur. Such changes have occurred in the natural gas business.

It is not yet possible to quantify the impact that increased competition would have on the electric power industry. Clearly one sound policy for utilities is to keep costs and prices low. While PacifiCorp believes that the increasingly competitive environment will increase pressure to keep prices low, that does not mean that demand-side resource acquisition must be a casualty of the environment. The formulation of the financial standards is a first step to designing programs that can be successful in the changing energy marketplace. The DSR goals in the RAMPP-3 action plan would increase prices by nearly 1 percent. This seems reasonable now, but any increase may be too much if competition forces dramatic reductions in the price of electricity.

Customers are concerned about electricity bills and are often unaware of utility prices. One utility strategy might be to reduce average customer bills through DSR programs and allow prices to rise. This will probably not be a successful competitive strategy. Once customers have reduced their electricity use, they will still make supplier decisions based on price. Lower prices translate into lower bills even at the new lower usage levels. The largest customers are not unaware of utility prices. Utilities can attempt to retain customers by making continued service a condition of participating in DSR programs. Such conditions may be hard to enforce or customers may simply find them unacceptable. ?

Economic Efficiency Justification For Considering Price Impacts

The Oregon Public Utility Commission, in its recent order on conservation cost effectiveness in UM 551, found that if a utility considers rate impacts in setting its demand-side targets, it should justify the decision in its least cost plan. According to the order, utilities would have to demonstrate that actual efficiency losses would occur if the utility acquired all DSR that passed the TRC test. The concerns expressed in the order are essentially those of economists. It is possible to respond to them in economic terms if one adopts a simplified model of a competitive world. Assume that:

- Alternative suppliers of electricity compete with utilities;
- The two classes of suppliers have the same marginal generation opportunities and costs;
- Utilities are required to operate DSR programs that increase their average price while alternative suppliers are not;
- Aside from this requirement, markets are competitive and prices equal marginal cost; and
- Customers incur costs if they switch from one supplier to another.

In this case, the utility's average price will be above the price charged by the alternative supplier, even though the two utilities face the same marginal cost. If the utility cannot offer a special discount to competitive customers (perhaps because market forces prevent "core" customers, who have fewer energy supplier choices, from accepting a price increase), then the competitive customer will switch to the alternative supplier. The costs associated with that customer's switch to the alternative supplier represent an economic loss, since the marginal costs associated with supplying the electricity have not been reduced.

If the utility discounts its price to the competitive customer and increases its price to core customers, the utility retains the load. Now, however, the price it charges core customers is further above marginal cost. The higher price causes core customers to consume less electricity, reducing the total amount of their disposable income which goes toward electricity purchases. They then have more disposable income available to purchase other goods. Their purchases of other goods is then higher than would be economically efficient. Again an inefficient outcome results.

It is not possible to know the extent to which the electricity industry of the future will conform to these assumptions. It is true that inefficiency may not occur if the industry is less competitive than assumed here, for example if utilities can retain customers without offering price discounts. It is also true that PacifiCorp has deviated only moderately from the TRC test. The company believes that its DSR goals are an appropriate response to the likelihood of increased competition.

Impact on Environmental Emissions

DSR reduces environmental emissions, but it is less effective than altering the mix of generating resources. Table 13-14 shows two alternative ways of reducing environmental emissions: 1) increasing DSR versus 2) decreasing coal and increasing renewable resources.

1,227,447

2756

Alternative Methods of Reducing Emissions
Table 13-13

Typo

	1997 Price Mills/kWh	50-Year NPV TRC $M	CO2 1000 tons	NOx 1000 tons
MG Starting Case (MD.AC.AR)	~~50.9~~ 46.1	47,903	61,972 1239430	138.6 2778
HG Increased DSR (AD.AC.AR)	~~51.7~~ 46.5	~~47,748~~ 47789 184	61,752 61377	~~138.4~~ 137.8
Percentage Impact	1.60%	-0.25% Incorrect sh[oul]d be .32%	-0.35%	-0.14% 2737
Alternative Generation (Avg of Any- and No-Coal under MD.SR)	~~51.0~~	48,636	59,616	132.6
SR AC	46.6	48368	61,102 1222047	136.8
SR NC	47.1	48903	58130 1162600	128.4
NC AR Percentage Impact	0.20%	1.53%	-3.80%	-4.33%
	46.7	48460	58589 1171,799	2568

meaningless! The average of two opposite strategies is impossible to attain!

28.8
2575

The starting case for this example assumed medium load growth, medium gas price, medium DSR, and the least costly mix of coal and renewable resources (AC -- any-coal and AR -- any-renewables). If DSR were increased to the accelerated DSR strategy, CO2 emissions would fall by 0.35 percent and NOx emissions would fall by 0.14 percent. Near-term prices (by 1997) would rise by 1.6 percent and the 50-year NPV of TRC would fall by 0.25 percent. On the other hand, using an alternative generation approach (averaging the results from two cases: any-coal with strategic-renewables and no-coal with strategic-renewables) reduces CO2 emissions from the same starting case by 3.80 percent and NOx emissions by 4.33 percent while increasing near-term prices by only 0.2 percent and increasing the 50-year NPV of TRC by 1.53 percent. Altering the generation mix has ten times the impact on CO2, 30 times the impact on NOx, and one-eighth the near-term price impact compared to increasing the DSR level. Additional acquisition of DSR beyond the 143 MWa identified from the financial analysis for the purpose of reducing environmental emissions appears unjustified.

this is all [illegible]

Planned DSR Actions

PacifiCorp views an appropriately sized DSR program as a means of deferring the need for investments in new plant and and as a means to help the company in meeting the challenges of a more competitive environment. PacifiCorp intends to acquire 40 MWa of DSR in the next two years, and seeks a total of 143 MWa of cost-effective DSR over the next five years. The company expects DSR to be approximately 26 percent of all new resources over the next 20 years. DSR is a larger share of PacifiCorp's resource plans than it is of the resource plans of other comparably sized utilities in the region.

The company concluded as a result of the RAMPP-3 process, and its own internal financial analysis, that it can vigorously acquire demand-side resources consistent with its concerns about price impacts. The company has long been concerned about competition and price impacts and is committed to finding ways to assure that energy efficiency programs are not a casualty of an increasingly competitive environment. That the company can identify a large DSR program that fully meets price impact concerns is significant progress.

1994-1995 DSR ACTION PLAN DETAIL

New Residential Buildings

PacifiCorp will work with state and local building code agencies to promote the adoption of Model Conservation Standards (MCS) into current building codes. The company will work with builders to improve builder compliance with existing and new codes. The Super Good Cents program will be used to help builders become more familiar with new technologies, materials, appliances and building practices. The Manufactured Housing Acquisition program (MAP) will capture cost effective lost opportunities above the current HUD standard. The MAP Program is being evaluated now and will, no doubt, be severely cut back in terms of dollars contributed per home, or eliminated. Demand-side action steps include the following:

a) Revise and implement a new Super Good Cents program in Oregon, Washington, Idaho, Montana, and Wyoming in 1994.
b) Streamline the Super Good Cents program to reflect a more prescriptive design, targeting a 20 percent reduction in administrative overhead by 1995.
c) Continue participation in MAP in Oregon, Washington, Idaho, Montana, and California in 1994. Work with BPA and others to adjust the incentive payment after the new HUD standard is adopted.
d) Continue to work with MAP collaborative group to improve program cost effectiveness. Analyze cost- effectiveness of measures to be included in MAP homes after 1994.
e) Participate in a 1994 collaborative study of residential code compliance in Oregon to improve compliance and enforcement of the residential energy code.
f) Participate in building code development in Idaho, Utah, and Wyoming. Facilitate possible adoption of codes equivalent to MCS.
g) Explore ways to quantify market movements to identify savings.
h) Work with other interested parties to educate builders on new Utah Model Energy Codes and other energy efficient construction practices which will yield higher compliance with state code.

Existing Residential

PacifiCorp will continue to provide energy education and information to help customers conduct cost-effective weatherization on their homes. The company initiatives will place less emphasis on house-by-house weatherization activities that carry higher administrative costs. Efforts will focus on streamlining delivery and minimizing program overheads while assuring quality installations. The company plans to:

a) Operate a residential retrofit program in Washington and California in 1994 and 1995. Revise the delivery of weatherization programs to improve cost-effectiveness.
b) Test market alternative financial assistance options such as third-party finance, rebates and the Energy Service charge.
c) Launch a Super Good Cents Home Improvement Retrofit Program in Oregon.
d) Continue company weatherization programs as required by state statutes.
e) Operate a direct-install water heating retrofit program targeted at multi-family residences in Utah in 1994.
f) Issue an RFP for a competitive bid, Pay-For-Performance low-income weatherization program in Oregon to test this as an alternative delivery system.
g) Continue to offer low-income weatherization programs and provide low-income program evaluations to regulatory agencies. In Oregon, provide a study to quantify the benefits of energy education and the affects of the low-income program on arrearage. In Washington, use a standardized audit and provide payments based on cost-effectiveness.
h) Develop educational and informational literature to provide more information on home energy usage through: brochures that include energy efficiency tips, packets that offer guidance for performing a home energy audit, and brochures that provide information for purchasing energy-efficient appliances.
i) Test market energy information displays in Oregon. Determine the value of providing energy efficiency information that influences the way customers use energy.

Appliances

The most cost-effective way to influence the adoption of energy-efficient appliances in the marketplace is through manufacturer programs and minimum efficiency standards. Rather than offering specific cash incentives, the company will provide information on efficient appliances, incorporate efficient appliances into its residential, commercial and industrial program designs, and work with state and regional organizations to establish standards and encourage the manufacture of energy efficient equipment. The company plans to:

a) Rely on improved standards as the best way to achieve energy savings from appliance use. Participate with other utilities through organizations such as the Western Utilities Consortium to improve the efficiency of new appliances.
b) Participate in collaborative efforts to adopt standards for such technologies as compact fluorescent lamps, horizontal axis washers and other new equipment. Investigate possible technologies such as microwave dryers as a cost- effective alternative.
c) Maintain board membership in the Super Efficient Refrigerator Project. Oversee implementation of the 1994 new model design and begin promoting these highly efficient refrigerators.

d) Continue to participate in BPA's Blue Clue program or a similar initiative to encourage the purchase of energy-efficient appliances. In addition, develop tips for increasing energy efficiency at home. Expand Blue Clue or a similar initiative to Utah and Wyoming.
e) Conduct a follow-up survey and verify results of the Oregon showerhead saturation program to determine applicability to other jurisdictions.
f) Explore ways to offer a saturation showerhead program for customers currently on schedule 5 in Utah.
g) Reassess the cost-effectiveness of direct control of electric water heaters through radio communication as allowed under schedule 5.
h) Continue installation of energy-efficient water heaters (.93 or equivalent) through the Hassle Free program. Aim for installation of up to 3,500 tanks per year in 1994 and 1995. Encourage the installation of low-flow showerheads, aerators and pipe wraps along with energy-efficient water heaters.
i) Pilot a water heater load control program in Oregon starting in 1994 as part of the company's automated distribution project.
j) Execute a multi-family showerhead program in Washington and Utah, and investigate extending the initiative to other jurisdictions.

Existing Commercial

The company's objective in the commercial retrofit market is to acquire cost-effective conservation when resources are needed by building capability through experimentation with alternate program designs and delivery mechanisms. The company plans to:

a) Continue to implement a comprehensive commercial retrofit program in Oregon for buildings with more than 20,000 square feet. The program includes controls, lighting and training in building operation and maintenance. Standards will be established to guide managers in operating their buildings efficiently.
b) Evaluate commercial retrofit program results in Oregon for 1994. Recommend revisions and assess feasibility for expanding the program to other jurisdictions in 1995.
c) Develop a small prescriptive commercial retrofit program for buildings under 20,000 square feet. Assess feasibility of implementing in Oregon before 1995.
d) Operate the EPA Green Lights program for company facilities. Complete site inventory, environmental assessment, energy efficiency audit and prioritization by 1994 and begin installations in 1995, to be completed within five years.
e) Develop a comprehensive catalog of energy efficiency products available for commercial applications. Distribute catalog to company field personnel by year-end 1994.
f) Evaluate the appropriate level of support for the REMPRO building managers' training program through the Everett and Portland Community College campuses.

g) Participate in collaboratives to adopt standards for technologies such as compact fluorescent lamps and packaged air conditioning systems.

New Commercial

The company will actively participate in the development of improved code standards as the best way to achieve energy savings in this market segment. In the absence of adequate building codes, the company will maintain lost opportunity programs that help capture energy efficiencies above current code. PacifiCorp will continue using the Energy FinAnswer programs to improve architects' and engineers' familiarity with new energy efficiency technologies, materials, appliances and building practices. The company plans to:

a) Participate in code development in Oregon and Washington. PacifiCorp will work with other agencies to establish training and educational programs for code compliance in Washington.
b) Conduct a detailed study to determine the impact of code changes on energy efficiency in new commercial construction. Complete a report which includes recommendations for changes to the Washington Energy FinAnswer Program in 1994 and the Oregon program in 1995.
c) Conduct a survey of common practices for new commercial construction in parts of the service area not covered by current research studies.
d) Improve program cost-effectiveness by reducing administrative costs, changing funding criteria, and improving program design. Reduce the steps in the commissioning process (including inspection and performance testing).
e) Enhance training and informational materials for trade allies (architects, design firms, etc.). Complete a pilot building design study to influence architects to consider passive efficiency design features.
f) Complete a study to verify savings, and refine modeling tools to estimate energy savings in new construction.
g) In 1994 participate in a collaborative study with LBL and BPA to quantify energy savings from the commissioning process.
h) Offer the Energy FinAnswer program in all jurisdictions. Achieve the following penetration rates in new commercial construction:

Energy FinAnswer Goals
Table 13-14

	Large Buildings (over 12,000 sq ft)		Small Buildings (less than 12,000 sq ft)	
	1994 %	1995 %	1994 %	1995 %
Oregon	67	70	40	45
Washington	45	65	20	30
Idaho	45	65	20	30
Montana	35	45	35	40
California	45	65	35	40
Wyoming	35	45	35	40
Utah	67	70	20	30

i) Participate in the National Building Commissioning Association to influence the adoption of commissioning standards. Provide funding to ASHRAE for the commissioning guidelines group to establish protocols for building code practices.
j) Establish protocols in 1994 for commissioning Path B program participants (customers who received an audit and a list of recommended measures, but did not use the ESc).

Industrial

The company plans to increase efforts to acquire energy savings in this low-cost target market. It is designing programs that will offer maximum flexibility, given the unique requirements of key industrial customers. The company will focus on making efficiency improvements to capture potential lost opportunities. PacifiCorp plans to:

a) Offer the Energy FinAnswer program to industrial customers in Oregon, Washington, California, and Utah, and expand the program to Idaho in 1994. The company will do a feasibility study on expanding the program to Montana and Wyoming in 1995.
b) Continue development of an industrial customer database to better determine the availability and cost of resources. Create major account plans for the top 50 customers, assessing the costs and opportunities for acquiring resources.
c) Work with Northwest Power Planning Council and others to complete an Original Equipment Manufacturers (OEM) study that examines ways to improve the efficiency of applications.
d) Add program options to address certain measures in industrial facilities, such as efficient motors and lighting.
e) Sign commercial and industrial Pay-For-Performance contracts in Utah in 1994 to evaluate the cost- effectiveness of alternative program delivery systems.
f) Improve cost-effectiveness of Irrigation FinAnswer in California in 1994. Examine alternative designs such as a prescriptive approach versus a customized approach.
g) Study program options for Idaho irrigation customers in 1994.
h) Continue the ditch-to-pipe proposal for Oregon in 1994.
i) Continue to offer radio communication direct-load control for irrigation pumps in Idaho and Utah. Test the system and seek more participants if cost- effective.
j) Participate in collaboratives to adopt standards for technologies such as motors and packaged air conditioning systems.

Other Demand-Side Resource Activities

The company has planned other DSR activities to benefit more than one sector.

a) Conduct a customer energy survey (Energy Decisions) to collect data on demographics, equipment, housing and attitudes. Analyze the data to assess resource potential and assist in program design. Complete a residential survey and assessment in 1994 and a commercial survey and assessment in 1995.
b) Evaluate pay-for-performance agreements with contractors for cost-effective DSR acquisition. Evaluate the competitive bidding process and recommend improvements to the process.
c) Continue participation in Evaluation and other Advisory Groups as recommended by regulatory agencies to obtain external review and input for improving the program evaluation process. (Northwest Evaluation Group, Utah Evaluation Collaborative, and Regional Evaluation Network).
d) Work with state agencies to develop a comprehensive plan for verifying savings estimates.
e) Conduct evaluations of program process and impacts to improve cost-effectiveness. Evaluations are planned in the following program areas:

Planned Program Evaluations
Table 13-15

	1994 Process	1994 Impact	1995 Process	1995 Impact
New Residential	+	+	+	+
Residential Weatherizat'n	+	+	+	+
Appliances	+	+		
New Commercial	+	+	+	+
Retrofit Commercial			+	+
Industrial	+	+	+	+
Competitive Bid	+	+		

f) Study the impact of free-drivers and market transformation on residential and commercial new construction and appliance improvements.
g) Design, implement, and evaluate a pilot project for an automated meter reading, real-time usage display, and time-of-day pricing in conjunction with the 1994/95 automated distribution project.
h) Study and report on the potential for a pilot experiment that would use DSR to reduce the need for transmission and distribution system upgrades to meet local peak requirements.

GLOSSARY

20-year NPV Op. Rev.
20-year net present value of operating revenue. Can also be thought of as the 20-year net present value of the Company's revenue requirement.

AC
See any coal

accelerated DSR
A strategy alternative for treating new DSR resources. In the model runs using the accelerated DSR strategy, the model was forced to select a set amount of DSR each year of the 20 years (no more and no less). That set amount is shown in the Analysis Plan chapter, and is between the medium and high DSR amounts.

adder
A cost, added to the utility's cost for resources, to represent a societal cost of emissions from that resource. See also environmental externallities.

AD
See accelerated DSR

AR
See any renewables

AFUDC
Allowance for funds used during construction. The cost of financing a project during its construction phase.

AGC
See automatic generation control

allowance, SO2
See SO2 allowance

annual cost ($/kW Yr)
As a result of levelization (see below) the capital cost of a resource is spread over several years, and the annual running cost is added to it.

any coal
A strategy alternative for treating new coal resources. In the model runs using the any coal strategy, the model was allowed to select any amount of coal whenever it was cost-effective against other resource choices.

any renewables
A strategy alternative for treating new renewable resources. In the model runs using the any renewables strategy, the model was allowed to select any amount of renewables whenever they were cost-effective against other resource choices.

automatic generation control
Equipment which controls the output of a utility's power sources based on local system loads or power needs.

average hydro
See average water

average megawatts (MWa)
A unit of electric consumption or production over a year. It is equivalent to the energy produced by the continuous use of one megawatt of capacity over a period of one year. It is equivalent to 8,760 megawatt hours, or 8,760,000 kilowatt hours.

average water
The amount of hydro generation expected if streamflows were at an amount equal to the average of streamflows experienced from 1929 through 1978.

avoided cost
The price at which qualifying facilities sell their power to utilities. Avoided costs are determined by a public utility commission process. They are intended to represent the costs a utility would otherwise incur to generate or purchase power if not acquired from another source. They are calculated by the utility based on resource additions as identified in their least cost plan.

baseload
A resource which operates most of the hours of a day, and continuously through the year except for maintenance and unscheduled outages. Other resources are used to meet changes in loads.

bidding
A process of inviting outside developers, generators, and utilities to provide bids for providing power to the utility. The utility then evaluates the various bids and selects the most cost effective for further negotiations.

binary cycle plant
Geothermal plant that uses a secondary working fluid, which is vaporized by hot geothermal fluids, to drive a turbine generator.

Bonneville Power Administration (BPA)
The federal agency which markets power from federal hydro dams in the Northwest. BPA sells power to public and private utilities, direct service industrial customers and various public agencies.

bottlenecks
Transportation design anomaly where insufficient capacity is available for the level of power needed to be transported.

BPA
See Bonneville Power Administration

BPA Residential Exchange Program
A program sponsored by BPA under which residential and small farm customers of investor owned utilities in the Northwest states receive a reduction in their electricity bills so that their bills more closely match those of customers who receive service from a PUD which receives preferential rates from BPA.

btu
British Thermal Unit. The amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit. 3,413 btu's are equal to one kilowatt-hour.

CAAA
See Clean Air Act Amendments

capacity
The maximum load a power plant or power system can produce or carry under specified conditions at a particular time. The capacity of generating equipment is expressed in kilowatts (kW) or megawatts (MW).

capacity factor
The percentage of a resource's maximum generation capacity that is actually used.

capital costs
Cost of investment in a new resource, typically expressed as $/kW.

carbon dioxide
An emission from the combustion of fossil fuels that may be linked to global warming.

case
A unique combination of load growth, gas prices, demand-side strategy, renewables strategy, coal strategy, and other input assumptions. Each case had a unique resource plan created for it by the model.

CCCT
See combined-cycle combustion turbine

CF
See capacity factor

Cholla
PacifiCorp coal plant, acquired from Arizona Public Service.

claus plant
Part of IGCC which takes sulfur compounds, removed from the intermediate BTU gas produced by the gasifier, and reduces it to elemental sulfur.

Clean Air Act Amendments
The Clean Air Act Amendments of 1990 represent the fifth major effort (other amendments were adopted in 1970, 1974, 1977) by Congress to address clean air legislation since the first Clean Air Act passed in 1967. The Amendments of 1990 tightened the standards for air pollution prevention and control, established a totally new allowance trading program for addressing acid rain control, and required an air operating permit program that states are to administer. The enforcement provisions of the Act were tightened and a program to address stratospheric ozone protection was added.

coal gasification
The process of converting coal to a synthetic gaseous fuel. The process used in integrated gasification combined cycle (IGCC) plants.

cogeneration
The simultaneous or sequential production of electricity and useful thermal energy from a fuel source. Often this is accomplished by the recovery of waste heat from an industrial or commercial operation to use for electricity generation, or by the recovery of waste heat from an electric generating plant to use for an industrial process.

CO2
Carbon dioxide. An emission from fossil fuel burning.
Also used as abbreviated reference to the CO2 tax scenario.

Colorado-Ute Electric Association
Utility which recently filed for bankruptcy. PacifiCorp acquired Craig and Hayden coal plants and agreed to sale with the Public Service Company of Colorado and seasonal exchange with Tri-State.

combined-cycle combustion turbine
A combination of a gas turbine and a steam turbine in an electric generating plant. The hot exhaust gasses from the gas turbine are passed through a heat recovery steam generator that produces steam for a conventional steam turbine generator. This added equipment allows the plant to produce more energy from the same amount of natural gas, when compared to a simple-cycle combustion turbine.

combustion turbine
A natural gas fired resource, may be either simple-cycle or combined-cycle.

commercial retrofit program
Commercial sector demand-side program.

conservation
Reductions in the use of electricity through improvements in end-use efficiency. Typically referred to as demand-side measures.

conservation cost effectiveness
A calculation which estimates the most the utility should pay for demand-side resources. It typically uses a utility's avoided costs with various adjustments specific to demand-side resources.

conservation load factor
A ratio which represents the energy savings compared to the peak savings of a demand-side measure. For example, a load factor of 1.2 would indicate greater energy savings than peak savings, such as from residential weatherization. A load factor of 0.6 would indicate greater peak savings than energy savings, such as from commercial lighting measures.

cost effective
An elusive term that is used to value choices among alternatives, and select the one which has the lowest cost with equivalent benefits. Difficulties arise because a choice may be the cost effective one in the short term but not in the long term, it may be cost effective from society's point of view but not from the utility's point of view.

Craig
PacifiCorp coal plant, acquired from Colorado-Ute.

critical hydro
See critical water

critical water
The greatest amount of hydro energy that would be available if the region experienced a recurrence of the worst stream flow sequence on record (1928-1932).

CT
see Combustion Turbine.

customer costs
Costs incurred by customers when installing energy efficiency measures, and those costs are not paid for by the utility.

D.S. Lost Ops.
Demand-side lost opportunities. see Demand-side programs, and Lost opportunity resource.

decoupling
Ratemaking mechanisms to undo the link between sales and profits.

demand
The greatest amount of electricity used by a customer or a group of customers at one point in time.

demand charge
That part of a customer's bill for electric or other energy service which is based on the maximum amount the customer uses at any one point in time.

demand-side programs
Programs which help meet the customer's need for electricity by increasing efficiencies.

demand-side resources
Energy efficient end-use measures and services that reduce customers' energy consumption and peak load demands.

demographics
Statistical data describing the population and population trends.

discount rate
The rate used in valuing cash flows to be received in the future. The rate used in a formula to convert future costs or benefits to their present value.

dispatch
Operating control of an integrated electrical system involving operations such as control of the operation of specific power plants, high-voltage lines, substations or other equipment.

dispatch, environmental
see environmental dispatch

dispatchability
The ability of the utility to choose when to operate or not operate a resource for economic reasons.

dispatchable
Resources which the utility has control over when the resource is generating, and at what level of generation.

distribution
Electric equipment which takes power from the transmission system and transports it directly to the customer's delivery point. Includes equipment from the substation to the customer's meter.

DRI
Data Resources Institute/McGraw-Hill is a national economic research institute and consulting firm whose national and regional economic forecasts are widely used.

DSM
Demand-side management. Used interchangeably with DSR.

DSR
Demand-side resources. A way to meet customers' energy service needs through programs which reduce the need for electricity, which frees up that electricity to be used by other customers.

elasticity
For electricity, the responsiveness of people's use of electricity to changes in the price of electricity.

electro-technology
Technology which uses electricity as its source of energy.

emissions
Pollutants resulting from a process. see CO2, SO2, NOx, and TSP.

end-use
Purpose or final use of energy. Residential end-use is primarily for space and water heating and appliances, commercial for lighting, industrial for processing.

energy
Total amount of electricity needed or used to serve customers over a period of time.

Energy FinAnswer
Commercial sector demand-side program which includes a mechanism for the customers of the program to pay for its costs.

Energy Partners
Industrial sector demand-side program.

Energy Service charge
Referred to as the ESc. Payments included in a customer's electricity bill, for the contracted portion of the cost of that customer agreed to pay for energy efficiency measures.

environmental dispatch
A way to dispatch the utility's generating plants which assumes that the operating cost of each plant includes an additional amount representing environmental externality values, even though the utility does not have to pay that environmental tax.

environmental externalities
Environmental effects that are not directly reflected in the cost of electricity to the consumer. See the Environmental Analysis chapter for a discussion of externalities within resource planning.

ESc
See Energy Service charge

exchange agreement
A purchased power arrangement whereby one utility agrees to provide a set amount of power to a second utility in the form of capacity whenever the second utility requests it. The second utility must return an equivalent amount of power, which could be at specified times, or the time of return could be at the discretion of the second utility, depending on the terms of the agreement.

Existing Resources
Term used on tables to refer to PacifiCorp's owned generating plants.

external costs
Costs added to the utility's cost of new resources to reflect environmental externalities. Usually in dollars per ton emitted.

externalities
The impacts one activity (i.e. electric power generation) would have on other activities (e.g. the environment, human health, etc.) that are not priced in the marketplace. See the Environmental Analysis chapter for a discussion of externalities within resource planning.

Federal Energy Regulatory Commission
A federal regulatory agency which regulates the rates and terms for any transmission services or wholesale sales of electricity for every public utility. It also regulates any mergers and relicensing hydro-electric generating facilities.

FERC
See Federal Energy Regulatory Commission

firm
Power that has assured availability whenever it is needed.

Firm Sales
Term used on tables to refer to existing contracts to sell power to other utilities.

fixed O&M
Operating costs which occur, regardless of the level of output of a resource. They are related to the size of the power plant, rather than the level of output, so they are expressed as $/kW.

flashed steam plant
Geothermal plant that uses hot geothermal fluids to directly drive a turbine generator.

forced outage
An outage at a generating plant which is unplanned and unexpected. Forced outages typically occur because of equipment problems.

fossil fuels
Coal, oil, natural gas and other fuels derived from fossilized geologic deposits.

fuel switching
A customer changing energy-using equipment from one fuel source to another. Typically, this is thought of as a residential customer changing a water heater or space heating equipment from electricity to natural gas.

future
A combination of a specific load growth projection and a specific gas price projection. Fifteen futures were possible through the combinations of five load growth projections and three gas price projections.

Gadsby
PacifiCorp plant. It was once a coal-fired plant, but has been converted to burn natural gas.

gasifier
Part of IGCC which takes pulverized coal and produces an intermediate BTU gas.

generation
The process of producing electricity from other forms of energy (from falling water, coal, gas, wind, solar, or other energy sources).

geographic areas
Defined regions within PacifiCorp's service territory. Each region or area includes specified loads and specified generating plants.

geothermal fluids
Natural underground moisture that contains the heat used for geothermal energy.

geothermal resources
Generating plants which rely on steam or hot liquid from the earth to generate electricity.

gross utility program cost
The direct utility cost, before costs or benefits have been shared with participants. Also, see TRC, and Utility cost.

GWh
Gigawatt-hours. One GWh equals one thousand MWh, or one million kWh.

H
The high load forecast, 3.8 percent annually.

Hayden
PacifiCorp coal plant, acquired from Colorado-Ute.

HD
See high DSR

heat rate
The rate at which a power plant converts a btu of fuel into a kWh of electricity. Expressed as btu/kWh.

HG
The high gas forecast, assumes 5.56 percent real annual price escalation for natural gas.

high DSR
A strategy alternative for treating new DSR resources. In the model runs using the high DSR strategy, the model was forced to select a set amount of DSR each year of the 20 years (no more and no less). That set amount is shown in the Analysis Plan chapter, and is between the highest of the four alternative DSR strategies.

hydro, average
See average water

hydro, critical
See critical water

hydro relicensing
A process required by the Federal Energy Regulatory Commission. Each utility which operates a hydro-electric facility must periodically apply to the FERC to continue to operate the facility, demonstrating that the greatest benefits to the greatest number will derive from continued operation by the utility.

ICF Resources, Inc.

The company from whom PacifiCorp has licensed the use of the IPM model for use in RAMPP-3.

IGCC plant

See integrated gasification combined cycle.

illustrative plan

A unique resource plan created for a specific case. (see definition of case above)

independent power producer

A power production facility that is not part of a regulated utility. An IPP may qualify under PURPA to be a qualifying facility (QF). An IPP sells its output to an electric utility, or to a large end-use customer.

integrated gasification combined cycle

A combined-cycle combustion turbine which uses, instead of natural gas, coal that has been gasified as its source of fuel.

Integrated Resource Planning

A style of long-range utility planning for new resources to meet load growth that incorporates uncertainty, demand-side resources (customer energy efficiency), external costs, and public involvement.

InterCompany Pool

The ICP (InterCompany Pool) is an office set up originally to arrange the scheduling of power among the following utilities: PacifiCorp, PGE, Puget, Water Power, Idaho, Montana, and Sierra Pacific. Also it arranges the allocation of surplus hydro from BPA, so BPA sees only one IOU entity. The ICP does not operate any projects. They're only a clearing house for inter-company wholesale sales and purchase transactions.

interruptible

Load that, by contract, can be interrupted in the event of a power supply deficiency. Typically, a contract between an individual customer and the company specifies the conditions under which the customer's load can be interrupted, in exchange for lower rates to the customer or specific payments to the customer.

Intertie

The Intertie consists of an AC (Alternating Current) path and a DC (Direct Current) path linking Oregon and California. The facilities in California are owned by California utilities. The AC facilities in Oregon are jointly owned by BPA, PacifiCorp, and Portland General Electric. The DC facilities in Oregon are owned by BPA. PacifiCorp has 400 MW of north-to-south rights in Oregon, (525 effective June 1, 1994). They are used for wholesale sales to California utilities. PacifiCorp's south-to-north rights, at 308 MW, are used to import resources from the southwest during the winter. PacifiCorp has no ownership rights on the DC Intertie, but effective January 1, 1994 will purchase 100 MW south-to-north from BPA, increasing to 200 MW on January 1, 1995, to be used to deliver power from SCE for the capacity purchase.

IPM
The name of the model from ICF Resources that PacifiCorp used in RAMPP-3 for the capacity expansion and production cost part of the analysis.

IPP
See independent power producer

IRP
See integrated resource planning

kilowatt
A unit of electrical energy use. The amount of power being used or produced at one moment in time. Used as a measure for peak or capacity. One kilowatt will light up ten 100-watt light bulbs.

kilowatt-hour
A unit of electrical energy use. The amount of energy used over a specified time period, typically one year, measured in kW.

kWh
See kilowatt-hour

kW
See kilowatt.

L
The low load forecast, 0.3 percent annual load growth.

LCP
See least cost planning

Least Cost Planning
Another term for planning which includes the same elements as integrated resource planning.

LD
See low DSR

levelized (levelization)
The present value of a resource's cost (including capital, financing and operating costs) converted into a stream of equal annual payments. By levelizing costs, resources with different lifetimes and generating capabilities can be compared.

levelized cost
The present value of a cost stream converted into a stream of equal annual payments. Real levelized cost results in a stream of payments which increase each year with inflation. Nominal levelized cost results in a stream of payments which are equal each year in nominal terms (like a mortgage payment). Real levelized costs are used in IRP.

LG
The low gas forecast, assumes 1.71 percent real annual price escalation for natural gas.

load
The amount of electricity used by a customer or group of customers during a specified time period.

load growth
The increase in demand for electric power that occurs over time as new customers move into an area and new uses for electricity are adopted.

load factor
A ratio or percentage which represents the proportion of time when power is used.

load following
Variation of generator output in response to changes in system loads and generation from other system resources within an hour.

load management
A way to reduce the peak load of a utility by reducing the amount of power used by its customers during the peak hour(s).

lost opportunity resource
Resource that is available only for a limited time.

low DSR
A strategy alternative for treating new DSR resources. In the model runs using the low DSR strategy, the model was forced to select a set amount of DSR each year of the 20 years (no more and no less). That set amount is shown in the Analysis Plan chapter, and is the lowest of the four DSR strategy alternatives.

Luz solar plant
A thermal solar plant which can use a conventional gas-fired steam turbine, when solar energy is not available.

M
The medium load forecast, 2.1 percent annual load growth.

margin, regulating
See regulating margin

margin, reserve
See reserve margin

MATO
Multi-attribute trade-off analysis, a form of analysis whereby multiple strategies are tested under multiple futures, to determine which strategies best meet multiple goals. In RAMPP-3, the multiple goals are lowest utility costs, lowest total resource costs, lowest prices, and lowest emissions.

MCS
Model Conservation Standards, adopted in Oregon and Washington. These standards require higher levels of insulation and other energy efficiency measures.

MD
See medium DSR

medium DSR
A strategy alternative for treating new DSR resources. In the model runs using the medium DSR strategy, the model was forced to select a set amount of DSR each year of the 20 years (no more and no less). That set amount is shown in the Analysis Plan chapter, and is between the low and accelerated DSR amounts.

megawatt
A unit of electric power equal to 1,000,000 watts or 1,000 kilowatts. One megawatt will light up 10,000 100-watt light bulbs. One megawatt is also needed to meet the electric demands of about 100 single family homes.
The amount of power being used or produced at one moment in time. Used as a measure for peak or capacity.

megawatt-hour
A unit of electrical energy use. The amount of energy used over a specified time period, typically one year, measured in megawatts.

MG
The medium gas forecast, assumes 3.78 percent real annual price escalation for natural gas.

MH
The medium-high load forecast, 3.0 percent annual load growth.

mill
One tenth of a penny. Used to represent the cost of electricity per kWh, for example 5 cents per kWh equals 50 mills/kWh.

mills/kWh
Used to signify price to retail customers, although it is an average over all states and all classes, thus it ignores allocation and class cost of service issues.

ML
The medium-low load forecast, 1.3 percent annual load growth.

mmbtu
Millions of BTUs.

model
A theory that is intended to capture the workings of the real world. A model used for electricity resource planning is intended to capture all of the factors that utilities consider in making resource acquisition decisions. It attempts to put into rules how each of these factors affects resource decisions, and how they interrelate.

multi-attribute trade-off analysis
An approach for resource planning which tests alternative resource strategies against alternative futures to determine which resource strategies perform best under different financial, emissions, or other criteria.

MW
See megawatt.

MWa
See average megawatt

MWh
See megawatt-hour

National Energy Policy Act of 1992
An Act passed by Congress which establishes standards for several areas of utility operation. Includes standards which state regulatory Commissions may adopt for integrated resource planning.

Native Load
Term used on tables to refer to

NC
See no coal

NERC
See North American Electric Reliability Council

net present value
A discounted cash flow technique used in comparing alternative future investments. Net present value allows a comparison of the time-adjusted value of one investment compared to another.

New Resources
Term used on tables to refer to

no coal
A strategy alternative for treating new coal resources. In the model runs using the no coal strategy, the model was not allowed to select any new coal resources.

nominal
Dollars, in the year's units as specified. Nominal dollars reflect inflation.

non-firm
Power that has no assured availability. The amount of non-firm energy is typically dependent on the hydro conditions.

non-firm purchase
Power which a utility can purchase from another if the seller has available power at that given time.

Non-Firm Purchases
Term used on tables to refer to

Non-Firm Sales
Term used on tables to refer to

non-spinning reserves
The portion of the operating reserve capable of being connected to the electrical system and loaded within ten minutes. Also included is any load which is designated for use as reserve and can be reduced by dispatcher action within 10 minutes (interruptible load). Thus, any unused generating capability that can be increased at a particular unit within 10 minutes can be considered non-spinning reserves. Non-spinning reserves are generally provided by units running at less than their maximum generating capacity and by interruptible loads.

North American Electric Reliability Council (NERC)
An organization formed by electric utilities in 1968 to coordinate, promote, and communicate about the reliability of their generation and transmission systems. NERC helps utilities work together to prevent blackouts. NERC's members are nine Regional Councils and one Affiliate encompassing virtually all of the electric utility systems in the U.S., Canada, and the northern portion of Baja California, Mexico.

Northwest Power Planning Council
A federally chartered council comprising Oregon, Washington, Idaho, and Montana that establishes policy on northwest electrical energy and related fish and wildlife issues.

Northwest Power Pool
The Northwest Power Pool is the already existing agency with responsibility for the Pacific Northwest Coordination Agreement's implementation. They do hydro regulation and related studies for the seventeen participating Northwest generating utilities.

NOx
Nitrogen oxide. An emission.

NPV
Net Present Value.

NPV at 8.8% (million $)
Term used on tables to refer to

NWPP
See Northwest Power Pool

NWPPC
See Northwest Power Planning Council

O&M
See operation and maintenance

operating reserves
Excess generating capability above firm system load capable of providing for regulation within the hour to cover load variations and power supply reductions. It consists of spinning and non-spinning reserve.

operating revenue
Can also be thought of as the company's revenue requirement.

operation and maintenance
Costs incurred to maintain equipment.

optimization model
A modeling approach which mathematically results in a least cost solution, given the input assumptions and constraints.

outage
A partial or complete reduction of generation or transmission resource capability. Forced outages are unanticipated breakdowns. Planned outages are periodic shutdowns of resources to allow for preventive maintenance and repair.

OWC
Signifies the company's service territory in the western area, including customers in Oregon, Washington, California, and Montana.

Pacific Northwest Coordination Agreement
An agreement signed in 1964 by the federal government and northwest utilities to agree to operate generating projects as a single entity to make optimum use of the water and storage resources of the Columbia River system. It governs the seasonal release of stored water to obtain the maximum usable energy subject to other uses.

peak
The maximum amount of electricity needed to serve customers at a given time.

peak management
See load management

penetration
The number of customers who will have equipment in the future for a particular end use for electricity.

photovoltaic (PV)
Solar technology that directly converts sunlight into electricity.

pipeline
Equipment which transports natural gas from one location to another, typically over a long distance.

planning reserves
The amount of excess generating capacity a utility must have available to serve its load and meet its obligation to others without imposing an undue degradation of reliability on any other system. Utilities employ a number of different methods for determining this reserve requirement. Planning Reserve often considers other sources of uncertainty beyond generator forced outages, such as peak load variability, load forecast error, uncertainty of new resource lead times, etc.

PNCA
See Pacific Northwest Coordination Agreement

portfolio
All of the potential resources the utility could use to meet the future electric service needs of its customers. It includes the generic supply-side technologies available in the marketplace, and the demand-side programs currently offered or planned to be offered by the utility.

power supply
The combination of power plants which generate electricity for a utility.

present value
The worth of future costs in terms of their current value. To obtain a present value, an interest rate is used to discount the future costs.

price
As used in the discussion of the analyses, price refers to real levelized cost in mills/kWh. It is the price customers would pay per kWh if the company charged all customers on a kWh basis (no basic or demand charge) and prices did not vary by customer class (pricing ignored allocation issues and cost of service by customer class).

price design
See rate design

price elasticity
The response of customers to the level and change in the price of a product. A high elasticity means that customers respond strongly to a high price and to a change in the price.

production cost
The cost the utility experiences for each kWh it produces. Each plant has its own associated production cost, and the utility as a whole has a total (average) production cost.

Public Utility Regulatory Policies Act of 1978
Federal legislation that requires utilities to purchase electricity from qualified independent power producers at a price that reflects what the utilities would have to pay for the construction of new generating resources (at avoided cost). The act was designed to encourage the development of small-scale cogeneration and renewable resources.

Pulverized coal plant
Conventional coal plant, which uses a subcritical steam boiler that burns sub-bituminous coal.

pumped storage
A generation technology which uses water in two reservoirs. The water is allowed to fall from the higher reservoir into the lower reservoir, passing through turbines and generators on the way, producing electricity. It is then pumped back up to the upper reservoir, using power from another power plant.

Pump Storage/Peak Return
Term used on tables to refer to

purchased power
Power which the utility purchases from another utility.

PURPA
See Public Utility Regulatory Policies Act of 1978

QF
See qualifying facility.

qualifying facility.
A private electric generating facility which "qualifies" for special treatment under the 1978 PURPA Act to sell power to utilities. A qualifying facility must generate its power using cogeneration, biomass, waste, geothermal energy, or renewable resources, such as solar and wind. Its size may be limited to 80 MW or smaller. Such qualifying facilities must receive payments from the utility at the current or contracted avoided cost rate.

RAG
Acronym for the RAMPP Advisory Group, PacifiCorp's public advisory group for the RAMPP process.

RAMPP
PacifiCorp's integrated resource planning process. RAMPP is an acronym for Resource and Market Planning Program.

RAMPP-1
PacifiCorp's first integrated resource plan, filed with state regulatory commissions in November of 1989.

RAMPP-2
PacifiCorp's second integrated resource plan, filed with state regulatory commissions in May of 1992.

RAMPP-3
PacifiCorp's third and current integrated resource plan, which this report documents.

ramp-up
Increase to a higher level.

rate design
The particular combination of energy charges, demand charges, and basic (customer) charges for a tariff.

real dollars
Dollars, adjusted for inflation. Real dollars represent constant purchasing power.

real levelized costs
Costs which are "levelized" into a series of periodic payments spanning a given time frame, and adjusted for inflation.

real levelized fixed charge
The percentage of the total investment which is allocated to the first year after the levelization process.

refurbishment
The process of repairing and maintaining equipment on generating plants so as to maintain their ability to generate electric power.

regulating margin
The amount of spinning reserve required to maintain frequency of the electrical current within a specified range.

reliability
A measurement of the availability of power delivery to a customer or group of customers over a defined period of time.

renewable resource
Resource which is based on natural sources, such as wind, solar, or geothermal.

reserve margin
An amount of generation capability which is not used for regular daily operations, because it is held in reserve to meet unanticipated demands for power, or to generate power in the event of outages in normal generating capacity.

reserve requirement
Additional power the utility is required to keep in reserve, in case of outages or other influences on the system which would cause the amount of power generated to be insufficient for the load needs.

Reserve Requirement
Term used on tables to refer to

reserves, planning
See planning reserves

reserves, operating
See operating reserves

reserves, spinning
See spinning reserves

reserves, non-spinning
See non-spinning reserves

residential exchange program
See BPA residential exchange

residential weatherization
Residential sector demand-side measure which increases the energy efficiency of a home and reducing the electricity needed to provide the same level of comfort.

resource planning
The process of predicting the future electricity and energy service needs of customers, and planning which new resources should be used to provide the services required.

resource supply
The system of generating plants available to a utility to meet the electricity needs of its customers.

retail wheeling
Rather than taking service from the utility in its own service area, a retail customer contracts with a utility in another designated service area to provide electricity. This requires the first utility to provide wheeling services to deliver the power to the customer.

RFP
Request for Proposal. A competitive bidding process in which a utility requests proposals from suppliers for resources to meet future load growth needs.

saturation level
Number of customers with the equipment for a particular end-use for electricity.

SCCT
See simple-cycle combustion turbine

SCE Contract
See Southern California Edison Contract

sensitivity
A unique case, which is a combination of a case from the base study plan, with one of the input assumptions altered, for example, the characteristics of a resource in the portfolio, or the price of wholesale power, or the transmission system.

shaping
Refers to the ability of a resource to match the shape of loads being served. For example, a hydro unit can generate at maximum capacity during the heavy load hours of the day, backing down to lower generating levels as loads drop off. This effectively levelizes the remaining load that other generating resources must supply, which allows baseload resources to operate at full capability over more hours, enhancing efficiency.

simple-cycle combustion turbine
Combustion turbine where natural gas is used to produce electricity. It is similar to a jet engine. Because it can be fired quickly, it is used for peaking.

siting
The process of preparing a power plant and associated services, such as transmission lines, for construction and operation. Steps include locating a site, developing the design, conducting a feasibility study, and preliminary engineering.

SO2 allowance
Authorization from the federal Environmental Protection Agency to emit one ton of SO2 from a thermal generating unit during or after a specific calendar year. SO2 allowances were established in Title IV of the Clean Air Act Amendments.

Southern California Edison Contract
A contract between PacifiCorp and Southern California Edison whereby SCE sells to PacifiCorp electric power during the winter months.

space heat
An end use for electricity, typically for residential customers, to heat their homes.

spinning reserves
An amount of generation available in reserve from resources whose output can be immediately changed to respond to load variations to give the utility the regulating margin needed to follow the second-by-second load variations on the system. The portion of the operating reserve which responds automatically to fluctuations in system frequency.

SR
See strategic renewables

steam turbine generator
Electric generator driven by steam.

strategic renewables
A strategy alternative for treating new renewable resources. In the model runs using the strategic renewables strategy, the model was forced to select a set amount (no more and no less) of renewable resources through the year 2001, after that point, the model could select any renewables as they were cost effective against other resource choices.

Super Good Cents program
Residential sector demand-side program.

supply-side resources
Resources which physically generate power to the be transmitted and distributed to customers, such as coal plants, gas-fired plants, or wind farms.

System Load (GWh)
Term used on the financial output summary table to indicate the total load forecast for all of PacifiCorp's retail customers for each year.

T&D
Transmission and distribution

tariff
A schedule filed by a utility with a regulatory agency describing transactions between the utility and customers in terms of type of service, conditions of service, rates charged, and means of payment.

thermal plant
A power plant which relies on heat to power an electric generator. The heat may be supplied by burning coal, oil, natural gas, or other fuel, by nuclear fission, or by solar or geothermal sources.

total fixed cost ($/kW Yr)
The sum of the Annual cost and Fixed O&M. see Annual cost, and Fixed O&M.

Total Requirements
Term used on tables to refer to

total resource cost
The sum of all direct costs paid by both the company and demand-side program participants. This is usually expressed as a levelized cost.

transmission
Electrical equipment which takes power from generating plants and transports it over long distances to a load area. At a substation it is delivered to the distribution system.

TRC
See total resource cost.

TSP
Total suspended particulates. An emission.

unconstrained
A combination of strategies used in some model runs which provide no constraints on how or when the model may select any resources from the portfolio to meet system needs arising from load growth.

UTA
Signifies the company's service territory within Utah, southern Idaho, and southwestern Wyoming.

Utility Cost
Term used on tables to refer to the direct utility cost to operate the utility system, considering both the costs of rate base and operating costs.

variable O&M
Operation and maintenance costs that vary with the level of output from a power plant, so they are expressed as mills/kWh.

water, average
See average water

water, critical
See critical water

watt
A basic unit of electrical power equal to 0.00134 horsepower.

Western System Coordinating Council (WSCC)
One of nine Regional Councils of the North American Electric Reliability Council. The WSCC coordinates the operation and planning of the electric power system for the western part of the U.S., Canada, and Mexico. The WSCC in 1992 included 62 member systems - 18 IOU's, 18 municipal utilities, 18 public power systems, four federal agencies, three Canadian systems, one Mexican system. The WSCC is the largest and most diverse of the nine regional Councils of the NERC. WSCC's service territory contains the provinces of British Columbia and Alberta, the 14 western states, and the northern portion of Baja California, Mexico.

wheeling
The use of one utility system's transmission facilities to transmit power of and for another system.

wholesale sales
Power sales made from one utility to another utility.

WSCC
See Western System Coordinating Council

WYO
Signifies the company's service territory in eastern Wyoming.

INDEX

This fold-out page is provided to help the reader with key acronyms and to identify case numbers for the base study plan.

FUTURES			Load	L			ML			M			MH			H		
			Gas	LG	MG	HG	LG	MG	HG	LG	MG	HG	LG	MG	HG	LG	MG	HG
UNCONSTRAINED					1			6		11	28	45		64			85	
STRATEGIES	LD	AC	AR							12	29	46		65			86	
	LD	AC	SR							13	30	47		66			87	
	LD	NC	AR							14	31	48		67			88	
	LD	NC	SR							15	32	49		68			89	
	MD	AC	AR		2			7		16	33	50		69			90	
	MD	AC	SR		3			8		17	34	51	62	70	81	83	91	102
	MD	NC	AR		4			9		18	35	52		71			92	
	MD	NC	SR		5			10		19	36	53	63	72	82	84	93	103
	AD	AC	AR							20	37	54		73			94	
	AD	AC	SR							21	38	55		74			95	
	AD	NC	AR							22	39	56		75			96	
	AD	NC	SR							23	40	57		76			97	
	HD	AC	AR							24	41	58		77			98	
	HD	AC	SR							25	42	59		78			99	
	HD	NC	AR							26	43	60		79			100	
	HD	NC	SR							27	44	61		80			101	

DSR Coal Renew

L	Low load growth	(0.33%/year)
ML	Medium-low load growth	(1.26%/year)
M	Medium load growth	(2.13%/year)
MH	Medium-high load growth	(3.02%/year)
H	High load growth	(3.75%/year)

LG	Low gas prices	(1.71% real growth/year)
MG	Medium gas prices	(3.78% real growth/year)
HG	High gas prices	(5.56% real growth/year)

Unconstrained — Model can select demand-side resources without regard to ramp rate or feasibility limits

LD	Low demand-side strategy	(30 mills cost effectiveness)
MD	Medium demand-side strategy	(55 mills cost effectiveness)
AD	Accelerated demand-side strategy	(55 mills cost effectiveness)
HD	High demand-side strategy	(70 mills cost effectiveness)

AC Any-coal strategy (model can select coal whenever cost effective)
NC No-coal strategy (model cannot select coal)

AR Any-renewables strategy (model can select renewables whenever cost effective)
SR Strategic-renewables strategy (model forced to add set amount of renewables 1994-2001)

POSITIONING FOR COMPETITION AND UNCERTAINTY

RAMPP

Resource and Market Planning Program

RAMPP - 3

LOAD FORECASTING APPENDIX

APRIL, 1994

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Load Forecasting - Methodology
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LOAD FORECASTING - METHODOLOGY

INTRODUCTION

The development of a long range electricity sales forecast is one of the first steps towards developing a least cost plan. The sales forecast is an estimate of how much electricity retail customers (this includes both interruptible and regular sales for resale customers) will require in the next twenty years. Utilities must evaluate their business over a twenty year planning horizon in order to make efficient least cost resource decisions involving supply and demand side options that can, in many instances, take many years to construct or develop. This chapter describes the methodology used in developing electricity sales forecasts and the economic and demographic forecasts from which they are derived.

Economic and demographic assumptions(such as employment, population and income) are two key factors influencing the forecasts of electricity sales. Absent other changes, demand for electricity will parallel other regional and national economic activities. However, several influences can change that parallel relationship, for example, changes in the price of electricity, the price and availability of competing fuels, changes in the composition of economic activity, the level of conservation, and the replacement rate for buildings and energy-using appliances. The forecasts consider all of these variables.

The forecasting process uses information "inputs" and produces forecast "outputs". The forecasting model uses a range of values for certain variables to produce a range of forecasts. The range of forecasts for RAMPP-3 is large enough to accommodate reasonable variation in load levels that might occur.

Recognizing that the future is highly uncertain, five separate forecasts have been developed to bound this uncertainty. These five separate forecasts are referred to as: low (L), medium-low (ML), medium (M), medium-high (MH), and high (H). A very large number of combinations of economic and demographic conditions make any outcome between the MH and ML energy forecasts very likely. Load growth between the MH and high range, or between the ML and low range is less likely. Only a dramatic change in economic, demographic, or consumer choices and behaviors could produce load growth above the high or below the low forecast. The medium forecast is a forecast where the chances of under- or over-shooting it are roughly equal. The purpose of this approach is to develop a flexible resource strategy that provides an adequate supply of electricity at the lowest cost. The risks are twofold: the risk of not having an adequate supply of electricity, and the risk of being saddled with expensive investments in unnecessary resources.

The Company uses three of Data Resource's (DRI) long term forecasts of the US economy - the Optimistic, Trend, & Pessimistic forecasts - in developing the five forecasts described above. The Company believes that DRI's forecasts encompass a wide range of National forecasts which allow resource decisions to be adequately tested. In addition, an extra refinement is to combine these national ranges with regional ranges which then generates the five different scenarios. The medium forecast combines the National Trend forecast with a regional economic forecast, in which, the regional economy grows at the same rate in the future as it has done historically. The MH and ML forecasts combine the National Trend forecast with regional economic forecasts, in which, compared to historic patterns, the regional economy grows faster (slower) than historically. The High (Low) forecasts differ from the Medium High (Medium Low) forecasts by replacing the Trend forecast with the Optimistic (Pessimistic) forecasts. The inputs which generate the forecasts are not from one particular historical period, but reflect a consistent set of inputs which could occur in the future. No point forecast can ever be exactly correct in projecting the future and it is important not to dwell on whether the forecast is perfect. Rather it is the range of forecasts that is more important and the belief that it will encompass a wide enough range of uncertainty to test the Company's resource strategies.

The forecast at sales level prepared by PacifiCorp (the Company) as part of the Least Cost Planning Process is an annual forecast for each of the residential, commercial, industrial, irrigation, and "other" customer classes. These forecasts when aggregated are referred to as the general business sales forecast. The forecast is derived from a consistent set of economic, demographic, and price projections specific to each of the nine zones, in seven states, served by the Company. These states are California, Idaho, Montana, Oregon, Utah, Washington, and Wyoming. Idaho and Wyoming each have one geographic area served by Utah Power and another area served by Pacific Power. Forecasts of economic and demographic variables, such as employment, population, and income are produced for each of the nine zones and the results are used as inputs into the electricity sales forecasting models. The system wide forecast for each level (high, MH, medium, ML, and low) is the sum of the nine zonal forecasts. For example, the "high" electricity sales forecast of the Company equals the sum of the "high" forecasts for all nine zones.

Two basic forecasting methods are used to predict general business sales: a combined econometric/end-use analysis of the residential and commercial models, and an econometric forecast of the remaining customers groups. The forecast encompasses both firm and interruptible sales. To these general business sales forecast, forecasts of regular retail sales for resale are added to produce a total retail sales forecast. To these total retail sales forecasts are added system losses (i.e. the losses in electricity in getting electricity from the generation source to the customer) to calculate the amount of annual energy required to serve the needs of the customers. After the annual energy forecast has been completed, an hourly load forecast is prepared for each of the nine zones. Separate hourly forecasts are made for firm and interruptible customers in the two zones where such forecasts are appropriate. The annual energy is first broken into monthly data on the basis of historic seasonal patterns. Further refinements are made to develop weekly, daily and finally hourly load forecasts using historical patterns of energy use. Summing up the respective zonal forecasts produces hourly load forecasts for the Pacific and Utah Divisions and the Total Company. The maximum load for each month is the peak load for the company, and the zonal load at that time is the zonal coincident peak. The maximum load for each zone during each month is the zonal non-coincident peak. The forecasting techniques used also allows the production of total and firm peak and energy forecasts. As new resources (both supply and demand side) are added, the hourly loads will change and these changes are reflected in the sales to customers after resource decisions are made.

The document contains the following chapters. First, a brief discussion of the employment and sales forecasts for each of the five scenarios. Tables that give average growth rates for employment and sales for the five scenarios at both the sector and zone levels are contained in Appendix 1. The next major section - **Economics and Demographics** - has three subsections which describes the methodology used to generate the Employment, Population, and Employment forecasts. The final major section - **Energy** - has six subsections, an introduction, and chapters describing the methodology used to produce the annual Residential, Commercial, Industrial, and Other Sales forecasts, and the Hourly Energy Forecasts. The main part of the text concludes with sections on **Public Process, Statistical Philosophy, Modeling Improvements Implemented Since RAMPP-2**, and **Anticipated Changes and Enhancements**. Following the main text are further appendices showing **Detailed Annual Sales Forecasts by Customer Class & Zone,** and **Monthly Peak & Energy Forecasts by Zone**.

EMPLOYMENT AND SALES FORECASTS

The employment forecasts show a wide range of results. In the medium case, total employment is expected to grow at an average rate of 1.7% per year between 1994 and 2013. At this rate of growth, 805,000 employees (40,000 per year) are added to total employment. The vast majority of these new employees (over 90%) are added to the non-basic employment category, indicating a continuing trend toward commercial and service-related employment.

In the medium high case, over 61,000 new employees are added annually each year to total employment as employment averages growth of 2.4% over the forecast period.

In the medium low case, over 435,000 new employees are added to total employment by 2013 as employment averages growth of 1.0% over the forecast period. All of the new growth is in the non-basic employment category, with three of the four basic employment categories declining over the forecast interval. This trend is even more obvious in the low forecast, in which, even though total employment grows by almost 120,000 employees, all four of the basic sectors decline over the forecast interval.

The sales forecast methodology resulted in five energy forecasts with growth rates for energy of 0.3 percent in the low case, 1.3 percent in the ML case, 2.1 percent in the medium case, 3.0 percent in the MH case, and 3.8 percent in the high case. The winter and summer peak forecasts average very similar growth rates for all five forecasts. The forecast grew faster in the early years of the forecast compared with the later years. In absolute terms, annual energy requirements in 2013 ranged from 5,373 MWa in the low case to 11,381 MWa in the high case (more than doubling the 1992 level). The winter and summer coincidental peaks respectively ranged from 7,504 MW and 7,194 MW in the low case to 15,949 MW and 15,456 MW in the high case.

The fastest growing component of retail sales is always commercial sales. In the low & ML scenarios, sales to residential customers grows faster then to industrial sales, while in the two high scenarios, this relationship is reversed. In the medium forecast, the two classes grow at the same rate.

To reiterate, these five forecasts demonstrate the magnitude of uncertainty that is faced with regard to future retail sales. On the one hand, under the low case total retail sales could be 3 percent higher (1.3 million Mwh) than they are today by the year 2013. On the other hand, under the high case total retail sales could be double the level they are today by the year 2013.

Appendix 1 contains two sets of tables. The first set of tables give the Annual Average Rates of Growth for electricity sales and employment by major sector for each of the five scenarios at the total company level. The second set of tables list the Annual Average Rates of Growth for electricity sales for the nine zones for each of the five scenarios.

ECONOMIC & DEMOGRAPHIC SECTION

Employment

Basic Employment

Within the Company's forecasting methodology, employment serves as the major determinant of future trends among the many economic and demographic variables used to "drive" the sales forecasting equations. Employment is also an input into the equations that forecast other economic and demographic variables. Recognition of the importance of employment determination can be understood through the examination of the concept of "regional export base theory." This methodology assumes that the local economy is comprised of two distinct sectors: "basic" and "non-basic".

The basic sector is comprised of those industries which are involved in the production of goods destined for sales outside of the local area and whose market demand is primarily determined at the national level. The employment categories that are treated as basic are: manufacturing, mining, agricultural, and federal government. A "regional share" approach is utilized to forecast most of the specific industries that make up the basic employment category. All basic sectors except mining are forecast similarly. For each historic year for which employment data is available, and for each employment category and zone, a "regional share" is calculated as follows:

$$\text{Regional Share}_{tij} = \text{Employment}_{tij} - \text{Employment}_{t-1ij} \times (\text{National Employment}_{tj}/\text{National Employment}_{t-1j})$$

where: t = current period

i = zone

j = specific employment group (must be either agriculture, federal government, or one of the manufacturing categories.)

Historic regional shares are thus the difference between the actual zonal employment in any year and the zonal employment that would have been projected if zonal and national employment had grown at the same rate.

For forecasting, the equation is inverted. Employment in the current period becomes the dependent variable. The equation then becomes:

$$\text{Employment}_{tij} = \text{Employment}_{t\text{-}1ij} \times (\text{National Employment}_{tj}/\text{National Employment}_{t\text{-}1j}) + \text{Regional Share}_{tij}$$

where: t = current period

i = zone

j = specific employment group (must be either agriculture, federal government, or one of the manufacturing categories.)

The regional shares used in the forecast are allowed to differ from their historic values. (They vary from higher than their historic average in the two high scenarios, to equal to their historic average in the medium scenario, to lower than their historic average in the two low scenarios. We do not assume, as a matter of consequence, regional growth is faster than the nation in the high forecast, rather, the comparison is between the forecast and historic regional shares, not the absolute rate of growth).

The final basic sector, mining employment, cannot be forecast in the same manner as the other basic sectors. This is because forecasts of mining employment are only available from DRI for total mining employment and hence are not available at the level of disaggregation necessary for the mineral specific equations used to forecast electricity sales.

In general, mining employment is forecast as a function of mining employment in the previous period and a regional or national variable representing output or a surrogate for mining output. The equation thus takes the form:

$$\text{Employment}_{ijt} = f(\text{Employment}_{ijt-1}, \text{Output}_{it})$$

where: i = specific mining category
t = current period
j = zone.

Non-Basic Employment

The non-basic sector theoretically represents those businesses whose output serves the local market and whose market demand is largely determined by the level of basic employment and output in the local economy. Employment categories that are treated as non-basic are: Transportation, Communications, and Public Utilities; Wholesale and Retail Trade; Finance, Insurance, and Real Estate; Services; Contract Construction; State and Local Government; and Non-Farm Proprietors. This simplistic definition of industries as basic or non-basic does not directly confront the problem that much commercial employment (traditionally treated as non-basic) has assumed a more basic nature. This problem is overcome by including variables such as Real Gross National Product, National Output, Housing Starts, a Time Trend, along with basic employment, in the equations which determine the non-basic employment forecasts. These equations are formed by regressing employment in each of the categories as a function of variables which will include some of the following: a lagged dependent variable, basic employment, and the national variables discussed previously. The inclusion of basic employment in the specification is a direct application of regional export base theory. As basic employment increases, it causes the non-basic sector to expand. The inclusion of the national variables in the specification allows us to model our theory that some non-basic employment behaves more like basic employment.

The relationship between the basic and non-basic sectors has not been constant over time. This is because as the productivity, and hence real wages, of basic sector workers has increased, their expanded purchasing power has caused the non-basic sector to develop more rapidly. A second reason is the changing preference and tastes of consumers which has caused a relative shift away from the good-producing or basic industries towards those which are more service-oriented. A third reason is that on a locational basis, more non-basic industries are behaving as basic industries.

Within a given sector not all of the zonal level equations will include all of the independent variables discussed above. The specifications for transportation, communications, and public utilities; wholesale and retail trade; finance, insurance, and real estate; services; state & local government, is:

$$\text{Employment}_{tj} = f(\text{Employment}_{t\text{-}1j}, \text{Basic Employment}_{tj}, \text{Real Gross National Product}_{t}, \text{Time}_{t}, \text{Agricultural Employment}_{tj}/\text{Basic Employment}_{tj})$$

where: t = current period
j = zone.

The final specification will include only those variables that statistically indicate a significant impact. Agricultural Employment divided by Basic Employment is used to explicitly model the assertion that changes in agricultural employment have less effect on the non-basic sector than do the other basic employment categories.

The next non-basic category, Contract Construction, does not have Agricultural Employment in the equation specifications. Either National Housing starts or the Effective Mortgage rate have been included in the specification as a surrogate for local construction activity. Historically, changes in local construction activity have been associated with changes in national housing starts and/or the mortgage rate, a relationship which is expected to continue in the future. The specification is thus:

$$\text{Employment}_{tj} = f(\text{Employment}_{t\text{-}1j}, \text{Basic Employment}_{tj}, \text{National Housing Starts}_{t}, \text{Effective Mortgage Rate}_{t}, \text{Time}_{t})$$

where: t = current period
j = zone.

The final non-basic category, Non-Farm Proprietors, is forecast simply as a function of the sum of the other six non-basic categories.

$$\text{Non Farm Proprietors}_{tj} = f(\bullet\ \text{Other Non-Basic Employment}_{tj})$$

where: t = current period
j = zone.

Population

DRI's Regional Information Service contains long-range forecasts of total population, and total non-agricultural employment for the states served by the Company. Population per non-agricultural employee at the zonal service territory level is forecast as a function of population per non-agricultural employee at the state level. This ratio is then multiplied by the forecast of non-agricultural employment at the service territory level to derive a population forecast.

Service Territory Population_{tj} = Service Territory Non-Agricultural Employment_{tj} x f(State Population_{tj}/State Non-Agric. Employment_{tj})

where: t = current period

j = zone.

Income

Two primary measures of income are utilized in producing the forecast of total electricity sales. Total personal income is used as a measure of "economic vitality" which impacts energy utilization in the commercial sector. Real per capita income is used as a measure of "purchasing power" which impacts energy choice in the residential sector. The Company's economic forecasting system projects total personal income on a service territory basis.

In order to accurately portray the differing income streams caused by the diversity of the economic base of the service territory, the total personal income forecast is formed from the sum of eight separate components. Four of these measures - manufacturing, mining, agricultural, and non-farm/non-industrial (commercial) income - combine to form labor & proprietors income. This level of disaggregation is necessary in order to capture differences in zonal level trends in various time streams within the Company's service territory which are largely caused by differences in the economic base of the area. The four remaining components of total personal income are contributions for social insurance, transfer payments, property income (dividends, interest and rent) and the net residence adjustment. The relationship among the components can be expressed in the following manner:

Total Personal Income = Labor & Proprietors Income - Contributions for Social Insurance + Property Income +Transfer Payments + Net Residence Adjustment.

Labor & proprietor's income comprises the largest share of personal income. It is primarily comprised of payments to salaried employees, hourly workers and the net income of unincorporated businesses, both farm and non-farm. Forecasts were derived through econometric specifications of the four primary components as previously described. This level of disaggregation allows for a more accurate reflection of the differences in employment patterns and wage & salary structures within each group.

Economic theory suggests that real wage increases will reflect corresponding increases in employee productivity and output. Subsequently, sectoral income can be derived as a function of the level of productivity (output/employee) and output. Equations to forecast commercial and manufacturing income utilized a national productivity index (there being no sub-national index available) in a pooled least squares regression. The general relationship for these two sectors is:

$$\text{Income}_{tj} = f(\text{Employment}_{tj}, \text{National Productivity}_t)$$

where: t = current period
j = zone.

Within the mining and agricultural sectors, reliable productivity measures which will yield acceptable results when attempting to specify an equation do not exist at the sub-national or national level. This is not surprising considering the specialized nature of the Company's mining and farm sectors. Because of this lack of reliable productivity measures, alternative specifications were sought. A simplistic equation was used to forecast Mining Income. The change in mining income was defined to be equal to the change in mining employment multiplied by the change in national manufacturing productivity. i.e. for the mining sector:

$$\text{Income}_{tj} = \text{Income}_{t-1j} \times (\text{Employment}_{tj}/\text{Employment}_{t-1j}) \times (\text{National Manufacturing Productivity}_t/\text{National Manufacturing Productivity}_{t-1})$$

where: t = current period
j = zone.

Farm income is specified on a real income per employee basis as a function of national farm proprietor's income per employee. The forecast of farm income will vary with different levels of zonal employment, national income and employment. For the farm sector:

$$\text{Income}_{tj} = f(\text{Employment}_{tj}, \text{National Farm Income Per Employee}_t)$$

where: t = current period
j = zone.

Contributions for social insurance, are payments made by individuals under the various social insurance programs. They are excluded from personal income through being handled as specific deductions. Forecasts are made for this variable by projecting the percentage of labor & proprietor's income going to social insurance deductions at the local level as a function of the same value at the national level. The equation is:

$$\text{Contributions For Social Insurance}_{tj} = \text{Labor \& Proprietor's Income}_{tj} \times f(\text{National Percentage Contribution for Social Insurance}_t)$$

where: t = current period
j = zone.

Property income consists of dividends, personal interest income, and royalty income of individuals. It is forecast on a per capita basis as a function of national per capita property income and time. The time variable allows for differing rates of growth of property income at the regional level as compared to the national level. The relationship is:

$$\text{Property Income}_{tj} = \text{Population}_{tj} \times f(\text{National Per Capita Property Income}_t, \text{Time}_t)$$

where: t = current period
j = zone.

Transfer payments consist of the income of persons from government or business for which no services are currently being rendered. Nationally, the largest component of this revenue stream is derived from federal Social Security, Public Assistance and Veterans benefit programs. Similarly to property income, local per capita transfer payments are forecast as a function of the national per capita transfer payments as follows:

$$\text{Transfer Payments}_{tj} = \text{Population}_{tj} \times f(\text{National Per Capita Transfer Payments}_t)$$

where: t = current period
j = zone.

Finally the net residence adjustment (the net difference between income earned by an area's residents outside the area, and income received by non-residents inside the area) is projected to continue as a constant percentage of personal income into the future.

ENERGY SECTION

Introduction

The major factor in forecasting future electricity sales is anticipated consumer use: "What electrical appliances will customers want and how will they use them?" The Company predicts the level of use for each of its four customer segments: residential, commercial, industrial and "other."

Each customer segment uses electricity in specific ways; i.e., each has particular end uses for electricity. For example, residential customers use electricity primarily for lighting, space and water heating. Commercial customers mainly use electricity for lighting and HVAC. Industrial customers use it for processing.

To predict the overall level of future electricity use for any one customer segment, the Company looks at how the customers in that sector use electricity and how much electricity they use. Future usage depends on:

1) How many customers are currently equipped for each end use (the saturation level);
2) How many additional customers will be equipped for that end use in the future (the penetration level);
3) How much electricity is currently consumed (level of use) for that activity;
4) How electricity consumption for that activity will change in the future.

One of the most important characteristics of an integrated resource plan is the fair evaluation of both supply-side and demand-side resources in building an overall portfolio designed to meet future electricity growth. In order to put increased demand-side efficiencies on an equal footing with supply-side resources, the retail sales forecast is developed using the "frozen efficiencies" concept. This means that important elements that constitute an individual customer's total electricity consumption, and average appliance usages are held at their 1992 levels throughout the forecast period. There are two exceptions - firstly, if it is known that a new appliance will have to be built to more stringent Government Standards than at present, then it is assumed that all appliances purchased after that date will conform to the standard. Secondly, if a state has energy standards, or is considering standards such as Oregon's model conservation standards, the model assumes that new buildings will observe them.

Residential Sales

The Company's Residential End-Use Forecasting Model has been developed to forecast specific uses of electricity in the customer's home. It is a hybrid econometric-enduse model. The model explicitly considers factors such as persons per household, fuel prices, per capita income, housing structure types, and other variables that influence residential customer demand for electricity. Residential demand is projected on the basis of fourteen end-uses. These uses are space heat, water heat, electric ranges, dishwashers, electric dryers, refrigerators, lighting, air conditioning, freezers, water beds, electric clothes washers, hot tubs, well pumps, & residual uses. Air conditioning can be either central, window, or evaporative (swamp cooler).

For each end use, the Company looks first at saturation levels (the number of customers equipped for that end use) and how those saturation levels may change with demographic and economic changes. The saturation level for each end use is estimated based on Company survey information. Then the Company determines the penetration level: given the economic and demographic future assumptions, how many new households are expected to adopt that end use in the future? In addition, how many houses which currently have that end use are being demolished? Historic information is used to estimate the demolition rate. Some appliances may be replaced several times before a home is demolished. The shorter lifetime of various appliances compared to the lifetime of a home is considered in determining the number of customers who use electricity for each end use.

The basic structure of the end-use model is to multiply forecast appliance saturations (percentage of homes with a particular appliance) by the appropriate housing stock. The result is then multiplied by the annual average electricity usage per appliance. The product, total annual electricity consumption by residential usage, is shown by the following equation:

$$\text{Total Appliance Consumption}_i = \bullet \text{ Housing Stock}_k \times \text{Saturation of Appliance}_{ik} \times \text{Electricity Usage of Appliance}_{ik}$$

where: i = Appliance type
k = Housing type.

Because consumption patterns vary with dwelling type and age, the residential model identifies three types of structures - single family, multi-family, and mobile homes - each comprised of existing and new homes. In addition, for existing homes, the single families are subdivided into three sizes of dwellings. For new houses, in addition to subdividing single family households, multi-families dwellings are also broken down into two different size groupings. Single family homes are defined as containing only one household and having an exterior exposed to the elements on all sides. Multiple family homes are defined as both traditional multiple unit dwellings such as apartment buildings, duplexes and triplexes, and any single family units that are attached on at least one side to other structures. Mobile homes are defined as all structures built initially upon a trailer chassis.

DRI's Regional Information Service contains long-range forecasts of total population, and households for the states served by the Company. The ratio of total residential customers to population at the zonal service territory level is forecast as a function of the ratio of households to population at the state level. (This specification assumes that the historic relationship between the zonal service territory and the entire state continues into the future. While this is not certain, the range of employment forecasts from the high to the low will generate a wide range of customer forecasts more than adequate to test the resource portfolio). This ratio is then multiplied by the forecast of population at the service territory level to derive a forecast of total residential customers. The equations look like:

$$\text{Residential Customers}_{tj} = \text{Service Territory Population}_{tj} \times f(\text{State Households}_{tj}/\text{State Population}_{tj})$$

where: t = current period
j = zone.

To project the number of new residential customers, an estimation of the demolition rate for existing buildings must be made. These rates are constructed from historic Company data and refer to the changes in the number of active customer accounts for whatever reason. The demolition rates are zone specific for each structure type because the composition of the existing housing stock in each zone is different and is subject to differing influences. It is assumed that the mobile homes as a group would be demolished at a higher rate than the multi-family structures, which would in turn be demolished at a higher rate than single family structures. The equation for new residential customers for each structure type and zone is thus:

$$\text{New Residential Customers}_{ijt} = \text{Total Residential Customers}_{ijt} - (1 - (\text{Demolition Rate}_{ij}))^{t*}(\text{Total Residential Customers}_{ij0})$$

where: t = current period
j = zone
i = structure type.

The distribution of existing residential customers among the various different types and sizes of structures is based upon survey data. The preference of new residential customers for different structures types is based upon econometric equations modeled on historic new connect information. The size distribution within the differing structure types is based upon survey data. New and existing customers choosing each structure can be summed to give the total number of single family, multi-family and mobile home customers.

For each zone, the percentage of the total number of residential customers (house-holds), having already chosen a structure type, expected to choose a particular heating type or appliance in the future (the saturation of the appliance) is estimated with an econometric equation, specific to each structure type, containing variables such as electricity price, income, & the price of competitive fuels. (The saturation for each appliance in the first year of the forecast (1992) is based upon estimates developed from Company survey data.) This approach is used for all of the end-uses except space and water heat where the percentage of the total number of new residential customers expected to choose electric space or water heat in the future (the penetration of the end use) is estimated with an econometric equation containing such variables as electricity price, income, & the price of competitive fuels.

In general, saturations and penetrations are calculated econometrically using logistic formulations. A logistic equation takes the following form:

$$(\text{Saturation})/(1 - \text{Saturation}) = F(\text{Real Prices, Income,...})$$

The logistic specification contains two properties which make it especially useful for analysis:

1. The saturation of the forecast variable is constrained between 0 & 100 percent. With the exception of appliances such as refrigerators and televisions, this is an obvious constraint.
2. The magnitude of the response of the saturation to a change in electric price depends upon where the saturation of the appliance is when the change in electric price occurs. This property is known as variable elasticity. The implication is that as the saturation increases, the same absolute change in price will have less effect upon the change in saturation.

Electric space heat penetrations for new households are forecast on an annual basis using econometric equations in logistic form. The penetrations are calculated for each structure type for each zone. The basic form of the equation is:

$$\text{Logit(Space Heat Penetration}_{ijt}) = \text{f(Logit(Space Heat Penetration}_{ijt-1}), \text{Real Electricity Price}_{ijt}/\text{Real Fossil Price}_{ijt})$$

where: t = current period
j = zone
i = structure type.

Real electricity prices are divided by a weighted average of real fossil fuel prices to obtain relative prices in the residential sector. For each structure type, the forecast penetration rate is multiplied by the number of newly constructed dwelling units to obtain the actual number of new electrically heated homes. To this figure is added the number of existing electric space heat units, less demolitions, to give the total number of electrically heated units in any given year.

This specification assumes that for existing residential dwellings, their choice of space heat is fixed throughout the forecast period. However surveys show that some space heating customers change fuels when they replace their electric furnace. Instead of replacing their electric furnace, they may instead install a gas furnace. After discussing this with the RAG participants, the group decided to impose fuel switching at varying rates from electric to gas only in the ML and low forecasts, where such a formulation resulted in an increase in the forecast range. (See the chapter - **Anticipated Changes and Enhancements**).

The number of water heat customers is forecast in a similar fashion, modified only by the fact of the shorter life time of a water heater as compared to the lifetime of the house. It is assumed that the average life of a water heater is 15 years. Each year, water heat penetrations are calculated for the new dwellings plus 1/15th of the remaining existing buildings. The equations take the form:

$$\text{Logit}(\text{Water Heat Penetration}_{ijt}) = f(\text{Logit}(\text{Non-Natural Gas Space Heat Penetration}_{ijt}))$$

where:
t = current period
j = zone
i = structure type.

This logistic formulation assumes that all non-gas space heat new connects will install electric water heaters. The form of the equation allows only natural gas space heat connects to install natural gas water heaters, and at the same time, constrains electric water heat penetrations to be less than 100%. As with space heat, for each structure type, the houses with new electric water heaters are added to the number of houses with old electric water heaters to yield the total number of homes with water heaters.

After calculating penetration rates for space heat & water heat, saturations are estimated for the other major appliances - electric ranges, dishwashers, electric dryers, refrigerators, lighting, air conditioning, freezers, water beds, electric clothes washers, hot tubs & well pumps. Logistic econometric equations are used to estimate most appliance saturations.

We do not have the depth of information, to specify different equations for every appliance in each zone for every structure types. In many cases an equation is specified for an appliance in each zone without differentiating between structure types. However we know, from survey data, the base year saturation for each appliance by zone and structure type. The equations are those modified by changing the constant term in each equation so that when the equation is solved for the base year, it yields the correct result.

The equations which forecast the saturations for the three types of air conditioners take the following form:

$$\text{Logit}(\text{Air Conditioning Saturation}_{ijt}) = f(\text{Logit}(\text{Air Conditioning Saturation}_{ijt-1}), \text{Real Electricity Price}_{jt})$$

where: t = current period
j = zone
i = central (c), window (w), swamp cooler (s).
and $\text{Saturation}_{cjt} + \text{Saturation}_{wjt} + \text{Saturation}_{sjt} \bullet 1$
for all j & t.

The equations which forecast the saturations for electric clothes dryers take the form:

$$\text{Logit(Clothes Dryers Saturation}_{jt}) = f(\text{Logit(Clothes Dryers Saturation}_{jt-1}), \text{Real Electricity Price}_{jt}/\text{Real Fossil Price}_{jt}, \text{Real Per Capita Income}_{jt}, \text{Gross National Product}_t)$$

where: t = current period
j = zone.

The assumption being made that all homes having a clothes dryer will also have a clothes washer, the equations that forecast clothes washers therefore take the form:

$$\text{Logit(Clothes Washers Saturation}_{jt}) = f(\text{Logit(Clothes Dryers Saturation}_{jt}),$$

where: t = current period
j = zone.
and: Clothes Washers Saturation • Clothes Dryers Saturation.

The equations which forecast the saturations for Dishwashers take the form:

$$\text{Logit(Dishwasher Saturation}_{jt}) = f(\text{Logit(Dishwasher Saturation}_{jt-1}), \text{Real Electricity Price}_{jt}, \text{Real Per Capita Income}_{jt})$$

where: t = current period
j = zone.

The equations which forecast the saturations for Freezers take the form:

$$\text{Logit(Freezer Saturation}_{jt}) = f(\text{Logit(Freezer Saturation}_{jt-1}), \text{Real Electricity Price}_{jt}, \text{Real Gross National Product}_t)$$

where: t = current period
j = zone.

The equations which forecast the saturations for electric ranges take the form:

$$\text{Logit(Range Saturation}_{jt}) = f(\text{Logit(Range Saturation}_{jt-1}), \text{Real Electricity Price}_{jt}, \text{Real Per Capita Income}_{jt}, \text{Time}_t)$$

where: t = current period
j = zone.

Insufficient historical data is available to accurate forecast the saturations of water beds and well pumps. They are therefore held constant at their most recent historical level.

The saturations levels for refrigerators, lighting and residual uses is set equal to one throughout the forecast period.

The preceding steps have allowed us to calculate, firstly the number of residential customers, and then the number of existing and new residential customers. The customers have then been distributed between various structure types and sizes (which differ depending whether the customer is new or exists in the first year of the forecast). Finally the number of customers that use electric space heat, water heat or own an electric appliance. We must now calculate the electric consumption level for each of the enduses and multiply it by the number of customers who have chosen electricity to supply that enduse. Summing the results will give us total residential sales.

Average consumption for each of the five existing structures types for space heat usage are estimated using a conditional demand approach. The estimates have embedded in them a level of wood heat consumption. In some parts of PacifiCorp's service territory (predominantly the Pacific Northwest), significant numbers of customers have both electric <u>and</u> wood heating equipment. The use of wood heating equipment (wood stoves) instead of the installed electric heating equipment was considered in projecting future consumption levels. Assumptions upon the rate and level at which wood space heat usage is displaced by electric space heat usage varies between the five scenarios. In the high scenario, all wood heat users convert to electric space heat within the first five years of the forecast. In the medium-high and medium forecast, all wood heat users convert to electric space heat within the forecast period. In the medium-low forecast, half the wood heat users convert to electric space heat within the forecast period. In the low forecast, the wood heat consumption continues at the existing level. Average consumption for water heat in existing homes is also calculated using a conditional demand approach. As these water heaters are replaced during the forecast period with new water heaters, their consumption levels is the same as that for water heaters installed in new residential dwellings.

Average consumption for future space heat and water heat usage are estimated using the prototypical residential models. If a state has enacted Energy Standards, or is expected to enact standards close to Model Conservation Standards, the space heat usage consistent with these standards is assumed for future space customers. For states which have not enacted MCS, houses are built to present Energy Standards. These usage levels are the basis upon which the conservation supply curves are based.

Usage for other appliances are estimated based upon generally accepted institutional, industry and engineering standards. If it is known that Governmental Standards will require that appliances be built to a higher efficiency than at present, that assumption is built into the forecast.

The forecast resulting from all of the preceding assumptions is referred to as a "Frozen Efficiency" forecast, although technically, the efficiencies are not frozen at present levels, but changed to reflect known intervention in the marketplace by the government and other institutional agencies. These usage numbers are input into the prototypical residential models used to develop the conservation supply curves. This determines that there is a consistency between the numbers used in developing the load forecast and those used in developing the conservation supply curves.

For each of the five scenarios, and for each of the forecast years, and for each zone, forecasts of existing and new space and water heat customers, and forecasts of the total number of residential customers using the appliances described above is passed to the conservation supply curves. Once these numbers have been input, forecasts of conservation that customers will perform upon their own initiative are calculated and the results input into the load forecasting model. The residential sales forecast resulting from this calculation, is the level of residential sales that is used in making resource decisions. The prototypical residential buildings consist of five types for existing homes (three single family, multi-family, mobile homes), and six types for new homes (three single family, multi-family, two mobile homes).

The estimates of base year saturations and base year usages are combined so that they conform to the actual customer sales history for the base year (1992). All historic sales data is temperature adjusted.

Commercial Sales

The commercial model, like the residential model, is a hybrid econometric-enduse model. The model forecasts electric energy use per square foot for each of seven enduses for twelve commercial activities for each of the nine zones served by the Company. The seven end-uses are space heating, water heating, space cooling, ventilation, refrigeration, lighting, & miscellaneous uses. Twelve vertical market segments (building types or commercial activities) are modeled: Communications/ Utilities/Transportation, Food Stores, Retail Stores, Restaurants, Wholesale Trade, Lodging, Schools, Hospitals, Other Health Services, Offices, Services, and a miscellaneous category.

The saturation levels and usage per square foot for each of the commercial end uses have been estimated using data from commercial surveys, commercial customer consumption data, and engineering estimates. Usage per square foot for existing buildings is based on 1992 levels. Usage per square foot for new buildings has been estimated using engineering models and assuming current practices.

Each of the twelve vertical market segments are defined based upon Standard Industrial Classifications (SIC). The basic structure of the end-use model is to multiply forecast enduse saturations (percentage of square foot with a particular enduse) by the appropriate amount of square foot. The result is then multiplied by the annual average electricity usage per square for each enduse. The product, total annual electricity consumption by commercial enduse, is shown by the following equation:

$$\text{Total Consumption}_i = \bullet\ \text{Square Foot}_k \times \text{Saturation of Appliance}_{ik} \times \text{Electricity Usage of Appliance}_{ik}$$

where: i = Enduse

k = Vertical Market Segment.

Employment is the major determinant of change in the commercial sector. While the growth in a particular activity will be caused by locational advantages, local real estate prices, tax policy, zoning ordinances, long term interest rates, and a myriad of other variables, growth for each particular commercial activity is estimated using employment in that commercial activity as a proxy variable. The theoretical appeal of employment is that it tends to travel the same paths of growth and decline as that of a vast array of coincident commercial indicators. On a more practical note, the availability and depth of employment data far surpasses other types of qualitative and quantitative data.

Forecasts of employment for each of the major commercial employment categories (at the 1 digit SIC level) need to be allocated to the twelve building types (which combines 2,3 & 4 level SIC). This information is not available at the service territory level for the nine zones. It is assumed that the distribution of employment at the state level (from DRI's Regional Service) does not differ from that at the zonal service territory level and employment is thus allocated in this manner.

Although as mentioned previously, changes in floorspace will not exactly follow changes in employment, we have had to make the simplistic assumption that total floorspace per employee will remain constant in the future. Each activity has a demolition rate (derived from Company records) which retires buildings. This does not mean that all "demolitions" are felled by wrecking crews. The model accepts the implied re-entry, to the commercial market, of buildings that have been at least partially renovated and now hold a different function in the commercial sector. Once we have forecast total square foot in each vertical market segment, and the amount of square foot remaining of the presently (1992) existing square foot, the amount of new square foot is determined to be the difference of the two numbers, i.e.

$$\text{New Commercial Square Foot}_{ijt} = \text{Total Commercial Square Foot}_{ijt} - (1 - (\text{Demolition Rate}_{ij}))^{t*}(\text{Total Commercial Square Foot}_{ij0})$$

where: t = current period

j = zone

i = vertical market segment.

Base year (1992) saturations levels and usage per square foot for each of the commercial end uses have been estimated using data from commercial surveys, commercial customer consumption data, and engineering estimates. These estimates of saturations and usages may be slightly modified so that when they are combined with the estimates of base year square feet, the resulting estimate of electricity sales agrees with the actual temperature adjusted electricity sales to each of the building types (for each zone) in 1992.

The commercial model forecasts the saturation of three end-uses, space heating, water heating, and space cooling. Ventilation, lighting, & miscellaneous uses are assumed as 100% electrically powered over the forecast period. Those vertical market segments that are refrigerated are also assumed to have a saturation of 100%. As in the residential sector, the saturations are forecast using a logistic specification. The equations take the form:

$$\begin{aligned}\text{Logit(Enduse Saturation}_{ijkt}) = f(&\text{Logit(Enduse Saturation}_{ijkt-1}),\\ &\text{Real Electricity Price}_{ijt}/\text{Real Fossil Fuel Price}_{jt},\\ &\text{Real Gross National Product}_t\,\text{Time}_t,)\end{aligned}$$

where: t = current period

j = zone.

i = vertical market segment

k = space heating, space cooling, water heating.

Usage per square foot for each enduse for existing buildings are frozen at their 1992 level during the forecast period. Usage per square foot for new buildings has been estimated using engineering models and assuming current practices - these estimates are similarly frozen throughout the forecast period.

Once again, the forecast resulting from these assumptions is a Frozen Efficiency forecast. These usage numbers are input into the prototypical commercial models used to develop the conservation supply curves. This determines that there is a consistency between the numbers used in developing the load forecast and those used in developing the conservation supply curves. For each of the five scenarios, and for each of the forecast years, and for each zone, forecasts of existing and new square foot for each of the twelve building types is passed to the supply curves. Once these numbers have been input, forecasts of the conservation that customers will perform upon their own initiative are calculated and the results input into the load forecasting model. The commercial sales forecast resulting from this calculation, is the level of commercial sales that is used in making resource decisions.

Forecasts of commercial customers are developed by summing the new and existing square foot numbers and dividing by the average square foot/customer (specific to each VMS and zone).

Industrial Sales

Unlike many other electric utilities, Pacific's industrial sector is not dominated by a small number of firms or industries. During 1992, the Company's largest industry (combining sales in both divisions), oil and gas exploration, accounted for less than 20% of total industrial sales. The heterogeneous mix of customers and industries, combined with their widely divergent electricity consumption characteristics per unit of output, indicates a substantial amount of disaggregation is needed in developing a proper forecasting model for this sector. Accordingly, the industrial sector has been heavily disaggregated within the manufacturing and mining customer segments. The manufacturing sector is broken down into ten categories based upon the Standard Industrial Classification Code System. These categories are Food Processing (SIC 20), Lumber & Wood Products (SIC 24), Paper & Allied Products (SIC 26), Chemicals & Allied Products (SIC 28), Petroleum Refining (SIC 29), Stone, Clay & Glass (SIC 32), Primary Metals (SIC 33), Electrical Machinery (SIC 36), Transportation Equipment (SIC 37). In all zones, sales to a residual manufacturing category (all remaining manufacturing SIC codes) are forecast. Forecasts are only made for the major SICs within a particular zone, when sales to that SIC within a zone are significant. Thus the definition of residual manufacturing is zonal specific. The forecast for a given industrial segment is not broken down into end uses because industrial customers in each segment tend to use electricity in the same way, although individual plant processes may vary.

The mining industry, located primarily in Wyoming and Utah, has also been subject to a significant level of disaggregation. Separate forecasts have been completed for the following industries: Coal Mining (SIC 12), Oil & Natural Gas Exploration, Pumping, & Transportation (SIC 13), Non-Metallic Mineral Mining (SIC 14); there also exists an "other" mining categories in a few zones.

The industrial sector is modeled using an econometric forecasting system. Conceptually, the best method of forecasting electricity sales would be on a per unit of output basis. However this information is not available at the state service territory level. Accordingly sales are forecast on a per employee basis. Therefore electricity sales per employee are regressed in equations which may contain the following independent variables: a lagged dependent variable, relative price (or electricity price & fossil fuel prices), national output in the industry, a time trend... Not all equations will contain all the independent variables. The resulting ratio is forecast and multiplied by the forecast of employment to arrive at the forecast of industrial electricity sales.

The disaggregated industrial sector allows the composition of industry mix to vary over time. Each's industry's employment is forecast to grow at a different rate and significant differences exist in both the level and trend of energy consumption per employee. Each industry also varies considerably in the magnitude of its response to changes in electricity and fossil fuel prices. Only with a disaggregated model can these differences be explicitly analyzed.

Breaking the industries' electricity consumption forecasts into two pieces, employment and megawatthour consumption per employee, and then multiplying them together to arrive at total consumption, allows for the explicit estimation of two distinct actions: changes in employment, and the intensity of use per employee.

The employment forecasts are been described earlier in this document. The forecasts of intensity of use per employee are based upon the effect that in the long run, capital stock, utilization rates, and technology are not fixed. Electricity use per employee will either increase or decrease as investments are made that substitute more or less electricity for all other factors of productions. This effect is captured by the inclusion of a lagged dependent variable, real electricity prices, and real fossil fuel prices in the electricity use per employee equations.

The sign of the electricity price coefficient in the equations is positive and its interpretation is straightforward; electricity conservation activities take places in response to rising electricity prices and tends to decrease the intensity of electricity use. The fossil fuel price coefficient is negative and captures the impact of a change in sales per employee caused by the substituting fossil fuels for electricity. Having a lagged dependent variable in the equation allows for the gradual adjustment in consumption patterns, by each industry, as a result of changes in the real price of electricity and fossil fuels. Business firms cannot react immediately to new price conditions. Major changes can only occur over time as older, less efficient machinery and factors are replaced with newer and more productive ones. There are many other factors which could have been included in the industrial sales per employee equations. The costs of labor and capital have theoretical implications as prices of substitutes or complements for electricity use. The use of real weekly wages and estimates of capital costs were included in early equation specifications but the results were unacceptable. Real Gross National Product, National Output & a Time Trend have been used as proxies for these variables.

In particular the equations for Food Processing (SIC 20) take the form:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}/\text{Real Fossil Fuel Price}_{jt,}\ \text{National Output}_{t})$$

where: t = current period
j = zone.

The equations for Lumber & Wood Products (SIC 24) take the form:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{t-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}/\text{Real Fossil Fuel Price}_{jt,}\ \text{National Output}_{t}, \text{Real Mortgage Rate}_{t})$$

where: t = current period
j = zone.

The equations for Paper & Allied Products (SIC 26) & Chemicals & Allied Products (SIC 28) take the form:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{National Output}_{t})$$

where: t = current period
j = zone.

The equations for Petroleum Refining (SIC 29) take the form:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}, \text{Real Gross National Product}_{t}, \text{National Output}_{t})$$

where: t = current period
j = zone.

In particular the equations for Stone, Clay & Glass (SIC 32) are represented as:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}, \text{Real Fossil Fuel Price}_{jt})$$

where: t = current period
j = zone.

In particular the equations for Primary Metals (SIC 33) take the form

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}/\text{Real Fossil Fuel Price}_{jt}, \text{Time}_{t})$$

where: t = current period
j = zone.

The equations for Electrical Machinery (SIC 36) take the form:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}, \text{National Output}_{t})$$

where: t = current period
j = zone.

The equations for Transportation Equipment (SIC 37) take the form:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}, \text{Time}_t)$$

where: t = current period

j = zone.

Finally, the equations for the residual manufacturing sales category take the form:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}/\text{Real Fossil Fuel Price}_{jt}, \text{National Output}_t, \text{Time}_t)$$

where: t = current period

j = zone.

Sales to three major mining categories are specified using econometric techniques.

The equations for Coal Mining (SIC 12) have the specification:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}/\text{Real Fossil Fuel Price}_{jt}, \text{Real Gross National Product}_t)$$

where: t = current period

j = zone.

The second major mining category - Oil & Natural Gas Exploration, Pumping, & Transportation (SIC 13) is specified as follows:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt-1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}/\text{Real Fossil Fuel Price}_{jt})$$

where: t = current period
j = zone.

The final major mining category is Non-Metallic Mineral Mining (SIC 14). The equations for this category are:

$$\text{Megawatthour Sales}_{jt} = \text{Employment}_{jt} * f(\text{Megawatthour Sales}_{jt1}/\text{Employment}_{jt-1}, \text{Real Electricity Price}_{jt}/\text{Real Fossil Fuel Price}_{jt}, \text{National Output}_{t}, \text{Real Gross National Product}_{t})$$

where: t = current period
j = zone.

Forecast of electricity sales, for each of the five scenarios, are passed to the supply curves, once again assuring consistency between the models. It is assumed that all background conservation measures will be picked up by the forecasting equations and that the conservation is already embedded in the forecast. Therefore the sales passed to the conservation curves and those used in resource decisions are the same sales forecast.

Other Sales

The other sectors to which electricity sales are made are: irrigation, street & highway lighting, interdepartmental and "other sales to public authorities."

Electricity sales to the these smaller customer categories are either forecast using econometric equations or the sales are held constant at historic levels.

Monthly System Peak and Energy

After the annual sales forecast has been completed for each of the customer classes, the results are summed to develop a forecast of total sales for each of the nine zones, the Pacific & Utah Divisions and the Total Company.

To these sales forecasts are added system losses (i.e. the losses in electricity in getting electricity from the generation source to the customer) to calculate the amount of annual energy required to serve the needs of the customers. The estimates of losses are developed for each customer class and zone. After the annual energy forecast has been completed, an hourly load forecast is prepared for each of the nine zones. Separate hourly forecasts are made for firm and interruptible customers in the two zones where such forecasts are appropriate. The annual energy is first broken into monthly data on the basis of historic seasonal patterns. Further refinements are made to develop weekly, daily and finally hourly load forecasts using historical patterns of energy use. Summing up the respective zonal forecasts produces hourly load forecasts for the Pacific and Utah Divisions and the Total Company. The maximum load for each month is the peak load for the company, and the zonal load at that time is the zonal coincident peak. The maximum load for each zone during each month is the zonal non-coincident peak. The forecasting techniques used also allow us to produce total and firm peak and energy forecasts. As new resources (both supply and demand side) are added, the hourly loads will change and these changes are reflected in the sales to customers after resource decisions are made.

Public Process

The RAMPP-3 Advisory Group (RAG) was an active participant in the development of this least cost plan. Thirteen all-day meetings were held with the RAG group plus two subgroup meetings which focused on Load Forecasting. These subgroup meetings were a great help in determining the forecasts used in this Least Cost Plan. There is a great wealth of detail underlying the forecast (both actual detailed forecast results and statistical parameters) which can only be discussed thoroughly in such a focused forum. We hope that this process will continue through the RAMPP-4 process and actively welcome (at any time) input into how the models can be improved and enhanced.

Two special studies were requested to review assumptions used throughout the RAMPP process.

First, the subgroup requested that when the final resource plans was selected, that the Company perform an analysis to determine the financial impact of the plans on the cost of electricity, compared to the electricity price assumptions in the initial forecast. This "closes the loop" in the planning process by determining whether the new resource additions and resulting prices create a significant change in a key assumption: the load forecast. As described in the main report, the electricity prices from the Financial Model were fed back into the Medium Load Forecast, resulting in the loads in the last year of the forecast period being 60 MWa higher than the initial forecast. This compares to a 1,626 MWa difference between the Medium High and Medium forecasts in the same year.

Secondly, electricity prices enters the Forecasting Models in both the industrial sector sales equations and the appliance choice equations in the commercial and residential sectors. The subgroup noted that the usage levels of potentially price sensitive enduses in the residential and commercial models were frozen as part of the modeling process. An experiment was designed to assign elasticities to these enduses and discover what effect it had on total sales.

The enduses chosen to be modeled were: space heating, water heating, and lighting, in the residential sector, and space heating, water heating, space cooling in the commercial sector. It was decided to assign an own price elasticity of -0.4 to uses in the enduses.

For simplicity, the calculation of the impact of these assumptions on the sales will be done using the sales in the final year of the forecast (2013) for the Medium Scenario. Choosing any year or scenario would have minimal effect on the results.

Medium Scenario - 2013

Residential Sales in the chosen enduses: 8,237,708 MWh
Total Residential Sales - 17,505,637 MWh
Commercial Usage in the chosen enduses: 5,074,274 MWh
Total Commercial Sales - 16,573,708 MWh
Total Sales in the chosen enduses: 13,311,982 MWh
Total Sales - 63,843,542 MWh

Total sales in the chosen enduses are 20.9% (13,311,982/63,843,542) of total sales. So assigning an elasticity of -0.4 to these enduses is equivalent to assigning an increase in elasticity to total sales of -0.084 (0.4*.209). I.E. a 10% price increase in one single year would lower sales by 0.8% - in 2013 that is equivalent to just over 500,000 MWh.

As a further experiment, the assignment of the -0.4 elasticity to the price sensitive enduses was combined with the new price forecast from the Financial Model previously described. When these two assumptions are combined and the results compared to the original Medium Forecast, the difference in the final year of the forecast is 20 MWa.

The Company realizes that the fuel choice components of the Residential and Commercial models are one of the weaker links in the Forecasting Model and intends to improve this in RAMPP-4. (See Chapter - **Anticipated Chances and Enhancements**).

Statistical Philosophy

A major technique used in the production of the Load Forecasting models has been "Least Squares Regression." In this technique, the dependent variable (the one we which to forecast) is historically regressed against a set of independent variables. Once an equation has been specified, forecast values of the independent variables are used to produce a forecast of the dependent variable.

It should be realized that there is no one perfect equation for any dependent variable. The equation chosen, is in the final instance, one chosen by the analyst. However there are certain statistical parameters that can assist the analyst. Indeed there are too many. Listing all the statistics for all of the variables and equations used in the generation of this forecast would have led to the production of an unwieldy document. Rather than do this, the following principles have been used in the production of the models.

The first is that the relationship between the dependent and independent variable is theoretically correct. (E.G. The relationship between electricity sales and electricity prices should be a negative one.) This means that if statistics indicate a variable should be contained in an equation, a wrong sign on the coefficient would have led to its automatic rejection.

Among the myriad number of statistics associated with any equation, we have chosen to forecast on three statistics.

The first is the Student's 't' statistic. This statistic is associated with each independent variable and a sweeping generalization is that if the absolute value of the 't' statistic is greater than two, than the variable should be included in the equation.

The second statistic is the R^2 for the equation. Each equation specification has associated with it an R^2 statistic. The higher the R^2 and the closer to one, the better the equation specification. (In the vast majority of cases the R^2 was greater than 0.8).

Thirdly the Durbin-Watson statistic (the Durbin 'H' statistic if one of the independent variables is the lagged dependent variable) tests for autocorrelation and the equation specification is corrected as indicated.

Modeling Improvements implemented since RAMPP-2

The merging of the two companies has meant that system and zonal peak forecasts will been of greater importance than they were to Pacific Power prior to the merger. Therefore of major importance, have been the improvements to the system peak forecasting capabilities, incorporating historical hourly load data. The model used in RAMPP-2 forecasted only monthly coincidental and non-coincidental peak and energy zonal forecasts. The new model forecasts each of the 8760 hours in the year, for every year in the forecast period, for each of the zones. The model results produced by the RAMPP-2 model are also outputs from the RAMPP-3 model.

As the system becomes more peak constrained and we wish to test new load control programs, the production of hourly load forecasts will assist in testing these programs.

Anticipated Changes and Enhancements

Most of the models used in the RAMPP-2 & RAMPP-3 forecasting process are an expansion of those used in the original RAMPP forecast for the Pacific Division. The following are improvements that we hope to make before and during RAMPP-4.

The hourly forecasts will be further enhanced to incorporate available data from load research. It is anticipated that these enhancements will include, but will not be restricted to, the consideration of class loads for each of the zones, and the incorporation of data from large industrial customers. The hourly model will also have a temperature sensitive component have added to it.

Improve the fuel choice and fuel switching capabilities of the residential model. The Company believes that there is enough information already available from surveys to incorporate a fuel choice component for both space and water heating in the residential model. It will have the following features -

> Changing the relative fuel price forecast will result in a change in customer's choice of fuel when customer's replace their heating systems.
> The availability of natural gas within a zone can be modeled.
> The relationship between a customer's preferred and actual choice of heating fuel when replacing a heating system can be modeled.

Appendix 1
Annual Average Rates of Growth for Electricity Sales and Employment
By Major Sector
Total Company

PacifiCorp - RAMPP-3 High Sales Forecast

Average Annual Rates of Growth

Total Company

	Residential	Commercial	Industrial	Other	Total
1993-1998	4.8%	5.3%	6.3%	4.1%	5.5%
1998-2003	3.2%	4.4%	3.9%	1.5%	3.8%
2003-2008	3.5%	3.9%	3.3%	1.4%	3.4%
2008-2013	3.7%	2.9%	2.4%	1.2%	2.8%
1993-2003	4.0%	4.8%	5.1%	2.8%	4.7%
2003-2013	3.6%	3.4%	2.8%	1.3%	3.1%
1993-2013	3.8%	4.1%	4.0%	2.1%	3.9%

PacifiCorp - RAMPP-3 High Employment Forecast

Average Annual Rates of Growth

Total Company

	Industrial	Other Basic	**Basic**	Non-Basic	**Total**
1993-1998	3.5%	0.6%	2.3%	3.8%	3.5%
1998-2003	2.6%	0.9%	2.0%	3.4%	3.1%
2003-2008	1.8%	1.1%	1.5%	3.1%	2.8%
2008-2013	0.9%	1.0%	0.9%	2.5%	2.3%
1993-2003	3.0%	0.8%	2.2%	3.6%	3.3%
2003-2013	1.3%	1.0%	1.2%	2.8%	2.5%
1993-2013	2.2%	0.9%	1.7%	3.2%	2.9%

PacifiCorp - RAMPP-3 Medium High Sales Forecast

Average Annual Rates of Growth

Total Company

	Residential	Commercial	Industrial	Other	Total
1993-1998	3.1%	3.8%	4.5%	3.4%	3.9%
1998-2003	2.4%	3.8%	3.2%	1.2%	3.1%
2003-2008	2.7%	3.5%	2.7%	1.2%	2.8%
2008-2013	3.1%	2.6%	1.8%	1.0%	2.3%
1993-2003	2.7%	3.8%	3.9%	2.3%	3.5%
2003-2013	2.9%	3.0%	2.2%	1.1%	2.6%
1993-2013	2.8%	3.4%	3.0%	1.7%	3.0%

PacifiCorp - RAMPP-3 Medium High Employment Forecast

Average Annual Rates of Growth

Total Company

	Industrial	Other Basic	Basic	Non-Basic	Total
1993-1998	2.5%	0.1%	1.5%	2.9%	2.6%
1998-2003	2.2%	0.6%	1.6%	2.8%	2.6%
2003-2008	1.5%	0.8%	1.3%	2.7%	2.4%
2008-2013	0.7%	0.7%	0.7%	2.2%	2.0%
1993-2003	2.3%	0.4%	1.6%	2.8%	2.6%
2003-2013	1.1%	0.7%	1.0%	2.4%	2.2%
1993-2013	1.7%	0.5%	1.3%	2.6%	2.4%

PacifiCorp - RAMPP-3 Medium Sales Forecast

Average Annual Rates of Growth

Total Company

	Residential	Commercial	Industrial	Other	Total
1993-1998	2.0%	2.5%	2.8%	2.9%	2.5%
1998-2003	1.4%	2.8%	2.7%	0.8%	2.3%
2003-2008	1.9%	2.7%	1.1%	0.8%	1.7%
2008-2013	2.6%	2.1%	1.4%	0.6%	1.9%
1993-2003	1.7%	2.7%	2.7%	1.8%	2.4%
2003-2013	2.2%	2.4%	1.3%	0.7%	1.8%
1993-2013	2.0%	2.5%	2.0%	1.3%	2.1%

PacifiCorp - RAMPP-3 Medium Employment Forecast

Average Annual Rates of Growth

Total Company

	Industrial	Other Basic	**Basic**	Non-Basic	**Total**
1993-1998	1.5%	-0.5%	0.7%	2.0%	1.7%
1998-2003	1.4%	0.1%	0.9%	2.1%	1.9%
2003-2008	0.9%	0.3%	0.7%	2.0%	1.8%
2008-2013	0.3%	0.3%	0.3%	1.7%	1.5%
1993-2003	1.5%	-0.2%	0.8%	2.0%	1.8%
2003-2013	0.6%	0.3%	0.5%	1.8%	1.6%
1993-2013	1.0%	0.0%	0.6%	1.9%	1.7%

PacifiCorp - RAMPP-3 Medium Low Sales Forecast

Average Annual Rates of Growth

Total Company

	Residential	Commercial	Industrial	Other	Total
1993-1998	0.9%	1.2%	0.8%	2.3%	1.0%
1998-2003	0.7%	1.9%	1.4%	0.4%	1.3%
2003-2008	1.2%	1.8%	1.0%	0.4%	1.2%
2008-2013	1.9%	1.5%	0.3%	0.2%	1.0%
1993-2003	0.8%	1.6%	1.1%	1.3%	1.1%
2003-2013	1.5%	1.6%	0.7%	0.3%	1.1%
1993-2013	1.2%	1.6%	0.9%	0.8%	1.1%

PacifiCorp - RAMPP-3 Medium Low Employment Forecast

Average Annual Rates of Growth

Total Company

	Industrial	Other Basic	**Basic**	Non-Basic	**Total**
1993-1998	0.5%	-1.0%	-0.1%	1.1%	0.9%
1998-2003	0.7%	-0.4%	0.3%	1.3%	1.1%
2003-2008	0.2%	-0.2%	0.1%	1.3%	1.1%
2008-2013	-0.2%	-0.2%	-0.2%	1.1%	0.9%
1993-2003	0.6%	-0.7%	0.1%	1.2%	1.0%
2003-2013	0.0%	-0.2%	-0.1%	1.2%	1.0%
1993-2013	0.3%	-0.5%	0.0%	1.2%	1.0%

PacifiCorp - RAMPP-3 Low Sales Forecast

Average Annual Rates of Growth

Total Company

	Residential	Commercial	Industrial	Other	Total
1993-1998	-1.2%	-0.1%	-0.9%	1.6%	-0.7%
1998-2003	-0.4%	1.1%	0.7%	0.1%	0.5%
2003-2008	0.1%	1.1%	0.2%	0.1%	0.4%
2008-2013	0.7%	0.6%	-0.8%	-0.1%	0.0%
1993-2003	-0.8%	0.5%	-0.1%	0.8%	-0.1%
2003-2013	0.4%	0.8%	-0.3%	0.0%	0.2%
1993-2013	-0.2%	0.7%	-0.2%	0.4%	0.0%

PacifiCorp - RAMPP-3 Low Employment Forecast

Average Annual Rates of Growth

Total Company

	Industrial	Other Basic	**Basic**	Non-Basic	**Total**
1993-1998	-0.6%	-1.4%	-0.9%	0.3%	0.1%
1998-2003	0.2%	-0.7%	-0.2%	0.6%	0.5%
2003-2008	-0.4%	-0.6%	-0.5%	0.6%	0.4%
2008-2013	-1.1%	-0.7%	-0.9%	0.4%	0.2%
1993-2003	-0.2%	-1.1%	-0.6%	0.5%	0.3%
2003-2013	-0.7%	-0.7%	-0.7%	0.5%	0.3%
1993-2013	-0.5%	-0.9%	-0.6%	0.5%	0.3%

Appendix 2
Annual Average Rates of Growth
Electricity Sales By Zone
By Scenario.

PacifiCorp - RAMPP-3 Sales Forecast

Average Annual Rates of Growth

Oregon

	High	Medium High	Medium	Medium-Low	Low
1993-1998	5.4%	3.5%	1.8%	0.4%	-1.3%
1998-2003	3.7%	3.2%	2.1%	1.3%	0.7%
2003-2008	3.5%	3.0%	2.1%	1.3%	0.5%
2008-2013	2.8%	2.3%	1.8%	1.3%	-0.1%
1993-2003	4.6%	3.3%	2.0%	0.9%	-0.3%
2003-2013	3.1%	2.7%	1.9%	1.3%	0.2%
1993-2013	3.9%	3.0%	2.0%	1.1%	0.0%

PacifiCorp - RAMPP-3 Sales Forecast

Average Annual Rates of Growth

Washington

	High	Medium High	Medium	Medium-Low	Low
1993-1998	5.6%	4.2%	3.3%	2.2%	0.5%
1998-2003	3.7%	3.0%	2.3%	1.2%	0.2%
2003-2008	3.4%	2.7%	2.2%	1.1%	0.0%
2008-2013	2.8%	2.3%	1.8%	0.8%	-0.2%
1993-2003	4.7%	3.6%	2.8%	1.7%	0.3%
2003-2013	3.1%	2.5%	2.0%	1.0%	-0.1%
1993-2013	3.9%	3.1%	2.4%	1.4%	0.1%

PacifiCorp - RAMPP-3 Sales Forecast

Average Annual Rates of Growth

North Idaho

	High	Medium High	Medium	Medium-Low	Low
1993-1998	5.6%	3.7%	2.3%	0.6%	-1.2%
1998-2003	4.0%	3.3%	2.4%	1.4%	0.0%
2003-2008	4.0%	3.4%	2.6%	1.6%	-0.3%
2008-2013	3.4%	2.9%	2.1%	0.8%	-1.0%
1993-2003	4.8%	3.5%	2.3%	1.0%	-0.6%
2003-2013	3.7%	3.1%	2.4%	1.2%	-0.7%
1993-2013	4.3%	3.3%	2.3%	1.1%	-0.6%

PacifiCorp - RAMPP-3 Sales Forecast

Average Annual Rates of Growth

Montana

	High	Medium High	Medium	Medium-Low	Low
1993-1998	5.3%	3.6%	2.3%	1.2%	0.0%
1998-2003	3.7%	2.8%	1.9%	1.1%	0.2%
2003-2008	3.8%	3.0%	2.2%	1.3%	0.3%
2008-2013	3.4%	2.7%	2.0%	1.2%	0.1%
1993-2003	4.5%	3.2%	2.1%	1.1%	0.1%
2003-2013	3.6%	2.9%	2.1%	1.3%	0.2%
1993-2013	4.0%	3.0%	2.1%	1.2%	0.2%

PacifiCorp - RAMPP-3 Sales Forecast

Average Annual Rates of Growth

California

	High	Medium High	Medium	Medium-Low	Low
1993-1998	5.8%	3.6%	1.8%	0.4%	-1.1%
1998-2003	4.0%	3.4%	2.7%	2.1%	1.0%
2003-2008	4.0%	3.3%	2.9%	2.4%	1.3%
2008-2013	3.5%	2.9%	2.5%	1.9%	0.8%
1993-2003	4.9%	3.5%	2.3%	1.2%	0.0%
2003-2013	3.7%	3.1%	2.7%	2.1%	1.0%
1993-2013	4.3%	3.3%	2.5%	1.7%	0.5%

PacifiCorp - RAMPP-3 Sales Forecast

Average Annual Rates of Growth

East Wyoming

	High	Medium High	Medium	Medium-Low	Low
1993-1998	5.1%	3.7%	2.1%	1.2%	-0.2%
1998-2003	3.3%	2.6%	2.4%	1.4%	0.8%
2003-2008	3.0%	2.5%	2.2%	1.3%	0.8%
2008-2013	2.5%	2.0%	1.7%	0.7%	0.2%
1993-2003	4.2%	3.2%	2.2%	1.3%	0.3%
2003-2013	2.7%	2.2%	2.0%	1.0%	0.5%
1993-2013	3.4%	2.7%	2.1%	1.2%	0.4%

PacifiCorp - RAMPP-3 Sales Forecast

Average Annual Rates of Growth

South Idaho

	High	Medium High	Medium	Medium-Low	Low
1993-1998	3.6%	2.3%	1.5%	0.7%	-0.7%
1998-2003	3.2%	2.4%	1.7%	0.9%	-0.2%
2003-2008	3.1%	2.4%	1.6%	0.7%	0.0%
2008-2013	2.8%	2.0%	1.1%	0.0%	-0.7%
1993-2003	3.4%	2.4%	1.6%	0.8%	-0.4%
2003-2013	2.9%	2.2%	1.3%	0.3%	-0.4%
1993-2013	3.2%	2.3%	1.5%	0.6%	-0.4%

PacifiCorp - RAMPP-3 Sales Forecast

Average Annual Rates of Growth

West Wyoming

	High	Medium High	Medium	Medium-Low	Low
1993-1998	4.7%	2.0%	-0.2%	-2.1%	-6.2%
1998-2003	2.3%	1.7%	2.3%	0.2%	-1.5%
2003-2008	1.7%	1.1%	-11.5%	-0.1%	-0.8%
2008-2013	1.0%	0.4%	3.1%	-0.4%	-1.1%
1993-2003	3.5%	1.8%	1.0%	-1.0%	-3.9%
2003-2013	1.4%	0.8%	-4.5%	-0.2%	-0.9%
1993-2013	2.4%	1.3%	-1.8%	-0.6%	-2.4%

PacifiCorp - RAMPP-3 Sales Forecast

Average Annual Rates of Growth

Utah

	High	Medium High	Medium	Medium-Low	Low
1993-1998	6.4%	4.9%	3.7%	1.6%	0.1%
1998-2003	4.3%	3.4%	2.5%	1.4%	0.8%
2003-2008	3.7%	3.1%	2.2%	1.4%	0.6%
2008-2013	3.2%	2.7%	2.0%	1.2%	0.4%
1993-2003	5.3%	4.1%	3.1%	1.5%	0.5%
2003-2013	3.4%	2.9%	2.1%	1.3%	0.5%
1993-2013	4.4%	3.5%	2.6%	1.4%	0.5%

PacifiCorp - RAMPP-3 Sales Forecast

Average Annual Rates of Growth

Total Company

	High	Medium High	Medium	Medium-Low	Low
1993-1998	5.5%	3.9%	2.5%	1.0%	-0.7%
1998-2003	3.8%	3.1%	2.3%	1.3%	0.5%
2003-2008	3.4%	2.8%	1.7%	1.2%	0.4%
	2.8%	2.3%	1.9%	1.0%	0.0%
	4.7%	3.5%	2.4%	1.1%	-0.1%
2008-2013					
	3.1%	2.6%	1.8%	1.1%	0.2%
1993-2003					
	3.9%	3.0%	2.1%	1.1%	0.0%
2003-2013					

Appendix 3
Detailed Annual Sales Forecasts by Customer Class & Zone

PacifiCorp - RAMPP-3 High Sales Forecast

Oregon (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	4,756,974	3,554,007	4,042,313	304,893	12,658,187
1994	5,211,833	3,833,483	4,399,237	352,437	13,796,990
1995	5,495,712	4,091,605	4,624,026	358,013	14,569,356
1996	5,760,128	4,346,078	4,780,679	363,112	15,249,997
1997	6,028,134	4,599,013	4,925,276	369,611	15,922,034
1998	6,204,357	4,839,253	5,053,035	373,435	16,470,080
1999	6,384,281	5,078,159	5,191,359	377,267	17,031,066
2000	6,597,386	5,328,556	5,363,117	381,738	17,670,797
2001	6,813,387	5,592,050	5,557,740	386,434	18,349,611
2002	7,027,460	5,858,632	5,754,151	391,004	19,031,247
2003	7,260,605	6,142,574	5,988,511	396,104	19,787,794
2004	7,497,788	6,433,118	6,209,728	401,017	20,541,651
2005	7,723,834	6,714,023	6,395,132	405,284	21,238,273
2006	7,945,047	6,990,149	6,579,085	409,328	21,923,609
2007	8,190,951	7,292,886	6,822,249	414,172	22,720,258
2008	8,494,876	7,580,736	7,035,009	418,971	23,529,592
2009	8,767,795	7,828,315	7,208,712	422,750	24,227,572
2010	9,035,905	8,056,855	7,400,146	426,376	24,919,282
2011	9,304,314	8,277,325	7,600,053	429,909	25,611,601
2012	9,576,590	8,495,725	7,804,589	433,393	26,310,297
2013	9,840,341	8,699,636	7,985,712	436,440	26,962,129

PacifiCorp - RAMPP-3 High Sales Forecast

Washington (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	1,419,289	1,093,723	929,451	148,484	3,590,947
1994	1,520,944	1,133,353	1,143,508	155,469	3,953,274
1995	1,593,563	1,190,449	1,237,331	158,045	4,179,388
1996	1,655,792	1,245,116	1,321,429	160,234	4,382,571
1997	1,719,689	1,291,158	1,395,453	162,871	4,569,171
1998	1,768,655	1,342,604	1,435,169	164,659	4,711,087
1999	1,824,117	1,397,141	1,488,110	166,789	4,876,157
2000	1,884,647	1,454,328	1,549,395	169,130	5,057,500
2001	1,952,095	1,512,818	1,615,729	171,622	5,252,264
2002	2,020,784	1,571,423	1,684,038	174,094	5,450,339
2003	2,093,191	1,631,939	1,758,923	176,688	5,660,741
2004	2,166,769	1,693,154	1,830,681	179,188	5,869,792
2005	2,238,520	1,752,785	1,894,054	181,440	6,066,799
2006	2,310,319	1,812,247	1,955,704	183,607	6,261,877
2007	2,384,570	1,873,591	2,025,401	185,897	6,469,459
2008	2,475,086	1,931,468	2,091,183	188,252	6,685,989
2009	2,563,295	1,985,745	2,150,417	190,372	6,889,829
2010	2,651,990	2,038,503	2,211,160	192,448	7,094,101
2011	2,741,841	2,091,094	2,272,897	194,501	7,300,333
2012	2,830,810	2,142,420	2,331,798	196,440	7,501,468
2013	2,918,644	2,191,403	2,386,246	198,231	7,694,524

PacifiCorp - RAMPP-3 High Sales Forecast

North Idaho (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	108,168	69,129	61,706	690	239,693
1994	116,539	73,032	67,965	825	258,361
1995	123,426	77,260	73,242	825	274,753
1996	130,196	81,743	77,199	826	289,964
1997	136,868	86,471	80,927	827	305,093
1998	141,609	90,371	82,679	825	315,484
1999	147,104	94,311	84,613	826	326,854
2000	153,042	98,375	87,613	826	339,856
2001	159,181	102,586	91,328	826	353,921
2002	165,090	106,892	95,033	826	367,841
2003	171,447	111,397	99,691	826	383,361
2004	177,826	116,005	104,657	826	399,314
2005	183,987	120,582	108,717	826	414,112
2006	190,092	125,133	113,179	826	429,230
2007	196,731	129,841	120,281	826	447,679
2008	204,871	134,500	126,173	826	466,370
2009	212,544	138,932	129,006	826	481,308
2010	220,383	143,265	133,072	825	497,545
2011	228,306	147,507	137,929	826	514,568
2012	236,279	151,665	144,639	826	533,409
2013	244,049	155,660	150,833	826	551,368

PacifiCorp - RAMPP-3 High Sales Forecast

Montana (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	327,472	237,666	188,071	3,475	756,684
1994	351,557	251,582	206,738	4,213	814,090
1995	373,845	267,769	213,638	4,217	859,469
1996	394,924	283,664	220,775	4,219	903,582
1997	415,549	299,213	228,049	4,228	947,039
1998	428,187	311,879	235,455	4,231	979,752
1999	441,056	324,895	243,032	4,235	1,013,218
2000	457,675	338,941	250,902	4,240	1,051,758
2001	473,235	354,000	259,107	4,242	1,090,584
2002	489,215	369,577	267,594	4,247	1,130,633
2003	507,035	386,443	276,329	4,251	1,174,058
2004	525,351	403,953	285,404	4,254	1,218,962
2005	543,309	421,450	294,616	4,260	1,263,635
2006	561,495	439,326	304,239	4,263	1,309,323
2007	582,140	459,005	314,057	4,267	1,359,469
2008	606,069	478,009	324,397	4,271	1,412,746
2009	627,707	495,542	334,936	4,275	1,462,460
2010	649,567	512,996	345,804	4,278	1,512,645
2011	672,052	530,922	356,988	4,283	1,564,245
2012	695,665	549,727	368,523	4,287	1,618,202
2013	719,047	568,579	380,393	4,291	1,672,310

PacifiCorp - RAMPP-3 High Sales Forecast

California (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	358,744	222,233	81,552	77,763	740,292
1994	396,969	243,842	79,690	88,257	808,758
1995	422,240	258,286	86,815	92,359	859,700
1996	445,147	272,324	91,886	95,971	905,328
1997	467,037	285,094	94,962	98,981	946,074
1998	480,388	301,381	96,524	101,389	979,682
1999	494,117	317,895	98,159	103,822	1,013,993
2000	510,743	335,118	101,705	106,687	1,054,253
2001	528,202	353,081	106,194	109,721	1,097,198
2002	546,902	371,373	110,360	112,815	1,141,450
2003	566,944	390,481	116,100	116,167	1,189,692
2004	587,480	410,065	121,370	119,516	1,238,431
2005	607,723	429,613	125,970	122,739	1,286,045
2006	628,049	449,339	130,555	125,941	1,333,884
2007	650,143	470,195	138,635	129,595	1,388,568
2008	678,805	490,672	143,394	133,418	1,446,289
2009	705,911	510,060	144,560	136,724	1,497,255
2010	733,309	529,244	146,325	140,043	1,548,921
2011	761,418	548,678	148,595	143,431	1,602,122
2012	790,730	568,695	152,793	147,051	1,659,269
2013	820,335	588,823	156,287	150,607	1,716,052

PacifiCorp - RAMPP-3 High Sales Forecast

East Wyoming (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	714,351	863,674	4,185,312	21,343	5,784,680
1994	750,091	913,749	4,772,514	23,081	6,459,435
1995	776,249	951,514	4,971,108	23,189	6,722,060
1996	801,355	988,208	5,152,694	23,272	6,965,529
1997	826,386	1,023,181	5,309,527	23,346	7,182,440
1998	852,286	1,071,964	5,458,898	23,420	7,406,568
1999	880,857	1,122,273	5,586,898	23,484	7,613,512
2000	906,755	1,173,527	5,742,769	23,558	7,846,609
2001	931,740	1,225,594	5,934,626	23,644	8,115,604
2002	958,881	1,277,959	6,140,013	23,732	8,400,585
2003	988,210	1,330,813	6,352,659	23,821	8,695,503
2004	1,019,383	1,383,815	6,578,827	23,914	9,005,939
2005	1,051,376	1,435,997	6,733,189	23,977	9,244,539
2006	1,084,465	1,487,854	6,916,024	24,050	9,512,393
2007	1,119,248	1,540,106	7,081,591	24,114	9,765,059
2008	1,164,968	1,592,089	7,298,403	24,198	10,079,658
2009	1,210,983	1,643,288	7,469,350	24,263	10,347,884
2010	1,258,096	1,694,389	7,642,528	24,329	10,619,342
2011	1,306,148	1,745,363	7,808,400	24,391	10,884,302
2012	1,354,911	1,796,086	7,965,236	24,449	11,140,682
2013	1,404,110	1,846,325	8,104,642	24,498	11,379,575

PacifiCorp - RAMPP-3 High Sales Forecast

South Idaho (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	564,306	209,116	1,621,730	389,196	2,784,348
1994	600,598	201,081	1,658,088	530,028	2,989,795
1995	627,200	209,885	1,706,641	537,348	3,081,074
1996	653,526	218,940	1,759,083	527,931	3,159,480
1997	680,604	228,702	1,815,753	525,689	3,250,748
1998	699,006	236,279	1,858,824	530,326	3,324,435
1999	716,060	243,730	1,916,317	536,079	3,412,186
2000	734,905	251,570	1,983,704	542,816	3,512,995
2001	755,131	259,801	2,060,722	550,421	3,626,075
2002	775,450	268,238	2,146,181	558,604	3,748,473
2003	798,126	277,167	2,249,836	568,409	3,893,538
2004	822,464	286,500	2,351,382	577,927	4,038,273
2005	847,245	295,872	2,427,946	585,142	4,156,205
2006	872,771	305,473	2,498,838	591,800	4,268,882
2007	900,586	315,815	2,582,821	599,599	4,398,821
2008	935,813	326,304	2,666,269	607,759	4,536,145
2009	970,641	336,586	2,742,790	615,137	4,665,154
2010	1,006,526	347,008	2,824,083	622,798	4,800,415
2011	1,043,875	357,762	2,908,864	630,673	4,941,174
2012	1,082,451	368,832	2,984,518	637,812	5,073,613
2013	1,121,708	380,029	3,049,974	644,120	5,195,831

PacifiCorp - RAMPP-3 High Sales Forecast

West Wyoming (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	91,021	82,120	1,873,583	2,454	2,049,178
1994	100,036	87,545	1,981,430	3,562	2,172,573
1995	105,355	91,545	2,031,560	3,561	2,232,021
1996	108,955	95,671	2,100,466	3,562	2,308,654
1997	112,718	99,857	2,274,891	3,562	2,491,028
1998	115,770	104,445	2,349,608	3,561	2,573,384
1999	118,985	109,388	2,396,872	3,563	2,628,808
2000	122,208	114,462	2,448,352	3,562	2,688,584
2001	125,538	119,824	2,508,095	3,561	2,757,018
2002	128,917	125,449	2,567,046	3,562	2,824,974
2003	132,673	131,366	2,621,340	3,562	2,888,941
2004	136,447	137,291	2,677,405	3,563	2,954,706
2005	140,102	143,012	2,710,181	3,562	2,996,857
2006	143,907	148,695	2,752,190	3,561	3,048,353
2007	148,131	154,509	2,780,810	3,562	3,087,012
2008	153,917	160,348	2,825,540	3,561	3,143,366
2009	159,775	166,153	2,852,578	3,562	3,182,068
2010	165,822	171,929	2,878,218	3,562	3,219,531
2011	172,140	177,858	2,899,352	3,561	3,252,911
2012	178,512	183,688	2,917,694	3,561	3,283,455
2013	184,946	189,418	2,930,361	3,562	3,308,287

PacifiCorp - RAMPP-3 High Sales Forecast

Utah (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	3,543,165	3,742,187	5,689,951	651,438	13,626,741
1994	3,685,066	4,003,188	6,388,541	684,015	14,760,810
1995	3,837,884	4,177,523	6,965,578	684,698	15,665,683
1996	3,993,181	4,364,341	7,608,547	700,015	16,666,084
1997	4,169,249	4,557,611	8,216,289	741,980	17,685,129
1998	4,307,351	4,730,202	8,768,296	754,209	18,560,058
1999	4,442,778	4,923,602	9,268,246	767,334	19,401,960
2000	4,588,145	5,127,526	9,751,952	780,791	20,248,414
2001	4,737,460	5,326,333	10,232,631	793,664	21,090,088
2002	4,885,804	5,530,390	10,731,531	806,611	21,954,336
2003	5,051,484	5,744,321	11,275,987	819,972	22,891,764
2004	5,232,366	5,960,240	11,815,881	833,193	23,841,680
2005	5,423,982	6,171,647	12,247,054	845,737	24,688,420
2006	5,629,973	6,388,242	12,665,458	858,334	25,542,007
2007	5,857,934	6,621,419	13,111,940	871,653	26,462,946
2008	6,150,699	6,835,149	13,568,697	883,847	27,438,392
2009	6,450,826	7,042,168	13,977,276	895,428	28,365,698
2010	6,766,654	7,254,436	14,401,776	907,135	29,330,001
2011	7,097,083	7,473,800	14,814,583	919,005	30,304,471
2012	7,433,958	7,691,040	15,183,547	930,533	31,239,078
2013	7,774,849	7,901,244	15,515,589	941,504	32,133,186

PacifiCorp - RAMPP-3 High Sales Forecast

Total Company (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	11,883,491	10,073,854	18,673,669	1,599,735	42,230,749
1994	12,733,633	10,740,854	20,697,711	1,841,888	46,014,086
1995	13,355,473	11,315,838	21,909,940	1,862,255	48,443,506
1996	13,943,206	11,896,085	23,112,758	1,879,140	50,831,189
1997	14,556,235	12,470,300	24,341,126	1,931,093	53,298,754
1998	14,997,609	13,028,378	25,338,487	1,956,055	55,320,529
1999	15,449,356	13,611,395	26,273,605	1,983,397	57,317,753
2000	15,955,506	14,222,404	27,279,510	2,013,346	59,470,766
2001	16,475,968	14,846,089	28,366,172	2,044,135	61,732,364
2002	16,998,503	15,479,931	29,495,945	2,075,498	64,049,877
2003	17,569,714	16,146,498	30,739,376	2,109,804	66,565,392
2004	18,165,874	16,824,140	31,975,335	2,143,398	69,108,747
2005	18,760,078	17,484,981	32,936,858	2,172,969	71,354,886
2006	19,366,118	18,146,457	33,915,272	2,201,711	73,629,558
2007	20,030,434	18,857,368	34,977,785	2,233,683	76,099,270
2008	20,865,104	19,529,274	36,079,065	2,265,103	78,738,546
2009	21,669,477	20,146,789	37,009,624	2,293,340	81,119,230
2010	22,488,251	20,748,624	37,983,112	2,321,796	83,541,783
2011	23,327,176	21,350,309	38,947,661	2,350,581	85,975,727
2012	24,179,906	21,947,878	39,853,338	2,378,350	88,359,472
2013	25,028,027	22,521,117	40,660,037	2,404,081	90,613,262

PacifiCorp - RAMPP-3 Medium High Sales Forecast

Oregon (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	4,756,974	3,554,007	4,042,313	304,893	12,658,187
1994	5,051,287	3,720,364	4,207,636	346,536	13,325,823
1995	5,226,885	3,884,003	4,309,801	348,508	13,769,197
1996	5,391,436	4,046,878	4,388,875	350,802	14,177,991
1997	5,570,228	4,219,801	4,484,895	355,176	14,630,100
1998	5,684,160	4,391,018	4,581,795	357,501	15,014,474
1999	5,813,478	4,574,139	4,706,311	360,322	15,454,250
2000	5,974,748	4,773,079	4,856,158	363,799	15,967,784
2001	6,132,292	4,980,160	5,011,721	367,264	16,491,437
2002	6,285,754	5,187,856	5,167,233	370,582	17,011,425
2003	6,452,177	5,407,003	5,349,071	374,282	17,582,533
2004	6,615,202	5,632,702	5,526,281	377,849	18,152,034
2005	6,770,643	5,852,370	5,670,953	380,882	18,674,848
2006	6,923,113	6,069,694	5,815,093	383,769	19,191,669
2007	7,095,106	6,308,196	6,004,832	387,330	19,795,464
2008	7,315,576	6,530,582	6,162,149	390,782	20,399,089
2009	7,510,395	6,719,853	6,289,099	393,377	20,912,724
2010	7,702,409	6,895,574	6,430,820	395,883	21,424,686
2011	7,894,892	7,066,554	6,577,469	398,320	21,937,235
2012	8,087,658	7,234,529	6,721,998	400,650	22,444,835
2013	8,272,079	7,390,380	6,845,742	402,587	22,910,788

PacifiCorp - RAMPP-3 Medium High Sales Forecast

Washington (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	1,419,289	1,093,723	929,451	148,484	3,590,947
1994	1,485,113	1,110,698	1,083,082	152,865	3,831,758
1995	1,537,261	1,153,222	1,164,427	154,568	4,009,478
1996	1,580,459	1,194,410	1,242,985	156,106	4,173,960
1997	1,625,471	1,228,165	1,303,547	157,998	4,315,181
1998	1,661,894	1,267,791	1,327,373	159,124	4,416,182
1999	1,704,132	1,310,355	1,363,897	160,601	4,538,985
2000	1,749,276	1,354,729	1,406,938	162,235	4,673,178
2001	1,800,278	1,399,690	1,452,929	163,986	4,816,883
2002	1,851,574	1,444,359	1,499,963	165,707	4,961,603
2003	1,905,281	1,490,252	1,551,346	167,513	5,114,392
2004	1,957,285	1,536,896	1,601,494	169,236	5,264,911
2005	2,007,825	1,582,449	1,645,744	170,780	5,406,798
2006	2,058,322	1,628,034	1,688,643	172,265	5,547,264
2007	2,110,567	1,675,115	1,737,437	173,853	5,696,972
2008	2,177,115	1,718,987	1,781,796	175,500	5,853,398
2009	2,241,435	1,759,776	1,820,444	176,946	5,998,601
2010	2,305,903	1,799,244	1,860,117	178,355	6,143,619
2011	2,371,006	1,838,533	1,900,293	179,743	6,289,575
2012	2,434,657	1,876,443	1,937,433	181,017	6,429,550
2013	2,497,033	1,912,288	1,970,620	182,160	6,562,101

PacifiCorp - RAMPP-3 Medium High Sales Forecast

North Idaho (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	108,168	69,129	61,706	690	239,693
1994	112,119	71,770	64,127	826	248,842
1995	116,539	75,015	67,177	826	259,557
1996	120,988	78,446	69,590	826	269,850
1997	125,357	82,073	72,504	825	280,759
1998	129,044	84,935	72,957	826	287,762
1999	133,546	87,866	74,348	826	296,586
2000	138,358	90,899	76,750	826	306,833
2001	143,155	94,005	79,092	826	317,078
2002	147,673	97,154	81,438	826	327,091
2003	152,483	100,431	84,930	826	338,670
2004	156,808	103,789	88,946	826	350,369
2005	160,961	107,125	92,255	827	361,168
2006	165,056	110,442	95,962	826	372,286
2007	169,564	113,893	101,833	825	386,115
2008	175,358	117,280	106,378	826	399,842
2009	180,752	120,475	108,430	826	410,483
2010	186,280	123,592	111,655	827	422,354
2011	191,850	126,637	115,538	826	434,851
2012	197,391	129,598	120,683	826	448,498
2013	202,730	132,414	125,317	825	461,286

PacifiCorp - RAMPP-3 Medium High Sales Forecast

Montana (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	327,472	237,666	188,071	3,475	756,684
1994	339,240	244,117	202,786	4,212	790,355
1995	354,185	255,014	207,566	4,216	820,981
1996	368,878	266,024	212,483	4,219	851,604
1997	383,766	277,258	217,435	4,227	882,686
1998	391,680	286,293	222,412	4,231	904,616
1999	400,481	296,090	227,451	4,235	928,257
2000	412,534	306,838	232,667	4,240	956,279
2001	422,914	318,091	238,099	4,243	983,347
2002	433,422	329,578	243,691	4,247	1,010,938
2003	445,171	341,930	249,403	4,251	1,040,755
2004	457,060	354,812	255,322	4,254	1,071,448
2005	468,696	367,692	261,241	4,259	1,101,888
2006	480,535	380,898	267,429	4,263	1,133,125
2007	494,192	395,477	273,663	4,267	1,167,599
2008	510,496	409,264	280,268	4,271	1,204,299
2009	524,984	421,819	286,913	4,276	1,237,992
2010	539,646	434,298	293,722	4,279	1,271,945
2011	554,755	447,130	300,678	4,283	1,306,846
2012	570,454	460,469	307,808	4,288	1,343,019
2013	585,837	473,717	315,091	4,291	1,378,936

PacifiCorp - RAMPP-3 Medium High Sales Forecast

California (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	358,744	222,233	81,552	77,763	740,292
1994	380,479	237,417	70,612	85,337	773,845
1995	395,577	247,055	73,767	87,770	804,169
1996	409,511	257,023	75,582	89,981	832,097
1997	423,054	266,291	76,674	91,836	857,855
1998	431,852	279,286	77,225	93,530	881,893
1999	441,732	292,928	78,705	95,435	908,800
2000	454,262	307,383	81,390	97,720	940,755
2001	466,997	322,323	84,022	100,028	973,370
2002	480,590	337,442	86,295	102,364	1,006,691
2003	495,009	353,144	89,507	104,867	1,042,527
2004	508,284	369,252	92,433	107,253	1,077,222
2005	521,263	385,338	94,840	109,542	1,110,983
2006	534,250	401,591	97,237	111,819	1,144,897
2007	548,493	418,763	101,925	114,425	1,183,606
2008	568,409	435,441	103,884	117,193	1,224,927
2009	586,943	451,126	103,584	119,567	1,261,220
2010	605,629	466,620	103,863	121,957	1,298,069
2011	624,766	482,305	104,550	124,403	1,336,024
2012	644,569	498,361	106,245	126,976	1,376,151
2013	664,400	514,418	107,476	129,490	1,415,784

PacifiCorp - RAMPP-3 Medium High Sales Forecast

East Wyoming (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	714,351	863,674	4,185,312	21,343	5,784,680
1994	726,732	889,006	4,628,861	22,991	6,267,590
1995	739,532	911,035	4,795,509	23,073	6,469,149
1996	752,386	933,913	4,943,812	23,132	6,653,243
1997	765,501	956,940	5,056,207	23,178	6,801,826
1998	776,748	994,484	5,158,123	23,225	6,952,580
1999	790,492	1,033,774	5,246,559	23,265	7,094,090
2000	803,764	1,074,113	5,361,200	23,317	7,262,394
2001	815,963	1,115,308	5,510,651	23,380	7,465,302
2002	829,942	1,156,952	5,672,270	23,449	7,682,613
2003	845,582	1,199,015	5,837,308	23,517	7,905,422
2004	862,495	1,241,394	6,016,693	23,589	8,144,171
2005	880,102	1,283,197	6,127,485	23,634	8,314,418
2006	898,573	1,324,760	6,265,767	23,688	8,512,788
2007	918,384	1,366,691	6,384,002	23,734	8,692,811
2008	947,484	1,408,326	6,550,333	23,799	8,929,942
2009	976,718	1,449,297	6,672,471	23,846	9,122,332
2010	1,006,784	1,490,243	6,795,867	23,893	9,316,787
2011	1,037,518	1,531,116	6,911,526	23,936	9,504,096
2012	1,068,683	1,571,753	7,018,297	23,976	9,682,709
2013	1,100,105	1,611,981	7,109,596	24,009	9,845,691

PacifiCorp - RAMPP-3 Medium High Sales Forecast

South Idaho (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	564,306	209,116	1,621,730	389,196	2,784,348
1994	586,206	196,831	1,628,980	524,301	2,936,318
1995	604,094	202,239	1,657,289	528,196	2,991,818
1996	622,556	208,064	1,685,810	515,177	3,031,607
1997	642,097	214,671	1,715,526	509,286	3,081,580
1998	655,541	219,401	1,736,895	511,186	3,123,023
1999	668,466	224,591	1,771,762	514,351	3,179,170
2000	682,948	230,187	1,816,476	518,582	3,248,193
2001	698,288	236,078	1,870,309	523,685	3,328,360
2002	713,421	242,113	1,931,349	529,333	3,416,216
2003	730,298	248,516	2,006,039	536,283	3,521,136
2004	747,427	255,276	2,080,308	543,070	3,626,081
2005	764,936	262,074	2,132,670	547,799	3,707,479
2006	782,976	269,034	2,178,720	551,937	3,782,667
2007	802,722	276,548	2,234,174	556,978	3,870,422
2008	828,798	284,040	2,286,746	562,193	3,961,777
2009	854,255	291,247	2,332,122	566,624	4,044,248
2010	880,360	298,479	2,380,584	571,267	4,130,690
2011	907,416	305,897	2,431,093	576,063	4,220,469
2012	935,040	313,435	2,473,098	580,141	4,301,714
2013	962,849	320,947	2,506,276	583,463	4,373,535

PacifiCorp - RAMPP-3 Medium High Sales Forecast

West Wyoming (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	91,021	82,120	1,873,583	2,454	2,049,178
1994	96,802	84,645	1,904,093	3,563	2,089,103
1995	100,521	86,855	1,944,355	3,561	2,135,292
1996	102,651	89,215	2,029,363	3,562	2,224,791
1997	104,924	91,691	1,996,743	3,562	2,196,920
1998	106,531	94,582	2,052,537	3,561	2,257,211
1999	108,171	97,723	2,082,108	3,562	2,291,564
2000	109,828	100,887	2,114,779	3,562	2,329,056
2001	111,457	104,234	2,154,342	3,562	2,373,595
2002	113,128	107,738	2,192,849	3,561	2,417,276
2003	115,066	111,413	2,226,652	3,563	2,456,694
2004	116,972	115,072	2,262,080	3,561	2,497,685
2005	118,784	118,547	2,277,459	3,562	2,518,352
2006	120,710	121,962	2,300,658	3,562	2,546,892
2007	122,966	125,437	2,311,672	3,562	2,563,637
2008	126,526	128,865	2,336,078	3,562	2,595,031
2009	130,095	132,208	2,345,432	3,562	2,611,297
2010	133,767	135,464	2,353,630	3,561	2,626,422
2011	137,608	138,790	2,358,032	3,562	2,637,992
2012	141,440	141,970	2,359,961	3,562	2,646,933
2013	145,274	145,012	2,357,285	3,562	2,651,133

PacifiCorp - RAMPP-3 Medium High Sales Forecast

Utah (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	3,543,165	3,742,187	5,689,951	651,438	13,626,741
1994	3,597,651	3,935,731	6,091,143	678,364	14,302,889
1995	3,701,935	4,082,117	6,575,841	677,010	15,036,903
1996	3,808,417	4,237,793	7,112,030	690,200	15,848,440
1997	3,918,776	4,399,128	7,597,194	730,002	16,645,100
1998	3,988,178	4,542,595	8,035,978	740,246	17,306,997
1999	4,061,977	4,705,858	8,415,754	751,418	17,935,007
2000	4,140,548	4,878,992	8,771,312	762,945	18,553,797
2001	4,215,891	5,043,484	9,122,814	773,722	19,155,911
2002	4,298,522	5,214,944	9,484,607	784,762	19,782,835
2003	4,393,022	5,392,782	9,877,822	796,068	20,459,694
2004	4,500,506	5,574,348	10,275,547	807,423	21,157,824
2005	4,619,207	5,756,210	10,578,189	818,436	21,772,042
2006	4,750,635	5,944,745	10,865,738	829,634	22,390,752
2007	4,899,930	6,147,885	11,174,369	841,512	23,063,696
2008	5,106,733	6,332,706	11,485,769	852,316	23,777,524
2009	5,319,042	6,512,335	11,751,899	862,610	24,445,886
2010	5,543,648	6,696,750	12,025,709	873,035	25,139,142
2011	5,779,352	6,887,764	12,290,148	883,651	25,840,915
2012	6,018,918	7,076,412	12,512,367	893,928	26,501,625
2013	6,260,892	7,259,452	12,699,929	903,730	27,124,003

PacifiCorp - RAMPP-3 Medium High Sales Forecast

Total Company (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	11,883,491	10,073,854	18,673,669	1,599,735	42,230,749
1994	12,375,629	10,490,579	19,881,321	1,818,995	44,566,524
1995	12,776,527	10,896,555	20,795,731	1,827,730	46,296,543
1996	13,157,283	11,311,766	21,760,530	1,834,004	48,063,583
1997	13,559,173	11,736,018	22,520,725	1,876,091	49,692,007
1998	13,825,628	12,160,387	23,265,295	1,893,429	51,144,739
1999	14,122,475	12,623,324	23,966,894	1,914,017	52,626,710
2000	14,466,266	13,117,108	24,717,671	1,937,223	54,238,268
2001	14,807,235	13,613,371	25,523,978	1,960,698	55,905,282
2002	15,154,025	14,118,137	26,359,694	1,984,832	57,616,688
2003	15,534,090	14,644,486	27,272,077	2,011,168	59,461,821
2004	15,922,039	15,183,541	28,199,103	2,037,062	61,341,745
2005	16,312,418	15,715,002	28,880,837	2,059,719	62,967,976
2006	16,714,172	16,251,160	29,575,245	2,081,762	64,622,339
2007	17,161,924	16,828,005	30,323,908	2,106,486	66,420,323
2008	17,756,494	17,365,490	31,093,399	2,130,445	68,345,828
2009	18,324,619	17,858,138	31,710,393	2,151,632	70,044,782
2010	18,904,426	18,340,264	32,355,968	2,173,056	71,773,714
2011	19,499,163	18,824,726	32,989,327	2,194,787	73,508,003
2012	20,098,811	19,302,970	33,557,890	2,215,363	75,175,034
2013	20,691,198	19,760,608	34,037,331	2,234,120	76,723,257

PacifiCorp - RAMPP-3 Medium Sales Forecast

Oregon (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	4,756,974	3,554,007	4,042,313	304,893	12,658,187
1994	4,946,908	3,636,736	4,013,525	341,632	12,938,801
1995	5,053,776	3,736,034	4,022,000	341,031	13,152,841
1996	5,159,053	3,838,630	4,043,221	341,403	13,382,307
1997	5,279,174	3,952,207	4,084,433	343,982	13,659,796
1998	5,319,059	4,065,310	4,134,057	344,471	13,862,897
1999	5,372,871	4,188,133	4,208,643	345,455	14,115,102
2000	5,455,025	4,323,366	4,304,870	347,065	14,430,326
2001	5,532,182	4,463,750	4,404,624	348,656	14,749,212
2002	5,604,244	4,602,721	4,502,327	350,104	15,059,396
2003	5,684,090	4,749,378	4,620,926	351,869	15,406,263
2004	5,766,902	4,899,332	4,733,283	353,572	15,753,089
2005	5,841,587	5,041,947	4,815,855	354,777	16,054,166
2006	5,913,330	5,180,840	4,896,097	355,850	16,346,117
2007	6,000,732	5,334,882	5,012,800	357,520	16,705,934
2008	6,148,525	5,474,668	5,097,316	359,264	17,079,773
2009	6,282,314	5,595,097	5,157,596	360,421	17,395,428
2010	6,416,933	5,709,600	5,230,079	361,600	17,718,212
2011	6,553,619	5,823,284	5,306,130	362,778	18,045,811
2012	6,691,387	5,936,432	5,380,723	363,906	18,372,448
2013	6,822,790	6,041,458	5,437,723	364,714	18,666,685

PacifiCorp - RAMPP-3 Medium Sales Forecast

Washington (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	1,419,289	1,093,723	929,451	148,484	3,590,947
1994	1,469,808	1,101,331	1,050,930	151,659	3,773,728
1995	1,511,911	1,135,979	1,113,269	152,656	3,913,815
1996	1,543,770	1,167,783	1,177,465	153,555	4,042,573
1997	1,576,165	1,191,139	1,226,061	154,832	4,148,197
1998	1,598,963	1,219,444	1,247,545	155,492	4,221,444
1999	1,626,418	1,249,661	1,279,715	156,446	4,312,240
2000	1,656,345	1,281,206	1,316,948	157,534	4,412,033
2001	1,691,718	1,312,897	1,356,037	158,723	4,519,375
2002	1,726,841	1,343,941	1,395,335	159,870	4,625,987
2003	1,763,738	1,375,755	1,437,934	161,087	4,738,514
2004	1,801,231	1,407,939	1,478,869	162,262	4,850,301
2005	1,837,022	1,438,887	1,514,084	163,264	4,953,257
2006	1,872,467	1,469,621	1,547,670	164,207	5,053,965
2007	1,909,146	1,501,425	1,586,055	165,238	5,161,864
2008	1,958,619	1,530,248	1,620,271	166,333	5,275,471
2009	2,005,748	1,556,253	1,649,298	167,241	5,378,540
2010	2,052,659	1,580,991	1,679,023	168,115	5,480,788
2011	2,099,776	1,605,451	1,708,976	168,970	5,583,173
2012	2,145,229	1,628,590	1,736,138	169,720	5,679,677
2013	2,189,328	1,649,911	1,759,825	170,352	5,769,416

PacifiCorp - RAMPP-3 Medium Sales Forecast

North Idaho (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	108,168	69,129	61,706	690	239,693
1994	108,945	70,481	62,113	826	242,365
1995	111,725	72,947	63,946	826	249,444
1996	114,521	75,495	65,737	826	256,579
1997	117,095	78,139	68,138	826	264,198
1998	119,061	80,112	67,990	827	267,990
1999	121,754	82,111	68,671	825	273,361
2000	124,895	84,305	70,284	826	280,310
2001	127,955	86,518	71,809	826	287,108
2002	130,692	88,721	73,303	826	293,542
2003	133,639	90,994	75,826	826	301,285
2004	136,569	93,293	78,797	827	309,486
2005	139,280	95,525	81,076	826	316,707
2006	141,879	97,691	83,678	825	324,073
2007	144,796	99,932	88,227	826	333,781
2008	148,778	102,066	91,526	826	343,196
2009	152,315	103,977	92,499	827	349,618
2010	155,896	105,768	94,486	826	356,976
2011	159,433	107,443	97,031	825	364,732
2012	162,871	108,993	100,674	827	373,365
2013	166,052	110,361	103,820	827	381,060

PacifiCorp - RAMPP-3 Medium Sales Forecast

Montana (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	327,472	237,666	188,071	3,475	756,684
1994	331,565	238,905	198,871	4,213	773,554
1995	341,944	246,151	201,605	4,217	793,917
1996	352,741	253,718	204,420	4,219	815,098
1997	363,684	261,542	207,176	4,227	836,629
1998	367,627	267,485	209,880	4,231	849,223
1999	372,329	274,099	212,583	4,236	863,247
2000	379,955	281,536	215,402	4,239	881,132
2001	385,929	289,362	218,372	4,243	897,906
2002	391,937	297,330	221,434	4,247	914,948
2003	398,993	306,013	224,550	4,251	933,807
2004	406,403	315,101	227,803	4,255	953,562
2005	413,528	324,123	230,987	4,258	972,896
2006	420,790	333,371	234,366	4,263	992,790
2007	429,628	343,777	237,718	4,266	1,015,389
2008	440,688	353,402	241,364	4,271	1,039,725
2009	450,071	361,877	244,973	4,275	1,061,196
2010	459,540	370,223	248,667	4,279	1,082,709
2011	469,336	378,817	252,426	4,284	1,104,863
2012	479,593	387,798	256,278	4,287	1,127,956
2013	489,521	396,646	260,197	4,291	1,150,655

PacifiCorp - RAMPP-3 Medium Sales Forecast

California (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	358,744	222,233	81,552	77,763	740,292
1994	369,439	230,233	66,651	83,312	749,635
1995	378,338	235,342	67,455	84,571	765,706
1996	386,501	240,794	68,146	85,777	781,218
1997	394,958	246,431	68,194	86,785	796,368
1998	399,121	256,157	68,002	87,743	811,023
1999	404,573	266,725	68,765	88,964	829,027
2000	412,636	278,182	70,710	90,585	852,113
2001	420,949	290,140	72,696	92,256	876,041
2002	430,056	302,270	74,424	93,969	900,719
2003	439,923	314,937	77,027	95,846	927,733
2004	450,082	327,954	79,421	97,737	955,194
2005	459,905	340,915	81,377	99,538	981,735
2006	469,677	353,986	83,330	101,324	1,008,317
2007	480,558	367,867	87,334	103,415	1,039,174
2008	496,391	381,200	88,958	105,645	1,072,194
2009	510,796	393,529	88,099	107,456	1,099,880
2010	525,197	405,602	87,392	109,239	1,127,430
2011	539,870	417,778	86,811	111,044	1,155,503
2012	555,025	430,229	86,957	112,947	1,185,158
2013	570,067	442,609	86,618	114,776	1,214,070

PacifiCorp - RAMPP-3 Medium Sales Forecast

East Wyoming (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	714,351	863,674	4,185,312	21,343	5,784,680
1994	718,655	877,964	4,531,278	22,936	6,150,833
1995	726,209	892,036	4,544,675	22,940	6,185,860
1996	733,528	906,502	4,574,717	22,939	6,237,686
1997	740,616	920,900	4,598,708	22,940	6,283,164
1998	745,508	949,531	4,694,870	22,980	6,412,889
1999	752,527	979,512	4,774,150	23,014	6,529,203
2000	758,814	1,010,213	4,877,331	23,056	6,669,414
2001	763,808	1,041,490	5,013,189	23,112	6,841,599
2002	770,224	1,073,010	5,159,370	23,172	7,025,776
2003	778,014	1,104,921	5,307,042	23,231	7,213,208
2004	787,123	1,137,137	5,467,570	23,295	7,415,125
2005	796,720	1,168,818	5,561,607	23,330	7,550,475
2006	806,980	1,200,250	5,682,306	23,375	7,712,911
2007	818,377	1,232,010	5,781,788	23,412	7,855,587
2008	837,659	1,263,442	5,927,641	23,467	8,052,209
2009	856,832	1,294,206	6,029,684	23,504	8,204,226
2010	876,562	1,324,900	6,131,876	23,540	8,356,878
2011	896,721	1,355,488	6,225,662	23,574	8,501,445
2012	917,139	1,385,844	6,310,867	23,603	8,637,453
2013	937,657	1,415,805	6,380,998	23,626	8,758,086

PacifiCorp - RAMPP-3 Medium Sales Forecast

South Idaho (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	564,306	209,116	1,621,730	389,196	2,784,348
1994	578,669	194,196	1,608,461	520,612	2,901,938
1995	592,347	197,837	1,625,700	522,682	2,938,566
1996	606,519	201,768	1,642,115	507,742	2,958,144
1997	621,119	206,198	1,658,694	499,830	2,985,841
1998	629,363	208,738	1,667,386	499,781	3,005,268
1999	636,894	211,595	1,687,651	500,827	3,036,967
2000	645,658	214,724	1,716,503	502,835	3,079,720
2001	654,955	218,012	1,753,168	505,621	3,131,756
2002	663,757	221,323	1,795,700	508,862	3,189,642
2003	673,857	224,857	1,850,019	513,288	3,262,021
2004	684,957	228,600	1,902,826	517,581	3,333,964
2005	696,043	232,254	1,934,307	519,812	3,382,416
2006	707,239	235,917	1,959,076	521,398	3,423,630
2007	719,599	239,934	1,991,619	523,774	3,474,926
2008	737,291	243,791	2,020,672	526,250	3,528,004
2009	753,982	247,263	2,042,308	527,901	3,571,454
2010	770,799	250,625	2,065,843	529,678	3,616,945
2011	787,998	254,013	2,090,334	531,530	3,663,875
2012	805,234	257,369	2,106,471	532,636	3,701,710
2013	822,178	260,574	2,113,955	532,950	3,729,657

PacifiCorp - RAMPP-3 Medium Sales Forecast

West Wyoming (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	91,021	82,120	1,873,583	2,454	2,049,178
1994	92,753	81,850	1,898,016	3,562	2,076,181
1995	93,694	82,232	1,856,199	3,562	2,035,687
1996	94,641	82,613	1,866,045	3,562	2,046,861
1997	95,614	83,054	1,762,720	3,562	1,944,950
1998	95,916	83,925	1,846,128	3,562	2,029,531
1999	96,178	84,958	1,906,499	3,561	2,091,196
2000	96,435	85,955	1,969,918	3,561	2,155,869
2001	96,620	87,052	2,039,827	3,562	2,227,061
2002	96,805	88,229	2,108,469	3,562	2,297,065
2003	97,195	89,494	2,082,293	3,562	2,272,544
2004	97,598	90,705	1,964,858	3,563	2,156,724
2005	97,918	91,743	1,736,233	3,561	1,929,455
2006	98,326	92,706	1,416,974	3,562	1,611,568
2007	99,016	93,688	994,069	3,562	1,190,335
2008	100,748	94,609	1,034,610	3,561	1,233,528
2009	102,456	95,447	1,073,315	3,562	1,274,780
2010	104,247	96,210	1,112,051	3,561	1,316,069
2011	106,120	97,000	1,150,396	3,562	1,357,078
2012	107,996	97,676	1,187,803	3,562	1,397,037
2013	109,867	98,251	1,224,355	3,561	1,436,034

PacifiCorp - RAMPP-3 Medium Sales Forecast

Utah (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	3,543,165	3,742,187	5,689,951	651,438	13,626,741
1994	3,541,837	3,852,463	5,959,278	672,101	14,025,679
1995	3,622,555	3,960,325	6,347,610	668,026	14,598,516
1996	3,702,217	4,071,162	6,779,609	678,235	15,231,223
1997	3,784,398	4,185,165	7,150,851	714,957	15,835,371
1998	3,823,958	4,280,781	7,484,205	722,053	16,310,997
1999	3,868,134	4,395,269	7,756,805	730,136	16,750,344
2000	3,916,483	4,518,576	8,001,334	738,611	17,175,004
2001	3,959,381	4,630,568	8,236,588	746,226	17,572,763
2002	4,008,600	4,749,509	8,477,439	754,198	17,989,746
2003	4,066,507	4,871,982	8,743,505	762,354	18,444,348
2004	4,133,987	4,995,846	9,009,171	770,505	18,909,509
2005	4,211,179	5,120,936	9,183,919	778,454	19,294,488
2006	4,298,966	5,251,722	9,341,951	786,623	19,679,262
2007	4,401,694	5,394,380	9,513,444	795,434	20,104,952
2008	4,553,848	5,521,969	9,713,027	803,418	20,592,262
2009	4,709,256	5,645,035	9,867,766	810,967	21,033,024
2010	4,873,902	5,771,752	10,023,958	818,654	21,488,266
2011	5,046,778	5,903,473	10,167,374	826,520	21,944,145
2012	5,221,874	6,033,060	10,270,791	834,109	22,359,834
2013	5,398,179	6,158,093	10,340,301	841,307	22,737,880

PacifiCorp - RAMPP-3 Medium Sales Forecast

Total Company (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	11,883,491	10,073,854	18,673,669	1,599,735	42,230,749
1994	12,158,579	10,284,159	19,389,123	1,800,853	43,632,714
1995	12,432,499	10,558,883	19,842,459	1,800,511	44,634,352
1996	12,693,491	10,838,465	20,421,475	1,798,258	45,751,689
1997	12,972,823	11,124,775	20,824,975	1,831,941	46,754,514
1998	13,098,575	11,411,485	21,420,064	1,841,138	47,771,262
1999	13,251,678	11,732,063	21,963,481	1,853,465	48,800,687
2000	13,446,247	12,078,061	22,543,299	1,868,312	49,935,919
2001	13,633,496	12,419,789	23,166,310	1,883,226	51,102,821
2002	13,823,155	12,767,054	23,807,800	1,898,811	52,296,820
2003	14,035,957	13,128,331	24,419,121	1,916,315	53,499,724
2004	14,264,852	13,495,907	24,942,598	1,933,598	54,636,955
2005	14,493,182	13,855,148	25,139,444	1,947,823	55,435,597
2006	14,729,654	14,216,105	25,245,448	1,961,425	56,152,632
2007	15,003,547	14,607,894	25,293,054	1,977,447	56,881,942
2008	15,422,546	14,965,396	25,835,384	1,993,035	58,216,361
2009	15,823,770	15,292,685	26,245,538	2,006,153	59,368,146
2010	16,235,734	15,615,670	26,673,374	2,019,496	60,544,274
2011	16,659,651	15,942,747	27,085,139	2,033,088	61,720,625
2012	17,086,348	16,265,992	27,436,703	2,045,594	62,834,637
2013	17,505,637	16,573,708	27,707,793	2,056,404	63,843,542

PacifiCorp - RAMPP-3 Medium Low Sales Forecast

Oregon (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	4,756,974	3,554,007	4,042,313	304,893	12,658,187
1994	4,814,997	3,527,376	3,852,076	336,402	12,530,851
1995	4,854,568	3,565,231	3,798,015	333,578	12,551,392
1996	4,906,834	3,615,990	3,784,921	332,388	12,640,133
1997	4,978,738	3,683,195	3,801,587	333,686	12,797,206
1998	4,995,519	3,752,457	3,812,929	333,053	12,893,958
1999	5,023,058	3,827,873	3,845,410	332,836	13,029,177
2000	5,074,928	3,912,189	3,895,897	333,168	13,216,182
2001	5,120,701	3,999,214	3,948,273	333,456	13,401,644
2002	5,160,842	4,083,596	3,997,450	333,593	13,575,481
2003	5,208,859	4,173,207	4,063,311	334,024	13,779,401
2004	5,258,673	4,264,296	4,121,999	334,385	13,979,353
2005	5,300,598	4,347,913	4,156,255	334,306	14,139,072
2006	5,340,405	4,427,719	4,188,731	334,127	14,290,982
2007	5,393,344	4,518,962	4,251,216	334,483	14,498,005
2008	5,482,817	4,598,145	4,285,201	334,772	14,700,935
2009	5,569,210	4,669,807	4,314,836	334,886	14,888,739
2010	5,659,740	4,741,853	4,353,669	335,112	15,090,374
2011	5,753,887	4,816,304	4,394,303	335,385	15,299,879
2012	5,849,887	4,892,130	4,433,000	335,646	15,510,663
2013	5,941,148	4,962,703	4,456,099	335,642	15,695,592

PacifiCorp - RAMPP-3 Medium Low Sales Forecast

Washington (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	1,419,289	1,093,723	929,451	148,484	3,590,947
1994	1,450,930	1,092,504	998,646	149,857	3,691,937
1995	1,487,406	1,119,877	1,044,773	150,299	3,802,355
1996	1,512,995	1,143,054	1,094,325	150,655	3,901,029
1997	1,537,965	1,156,887	1,132,604	151,446	3,978,902
1998	1,544,625	1,174,853	1,137,129	151,318	4,007,925
1999	1,554,689	1,193,817	1,148,346	151,392	4,048,244
2000	1,570,953	1,213,308	1,162,623	151,638	4,098,522
2001	1,592,007	1,232,299	1,177,759	151,968	4,154,033
2002	1,612,072	1,250,135	1,192,642	152,244	4,207,093
2003	1,633,137	1,268,194	1,210,275	152,579	4,264,185
2004	1,654,153	1,286,148	1,226,278	152,871	4,319,450
2005	1,673,073	1,302,595	1,237,239	153,003	4,365,910
2006	1,691,211	1,318,475	1,246,798	153,078	4,409,562
2007	1,710,004	1,334,942	1,260,458	153,238	4,458,642
2008	1,739,867	1,348,504	1,270,355	153,464	4,512,190
2009	1,767,058	1,359,349	1,275,693	153,513	4,555,613
2010	1,793,513	1,368,866	1,281,540	153,530	4,597,449
2011	1,819,604	1,377,923	1,287,481	153,530	4,638,538
2012	1,843,648	1,385,616	1,291,120	153,430	4,673,814
2013	1,866,051	1,391,606	1,291,819	153,224	4,702,700

PacifiCorp - RAMPP-3 Medium Low Sales Forecast

North Idaho (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	108,168	69,129	61,706	690	239,693
1994	106,924	69,528	59,099	825	236,376
1995	108,488	71,621	58,235	825	239,169
1996	109,866	73,299	58,741	826	242,732
1997	111,248	74,975	60,387	826	247,436
1998	111,025	76,076	59,646	826	247,573
1999	112,291	77,159	59,635	827	249,912
2000	114,140	78,540	60,452	826	253,958
2001	115,838	79,880	61,143	827	257,688
2002	117,167	81,153	61,763	826	260,909
2003	118,617	82,432	63,295	826	265,170
2004	119,979	83,674	65,199	826	269,678
2005	121,075	84,791	66,433	827	273,126
2006	122,000	85,782	67,915	825	276,522
2007	123,144	86,774	71,122	826	281,866
2008	125,136	87,593	73,156	826	286,711
2009	126,629	88,132	73,037	826	288,624
2010	128,056	88,479	73,762	827	291,124
2011	129,333	88,629	74,946	826	293,734
2012	130,412	88,567	77,070	826	296,875
2013	131,138	88,229	78,712	827	298,906

PacifiCorp - RAMPP-3 Medium Low Sales Forecast

Montana (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	327,472	237,666	188,071	3,475	756,684
1994	322,239	232,863	193,298	4,213	752,613
1995	329,826	237,901	193,951	4,217	765,895
1996	338,367	243,606	194,689	4,219	780,881
1997	347,374	249,694	195,472	4,227	796,767
1998	347,326	254,128	196,198	4,230	801,882
1999	349,632	259,196	196,904	4,235	809,967
2000	351,827	264,985	197,706	4,239	818,757
2001	355,063	270,690	198,640	4,244	828,637
2002	357,545	275,847	199,647	4,246	837,285
2003	360,876	281,566	200,686	4,251	847,379
2004	364,428	287,555	201,843	4,255	858,081
2005	367,631	293,385	202,910	4,259	868,185
2006	370,876	299,314	204,151	4,264	878,605
2007	375,438	306,171	205,345	4,267	891,221
2008	381,839	312,217	206,812	4,270	905,138
2009	386,653	317,142	208,220	4,276	916,291
2010	391,437	321,852	209,692	4,279	927,260
2011	396,405	326,677	211,207	4,283	938,572
2012	401,677	331,736	212,793	4,286	950,492
2013	406,573	336,578	214,424	4,291	961,866

PacifiCorp - RAMPP-3 Medium Low Sales Forecast

California (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	358,744	222,233	81,552	77,763	740,292
1994	357,406	221,154	64,554	81,167	724,281
1995	361,539	222,798	64,211	81,574	730,122
1996	365,665	226,233	64,522	82,205	738,625
1997	370,527	229,766	64,266	82,682	747,241
1998	369,891	237,156	63,827	82,989	753,863
1999	372,272	245,267	64,292	83,712	765,543
2000	376,722	254,152	65,872	84,783	781,529
2001	381,601	263,430	67,495	85,920	798,446
2002	387,110	272,791	68,876	87,085	815,862
2003	393,241	282,592	71,075	88,402	835,310
2004	399,561	292,657	73,079	89,726	855,023
2005	405,491	302,601	74,675	90,958	873,725
2006	411,300	312,582	76,263	92,169	892,314
2007	418,067	323,263	79,749	93,669	914,748
2008	429,086	333,315	81,038	95,269	938,708
2009	438,624	342,319	80,026	96,454	957,423
2010	448,000	350,986	79,135	97,595	975,716
2011	457,462	359,658	78,347	98,743	994,210
2012	467,214	368,505	78,216	99,968	1,013,903
2013	476,700	377,192	77,637	101,113	1,032,642

PacifiCorp - RAMPP-3 Medium Low Sales Forecast

East Wyoming (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	714,351	863,674	4,185,312	21,343	5,784,680
1994	710,061	857,871	4,494,534	22,906	6,085,372
1995	713,524	862,332	4,497,778	22,898	6,096,532
1996	715,594	867,287	4,495,359	22,874	6,101,114
1997	716,953	872,235	4,474,702	22,848	6,086,738
1998	716,072	891,128	4,521,336	22,857	6,151,393
1999	716,969	911,052	4,550,491	22,861	6,201,373
2000	716,881	931,426	4,602,318	22,874	6,273,499
2001	715,329	952,154	4,685,036	22,902	6,375,421
2002	714,875	972,980	4,776,342	22,933	6,487,130
2003	715,552	994,236	4,867,270	22,962	6,600,020
2004	717,313	1,015,858	4,969,494	22,999	6,725,664
2005	719,402	1,037,075	5,006,170	23,004	6,785,651
2006	721,999	1,058,128	5,067,180	23,020	6,870,327
2007	725,567	1,079,569	5,105,218	23,028	6,933,382
2008	735,733	1,100,757	5,184,942	23,055	7,044,487
2009	745,584	1,121,387	5,219,915	23,062	7,109,948
2010	755,742	1,142,009	5,253,180	23,069	7,174,000
2011	766,109	1,162,605	5,276,816	23,070	7,228,600
2012	776,552	1,183,082	5,291,577	23,068	7,274,279
2013	786,912	1,203,279	5,291,051	23,061	7,304,303

PacifiCorp - RAMPP-3 Medium Low Sales Forecast

South Idaho (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	564,306	209,116	1,621,730	389,196	2,784,348
1994	569,911	191,892	1,585,024	516,467	2,863,294
1995	580,868	194,036	1,589,351	516,683	2,880,938
1996	591,072	196,353	1,593,710	499,861	2,880,996
1997	601,040	198,897	1,598,502	490,082	2,888,521
1998	605,200	199,552	1,594,038	488,117	2,886,907
1999	608,456	200,407	1,600,170	487,156	2,896,189
2000	612,635	201,415	1,613,839	487,055	2,914,944
2001	617,037	202,467	1,634,173	487,632	2,941,309
2002	620,672	203,429	1,659,203	488,564	2,971,868
2003	625,182	204,485	1,694,379	490,557	3,014,603
2004	630,278	205,619	1,727,093	492,326	3,055,316
2005	635,004	206,547	1,739,026	492,010	3,072,587
2006	639,459	207,349	1,743,898	490,971	3,081,677
2007	644,584	208,324	1,755,108	490,604	3,098,620
2008	654,105	208,996	1,762,288	490,233	3,115,622
2009	662,258	209,160	1,761,887	488,969	3,122,274
2010	670,026	209,052	1,762,335	487,719	3,129,132
2011	677,617	208,779	1,762,784	486,432	3,135,612
2012	684,708	208,277	1,755,027	484,327	3,132,339
2013	690,998	207,435	1,738,788	481,344	3,118,565

PacifiCorp - RAMPP-3 Medium Low Sales Forecast

West Wyoming (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	91,021	82,120	1,873,583	2,454	2,049,178
1994	90,892	79,838	1,891,940	3,563	2,066,233
1995	90,684	79,002	1,846,671	3,562	2,019,919
1996	91,214	78,115	1,831,142	3,561	2,004,032
1997	91,294	77,294	1,652,520	3,562	1,824,670
1998	90,774	76,947	1,667,051	3,561	1,838,333
1999	90,797	76,743	1,662,466	3,562	1,833,568
2000	90,822	76,505	1,662,514	3,562	1,833,403
2001	91,050	76,356	1,670,211	3,561	1,841,178
2002	91,423	76,275	1,678,311	3,561	1,849,570
2003	91,380	76,272	1,683,567	3,562	1,854,781
2004	91,438	76,224	1,691,642	3,562	1,862,866
2005	91,521	76,040	1,682,348	3,562	1,853,471
2006	91,784	75,807	1,681,233	3,562	1,852,386
2007	92,328	75,600	1,671,178	3,562	1,842,668
2008	93,865	75,355	1,674,036	3,562	1,846,818
2009	94,746	75,059	1,666,191	3,561	1,839,557
2010	95,797	74,719	1,659,217	3,562	1,833,295
2011	97,159	74,414	1,650,941	3,561	1,826,075
2012	98,643	74,038	1,642,596	3,561	1,818,838
2013	100,319	73,604	1,632,361	3,561	1,809,845

PacifiCorp - RAMPP-3 Medium Low Sales Forecast

Utah (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	3,543,165	3,742,187	5,689,951	651,438	13,626,741
1994	3,473,871	3,745,459	5,776,313	663,974	13,659,617
1995	3,530,732	3,813,156	5,994,217	656,831	13,994,936
1996	3,590,417	3,887,931	6,131,226	664,066	14,273,640
1997	3,649,223	3,961,186	6,268,139	697,746	14,576,294
1998	3,654,664	4,017,492	6,413,422	701,891	14,787,469
1999	3,660,584	4,091,688	6,527,105	707,114	14,986,491
2000	3,669,423	4,173,832	6,636,968	712,809	15,193,032
2001	3,684,698	4,242,304	6,747,333	717,577	15,391,912
2002	3,705,530	4,317,914	6,866,181	722,798	15,612,423
2003	3,732,125	4,394,570	7,007,203	728,108	15,862,006
2004	3,765,240	4,470,687	7,146,585	733,346	16,115,858
2005	3,806,806	4,549,029	7,212,644	738,527	16,307,006
2006	3,857,177	4,632,509	7,278,192	744,000	16,511,878
2007	3,919,950	4,725,812	7,347,043	750,068	16,742,873
2008	4,024,290	4,806,606	7,416,570	755,406	17,002,872
2009	4,129,993	4,883,531	7,449,737	760,385	17,223,646
2010	4,242,274	4,963,246	7,482,966	765,507	17,453,993
2011	4,360,313	5,046,784	7,504,317	770,800	17,682,214
2012	4,479,098	5,128,368	7,503,318	775,886	17,886,670
2013	4,597,972	5,206,159	7,481,831	780,664	18,066,626

PacifiCorp - RAMPP-3 Medium Sales Forecast

Total Company (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	11,883,491	10,073,854	18,673,669	1,599,735	42,230,749
1994	11,897,231	10,018,486	18,915,485	1,779,372	42,610,574
1995	12,057,636	10,165,953	19,087,204	1,770,466	43,081,259
1996	12,222,024	10,331,867	19,248,636	1,760,656	43,563,183
1997	12,404,361	10,504,130	19,248,179	1,787,103	43,943,773
1998	12,435,094	10,679,788	19,465,575	1,788,847	44,369,304
1999	12,488,748	10,883,202	19,654,819	1,793,695	44,820,464
2000	12,578,331	11,106,350	19,898,190	1,800,956	45,383,827
2001	12,673,325	11,318,794	20,190,064	1,808,083	45,990,266
2002	12,767,236	11,534,121	20,500,415	1,815,851	46,617,623
2003	12,878,968	11,757,554	20,861,062	1,825,272	47,322,856
2004	13,001,063	11,982,716	21,223,213	1,834,297	48,041,289
2005	13,120,600	12,199,978	21,377,700	1,840,453	48,538,731
2006	13,246,210	12,417,663	21,554,362	1,846,019	49,064,254
2007	13,402,425	12,659,417	21,746,436	1,853,746	49,662,024
2008	13,666,737	12,871,487	21,954,398	1,860,859	50,353,481
2009	13,920,754	13,065,886	22,049,542	1,865,933	50,902,115
2010	14,184,587	13,261,062	22,155,497	1,871,197	51,472,343
2011	14,457,890	13,461,772	22,241,141	1,876,632	52,037,435
2012	14,731,837	13,660,319	22,284,717	1,881,001	52,557,874
2013	14,997,813	13,846,785	22,262,719	1,883,728	52,991,045

PacifiCorp - RAMPP-3 Low Sales Forecast

Oregon (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	4,756,974	3,554,007	4,042,313	304,893	12,658,187
1994	4,625,639	3,401,010	3,659,731	329,791	12,016,171
1995	4,589,420	3,376,315	3,589,277	325,107	11,880,119
1996	4,578,626	3,369,317	3,572,407	322,457	11,842,807
1997	4,590,491	3,382,250	3,563,766	322,164	11,858,671
1998	4,549,556	3,400,367	3,552,602	331,680	11,834,205
1999	4,525,956	3,432,639	3,571,617	342,249	11,872,461
2000	4,528,249	3,478,831	3,610,001	353,865	11,970,946
2001	4,525,448	3,529,587	3,647,999	365,555	12,068,589
2002	4,517,768	3,578,847	3,680,438	377,001	12,154,054
2003	4,515,057	3,631,192	3,722,215	388,700	12,257,164
2004	4,512,264	3,683,005	3,753,885	400,176	12,349,330
2005	4,500,625	3,726,129	3,758,868	410,763	12,396,385
2006	4,486,625	3,764,536	3,760,226	420,916	12,432,303
2007	4,481,648	3,810,053	3,783,457	431,639	12,506,797
2008	4,507,619	3,843,824	3,776,125	441,768	12,569,336
2009	4,519,069	3,860,798	3,742,546	450,593	12,573,006
2010	4,529,259	3,872,357	3,716,035	459,189	12,576,840
2011	4,538,651	3,881,952	3,689,776	467,630	12,578,009
2012	4,545,268	3,888,690	3,658,151	475,797	12,567,906
2013	4,546,326	3,889,607	3,613,667	483,443	12,533,043

PacifiCorp - RAMPP-3 Low Sales Forecast

Washington (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	1,419,289	1,093,723	929,451	148,484	3,590,947
1994	1,415,334	1,074,565	928,405	147,074	3,565,378
1995	1,432,815	1,090,673	942,500	146,286	3,612,274
1996	1,439,269	1,101,842	965,357	145,536	3,652,004
1997	1,443,921	1,102,771	986,883	145,394	3,678,969
1998	1,428,136	1,107,555	995,464	147,509	3,678,664
1999	1,415,630	1,113,454	1,003,074	149,666	3,681,824
2000	1,408,715	1,119,813	1,011,122	151,928	3,691,578
2001	1,406,388	1,125,440	1,016,287	154,185	3,702,300
2002	1,402,773	1,129,686	1,020,843	156,346	3,709,648
2003	1,399,473	1,133,683	1,026,936	158,524	3,718,616
2004	1,395,616	1,137,145	1,031,129	160,622	3,724,512
2005	1,389,483	1,138,877	1,030,634	162,508	3,721,502
2006	1,382,401	1,139,774	1,031,951	164,349	3,718,475
2007	1,375,341	1,140,718	1,037,363	166,249	3,719,671
2008	1,377,540	1,138,876	1,040,215	168,175	3,724,806
2009	1,377,302	1,134,643	1,040,283	169,907	3,722,135
2010	1,376,146	1,129,183	1,040,600	171,571	3,717,500
2011	1,374,342	1,123,204	1,041,154	173,192	3,711,892
2012	1,373,351	1,115,879	1,039,761	174,719	3,703,710
2013	1,371,954	1,107,124	1,036,383	176,136	3,691,597

PacifiCorp - RAMPP-3 Low Sales Forecast

North Idaho (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	108,168	69,129	61,706	690	239,693
1994	104,292	69,409	55,002	826	229,529
1995	104,440	70,967	53,071	827	229,305
1996	104,320	71,977	51,825	827	228,949
1997	103,999	72,817	50,772	825	228,413
1998	102,345	73,063	48,861	1,130	225,399
1999	101,546	73,239	48,507	1,417	224,709
2000	101,273	73,666	48,937	1,713	225,589
2001	100,794	74,000	49,133	1,993	225,920
2002	99,924	74,213	49,187	2,256	225,580
2003	99,057	74,355	49,812	2,510	225,734
2004	98,034	74,383	50,644	2,750	225,811
2005	96,695	74,210	50,729	2,969	224,603
2006	95,158	73,841	50,989	3,170	223,158
2007	93,708	73,381	52,535	3,362	222,986
2008	93,644	72,648	52,845	3,542	222,679
2009	93,752	71,557	51,453	3,718	220,480
2010	93,737	70,189	50,795	3,893	218,614
2011	93,517	68,533	50,413	4,066	216,529
2012	93,222	66,560	50,427	4,237	214,446
2013	92,919	64,209	49,942	4,405	211,475

PacifiCorp - RAMPP-3 Low Sales Forecast

Montana (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	327,472	237,666	188,071	3,475	756,684
1994	313,603	233,326	190,673	4,213	741,815
1995	316,708	235,707	190,218	4,217	746,850
1996	320,643	238,525	189,853	4,219	753,240
1997	324,733	241,376	189,536	4,228	759,873
1998	319,848	242,941	189,168	5,479	757,436
1999	317,638	245,344	188,784	6,765	758,531
2000	315,259	248,485	188,500	8,092	760,336
2001	313,954	251,409	188,353	9,396	763,112
2002	311,853	253,624	188,282	10,636	764,395
2003	310,292	256,133	188,249	11,884	766,558
2004	308,777	258,689	188,338	13,119	768,923
2005	306,758	260,870	188,341	14,308	770,277
2006	304,675	262,957	188,523	15,462	771,617
2007	303,461	265,592	188,661	16,639	774,353
2008	303,726	267,279	189,077	17,751	777,833
2009	302,739	267,944	189,439	18,769	778,891
2010	301,694	268,337	189,868	19,752	779,651
2011	300,696	268,686	190,346	20,712	780,440
2012	299,658	268,952	190,897	21,653	781,160
2013	298,205	268,840	191,498	22,555	781,098

PacifiCorp - RAMPP-3 Low Sales Forecast

California (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	358,744	222,233	81,552	77,763	740,292
1994	350,728	219,234	59,968	79,985	709,915
1995	351,499	219,401	57,924	79,789	708,613
1996	351,327	220,918	55,608	79,608	707,461
1997	351,340	222,109	53,064	79,219	705,732
1998	345,055	226,292	50,932	79,460	701,739
1999	341,899	231,264	50,530	80,250	703,943
2000	340,924	237,032	51,531	81,471	710,958
2001	340,425	243,131	52,799	82,801	719,156
2002	340,539	249,234	54,014	84,179	727,966
2003	341,058	255,598	55,738	85,666	738,060
2004	341,596	262,058	57,239	87,136	748,029
2005	341,546	268,222	58,239	88,460	756,467
2006	341,252	274,266	59,163	89,726	764,407
2007	341,606	280,745	61,241	91,196	774,788
2008	345,479	286,439	61,480	92,710	786,108
2009	347,964	291,126	60,239	93,832	793,161
2010	350,234	295,457	59,208	94,900	799,799
2011	352,453	299,710	58,280	95,953	806,396
2012	354,615	303,911	57,564	97,007	813,097
2013	356,371	307,830	56,565	97,959	818,725

PacifiCorp - RAMPP-3 Low Sales Forecast

East Wyoming (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	714,351	863,674	4,185,312	21,343	5,784,680
1994	692,028	827,453	4,311,116	22,794	5,853,391
1995	687,739	822,366	4,281,046	22,762	5,813,913
1996	683,049	819,571	4,246,290	22,715	5,771,625
1997	677,796	817,709	4,187,495	22,662	5,705,662
1998	668,392	830,174	4,200,117	27,959	5,726,642
1999	661,289	844,169	4,198,721	33,182	5,737,361
2000	654,971	858,505	4,220,060	38,337	5,771,873
2001	647,428	872,971	4,270,785	43,400	5,834,584
2002	640,933	887,272	4,328,610	48,347	5,905,162
2003	635,502	901,964	4,383,056	53,252	5,973,774
2004	631,203	917,195	4,446,391	58,145	6,052,934
2005	627,362	932,284	4,452,433	62,960	6,075,039
2006	624,182	947,477	4,481,126	67,745	6,120,530
2007	621,984	963,221	4,484,059	72,517	6,141,781
2008	626,161	978,935	4,525,481	77,269	6,207,846
2009	630,247	994,461	4,528,375	81,951	6,235,034
2010	634,683	1,010,244	4,527,517	86,615	6,259,059
2011	639,374	1,026,278	4,516,807	91,270	6,273,729
2012	644,163	1,042,464	4,500,159	95,911	6,282,697
2013	648,962	1,058,733	4,470,618	100,541	6,278,854

PacifiCorp - RAMPP-3 Low Sales Forecast

South Idaho (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	564,306	209,116	1,621,730	389,196	2,784,348
1994	560,087	189,774	1,541,999	509,856	2,801,716
1995	565,256	189,895	1,537,286	508,226	2,800,663
1996	569,624	189,886	1,510,552	487,095	2,757,157
1997	573,472	190,039	1,477,988	472,455	2,713,954
1998	570,006	188,639	1,458,047	468,777	2,685,469
1999	566,365	187,566	1,443,033	465,628	2,662,592
2000	563,652	186,781	1,435,870	463,432	2,649,735
2001	561,126	186,136	1,435,463	461,974	2,644,699
2002	557,850	185,479	1,444,406	461,399	2,649,134
2003	555,176	184,931	1,460,793	461,665	2,662,565
2004	552,817	184,447	1,473,602	461,577	2,672,443
2005	549,869	183,746	1,481,556	460,867	2,676,038
2006	546,476	182,893	1,481,906	459,294	2,670,569
2007	543,369	182,133	1,484,902	458,017	2,668,421
2008	544,054	181,032	1,482,791	456,542	2,664,419
2009	543,421	179,464	1,474,482	454,225	2,651,592
2010	542,292	177,640	1,464,638	451,663	2,636,233
2011	540,813	175,651	1,453,909	448,951	2,619,324
2012	540,892	173,419	1,436,807	445,714	2,596,832
2013	541,236	170,876	1,413,619	441,843	2,567,574

PacifiCorp - RAMPP-3 Low Sales Forecast

West Wyoming (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	91,021	82,120	1,873,583	2,454	2,049,178
1994	89,729	78,038	1,877,907	3,562	2,049,236
1995	88,737	76,510	1,830,021	3,562	1,998,830
1996	88,514	74,899	1,808,998	3,562	1,975,973
1997	87,791	73,362	1,503,581	3,562	1,668,296
1998	86,475	72,380	1,321,624	3,888	1,484,367
1999	85,718	71,590	1,230,503	4,216	1,392,027
2000	85,034	70,783	1,223,333	4,533	1,383,683
2001	84,545	70,081	1,221,960	4,847	1,381,433
2002	84,252	69,463	1,220,656	5,160	1,379,531
2003	83,565	68,935	1,216,877	5,469	1,374,846
2004	82,993	68,374	1,214,919	5,767	1,372,053
2005	82,468	67,690	1,199,628	6,046	1,355,832
2006	82,143	66,971	1,190,211	6,316	1,345,641
2007	82,097	66,289	1,173,935	6,582	1,328,903
2008	83,005	65,579	1,166,805	6,838	1,322,227
2009	83,299	64,842	1,152,415	7,085	1,307,641
2010	83,771	64,081	1,139,113	7,325	1,294,290
2011	84,544	63,371	1,125,327	7,563	1,280,805
2012	85,451	62,613	1,111,768	7,793	1,267,625
2013	86,561	61,823	1,097,363	8,016	1,253,763

PacifiCorp - RAMPP-3 Low Sales Forecast

Utah (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	3,543,165	3,742,187	5,689,951	651,438	13,626,741
1994	3,270,006	3,705,446	5,599,542	660,149	13,235,143
1995	3,218,002	3,751,914	5,757,651	651,170	13,378,737
1996	3,170,087	3,797,754	5,861,489	656,211	13,485,541
1997	3,118,344	3,835,497	5,984,257	687,329	13,625,427
1998	3,091,307	3,859,332	6,069,091	705,688	13,725,418
1999	3,067,419	3,903,369	6,130,008	726,512	13,827,308
2000	3,045,310	3,955,024	6,191,113	748,359	13,939,806
2001	3,028,042	3,992,019	6,254,174	767,491	14,041,726
2002	3,017,361	4,035,288	6,319,084	787,917	14,159,650
2003	3,010,205	4,078,007	6,398,655	807,618	14,294,485
2004	3,008,144	4,120,226	6,470,080	826,930	14,425,380
2005	3,013,536	4,165,786	6,453,723	847,049	14,480,094
2006	3,026,871	4,217,231	6,426,486	867,857	14,538,445
2007	3,050,701	4,277,547	6,403,541	889,619	14,621,408
2008	3,110,790	4,326,713	6,376,049	910,701	14,724,253
2009	3,171,668	4,373,559	6,318,475	931,393	14,795,095
2010	3,237,396	4,423,059	6,256,183	952,285	14,868,923
2011	3,307,235	4,476,050	6,180,140	973,410	14,936,835
2012	3,376,713	4,527,292	6,083,835	994,236	14,982,076
2013	3,446,100	4,576,076	5,972,416	1,014,742	15,009,334

PacifiCorp - RAMPP-3 Low Sales Forecast

Total Company (Megawatt Hours)

	Residential	Commercial	Industrial	Other	Total
1993	11,883,491	10,073,854	18,673,669	1,599,735	42,230,749
1994	11,421,446	9,798,254	18,224,342	1,758,251	41,202,293
1995	11,354,616	9,833,749	18,238,994	1,741,945	41,169,304
1996	11,305,459	9,884,690	18,262,378	1,722,230	41,174,757
1997	11,271,887	9,937,931	17,997,343	1,737,835	40,944,996
1998	11,161,119	10,000,742	17,885,906	1,732,905	40,780,672
1999	11,083,460	10,102,634	17,864,777	1,731,180	40,782,051
2000	11,043,386	10,228,917	17,980,468	1,732,153	40,984,924
2001	11,008,150	10,344,773	18,136,952	1,732,868	41,222,743
2002	10,973,252	10,463,106	18,305,520	1,734,786	41,476,664
2003	10,949,385	10,584,799	18,502,332	1,737,799	41,774,315
2004	10,931,445	10,705,523	18,686,228	1,740,183	42,063,379
2005	10,908,342	10,817,813	18,674,151	1,741,189	42,141,495
2006	10,889,782	10,929,947	18,670,582	1,741,562	42,231,873
2007	10,893,914	11,059,680	18,669,694	1,743,503	42,366,791
2008	10,992,018	11,161,327	18,670,868	1,744,630	42,568,843
2009	11,069,462	11,238,395	18,557,707	1,743,569	42,609,133
2010	11,149,213	11,310,547	18,443,958	1,742,350	42,646,068
2011	11,231,626	11,383,435	18,306,153	1,741,104	42,662,318
2012	11,313,333	11,449,780	18,129,369	1,738,997	42,631,479
2013	11,388,634	11,505,119	17,902,071	1,735,640	42,531,464

Appendix 4
Monthly Peak & Energy Forecasts by Zone.

Oregon (Megawatts)

Year		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		3018	2876	2651	2389	2139	2139	2182	2243	2090	2340	2564	2938
	ENERGY	1785	2021	1984	1805	1655	1672	1620	1698	1706	1662	1680	1857	2073
1995	PEAK		3187	3036	2799	2523	2259	2259	2294	2369	2207	2471	2708	3102
	ENERGY	1885	2134	2095	1906	1747	1765	1710	1793	1801	1755	1774	1961	2189
1996	PEAK		3335	3178	2930	2640	2364	2364	2389	2479	2310	2586	2834	3247
	ENERGY	1979	2234	2271	1995	1829	1848	1791	1877	1885	1837	1856	2052	2291
1997	PEAK		3482	3318	3059	2757	2468	2469	2518	2589	2412	2700	2959	3390
	ENERGY	2060	2332	2289	2082	1909	1929	1869	1959	1968	1918	1938	2142	2392
1998	PEAK		3602	3432	3164	2851	2553	2553	2604	2678	2495	2793	3061	3506
	ENERGY	2131	2412	2368	2154	1975	1996	1933	2027	2036	1984	2005	2216	2474
1999	PEAK		3725	3549	3272	2949	2640	2640	2682	2769	2580	2888	3165	3626
	ENERGY	2203	2494	2449	2227	2042	2063	1999	2096	2105	2052	2073	2292	2558
2000	PEAK		3864	3682	3394	3059	2739	2739	2768	2873	2677	2996	3284	3762
	ENERGY	2293	2588	2631	2311	2119	2141	2075	2174	2184	2129	2151	2378	2654
2001	PEAK		4013	3843	3525	3177	2844	2868	2901	2983	2779	3111	3410	3906
	ENERGY	2374	2687	2638	2400	2200	2223	2154	2258	2268	2210	2233	2469	2756
2002	PEAK		4162	3965	3656	3295	2950	2950	3016	3094	2883	3226	3536	4051
	ENERGY	2462	2787	2736	2489	2282	2306	2234	2342	2352	2292	2316	2560	2859
2003	PEAK		4327	4123	3801	3425	3067	3067	3128	3217	2997	3355	3677	4212
	ENERGY	2560	2898	2845	2587	2372	2397	2322	2435	2446	2383	2408	2662	2972
2004	PEAK		4492	4280	3946	3556	3184	3184	3218	3339	3111	3482	3817	4372
	ENERGY	2665	3008	3059	2686	2463	2488	2411	2527	2539	2474	2501	2763	3085
2005	PEAK		4644	4425	4079	3676	3292	3292	3357	3452	3217	3600	3946	4521
	ENERGY	2747	3110	3053	2777	2546	2573	2493	2613	2625	2558	2585	2857	3190
2006	PEAK		4794	4590	4211	3795	3398	3398	3452	3564	3320	3716	4073	4666
	ENERGY	2836	3210	3151	2867	2628	2656	2573	2697	2709	2640	2668	2949	3293
2007	PEAK		4968	4757	4364	3933	3521	3551	3592	3693	3441	3851	4221	4836
	ENERGY	2939	3327	3266	2971	2724	2752	2666	2795	2808	2736	2765	3056	3412
2008	PEAK		5145	4902	4519	4073	3646	3647	3685	3824	3563	3988	4371	5008
	ENERGY	3053	3445	3503	3076	2821	2850	2762	2895	2908	2834	2864	3165	3534
2009	PEAK		5297	5047	4653	4193	3755	3755	3830	3938	3669	4107	4501	5157
	ENERGY	3134	3547	3482	3168	2904	2935	2843	2980	2994	2918	2948	3259	3639
2010	PEAK		5274	5191	4786	4313	3862	3862	3923	4050	3774	4224	4629	5304
	ENERGY	3223	3648	3582	3258	2987	3018	2924	3065	3079	3001	3032	3352	3743
2011	PEAK		5421	5336	4919	4433	3969	3970	4032	4163	3878	4341	4758	5451
	ENERGY	3313	3750	3681	3348	3070	3102	3005	3151	3165	3084	3117	3445	3846
2012	PEAK		5568	5481	5053	4554	4077	4078	4121	4276	3984	4460	4888	5600
	ENERGY	3413	3852	3917	3440	3154	3187	3088	3237	3251	3168	3202	3539	3951
2013	PEAK		5706	5617	5178	4666	4178	4179	4272	4382	4083	4570	5009	5738
	ENERGY	3487	3947	3875	3525	3232	3266	3164	3317	3332	3247	3281	3627	4049

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Washington(Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		801	850	709	648	591	587	683	735	719	694	745	833
	ENERGY	515	589	581	500	454	462	443	509	491	514	507	526	607
1995	PEAK		848	899	750	685	625	621	709	777	760	734	787	881
	ENERGY	545	622	614	529	480	489	469	538	519	544	536	556	642
1996	PEAK		886	942	787	718	655	651	809	815	797	770	826	924
	ENERGY	573	653	667	554	503	512	491	565	545	570	562	583	673
1997	PEAK		906	982	820	749	683	678	795	849	831	803	861	963
	ENERGY	595	680	672	578	524	534	512	589	568	595	586	608	702
1998	PEAK		934	1013	845	772	704	700	815	876	857	828	888	993
	ENERGY	614	702	693	596	541	551	528	607	585	613	604	627	723
1999	PEAK		967	1048	875	799	729	724	827	907	887	857	919	1028
	ENERGY	635	726	717	617	560	570	547	628	606	634	625	649	749
2000	PEAK		1025	1087	908	829	756	751	933	940	920	888	953	1066
	ENERGY	661	753	770	640	580	591	567	652	628	658	648	673	776
2001	PEAK		1042	1161	943	861	785	821	908	976	955	923	990	1107
	ENERGY	684	782	772	664	603	614	589	677	652	683	673	699	806
2002	PEAK		1081	1172	978	893	815	809	956	1013	991	957	1027	1149
	ENERGY	710	812	801	689	625	637	611	702	677	709	699	725	837
2003	PEAK		1122	1217	1016	928	846	841	985	1052	1030	994	1067	1193
	ENERGY	738	843	832	716	650	662	635	729	703	737	726	753	869
2004	PEAK		1164	1262	1053	962	878	872	1083	1091	1068	1031	1106	1238
	ENERGY	767	874	894	743	674	686	658	756	729	764	752	781	901
2005	PEAK		1227	1304	1089	994	907	901	1049	1128	1103	1066	1143	1279
	ENERGY	790	903	892	767	696	709	680	782	754	789	778	807	931
2006	PEAK		1242	1230	1124	1026	936	930	1062	1164	1139	1100	1180	1320
	ENERGY	816	933	921	792	719	732	702	807	778	815	803	833	961
2007	PEAK		1278	1430	1161	1060	967	1006	1119	1203	1177	1136	1219	1364
	ENERGY	843	963	951	818	742	756	725	833	804	842	829	861	993
2008	PEAK		1321	1437	1200	1096	1000	993	1234	1243	1216	1175	1260	1410
	ENERGY	874	996	1018	846	767	782	750	861	830	870	857	890	1026
2009	PEAK		1365	1481	1237	1129	1030	1023	1192	1281	1253	1210	1298	1453
	ENERGY	898	1026	1013	871	791	805	773	888	856	896	883	917	1058
2010	PEAK		1526	1525	1273	1163	1061	1053	1203	1319	1290	1246	1337	1496
	ENERGY	924	1056	1043	897	814	829	796	914	881	923	909	944	1089
2011	PEAK		1571	1570	1310	1197	1091	1084	1239	1357	1328	1282	1375	1539
	ENERGY	951	1087	1073	923	838	853	819	941	907	950	936	971	1121
2012	PEAK		1614	1613	1346	1230	1122	1114	1385	1395	1364	1318	1413	1582
	ENERGY	980	1117	1142	949	861	877	841	967	932	976	961	998	1152
2013	PEAK		1655	1654	1381	1261	1150	1143	1350	1431	1399	1352	1450	1622
	ENERGY	1003	1146	1131	973	883	899	863	991	956	1001	986	1024	1181

North Idaho (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		64	66	56	48	43	40	35	41	40	45	52	59
	ENERGY	34	42	42	38	34	29	28	28	28	29	30	37	40
1995	PEAK		68	70	59	51	46	42	38	44	42	48	55	63
	ENERGY	36	45	45	40	36	31	30	30	30	31	32	39	42
1996	PEAK		72	74	62	54	49	45	46	46	45	50	58	66
	ENERGY	38	48	49	43	38	33	31	31	31	33	34	41	44
1997	PEAK		77	77	66	57	51	47	41	48	47	53	61	69
	ENERGY	40	50	50	45	40	34	33	33	33	34	36	43	47
1998	PEAK		78	80	68	59	53	49	43	50	49	55	63	72
	ENERGY	41	52	52	46	41	35	34	34	34	35	37	45	48
1999	PEAK		80	83	70	61	55	50	45	52	50	57	65	74
	ENERGY	43	54	54	48	42	37	35	35	35	37	39	47	50
2000	PEAK		84	86	73	63	57	52	54	54	52	59	68	77
	ENERGY	45	56	58	50	44	38	37	37	37	38	40	48	52
2001	PEAK		89	78	76	66	59	49	49	56	55	61	71	81
	ENERGY	46	58	58	52	46	40	38	38	38	40	42	50	54
2002	PEAK		91	93	79	68	62	57	51	58	57	64	74	84
	ENERGY	48	60	61	54	48	41	40	40	40	41	43	52	56
2003	PEAK		93	97	83	71	64	59	53	61	59	67	77	87
	ENERGY	50	63	63	56	50	43	41	41	41	43	45	55	59
2004	PEAK		101	101	86	74	67	62	63	63	62	69	80	91
	ENERGY	52	66	68	59	52	45	43	43	43	45	47	57	61
2005	PEAK		104	105	89	77	70	64	57	66	64	72	83	94
	ENERGY	54	68	68	61	54	47	45	45	45	47	49	59	63
2006	PEAK		107	107	92	80	72	66	58	68	66	74	86	98
	ENERGY	56	71	71	63	56	48	46	46	46	48	51	61	66
2007	PEAK		113	112	96	83	75	62	61	71	69	78	90	102
	ENERGY	58	74	74	66	58	50	48	48	48	50	53	64	69
2008	PEAK		117	118	100	87	78	72	74	74	72	81	93	106
	ENERGY	61	77	79	69	61	52	50	50	50	52	55	67	71
2009	PEAK		119	122	104	90	81	74	66	76	74	84	96	110
	ENERGY	63	79	79	71	62	54	52	52	52	54	57	69	74
2010	PEAK		127	126	107	93	84	77	67	79	77	86	99	113
	ENERGY	65	82	82	73	65	56	54	54	54	56	59	71	76
2011	PEAK		131	131	111	96	86	79	70	82	79	89	103	117
	ENERGY	67	85	85	76	67	58	56	56	56	58	61	73	79
2012	PEAK		136	135	115	99	90	82	85	85	82	93	107	121
	ENERGY	70	88	91	78	69	60	58	58	58	60	63	76	82
2013	PEAK		140	140	119	103	93	85	75	87	85	96	110	126
	ENERGY	72	91	91	81	72	62	60	60	60	62	65	79	85

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Montana (Megawatts)

Year		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		164	163	152	140	124	118	109	123	129	135	144	161
	ENERGY	105	125	123	116	103	96	93	90	90	94	100	113	117
1995	PEAK		175	172	161	148	131	125	113	130	136	142	152	170
	ENERGY	111	132	129	122	109	101	98	95	95	99	106	119	123
1996	PEAK		184	181	169	156	137	131	135	136	143	149	160	179
	ENERGY	117	139	141	129	114	106	103	100	100	105	111	125	130
1997	PEAK		193	190	177	163	144	137	125	143	150	157	167	188
	ENERGY	122	145	143	135	120	112	108	104	104	110	117	131	136
1998	PEAK		200	196	183	169	149	142	129	148	155	162	173	194
	ENERGY	126	150	147	139	124	115	112	108	108	113	121	136	141
1999	PEAK		204	203	190	175	154	147	132	153	160	168	179	201
	ENERGY	130	155	153	144	128	119	116	112	112	117	125	140	145
2000	PEAK		211	211	197	182	160	152	157	159	166	174	186	209
	ENERGY	136	161	164	150	133	124	120	116	116	122	130	146	151
2001	PEAK		222	218	204	188	166	144	145	165	172	180	193	216
	ENERGY	140	167	164	155	138	129	125	120	120	126	134	151	157
2002	PEAK		231	226	212	195	172	164	150	171	179	187	200	224
	ENERGY	146	173	170	161	143	133	129	125	125	131	139	157	162
2003	PEAK		239	235	220	203	179	170	155	177	185	194	207	233
	ENERGY	151	180	177	167	148	138	134	130	130	136	145	163	168
2004	PEAK		249	244	228	210	185	177	182	184	193	202	215	242
	ENERGY	157	187	190	174	154	144	139	134	134	141	150	169	175
2005	PEAK		258	253	237	218	192	183	168	191	200	209	223	251
	ENERGY	163	194	190	180	160	149	144	139	139	146	156	175	181
2006	PEAK		267	247	245	226	199	190	172	198	207	217	231	260
	ENERGY	169	201	197	186	166	154	150	144	144	152	161	181	188
2007	PEAK		277	272	255	235	207	180	181	205	215	225	240	270
	ENERGY	175	208	205	193	172	160	155	150	150	157	168	188	195
2008	PEAK		288	283	265	244	215	205	211	213	223	234	250	280
	ENERGY	182	217	220	201	179	166	161	156	156	163	174	196	203
2009	PEAK		298	293	274	252	222	212	192	221	231	242	258	290
	ENERGY	188	224	220	208	185	172	167	161	161	169	180	203	210
2010	PEAK		307	303	283	261	230	219	198	228	239	250	267	300
	ENERGY	195	232	228	215	191	178	173	167	167	175	186	209	217
2011	PEAK		318	313	293	270	238	227	206	236	247	259	276	310
	ENERGY	201	240	235	223	198	184	179	173	173	181	193	217	224
2012	PEAK		329	324	303	279	246	235	241	244	256	268	286	321
	ENERGY	209	248	252	230	205	191	185	179	179	187	200	224	232
2013	PEAK		340	335	313	289	254	242	220	253	264	277	295	332
	ENERGY	215	256	252	238	211	197	191	184	184	194	206	232	240

East Wyoming (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		1022	1036	1046	999	1027	1023	995	1025	1020	1041	1057	1067
	ENERGY	931	945	935	935	924	919	921	920	922	929	937	943	947
1995	PEAK		1060	1076	1087	1037	1067	1063	1056	1065	1060	1081	1098	1108
	ENERGY	968	982	971	971	959	954	957	955	957	965	974	980	984
1996	PEAK		1095	1114	1125	1074	1104	1100	1099	1102	1097	1119	1136	1147
	ENERGY	1004	1017	1041	1005	993	988	990	989	991	999	1008	1014	1018
1997	PEAK		1127	1148	1159	1107	1138	1134	1108	1136	1130	1153	1171	1182
	ENERGY	1032	1048	1036	1036	1023	1018	1020	1019	1021	1029	1039	1045	1049
1998	PEAK		1163	1183	1195	1140	1173	1169	1142	1170	1165	1189	1207	1219
	ENERGY	1064	1080	1068	1068	1055	1049	1051	1050	1053	1061	1070	1077	1081
1999	PEAK		1194	1216	1228	1172	1205	1201	1189	1203	1197	1222	1240	1252
	ENERGY	1093	1110	1097	1097	1084	1078	1081	1079	1082	1090	1100	1107	1111
2000	PEAK		1229	1253	1265	1207	1241	1237	1235	1239	1233	1258	1278	1290
	ENERGY	1129	1143	1171	1130	1117	1111	1113	1112	1114	1123	1133	1140	1145
2001	PEAK		1270	1269	1307	1247	1283	1246	1242	1280	1274	1300	1320	1333
	ENERGY	1163	1181	1168	1168	1154	1148	1150	1149	1151	1160	1171	1178	1183
2002	PEAK		1314	1338	1352	1290	1326	1322	1286	1324	1317	1345	1365	1378
	ENERGY	1203	1221	1207	1208	1193	1187	1189	1188	1190	1200	1211	1218	1223
2003	PEAK		1359	1384	1398	1334	1371	1367	1331	1369	1362	1390	1412	1425
	ENERGY	1244	1263	1249	1249	1234	1227	1230	1228	1231	1241	1252	1260	1265
2004	PEAK		1406	1432	1446	1380	1419	1414	1412	1416	1409	1438	1460	1474
	ENERGY	1290	1306	1338	1292	1276	1269	1272	1271	1274	1284	1295	1303	1308
2005	PEAK		1442	1470	1484	1416	1456	1452	1411	1454	1447	1476	1499	1513
	ENERGY	1321	1341	1326	1326	1310	1303	1306	1304	1307	1318	1329	1338	1343
2006	PEAK		1483	1493	1527	1457	1498	1493	1478	1495	1488	1519	1542	1557
	ENERGY	1359	1379	1364	1364	1348	1340	1343	1342	1345	1355	1367	1376	1381
2007	PEAK		1517	1519	1567	1496	1538	1489	1493	1535	1528	1559	1583	1598
	ENERGY	1395	1416	1400	1400	1383	1376	1379	1377	1380	1391	1404	1412	1418
2008	PEAK		1566	1601	1616	1543	1586	1581	1578	1583	1576	1608	1633	1648
	ENERGY	1443	1461	1496	1444	1427	1419	1422	1421	1424	1435	1448	1457	1463
2009	PEAK		1612	1643	1659	1584	1628	1623	1580	1625	1617	1651	1676	1692
	ENERGY	1477	1499	1482	1483	1465	1457	1460	1458	1462	1473	1486	1496	1502
2010	PEAK		1711	1686	1703	1625	1671	1665	1649	1668	1660	1694	1720	1736
	ENERGY	1516	1539	1521	1522	1503	1495	1498	1497	1500	1512	1525	1535	1541
2011	PEAK		1754	1729	1745	1666	1713	1707	1695	1710	1701	1736	1763	1780
	ENERGY	1554	1577	1559	1560	1541	1533	1536	1534	1537	1550	1563	1573	1580
2012	PEAK		1796	1770	1787	1706	1754	1748	1745	1751	1742	1778	1805	1822
	ENERGY	1595	1615	1654	1597	1577	1569	1573	1571	1574	1587	1601	1611	1617
2013	PEAK		1835	1809	1826	1743	1792	1786	1746	1789	1780	1817	1845	1862
	ENERGY	1626	1650	1632	1632	1612	1603	1607	1605	1609	1621	1636	1646	1653

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California (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		190	176	158	147	146	152	169	155	117	133	150	180
	ENERGY	106	122	106	101	98	104	111	121	108	94	91	96	118
1995	PEAK		202	187	168	157	155	162	173	165	125	141	159	192
	ENERGY	113	130	113	107	105	110	118	129	115	100	96	102	125
1996	PEAK		213	197	177	165	163	171	187	173	131	149	168	202
	ENERGY	119	137	123	113	110	116	125	136	121	105	102	108	132
1997	PEAK		223	206	185	172	171	178	198	181	137	155	175	211
	ENERGY	124	143	124	118	115	121	130	142	126	110	106	113	138
1998	PEAK		230	213	191	178	177	185	205	188	142	161	181	219
	ENERGY	128	148	128	122	119	126	135	147	131	114	110	117	143
1999	PEAK		239	220	198	185	183	191	207	194	147	166	188	226
	ENERGY	133	153	133	126	123	130	140	152	136	118	113	121	148
2000	PEAK		248	229	206	192	190	199	218	202	153	173	195	235
	ENERGY	139	159	143	131	129	135	145	158	141	123	118	125	154
2001	PEAK		258	255	214	200	198	220	230	210	159	180	203	245
	ENERGY	144	166	144	136	133	141	151	165	147	128	123	131	160
2002	PEAK		269	248	223	208	206	215	239	219	166	187	211	255
	ENERGY	149	172	150	142	139	146	157	171	153	133	128	136	166
2003	PEAK		280	258	232	217	215	224	249	228	173	195	220	266
	ENERGY	156	180	156	148	145	153	164	179	159	138	133	142	173
2004	PEAK		291	269	242	225	223	233	256	237	180	203	229	276
	ENERGY	163	187	168	154	151	159	170	186	166	144	139	147	180
2005	PEAK		303	279	251	234	232	242	269	246	187	211	238	287
	ENERGY	168	194	168	160	156	165	177	193	172	150	144	153	187
2006	PEAK		314	322	260	243	241	251	272	255	194	219	247	298
	ENERGY	175	201	175	166	162	171	184	200	178	155	149	159	194
2007	PEAK		327	322	271	253	251	282	291	266	202	228	257	310
	ENERGY	182	210	182	173	169	178	191	208	186	161	155	165	202
2008	PEAK		340	314	282	263	261	273	299	277	210	237	268	323
	ENERGY	190	218	197	180	176	186	199	217	193	168	162	172	211
2009	PEAK		352	325	292	273	270	282	313	287	217	246	277	334
	ENERGY	196	226	196	186	182	192	206	225	200	174	168	178	218
2010	PEAK		349	337	302	282	280	292	316	297	225	254	287	346
	ENERGY	203	234	203	193	188	199	213	232	207	180	173	184	226
2011	PEAK		361	348	313	292	289	302	327	307	232	263	297	358
	ENERGY	210	242	210	199	195	206	221	240	214	186	179	191	233
2012	PEAK		374	361	324	302	299	313	343	318	241	272	307	370
	ENERGY	218	251	225	206	202	213	228	249	222	193	186	197	242
2013	PEAK		387	373	335	312	310	323	359	329	249	282	318	383
	ENERGY	225	259	225	213	209	220	236	258	229	200	192	204	250

Utah (Megawatts)

Year	Type	Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		2185	2108	2033	1962	2016	2380	2603	2425	2178	2118	2161	2182
	ENERGY	1681	1726	1697	1631	1579	1583	1680	1762	1736	1675	1680	1704	1724
1995	PEAK		2379	2249	2169	2093	2151	2540	2799	2588	2324	2259	2305	2328
	ENERGY	1794	1842	1810	1741	1684	1689	1792	1880	1852	1787	1792	1818	1839
1996	PEAK		2548	2405	2319	2239	2300	2716	2871	2767	2485	2416	2465	2490
	ENERGY	1924	1969	2005	1861	1801	1806	1917	2010	1981	1911	1917	1944	1967
1997	PEAK		2709	2564	2473	2387	2452	2896	3167	2950	2650	2576	2628	2655
	ENERGY	2045	2100	2064	1984	1920	1926	2043	2143	2112	2037	2043	2073	2097
1998	PEAK		2856	2701	2604	2514	2583	3050	3336	3108	2791	2713	2768	2796
	ENERGY	2154	2212	2174	2090	2023	2028	2152	2257	2224	2146	2152	2184	2209
1999	PEAK		2992	2832	2731	2636	2708	3198	3525	3259	2926	2845	2903	2932
	ENERGY	2259	2319	2280	2192	2121	2127	2257	2367	2333	2250	2257	2290	2316
2000	PEAK		3073	2965	2859	2759	2835	3348	3539	3411	3063	2978	3039	3069
	ENERGY	2371	2427	2471	2294	2220	2226	2362	2478	2442	2355	2362	2397	2424
2001	PEAK		3207	3166	2985	2881	2960	3462	3823	3562	3199	3110	3173	3205
	ENERGY	2469	2535	2492	2396	2318	2325	2467	2587	2550	2460	2467	2503	2532
2002	PEAK		3346	3231	3115	3007	3089	3648	3990	3717	3338	3246	3312	3345
	ENERGY	2577	2646	2601	2500	2419	2427	2574	2700	2661	2567	2575	2612	2642
2003	PEAK		3501	3377	3257	3143	3229	3814	4171	3886	3490	3393	3462	3496
	ENERGY	2694	2765	2718	2614	2529	2536	2691	2822	2782	2683	2691	2730	2762
2004	PEAK		3724	3526	3400	3281	3371	3981	4209	4056	3643	3542	3614	3650
	ENERGY	2820	2887	2939	2728	2640	2647	2809	2946	2904	2801	2809	2850	2883
2005	PEAK		3792	3658	3527	3404	3498	4131	4518	4209	3779	3675	3749	3787
	ENERGY	2918	2995	2944	2831	2739	2747	2915	3057	3013	2906	2915	2957	2991
2006	PEAK		3927	3977	3656	3529	3625	4281	4718	4362	3917	3808	3886	3925
	ENERGY	3024	3104	3052	2934	2839	2847	3021	3168	3122	3012	3021	3065	3100
2007	PEAK		4074	4022	3794	3662	3763	4400	4861	4527	4066	3953	4033	4074
	ENERGY	3139	3222	3167	3045	2947	2955	3136	3289	3241	3126	3136	3181	3218
2008	PEAK		4232	4088	3941	3804	3908	4615	4879	4703	4223	4106	4189	4231
	ENERGY	3269	3347	3408	3163	3061	3069	3257	3416	3367	3247	3256	3304	3342
2009	PEAK		4387	4232	4081	3939	4047	4779	5227	4869	4373	4251	4338	4381
	ENERGY	3376	3465	3407	3275	3169	3178	3372	3537	3486	3362	3372	3422	3461
2010	PEAK		4417	4383	4226	4079	4191	4949	5454	5043	4528	4403	4492	4537
	ENERGY	3496	3589	3528	3392	3282	3292	3492	3663	3610	3482	3492	3543	3584
2011	PEAK		4570	4535	4373	4221	4336	5121	5644	5218	4686	4556	4648	4695
	ENERGY	3617	3713	3650	3509	3396	3406	3614	3790	3735	3603	3614	3666	3708
2012	PEAK		4717	4681	4514	4357	4476	5286	5588	5386	4836	4702	4798	4846
	ENERGY	3744	3833	3902	3622	3505	3515	3730	3912	3855	3719	3730	3784	3828
2013	PEAK		4858	4821	4648	4487	4610	5444	5953	5546	4981	4843	4941	4991
	ENERGY	3845	3947	3880	3731	3610	3620	3841	4029	3970	3830	3841	3897	3942

PacifiCorp - RAMPP-3 High Forecast: Firm Load

South Idaho (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		242	260	237	224	256	445	488	430	332	259	233	216
	ENERGY	239	199	200	182	168	204	339	419	343	248	208	190	162
1995	PEAK		252	273	248	235	268	466	508	451	348	272	244	226
	ENERGY	250	208	209	191	176	214	355	438	359	260	218	199	170
1996	PEAK		266	283	258	244	279	484	547	468	362	282	253	235
	ENERGY	260	216	225	198	183	222	369	456	373	270	226	207	176
1997	PEAK		275	295	269	255	291	505	554	488	377	295	264	246
	ENERGY	271	226	227	207	191	232	385	475	390	282	236	216	184
1998	PEAK		285	305	278	263	300	522	572	505	390	305	273	254
	ENERGY	280	233	234	214	198	240	398	491	403	292	244	223	190
1999	PEAK		295	317	289	273	312	543	591	525	405	316	284	264
	ENERGY	291	242	243	222	205	249	414	511	418	303	253	232	197
2000	PEAK		307	331	301	285	326	566	640	547	423	330	296	275
	ENERGY	304	253	263	232	214	259	431	533	437	316	264	242	206
2001	PEAK		326	333	315	298	341	614	649	572	442	345	310	288
	ENERGY	318	264	266	242	224	271	451	557	457	330	276	253	215
2002	PEAK		339	363	330	313	357	620	679	600	463	362	325	302
	ENERGY	333	277	278	254	235	284	473	584	478	346	290	265	226
2003	PEAK		356	383	348	330	376	654	716	632	488	381	342	318
	ENERGY	351	292	293	268	248	300	498	615	504	365	305	279	238
2004	PEAK		373	402	366	346	396	688	777	665	513	401	360	334
	ENERGY	370	307	319	281	260	315	524	647	530	384	321	294	250
2005	PEAK		388	418	380	360	411	715	784	691	534	417	374	347
	ENERGY	384	319	321	293	271	328	545	673	551	399	334	305	260
2006	PEAK		393	384	394	373	426	741	809	716	553	432	388	360
	ENERGY	398	331	332	303	281	340	565	697	571	414	346	317	270
2007	PEAK		423	433	410	388	444	801	844	745	576	450	403	375
	ENERGY	414	344	346	316	292	353	588	725	595	430	360	329	280
2008	PEAK		438	470	427	405	462	803	908	776	599	468	420	390
	ENERGY	432	358	373	329	304	368	612	755	619	448	375	343	292
2009	PEAK		452	487	443	420	479	833	912	805	622	486	436	405
	ENERGY	447	372	373	341	315	382	635	784	642	465	389	356	303
2010	PEAK		509	505	460	435	497	864	943	835	645	504	452	420
	ENERGY	464	386	388	354	327	396	658	813	666	482	403	369	314
2011	PEAK		528	524	477	452	516	897	978	867	669	523	469	436
	ENERGY	481	400	402	367	339	411	683	844	691	500	419	383	326
2012	PEAK		546	542	493	467	533	927	1048	896	692	541	485	451
	ENERGY	499	414	431	380	351	425	707	873	715	517	433	396	337
2013	PEAK		563	559	508	481	550	956	1047	924	714	557	500	464
	ENERGY	513	427	429	391	362	438	728	899	737	533	446	408	348

West Wyoming (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		288	304	291	297	288	282	286	285	270	284	282	297
	ENERGY	260	273	275	268	267	259	256	256	256	253	248	252	256
1995	PEAK		293	312	299	305	296	289	287	293	278	292	290	306
	ENERGY	267	280	282	276	275	266	263	263	263	260	254	259	263
1996	PEAK		315	323	309	316	306	299	304	303	287	302	300	316
	ENERGY	277	290	302	285	284	275	272	272	272	269	263	268	272
1997	PEAK		331	348	334	341	331	323	327	327	310	325	324	341
	ENERGY	298	313	315	308	307	296	294	294	294	290	284	289	294
1998	PEAK		341	360	345	352	342	334	339	338	320	336	334	352
	ENERGY	308	323	325	318	317	306	304	304	304	300	293	298	304
1999	PEAK		345	368	352	359	349	341	338	345	327	343	341	360
	ENERGY	314	330	332	325	323	313	310	310	310	306	300	305	310
2000	PEAK		353	376	360	368	357	348	354	353	334	351	349	368
	ENERGY	323	337	352	332	331	320	317	317	317	313	306	312	317
2001	PEAK		376	361	369	377	366	347	363	362	343	360	358	377
	ENERGY	330	346	349	340	339	328	325	325	325	321	314	320	325
2002	PEAK		376	395	378	386	375	366	371	371	351	369	367	387
	ENERGY	338	354	357	349	348	336	333	333	333	329	322	328	333
2003	PEAK		380	404	387	395	383	374	381	379	359	377	375	395
	ENERGY	346	362	365	357	356	344	341	341	341	337	329	335	341
2004	PEAK		392	413	396	404	392	383	389	388	367	386	384	404
	ENERGY	354	371	387	365	364	352	349	349	349	344	337	343	349
2005	PEAK		393	419	401	410	398	388	394	393	373	391	389	410
	ENERGY	358	376	379	370	369	357	354	354	354	349	342	347	354
2006	PEAK		400	397	408	417	405	395	390	400	379	398	396	417
	ENERGY	365	382	385	376	375	363	360	360	360	355	348	353	360
2007	PEAK		410	405	413	422	410	393	406	405	384	403	401	423
	ENERGY	369	387	390	381	380	367	364	364	364	360	352	358	364
2008	PEAK		419	440	421	430	417	407	414	412	391	411	408	430
	ENERGY	377	394	412	388	387	374	371	371	371	366	358	365	371
2009	PEAK		423	445	426	435	422	412	417	417	396	416	413	436
	ENERGY	381	399	402	393	392	379	376	375	375	371	363	369	375
2010	PEAK		452	450	431	440	427	417	414	422	400	421	418	441
	ENERGY	385	404	407	398	396	383	380	380	380	375	367	373	380
2011	PEAK		456	455	436	445	432	422	418	427	405	425	422	445
	ENERGY	389	408	411	402	400	387	384	384	384	379	371	377	384
2012	PEAK		460	459	440	449	436	426	432	431	408	429	426	450
	ENERGY	394	412	430	406	404	391	388	387	387	383	374	381	387
2013	PEAK		464	463	443	452	439	429	435	434	411	432	430	453
	ENERGY	396	415	418	409	407	394	390	390	390	385	377	384	390

PacifiCorp - RAMPP-3 High Forecast: Firm Load

Total Company (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		7974	7838	7333	6854	6630	7167	7550	7462	6895	7048	7387	7935
	ENERGY	5656	6042	5942	5576	5281	5327	5491	5802	5680	5499	5480	5718	6043
1995	PEAK		8463	8274	7740	7234	6997	7567	7975	7880	7279	7440	7798	8377
	ENERGY	5967	6375	6269	5882	5571	5619	5793	6122	5992	5802	5782	6033	6377
1996	PEAK		8914	8697	8136	7605	7358	7961	8387	8290	7657	7824	8200	8807
	ENERGY	6291	6701	6825	6183	5855	5906	6089	6435	6300	6099	6079	6343	6703
1997	PEAK		9322	9130	8541	7986	7729	8367	8833	8712	8044	8217	8611	9245
	ENERGY	6588	7036	6919	6493	6150	6203	6396	6759	6616	6405	6384	6660	7038
1998	PEAK		9689	9484	8874	8299	8034	8703	9186	9060	8363	8540	8949	9605
	ENERGY	6846	7311	7189	6747	6391	6446	6648	7025	6877	6658	6636	6922	7313
1999	PEAK		10040	9837	9205	8609	8336	9036	9537	9405	8680	8862	9284	9963
	ENERGY	7102	7583	7457	6998	6629	6687	6898	7290	7136	6908	6885	7181	7585
2000	PEAK		10394	10220	9563	8944	8661	9393	9899	9777	9021	9208	9647	10351
	ENERGY	7400	7878	8023	7270	6886	6946	7168	7576	7416	7177	7153	7461	7879
2001	PEAK		10802	10683	9938	9295	9002	9771	10309	10167	9379	9571	10027	10758
	ENERGY	7669	8187	8050	7554	7156	7218	7450	7876	7709	7459	7434	7753	8189
2002	PEAK		11208	11032	10323	9655	9352	10152	10738	10566	9745	9943	10416	11174
	ENERGY	7966	8503	8361	7846	7432	7498	7741	8185	8009	7749	7722	8053	8505
2003	PEAK		11658	11479	10740	10045	9732	10571	11167	11001	10143	10347	10838	11626
	ENERGY	8289	8846	8698	8162	7731	7800	8057	8520	8336	8063	8035	8378	8847
2004	PEAK		12192	11929	11162	10440	10115	10993	11589	11440	10546	10755	11265	12082
	ENERGY	8640	9193	9362	8482	8034	8106	8377	8860	8667	8381	8351	8708	9193
2005	PEAK		12550	12332	11538	10791	10456	11368	12007	11829	10903	11117	11645	12489
	ENERGY	8904	9501	9341	8765	8301	8377	8658	9159	8959	8662	8630	8999	9502
2006	PEAK		12926	12747	11917	11145	10800	11746	12411	12222	11263	11484	12029	12901
	ENERGY	9196	9812	9648	9052	8573	8652	8943	9462	9254	8946	8914	9295	9813
2007	PEAK		13388	13271	12332	11532	11175	12165	12848	12651	11656	11883	12447	13350
	ENERGY	9514	10151	9981	9363	8867	8949	9253	9791	9575	9255	9221	9615	10152
2008	PEAK		13866	13652	12771	11943	11574	12596	13282	13106	12073	12308	12892	13827
	ENERGY	9881	10513	10705	9696	9181	9267	9585	10142	9919	9584	9550	9958	10513
2009	PEAK		14306	14076	13169	12314	11935	12994	13728	13520	12452	12692	13294	14257
	ENERGY	10159	10838	10655	9996	9465	9554	9883	10460	10228	9883	9846	10267	10839
2010	PEAK		14672	14507	13571	12691	12302	13399	14167	13941	12838	13082	13702	14692
	ENERGY	10470	11169	10981	10301	9754	9847	10189	10785	10544	10186	10148	10581	11170
2011	PEAK		15110	14940	13976	13070	12671	13808	14609	14365	13226	13475	14112	15131
	ENERGY	10783	11502	11307	10607	10044	10140	10496	11111	10861	10491	10452	10897	11502
2012	PEAK		15541	15366	14374	13442	13033	14208	14988	14781	13606	13860	14516	15562
	ENERGY	11122	11829	12044	10908	10329	10427	10797	11431	11173	10790	10749	11207	11828
2013	PEAK		15948	15770	14752	13795	13376	14586	15456	15174	13967	14225	14897	15971
	ENERGY	11381	12138	11932	11193	10597	10700	11081	11733	11467	11073	11031	11500	12138

Oregon (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		2915	2777	2560	2308	2066	2066	2099	2167	2019	2260	2477	2838
	ENERGY	1724	1952	1916	1743	1598	1615	1565	1640	1647	1606	1622	1793	2002
1995	PEAK		3012	2870	2646	2384	2135	2135	2168	2239	2086	2335	2559	2932
	ENERGY	1782	2017	1980	1801	1651	1669	1617	1695	1702	1659	1676	1853	2069
1996	PEAK		3101	2955	2724	2455	2198	2198	2222	2305	2148	2404	2635	3019
	ENERGY	1840	2077	2112	1855	1700	1718	1665	1745	1753	1708	1726	1908	2130
1997	PEAK		3200	3049	2811	2533	2268	2268	2314	2379	2216	2481	2719	3115
	ENERGY	1893	2143	2104	1914	1755	1773	1717	1800	1809	1763	1781	1969	2198
1998	PEAK		3227	3129	2885	2600	2328	2328	2365	2441	2275	2546	2790	3197
	ENERGY	1943	2199	2159	1964	1801	1819	1763	1848	1856	1809	1828	2020	2256
1999	PEAK		3380	3221	2969	2676	2396	2396	2444	2513	2341	2620	2872	3290
	ENERGY	2000	2263	2222	2021	1853	1873	1814	1902	1910	1862	1881	2080	2322
2000	PEAK		3492	3328	3068	2765	2475	2476	2502	2596	2419	2707	2967	3400
	ENERGY	2072	2339	2378	2089	1915	1935	1875	1965	1974	1924	1944	2149	2399
2001	PEAK		3607	3454	3168	2855	2556	2557	2607	2681	2498	2796	3065	3511
	ENERGY	2134	2415	2371	2157	1978	1998	1936	2029	2038	1987	2007	2219	2477
2002	PEAK		3720	3545	3268	2945	2637	2637	2695	2766	2577	2884	3161	3622
	ENERGY	2201	2491	2446	2225	2040	2061	1997	2093	2103	2049	2071	2289	2556
2003	PEAK		3845	3664	3378	3044	2725	2726	2779	2858	2663	2981	3267	3743
	ENERGY	2275	2575	2528	2299	2108	2130	2064	2163	2173	2118	2140	2366	2641
2004	PEAK		3970	3782	3487	3142	2814	2814	2844	2951	2749	3077	3373	3864
	ENERGY	2356	2658	2703	2374	2177	2199	2131	2233	2244	2187	2210	2442	2727
2005	PEAK		3953	3891	3587	3233	2895	2895	2940	3036	2829	3166	3470	3975
	ENERGY	2416	2735	2685	2442	2239	2262	2192	2298	2308	2249	2273	2513	2805
2006	PEAK		4063	4019	3686	3322	2975	2975	3021	3120	2907	3254	3566	4085
	ENERGY	2483	2810	2759	2510	2301	2325	2252	2361	2372	2312	2336	2582	2883
2007	PEAK		4329	4145	3802	3427	3068	3086	3130	3218	2998	3356	3678	4214
	ENERGY	2561	2899	2846	2588	2373	2398	2323	2435	2446	2384	2409	2663	2973
2008	PEAK		4461	4250	3918	3531	3162	3162	3195	3316	3090	3458	3790	4342
	ENERGY	2647	2987	3037	2667	2446	2471	2395	2510	2522	2457	2484	2744	3064
2009	PEAK		4427	4379	4017	3620	3241	3242	3306	3399	3167	3545	3886	4451
	ENERGY	2705	3062	3006	2734	2507	2533	2454	2573	2584	2519	2545	2813	3141
2010	PEAK		4535	4464	4115	3709	3320	3321	3372	3483	3245	3632	3981	4560
	ENERGY	2771	3137	3080	2801	2569	2595	2514	2636	2648	2580	2607	2882	3218
2011	PEAK		4643	4570	4213	3797	3400	3400	3454	3566	3322	3719	4076	4669
	ENERGY	2838	3212	3153	2868	2630	2657	2575	2699	2711	2642	2670	2951	3295
2012	PEAK		4751	4676	4311	3885	3478	3479	3516	3648	3399	3805	4170	4777
	ENERGY	2912	3286	3342	2935	2691	2719	2635	2761	2774	2703	2732	3019	3371
2013	PEAK		4849	4773	4400	3966	3551	3551	3629	3724	3470	3884	4257	4876
	ENERGY	2963	3354	3293	2996	2747	2775	2689	2818	2831	2759	2788	3082	3441

PacifiCorp - RAMPP-3 Medium High Forecast: Firm Load

Washington(Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		775	824	688	628	573	569	649	712	697	673	722	808
	ENERGY	499	571	563	485	440	448	430	494	476	499	491	510	588
1995	PEAK		812	862	720	657	599	595	680	745	729	704	755	845
	ENERGY	522	597	590	507	460	469	450	517	498	522	514	533	616
1996	PEAK		827	897	749	684	624	620	770	776	759	733	786	880
	ENERGY	546	622	636	528	479	488	468	538	519	543	535	556	641
1997	PEAK		853	928	774	707	645	641	752	802	785	758	813	910
	ENERGY	562	643	634	546	495	504	484	556	536	561	553	574	663
1998	PEAK		869	949	793	724	660	656	750	821	803	776	832	931
	ENERGY	575	658	649	559	507	516	495	569	549	575	566	588	678
1999	PEAK		899	976	815	744	679	674	785	844	826	797	855	957
	ENERGY	591	676	667	574	521	531	509	585	564	591	582	604	697
2000	PEAK		925	1005	839	766	699	694	863	869	850	821	880	985
	ENERGY	611	696	711	591	536	546	524	602	581	608	599	622	717
2001	PEAK		951	1065	864	790	720	715	833	896	876	846	908	1016
	ENERGY	628	717	708	609	553	563	540	621	598	627	617	641	740
2002	PEAK		976	1067	890	813	742	737	872	922	902	872	935	1046
	ENERGY	646	739	729	628	569	580	556	639	616	646	636	660	762
2003	PEAK		1010	1100	918	838	765	759	890	951	930	898	964	1078
	ENERGY	666	762	752	647	587	598	574	659	635	665	656	681	785
2004	PEAK		1036	1132	945	863	787	782	972	979	958	925	992	1110
	ENERGY	688	784	802	666	604	615	591	678	654	685	675	701	808
2005	PEAK		1163	1162	970	886	808	803	917	1005	983	950	1019	1140
	ENERGY	704	805	795	684	620	632	606	697	672	704	693	719	830
2006	PEAK		1193	1090	996	909	829	824	941	1031	1009	974	1045	1170
	ENERGY	723	826	816	702	637	648	622	715	689	722	711	738	852
2007	PEAK		1120	1259	1022	934	852	890	984	1059	1036	1001	1073	1201
	ENERGY	742	848	838	721	654	666	639	734	708	741	730	758	875
2008	PEAK		1151	1258	1050	959	875	869	1080	1088	1065	1028	1103	1234
	ENERGY	765	872	891	741	672	684	656	754	727	762	750	779	899
2009	PEAK		1291	1185	1077	983	897	891	1038	1115	1091	1054	1130	1265
	ENERGY	782	893	882	759	688	701	673	773	745	781	769	798	921
2010	PEAK		1322	1321	1103	1007	919	912	1042	1142	1117	1079	1158	1295
	ENERGY	800	915	903	777	705	718	689	792	763	799	787	817	943
2011	PEAK		1353	1352	1129	1031	940	934	1066	1169	1144	1105	1185	1326
	ENERGY	820	937	925	796	722	735	705	810	781	818	806	837	966
2012	PEAK		1383	1382	1154	1054	961	955	1187	1195	1169	1129	1211	1356
	ENERGY	840	958	979	813	738	752	721	828	799	837	824	856	987
2013	PEAK		1412	1411	1178	1076	981	974	1153	1220	1193	1153	1236	1383
	ENERGY	855	977	965	830	753	767	736	845	815	854	841	873	1008

North Idaho (Megawatts)

Year		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		61	63	54	46	42	38	33	39	38	43	50	57
	ENERGY	32	41	41	37	32	28	27	27	27	28	29	35	38
1995	PEAK		64	66	56	48	44	40	36	41	40	45	52	59
	ENERGY	34	43	43	38	34	29	28	28	28	29	31	37	40
1996	PEAK		68	69	58	50	45	42	43	43	42	47	54	61
	ENERGY	35	44	46	40	35	30	29	29	29	30	32	39	41
1997	PEAK		70	71	60	52	47	43	38	44	43	49	56	64
	ENERGY	37	46	46	41	36	32	30	30	30	32	33	40	43
1998	PEAK		71	73	62	54	48	44	38	46	44	50	58	66
	ENERGY	38	47	47	42	37	32	31	31	31	32	34	41	44
1999	PEAK		73	75	64	55	50	46	41	47	46	51	59	68
	ENERGY	39	49	49	44	38	33	32	32	32	33	35	42	45
2000	PEAK		76	78	66	57	52	47	49	49	47	53	61	70
	ENERGY	40	50	52	45	40	35	33	33	33	34	36	44	47
2001	PEAK		80	70	68	59	53	49	44	50	49	55	63	72
	ENERGY	41	52	52	47	41	36	34	34	34	36	37	45	49
2002	PEAK		81	83	70	61	55	50	45	52	50	57	65	74
	ENERGY	43	54	54	48	42	37	35	35	35	37	39	47	50
2003	PEAK		85	86	73	63	57	52	47	54	52	59	68	77
	ENERGY	44	56	56	50	44	38	37	37	37	38	40	48	52
2004	PEAK		86	89	75	65	59	54	56	56	54	61	70	80
	ENERGY	46	58	60	52	45	39	38	38	38	39	41	50	54
2005	PEAK		92	92	78	67	61	56	49	57	56	63	72	82
	ENERGY	47	59	59	53	47	41	39	39	39	41	43	51	55
2006	PEAK		95	92	80	69	63	57	51	59	57	65	74	85
	ENERGY	49	61	61	55	48	42	40	40	40	42	44	53	57
2007	PEAK		98	86	83	72	65	54	53	61	60	67	77	88
	ENERGY	50	63	63	57	50	43	42	42	42	43	46	55	59
2008	PEAK		101	102	86	74	67	62	63	63	62	69	80	91
	ENERGY	52	66	68	59	52	45	43	43	43	45	47	57	61
2009	PEAK		105	103	88	76	69	63	56	65	63	71	82	93
	ENERGY	54	67	68	60	53	46	44	44	44	46	48	58	63
2010	PEAK		108	107	91	79	71	65	57	67	65	73	84	96
	ENERGY	55	69	69	62	55	48	46	46	46	47	50	60	65
2011	PEAK		111	110	94	81	73	67	59	69	67	75	87	99
	ENERGY	57	71	72	64	56	49	47	47	47	49	51	62	67
2012	PEAK		114	114	97	83	75	69	71	71	69	78	90	102
	ENERGY	59	74	76	66	58	50	48	48	48	50	53	64	69
2013	PEAK		118	117	99	86	78	71	63	73	71	80	92	105
	ENERGY	60	76	76	68	60	52	50	50	50	52	54	66	71

PacifiCorp - RAMPP-3 Medium High Forecast: Firm Load

Montana (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		161	158	148	136	120	115	104	119	125	131	140	157
	ENERGY	102	121	119	112	100	93	90	87	87	91	97	109	113
1995	PEAK		167	164	154	142	125	119	108	124	130	136	145	163
	ENERGY	106	126	124	117	104	97	94	91	91	95	101	114	118
1996	PEAK		174	171	159	147	130	123	127	129	134	141	150	169
	ENERGY	110	131	133	121	108	100	97	94	94	99	105	118	122
1997	PEAK		180	177	165	152	134	128	117	133	139	146	156	175
	ENERGY	114	135	133	126	112	104	101	97	97	102	109	122	127
1998	PEAK		185	181	169	156	138	131	119	137	143	150	160	179
	ENERGY	116	139	136	129	114	107	103	100	100	105	112	125	130
1999	PEAK		189	186	174	160	141	135	123	140	147	154	164	184
	ENERGY	120	142	140	132	117	109	106	102	102	107	114	129	133
2000	PEAK		195	191	179	165	145	139	143	144	151	158	169	190
	ENERGY	124	147	149	136	121	113	109	106	105	111	118	132	137
2001	PEAK		201	197	184	170	150	143	130	148	155	163	174	195
	ENERGY	127	151	148	140	124	116	112	108	108	114	121	136	141
2002	PEAK		206	202	189	174	154	147	134	153	160	167	179	200
	ENERGY	130	155	152	144	128	119	116	112	112	117	125	140	145
2003	PEAK		210	208	195	180	158	151	138	157	164	172	184	206
	ENERGY	134	160	157	148	132	123	119	115	115	120	128	144	149
2004	PEAK		219	215	201	185	163	155	160	162	169	177	189	212
	ENERGY	138	164	167	153	135	126	122	118	118	124	132	148	154
2005	PEAK		224	221	206	190	168	160	145	166	174	182	195	218
	ENERGY	142	169	166	157	139	130	126	122	122	128	136	153	158
2006	PEAK		230	212	212	196	172	164	149	171	179	187	200	225
	ENERGY	146	174	171	161	143	134	130	125	125	131	140	157	163
2007	PEAK		238	234	219	202	178	156	155	176	184	193	206	232
	ENERGY	150	179	176	166	148	138	133	129	129	135	144	162	168
2008	PEAK		246	241	225	208	183	175	180	182	190	199	213	239
	ENERGY	156	185	188	171	152	142	138	133	133	139	149	167	173
2009	PEAK		251	234	232	214	188	179	163	187	196	205	219	245
	ENERGY	159	190	186	176	157	146	141	137	137	143	153	171	178
2010	PEAK		258	255	238	220	193	184	166	192	201	210	225	252
	ENERGY	164	195	191	181	161	150	145	140	140	147	157	176	183
2011	PEAK		265	262	245	226	199	189	172	197	206	216	231	259
	ENERGY	168	200	197	186	165	154	149	144	144	151	161	181	188
2012	PEAK		273	269	251	232	204	195	200	203	212	222	237	266
	ENERGY	173	206	209	191	170	158	154	148	148	155	166	186	193
2013	PEAK		280	276	258	238	210	200	181	208	218	228	244	273
	ENERGY	178	211	208	196	174	163	158	152	152	160	170	191	198

East Wyoming (Megawatts)

Year		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		993	1009	1019	973	1000	997	989	998	993	1014	1029	1039
	ENERGY	907	921	910	911	900	895	897	896	898	905	913	919	922
1995	PEAK		1018	1041	1051	1003	1031	1028	1022	1030	1025	1046	1062	1072
	ENERGY	936	950	939	939	928	923	925	924	926	933	941	947	951
1996	PEAK		1049	1070	1081	1031	1061	1057	1055	1059	1053	1075	1092	1102
	ENERGY	965	977	1000	966	954	949	951	950	952	960	968	974	978
1997	PEAK		1070	1095	1105	1055	1085	1081	1053	1083	1078	1100	1116	1127
	ENERGY	984	999	988	988	976	971	973	972	974	981	990	996	1000
1998	PEAK		1098	1120	1130	1079	1109	1106	1100	1107	1102	1125	1142	1153
	ENERGY	1006	1021	1010	1010	998	993	995	994	996	1004	1013	1019	1023
1999	PEAK		1122	1143	1154	1102	1133	1129	1097	1131	1125	1148	1166	1177
	ENERGY	1027	1043	1031	1031	1019	1013	1016	1014	1017	1025	1034	1040	1044
2000	PEAK		1149	1171	1182	1128	1160	1156	1154	1158	1152	1176	1194	1205
	ENERGY	1055	1068	1094	1056	1043	1038	1040	1039	1041	1049	1059	1065	1070
2001	PEAK		1176	1178	1215	1159	1192	1188	1155	1190	1184	1208	1227	1239
	ENERGY	1081	1098	1085	1085	1072	1066	1069	1068	1070	1078	1088	1095	1099
2002	PEAK		1214	1237	1250	1193	1226	1222	1195	1224	1218	1243	1262	1274
	ENERGY	1112	1129	1116	1117	1103	1097	1100	1098	1101	1109	1119	1126	1131
2003	PEAK		1249	1273	1285	1227	1261	1257	1226	1259	1253	1279	1298	1311
	ENERGY	1144	1161	1148	1149	1135	1129	1131	1130	1132	1141	1151	1159	1163
2004	PEAK		1287	1311	1323	1263	1299	1294	1292	1296	1290	1317	1337	1350
	ENERGY	1181	1196	1225	1183	1168	1162	1165	1163	1166	1175	1185	1193	1198
2005	PEAK		1359	1339	1352	1290	1327	1322	1313	1324	1318	1345	1366	1379
	ENERGY	1203	1222	1208	1208	1193	1187	1190	1188	1191	1200	1211	1219	1223
2006	PEAK		1391	1354	1385	1321	1359	1354	1340	1356	1350	1377	1398	1412
	ENERGY	1232	1251	1237	1237	1222	1216	1218	1217	1220	1229	1240	1248	1253
2007	PEAK		1371	1372	1415	1350	1388	1348	1352	1386	1379	1407	1429	1443
	ENERGY	1259	1278	1264	1264	1249	1242	1245	1243	1246	1256	1267	1275	1280
2008	PEAK		1411	1439	1453	1387	1426	1421	1419	1423	1416	1446	1468	1482
	ENERGY	1297	1313	1345	1298	1283	1276	1279	1277	1280	1290	1302	1310	1315
2009	PEAK		1493	1452	1485	1417	1457	1453	1416	1455	1448	1478	1500	1515
	ENERGY	1322	1342	1327	1327	1311	1304	1307	1305	1308	1319	1330	1339	1344
2010	PEAK		1525	1503	1518	1449	1489	1485	1477	1487	1480	1510	1533	1548
	ENERGY	1351	1371	1356	1356	1340	1333	1336	1334	1337	1348	1359	1368	1373
2011	PEAK		1557	1534	1549	1479	1521	1516	1500	1518	1510	1541	1565	1580
	ENERGY	1379	1400	1384	1385	1368	1360	1363	1362	1365	1376	1388	1397	1402
2012	PEAK		1588	1565	1580	1508	1550	1545	1543	1548	1540	1572	1596	1611
	ENERGY	1410	1428	1462	1412	1395	1387	1390	1389	1392	1403	1415	1424	1430
2013	PEAK		1616	1593	1608	1535	1578	1573	1537	1576	1568	1600	1625	1640
	ENERGY	1432	1453	1437	1437	1420	1412	1415	1414	1417	1428	1441	1450	1456

PacifiCorp - RAMPP-3 Medium High Forecast: Firm Load

California (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		182	168	151	141	140	146	157	148	112	127	143	173
	ENERGY	101	117	101	96	94	99	107	116	103	90	87	92	113
1995	PEAK		189	175	157	146	145	152	162	154	117	132	149	179
	ENERGY	105	121	105	100	98	103	111	121	107	94	90	96	117
1996	PEAK		196	181	162	151	150	157	172	159	121	137	154	186
	ENERGY	109	126	113	103	101	107	115	125	111	97	93	99	121
1997	PEAK		202	186	167	156	155	162	180	164	124	141	159	191
	ENERGY	112	130	112	107	104	110	118	129	115	100	96	102	125
1998	PEAK		207	192	172	161	159	166	177	169	128	145	163	197
	ENERGY	115	133	116	110	107	113	121	132	118	103	99	105	128
1999	PEAK		214	197	177	165	164	171	190	174	132	149	168	203
	ENERGY	119	137	119	113	111	117	125	136	121	106	102	108	132
2000	PEAK		221	204	184	171	170	177	195	180	137	154	174	210
	ENERGY	124	142	128	117	115	121	130	141	126	109	106	112	137
2001	PEAK		229	226	190	177	176	183	204	186	141	160	180	217
	ENERGY	127	147	128	121	118	125	134	146	130	113	109	116	142
2002	PEAK		237	219	196	183	182	190	211	193	146	165	186	225
	ENERGY	132	152	132	125	122	129	139	151	135	117	113	120	147
2003	PEAK		245	227	203	190	188	196	218	200	151	171	193	233
	ENERGY	137	157	137	130	127	134	144	156	139	121	117	124	152
2004	PEAK		253	234	210	196	194	203	223	206	156	177	200	240
	ENERGY	141	163	146	134	131	138	148	162	144	125	121	128	157
2005	PEAK		251	241	217	202	200	209	225	213	161	182	206	248
	ENERGY	145	168	146	138	135	143	153	167	149	129	124	132	162
2006	PEAK		258	277	223	208	207	216	231	219	166	188	212	256
	ENERGY	150	173	150	142	139	147	158	172	153	133	128	136	167
2007	PEAK		278	275	231	215	214	240	248	227	172	194	219	264
	ENERGY	155	179	155	147	144	152	163	178	158	138	132	141	172
2008	PEAK		288	266	239	223	221	231	254	235	178	201	227	273
	ENERGY	161	185	167	152	149	157	169	184	164	142	137	146	178
2009	PEAK		285	305	246	230	228	238	264	241	183	207	234	281
	ENERGY	165	190	165	157	153	162	174	189	169	147	141	150	184
2010	PEAK		293	282	253	236	234	245	263	249	188	213	240	290
	ENERGY	170	196	170	161	158	167	179	195	174	151	145	154	189
2011	PEAK		301	290	261	243	241	252	271	256	194	219	247	298
	ENERGY	175	202	175	166	163	171	184	200	179	155	150	159	195
2012	PEAK		310	299	269	251	248	259	285	263	200	226	255	307
	ENERGY	181	208	187	171	167	177	189	207	184	160	154	164	200
2013	PEAK		319	308	276	258	256	267	296	271	205	232	262	316
	ENERGY	185	214	185	176	172	182	195	212	189	165	158	168	206

Utah (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		2109	2037	1964	1895	1947	2300	2534	2343	2104	2046	2087	2108
	ENERGY	1624	1668	1639	1576	1525	1530	1623	1702	1677	1618	1623	1646	1665
1995	PEAK		2272	2151	2074	2002	2057	2429	2677	2475	2223	2161	2205	2227
	ENERGY	1716	1761	1732	1665	1611	1616	1714	1798	1772	1709	1714	1739	1759
1996	PEAK		2413	2278	2196	2120	2178	2572	2719	2621	2354	2288	2335	2358
	ENERGY	1822	1865	1899	1763	1706	1711	1815	1904	1876	1810	1815	1842	1863
1997	PEAK		2541	2402	2316	2236	2297	2713	2968	2764	2482	2413	2462	2487
	ENERGY	1916	1967	1934	1859	1799	1804	1914	2008	1979	1909	1914	1942	1965
1998	PEAK		2648	2506	2416	2332	2396	2830	3118	2883	2589	2517	2568	2594
	ENERGY	1999	2052	2017	1939	1876	1882	1997	2094	2064	1991	1997	2026	2049
1999	PEAK		2700	2604	2511	2423	2490	2940	3216	2996	2690	2616	2669	2696
	ENERGY	2077	2132	2096	2015	1950	1956	2075	2176	2145	2069	2075	2105	2129
2000	PEAK		2800	2701	2604	2514	2582	3050	3224	3107	2790	2713	2768	2796
	ENERGY	2160	2211	2252	2090	2022	2028	2152	2257	2224	2146	2152	2183	2208
2001	PEAK		2893	2857	2695	2601	2672	3156	3452	3216	2888	2807	2865	2893
	ENERGY	2229	2288	2250	2163	2093	2099	2227	2336	2302	2220	2227	2259	2285
2002	PEAK		2992	2893	2789	2692	2766	3267	3572	3328	2989	2906	2965	2995
	ENERGY	2307	2369	2328	2239	2166	2173	2305	2418	2382	2298	2305	2339	2366
2003	PEAK		3102	2999	2891	2791	2867	3386	3703	3450	3098	3012	3073	3104
	ENERGY	2392	2455	2414	2320	2245	2252	2390	2506	2470	2382	2389	2424	2452
2004	PEAK		3222	3108	2997	2892	2972	3509	3710	3576	3211	3122	3185	3217
	ENERGY	2486	2545	2591	2405	2327	2334	2476	2597	2559	2469	2476	2512	2541
2005	PEAK		3228	3204	3089	2982	3063	3618	3987	3686	3310	3218	3284	3317
	ENERGY	2555	2623	2579	2479	2399	2406	2553	2677	2639	2545	2553	2590	2620
2006	PEAK		3326	3462	3182	3072	3156	3727	4107	3797	3410	3315	3383	3417
	ENERGY	2633	2702	2657	2554	2471	2479	2630	2758	2718	2622	2630	2668	2699
2007	PEAK		3528	3482	3284	3170	3257	3809	4206	3918	3519	3421	3491	3526
	ENERGY	2716	2789	2741	2635	2550	2558	2714	2846	2805	2706	2714	2753	2785
2008	PEAK		3638	3517	3391	3274	3363	3972	4199	4047	3634	3533	3605	3641
	ENERGY	2813	2880	2932	2722	2634	2641	2802	2939	2897	2794	2802	2843	2876
2009	PEAK		3650	3780	3492	3371	3463	4090	4473	4167	3742	3638	3712	3749
	ENERGY	2889	2965	2915	2803	2712	2720	2886	3027	2983	2877	2886	2928	2962
2010	PEAK		3759	3730	3597	3472	3567	4212	4642	4292	3854	3747	3823	3862
	ENERGY	2975	3054	3002	2887	2793	2801	2972	3117	3072	2964	2972	3016	3050
2011	PEAK		3869	3840	3702	3574	3672	4336	4778	4418	3967	3857	3936	3975
	ENERGY	3063	3144	3091	2971	2875	2884	3060	3209	3162	3051	3060	3104	3140
2012	PEAK		3974	3943	3802	3670	3770	4453	4707	4537	4074	3961	4042	4082
	ENERGY	3154	3229	3287	3051	2953	2961	3142	3295	3248	3133	3142	3188	3224
2013	PEAK		4072	4041	3896	3761	3864	4563	4990	4649	4175	4059	4141	4183
	ENERGY	3223	3308	3252	3127	3026	3035	3220	3377	3328	3210	3220	3267	3304

PacifiCorp - RAMPP-3 Medium High Forecast: Firm Load

South Idaho (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		234	253	230	218	249	432	472	418	323	252	226	210
	ENERGY	232	193	194	177	164	198	330	407	334	241	202	185	157
1995	PEAK		236	260	237	224	256	445	487	431	333	260	233	216
	ENERGY	239	199	200	182	169	204	339	419	343	249	208	190	162
1996	PEAK		249	266	242	229	261	455	514	439	339	265	238	221
	ENERGY	245	203	211	186	172	208	346	428	351	254	212	194	165
1997	PEAK		253	273	248	235	268	466	511	451	348	272	244	227
	ENERGY	250	208	209	191	176	214	355	439	359	260	218	199	170
1998	PEAK		259	278	253	240	274	476	518	460	355	277	249	231
	ENERGY	255	212	213	195	180	218	363	448	367	265	222	203	173
1999	PEAK		266	286	260	246	281	489	535	472	365	285	256	238
	ENERGY	262	218	219	200	185	224	372	460	377	273	228	209	178
2000	PEAK		274	295	268	254	290	505	571	488	377	294	264	245
	ENERGY	272	225	234	207	191	231	385	475	389	282	235	216	184
2001	PEAK		286	294	278	264	301	523	573	506	391	305	274	254
	ENERGY	281	234	235	214	198	240	399	492	403	292	244	224	190
2002	PEAK		296	318	289	274	313	544	595	526	406	317	284	264
	ENERGY	292	243	244	222	206	249	414	511	419	303	254	232	198
2003	PEAK		309	332	302	286	327	568	622	549	424	331	297	276
	ENERGY	305	254	255	232	215	260	433	534	438	317	265	243	207
2004	PEAK		322	346	315	298	341	592	669	572	442	345	310	288
	ENERGY	319	264	275	242	224	272	451	557	457	330	276	253	215
2005	PEAK		360	357	325	308	351	611	666	591	456	356	320	297
	ENERGY	328	273	274	250	231	280	466	575	471	341	285	261	222
2006	PEAK		370	326	334	317	361	628	684	608	469	366	329	305
	ENERGY	337	281	282	257	238	288	479	591	485	351	293	268	229
2007	PEAK		356	365	345	327	373	674	710	627	484	378	339	315
	ENERGY	348	290	291	266	246	297	494	610	500	362	303	277	236
2008	PEAK		367	392	356	338	385	670	757	648	500	391	350	326
	ENERGY	360	299	311	274	254	307	511	630	517	374	313	286	244
2009	PEAK		406	359	367	347	396	689	754	666	514	402	360	335
	ENERGY	370	308	309	282	261	316	525	648	531	384	322	294	251
2010	PEAK		418	415	377	357	408	709	774	685	529	413	371	345
	ENERGY	381	317	318	290	268	325	540	667	547	396	331	303	258
2011	PEAK		430	427	388	368	420	730	795	706	545	426	382	355
	ENERGY	392	326	327	299	276	335	556	687	563	407	341	312	265
2012	PEAK		441	438	398	377	431	749	846	724	559	437	392	364
	ENERGY	403	334	348	306	283	343	571	704	577	418	349	320	272
2013	PEAK		451	447	407	386	440	765	839	740	571	446	400	372
	ENERGY	411	342	343	313	290	351	583	720	590	427	357	327	278

West Wyoming (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		275	292	280	286	277	271	269	274	260	273	271	286
	ENERGY	250	262	264	258	257	249	247	246	246	243	238	242	247
1995	PEAK		280	299	286	292	283	277	270	280	266	279	277	292
	ENERGY	255	268	270	264	263	254	252	252	252	249	243	248	252
1996	PEAK		303	311	298	304	295	288	293	292	277	291	289	305
	ENERGY	267	279	291	275	274	265	263	262	263	259	254	258	263
1997	PEAK		292	307	294	300	292	285	288	288	273	287	285	301
	ENERGY	263	276	278	271	270	261	259	259	259	256	250	255	259
1998	PEAK		297	316	302	309	300	293	289	296	281	295	293	309
	ENERGY	270	283	285	279	278	269	266	266	266	263	257	262	266
1999	PEAK		305	320	307	313	304	297	302	301	285	299	298	314
	ENERGY	274	288	290	283	282	273	270	270	270	267	261	266	270
2000	PEAK		305	326	312	318	309	302	307	306	290	304	302	319
	ENERGY	279	292	305	288	287	277	275	275	275	271	265	270	275
2001	PEAK		317	308	318	324	315	308	312	311	295	310	308	325
	ENERGY	284	298	300	293	292	282	280	280	280	277	271	275	280
2002	PEAK		322	338	324	330	321	313	318	317	301	316	314	331
	ENERGY	289	303	306	299	298	288	285	285	285	282	276	280	285
2003	PEAK		327	344	329	336	326	318	318	322	306	321	319	336
	ENERGY	294	308	311	303	302	292	290	290	290	286	280	285	290
2004	PEAK		332	349	334	341	332	324	329	328	311	326	324	342
	ENERGY	300	313	327	308	307	297	295	295	295	291	285	290	295
2005	PEAK		353	352	337	344	334	326	319	330	313	329	327	345
	ENERGY	301	316	318	311	310	300	297	297	297	293	287	292	297
2006	PEAK		357	329	341	348	338	330	329	334	317	333	331	349
	ENERGY	305	320	322	315	313	303	301	300	300	297	290	295	301
2007	PEAK		342	331	343	350	340	327	336	336	319	335	333	351
	ENERGY	307	322	324	317	316	305	303	302	302	299	292	297	303
2008	PEAK		345	363	348	355	344	336	342	340	323	339	337	355
	ENERGY	311	326	340	321	319	309	306	306	306	302	296	301	306
2009	PEAK		366	337	350	357	347	338	342	343	325	341	339	357
	ENERGY	312	328	330	322	321	311	308	308	308	304	298	303	308
2010	PEAK		368	367	352	359	349	340	332	345	327	343	341	360
	ENERGY	314	330	332	324	323	313	310	310	310	306	299	305	310
2011	PEAK		370	369	353	361	350	342	340	346	328	345	343	361
	ENERGY	316	331	333	326	325	314	311	311	311	307	301	306	311
2012	PEAK		371	370	354	362	351	343	349	347	329	346	344	362
	ENERGY	318	332	347	327	326	315	312	312	312	308	302	307	312
2013	PEAK		372	371	355	362	352	344	349	348	330	346	344	363
	ENERGY	317	333	335	327	326	315	313	313	313	309	302	307	313

PacifiCorp - RAMPP-3 Medium High Forecast: Firm Load

Total Company (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		7706	7582	7093	6631	6414	6934	7306	7220	6672	6819	7146	7675
	ENERGY	5473	5845	5749	5395	5110	5154	5314	5615	5496	5321	5303	5532	5846
1995	PEAK		8050	7888	7380	6899	6676	7220	7611	7519	6947	7097	7437	7986
	ENERGY	5695	6082	5981	5613	5317	5363	5529	5843	5719	5538	5519	5757	6084
1996	PEAK		8379	8197	7670	7172	6943	7512	7915	7823	7227	7381	7733	8301
	ENERGY	5938	6323	6440	5836	5529	5576	5749	6074	5947	5759	5740	5987	6324
1997	PEAK		8661	8488	7942	7427	7191	7787	8220	8109	7489	7646	8011	8597
	ENERGY	6131	6546	6438	6042	5724	5773	5952	6290	6158	5964	5945	6200	6549
1998	PEAK		8860	8744	8183	7653	7412	8029	8475	8360	7720	7880	8255	8857
	ENERGY	6318	6745	6633	6226	5898	5949	6134	6481	6346	6146	6127	6389	6748
1999	PEAK		9148	9008	8431	7885	7637	8277	8733	8617	7956	8120	8507	9126
	ENERGY	6509	6949	6833	6414	6076	6128	6320	6678	6539	6332	6312	6582	6952
2000	PEAK		9437	9298	8701	8138	7883	8545	9005	8896	8213	8382	8781	9419
	ENERGY	6736	7171	7303	6618	6270	6323	6522	6892	6748	6534	6514	6793	7174
2001	PEAK		9740	9648	8981	8399	8136	8822	9309	9184	8477	8651	9063	9722
	ENERGY	6932	7400	7276	6829	6469	6525	6731	7114	6965	6743	6722	7010	7404
2002	PEAK		10045	9902	9266	8666	8395	9106	9637	9480	8749	8927	9352	10031
	ENERGY	7152	7635	7507	7046	6674	6733	6947	7343	7188	6958	6936	7233	7639
2003	PEAK		10382	10231	9574	8954	8675	9414	9941	9800	9042	9224	9663	10365
	ENERGY	7390	7888	7756	7279	6895	6956	7180	7590	7429	7190	7166	7473	7891
2004	PEAK		10727	10566	9888	9247	8959	9728	10254	10125	9340	9527	9980	10703
	ENERGY	7654	8145	8295	7516	7120	7183	7417	7842	7674	7426	7401	7717	8148
2005	PEAK		10983	10860	10162	9503	9208	10000	10562	10409	9600	9792	10257	11001
	ENERGY	7843	8370	8229	7722	7315	7381	7621	8059	7886	7630	7605	7930	8373
2006	PEAK		11284	11162	10440	9763	9460	10276	10854	10696	9864	10060	10539	11303
	ENERGY	8057	8598	8454	7933	7513	7581	7830	8280	8102	7838	7812	8146	8602
2007	PEAK		11660	11549	10744	10046	9734	10584	11174	11009	10151	10353	10846	11633
	ENERGY	8289	8847	8698	8161	7729	7799	8056	8520	8337	8064	8037	8381	8851
2008	PEAK		12006	11829	11068	10348	10027	10897	11489	11342	10457	10665	11173	11983
	ENERGY	8563	9112	9279	8405	7960	8032	8299	8777	8588	8306	8279	8633	9116
2009	PEAK		12272	12134	11353	10615	10286	11183	11813	11638	10729	10941	11462	12293
	ENERGY	8758	9346	9188	8621	8164	8239	8512	9004	8809	8520	8492	8855	9351
2010	PEAK		12586	12444	11643	10886	10550	11473	12126	11941	11006	11221	11756	12607
	ENERGY	8982	9584	9422	8840	8371	8449	8731	9236	9036	8738	8709	9081	9589
2011	PEAK		12901	12755	11935	11159	10815	11766	12436	12244	11284	11503	12051	12923
	ENERGY	9206	9823	9657	9060	8580	8660	8951	9469	9263	8957	8927	9308	9828
2012	PEAK		13205	13056	12216	11421	11071	12047	12703	12536	11552	11775	12336	13228
	ENERGY	9450	10054	10237	9273	8781	8862	9162	9693	9482	9167	9137	9527	10059
2013	PEAK		13489	13337	12478	11666	11309	12308	13038	12808	11801	12029	12602	13512
	ENERGY	9624	10269	10094	9471	8967	9051	9358	9901	9685	9363	9332	9731	10274

Oregon (Megawatts)

Year		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		2740	2697	2486	2241	2006	2006	2046	2104	1960	2194	2405	2755
	ENERGY	1674	1895	1861	1693	1552	1568	1519	1592	1600	1559	1575	1741	1944
1995	PEAK		2785	2741	2527	2278	2039	2040	2079	2139	1993	2231	2445	2801
	ENERGY	1702	1927	1891	1721	1578	1594	1544	1619	1626	1585	1601	1770	1976
1996	PEAK		2834	2789	2571	2317	2075	2075	2097	2176	2028	2269	2487	2850
	ENERGY	1737	1960	1993	1751	1605	1622	1572	1647	1654	1612	1629	1801	2011
1997	PEAK		2892	2847	2625	2365	2118	2118	2160	2221	2070	2316	2539	2909
	ENERGY	1768	2001	1964	1787	1638	1655	1604	1681	1689	1646	1663	1838	2052
1998	PEAK		2935	2889	2664	2400	2149	2150	2192	2254	2100	2351	2577	2952
	ENERGY	1794	2031	1993	1813	1663	1680	1628	1706	1714	1670	1688	1866	2083
1999	PEAK		2989	2942	2712	2444	2188	2189	2222	2295	2138	2394	2623	3005
	ENERGY	1826	2067	2030	1846	1693	1710	1657	1737	1745	1701	1718	1900	2121
2000	PEAK		3055	3007	2772	2499	2237	2238	2261	2346	2186	2447	2682	3072
	ENERGY	1873	2113	2149	1888	1731	1749	1695	1776	1784	1739	1757	1942	2168
2001	PEAK		3123	3089	2834	2554	2287	2300	2332	2398	2234	2501	2741	3140
	ENERGY	1908	2160	2121	1929	1769	1787	1731	1815	1823	1777	1796	1985	2216
2002	PEAK		3189	3138	2893	2607	2335	2344	2387	2449	2281	2554	2799	3206
	ENERGY	1948	2206	2165	1970	1806	1825	1768	1853	1862	1814	1833	2026	2262
2003	PEAK		3262	3211	2960	2667	2388	2389	2426	2505	2334	2612	2863	3280
	ENERGY	1993	2256	2215	2015	1848	1867	1809	1896	1904	1856	1875	2073	2315
2004	PEAK		3335	3283	3026	2727	2442	2442	2468	2561	2386	2671	2928	3354
	ENERGY	2044	2307	2346	2060	1889	1909	1850	1938	1947	1898	1918	2120	2367
2005	PEAK		3399	3346	3084	2780	2489	2489	2538	2610	2432	2722	2983	3418
	ENERGY	2077	2351	2308	2100	1925	1945	1885	1976	1984	1934	1954	2160	2412
2006	PEAK		3461	3423	3140	2830	2534	2534	2585	2658	2476	2772	3038	3480
	ENERGY	2115	2394	2350	2138	1960	1981	1919	2011	2020	1969	1990	2199	2456
2007	PEAK		3537	3499	3209	2892	2590	2612	2641	2716	2531	2832	3104	3557
	ENERGY	2161	2446	2402	2185	2003	2024	1961	2056	2065	2012	2034	2248	2510
2008	PEAK		3616	3559	3281	2957	2648	2648	2676	2777	2587	2896	3174	3636
	ENERGY	2217	2501	2543	2234	2048	2069	2005	2102	2112	2057	2080	2298	2566
2009	PEAK		3683	3625	3342	3012	2696	2697	2738	2828	2635	2949	3232	3703
	ENERGY	2250	2547	2501	2275	2086	2108	2042	2140	2150	2095	2117	2340	2613
2010	PEAK		3751	3692	3404	3067	2746	2747	2790	2880	2684	3004	3292	3772
	ENERGY	2292	2595	2547	2317	2124	2147	2080	2180	2190	2134	2157	2384	2662
2011	PEAK		3820	3760	3466	3124	2797	2798	2841	2934	2733	3059	3353	3842
	ENERGY	2335	2642	2594	2360	2164	2186	2118	2220	2230	2174	2196	2428	2711
2012	PEAK		3889	3828	3529	3181	2848	2848	2878	2987	2783	3115	3414	3911
	ENERGY	2384	2690	2736	2403	2203	2226	2157	2261	2271	2213	2236	2472	2760
2013	PEAK		3952	3909	3586	3231	2893	2894	2943	3035	2827	3165	3468	3974
	ENERGY	2415	2734	2683	2441	2238	2261	2191	2297	2307	2248	2272	2511	2804

PacifiCorp - RAMPP-3 Medium Forecast: Firm Load

Washington(Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		812	811	677	619	564	560	653	702	686	663	711	796
	ENERGY	492	562	555	477	433	441	423	486	469	491	484	502	579
1995	PEAK		842	841	702	642	585	581	676	728	712	688	737	825
	ENERGY	510	583	575	495	449	458	439	504	486	509	502	521	601
1996	PEAK		870	869	726	663	604	600	746	752	735	710	762	852
	ENERGY	528	602	616	511	464	473	453	521	502	526	518	538	621
1997	PEAK		892	892	744	680	620	616	722	771	754	729	782	875
	ENERGY	541	618	610	525	476	485	465	534	515	540	532	552	637
1998	PEAK		908	908	758	692	631	627	731	785	768	742	795	890
	ENERGY	550	629	621	534	484	493	473	544	524	549	541	562	648
1999	PEAK		928	927	774	707	645	641	733	802	784	758	812	909
	ENERGY	562	642	634	545	495	504	484	556	536	561	553	574	662
2000	PEAK		949	949	792	723	660	655	814	820	802	775	831	930
	ENERGY	577	657	672	558	506	516	495	568	548	574	565	587	677
2001	PEAK		972	999	811	741	676	706	781	840	822	794	852	953
	ENERGY	589	673	664	572	519	528	507	582	561	588	579	601	694
2002	PEAK		995	995	830	758	692	722	813	860	841	813	872	975
	ENERGY	603	689	680	585	531	541	519	596	575	602	593	616	710
2003	PEAK		1019	1019	850	777	708	704	806	881	862	832	893	999
	ENERGY	617	706	697	599	544	554	531	610	589	617	607	631	728
2004	PEAK		1044	1043	870	795	725	720	895	902	882	852	914	1023
	ENERGY	634	722	739	614	557	567	544	625	603	631	622	646	745
2005	PEAK		1066	1065	889	812	741	735	856	921	901	870	933	1044
	ENERGY	645	738	728	627	568	579	555	638	615	645	635	659	761
2006	PEAK		1087	992	907	828	756	750	874	940	919	888	952	1066
	ENERGY	659	753	743	639	580	591	567	651	628	658	648	672	776
2007	PEAK		1111	1141	926	846	772	806	892	960	939	907	973	1088
	ENERGY	673	769	759	653	592	603	579	665	641	672	662	687	793
2008	PEAK		1135	1134	947	865	789	783	974	981	959	927	994	1112
	ENERGY	690	786	803	667	605	617	592	680	655	686	676	702	810
2009	PEAK		1157	1156	965	882	804	799	912	1000	978	945	1013	1134
	ENERGY	701	801	791	680	617	629	603	693	668	700	689	716	826
2010	PEAK		1179	1178	984	898	819	814	929	1019	997	963	1033	1156
	ENERGY	714	816	806	693	629	641	615	706	681	713	703	729	841
2011	PEAK		1201	1200	1002	915	835	829	947	1038	1015	981	1052	1177
	ENERGY	727	832	821	706	641	653	626	719	693	727	716	743	857
2012	PEAK		1222	1221	1019	931	849	843	1048	1056	1033	998	1070	1197
	ENERGY	742	846	865	719	652	664	637	732	705	739	728	756	872
2013	PEAK		1241	1138	1035	946	863	857	986	1073	1049	1013	1087	1216
	ENERGY	752	859	848	730	662	674	647	743	717	751	740	768	886

North Idaho (Megawatts)

Year		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		62	62	52	45	41	37	34	38	37	42	48	55
	ENERGY	32	40	40	36	31	27	26	26	26	27	29	35	37
1995	PEAK		64	63	54	46	42	38	35	40	38	43	50	57
	ENERGY	33	41	41	37	32	28	27	27	27	28	29	36	38
1996	PEAK		65	65	55	48	43	40	41	41	40	45	51	58
	ENERGY	34	42	44	38	33	29	28	28	28	29	30	37	39
1997	PEAK		67	67	57	49	44	41	36	42	41	46	53	60
	ENERGY	34	43	43	39	34	30	29	29	29	30	31	38	40
1998	PEAK		68	68	58	50	45	41	37	42	41	46	54	61
	ENERGY	35	44	44	39	35	30	29	29	29	30	32	38	41
1999	PEAK		70	69	59	51	46	37	36	43	42	47	55	62
	ENERGY	36	45	45	40	35	31	30	30	30	31	32	39	42
2000	PEAK		71	71	60	52	47	43	44	44	43	49	56	64
	ENERGY	37	46	48	41	36	32	30	30	30	31	33	40	43
2001	PEAK		73	64	62	53	48	40	39	45	44	50	57	65
	ENERGY	37	47	47	42	37	32	31	31	31	32	34	41	44
2002	PEAK		75	75	63	55	49	42	40	47	45	51	59	67
	ENERGY	38	48	48	43	38	33	32	32	32	33	35	42	45
2003	PEAK		77	76	65	56	51	46	41	48	46	52	60	69
	ENERGY	39	50	50	44	39	34	33	33	33	34	36	43	46
2004	PEAK		79	79	67	58	52	48	49	49	48	54	62	70
	ENERGY	41	51	53	46	40	35	33	33	33	35	36	44	47
2005	PEAK		81	80	68	59	53	49	44	50	49	55	63	72
	ENERGY	41	52	52	47	41	36	34	34	34	36	37	45	49
2006	PEAK		83	81	70	60	54	50	45	51	50	56	65	74
	ENERGY	42	53	53	48	42	36	35	35	35	36	38	46	50
2007	PEAK		85	74	72	62	56	47	46	53	52	58	67	76
	ENERGY	44	55	55	49	43	38	36	36	36	37	39	48	51
2008	PEAK		87	87	74	64	58	53	54	54	53	60	69	78
	ENERGY	45	56	58	51	45	39	37	37	37	39	40	49	53
2009	PEAK		89	89	75	65	59	54	48	55	54	61	70	80
	ENERGY	46	57	57	51	45	39	38	38	38	39	41	50	54
2010	PEAK		91	91	77	66	60	55	49	57	55	62	71	81
	ENERGY	47	59	59	53	46	40	39	39	39	40	42	51	55
2011	PEAK		93	93	79	68	61	56	50	58	56	63	73	83
	ENERGY	48	60	60	54	47	41	39	39	39	41	43	52	56
2012	PEAK		95	95	80	69	63	58	59	59	58	65	75	85
	ENERGY	49	61	64	55	48	42	40	40	40	42	44	53	57
2013	PEAK		97	94	82	71	64	59	52	60	59	66	76	87
	ENERGY	50	63	63	56	49	43	41	41	41	43	45	54	58

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Montana (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		157	155	145	134	118	112	102	117	122	128	137	153
	ENERGY	100	119	116	110	98	91	88	85	85	90	95	107	111
1995	PEAK		161	159	149	137	121	115	106	120	125	131	140	157
	ENERGY	102	122	119	113	100	94	91	88	88	92	98	110	114
1996	PEAK		166	163	153	141	124	118	122	123	129	135	144	162
	ENERGY	105	125	127	116	103	96	93	90	90	94	101	113	117
1997	PEAK		170	168	157	144	127	121	111	126	132	138	148	166
	ENERGY	108	128	126	119	106	99	96	92	92	97	103	116	120
1998	PEAK		172	170	159	147	129	123	111	128	134	141	150	168
	ENERGY	109	130	128	121	107	100	97	94	94	98	105	118	122
1999	PEAK		175	173	162	149	131	115	113	130	136	143	153	171
	ENERGY	111	132	130	123	109	102	99	95	95	100	106	120	124
2000	PEAK		179	176	165	152	134	128	131	133	139	146	156	175
	ENERGY	114	135	137	125	111	104	101	97	97	102	109	122	126
2001	PEAK		182	176	168	155	137	121	120	136	142	149	159	178
	ENERGY	116	138	135	128	114	106	103	99	99	104	111	124	129
2002	PEAK		186	183	171	158	139	122	121	138	144	151	162	181
	ENERGY	118	140	138	130	116	108	105	101	101	106	113	127	131
2003	PEAK		190	187	175	161	142	135	123	141	147	155	165	185
	ENERGY	120	143	141	133	118	110	107	103	103	108	115	129	134
2004	PEAK		194	191	179	165	145	138	142	144	151	158	168	189
	ENERGY	123	146	149	136	121	112	109	105	105	110	118	132	137
2005	PEAK		198	195	182	168	148	141	130	147	154	161	172	193
	ENERGY	125	149	146	138	123	115	111	107	107	113	120	135	140
2006	PEAK		202	189	186	171	151	144	132	150	157	164	175	197
	ENERGY	128	152	149	141	126	117	113	110	110	115	122	138	142
2007	PEAK		206	203	190	175	154	135	135	153	160	168	179	201
	ENERGY	131	156	153	144	128	120	116	112	112	118	125	141	146
2008	PEAK		211	208	195	179	158	151	155	157	164	172	184	206
	ENERGY	134	159	162	148	131	123	119	115	115	120	128	144	149
2009	PEAK		215	212	199	183	161	154	139	160	168	176	187	210
	ENERGY	137	163	160	151	134	125	121	117	117	123	131	147	152
2010	PEAK		220	217	203	187	165	157	143	163	171	179	191	215
	ENERGY	139	166	163	154	137	128	124	119	119	125	133	150	155
2011	PEAK		224	221	207	191	168	160	145	167	174	183	195	219
	ENERGY	142	169	166	157	140	130	126	122	122	128	136	153	159
2012	PEAK		229	226	211	195	172	164	168	170	178	187	199	224
	ENERGY	146	173	176	161	143	133	129	124	124	131	139	156	162
2013	PEAK		234	215	215	199	175	167	149	174	182	190	203	228
	ENERGY	148	176	173	164	145	136	132	127	127	133	142	159	165

East Wyoming (Megawatts)

Year		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		1007	993	1002	957	984	981	954	982	977	997	1013	1022
	ENERGY	892	906	896	896	885	880	882	881	883	890	898	904	907
1995	PEAK		1016	1001	1011	965	992	989	961	990	985	1006	1021	1031
	ENERGY	900	913	903	903	892	888	890	888	890	897	905	911	915
1996	PEAK		1027	1012	1022	975	1003	999	998	1001	996	1016	1032	1042
	ENERGY	912	923	945	913	902	897	899	898	900	907	915	921	925
1997	PEAK		1037	1022	1032	985	1012	1009	985	1011	1006	1026	1042	1052
	ENERGY	918	932	922	922	911	906	908	907	909	916	924	930	934
1998	PEAK		1059	1044	1054	1006	1034	1031	1007	1032	1027	1048	1064	1075
	ENERGY	938	952	941	942	930	925	927	926	928	936	944	950	954
1999	PEAK		1079	1064	1074	1025	1054	1050	1045	1052	1047	1068	1085	1095
	ENERGY	956	971	960	960	948	943	945	944	946	954	962	968	972
2000	PEAK		1103	1087	1098	1048	1077	1074	1072	1075	1070	1092	1109	1119
	ENERGY	980	992	1016	981	969	964	966	965	967	975	983	989	993
2001	PEAK		1132	1093	1126	1075	1105	1072	1076	1103	1098	1120	1137	1148
	ENERGY	1002	1018	1006	1006	994	989	991	990	992	1000	1009	1015	1019
2002	PEAK		1162	1145	1156	1104	1135	1106	1105	1133	1127	1150	1168	1179
	ENERGY	1029	1045	1033	1033	1021	1015	1018	1016	1019	1027	1036	1042	1046
2003	PEAK		1193	1176	1187	1133	1165	1161	1153	1163	1157	1181	1199	1210
	ENERGY	1057	1073	1061	1061	1048	1042	1045	1043	1046	1054	1063	1070	1074
2004	PEAK		1226	1208	1220	1164	1197	1193	1191	1195	1189	1214	1232	1244
	ENERGY	1089	1102	1129	1090	1077	1071	1074	1072	1075	1083	1093	1100	1104
2005	PEAK		1250	1231	1243	1187	1220	1216	1188	1218	1212	1237	1256	1268
	ENERGY	1107	1124	1111	1111	1098	1092	1094	1093	1095	1104	1114	1121	1125
2006	PEAK		1277	1243	1271	1213	1247	1243	1211	1245	1239	1264	1284	1296
	ENERGY	1131	1149	1136	1136	1122	1116	1118	1117	1120	1128	1138	1146	1150
2007	PEAK		1302	1256	1296	1237	1272	1232	1235	1269	1263	1289	1309	1321
	ENERGY	1153	1171	1158	1158	1144	1138	1140	1139	1141	1151	1161	1168	1173
2008	PEAK		1335	1316	1328	1268	1304	1299	1297	1301	1295	1322	1342	1355
	ENERGY	1186	1200	1229	1187	1173	1166	1169	1168	1170	1180	1190	1197	1202
2009	PEAK		1362	1342	1355	1293	1330	1325	1318	1327	1321	1348	1368	1382
	ENERGY	1206	1224	1210	1211	1196	1190	1192	1191	1193	1203	1214	1221	1226
2010	PEAK		1388	1368	1381	1318	1356	1351	1337	1353	1347	1374	1395	1409
	ENERGY	1230	1248	1234	1234	1219	1213	1216	1214	1217	1227	1237	1245	1250
2011	PEAK		1414	1393	1407	1343	1381	1376	1369	1378	1372	1400	1421	1435
	ENERGY	1252	1271	1257	1257	1242	1235	1238	1237	1239	1249	1260	1268	1273
2012	PEAK		1439	1418	1432	1366	1405	1400	1398	1402	1395	1424	1446	1460
	ENERGY	1278	1294	1325	1279	1264	1257	1260	1258	1261	1271	1282	1290	1295
2013	PEAK		1461	1420	1454	1388	1427	1422	1412	1424	1417	1446	1469	1483
	ENERGY	1294	1314	1299	1299	1283	1277	1280	1278	1281	1291	1302	1311	1316

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California (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		169	163	146	136	135	141	157	144	109	123	139	167
	ENERGY	98	113	98	93	91	96	103	112	100	87	84	89	109
1995	PEAK		173	166	149	139	138	144	160	147	111	126	142	171
	ENERGY	100	116	100	95	93	98	105	115	102	89	86	91	112
1996	PEAK		176	170	152	142	141	147	162	150	113	128	145	174
	ENERGY	103	118	106	97	95	100	108	117	104	91	88	93	114
1997	PEAK		180	173	155	145	144	150	167	152	116	131	147	178
	ENERGY	104	120	104	99	97	102	110	120	106	93	89	95	116
1998	PEAK		183	176	158	148	146	153	170	155	118	133	150	181
	ENERGY	106	122	106	101	99	104	112	122	108	94	91	96	118
1999	PEAK		187	180	162	151	150	168	168	159	120	136	154	185
	ENERGY	109	125	109	103	101	106	114	124	111	96	93	99	121
2000	PEAK		192	185	166	155	154	161	176	163	124	140	158	190
	ENERGY	112	129	116	106	104	109	117	128	114	99	96	101	124
2001	PEAK		198	202	171	159	158	176	183	168	127	144	162	196
	ENERGY	115	132	115	109	107	112	121	131	117	102	98	104	128
2002	PEAK		203	196	176	164	163	183	189	172	131	148	167	201
	ENERGY	118	136	118	112	110	116	124	135	120	105	101	107	131
2003	PEAK		209	202	181	169	167	175	189	178	135	152	172	207
	ENERGY	121	140	122	115	113	119	128	139	124	108	104	110	135
2004	PEAK		215	208	186	174	172	180	198	183	139	157	177	213
	ENERGY	125	144	130	119	116	123	132	143	128	111	107	114	139
2005	PEAK		221	213	192	179	177	185	206	188	142	161	182	219
	ENERGY	129	148	129	122	119	126	135	147	131	114	110	117	143
2006	PEAK		227	244	197	184	182	190	211	193	146	166	187	225
	ENERGY	132	152	132	125	123	129	139	151	135	117	113	120	147
2007	PEAK		234	241	203	189	188	211	218	199	151	171	192	232
	ENERGY	136	157	136	129	126	133	143	156	139	121	116	124	151
2008	PEAK		242	233	209	195	193	202	222	205	156	176	199	239
	ENERGY	141	162	146	133	130	138	148	161	143	125	120	128	156
2009	PEAK		248	239	215	200	198	207	223	211	160	181	204	245
	ENERGY	144	166	144	137	134	141	151	165	147	128	123	131	160
2010	PEAK		254	245	220	205	203	212	229	216	164	185	209	252
	ENERGY	148	170	148	140	137	145	155	169	151	131	126	134	164
2011	PEAK		261	251	225	210	209	218	235	221	168	190	214	258
	ENERGY	151	175	151	144	141	148	159	173	154	134	129	137	168
2012	PEAK		267	258	231	216	214	223	245	227	172	195	219	264
	ENERGY	156	179	161	147	144	152	163	178	158	138	133	141	173
2013	PEAK		274	290	237	221	219	229	247	232	176	199	225	271
	ENERGY	159	183	159	151	148	156	167	182	162	141	136	144	177

Utah (Megawatts)

Year		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		2009	1994	1922	1855	1906	2251	2462	2294	2060	2003	2043	2064
	ENERGY	1590	1632	1605	1543	1493	1497	1588	1666	1642	1584	1588	1612	1630
1995	PEAK		2099	2083	2008	1939	1992	2352	2572	2397	2152	2092	2135	2156
	ENERGY	1661	1706	1677	1612	1560	1564	1660	1741	1716	1655	1660	1684	1703
1996	PEAK		2199	2182	2104	2031	2086	2464	2605	2510	2254	2192	2236	2259
	ENERGY	1745	1786	1819	1689	1634	1638	1738	1823	1797	1733	1739	1764	1784
1997	PEAK		2294	2276	2195	2119	2177	2570	2811	2619	2352	2287	2333	2356
	ENERGY	1816	1864	1832	1762	1705	1709	1814	1902	1875	1808	1814	1840	1861
1998	PEAK		2369	2351	2267	2188	2248	2654	2902	2705	2429	2361	2409	2434
	ENERGY	1875	1925	1892	1819	1760	1765	1873	1964	1936	1868	1873	1900	1922
1999	PEAK		2438	2420	2333	2252	2313	2725	3011	2784	2500	2430	2480	2505
	ENERGY	1930	1981	1947	1872	1812	1817	1928	2022	1993	1922	1928	1956	1979
2000	PEAK		2505	2486	2397	2314	2377	2807	2968	2860	2568	2497	2548	2574
	ENERGY	1988	2035	2072	1924	1861	1867	1981	2077	2047	1975	1981	2010	2033
2001	PEAK		2568	2605	2457	2372	2437	2850	3148	2932	2633	2560	2612	2638
	ENERGY	2033	2086	2051	1972	1908	1914	2030	2130	2099	2025	2030	2060	2084
2002	PEAK		2634	2614	2520	2432	2499	2923	3228	3007	2700	2625	2679	2706
	ENERGY	2085	2140	2104	2023	1957	1963	2083	2184	2152	2076	2083	2113	2137
2003	PEAK		2705	2685	2589	2499	2567	3032	3341	3089	2774	2697	2752	2779
	ENERGY	2141	2198	2161	2078	2010	2016	2139	2244	2211	2133	2139	2170	2195
2004	PEAK		2779	2758	2659	2566	2637	3114	3292	3173	2849	2770	2826	2855
	ENERGY	2206	2258	2299	2134	2065	2071	2197	2304	2271	2191	2197	2229	2255
2005	PEAK		2840	2818	2717	2623	2694	3182	3480	3242	2911	2831	2888	2917
	ENERGY	2248	2307	2268	2181	2110	2116	2245	2355	2321	2239	2245	2278	2304
2006	PEAK		2900	3011	2775	2679	2752	3250	3554	3311	2974	2891	2950	2980
	ENERGY	2296	2357	2317	2227	2155	2162	2293	2405	2370	2287	2293	2327	2354
2007	PEAK		2968	3011	2840	2741	2816	3293	3637	3388	3043	2958	3018	3049
	ENERGY	2349	2411	2370	2279	2205	2212	2347	2461	2425	2340	2347	2381	2408
2008	PEAK		3044	3021	2913	2812	2889	3412	3606	3476	3122	3035	3097	3128
	ENERGY	2416	2474	2519	2338	2262	2269	2407	2525	2488	2400	2407	2442	2471
2009	PEAK		3114	3090	2980	2876	2955	3489	3846	3555	3193	3104	3167	3199
	ENERGY	2465	2530	2487	2391	2314	2321	2462	2583	2545	2455	2462	2498	2527
2010	PEAK		3186	3162	3048	2942	3023	3570	3934	3637	3267	3176	3240	3273
	ENERGY	2522	2589	2545	2447	2367	2374	2519	2642	2604	2512	2519	2556	2585
2011	PEAK		3258	3233	3117	3009	3091	3651	4023	3720	3340	3248	3314	3347
	ENERGY	2579	2647	2602	2502	2421	2428	2576	2702	2663	2569	2576	2614	2644
2012	PEAK		3324	3298	3180	3070	3154	3724	3937	3795	3408	3313	3380	3414
	ENERGY	2638	2701	2750	2552	2470	2477	2628	2756	2716	2620	2628	2666	2697
2013	PEAK		3383	3503	3237	3125	3210	3791	4178	3863	3469	3373	3441	3476
	ENERGY	2678	2749	2702	2598	2514	2522	2675	2806	2765	2667	2675	2714	2746

PacifiCorp - RAMPP-3 Medium Forecast: Firm Load

South Idaho (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		250	248	226	214	244	425	466	410	317	248	222	206
	ENERGY	228	190	190	174	161	195	324	399	327	237	198	181	154
1995	PEAK		255	253	230	218	249	433	474	419	323	252	227	210
	ENERGY	232	193	194	177	164	199	330	407	334	242	202	185	158
1996	PEAK		258	256	233	220	252	438	495	423	327	255	229	213
	ENERGY	235	195	203	179	166	201	333	412	337	244	204	187	159
1997	PEAK		262	260	236	224	255	444	487	429	332	259	232	216
	ENERGY	238	198	199	182	168	204	338	418	342	248	207	190	161
1998	PEAK		264	262	239	226	258	448	492	434	335	262	235	218
	ENERGY	241	200	201	184	170	206	342	422	346	250	209	192	163
1999	PEAK		269	267	242	230	262	474	496	441	340	266	238	222
	ENERGY	245	203	204	187	173	209	347	429	351	254	213	195	166
2000	PEAK		274	272	248	235	268	466	526	450	348	272	244	226
	ENERGY	251	208	216	191	176	214	355	438	359	260	217	199	169
2001	PEAK		281	269	254	241	275	498	524	462	357	279	250	232
	ENERGY	256	213	214	196	181	219	364	450	368	267	223	204	174
2002	PEAK		289	287	261	247	283	509	538	475	367	286	257	239
	ENERGY	264	219	220	201	186	225	374	462	379	274	229	210	179
2003	PEAK		299	297	270	256	292	508	553	491	379	296	266	247
	ENERGY	273	227	228	208	192	233	387	478	392	283	237	217	185
2004	PEAK		309	307	279	264	302	525	593	507	392	306	274	255
	ENERGY	282	234	244	215	199	241	400	494	405	293	245	224	191
2005	PEAK		316	313	285	270	308	536	587	518	400	312	280	260
	ENERGY	288	239	240	219	203	246	408	504	413	299	250	229	195
2006	PEAK		321	283	290	275	314	545	597	527	407	318	285	265
	ENERGY	293	244	245	223	206	250	416	513	420	304	255	233	198
2007	PEAK		328	312	296	281	321	578	611	539	416	325	291	271
	ENERGY	299	249	250	228	211	255	425	524	430	311	260	238	203
2008	PEAK		335	333	303	287	328	569	644	551	425	332	298	277
	ENERGY	306	254	265	233	216	261	434	536	439	318	266	243	207
2009	PEAK		341	339	308	292	333	580	634	560	433	338	303	282
	ENERGY	311	259	260	237	219	266	442	545	447	323	271	248	211
2010	PEAK		348	345	314	297	339	590	645	570	441	344	309	287
	ENERGY	317	263	265	242	223	271	450	555	455	329	275	252	215
2011	PEAK		354	351	320	303	346	601	656	581	449	350	314	292
	ENERGY	323	268	270	246	228	276	458	565	463	335	281	257	219
2012	PEAK		359	357	324	307	351	610	689	589	455	356	319	296
	ENERGY	328	272	283	250	231	280	465	574	470	340	285	260	222
2013	PEAK		363	322	328	310	354	616	672	596	460	359	322	299
	ENERGY	331	275	276	252	233	282	470	580	475	344	288	263	224

West Wyoming (Megawatts)

Year		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		291	290	278	284	276	269	274	272	258	271	270	284
	ENERGY	248	260	262	256	256	247	245	245	245	242	237	241	245
1995	PEAK		285	285	273	278	270	264	267	267	253	266	264	279
	ENERGY	244	255	257	251	251	242	240	240	240	237	232	236	240
1996	PEAK		287	286	274	280	272	265	270	269	255	267	266	280
	ENERGY	246	257	268	253	252	244	242	241	241	238	233	237	242
1997	PEAK		273	272	260	266	258	252	255	255	242	254	253	266
	ENERGY	233	244	246	240	239	231	230	229	229	227	222	225	229
1998	PEAK		285	284	272	277	269	263	266	266	252	265	264	278
	ENERGY	243	255	257	251	250	241	240	239	239	236	231	235	239
1999	PEAK		293	292	280	286	278	264	268	274	260	273	272	286
	ENERGY	250	262	264	258	257	249	247	247	247	244	238	242	247
2000	PEAK		302	301	289	295	286	279	284	283	268	282	280	295
	ENERGY	259	270	282	266	265	257	254	254	254	251	246	250	254
2001	PEAK		312	287	298	304	296	282	292	292	277	291	289	305
	ENERGY	266	279	282	275	274	265	263	263	263	259	254	258	263
2002	PEAK		322	321	308	314	305	293	301	301	286	300	298	314
	ENERGY	275	288	290	284	283	273	271	271	271	268	262	266	271
2003	PEAK		319	318	304	311	302	295	293	298	283	297	295	311
	ENERGY	272	285	287	281	280	270	268	268	268	265	259	263	268
2004	PEAK		302	302	289	295	286	280	284	283	268	282	280	295
	ENERGY	259	271	282	266	265	257	255	254	254	251	246	250	255
2005	PEAK		271	270	258	264	256	250	253	253	240	252	251	264
	ENERGY	231	242	244	238	238	230	228	228	228	225	220	224	228
2006	PEAK		226	208	216	220	214	209	208	211	200	211	209	221
	ENERGY	193	202	204	199	198	192	190	190	190	188	184	187	190
2007	PEAK		167	153	159	163	158	151	156	156	148	155	155	163
	ENERGY	142	149	150	147	146	142	140	140	140	139	136	138	141
2008	PEAK		173	172	165	169	164	160	162	162	153	161	160	169
	ENERGY	148	155	162	152	152	147	146	146	146	144	141	143	146
2009	PEAK		179	178	171	174	169	165	164	167	159	167	166	175
	ENERGY	152	160	161	157	157	152	150	150	150	149	145	148	150
2010	PEAK		185	184	176	180	175	171	160	173	164	172	171	180
	ENERGY	157	165	166	163	162	157	155	155	155	153	150	153	155
2011	PEAK		190	190	182	186	180	176	167	178	169	177	176	186
	ENERGY	162	170	172	168	167	161	160	160	160	158	155	157	160
2012	PEAK		196	195	187	191	185	181	184	183	174	182	181	191
	ENERGY	168	175	183	173	172	166	165	165	165	163	159	162	165
2013	PEAK		201	189	192	196	191	186	184	188	179	188	187	197
	ENERGY	172	180	182	177	177	171	169	169	169	167	164	166	170

PacifiCorp - RAMPP-3 Medium Forecast: Firm Load

Total Company (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		7497	7412	6935	6484	6274	6783	7147	7063	6527	6669	6987	7503
	ENERGY	5354	5717	5623	5277	4999	5043	5199	5494	5377	5207	5188	5412	5718
1995	PEAK		7680	7594	7104	6642	6428	6956	7331	7245	6694	6835	7161	7687
	ENERGY	5484	5855	5759	5404	5119	5164	5326	5629	5509	5334	5315	5544	5857
1996	PEAK		7881	7792	7290	6817	6600	7146	7533	7444	6876	7018	7352	7890
	ENERGY	5645	6009	6121	5546	5253	5299	5466	5777	5655	5476	5457	5691	6011
1997	PEAK		8067	7976	7461	6977	6756	7322	7734	7627	7043	7186	7529	8078
	ENERGY	5759	6149	6047	5674	5374	5421	5592	5912	5787	5603	5585	5824	6152
1998	PEAK		8244	8152	7627	7133	6910	7490	7908	7802	7204	7349	7698	8256
	ENERGY	5891	6288	6183	5803	5498	5545	5720	6046	5919	5732	5714	5957	6291
1999	PEAK		8428	8333	7798	7294	7067	7664	8093	7980	7369	7515	7871	8441
	ENERGY	6024	6430	6323	5935	5623	5671	5850	6183	6053	5862	5844	6092	6432
2000	PEAK		8632	8536	7987	7472	7240	7850	8277	8176	7549	7699	8063	8646
	ENERGY	6189	6586	6709	6080	5761	5810	5994	6335	6201	6006	5987	6241	6589
2001	PEAK		8842	8784	8181	7654	7417	8044	8494	8376	7734	7887	8259	8856
	ENERGY	6323	6747	6635	6228	5902	5953	6141	6490	6354	6153	6133	6393	6750
2002	PEAK		9055	8954	8379	7840	7598	8242	8722	8581	7923	8079	8459	9069
	ENERGY	6477	6911	6797	6381	6046	6099	6292	6651	6510	6304	6284	6549	6914
2003	PEAK		9273	9170	8581	8028	7783	8444	8925	8793	8117	8275	8664	9288
	ENERGY	6634	7078	6960	6534	6191	6245	6446	6814	6669	6457	6436	6707	7080
2004	PEAK		9483	9377	8775	8208	7959	8640	9112	8997	8304	8463	8862	9498
	ENERGY	6803	7236	7369	6679	6329	6384	6593	6970	6821	6603	6581	6858	7239
2005	PEAK		9640	9532	8919	8340	8087	8783	9282	9147	8441	8601	9009	9656
	ENERGY	6890	7351	7227	6783	6425	6484	6696	7082	6929	6707	6686	6967	7356
2006	PEAK		9785	9675	9052	8460	8204	8916	9416	9287	8569	8730	9145	9803
	ENERGY	6988	7455	7329	6877	6512	6573	6790	7184	7028	6802	6781	7068	7463
2007	PEAK		9938	9890	9192	8586	8326	9065	9572	9433	8702	8864	9289	9958
	ENERGY	7088	7563	7433	6972	6600	6665	6887	7289	7130	6900	6879	7171	7575
2008	PEAK		10179	10064	9415	8795	8529	9277	9791	9664	8914	9080	9515	10200
	ENERGY	7283	7748	7887	7143	6762	6828	7056	7468	7305	7069	7048	7347	7759
2009	PEAK		10388	10271	9609	8977	8706	9470	10022	9864	9099	9268	9711	10410
	ENERGY	7412	7908	7772	7291	6902	6970	7202	7622	7456	7215	7194	7499	7920
2010	PEAK		10602	10482	9807	9162	8887	9667	10216	10069	9288	9459	9912	10624
	ENERGY	7565	8071	7932	7442	7046	7114	7352	7780	7610	7365	7343	7654	8083
2011	PEAK		10816	10693	10005	9348	9068	9864	10433	10274	9477	9651	10113	10838
	ENERGY	7719	8235	8093	7593	7190	7259	7501	7938	7765	7515	7492	7809	8247
2012	PEAK		11020	10895	10195	9525	9240	10051	10607	10469	9656	9834	10304	11043
	ENERGY	7888	8391	8541	7738	7326	7396	7643	8088	7912	7657	7634	7957	8403
2013	PEAK		11206	11080	10367	9687	9396	10220	10823	10645	9818	10000	10479	11230
	ENERGY	7998	8534	8386	7869	7450	7522	7772	8223	8045	7786	7763	8092	8545

Oregon (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		2654	2612	2408	2170	1943	1943	1982	2038	1899	2125	2329	2668
	ENERGY	1622	1836	1802	1639	1503	1519	1471	1542	1549	1510	1526	1687	1883
1995	PEAK		2658	2616	2412	2174	1946	1946	1967	2041	1902	2129	2333	2673
	ENERGY	1624	1839	1805	1642	1505	1521	1474	1545	1552	1512	1528	1689	1886
1996	PEAK		2677	2635	2429	2189	1960	1960	1981	2056	1915	2144	2350	2692
	ENERGY	1641	1852	1883	1654	1516	1532	1485	1556	1563	1523	1539	1701	1899
1997	PEAK		2710	2667	2459	2216	1984	1985	2024	2081	1939	2170	2379	2725
	ENERGY	1656	1875	1840	1674	1535	1551	1503	1575	1582	1542	1558	1722	1923
1998	PEAK		2730	2688	2478	2233	1999	2000	2040	2097	1954	2187	2397	2746
	ENERGY	1669	1889	1854	1687	1547	1563	1514	1587	1594	1554	1570	1735	1937
1999	PEAK		2759	2716	2504	2256	2020	2020	2051	2119	1974	2210	2422	2774
	ENERGY	1686	1908	1874	1704	1563	1579	1530	1604	1611	1570	1586	1753	1958
2000	PEAK		2799	2755	2539	2289	2049	2049	2071	2149	2002	2241	2456	2814
	ENERGY	1715	1936	1968	1729	1585	1602	1552	1627	1634	1592	1609	1779	1986
2001	PEAK		2838	2807	2575	2321	2078	2096	2120	2179	2030	2273	2491	2854
	ENERGY	1734	1963	1927	1753	1607	1624	1573	1649	1657	1615	1632	1804	2014
2002	PEAK		2875	2829	2608	2351	2105	2114	2152	2207	2057	2302	2523	2891
	ENERGY	1757	1989	1952	1776	1628	1645	1594	1671	1678	1636	1653	1827	2040
2003	PEAK		2918	2872	2648	2386	2136	2137	2179	2241	2088	2337	2561	2934
	ENERGY	1783	2018	1981	1802	1653	1670	1618	1696	1703	1660	1678	1854	2070
2004	PEAK		2960	2914	2686	2421	2167	2168	2190	2273	2118	2371	2598	2977
	ENERGY	1814	2047	2082	1829	1677	1694	1642	1721	1728	1684	1702	1881	2100
2005	PEAK		2994	2947	2717	2448	2192	2192	2235	2299	2142	2398	2628	3011
	ENERGY	1829	2071	2033	1849	1696	1713	1660	1740	1748	1703	1721	1903	2124
2006	PEAK		3026	2978	2746	2475	2216	2216	2251	2324	2165	2423	2656	3043
	ENERGY	1849	2093	2055	1869	1714	1732	1678	1759	1767	1722	1740	1923	2147
2007	PEAK		3070	3037	2785	2510	2248	2267	2282	2357	2196	2458	2694	3087
	ENERGY	1876	2124	2085	1896	1739	1757	1702	1784	1792	1747	1765	1951	2178
2008	PEAK		3113	3064	2824	2545	2279	2279	2303	2390	2227	2493	2732	3130
	ENERGY	1908	2153	2189	1923	1763	1781	1726	1809	1818	1771	1790	1978	2209
2009	PEAK		3152	3103	2860	2578	2308	2309	2345	2421	2256	2525	2767	3170
	ENERGY	1926	2181	2141	1947	1786	1804	1748	1832	1841	1794	1813	2004	2237
2010	PEAK		3195	3145	2899	2613	2339	2340	2386	2454	2286	2559	2804	3213
	ENERGY	1952	2210	2170	1974	1810	1829	1771	1857	1865	1818	1837	2031	2267
2011	PEAK		3239	3189	2939	2649	2372	2372	2419	2488	2318	2594	2843	3257
	ENERGY	1980	2241	2200	2001	1835	1854	1796	1883	1891	1843	1863	2059	2299
2012	PEAK		3284	3232	2980	2686	2404	2405	2430	2522	2350	2630	2882	3302
	ENERGY	2013	2272	2310	2029	1860	1879	1821	1909	1917	1869	1888	2087	2330
2013	PEAK		3323	3271	3015	2718	2433	2434	2487	2552	2378	2661	2917	3342
	ENERGY	2031	2299	2257	2053	1882	1902	1842	1931	1940	1891	1911	2112	2358

PacifiCorp - RAMPP-3 Medium Low Forecast: Firm Load

Washington(Megawatts)

Year		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		794	794	663	605	552	548	638	686	671	649	696	778
	ENERGY	481	550	543	467	424	432	414	476	459	480	473	491	567
1995	PEAK		818	817	682	623	568	565	702	707	692	668	716	802
	ENERGY	495	566	559	481	436	444	426	490	472	495	487	506	584
1996	PEAK		839	839	700	639	583	579	720	725	709	685	735	822
	ENERGY	510	581	594	493	448	456	437	503	485	508	500	519	599
1997	PEAK		856	855	714	652	595	591	692	740	724	699	750	839
	ENERGY	518	593	585	503	457	465	446	513	494	518	510	529	611
1998	PEAK		862	862	719	657	599	595	695	745	729	704	755	845
	ENERGY	522	597	589	507	460	469	449	516	498	522	514	533	615
1999	PEAK		871	870	727	664	605	601	688	753	736	711	763	853
	ENERGY	527	603	595	512	464	473	454	522	503	527	519	539	622
2000	PEAK		882	881	736	672	613	609	756	762	745	720	772	864
	ENERGY	536	610	624	519	470	479	460	528	509	533	525	546	629
2001	PEAK		894	918	746	681	621	648	718	772	755	730	783	876
	ENERGY	541	619	611	525	477	486	466	535	516	540	532	553	638
2002	PEAK		905	905	755	690	629	656	738	782	765	739	793	887
	ENERGY	548	627	619	532	483	492	472	542	523	547	539	560	646
2003	PEAK		917	917	765	699	638	633	742	793	776	749	803	899
	ENERGY	556	635	627	539	489	498	478	549	530	555	547	567	655
2004	PEAK		929	929	775	708	646	641	797	803	786	759	814	911
	ENERGY	565	643	658	546	496	505	485	556	537	562	554	575	663
2005	PEAK		939	939	784	716	653	648	755	812	794	767	823	920
	ENERGY	569	650	642	552	501	510	490	562	542	568	560	581	670
2006	PEAK		949	948	791	723	659	655	747	820	802	775	831	930
	ENERGY	575	657	648	558	506	515	494	568	548	574	565	587	677
2007	PEAK		959	985	800	731	667	693	756	829	811	783	840	940
	ENERGY	581	664	656	564	512	521	500	574	554	580	572	593	685
2008	PEAK		971	970	810	740	675	670	833	839	821	793	850	951
	ENERGY	590	672	687	571	518	527	506	581	560	587	578	601	693
2009	PEAK		980	979	818	747	681	676	774	847	829	800	858	960
	ENERGY	594	678	670	576	523	533	511	587	566	593	584	606	699
2010	PEAK		989	988	825	754	687	683	796	855	836	808	866	969
	ENERGY	599	685	676	582	527	537	516	592	571	598	589	612	706
2011	PEAK		998	997	832	760	694	689	802	862	844	815	874	978
	ENERGY	604	691	682	587	532	542	520	598	576	604	595	617	712
2012	PEAK		1006	1005	839	766	699	694	863	869	850	821	881	985
	ENERGY	611	696	712	591	536	546	524	602	581	608	599	622	718
2013	PEAK		1012	1011	844	771	703	698	827	874	855	826	886	991
	ENERGY	613	700	691	595	540	550	527	606	584	612	603	626	722

North Idaho (Megawatts)

Year		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		60	60	51	44	40	36	33	37	36	41	47	54
	ENERGY	31	39	39	35	31	27	26	26	26	27	28	34	36
1995	PEAK		61	61	51	44	40	37	38	38	37	41	48	54
	ENERGY	31	39	39	35	31	27	26	26	26	27	28	34	37
1996	PEAK		62	62	52	45	41	37	38	38	37	42	49	55
	ENERGY	32	40	41	36	32	27	26	26	26	27	29	35	37
1997	PEAK		63	63	53	46	42	38	34	39	38	43	49	56
	ENERGY	32	41	41	36	32	28	27	27	27	28	29	35	38
1998	PEAK		63	63	53	46	42	38	34	39	38	43	49	56
	ENERGY	32	41	41	36	32	28	27	27	27	28	29	35	38
1999	PEAK		64	63	54	46	42	39	33	40	39	43	50	57
	ENERGY	33	41	41	37	32	28	27	27	27	28	29	36	38
2000	PEAK		65	64	55	47	43	39	40	40	39	44	51	58
	ENERGY	33	42	43	37	33	29	27	27	27	29	30	36	39
2001	PEAK		66	57	55	48	43	36	35	41	40	45	52	59
	ENERGY	34	42	42	38	33	29	28	28	28	29	30	37	39
2002	PEAK		66	66	56	49	44	36	36	41	40	45	52	59
	ENERGY	34	43	43	38	34	29	28	28	28	29	31	37	40
2003	PEAK		68	67	57	49	45	41	36	42	41	46	53	60
	ENERGY	35	44	44	39	34	30	29	29	29	30	31	38	41
2004	PEAK		69	68	58	50	45	42	43	43	42	47	54	61
	ENERGY	35	44	46	40	35	30	29	29	29	30	32	38	41
2005	PEAK		70	69	59	51	46	42	38	43	42	47	55	62
	ENERGY	36	45	45	40	35	31	29	30	29	31	32	39	42
2006	PEAK		70	70	60	51	46	43	38	44	43	48	55	63
	ENERGY	36	45	45	41	36	31	30	30	30	31	33	39	42
2007	PEAK		72	63	61	52	47	39	38	45	43	49	56	64
	ENERGY	37	46	46	41	37	32	30	30	30	32	33	40	43
2008	PEAK		73	73	62	53	48	44	45	45	44	50	57	65
	ENERGY	38	47	49	42	37	32	31	31	31	32	34	41	44
2009	PEAK		74	73	62	54	49	44	40	46	45	50	58	66
	ENERGY	38	47	47	42	37	32	31	31	31	32	34	41	44
2010	PEAK		74	74	63	54	49	45	40	46	45	51	58	66
	ENERGY	38	48	48	43	38	33	31	31	31	33	34	41	45
2011	PEAK		75	75	63	55	49	45	41	47	45	51	59	67
	ENERGY	38	48	48	43	38	33	32	32	32	33	35	42	45
2012	PEAK		76	75	64	55	50	46	47	47	46	52	59	68
	ENERGY	39	49	51	44	39	33	32	32	32	33	35	42	46
2013	PEAK		76	76	64	56	50	46	41	47	46	52	60	68
	ENERGY	39	49	49	44	39	34	32	32	32	34	35	43	46

PacifiCorp - RAMPP-3 Medium Low Forecast: Firm Load

Montana (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		153	151	141	130	114	109	99569	114	119	125	133	149
	ENERGY	97	115	113	107	95	89	86	83	83	87	93	104	108
1995	PEAK		156	153	143	132	117	111	114	116	121	127	135	152
	ENERGY	99	117	115	109	97	90	88	84	84	89	94	106	110
1996	PEAK		159	156	146	135	119	113	116	118	123	129	138	155
	ENERGY	101	120	122	111	99	92	89	86	86	90	96	108	112
1997	PEAK		162	160	149	138	121	116	104	120	126	132	141	158
	ENERGY	103	122	120	113	101	94	91	88	88	92	98	110	114
1998	PEAK		163	161	150	138	122	116	106	121	127	133	142	159
	ENERGY	103	123	121	114	101	95	92	88	88	93	99	111	115
1999	PEAK		164	162	152	140	123	117	106	122	128	134	143	161
	ENERGY	104	124	122	115	102	95	93	89	89	94	100	112	116
2000	PEAK		166	164	153	141	125	119	122	124	129	135	145	162
	ENERGY	106	126	128	117	104	96	94	90	90	95	101	113	117
2001	PEAK		168	162	155	143	126	110	111	125	131	137	146	164
	ENERGY	107	127	125	118	105	98	95	91	91	96	102	115	119
2002	PEAK		170	168	157	145	127	111	111	126	132	139	148	166
	ENERGY	108	128	126	119	106	99	96	92	92	97	103	116	120
2003	PEAK		172	170	159	146	129	123	112	128	134	140	150	168
	ENERGY	109	130	128	121	107	100	97	93	93	98	104	117	122
2004	PEAK		174	172	161	148	131	124	128	130	136	142	152	170
	ENERGY	111	132	134	122	108	101	98	95	95	99	106	119	123
2005	PEAK		176	174	163	150	132	126	116	131	137	144	153	172
	ENERGY	112	133	131	124	110	102	99	96	96	100	107	120	125
2006	PEAK		178	176	165	152	134	127	117	133	139	145	155	174
	ENERGY	113	135	132	125	111	104	100	97	97	102	108	122	126
2007	PEAK		181	178	167	154	136	119	117	135	141	147	157	177
	ENERGY	115	137	134	127	113	105	102	98	98	103	110	123	128
2008	PEAK		184	181	169	156	138	131	135	137	143	150	160	179
	ENERGY	117	139	141	129	114	107	103	100	100	105	112	125	130
2009	PEAK		186	183	172	158	139	133	120	138	145	152	162	182
	ENERGY	118	141	138	130	116	108	105	101	101	106	113	127	132
2010	PEAK		188	186	174	160	141	134	123	140	146	153	164	184
	ENERGY	119	142	140	132	117	109	106	102	102	107	114	128	133
2011	PEAK		191	188	176	162	143	136	125	142	148	155	166	186
	ENERGY	121	144	141	134	119	111	107	104	104	109	116	130	135
2012	PEAK		193	190	178	164	145	138	142	144	150	157	168	188
	ENERGY	123	146	148	135	120	112	109	105	105	110	117	132	136
2013	PEAK		195	193	180	166	146	139	126	145	152	159	170	191
	ENERGY	124	147	145	137	122	113	110	106	106	111	119	133	138

East Wyoming (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		998	984	993	948	975	971	951	973	968	988	1003	1013
	ENERGY	884	897	887	887	877	872	874	873	875	882	890	895	899
1995	PEAK		1003	989	998	953	980	976	975	978	973	993	1008	1018
	ENERGY	888	902	892	892	881	876	878	877	879	886	894	900	903
1996	PEAK		1007	993	1002	957	984	980	979	982	977	997	1012	1022
	ENERGY	895	906	927	896	885	880	882	881	883	890	898	903	907
1997	PEAK		1009	994	1004	958	985	982	957	983	979	999	1014	1024
	ENERGY	893	907	897	897	886	881	883	882	884	891	899	905	908
1998	PEAK		1022	1007	1017	970	998	994	968	996	991	1011	1027	1037
	ENERGY	905	919	908	908	897	893	895	894	896	903	911	916	920
1999	PEAK		1033	1018	1027	981	1008	1005	994	1006	1002	1022	1038	1048
	ENERGY	915	928	918	918	907	902	904	903	905	912	920	926	930
2000	PEAK		1047	1031	1042	994	1022	1019	1017	1020	1015	1036	1052	1062
	ENERGY	930	941	964	931	919	914	917	915	917	925	933	939	942
2001	PEAK		1065	1028	1060	1012	1040	1014	1007	1038	1033	1054	1071	1081
	ENERGY	943	958	947	947	936	931	933	932	934	941	949	955	959
2002	PEAK		1085	1069	1080	1031	1060	1033	1032	1058	1053	1074	1091	1101
	ENERGY	961	976	965	965	953	948	950	949	951	959	967	973	977
2003	PEAK		1105	1089	1100	1050	1079	1076	1051	1077	1072	1094	1111	1122
	ENERGY	979	994	983	983	971	966	968	967	969	977	985	991	995
2004	PEAK		1128	1111	1122	1071	1101	1097	1096	1099	1094	1116	1133	1144
	ENERGY	1001	1014	1038	1003	990	985	987	986	988	996	1005	1011	1015
2005	PEAK		1141	1124	1135	1083	1114	1110	1081	1112	1106	1129	1146	1157
	ENERGY	1010	1026	1014	1014	1002	996	999	997	1000	1008	1017	1023	1027
2006	PEAK		1157	1140	1151	1099	1130	1126	1120	1128	1122	1145	1163	1174
	ENERGY	1025	1040	1029	1029	1016	1011	1013	1012	1014	1022	1031	1038	1042
2007	PEAK		1171	1129	1165	1112	1143	1108	1132	1141	1136	1159	1177	1188
	ENERGY	1037	1053	1041	1041	1028	1023	1025	1024	1026	1034	1043	1050	1054
2008	PEAK		1191	1174	1185	1131	1163	1159	1157	1161	1155	1179	1197	1209
	ENERGY	1058	1071	1097	1059	1046	1041	1043	1042	1044	1052	1062	1068	1073
2009	PEAK		1205	1188	1199	1145	1177	1173	1167	1175	1169	1193	1211	1223
	ENERGY	1068	1084	1072	1072	1059	1053	1055	1054	1057	1065	1074	1081	1085
2010	PEAK		1219	1202	1213	1158	1191	1187	1155	1189	1183	1207	1226	1237
	ENERGY	1080	1097	1084	1084	1071	1065	1068	1067	1069	1077	1087	1094	1098
2011	PEAK		1232	1214	1226	1170	1203	1199	1166	1201	1195	1220	1239	1251
	ENERGY	1092	1108	1096	1096	1082	1077	1079	1078	1080	1089	1098	1105	1110
2012	PEAK		1244	1226	1238	1182	1215	1211	1209	1213	1207	1232	1250	1262
	ENERGY	1105	1119	1146	1106	1093	1087	1089	1088	1090	1099	1109	1116	1120
2013	PEAK		1254	1236	1248	1191	1224	1220	1191	1222	1216	1241	1260	1272
	ENERGY	1110	1127	1115	1115	1101	1095	1098	1097	1099	1108	1117	1125	1129

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California (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		163	157	141	132	131	136	152	139	105	119	134	162
	ENERGY	95	109	95	90	88	93	100	109	97	84	81	86	106
1995	PEAK		165	159	142	133	132	138	151	140	106	120	135	163
	ENERGY	96	110	96	91	89	94	101	110	98	85	82	87	106
1996	PEAK		167	160	144	134	133	139	153	141	107	121	137	165
	ENERGY	97	112	100	92	90	95	102	111	99	86	83	88	108
1997	PEAK		169	162	146	136	135	141	156	143	108	123	138	167
	ENERGY	98	113	98	93	91	96	103	112	100	87	84	89	109
1998	PEAK		170	164	147	137	136	142	158	144	109	124	140	168
	ENERGY	99	114	99	94	92	97	104	113	101	88	84	90	110
1999	PEAK		173	166	149	139	138	144	155	147	111	126	142	171
	ENERGY	100	116	100	95	93	98	105	115	102	89	86	91	112
2000	PEAK		176	170	153	142	141	147	162	150	113	128	145	174
	ENERGY	103	118	106	97	95	100	108	117	105	91	88	93	114
2001	PEAK		180	185	156	145	144	162	167	153	116	131	148	178
	ENERGY	105	121	105	99	97	102	110	120	107	93	89	95	116
2002	PEAK		184	177	159	149	147	166	171	156	118	134	151	182
	ENERGY	107	123	107	101	99	105	112	122	109	95	91	97	119
2003	PEAK		188	181	163	152	151	157	175	160	121	137	155	186
	ENERGY	109	126	109	104	102	107	115	125	112	97	93	99	122
2004	PEAK		193	186	167	156	154	161	177	164	124	140	158	191
	ENERGY	112	129	116	106	104	110	118	128	114	99	96	102	125
2005	PEAK		197	190	171	159	158	165	183	167	127	143	162	195
	ENERGY	114	132	114	109	106	112	120	131	117	102	98	104	127
2006	PEAK		201	194	174	162	161	168	181	171	129	147	165	199
	ENERGY	117	135	117	111	109	115	123	134	119	104	100	106	130
2007	PEAK		206	212	179	167	165	186	184	175	133	150	169	204
	ENERGY	120	138	120	114	111	117	126	137	122	106	102	109	133
2008	PEAK		212	204	183	171	169	177	194	180	136	154	174	209
	ENERGY	123	142	128	117	114	120	129	141	126	109	105	112	137
2009	PEAK		216	208	187	174	173	180	194	183	139	157	177	214
	ENERGY	125	145	125	119	116	123	132	144	128	111	107	114	139
2010	PEAK		220	212	190	178	176	184	204	187	142	160	181	218
	ENERGY	128	147	128	121	119	125	134	146	130	113	109	116	142
2011	PEAK		224	216	194	181	179	187	208	190	144	163	184	222
	ENERGY	130	150	130	124	121	128	137	149	133	116	111	118	145
2012	PEAK		229	220	198	185	183	191	210	194	147	166	188	226
	ENERGY	133	153	138	126	124	130	140	152	136	118	114	121	148
2013	PEAK		233	224	202	188	186	195	216	198	150	170	191	230
	ENERGY	135	156	135	128	126	133	142	155	138	120	116	123	150

Utah (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		1951	1936	1867	1802	1852	2187	2391	2228	2001	1945	1985	2005
	ENERGY	1545	1586	1559	1499	1450	1454	1543	1618	1595	1538	1543	1566	1584
1995	PEAK		2004	1989	1918	1851	1902	2246	2374	2288	2055	1998	2039	2059
	ENERGY	1586	1629	1601	1539	1489	1494	1585	1662	1638	1580	1585	1608	1627
1996	PEAK		2048	2033	1960	1892	1944	2295	2426	2339	2100	2042	2083	2104
	ENERGY	1626	1664	1695	1573	1522	1526	1620	1699	1674	1615	1620	1643	1662
1997	PEAK		2096	2080	2006	1936	1989	2349	2569	2393	2149	2090	2132	2153
	ENERGY	1659	1703	1674	1610	1558	1562	1658	1738	1713	1653	1658	1682	1701
1998	PEAK		2130	2113	2038	1967	2021	2386	2610	2432	2184	2123	2166	2188
	ENERGY	1686	1730	1701	1635	1583	1587	1684	1766	1741	1679	1684	1709	1728
1999	PEAK		2161	2145	2068	1996	2051	2422	2669	2468	2216	2154	2198	2220
	ENERGY	1711	1756	1726	1660	1606	1611	1709	1792	1766	1704	1709	1734	1754
2000	PEAK		2194	2177	2099	2026	2082	2459	2599	2505	2250	2187	2232	2254
	ENERGY	1741	1783	1815	1685	1630	1635	1735	1820	1793	1730	1735	1760	1780
2001	PEAK		2226	2258	2130	2056	2112	2470	2728	2541	2282	2219	2264	2286
	ENERGY	1762	1808	1778	1709	1654	1659	1760	1846	1819	1755	1760	1786	1806
2002	PEAK		2261	2243	2163	2088	2145	2509	2771	2581	2318	2253	2299	2322
	ENERGY	1789	1837	1806	1736	1680	1685	1787	1875	1848	1782	1788	1814	1835
2003	PEAK		2300	2283	2201	2124	2183	2577	2819	2626	2358	2293	2340	2363
	ENERGY	1821	1869	1837	1766	1709	1714	1819	1908	1880	1813	1819	1845	1867
2004	PEAK		2340	2323	2239	2162	2221	2623	2772	2672	2400	2333	2380	2404
	ENERGY	1858	1902	1936	1797	1739	1744	1850	1941	1913	1845	1850	1878	1899
2005	PEAK		2371	2353	2268	2190	2250	2657	2906	2707	2431	2363	2411	2436
	ENERGY	1877	1926	1894	1821	1762	1767	1875	1966	1938	1869	1875	1902	1924
2006	PEAK		2403	2385	2300	2220	2280	2693	2968	2744	2464	2396	2444	2469
	ENERGY	1902	1953	1920	1846	1786	1791	1900	1993	1964	1895	1900	1928	1950
2007	PEAK		2440	2475	2335	2253	2315	2707	3013	2786	2502	2432	2482	2507
	ENERGY	1931	1983	1949	1874	1813	1818	1929	2023	1994	1924	1929	1957	1980
2008	PEAK		2481	2462	2374	2292	2354	2780	2939	2833	2544	2473	2524	2549
	ENERGY	1969	2016	2053	1905	1844	1849	1962	2058	2028	1956	1962	1990	2013
2009	PEAK		2516	2497	2408	2324	2388	2820	3107	2873	2580	2508	2559	2585
	ENERGY	1992	2045	2010	1932	1870	1875	1990	2087	2056	1984	1990	2019	2042
2010	PEAK		2553	2533	2443	2358	2422	2861	3128	2915	2617	2545	2597	2623
	ENERGY	2021	2074	2039	1960	1897	1903	2018	2117	2086	2013	2019	2048	2072
2011	PEAK		2589	2569	2477	2391	2457	2901	3173	2956	2655	2581	2633	2660
	ENERGY	2049	2104	2068	1988	1924	1930	2047	2147	2116	2041	2047	2077	2101
2012	PEAK		2622	2602	2508	2421	2488	2938	3105	2993	2688	2613	2666	2693
	ENERGY	2081	2130	2169	2013	1948	1954	2073	2174	2143	2067	2073	2103	2127
2013	PEAK		2650	2630	2536	2448	2515	2970	3248	3026	2717	2642	2696	2723
	ENERGY	2098	2153	2117	2035	1969	1975	2096	2198	2166	2089	2096	2126	2151

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South Idaho (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		245	243	221	209	239	416	456	402	310	242	217	202
	ENERGY	223	186	186	170	157	191	317	391	320	232	194	178	151
1995	PEAK		247	245	223	211	241	420	474	406	313	245	220	204
	ENERGY	225	187	188	172	159	192	320	395	324	234	196	179	153
1996	PEAK		247	245	223	211	241	420	474	406	313	245	220	204
	ENERGY	226	187	195	172	159	192	320	395	324	234	196	179	153
1997	PEAK		248	246	224	212	242	421	461	407	315	246	220	205
	ENERGY	226	188	189	172	160	193	321	397	325	235	197	180	153
1998	PEAK		248	246	224	212	242	421	461	407	314	246	220	205
	ENERGY	226	188	189	172	159	193	321	396	325	235	197	180	153
1999	PEAK		249	247	225	213	243	423	462	409	316	247	221	206
	ENERGY	227	189	190	173	160	194	323	398	326	236	198	181	154
2000	PEAK		252	250	227	215	246	428	483	413	319	249	224	208
	ENERGY	230	191	199	175	162	196	326	402	330	239	200	183	156
2001	PEAK		255	243	231	218	249	450	475	419	324	253	227	211
	ENERGY	233	194	195	177	164	199	330	408	334	242	202	185	158
2002	PEAK		260	258	234	222	254	457	483	426	329	257	231	214
	ENERGY	237	197	198	180	167	202	336	415	340	246	206	188	160
2003	PEAK		265	264	240	227	259	451	493	436	336	263	236	219
	ENERGY	242	201	202	184	171	207	343	424	347	251	210	192	164
2004	PEAK		271	269	245	232	265	460	520	445	344	268	241	224
	ENERGY	248	205	214	188	174	211	351	433	355	257	215	197	167
2005	PEAK		273	271	247	234	267	464	508	449	346	271	243	226
	ENERGY	249	207	208	190	176	213	354	437	358	259	217	198	169
2006	PEAK		275	273	248	235	268	466	508	451	348	272	244	227
	ENERGY	250	208	209	191	177	214	355	439	359	260	218	199	170
2007	PEAK		277	264	250	237	270	488	511	454	351	274	246	228
	ENERGY	252	210	211	192	178	216	358	442	362	262	219	201	171
2008	PEAK		279	277	252	239	273	474	536	458	354	276	248	230
	ENERGY	255	212	220	194	179	217	361	446	366	264	221	202	172
2009	PEAK		280	278	253	240	274	476	519	460	355	277	249	231
	ENERGY	255	212	213	195	180	218	362	447	367	265	222	203	173
2010	PEAK		281	279	254	240	274	477	523	461	356	278	250	232
	ENERGY	256	213	214	195	181	219	364	449	368	266	223	204	174
2011	PEAK		282	280	255	241	275	479	524	463	357	279	250	233
	ENERGY	257	214	215	196	181	220	365	450	369	267	223	204	174
2012	PEAK		282	279	254	241	275	478	540	462	357	279	250	232
	ENERGY	257	213	222	196	181	219	364	450	369	267	223	204	174
2013	PEAK		280	278	253	239	273	475	520	459	354	277	248	231
	ENERGY	255	212	213	194	180	218	362	447	366	265	222	203	173

West Wyoming (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		290	289	277	282	274	268	270	271	257	270	268	283
	ENERGY	247	259	261	255	254	246	244	244	244	241	236	240	244
1995	PEAK		283	282	271	276	268	262	266	265	251	264	262	277
	ENERGY	242	253	255	249	249	240	238	238	238	235	230	234	238
1996	PEAK		281	280	268	274	266	260	264	263	249	262	260	274
	ENERGY	240	251	262	248	247	238	237	236	236	234	228	232	237
1997	PEAK		256	255	244	249	242	236	239	239	227	238	237	250
	ENERGY	218	229	231	225	225	217	215	215	215	213	208	212	215
1998	PEAK		258	257	246	251	244	238	241	241	229	240	239	252
	ENERGY	220	231	232	227	226	219	217	217	217	214	210	213	217
1999	PEAK		257	256	246	251	243	238	235	241	228	240	238	251
	ENERGY	219	230	232	226	226	218	216	216	216	214	209	213	216
2000	PEAK		257	256	246	251	243	238	241	241	228	239	238	251
	ENERGY	220	230	240	226	226	218	216	216	216	214	209	213	216
2001	PEAK		258	238	247	252	244	234	241	242	229	241	239	252
	ENERGY	220	231	233	227	227	219	217	217	217	215	210	213	217
2002	PEAK		259	259	248	253	245	235	242	243	230	242	240	253
	ENERGY	221	232	234	228	228	220	218	218	218	216	211	214	218
2003	PEAK		260	259	248	254	246	240	243	243	231	242	241	254
	ENERGY	222	233	234	229	228	221	219	219	219	216	211	215	219
2004	PEAK		261	260	249	255	247	241	245	244	232	243	242	255
	ENERGY	223	234	244	230	229	222	220	220	220	217	212	216	220
2005	PEAK		260	259	248	253	246	240	244	243	231	242	241	254
	ENERGY	222	233	234	229	228	221	219	219	219	216	211	215	219
2006	PEAK		260	259	248	253	246	240	238	243	230	242	241	254
	ENERGY	222	232	234	229	228	220	219	219	219	216	211	215	219
2007	PEAK		258	238	247	252	245	232	236	242	229	241	239	252
	ENERGY	220	231	233	228	227	219	217	217	217	215	210	214	217
2008	PEAK		259	258	247	252	245	239	243	242	230	241	240	253
	ENERGY	222	232	242	228	227	220	218	218	218	215	211	214	218
2009	PEAK		258	257	246	251	244	238	236	241	229	240	239	252
	ENERGY	220	231	233	227	226	219	217	217	217	214	210	213	217
2010	PEAK		257	256	246	251	243	238	239	240	228	239	238	251
	ENERGY	219	230	232	226	226	218	216	216	216	214	209	213	216
2011	PEAK		256	255	245	250	242	237	238	240	227	239	237	250
	ENERGY	218	229	231	226	225	217	216	215	215	213	208	212	216
2012	PEAK		255	254	244	249	241	236	240	239	226	238	236	249
	ENERGY	218	228	238	225	224	216	215	215	215	212	207	211	215
2013	PEAK		254	253	242	247	240	235	237	237	225	236	235	248
	ENERGY	216	227	229	224	223	215	214	214	214	211	206	210	214

PacifiCorp - RAMPP-3 Medium Low Forecast: Firm Load

Total Company (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		7308	7226	6762	6323	6119	6615	106441	6888	6367	6504	6813	7314
	ENERGY	5224	5577	5486	5149	4879	4921	5074	5361	5247	5081	5063	5280	5577
1995	PEAK		7395	7312	6841	6398	6194	6700	7061	6978	6450	6584	6896	7401
	ENERGY	5287	5643	5551	5210	4936	4979	5135	5427	5311	5144	5125	5343	5644
1996	PEAK		7487	7403	6926	6477	6271	6784	7152	7068	6533	6667	6983	7494
	ENERGY	5367	5713	5820	5274	4996	5039	5197	5493	5376	5207	5188	5409	5713
1997	PEAK		7569	7484	7000	6544	6336	6859	7237	7147	6605	6739	7060	7577
	ENERGY	5404	5770	5675	5325	5043	5088	5247	5547	5429	5258	5241	5464	5773
1998	PEAK		7646	7560	7072	6612	6403	6931	7312	7222	6674	6810	7135	7655
	ENERGY	5462	5831	5734	5381	5097	5142	5302	5604	5486	5314	5297	5523	5834
1999	PEAK		7731	7644	7151	6686	6475	7009	7394	7304	6750	6887	7215	7741
	ENERGY	5522	5896	5798	5441	5154	5199	5361	5666	5546	5373	5356	5584	5899
2000	PEAK		7837	7749	7249	6778	6563	7106	7492	7404	6842	6981	7314	7848
	ENERGY	5614	5976	6087	5516	5224	5270	5434	5743	5622	5447	5429	5661	5980
2001	PEAK		7950	7896	7354	6875	6658	7219	7603	7510	6940	7082	7420	7961
	ENERGY	5678	6063	5962	5595	5300	5346	5512	5826	5703	5525	5508	5742	6067
2002	PEAK		8065	7974	7461	6975	6756	7316	7735	7621	7042	7185	7528	8076
	ENERGY	5762	6151	6048	5677	5377	5425	5594	5912	5787	5607	5589	5827	6155
2003	PEAK		8194	8102	7581	7087	6865	7435	7850	7746	7157	7301	7649	8205
	ENERGY	5855	6250	6145	5768	5464	5512	5686	6010	5882	5698	5679	5921	6254
2004	PEAK		8325	8231	7702	7201	6977	7558	7969	7872	7273	7419	7772	8337
	ENERGY	5967	6351	6467	5861	5553	5602	5779	6109	5979	5790	5772	6017	6354
2005	PEAK		8421	8326	7790	7283	7057	7644	8065	7963	7356	7504	7861	8432
	ENERGY	6018	6423	6315	5927	5615	5666	5844	6178	6046	5856	5837	6085	6427
2006	PEAK		8520	8423	7882	7369	7140	7734	8167	8056	7443	7593	7954	8532
	ENERGY	6089	6499	6389	5998	5682	5732	5913	6250	6117	5925	5906	6157	6503
2007	PEAK		8634	8581	7988	7468	7236	7839	8269	8164	7542	7694	8061	8647
	ENERGY	6169	6585	6474	6077	5757	5808	5990	6332	6197	6003	5984	6238	6590
2008	PEAK		8763	8663	8108	7580	7344	7955	8387	8285	7654	7809	8182	8776
	ENERGY	6279	6684	6805	6168	5843	5895	6080	6426	6290	6093	6074	6332	6688
2009	PEAK		8868	8767	8205	7671	7432	8049	8502	8384	7745	7903	8281	8883
	ENERGY	6336	6763	6649	6241	5913	5965	6151	6500	6363	6165	6146	6408	6769
2010	PEAK		8977	8875	8306	7765	7524	8148	8595	8486	7840	8000	8383	8993
	ENERGY	6413	6846	6730	6318	5985	6038	6225	6578	6440	6240	6221	6487	6853
2011	PEAK		9086	8983	8408	7859	7615	8246	8695	8588	7934	8097	8486	9103
	ENERGY	6489	6929	6811	6394	6057	6110	6299	6656	6516	6314	6296	6565	6936
2012	PEAK		9189	9085	8503	7948	7699	8336	8785	8682	8020	8187	8581	9207
	ENERGY	6580	7006	7132	6465	6124	6177	6367	6726	6587	6383	6365	6638	7013
2013	PEAK		9277	9171	8584	8023	7771	8411	8894	8761	8094	8264	8663	9296
	ENERGY	6621	7072	6950	6525	6181	6235	6423	6785	6645	6441	6424	6700	7080

Oregon (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		2545	2505	2309	2081	1863	1864	1893	1954	1821	2038	2234	2559
	ENERGY	1555	1760	1728	1572	1441	1456	1411	1479	1486	1448	1463	1617	1806
1995	PEAK		2516	2476	2283	2057	1842	1842	1871	1932	1800	2015	2208	2530
	ENERGY	1537	1740	1709	1554	1425	1440	1395	1462	1469	1432	1447	1599	1785
1996	PEAK		2508	2469	2276	2051	1836	1837	1856	1926	1795	2009	2201	2522
	ENERGY	1537	1735	1764	1550	1421	1435	1391	1458	1464	1427	1442	1594	1780
1997	PEAK		2511	2472	2279	2054	1839	1839	1867	1929	1797	2011	2204	2525
	ENERGY	1535	1737	1705	1551	1422	1437	1392	1460	1466	1429	1444	1596	1782
1998	PEAK		2506	2467	2274	2050	1835	1835	1864	1925	1793	2007	2200	2520
	ENERGY	1532	1734	1702	1548	1420	1434	1390	1457	1463	1426	1441	1593	1778
1999	PEAK		2514	2475	2282	2056	1841	1841	1870	1931	1799	2014	2207	2528
	ENERGY	1536	1739	1707	1553	1424	1439	1394	1461	1468	1431	1446	1598	1784
2000	PEAK		2535	2495	2300	2073	1856	1857	1876	1947	1814	2030	2225	2549
	ENERGY	1554	1754	1783	1566	1436	1451	1406	1474	1480	1443	1458	1611	1799
2001	PEAK		2556	2528	2319	2090	1871	1888	1909	1963	1829	2047	2243	2570
	ENERGY	1562	1768	1736	1579	1448	1463	1417	1485	1492	1454	1470	1624	1814
2002	PEAK		2574	2534	2336	2105	1885	1885	1927	1977	1842	2061	2259	2588
	ENERGY	1573	1780	1748	1590	1458	1473	1427	1496	1503	1465	1480	1636	1826
2003	PEAK		2596	2568	2355	2123	1901	1901	1938	1993	1857	2079	2278	2610
	ENERGY	1586	1795	1763	1603	1470	1486	1439	1509	1515	1477	1492	1650	1842
2004	PEAK		2615	2574	2373	2139	1915	1915	1935	2008	1871	2094	2296	2630
	ENERGY	1603	1809	1840	1616	1481	1497	1450	1520	1527	1488	1504	1662	1856
2005	PEAK		2625	2584	2382	2147	1922	1922	1961	2016	1878	2102	2304	2640
	ENERGY	1604	1816	1783	1622	1487	1502	1456	1526	1533	1494	1509	1668	1863
2006	PEAK		2633	2591	2389	2153	1928	1928	1958	2022	1884	2108	2311	2647
	ENERGY	1609	1821	1788	1626	1491	1507	1460	1530	1537	1498	1514	1673	1868
2007	PEAK		2649	2620	2403	2166	1939	1940	1969	2034	1895	2121	2325	2663
	ENERGY	1618	1832	1799	1636	1500	1516	1468	1539	1546	1507	1523	1683	1879
2008	PEAK		2662	2620	2415	2177	1949	1949	1970	2044	1905	2132	2336	2677
	ENERGY	1632	1841	1872	1644	1508	1523	1476	1547	1554	1515	1531	1692	1889
2009	PEAK		2663	2621	2416	2177	1949	1950	1989	2045	1905	2132	2337	2677
	ENERGY	1627	1842	1808	1645	1508	1524	1476	1548	1555	1515	1531	1692	1889
2010	PEAK		2663	2622	2417	2178	1950	1950	1981	2045	1906	2133	2338	2678
	ENERGY	1628	1842	1809	1645	1508	1524	1477	1548	1555	1515	1531	1693	1890
2011	PEAK		2664	2622	2417	2178	1950	1951	1980	2045	1906	2133	2338	2678
	ENERGY	1628	1843	1809	1645	1509	1524	1477	1548	1555	1516	1531	1693	1890
2012	PEAK		2661	2620	2415	2176	1949	1949	1969	2044	1904	2131	2336	2676
	ENERGY	1631	1841	1872	1644	1508	1523	1476	1547	1554	1514	1530	1691	1888
2013	PEAK		2654	2612	2408	2170	1943	1944	1986	2038	1899	2126	2330	2669
	ENERGY	1622	1836	1802	1640	1503	1519	1472	1543	1550	1510	1526	1687	1883

PacifiCorp - RAMPP-3 Low Forecast: Firm Load

Washington(Megawatts)

Year		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		767	767	640	584	533	529	604	663	648	626	672	752
	ENERGY	465	531	524	451	409	417	400	459	443	464	457	474	547
1995	PEAK		777	777	648	592	540	536	612	672	657	635	681	762
	ENERGY	471	538	531	457	414	422	405	465	449	470	463	481	555
1996	PEAK		786	785	655	599	546	542	674	679	664	642	688	770
	ENERGY	477	544	556	462	419	427	410	470	454	475	468	486	561
1997	PEAK		792	791	660	603	550	546	625	684	669	646	693	776
	ENERGY	479	548	541	465	422	430	413	474	457	479	472	490	565
1998	PEAK		791	791	660	603	550	546	625	684	669	646	693	776
	ENERGY	479	548	541	465	422	430	413	474	457	479	472	489	565
1999	PEAK		792	792	661	603	550	547	625	685	670	647	694	776
	ENERGY	480	548	541	466	422	430	413	474	457	479	472	490	565
2000	PEAK		794	794	663	605	552	548	681	686	671	648	696	778
	ENERGY	482	550	562	467	424	432	414	476	459	480	473	491	567
2001	PEAK		797	818	664	607	554	579	640	688	673	650	698	781
	ENERGY	482	551	544	468	425	433	415	477	460	482	475	493	568
2002	PEAK		798	798	666	608	555	551	652	690	675	652	699	782
	ENERGY	483	553	545	469	426	434	416	478	461	483	476	494	570
2003	PEAK		800	735	667	610	556	552	647	691	676	653	701	784
	ENERGY	485	554	547	470	427	435	417	479	462	484	477	495	571
2004	PEAK		801	801	668	610	557	553	687	692	677	654	702	785
	ENERGY	487	555	567	471	427	435	418	480	463	485	477	496	572
2005	PEAK		801	800	668	610	556	553	643	692	677	654	701	785
	ENERGY	485	554	547	471	427	435	417	479	462	484	477	495	571
2006	PEAK		800	799	667	609	556	552	630	691	676	653	701	784
	ENERGY	484	554	547	470	427	435	417	479	462	484	477	495	571
2007	PEAK		800	822	668	610	556	552	627	692	676	653	701	784
	ENERGY	485	554	547	470	427	435	417	479	462	484	477	495	571
2008	PEAK		801	801	668	611	557	553	688	692	677	654	702	785
	ENERGY	487	555	567	471	427	435	418	480	463	485	477	496	572
2009	PEAK		801	800	668	610	557	553	646	692	677	654	701	785
	ENERGY	485	554	547	471	427	435	417	480	462	484	477	495	571
2010	PEAK		800	799	667	609	556	552	631	691	676	653	700	784
	ENERGY	484	554	547	470	427	435	417	479	462	484	477	495	571
2011	PEAK		799	798	666	608	555	551	629	690	675	652	699	783
	ENERGY	484	553	546	470	426	434	416	478	461	483	476	494	570
2012	PEAK		797	796	665	607	554	550	684	689	674	651	698	781
	ENERGY	484	552	564	469	425	433	415	477	460	482	475	493	569
2013	PEAK		794	794	663	605	552	548	648	686	671	648	696	778
	ENERGY	481	550	543	467	424	432	414	476	459	480	473	491	567

North Idaho (Megawatts)

Year		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		58	58	49	43	39	35	32	36	35	40	46	52
	ENERGY	30	38	38	34	30	26	25	25	25	26	27	33	35
1995	PEAK		58	58	49	43	39	35	32	36	35	40	46	52
	ENERGY	30	38	38	34	30	26	25	25	25	26	27	33	35
1996	PEAK		58	58	49	43	38	35	36	36	35	40	46	52
	ENERGY	30	38	39	34	30	26	25	25	25	26	27	33	35
1997	PEAK		58	58	49	42	38	35	30	36	35	40	46	52
	ENERGY	30	38	38	34	30	26	25	25	25	26	27	33	35
1998	PEAK		57	57	49	42	38	35	31	36	35	39	45	51
	ENERGY	29	37	37	33	29	25	24	24	24	25	27	32	35
1999	PEAK		57	57	48	42	38	35	31	36	35	39	45	51
	ENERGY	29	37	37	33	29	25	24	24	24	25	26	32	34
2000	PEAK		57	57	49	42	38	35	36	36	35	39	45	51
	ENERGY	30	37	39	33	29	25	24	24	24	25	27	32	35
2001	PEAK		58	50	49	42	38	33	31	36	35	39	45	51
	ENERGY	29	37	37	33	29	25	24	24	24	25	27	32	35
2002	PEAK		57	57	49	42	38	35	31	36	35	39	45	51
	ENERGY	29	37	37	33	29	25	24	24	24	25	27	32	35
2003	PEAK		58	58	49	42	38	35	31	36	35	39	45	51
	ENERGY	29	37	37	33	29	25	24	24	24	25	27	32	35
2004	PEAK		58	57	49	42	38	35	36	36	35	39	45	51
	ENERGY	30	37	38	33	29	25	24	24	24	25	27	32	35
2005	PEAK		57	57	48	42	38	35	31	36	35	39	45	51
	ENERGY	29	37	37	33	29	25	24	24	24	25	26	32	34
2006	PEAK		57	57	48	42	38	34	31	35	34	39	45	51
	ENERGY	29	37	37	33	29	25	24	24	24	25	26	32	34
2007	PEAK		57	51	48	41	37	34	31	35	34	39	45	51
	ENERGY	29	37	37	33	29	25	24	24	24	25	26	32	34
2008	PEAK		57	57	48	41	37	34	35	35	34	39	45	51
	ENERGY	29	37	38	33	29	25	24	24	24	25	26	32	34
2009	PEAK		56	56	47	41	37	34	30	35	34	38	44	50
	ENERGY	29	36	36	32	29	25	24	24	24	25	26	31	34
2010	PEAK		56	55	47	41	37	34	29	35	34	38	44	50
	ENERGY	29	36	36	32	28	25	24	24	24	25	26	31	34
2011	PEAK		55	55	47	40	36	33	29	34	33	38	43	49
	ENERGY	28	36	36	32	28	24	23	23	23	24	26	31	33
2012	PEAK		55	54	46	40	36	33	34	34	33	37	43	49
	ENERGY	28	35	37	32	28	24	23	23	23	24	25	31	33
2013	PEAK		54	54	46	39	36	33	29	34	33	37	42	48
	ENERGY	28	35	35	31	27	24	23	23	23	24	25	30	32

PacifiCorp - RAMPP-3 Low Forecast: Firm Load

Montana (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		151	149	139	128	113	108	98190	112	117	123	131	147
	ENERGY	96	114	112	106	94	87	85	82	82	86	91	103	106
1995	PEAK		152	150	140	129	114	108	98257	113	118	124	132	148
	ENERGY	96	115	112	106	94	88	85	82	82	86	92	103	107
1996	PEAK		153	151	141	130	115	109	112	114	119	125	133	149
	ENERGY	97	116	117	107	95	89	86	83	83	87	93	104	108
1997	PEAK		154	152	142	131	116	110	99017	115	120	126	134	151
	ENERGY	98	117	114	108	96	90	87	84	84	88	94	105	109
1998	PEAK		154	152	142	131	115	110	99145	114	120	125	134	150
	ENERGY	98	116	114	108	96	89	87	84	84	88	93	105	109
1999	PEAK		154	152	142	131	115	110	99585	115	120	126	134	150
	ENERGY	98	116	114	108	96	89	87	84	84	88	94	105	109
2000	PEAK		154	152	142	131	116	110	113	115	120	126	134	151
	ENERGY	98	117	119	108	96	90	87	84	84	88	94	105	109
2001	PEAK		155	153	143	132	116	101	102	115	121	126	135	151
	ENERGY	98	117	115	109	96	90	87	84	84	88	94	106	110
2002	PEAK		155	153	143	132	116	111	101	115	121	126	135	152
	ENERGY	98	117	115	109	97	90	87	84	84	88	94	106	110
2003	PEAK		156	149	144	132	117	111	100	116	121	127	135	152
	ENERGY	99	118	115	109	97	90	88	85	85	89	95	106	110
2004	PEAK		156	154	144	133	117	111	115	116	121	127	136	152
	ENERGY	99	118	120	109	97	91	88	85	85	89	95	107	110
2005	PEAK		156	154	144	133	117	112	103	116	122	127	136	153
	ENERGY	99	118	116	110	97	91	88	85	85	89	95	107	111
2006	PEAK		157	155	144	133	117	112	102	117	122	128	136	153
	ENERGY	99	118	116	110	98	91	88	85	85	89	95	107	111
2007	PEAK		157	155	145	134	118	112	102	117	122	128	137	154
	ENERGY	100	119	117	110	98	91	89	85	85	90	95	107	111
2008	PEAK		158	156	146	134	118	113	116	117	123	129	137	154
	ENERGY	100	119	121	111	98	92	89	86	86	90	96	108	112
2009	PEAK		158	156	146	134	118	113	103	118	123	129	138	154
	ENERGY	100	119	117	111	98	92	89	86	86	90	96	108	112
2010	PEAK		158	156	146	135	119	113	103	118	123	129	138	155
	ENERGY	100	120	117	111	99	92	89	86	86	90	96	108	112
2011	PEAK		158	156	146	135	119	113	103	118	123	129	138	155
	ENERGY	100	120	117	111	99	92	89	86	86	90	96	108	112
2012	PEAK		159	156	146	135	119	113	116	118	123	129	138	155
	ENERGY	101	120	122	111	99	92	89	86	86	90	96	108	112
2013	PEAK		159	156	146	135	119	113	102	118	123	129	138	155
	ENERGY	101	120	118	111	99	92	89	86	86	90	96	108	112

East Wyoming (Megawatts)

Year		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		965	951	960	916	942	939	935	941	936	955	970	979
	ENERGY	855	868	858	858	848	843	845	844	846	853	860	866	869
1995	PEAK		963	949	958	914	940	937	932	938	934	953	968	977
	ENERGY	853	866	856	856	846	841	843	842	844	851	858	864	867
1996	PEAK		960	946	955	912	938	935	933	936	931	951	965	974
	ENERGY	853	863	884	854	843	839	841	840	842	848	856	861	865
1997	PEAK		954	941	950	906	932	929	924	930	926	945	959	968
	ENERGY	845	858	849	849	838	834	836	835	837	843	851	856	859
1998	PEAK		961	947	956	913	938	935	929	937	932	951	966	975
	ENERGY	851	864	854	855	844	840	842	841	842	849	857	862	865
1999	PEAK		966	952	962	918	944	941	935	942	937	957	971	981
	ENERGY	856	869	859	859	849	844	846	845	847	854	861	867	870
2000	PEAK		975	961	970	926	952	949	947	950	946	965	980	989
	ENERGY	866	877	898	867	856	852	854	853	855	862	869	875	878
2001	PEAK		988	955	983	938	965	934	936	963	958	978	993	1003
	ENERGY	875	888	878	879	868	863	865	864	866	873	881	886	890
2002	PEAK		1002	988	997	952	979	975	953	977	972	992	1007	1017
	ENERGY	888	901	891	891	880	875	877	876	878	885	893	899	902
2003	PEAK		1016	988	1011	965	992	989	965	990	986	1006	1021	1031
	ENERGY	900	914	903	903	892	888	890	889	891	898	906	911	915
2004	PEAK		1032	1017	1026	980	1007	1004	1002	1005	1001	1021	1037	1047
	ENERGY	916	928	950	917	906	901	903	902	904	911	919	925	929
2005	PEAK		1039	1024	1034	987	1015	1011	990	1013	1008	1029	1044	1054
	ENERGY	920	934	924	924	913	908	910	909	911	918	926	932	936
2006	PEAK		1050	1035	1045	997	1025	1022	1016	1024	1019	1039	1055	1066
	ENERGY	930	944	934	934	922	917	919	918	920	928	936	942	946
2007	PEAK		1058	1021	1052	1004	1033	1029	1017	1031	1026	1047	1063	1073
	ENERGY	937	951	940	940	929	924	926	925	927	934	943	949	952
2008	PEAK		1072	1056	1067	1018	1047	1043	1041	1045	1040	1061	1077	1088
	ENERGY	952	964	987	953	941	936	939	937	939	947	955	961	965
2009	PEAK		1081	1065	1075	1026	1055	1052	1023	1053	1048	1070	1086	1096
	ENERGY	957	972	961	961	949	944	946	945	947	955	963	969	973
2010	PEAK		1089	1073	1084	1034	1063	1060	1054	1061	1056	1078	1094	1105
	ENERGY	964	979	968	968	956	951	954	952	954	962	971	977	981
2011	PEAK		1096	1080	1091	1041	1070	1067	1061	1068	1063	1085	1102	1112
	ENERGY	971	986	974	975	963	958	960	959	961	968	977	983	987
2012	PEAK		1103	1087	1097	1047	1077	1073	1071	1075	1069	1091	1108	1119
	ENERGY	979	991	1015	980	968	963	966	964	966	974	983	989	993
2013	PEAK		1107	1091	1102	1052	1081	1078	1054	1079	1074	1096	1113	1124
	ENERGY	981	996	984	985	973	968	970	969	971	978	987	993	997

PacifiCorp - RAMPP-3 Low Forecast: Firm Load

California (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		160	154	139	129	128	134	143	136	103	117	131	158
	ENERGY	93	107	93	88	86	91	98	107	95	83	79	84	103
1995	PEAK		160	154	138	129	128	134	143	136	103	116	131	158
	ENERGY	93	107	93	88	86	91	98	106	95	82	79	84	103
1996	PEAK		160	154	138	129	128	133	146	135	103	116	131	158
	ENERGY	93	107	96	88	86	91	97	106	95	82	79	84	103
1997	PEAK		159	153	138	128	127	133	143	135	102	116	131	158
	ENERGY	92	107	92	88	86	91	97	106	94	82	79	84	103
1998	PEAK		158	152	137	128	127	132	143	134	102	115	130	157
	ENERGY	92	106	92	87	85	90	97	105	94	82	79	83	102
1999	PEAK		159	153	137	128	127	133	142	135	102	116	130	157
	ENERGY	92	106	92	88	86	90	97	106	94	82	79	84	103
2000	PEAK		160	154	139	129	128	134	147	136	103	117	132	159
	ENERGY	93	107	97	88	87	91	98	107	95	83	80	85	104
2001	PEAK		162	166	140	131	130	146	151	138	104	118	133	160
	ENERGY	94	109	94	89	87	92	99	108	96	84	80	86	105
2002	PEAK		164	158	142	133	131	137	152	139	106	120	135	162
	ENERGY	95	110	95	91	89	93	100	109	97	85	81	87	106
2003	PEAK		166	178	144	134	133	139	155	141	107	121	137	165
	ENERGY	97	111	97	92	90	95	102	111	99	86	83	88	108
2004	PEAK		169	163	146	136	135	141	155	143	109	123	139	167
	ENERGY	98	113	101	93	91	96	103	112	100	87	84	89	109
2005	PEAK		171	164	148	138	137	143	158	145	110	124	140	169
	ENERGY	99	114	99	94	92	97	104	114	101	88	85	90	110
2006	PEAK		172	166	149	139	138	144	155	146	111	126	142	171
	ENERGY	100	115	100	95	93	98	105	115	102	89	86	91	111
2007	PEAK		175	180	151	141	140	146	158	148	112	127	143	173
	ENERGY	101	117	102	96	94	99	107	116	104	90	87	92	113
2008	PEAK		177	171	153	143	142	148	163	151	114	129	146	175
	ENERGY	103	119	107	98	96	101	108	118	105	91	88	94	115
2009	PEAK		179	172	155	144	143	149	166	152	115	130	147	177
	ENERGY	104	120	104	99	97	102	109	119	106	92	89	94	116
2010	PEAK		180	174	156	146	144	151	163	153	116	131	148	178
	ENERGY	105	121	105	99	97	103	110	120	107	93	90	95	117
2011	PEAK		182	175	157	147	146	152	165	154	117	132	149	180
	ENERGY	106	122	106	100	98	103	111	121	108	94	90	96	117
2012	PEAK		183	177	159	148	147	153	168	156	118	134	151	181
	ENERGY	107	123	110	101	99	104	112	122	109	95	91	97	118
2013	PEAK		185	178	160	149	148	154	171	157	119	134	152	183
	ENERGY	107	124	107	102	100	105	113	123	109	95	92	97	119

Utah (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		1885	1870	1803	1741	1788	2112	2328	2152	1932	1879	1917	1936
	ENERGY	1492	1531	1505	1447	1400	1405	1490	1563	1540	1486	1490	1512	1529
1995	PEAK		1908	1893	1825	1762	1810	2138	2356	2178	1956	1902	1940	1960
	ENERGY	1510	1550	1524	1465	1418	1422	1508	1582	1559	1504	1508	1530	1548
1996	PEAK		1925	1910	1842	1778	1826	2157	2280	2198	1973	1919	1958	1977
	ENERGY	1528	1564	1592	1478	1430	1434	1522	1596	1573	1517	1522	1544	1562
1997	PEAK		1947	1932	1863	1798	1847	2182	2404	2223	1996	1941	1980	2000
	ENERGY	1541	1582	1555	1495	1447	1451	1540	1615	1591	1535	1540	1562	1580
1998	PEAK		1963	1948	1878	1813	1863	2200	2424	2241	2013	1957	1997	2017
	ENERGY	1554	1595	1568	1507	1459	1463	1552	1628	1604	1548	1552	1575	1593
1999	PEAK		1979	1964	1894	1828	1878	2218	2444	2260	2029	1973	2013	2033
	ENERGY	1567	1608	1581	1520	1471	1475	1565	1642	1618	1561	1565	1588	1606
2000	PEAK		1997	1982	1911	1845	1895	2238	2366	2280	2048	1991	2032	2052
	ENERGY	1585	1623	1653	1534	1484	1488	1579	1656	1632	1575	1579	1602	1621
2001	PEAK		2014	2042	1927	1860	1911	2235	2468	2299	2065	2007	2048	2069
	ENERGY	1594	1636	1608	1546	1496	1501	1592	1670	1646	1588	1592	1616	1634
2002	PEAK		2033	2017	1945	1877	1929	2278	2490	2321	2084	2026	2067	2088
	ENERGY	1609	1652	1624	1561	1510	1515	1607	1686	1661	1602	1607	1631	1649
2003	PEAK		2054	2128	1966	1897	1949	2302	2518	2345	2106	2048	2089	2110
	ENERGY	1626	1669	1641	1577	1526	1531	1624	1704	1679	1619	1624	1648	1667
2004	PEAK		2075	2059	1986	1916	1969	2325	2458	2369	2128	2069	2111	2132
	ENERGY	1647	1686	1717	1593	1542	1546	1641	1721	1696	1636	1641	1665	1684
2005	PEAK		2084	2068	1994	1925	1978	2335	2555	2379	2137	2077	2120	2141
	ENERGY	1650	1693	1665	1600	1549	1553	1648	1728	1703	1643	1648	1672	1691
2006	PEAK		2094	2078	2003	1934	1987	2346	2585	2390	2147	2087	2129	2151
	ENERGY	1657	1701	1672	1608	1556	1560	1655	1736	1711	1651	1655	1680	1699
2007	PEAK		2107	2137	2016	1946	1999	2361	2602	2406	2160	2100	2143	2165
	ENERGY	1668	1712	1683	1618	1566	1570	1666	1747	1722	1661	1666	1690	1710
2008	PEAK		2124	2107	2032	1961	2015	2380	2516	2425	2177	2117	2160	2182
	ENERGY	1685	1725	1757	1631	1578	1582	1679	1761	1736	1674	1679	1704	1723
2009	PEAK		2135	2119	2043	1972	2026	2393	2617	2438	2189	2128	2172	2193
	ENERGY	1690	1735	1705	1640	1586	1591	1688	1771	1745	1683	1688	1713	1733
2010	PEAK		2147	2131	2054	1983	2037	2406	2652	2451	2201	2140	2184	2206
	ENERGY	1699	1745	1715	1649	1595	1600	1698	1781	1755	1693	1698	1723	1742
2011	PEAK		2158	2142	2065	1993	2048	2418	2665	2464	2213	2151	2195	2217
	ENERGY	1708	1754	1724	1657	1604	1608	1707	1790	1764	1702	1707	1731	1751
2012	PEAK		2166	2149	2072	2000	2055	2427	2565	2473	2221	2159	2203	2225
	ENERGY	1719	1760	1792	1663	1609	1614	1712	1796	1770	1707	1712	1737	1757
2013	PEAK		2170	2154	2077	2005	2060	2432	2661	2478	2225	2164	2208	2230
	ENERGY	1718	1764	1734	1667	1613	1618	1716	1800	1774	1711	1716	1741	1761

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South Idaho (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		236	235	214	202	231	401	437	388	300	234	210	195
	ENERGY	215	179	180	164	152	184	306	378	309	224	187	171	146
1995	PEAK		236	235	213	202	231	401	438	388	299	234	210	195
	ENERGY	215	179	180	164	152	184	306	377	309	224	187	171	146
1996	PEAK		230	229	208	197	225	391	442	378	292	228	205	190
	ENERGY	210	175	182	160	148	179	298	368	302	218	182	167	142
1997	PEAK		224	223	203	192	219	381	416	368	285	222	199	185
	ENERGY	205	170	171	156	144	175	290	359	294	213	178	163	139
1998	PEAK		221	219	199	189	215	374	408	362	280	218	196	182
	ENERGY	201	167	168	153	142	172	285	352	289	209	175	160	136
1999	PEAK		217	216	196	186	212	369	403	357	276	215	193	179
	ENERGY	198	165	166	151	140	169	281	347	285	206	172	158	134
2000	PEAK		216	214	195	184	211	366	414	354	273	214	192	178
	ENERGY	197	164	170	150	139	168	279	345	282	204	171	156	133
2001	PEAK		215	205	194	184	210	379	400	353	273	213	191	177
	ENERGY	196	163	164	149	138	167	278	343	281	204	170	156	133
2002	PEAK		216	214	195	184	211	366	401	354	273	213	191	178
	ENERGY	196	163	164	150	139	168	279	344	282	204	171	156	133
2003	PEAK		217	192	196	186	212	369	405	357	276	215	193	179
	ENERGY	198	165	166	151	140	169	281	347	285	206	172	158	134
2004	PEAK		219	217	198	187	214	371	420	359	277	217	194	181
	ENERGY	200	166	173	152	141	170	283	350	286	207	173	159	135
2005	PEAK		219	218	198	188	214	372	408	360	278	217	195	181
	ENERGY	200	166	167	152	141	171	284	350	287	208	174	159	135
2006	PEAK		219	217	197	187	213	371	405	359	277	216	194	180
	ENERGY	199	166	166	152	140	170	283	349	286	207	173	158	135
2007	PEAK		218	208	197	187	213	370	404	358	277	216	194	180
	ENERGY	199	165	166	152	140	170	282	349	286	207	173	158	135
2008	PEAK		218	216	197	186	213	370	418	357	276	215	193	180
	ENERGY	199	165	172	151	140	169	282	348	285	206	173	158	134
2009	PEAK		216	214	195	185	211	367	402	354	274	214	192	178
	ENERGY	197	164	164	150	139	168	279	345	283	205	171	157	133
2010	PEAK		214	212	193	183	209	363	395	351	271	212	190	176
	ENERGY	195	162	163	149	137	166	277	342	280	203	169	155	132
2011	PEAK		212	210	191	181	207	359	392	347	268	209	188	175
	ENERGY	193	160	161	147	136	165	274	338	277	200	168	153	131
2012	PEAK		208	207	188	178	204	354	400	342	264	206	185	172
	ENERGY	190	158	164	145	134	162	270	333	273	197	165	151	129
2013	PEAK		205	203	185	175	200	347	381	336	259	202	182	169
	ENERGY	186	155	156	142	131	159	265	327	268	194	162	148	126

West Wyoming (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		287	287	274	280	272	266	263	269	255	268	266	281
	ENERGY	245	257	259	253	252	244	242	242	242	239	234	238	242
1995	PEAK		280	279	268	273	265	259	258	262	249	261	260	274
	ENERGY	239	251	253	247	246	238	236	236	236	233	228	232	236
1996	PEAK		277	276	265	270	262	256	260	259	246	258	257	271
	ENERGY	237	248	259	244	243	235	233	233	233	230	225	229	233
1997	PEAK		234	233	223	228	221	216	214	219	207	218	217	228
	ENERGY	200	209	211	206	205	199	197	197	197	194	190	193	197
1998	PEAK		208	208	199	203	197	192	190	195	185	194	193	203
	ENERGY	178	186	188	183	183	177	175	175	175	173	169	172	175
1999	PEAK		195	195	186	190	185	180	179	183	173	182	181	191
	ENERGY	167	175	176	172	171	166	164	164	164	162	159	161	164
2000	PEAK		194	193	185	189	184	179	182	182	172	181	180	189
	ENERGY	166	174	181	171	170	165	163	163	163	161	158	160	163
2001	PEAK		194	181	185	189	183	176	182	181	172	180	179	189
	ENERGY	165	173	175	171	170	164	163	163	163	161	157	160	163
2002	PEAK		193	193	185	189	183	179	177	181	172	180	179	189
	ENERGY	165	173	174	170	170	164	163	163	163	161	157	160	163
2003	PEAK		193	179	184	188	182	178	180	180	171	180	179	188
	ENERGY	164	173	174	170	169	164	162	162	162	160	157	159	162
2004	PEAK		192	192	184	188	182	178	181	180	171	179	178	188
	ENERGY	165	172	180	169	169	163	162	162	162	160	156	159	162
2005	PEAK		190	190	182	185	180	176	178	178	169	177	176	186
	ENERGY	162	170	171	167	167	161	160	160	160	158	155	157	160
2006	PEAK		189	188	180	184	179	174	170	177	167	176	175	184
	ENERGY	161	169	170	166	166	160	159	159	159	157	153	156	159
2007	PEAK		186	172	178	182	176	172	168	174	165	174	173	182
	ENERGY	159	167	168	164	164	158	157	157	157	155	151	154	157
2008	PEAK		185	185	177	181	175	171	174	173	164	173	172	181
	ENERGY	159	166	173	163	163	157	156	156	156	154	151	153	156
2009	PEAK		183	183	175	179	174	169	171	172	163	171	170	179
	ENERGY	156	164	165	161	161	156	154	154	154	152	149	152	154
2010	PEAK		182	181	173	177	172	168	164	170	161	169	168	177
	ENERGY	155	162	164	160	159	154	153	153	153	151	148	150	153
2011	PEAK		180	179	172	175	170	166	158	168	159	167	166	175
	ENERGY	153	161	162	158	158	152	151	151	151	149	146	149	151
2012	PEAK		178	177	170	173	168	164	167	166	158	166	165	174
	ENERGY	152	159	166	157	156	151	150	150	150	148	145	147	150
2013	PEAK		176	175	168	171	166	162	161	164	156	164	163	172
	ENERGY	150	157	158	155	154	149	148	148	148	146	143	145	148

PacifiCorp - RAMPP-3 Low Forecast: Firm Load

Total Company (Megawatts)

		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		7055	6975	6527	6105	5909	6388	104825	6651	6148	6279	6577	7059
	ENERGY	5045	5386	5297	4973	4713	4753	4901	5178	5068	4907	4890	5098	5385
1995	PEAK		7050	6971	6523	6102	5909	6391	104899	6655	6151	6279	6575	7055
	ENERGY	5044	5383	5295	4971	4711	4751	4901	5178	5068	4907	4890	5097	5382
1996	PEAK		7057	6978	6529	6108	5914	6395	6740	6661	6158	6286	6583	7064
	ENERGY	5063	5389	5489	4976	4715	4755	4903	5179	5070	4912	4895	5103	5389
1997	PEAK		7034	6955	6507	6084	5890	6372	105640	6639	6138	6265	6564	7044
	ENERGY	5025	5366	5276	4952	4691	4731	4876	5153	5045	4889	4873	5082	5369
1998	PEAK		7020	6941	6494	6070	5878	6360	105759	6628	6128	6253	6553	7031
	ENERGY	5013	5353	5264	4940	4679	4720	4864	5140	5032	4878	4864	5072	5359
1999	PEAK		7035	6955	6508	6083	5891	6373	106214	6642	6141	6267	6568	7047
	ENERGY	5023	5364	5274	4950	4688	4729	4872	5147	5041	4887	4874	5082	5370
2000	PEAK		7084	7004	6554	6125	5932	6416	6763	6686	6183	6311	6615	7097
	ENERGY	5072	5401	5500	4985	4721	4761	4905	5181	5075	4921	4908	5118	5408
2001	PEAK		7138	7099	6605	6172	5978	6469	6818	6736	6229	6359	6666	7152
	ENERGY	5096	5443	5351	5023	4758	4799	4941	5219	5113	4958	4946	5158	5451
2002	PEAK		7193	7111	6657	6221	6026	6516	6884	6789	6278	6410	6718	7208
	ENERGY	5137	5486	5394	5064	4797	4838	4981	5261	5154	4998	4986	5200	5494
2003	PEAK		7256	7175	6716	6277	6080	6576	6940	6850	6335	6468	6778	7271
	ENERGY	5184	5535	5442	5110	4841	4882	5027	5309	5201	5044	5032	5247	5543
2004	PEAK		7317	7234	6773	6331	6134	6634	6989	6910	6390	6523	6837	7333
	ENERGY	5245	5583	5685	5155	4884	4925	5072	5356	5247	5089	5076	5293	5591
2005	PEAK		7343	7259	6798	6354	6156	6658	7027	6935	6412	6547	6861	7359
	ENERGY	5249	5604	5509	5173	4902	4944	5091	5375	5266	5107	5095	5312	5612
2006	PEAK		7370	7286	6824	6378	6180	6684	7053	6960	6437	6572	6888	7387
	ENERGY	5269	5625	5530	5194	4921	4963	5111	5396	5287	5127	5115	5334	5634
2007	PEAK		7407	7366	6859	6411	6212	6718	7077	6995	6469	6606	6923	7425
	ENERGY	5296	5654	5558	5220	4947	4989	5136	5422	5313	5153	5141	5361	5663
2008	PEAK		7454	7368	6903	6452	6253	6761	7120	7040	6511	6649	6968	7472
	ENERGY	5346	5691	5794	5255	4980	5022	5170	5457	5348	5187	5176	5397	5700
2009	PEAK		7472	7386	6920	6469	6270	6779	7147	7058	6528	6666	6986	7491
	ENERGY	5345	5706	5608	5269	4994	5036	5184	5471	5362	5201	5190	5411	5715
2010	PEAK		7489	7403	6937	6485	6287	6796	7172	7075	6544	6683	7004	7509
	ENERGY	5359	5721	5623	5284	5008	5050	5197	5484	5375	5215	5205	5426	5730
2011	PEAK		7503	7417	6952	6499	6301	6811	7183	7090	6558	6697	7019	7524
	ENERGY	5371	5733	5635	5295	5019	5061	5208	5494	5386	5227	5216	5438	5743
2012	PEAK		7510	7423	6958	6505	6308	6817	7176	7096	6564	6704	7026	7532
	ENERGY	5392	5739	5842	5301	5026	5067	5213	5498	5391	5232	5223	5445	5749
2013	PEAK		7504	7418	6954	6501	6304	6811	7193	7090	6560	6700	7022	7527
	ENERGY	5373	5736	5637	5299	5024	5065	5209	5493	5387	5229	5220	5442	5747

Total Company (Megawatts)

Year		Annual Calendar Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	PEAK		245	276	321	291	269	320	283	270	272	269	298	195
	ENERGY	299	314	325	322	320	311	318	285	290	264	255	295	288
1995	PEAK		273	275	322	284	263	323	285	271	274	266	298	200
	ENERGY	299	314	325	322	320	311	318	285	290	264	255	295	288
1996	PEAK		268	297	317	294	286	312	295	295	279	254	324	236
	ENERGY	300	314	337	322	320	311	318	285	290	264	255	295	288
1997	PEAK		229	276	326	283	262	333	279	274	274	251	300	200
	ENERGY	299	314	325	322	320	311	318	285	290	264	255	295	288
1998	PEAK		260	275	325	253	268	312	277	275	274	252	278	200
	ENERGY	299	314	325	322	320	311	318	285	290	264	255	295	288
1999	PEAK		280	276	321	292	269	320	280	284	273	248	292	196
	ENERGY	299	314	325	322	320	311	318	285	290	264	255	295	288
2000	PEAK		277	299	307	288	287	315	285	281	270	252	322	236
	ENERGY	300	314	337	322	320	311	318	285	290	264	255	295	288
2001	PEAK		268	304	330	283	262	334	291	272	275	252	299	200
	ENERGY	299	314	325	322	320	311	318	285	290	264	255	295	288
2002	PEAK		281	276	325	283	262	330	287	271	275	252	301	199
	ENERGY	299	314	325	322	320	311	318	285	290	264	255	295	288
2003	PEAK		278	290	326	283	262	333	288	274	274	251	300	200
	ENERGY	299	314	325	322	320	311	318	285	290	264	255	295	288
2004	PEAK		289	302	314	295	289	356	284	304	272	247	309	235
	ENERGY	300	314	337	322	320	311	318	285	290	264	255	295	288
2005	PEAK		245	276	321	291	269	320	291	270	272	269	298	195
	ENERGY	299	314	325	322	320	311	318	285	290	264	255	295	288
2006	PEAK		238	275	322	284	263	323	285	271	274	266	298	200
	ENERGY	299	314	325	322	320	311	318	285	290	264	255	295	288
2007	PEAK		268	304	330	283	262	325	285	271	275	252	299	200
	ENERGY	299	314	325	322	320	311	318	285	290	264	255	295	288
2008	PEAK		267	297	317	296	285	328	285	316	274	241	324	236
	ENERGY	300	314	337	322	320	311	318	285	290	264	255	295	288
2009	PEAK		260	275	325	253	268	312	287	275	274	252	297	200
	ENERGY	299	314	325	322	320	311	318	285	290	264	255	295	288
2010	PEAK		253	276	321	292	269	320	280	284	273	248	292	196
	ENERGY	299	314	325	322	320	311	318	285	290	264	255	295	288
2011	PEAK		245	276	321	291	269	320	283	270	272	269	298	195
	ENERGY	299	314	325	322	320	311	318	285	290	264	255	295	288
2012	PEAK		238	298	310	296	286	317	285	280	279	241	323	237
	ENERGY	300	314	337	322	320	311	318	285	290	264	255	295	288
2013	PEAK		228	276	325	283	262	330	287	271	275	252	298	199
	ENERGY	299	314	325	322	320	311	318	285	290	264	255	295	288

POSITIONING FOR COMPETITION AND UNCERTAINTY

RAMPP

Resource and Market Planning Program

RAMPP - 3

DEMAND-SIDE APPENDIX

APRIL, 1994

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RAMPP

Resource and Market Planning Program

RAMPP - 3

DEMAND-SIDE APPENDIX

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Part II: Program Planning Process

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List of Acronyms

AD	accelerated DSR rate, base case
A2	second accelerated rate suggested by the advisory group
ASHRAE	American Society of Heating, Refrigerating and Ventilating Engineers
BPA	Bonneville Power Administration
BTU	British thermal unit
CDM	conditional demand model
CLF	conservation load factor
CRF	capital recovery factor
C/T/U	Commercial/Transportation/Utility
DHW	domestic hot water
DSR	demand side resource
ECM	energy conservation measure
ELCAP	End-Use Load and Consumer Assessment Project
EPA	Environmental Protection Agency
ESC	energy service charge
EOY	end of year
FAF	forced air furnace
HD	high DSR rate, base case
HPS	high pressure sodium lamp (streetlights)
HRCP	Hood River Conservation Project
HUD	United States Department of Housing and Urban Development
ITP	Industrial Test Program
IRP	integrated resource plan or planning
kW	kilowatt
kWh	kilowatt-hour
LBL	Lawrence Berkeley Laboratory
LD	low DSR rate, base case
MAP	Manufactured Housing Acquisition Program
MCS	model conservation standards
MD	medium DSR rate, base case
MFD	multi-family dwelling
MMBTU	a million BTUs
MW	megawatt
MWa	average megawatts
MWh	megawatt-hour
NPPC	Northwest Power Planning Council
NPV	net present value
O&M	operations and maintenance
ODOE	Oregon Department of Energy
OEM	original equipment manufacturer

OPUC	Oregon Public Utility Commission
PP&L	Pacific Power and Light
RAMPP	Resource and Market Planning Program
SFD	single-family dwelling
SGC	Super Good Cents program
SIC	Standard Industrial Classification
T&D	transmission and distribution
TRC	total resource cost
UIC	United Industries Corporation
UP&L	Utah Power and Light
USDOE	United States Department of Energy
VHO	very high output (fluorescent lighting)
VMS	vertical market segment
VSD	variable speed drive

SECTION 1.0 Executive Summary

PacifiCorp has completed the third Resource and Market Program Planning document (RAMPP-3). This report is a detailed description of the company's analysis for determining supply curves for demand-side resources, and the program planning and design steps effort undertaken to define programs and an action plan for acquiring demand-side resources.

The supply curves show how much demand-side resource (DSR) is available at what price. Program planning and design involves factors such as cost-effectiveness of the different resources under consideration, characteristics of the different markets for the resources, delivery mechanisms such as ramp rates (how quickly a program can be delivered) and penetration rates (how widely) will customers participate in programs. These rates are studied and subdivided by market sector and geographic area.

1.1 Developing Supply Curves

In order to study how supply curves are generated, the company's customers were divided into market sectors, such as commercial, residential, industrial and irrigation. Next the available conservation resources for these sectors were evaluated using an integration model based on load shapes. The goal of this conservation resource assessment and market analysis was to determine the technical potential, or maximum, demand-side resources available to the company over the 20-year planning horizon.

In studying the market sectors, the largest low cost resource potential was found to be with industrial customers, who account for the largest amount of sales, with commercial and residential splitting the remainder. Utah has a large and diversified industrial base.

Load shapes were developed to provide more detail about consumption during peak and off-peak periods for different end uses for several customer classes. The load shapes are really conservation load shapes, representing the difference in consumption between a building with a package of conservation measures, and a base case building with none.

The methodology for deriving load shapes differed by market sector. Ideally, monitored or metered loads are best for this purpose, but when unavailable prototype models were used to generate load shapes. Simulations of prototypical cases were done for building types in the commercial sector. The same method was used to estimate the technical potential for energy savings. For RAMPP-3, the simulation models were used to generate hourly load shapes as well as annual energy savings.

The resulting load shapes differ for different service territories and forecast assumptions. In generating the curves, other factors were taken into account, such as capacity savings and diversity factors. Financial parameters, including the real discount rate, capital recovery factor, and levelized cost, were used in evaluating cost-effectiveness of various demand-side resource options. The resulting curves rank the amount of resources at a given cost from least to most expensive.

1.1.1 Residential Sector

Space heating analysis in the residential sector was based on three prototype homes: single family dwelling, manufactured home dwelling, and a multi-family residence. Heat loss coefficients, or UA-values, were calculated based on survey information regarding existing insulation levels and retrofit U-values developed by the Bonneville Power Administration and analyzed by the Northwest Power Planning Council. UA-values for different climates and construction periods were also derived.

From this data, the amount of space heat consumption was estimated, and the results were then adjusted from the prototype models to agree with actual usage. Actual savings proved to be less than the engineering estimates, we assume, due to customer "amenity takeback" choices. Apparently some customers choose to trade increased comfort over increased savings, and adjust their thermostats accordingly. Rebound in usage was accounted for by either downrating the savings to agree with monitored results, or treating it as an increase in the demand forecast. Other aspects of low-cost resources were considered in this study, including solar access.

In the residential sector, energy conservation measures for appliances were also studied. Costs and market saturation levels for appliance ECMs are detailed in the appendices of this report. The technical potential for appliances is high. However, this potential is not immediately accessible due to natural replacement cycles, which is why more savings from this resource are not included in the programs.

1.1.2 Commercial Sector

In the commercial sector, the methodology for estimating energy savings was based on a set of prototype buildings modeled by the United Industries Corporation for the Bonneville Power Administration using a Department of Energy computer program (DOE-2). New buildings are supposed to be constructed in accordance with Model Construction Standard (MCS) codes when it comes to energy use, but a study of current practice shows this is not always the case.

Prototype buildings, therefore, were modeled using "end-use splits," or ways energy is apportioned in a building. Different end uses were modeled using load shapes, derived from research results, and load shapes were created for different day types, or typical day profiles, generally separating weekday from weekend for most building types.

The baseline consumption included in the forecast assumes that 85 percent of new buildings will comply with commercial code in the Northwest states. The remaining 15 percent will be equivalent to current practice.

As far as climate considerations, models were run using Portland and Salt Lake as the two major cities. Commercial buildings are only slightly sensitive to climate because of low saturation of electric space heat and low cooling usage. Lighting and receptacle loads were found to be unaffected by climate.

1.1.3 Industrial Sector and Irrigation

Energy usage is expressed differently for the industrial sector than it is for the residential and commercial sectors. The industrial costs and energy supply in this study were based on a variety of data and reports, including data from Bonneville Power Administration, Industrial Test Program, the planning division of the Oregon Department of Energy, and Dun and Bradstreet.

These data were modified to reflect industries in the company's territories. Other adjustments were made, such as increasing the energy use for pumping to allow for plant-owned well pumps in light of the predominantly rural nature of the company's service territory. Specific conservation measures in areas such as lighting, heating, ventilation and air conditioning, compressed air systems, pumping systems, pneumatic conveying and refrigeration are detailed in the report.

Irrigation savings were also studied. A rough estimate of technical potential is that a 15 percent savings from pump efficiency and another 15 percent from improved scheduling can be achieved. However, there are serious constraints on achieving this potential. Farmers are reluctant to experiment with water-savings measures because they are highly adverse to taking any risks when it comes to their crops.

PacifiCorp is currently conducting a pilot program in California. The results of this pilot will help the company determine the best ways to market approaches to improving irrigation efficiency.

1.1.4 Other Resources—Fuel Switching and Street Lighting

Fuel switching-which is the replacement of electric space or water heating equipment in an existing building with fossil-fuel fired equipment—is considered a potential demand-side resource because it reduces the electrical utility load. However, since another fuel rather than electricity is still being consumed, is treated as a "load shedding" option rather than energy conservation.

In analyzing the potential of fuel switching, the economic break-even point for removing an electric furnace and replacing it with a gas model was evaluated based on a least cost approach. In general, converting from an electric to gas furnace, after undertaking other lower cost efficiency options, would be cost effective for only a small percentage of customers.

A similar case was demonstrated for fuel switching regarding water heaters. Again the development, marketing, and administrative costs of a full-scale fuel switching program for water heating could not be justified, after looking at lower cost efficiency options.

PacifiCorp offers a street lighting service in most of its territory. Older mercury vapor lamps can be replaced by more efficient high pressure sodium lamps, achieving a 40 percent savings in energy use. However, the company has a policy of retrofitting mercury vapor with high-pressure sodium during normal maintenance and replacement, and most of the company's lamps have already been changed. Accelerating the replacement is not a sufficiently large resource to consider this as a program opportunity.

1.1.5 Background Conservation and Lost Opportunities

Background conservation is the amount of conservation customers perceive as cost-effective and do on their own. Outside of solar options, there are no low-cost opportunities in new residential construction which aren't already incorporated in building codes. The largest amount of background conservation exists in the commercial sector, where there are many low-cost options. The industrial sector is not included in this specific study because industrial "background" trends are already included in the econometric forecasting model.

"Lost opportunities" are conservation measures that will be cost-effective during their lifetime if installed now, but not if installed later as part of a more expensive retrofit. The bulk of lost opportunities, analysts found, occur in the commercial sector, both in new construction and building remodeling, where programs are not in place. Lost opportunities also occur in industrial new construction.

1.2 Program Planning and Design

With the information available from the supply curves, the criteria for program design and a two-year action plan was established. Input from program managers and field staff was incorporated into program design. Existing program experience, program evaluation results also feed into program planning.

1.2.1 Resource Opportunities

A number of factors influenced the company's decisions on the priorities of demand-side resource acquisition. These criteria include the cost of the resource, impact on customer prices, size of resource, ease of acquisition, and lost opportunities.

As far as size of the resource opportunity, results show a technical potential for conservation of about 1,500 MWa, based on a medium load growth forecast. Results by sector are detailed in the report.

1.2.2 Program Potential

Program potential was calculated from the estimated technical potential by program area. Line losses were added to estimate the gross savings potential, which was then multiplied by the effective penetration rate to get gross program potentials. "Free riders," if any, were subtracted for net program potential.

Determining the programmatic supply curve was complicated because of the synergies and interactions between conservation programs. Cost differences for complete programs appeared to be minor, with most programs estimated to cost around 30 mills/kWh. In general, a difference was found between technical potential and market potential due to the existence of market barriers, and timing issues.

1.2.3 Program Design

Assessing and targeting markets is a major focus of program design. An increasing number of DSR programs are expected to be offered over the next 20 years as the company learns more about how to efficiently and effectively deliver demand-side resources. There are barriers to overcome, including customer perception regarding the value of investing in energy conservation as well as the cost of conservation measures.

Planning for DSR programs must include administrative costs as one component of the Total Resource Cost. Other factors to be considered in calculating cost include the possibility of an energy service charge, and net present value (NPV) program multipliers.

"Commissioning" is a tool the company will use to assure persistence of energy savings from the energy conservation measures. Commissioning also includes training of the maintenance personnel On-going and specific program evaluations are another component of the company's quality control strategy.

1.2.4 Ramp Rates

Most programs have ramp-up over about five years. These programs are also affected by annual construction cycles. It will take more than one yearly cycle for the full effect of any particular feature or program incentive to be integrated into the plans of prospective participants. Furthermore, program efficiencies won't be evident until they've operated in a program for at least three years.

For RAMPP-3, a new approach was utilized to assist in development of the ramp-up rates: the integration model was run in an "unconstrained" mode, in which the model selected the optimum DSR resource timing without consideration of logistic constraints.

1.2.5 Program Options

Demand-side program options include programs in the areas of:

- new residential construction
- residential retrofit—non-low income
- residential retrofit—low income
- residential appliances
- water heater load control
- new commercial construction
- commercial retrofit
- industrial

These categories were defined to capture the logical segments of customer types and end use applications in the market.

1.2.6 Cost-effectiveness

To screen and select demand-side resource options, the company used two tests: the total resource cost test, and the utility cost test. Other economic screening criteria included examining a program's financial soundness using an internal rate of return (IRR) calculation, and examining the program's impacts on prices.

1.2.7 Two-Year Action Plan and Acquisition Targets

Management and company staff developed a DSR action plan in November, 1993. The plan is aimed at developing demand-side programs and increasing program offerings throughout the company's Utah and Pacific service territories over the next two years, while mitigating potential adverse impacts associated with poor performing programs.
Specific action items were drawn up in the program areas of new residential buildings, existing residential buildings, appliances, commercial retrofit, new commercial, and industrial and irrigation. The company also has other DSR activities planned, which will benefit more than one sector or program.

A study of energy savings targets, broken down by state and program, are included. The MWa savings shown in the two-year action plan, with a target of 40 MWa, represent the first two years of the company's five-year goal of 143 Mwa.

Jerry 467-7080

SECTION 2.0 Overview of the RAMPP-3 DSR Analysis Process

In this section we present a step-by-step description of the process we have used in estimating the DSR supply curves, developing program design, and adapting DSR targets to the programs. There are many smaller steps, such as additional feedback loops, not presented in this overview, but the essential steps are shown in the accompanying chart.

Each of the major steps of the process are identified in the chart and referred to by box number. Each "process box" box is labeled as Box 1, Box 2 and so on corresponding with the narrative discussion below. After the narrative for each box, are cross references to sections in the body of the report where the process is discussed. The text in each box is descriptive of the method or focus for the step it is associated with. The entire process has been organized into two major groups, one for *DSR Supply Curve Estimation* (Boxes 1 through 16, and 28 through 38) and one for *DSR Program Design* (Boxes 17 through 27).

2.1 DSR Supply Curve Estimation Process

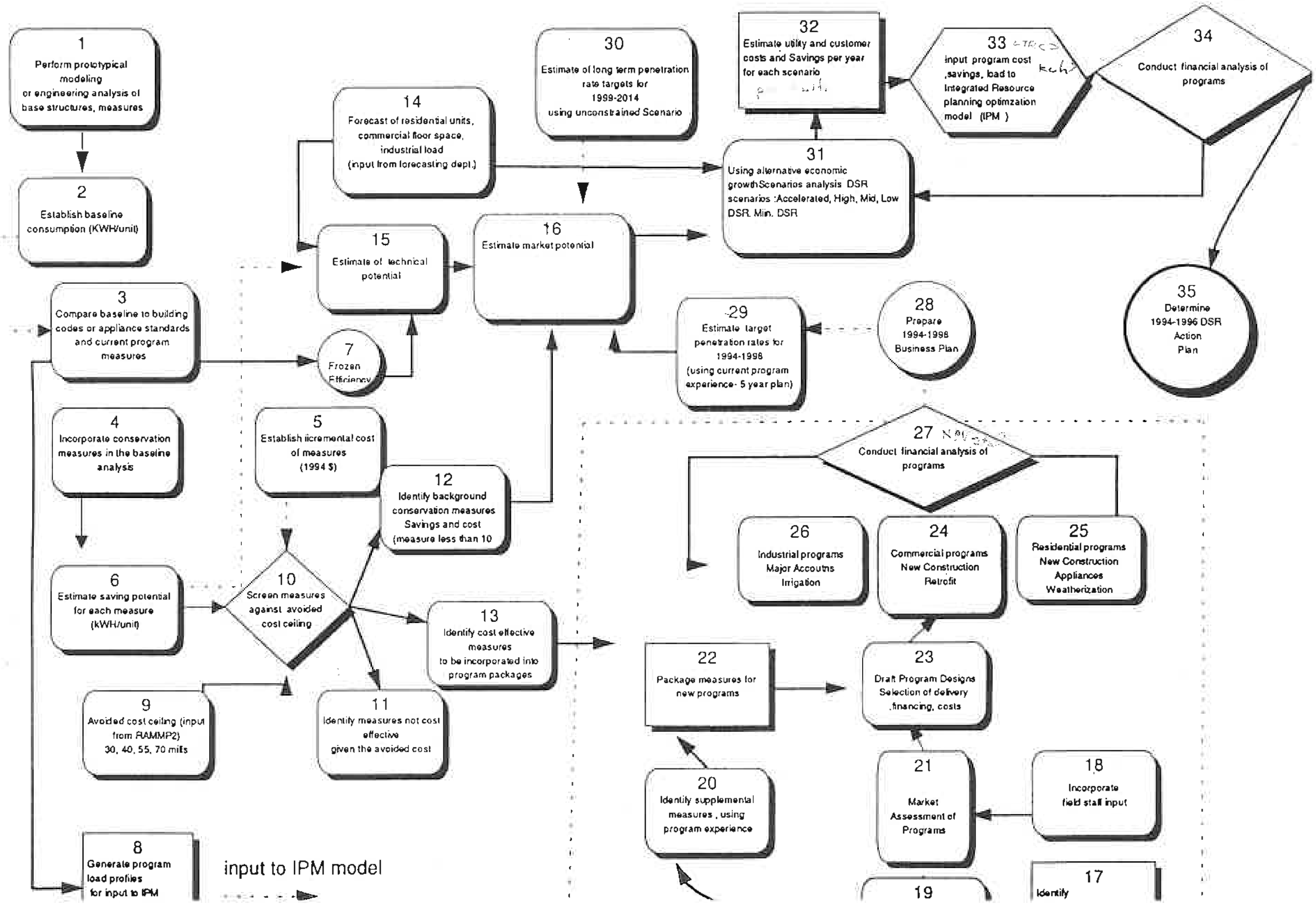
The DSR supply curve estimation focuses on determining base energy consumption for each end use across all customers classes, and determining technical potential of DSR resources. Technical potential is the maximum potential energy savings available. Supply curves are then generated for the availability of resources, given various levels of resource cost. By taking into account forecasts and market barriers, technical potential is then converted to market potential, and market potential becomes the basis for DSR program planning and design.

Box 1: The starting point in our analysis is to establish prototypical modeling or engineering analysis of base structures and demand-side measures. This approach takes into account the unique characteristics of the customers in our service area. It provides an approximate representation of our service area by modeling a number of prototypes which provide an average for a given segment. These prototypes, while useful in aggregate, are not expected to reflect any specific building. [*Sections 4.0, 4.1, 4.6, 6.3 and 8.2*]

Box 2: Based on the prototypical modeling and engineering analysis, we establish baseline energy consumption (in kWh/unit). The baseline consumptions are refined using best available information from surveys, actual experience, monitoring and various other sources. [*Sections 4.1, 4.4.2, 4.5, 5.1, 6.1, 6.2 and 7.1*]

RAMPP-3 DSR Analysis Process

DSR Supply Curve Estimation Process



Box 3: We then compare baseline to building energy codes or appliance standards and current program measures. This step helps make sure we are setting the program baseline at the appropriate level. The consumption information is then provided to the forecasting department in the form of a *"Frozen Efficiency"** (fixed kWh/unit) forecast. [*Sections 3.3 and 4.4 and Appendices B, C, D, E, F and G*]

Box 4: Once we have established an accurate estimate of baseline consumption for each customer class and measure, we incorporate conservation measures in the baseline analysis. Conservation impacts are measured by modeling the impact of the energy conservation measures, using energy simulation modeling, or through the use of engineering analysis. [*Sections 4.7, 5.2, 6.1, 12.3.1, 12.3.2, and 12.5.2*]

Box 5: For each energy conservation measure analyzed we also need to establish the incremental cost of the measures (in 1994 dollars). The cost information collected includes the cost of installing the measure as well as the cost of operating and maintaining the measure. We estimate: the incremental cost of equipment compared to the baseline equipment; O&M costs or savings; and number of times a measure will be replaced during 1994-2014 period. Replacement frequency is based upon the measure's life. [*Section 5.4*]

Box 6: Once we have estimated the energy consumption for the baseline measure and the energy consumption after installation of the conservation measure we estimate saving potential for each measure (kWh/unit) by taking the difference between post- and pre-installation levels of energy consumption. [*Section 6.1*]

Box 7: Forecasting of total energy consumption is based on "frozen efficiency" levels for each end use and customer class. [*Section 10.0*]

Box 8: In this step, the baseline energy consumption (kWh/unit) for each measure is combined with the hourly load profile for the measure to estimate hourly kW demand for the measure. The difference between the base load and the measure's load profile, integrated over time, is the energy savings for the measure. The load profiles are used as input for the IPM forecasting model. We use package load profiles to generate program load profiles and convert kWh to kW savings.

In a later step of the process as the program design is completed, we generate program load profiles for input to the IPM model. [*Sections 3.2, 3.3, 3.4, 4.8, 5.5, 6.4 and 7.3*]

Box 9: We use different avoided cost levels (input from RAMPP-2) at 30, 40, 55, and 70 mills/kWh from the particular scenario under analysis to determine the selection of measures from the conservation supply curves. [*Section 12.5.1*]

Box 10: We screen measures on a total resource cost basis against an avoided cost ceiling. We compare the net present value of costs and energy savings for each measure, including incremental cost and O&M costs. This is a first level screening used in the RAMPP planning. As a result of screening, measures are grouped into three categories (Boxes 11, 12 and 13) [*Section 12.5*].

Box 11: Given the avoided cost criteria, non-cost effective measures are determined. These measures are excluded from base analysis. However savings are added back in the scenario analysis to reflect a hypothetical higher avoided cost. [*Section 12.6*].

Box 12: We also identify background conservation measures savings and cost (those which measure less than 10 mills). Background conservation calculation is an attempt to estimating naturally occurring conservation. Background conservation savings and costs are deducted from <u>the technical potential to yield market potential</u>. There are other additional adjustments made to get from technical to market potential. [*Sections 10.0 and 12.2*]

Box 13: We then identify cost-effective measures to be incorporated into program packages. These are measures that have passed the first level screening and are eligible for inclusion into a program. [*Sections 12.1.1, 12.5*].

Box 14: In this step we bring in the forecast of residential units, commercial floor space, industrial load (inputs from forecasting). [*Appendix H*]

Box 15: The base consumption, from Box 3, is provided to the forecasting department as frozen efficiency consumption levels for each end use for each customer class. The projected number of units and kWh/unit from the forecast, compiled in Box 14, are then used to as the energy consumption base from which we estimate the DSR resource technical potential. [*Sections 5.4, 9.0, 12.2, and 12.3*]

Box 16: We then convert technical potential to market potential, taking into account forecasts (frozen efficiency, Box 14) and subtracting background conservation, Box 12). [*Section 13.1*]

2.2 DSR Program Design Process

The program design process is non-linear with substantial feedback and interaction loops. The process involves coordinated efforts among resource planners, program managers, financial experts, evaluation personnel, and field staff.

Box 17: The program design takes into account external factors such as laws and public policies, environmental concerns and other influence beyond energy and cost concerns.

Box 18: Field staff evaluate program options and program design criteria, based on actual customer interactions. The benefit of their experience is important when working with program managers to define the best ways to target, market and deliver programs. [*Section 14.0*]

Box 19: Specific information from program evaluations and program experience is critical feedback for adjusting aspects of existing programs and designing new ones. [*Section 14.5*]

Box 20: We add supplemental measures, using program experience. Supplemental measures are those measures that are beyond the avoided cost-effectiveness criterion, but are included in the program because they provide additional value to the customers and encourage program participation. [*Section 12.6*]

Box 21: In order to design an effective program we need to assess the market characteristics for each program. This analysis brings together input from program managers, field staff, *and* evaluation results from current programs. [*Sections 14.1, 14.1.1, and 14.1.2*]

Box 22: The first step in the program design process is to package measures for new programs. To bundle the measures into programs we combine cost-effective measures with the supplemental measures. [*Section 14.2*]

Box 23: Using market assessment findings we draft program designs. Alternative delivery mechanisms, marketing approaches, and tracking requirements are evaluated and the cost of each option is considered. We produce draft program designs for all markets identified through the planning forecast.

The programs target residential, commercial, and industrial initiatives for both new and existing markets . The program designs, and costs for the 1994-1998 programs, are based on current operating programs, modified by future expectations. The program designs, and costs for 1999-2014 are based on *average*, rather generic costs. [*Sections 14.3, 14.3.1, 14.3.2*]

Box 24: The commercial programs for the 1994-1998 are broken out in more detail and include initiatives such as Energy FinAnswer, Energy FinAnswer 12,000, Energy FinAnswer Retrofit: Comprehensive and Lighting Measures, competitive bids, and Green Lights. The commercial programs for 1999-2014 are combined in generic offerings for new commercial construction and retrofit markets. [*Section 16.4 and Section 16.5*]

Box 25: The residential programs for the 1994-1998 (Business Plan period) include Home Comfort, Low Income, H-pro Heat Pump, H-pro Air Conditioning, Super Good Cents Home improvement, Super Good Cents, Manufactured Acquisition Program (MAP), Hassle Free, and competitive bids. The residential programs for the later 1999-2014 period are New Construction, Appliances, Weatherization Low Income. [*Sections 16.1, 16.2, 16.3 and 16.7*]

Box 26: Industrial programs for the 1994-1998 include Industrial FinAnswer, Irrigation FinAnswer, Ditch-to-Pipe, and Large Accounts. The industrial programs for the 1999-2014 include industrial, and Irrigation programs. [*Section 16.6*]

Box 27: An important step in the program design process is financial analysis of the program impacts. The results of the financial analysis are used as a feedback to the program design. [*Section 14.4.3*]

Box 28: The results of the program planning and financial analysis are used to prepare the Five year (1994-1998) Plans. [*Section 18.0*]

Box 29: One of the outcomes of the five-year plans are the estimates of target penetration rates for 1994-1998 (using current program experience). For each program we estimate a target penetration rate. Target penetrations are guided by evaluating current program efforts and deriving reasonable ramp-up rates to reflect a mature level of program activity. [*Appendix H*]

Box 30: The estimates of long term penetration rate targets for 1999-2014 are based on the resource requirements for the system. The penetration rates for 1999-2014 are mature program penetration rates. We have used an unconstrained DSR scenario as a guide in estimating the target penetration rates for this period. [*Sections 15.0, 15.1, and 15.2*]

Box 31: We then test for the sensitivity of the DSR options using alternative economic growth scenario analysis. We evaluated several DSR scenarios including those base on high, medium, low, and minimum economic growth scenarios. [*Sections 15.0, 15.1, and 15.2*]

Box 32: As an input to the scenario analysis we estimate utility and customer costs and savings per year for each scenario. [*Appendix H*]

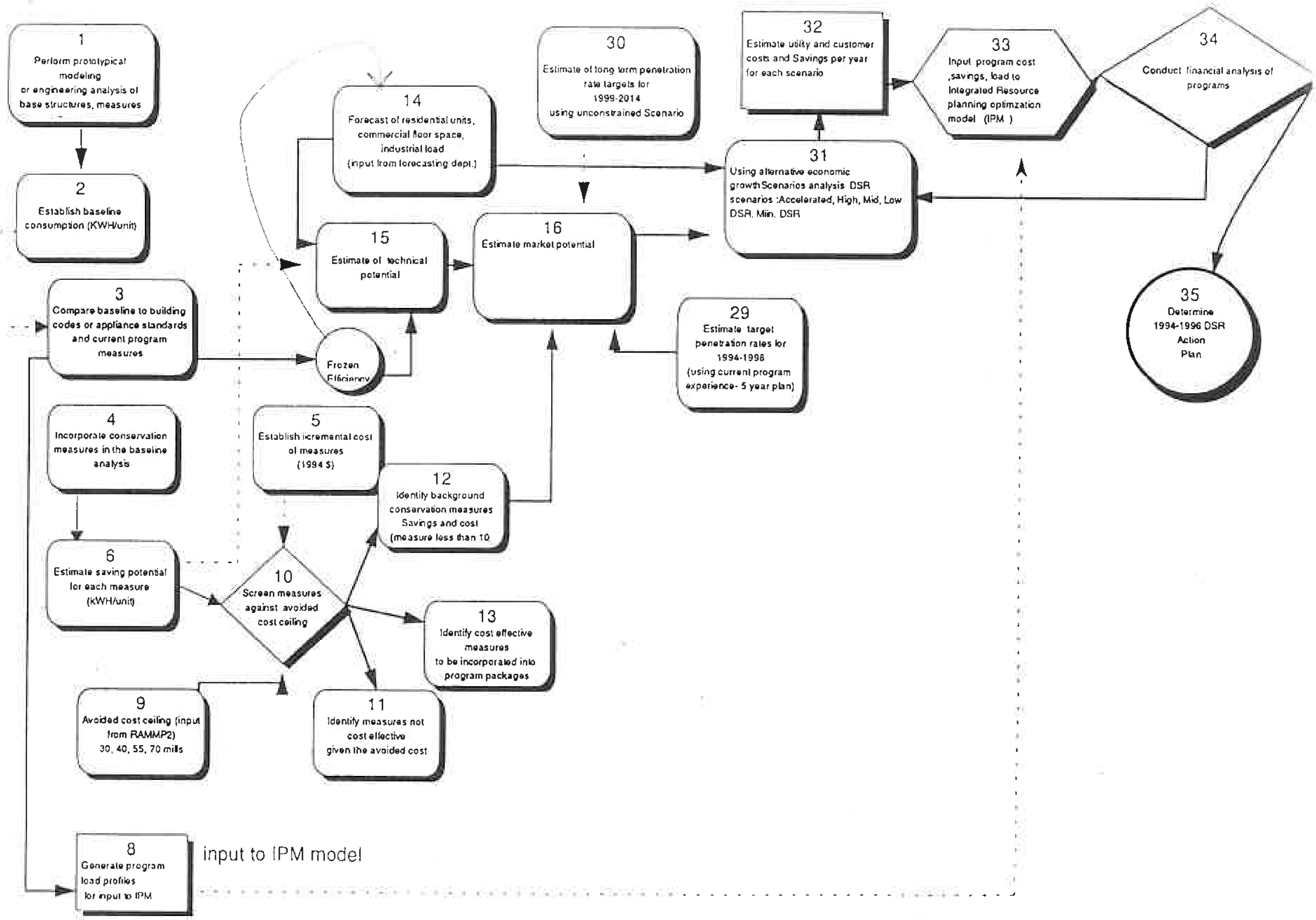
Box 33: We then input program cost, savings, and conservation load potential into Integrated Resource Planning Optimization Model (IPM Model)" for each scenario. [*Sections 16.0 and 17.0*]

Box 34: Although the processes described in Boxes 34, and 35 are not part of the detailed documentation provided in this document. They are addressed in the main RAMPP-3 report. [*Sections 17.0, 17.2, and 17.3*]

Box 35: See Box 34. [*Section 18.0*]

PART I

DSR Supply Curve Estimation Process



SECTION 3.0 An Integration Model for Generating Supply Curves

Foundations and Methodology

We have divided our customers into several discrete market segments*[1] and evaluated the available conservation resources for these sectors using an integration model* based on load shapes. Ultimately, the goal of the conservation resource assessment and market analysis work was to determine the technical potential, or maximum, demand-side resources* available to the company over the 20-year planning horizon.

IS THIS DISTINCT FROM PROGRAM POTENTIAL ?

3.1 Market Sector Definition and Energy End Use

Commercial and industrial *market sectors** were subdivided based on the groupings categorized in Tables 1 and 2.

Table 1—Commercial Market Segmentation

VMS	Commercial Segment	SIC Code
10	Office	4310-20, 6010-7010, 9000-10000
1	Construction/Transportation/Utility	4000-4220, 4230-40, 4410-4620, 4710-4970
11	Services	7200-8009, 8110-20, 8320-30, 8350-60, 8390-8700, 8910-9000
9	Other Health	8010-50, 8070-8100
3	Retail	5200-5409, 5440-50, 5510-6000
2	Grocery	5410-5440, 5450-5500
6	Lodging	7010-7050, 8360-8370
5	Warehouse (including refrigeration)	4990-5200, 4220-4230
4	Restaurant and Fast Food	5810-20
7	School	8210-8300, 8330-8350
8	Hospital	8050-70
12	Other Structures	1-3999, 4970-80, 8810-20

[1] Technical terms are italicized and marked with an asterisk* when first encountered, then defined in the Glossary at the end of this report.

These tables are based on the Vertical Market Segment (VMS) number assigned by the company's Market Assessment Services to identify market segments. These segments comprise a range of Standard Industrial Codes (SICs).

Table 2—Industrial Sector Segmentation

Industrial Sector	SIC Code
Oil and Gas	13
Mining	12, 14, 109-147
• Coal	12
• Vermiculite	14
• Uranium	109
• Bentonite	145
• Trona	147
Food Processing	20
Lumber	24
Pulp and Paper	26
Chemicals	28
Petroleum Refining	29
Pipelines	33
Other Manufacturing	46
	—

Notice that the Construction, Transportation, Utility, Services, and Other Health categories were treated as small office buildings and combined with the Office category. The "Other" category for the industrial sector includes all other segments not explicitly identified. However, industries in these segments are not necessarily small just because the segment is not differentiated in more detail. Details and characterization of the market sectors are included in the forecasting volume.

Figure 2 represents loads and energy sources for 1992, the most recent year with full data available prior to the development of the plan. Data for Figure 2 can be found in Tables 3 and 4. Industrial customers account for the largest amount of sales, with commercial and residential splitting most of the rest. Utah has a large and diversified industrial base. In the Northwest, Oregon accounts for about half of sales. Wyoming is substantial portion of the industrial sales, based on mining and petroleum.

3.2 Compiling and Normalizing Load Shapes

For this RAMPP-3 analysis, *load shapes** were developed which provide more detail about consumption during *off-peak** periods. The load shapes are supplied to the integration model in the form of specific files for each demand-side program. A program in this context is the collection of all measures that are bundled for that program. If there are 10 measures under a program, the load shape for the program is the aggregation of the individual measure loads.

The load shapes are actually conservation load shapes. They represent the hourly profile of the difference in consumption between the base case and the building with an entire package of

The load shapes are actually conservation load shapes. They represent the hourly profile of the difference in consumption between the base case and the building with an entire package of cost-effective measures installed. The definition of the measure package assumes that we have, to some degree, defined the program. For example, the residential weatherization load shape assumes a specific amount of the savings coming from appliance measures like low flow showers and a specific amount coming from *shell measures**. The appliance measures still save energy in the summer; the shell measures only save during the heating season. The program load shape is an energy weighted sum of the two different profiles.

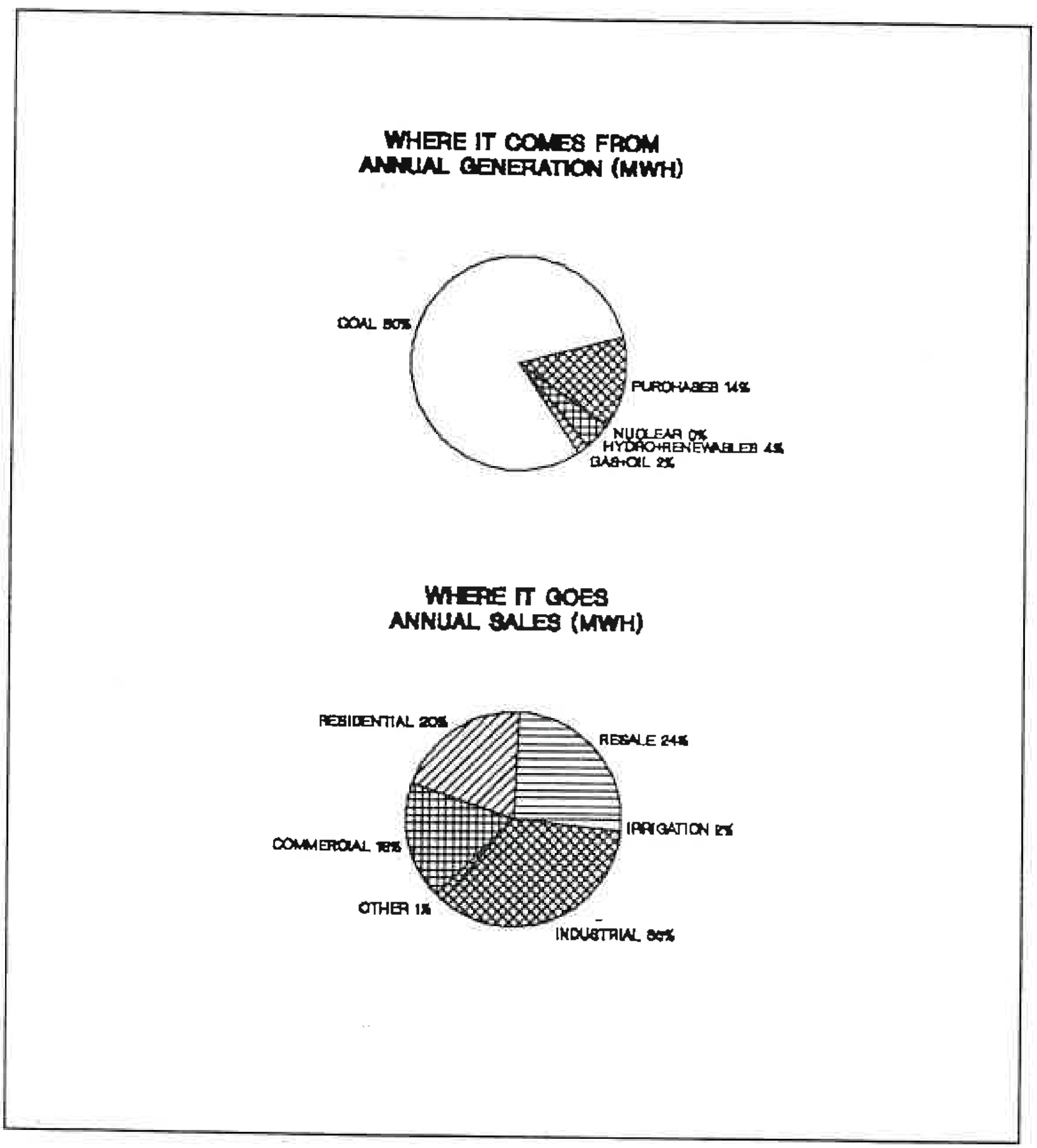


Figure 2— Company Energy Sources and Sales

Table 3—Number of Customers in 1993

	COMPANY	OR	WA	ID (P)	MT	WY (P)	CA	ID (U)	WY (U)	UT	PPL TOTAL	UPL TOTAL
RESIDENTIAL	1,102,789	367,651	90,015	7,684	25,518	82,490	31,491	37,303	9,259	451,387	604,849	497,949
COMMERCIAL	147,289	55,530	13,329	1,569	4,696	16,102	6,198	4,964	1,731	43,170	97,424	97,424
INDUSTRIAL	16,769	2,030	653	157	157	2,050	684	1,261	466	9,311	5,731	11,038
IRRIGATION	9,269	3,932	2,782	54	54	307	295	1,629	14	229	7,424	1,872
OTHER	2,969	374	2	41	41	118	2,174	948		99	648	2,321
TOTALS	1,279,121	429,517	106,781	9,505	30,466	101,067	38,740	45,256	11,518	506,271	716,076	563,045
% OF TOTAL		33.6%	8.3%	0.7%	2.4%	7.9%	3.0%	3.5%	0.9%	39.6%	56.0%	44.0%

Table 4—Sales to Customers in 1992 (megawatt-hours)

	COMPANY	OR	WA	ID (P)	MT	WY	CA	ID (U)	WY	UT
RESIDENTIAL	11,190,947	4,412,859	1,347,111	97,051	290,633	676,768	355,408	537,213	86,951	3,386,953
COMMERCIAL	9,721,162	3,440,244	1,052,815	65,584	219,640	834,864	217,473	199,776	80,843	3,609,923
INDUSTRIAL	19,190,159	3,946,225	1,092,275	178,264	181,264	4,257,195	137,757	1,658,945	1,821,617	5,916,341
IRRIGATION	851,590	243,036	45	2,425	2,425	11,153	20,446	556,992	2,504	12,564
OTHER	608,551	44,916	7,782	2,288	2,288	11,286	2,994	1,846	1,507	6,533,644
TOTAL	41,562,409	12,087,280	3,500,028	345,612	696,526	5,791,266	734,078	2,954,772	1,993,422	13,459,425
% OF TOTAL		29.1%	8.4%	0.8%	1.7%	13.9%	1.8%	7.1%	4.8%	32.4%

Each file includes a 24-hour profile for three *daytypes** during each of four seasons. A daytype is a typical load profile for a typical day. The three daytypes are typical weekday, typical weekend day and peak day. The seasons are the conventional ones of December-February, March-May, June-August, and September-November. The integration model uses the weekday and weekend days to assemble a simulated *load duration curve** that represents annual energy consumption. The peak day load shape is used only to estimate capacity reserve margin requirements as discussed in the Integrated Modeling Appendix.

Load shapes are different for specific *end uses** and for interactions between end uses. For example, commercial lighting is hat-shaped, whereas space heating shows an early morning peak. As a result, the overall load shapes vary with the type of fuel used for *space heat** as well as with the market sector and end uses addressed by a program.

Each program load shape must be assembled by adding up the underlying end use load shapes. It is important that the result be correctly normalized to the underlying resource amounts within each program. As a general rule, the programmatic load shape files were normalized to units of one MWh. This means that the load shape represents the hourly kW impact of one MWh dispersed over the year. The impacts can then be adjusted easily to different program amounts by multiplying times the expected annual MWh impact for the program. The method assumes that the relative proportions of different measures and end uses will be the same over the range of programmatic scale being considered.

To some extent, load shapes take into account programmatic considerations, such as selective market sectors and packages or groupings of measures, although the program design step actually follows development of the *supply curve** estimate of *technical potential**. Program influences on load shapes are discussed in the second half of this report.

3.3 Methodology for Deriving Load Shapes

The methodology for deriving load shapes differed by market sector. Ideally, one would like to have monitored or metered loads. Monitored data were used to derive the space heating load shape for existing and new residential buildings. The existing case was based on the Hood River monitoring of hourly load before and after weatherization. The new case was based on monitoring conducted by BPA for the Residential Conservation Demonstration Program (RCDP). The RCDP data set included loads for Model Conservation Standards (MCS) buildings and a control group. The difference between the two is assumed to represent the conservation load shape for MCS construction. There are some caveats applied to these data. The MCS group included many zonal heating systems so the results may be questionable for the company since new construction tends to include many heat pump systems.

Monitoring results were adjusted to provide representative end use loads for residential appliances. For example, one important residential appliance load is water heating. It is anticipated that programs will provide more efficient water heaters (lower standby loss) and low flow shower heads (lower variable use). These measures have different load shapes.

A reduction in standby loss is expected to be uniformly distributed, meaning it has a flat load shape. A reduction in variable use, however, will be more likely to occur during peaks. Accordingly, two load shapes were developed. A flat shape represents reductions in tank loss, based on the minimum consumption level at night. Shower savings are assumed to be a ratio of the variable usage to the night time level. The hourly savings from these measures are added to those from space heat savings in order to derive programmatic load shapes. Obviously, then, the program results will depend on the relative proportions of the measures expected to be included in the programs.

Monitoring results from BPA were also used for load shapes in the industrial and irrigation sectors. The industrial loads for large facilities tend to be flat—that is, they operate 24 hours per day and show little hourly variation. The large facilities tend to dominate the sector. Load shapes for small and large facilities were aggregated based on the relative sizes of the potential participant. The results show slight hourly variation in the Northwest and virtually no hourly variation in Utah and Wyoming. The *conservation load factor** is close to 100%. This result is a change from RAMPP-2 which assumed a 60% load factor.

3.4 Using Prototype Models to Generate Load Shapes for End Uses in Commercial Buildings

Monitoring data often do not exist, especially for assessing the conservation impact—comparing with and without demand-side measures. For this reason, the load shapes were derived from simulations of *prototypes** representing a span of *building types** for the commercial sector. This same method was used to estimate the technical potential for energy savings. For RAMPP-3, the simulation models were used to generate hourly load shapes as well as annual energy savings.

Runs were completed for the building with greatest market potential —large office, small office, retail, school, and grocery—for new and existing building stock, for three different space heat fuels and four different cities. This step creates a large number of hourly data files. The resulting hourly loads must then be aggregated in proportion to the number of buildings in different market segments and for different fuel saturations.

The resulting load shapes differ for different service territories and forecast assumptions. For example, Utah has primarily gas-heated buildings where the important demand-side measures are lighting-related. The technical potential will be smaller without electric space heating measures but the hourly impacts will follow system peaks closely. Thus, the demand-side program in Utah will have more capacity benefits per annual megawatt-hour although fewer megawatt-hours per participant. The base case assumptions and applied energy conservation measures are represented in the commercial sector worksheets of Appendix F.

*Diversity factor** is an issue for modeled conservation load shapes. The shapes derived from monitoring include the diversity of the sampled buildings but the modeled load shapes do not. Diversity was not explicitly included although weighing the load shapes across building types and fuel types tends to produce an averaged load profile. Further elaboration of the modeled profiles to include diversity is an anticipated future refinement of the methodology.

Diverse load shapes for groups of customers are smoother than for individual customers

3.5 Taking into Account Capacity Savings and Diversity Factors of Peak Average Reduction Over Four Seasons

*Capacity savings** are reported for the programs are based on an average reduction winter, summer, fall, and spring peaks. The conservation load factors used for this estimate have been derived from the load shapes. They are an output, rather than an input, of the analysis. Those factors are listed in Table 5.

Table 5— Conservation Load Profile (revised), Supported by 1993 RAMPP-3 Analysis

Program Description	Conservation Load Factor
Oregon, Washington, California Appliance	63%
Utah Appliance	60%
Wyoming Appliance	60%
UT Super Good Cents	84%
Wyoming Super Good Cents	84%
Oregon, Washington, California SGC	80%
Utah Residential Weatherization	73%
Oregon, Washington, California Residential Weatherization	74%
Utah Commercial FinAnswer	54%
Wyoming Commercial FinAnswer	54%
Oregon, Washington, California Commercial Retrofit	52%
Oregon Washington California Commercial FinAnswer	38%
Utah Commercial Retrofit	55%
Wyoming Commercial Retrofit	55%
Utah FinAnswer 12000	54%
Wyoming FinAnswer 12000	54%
Oregon, Washington, California FinAnswer 12000	38%
Oregon, Washington, California Industrial	94%
Wyoming Industrial	100%
Utah Industrial	98%
Oregon, Washington, California water heater load control	42%
Utah Irrigation	73%
Oregon, Washington, California Irrigation	73%

Conservation load factors presented in table 5 were revised values. They were not directly used in the estimation of the capcity value of the DSR resources. The RAMPP planning model, IPM, used programatic load profiles to estimate the capacity value for each program.

The supply curve worksheets have been established strictly to account for energy savings. However, the Energy Conservation Measures (ECMs) listed in the worksheet tables (see Appendices B, C, D, E, F and G) usually provide the additional benefit of capacity savings as well. The amount of capacity benefit depends on the type of measure and its likelihood of contributing during times of system peak. (Peak conditions can be defined for different seasons and are discussed in the Integrated Modeling Appendix. RAMPP-3 looked at winter peak as the *merged system constraint**).

Commercial lighting measures, for example, will likely be in effect during system peak and will provide significant demand savings. On the other hand, residential weatherization has a much lower impact on peak. This is because the size of the residential furnace is not changed when insulation is installed—the furnace still comes on with a demand spike on a winter's morning. The duration of that spike is less than, say, a lighting peak, and so there are demand savings, but the relative impact is not as large as the energy savings.

*Capacity** calculations for RAMPP-2 relied on a Conservation Load Factor. Peak savings can be computed from the relation:

Peak Savings (kW) = (Energy Savings (kWh)/ Number of hours)/ CLF

The Conservation Load Factor (CLF) is usually calculated for specific periods of interest such as the winter and summer peak hours. The number of hours used in the above equation depend on the period of interest. Although the CLF is still a useful concept for quantifying the value of avoided cost for demand-side options, RAMPP-3 relied on load profiles developed for the various programs.

The programmatic conservation load factors used in evaluation of the capacity impact of the programs is an aggregation of the measure conservation load profiles. The appliance load profiles were combined with the space heating load profiles to generate the programmatic conservation load profiles. The new residential program in Northwest contain 26 percent savings from appliance, in Utah this percentage was zero. As a result, of the effect of the appliance load profiles on the aggregate load profile, the conservation load factor for new residential program in Utah is higher than Northwest's conservation load profile.

3.6 Financial Parameters—Real Discount Rate, Capital Recovery Factor, and Levelized Cost

Costs used in this report were computed in real terms to avoid the complexities introduced by various inflation assumptions. All cost in the analysis are based on 1994 real dollars. The primary comparison of measures is on the basis of their levelized *lifecycle cost** in mills/kWh. This avoids concerns about differing lifetimes. If components of an ECM have different lifetimes, we must calculate an effective present value of the installation cost, taking into account replacement costs. This procedure needed to be applied in only a few cases, such as calculating the present value of O&M savings.

Details of the financial parameters are presented in the Appendix H. The financial parameters used were mainly the *discount rate** and *capital recovery factor**. The discount rate is defined in Figure 3.

Capital recovery factor is used to convert up-front cost of different measures into comparable units. If two measures have different first cost, savings, and measure lives they need to be converted into a common unit of measurement. The capital recovery factor is multiplied by the first cost of the measure, to convert it into an annual flow. The result is divided by the annual savings from the measure to get a dollars per kWh savings from each measure.

Annual capital recovery factor is calculated as:

$$CRF = [i * (1+i)^N]/[(1+i)^N-1]$$

where N is measure life and
i is real discount rate

Capital Recovery Factor (CRF) will change if the discount rate changes, or the measure life changes. The CRF decreases as measure life increases. The capital recovery factor for a 10 year measure at 5.3% discount rate is 0.1309. The CRF for a 30 year measure life using the same discount rate is 0.0668.

Discount Rate

Company's post-tax cost of capital: 8.81%

Inflation, DRI 20 year forecast: 3.4%

Effective real discount rate is calculated by a ratio formula to correct for inflation or escalation rate as follows:

$$r' = \frac{(1 + r)}{(1 + i)} - 1 = 5.23\%$$

where:

r' is the effective discount rate
r is the nominal discount rate
i is the inflation or escalation rate

Figure 3—Discount Rate

The capital recovery factors (CRF) using different measure lives are compared here:

	10 year	30 year	70 year
CRF @ 5.23%	.1309	.0668	.0538

How

Discount rate affects the conservation supply curve through change in the calculated present value of the discounted flow of future benefits and discounted flow of future O&M costs for the measure. Every thing else being equal, as the discount rate increases fewer measures will be found cost-effective.

Another key economic concept applied in analyzing energy conservation measures is *levelized cost**, or LC:

replacement costs

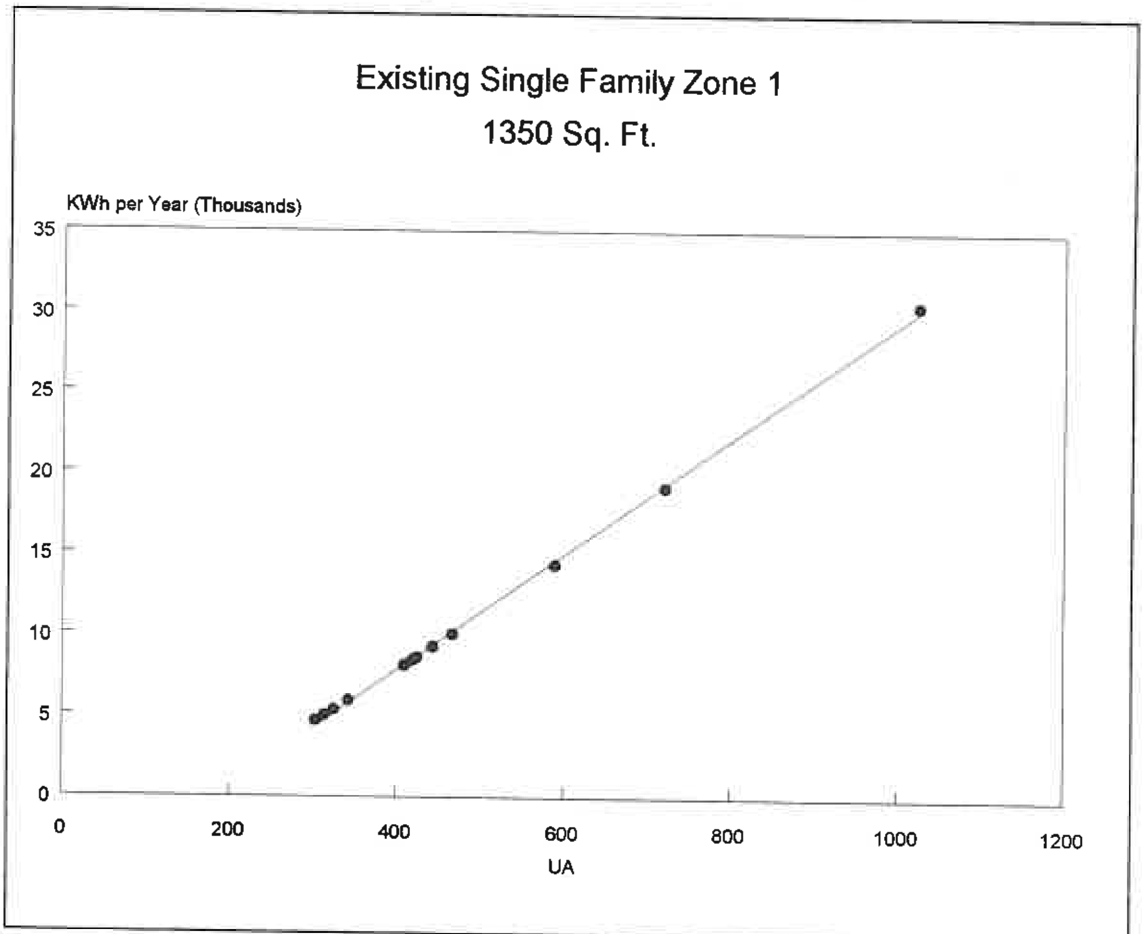
LC = (first cost + NPV of O&M) * CRF/annual kWh savings

Levelized costs takes into account the relative cost of a measure compared to its expected annual energy savings over the measure's life.

SECTION 4.0 Residential Sector—Space Heating

The basic methodology for analyzing residential space heating relies on the assumption that only three prototype homes are necessary to represent all the residential single family housing stock. The homes have been modeled using the SUNDAY computer program over a range of different *heat loss coefficients**, or *UA values**. In the region of interest, the modeled energy usage appears to be a highly linear function of UA as shown in Figure 4.

Figure 4—Regression of SUNDAY-Modeled Consumption Against UA Value



Hence, the slope and intercept values are listed in the data sheet. The linear assumption simplifies energy use calculations since one has only to multiply delta UA times slope to obtain the change in energy usage. Non-linearity does creep in as the UA becomes small (around 200 BTU/hr-°F). However, such a small UA is unlikely to be encountered except perhaps in small manufactured homes.

4.1 Distribution of Different Types of Residential Dwellings

For space heating analysis, the residential building stock, both existing and new, is allocated to a set of prototype homes. There are three single family dwelling (SFD) prototypes, one or two manufactured home dwelling (MFD) prototypes and one multifamily prototype. These prototypes are taken from the planning models of the Northwest Power Planning Council (NPPC)[1].

The existing housing stock is slowly decreasing due to a small demolition rate. Our breakdown of the housing stock by the end of the planning horizon is:

	Fraction of Existing Stock	Fraction of New Stock
Residential		
Small SFD	.170	.258
Medium SFD	.251	.125
Large SFD	.191	.118
Small MFD	.200	.113
Large MFD	—	.187
Multifamily	.187	.199
Total	1.00	1.00

Some of the states span more than one *climate zone**. New and existing residential homes were apportioned to zones using the following fractions:

Oregon Zone 1	0.8512
Oregon Zone 2	0.1488
California Zone 1	0.8587
California Zone 2	0.1414

4.2 Calculation of Dwelling UA—Empirical Versus Nominal Insulation Levels

For existing residential buildings, the heat loss coefficients, or UA values, were calculated based on survey information regarding existing insulation levels and the *retrofit** U values developed by Bonneville. This approach leads to some complications because the U values used by Bonneville were based on *empirically* derived R values for different insulation measures. (The *R value** of a material is the inverse of the U value). Generally, U values can be added. For example R-11 insulation added to R-19 batting in a ceiling produces an R-30 insulation level. But added values are nominal; the incremental R changes are not strictly additive.

For example, an empty ceiling (no insulation) has a U value of 0.285 or an R value of 3.5. One might expect that adding R-38 insulation would raise the R value to R-41.5. But this is not the case. Bonneville uses a final U value for a R-38 ceiling of 0.039 or an equivalent R value of 25.6, considerably less than 41.5. The difference represents the empirical value of insulation on a retrofit basis with attendant voids, gaps and other installation imperfections.

Mean insulation values are used based on survey information or on informed judgment when necessary. The existing mean UA is shown as the base in the worksheets in Appendices B, C and D. Incremental changes in UA are shown for each measure; however, not every measure applies to every home. The acceptance factor shown in the worksheet is the fraction of the homes for which the measure would be appropriate. Measure acceptance is limited by physical barriers preventing installation, and presence of measures already installed.

4.3 UA Values for Different Climates and Construction Periods

The survey data for Oregon Zone 1 comes from the Oregon Department of Energy (ODOE) survey of pre-1979 housing conducted by Bardsley Haslicher[2]. A PP&L sample was used for Zone 1. Zone 2 suffers from a small sample size in the ODOE study. Instead, values for Zone 2 were computed from unpublished Hood River Conservation Project (HRCP) data[3]. The HRCP information on pre-retrofit conditions in Hood River was assumed to represent Zones 2 and 3 in other states.

The numbers for the interim stock built during the period 1980-1987 is known from historic data. In most areas, this is a relatively small amount because economic conditions have not encouraged new construction. The amount of new building stock from the interim time period ranges from about 8% in the Willamette Valley to about 16% in Idaho. The UA values were adjusted by assuming that new construction conformed with energy efficiency codes in place at that time. This is an optimistic assumption but should have little effect on estimates due to the small amount of recent construction relative to the total housing stock.

To adjust for the recent construction, the existing housing stock was grouped into "bins" for different insulation levels. A fraction—equivalent to the proportion of the stock represented by recent construction—was removed from the lowest bin and transferred to the highest bin. This amount transferred represents the effect of recent construction on the aggregate insulation level. Thus, if 20% of the homes had no wall insulation in the older population of homes and 8% of the population represents recent construction, it was assumed that a total of 88% of the current stock are in the fully-insulated bin and only 12% have no wall insulation. In other words, the uninsulated stock has been reduced from 20% to 8% of the total stock, as new insulated homes have been built since 1986.

The above section described the stock adjustment process used in the calculations. As the stock of new homes increases, percentage of stock for existing older homes decreases. So percentage of homes with no wall insulation is reduced even if none of these are being replaced with new homes.

In the above process we track number of homes with different levels of insulation, and break up the existing stock of homes into bins for different insulation levels. As new homes are added to the existing stock, the percentage of homes with no insulation is reduced. We do not assume that for every new home built there is a one to one reduction in number of homes with no insulation.

For new construction, building UA values were taken from the NPPC spreadsheets referenced in their 1991 Plan. They represent a synthesis of recent work conducted by Bonneville and the Council staff. New buildings are expected to conform to an MCS standard in Oregon and Washington where energy codes have been adopted in 1992. It is also assumed that homes in Idaho and Montana will achieve MCS compliance within a few years due to commitments already made. Utah has few electrically heated homes and residences are expected to comply with an energy standard almost as efficient as MCS. Manufactured homes in the Northwest are expected to comply with Manufactured Acquisition Program (MAP) requirements for the entire forecast period.

4.4 Calibration of the Residential Prototype Models to Historic Sales

The models of existing residential building stock were calibrated to base year sales in two steps. First, we estimated the amount of residential sales due to space heat consumption. Then, we adjusted the prototype models to agree with actual usage.

4.4.1 Estimating the Amount of Space Heat Consumption

Note that, unlike the Northwest Power Planning Council (NPPC), the company includes the consumption of customers with partial wood heat. This is because most of our residential customers live in small towns or rural areas. They tend to have a wood stove and obtain some space heating from it.

Average temperature-adjusted residential sales and average space heat consumption are shown below in Table 6. The estimate of space heat is derived from two sources. One source is the base load study[4]. This study looks at a three-way comparison of total consumption for electric/gas/wood heated customers. From this comparison an estimate is derived for electric space heat and the contribution of wood heat to space heating.

The second source is a conditional demand study[5]. In this study, consumption is analyzed for a sample of customers where appliance saturations have been determined. Dummy variables are assigned for the presence of various appliances and consumption is regressed against the explanatory variables. Results of the method are shown in Table 6.

The *conditional demand model** (CDM) is the preferred method for disaggregating space and water heating because it includes other appliances explicitly. However, the application for other appliances can be problematic because the model tends to pick up other consumption which correlates with the appliance usage. For example, the conditional demand model yields a high value for a hot tub, probably because of other consumption associated with the income level and demographics associated with hot tub owners.

Table 6—Actual Consumption and Weather Adjusted Space Heating, Existing Residential Dwellings (1992)

	OR	WA	ID	MT	WY	CA	UP&L UT	UP&L ID	UP&L WY
Average kWh per Customer(Forecast)	12819	15510	13290	12104	8537	10987	7453	14608	9415
Average Space Heat, kWh(CDM)	4772	6718	6000	5175	5877	3000	3632	8884	5031
Electric Space Heating % Saturation (Energy Decision Survey 92)	48%	54%	57%	42%	19%	53%	14%	49%	25%
Base Load Study(Not used)	5180	6718	NA	8672	8023	3321	NA	8438	NA
Electric Space Heat	6247	8348	NA	9593	8651	6391	NA	NA	NA
Space Heat with Wood	4070	3553	NA	8219	7586	2185	NA	NA	NA
Wood Adjustment %	34.8%	57.4%	57.4%	14.3%	12.3%	65.8%	-11.0%	18.0%	NA
Conditional Demand Model Model Total kWh	13194	15432	13545	12857	9963	13167	7226	11804	8241
Single Family	13932	16244	14135	13164	10593	14163	7827	13565	9256
Multi Family	9846	11051	11138	12006	8731	9488	5411	5411	5411
Mobile Home	13287	16391	13287	12226	8035	12257	7406	7406	7406

Underlined figure is from the Baseload Study.

4.4.2 Adjustment of Results from Prototype Models to Agree with Actual Usage

The prototypes are modeled with computer simulation referred to as the *engineering model**. This model over predicts actual consumption for a variety of reasons. The engineering model does not consider the partial use of wood heat. The simulations are run for only one city—Portland for climate Zone 1. It is not surprising that the results differ from actual consumption in another town, for example Medford. Consumption is influenced by *economic, or price elasticity** choices. That is, residents of an unweatherized house may chose to operate the house to a lower degree of comfort than assumed in the engineering models because they cannot afford higher energy bills. Finally, the prototypes may not exactly match actual building stock. For all these reasons, an adjustment is expected.

The downrating adjustment is shown in Table 7. For example, in Oregon space heating is reduced by about 50%. This seems like a large adjustment. However, about half the adjustment can be explained based on what is known about wood heat and heat pump saturations. The remaining adjustment represents climate differences, economic elasticity and prototype mismatch. The 1990 and 1992 Energy Decisions surveys conducted by the Company indicates that wood usage in Utah in not decreasing. The 1990 survey showed 3 percent of residential customers consider wood as primary heating fuel, and 39 percent use wood as supplemental heat. In 1992 survey we found 5 percent of homes use wood for primary heating and 49 percent use wood for supplemental heating.

Table 7—Adjustment to Engineering Estimates for Existing Residential Space Heating

Engineering Model Estimates, Existing Stock with a 30% Economic Takeback, Climate Zone 3									
	OR	WA	ID	MT	WY	CA	UP&L UT	UP&L ID	UP&L WY
All Stock Average (kWh)	9839	9065	13904	15363	14696	12111	9399	16456	15110
Single Family Dwelling (Engineering Estimates-Adjusted) (kWh)									
• Average	11226	10348	15751	17131	16670	14440	10328	17563	17824
• Small	6608	6117	9390	9972	9558	9151	6117	9972	9972
• Medium	9493	8683	14087	15595	14524	13179	8683	15595	15595
• Large	14611	3629	20175	22994	20992	20508	13629	22994	22994
Multi Family (kWh)	4200	3914	5825	6859	6125	4181	6859	6859	6859
Mobil Home(kWh)	9203	8399	13762	16169	14460	9149	8399	16169	16169
Engineering Estimate is Greater Than Actual Space Heating									
Economic Takeback Adjustment	OR	WA	ID	MT	WY	CA	UP&L UT	UP&L ID	UP&L WY
All Stock Average	51.5%	25.9%	56.8%	66.3%	60.0%	75.2%	61.4%	46.0%	66.7%
(30 % adjustment factor + calibration correction factor)									

In this study the downrating adjustment was applied and savings benefits reduced to reflect modeling uncertainty. It should be noted that the NPPC derives an adjustment to estimated space heating of about 30%. In their modeling, that adjustment is primarily due to economic elasticity.

Since part of the adjustment may be due to the use of wood heat and since wood heat is expected to decline, projected space heating should show a slight increase for existing buildings. A projection including some decrease in wood heat is shown in Table 8.

Table 8—Projected Residential Space Heat Demand, kWh

Current 1992 Space Heat Consumption—Existing Stock
(Based on Conditional Demand Model)

	OR	WA	ID	MT	WY	CA	UT UP&L	ID UP&L	WY UP&L
All Stock Average	4772	6718	6000	5175	5877	3000	3632	8884	5031
Single Family Dwelling Average	5323	7533	6250	5373	6377	3110	2755	10448	5410
• Small	3712	5618	4060	4371	5496	1935	1638	6302	4371
• Medium	4415	5961	5579	4495	5128	2643	2327	8955	4495
• Large	6766	9760	7863	6823	7644	4759	3620	13930	6823
Multi Family	2795	3731	4401	3734	3819	2246	5442	2614	3734
Mobil Home	4194	5944	6603	5869	5677	3329	7406	5240	5869

Year 2014 Space Heat Consumption—Existing Stock
Based on Adjusted Engineering estimates Space Heat Consumption with Decreasing Trend in Wood Usage

	OR	WA	ID	MT	WY	CA	UT UP&L	ID UP&L	WY UP&L
All Stock Average	5539	7543	8693	5864	6335	5634	3632	9890	5503
Single Family Dwelling Average	6303	8586	9600	6203	6940	6591	2755	11680	6025
• Small	4196	6127	5893	4749	5708	4073	1638	7002	4592
• Medium		5292	6958	8533	5277	5673	5982	2327	10050
5081									
• Large	8039	11091	12267	7976	8355	9482	3620	15544	7601
Multi Family	2861	3742	4568	3847	3868	2383	5442	2682	3789
Mobile Home	4659	6523	8817	6494	6069	4413	7406	5735	6307

The 1992 space heating consumption figures shown in Table 8 are based on conditional demand analysis. The figures shown for 2014 space heat consumption are based on the engineering estimates shown in Table 7, and adjustment factors for that residence type.

The results of the conditional demand study and the baseload study do not translate into the average kWh per customer, and average space heat kWh. The estimates for space heating energy consumption is the result of the conditional demand analysis using the appliance saturation's and consumption levels. Baseload study was used in the calibration of the actual space heat estimates and the conditional demand estimates for space heating.

For example, in Table 8 we find that 1992 space heating consumptions was estimated to be 5323 in state of Oregon. This value was calculated based on following formulas.

$$SH = \Sigma \text{ CDM (for each dwelling type)} * CF$$

Where:

SH is space heating consumptions for single family residences

CDM is space heating consumption from conditional demand analysis

CF is a calibration factor

The conditional analysis was performed for single family, multifamily and mobile homes. The single family was further divided into small, medium and large dwellings.

The calibration factor was calculated as ratio of average space heating consumption to the estimate of space heating from conditional demand analysis. For the case of Oregon, the calibration factor was estimated to be unity (1.0). The Conditional Demand Study was finalized in December 1990.

Application of this adjustment factor is particularly problematic when applied to new MCS construction. The Council found good agreement between their engineering estimates and econometric estimates for new construction. Thus, they took no correction for "amenities". The base case for existing Utah was taken at a low level representing current practice. Utah has adopted an energy code which comes close to MCS. As enforcement of the new code improves, the Utah base case will need to be upgraded to represent more efficient buildings entering the building stock. Estimates for new residential space heating are shown in Table 9.

Table 9— Residential Space Heat Estimates for New Construction, 1994-2013 (kWh/yr)

Engineering Model for New Stock
- 85% Built to MCS in the Northwest
- No MCS in Wyoming
- New Energy Code in Utah

	OR	WA	ID	MO	WY	CA	UP&L UT	UP&L ID	UP&L WY
All Stock Average	6542	9765	10098	11430	16501	6347	15799	12315	19384
Single Family Dwelling									
• Average	8193	12593	12536	14062	20571	7967	19779	14568	24317
• Small	5184	8267	8267	9838	14610	5184	13253	9838	17168
• Medium	8578	13081	13081	15452	20741	8578	20416	15452	24306
• Large	9092	13961	13961	15343	22727	9092	21151	15343	26654
Multi Family	1530	2719	2719	3300	2719	1530	2850	3300	6085
Mobile Home									
• Small	2463	2115	4434	5348	9914	2463	9914	5348	11736
• Large	4276	3771	7135	8580	12179	4276	12179	8580	14424

4.5 Takeback Adjustment

The modeling assumes that homes will continue to be operated under the same conditions (*Standard Operation Conditions** as specified in the NPPC Plan) regarding thermostat setting, room closure, fuel choice, and an array of human behavioral operations which cannot be captured in an engineering model. Although this is clearly not the case with real inhabitants, these assumptions attempt to capture all the behavioral changes people make do in the real world. Examples are how occupants treat room closure, night setback, lower setpoint and choices to wear a sweater instead of turning up the heat. These choices are approximated by assuming key variables such as the setpoint and the amount of internal gains from appliances.

Actual savings are less than the engineering estimates due to a variety of consumer *"amenity takeback"** choices. It is as if consumers choose to take some energy savings in the form of increased comfort rather than increased money savings, also referred to as a rebound effect. The planner has a choice of how to account for takeback:

1. One can downrate the savings to agree with monitored results. This ignores the economic value of the increase in amenity and makes the conservation appear more expensive.

2. One can use the engineering estimates of savings without applying downrating. The increase or rebound in usage ("take back") would be treated as an increase in the demand forecast. This method does not penalize conservation for customers' usage. However, it may fail to reflect uncertainty and modeling error in the engineering estimates.

3. One can develop an econometric model to estimate rebound in usage as a function of bill reductions, that is, apply price elasticity. This assumes that one knows price elasticity, which is usually not the case.

In our study, we chose a combination of options (1) and (2) in calculating supply curves based on *Total Resource Cost** (TRC). New construction is not adjusted consistent with NPPC conclusions that the engineering models are adequate to reflect actual usage. However, for the case of existing buildings, a large correction to the engineering model is necessary to account for takeback.

Actual billing shows poor agreement with engineering estimates. For this adjustment, the engineering models were first derated 30% for economic takeback consistent with the NPPC methodology. Then the adjustment factors in Table 7 are applied. The 30% economic takeback is derived from the NPPC results by comparing their engineering estimate of space heat consumption with their result after running through the economic model. The result reduces retrofit weatherization savings to estimates that more closely agree with actual consumption and program results. Such downrating has been included in estimates of the utility's program resource cost.

4.6 Solar Access

*Solar access** is an important low-cost resource which is often overlooked in utility planning. The methodology for evaluation is based on that developed by ODOE for the Metropolitan Solar Access Study in the Portland Area[6].

The prototype homes were evaluated for space heating energy requirements using the WATTSUN computer program and assuming 1992 Oregon code-efficient building shells. The critical parameter is *alignment**, that is, orientation of the house along an east-west axis so that a long side faces south toward the sun. Scenarios rely on actual survey data from Portland to specify current practice for alignment, shading and window placement. Data for these scenarios are presented in Table 10.

Table 10—Solar Design Scenario Assumptions

Critical Parameter—Alignment	Base Case	Optimized Solar Orientation Scenario
NS orientation	• alignment 55% NS, with 40% shade • windows: 10% on N and S, 40% on E and W	• alignment 20% NW, with 30% shade • no window realignment
EW orientation	• alignment, 45% EW with 22% shade • windows: 10% on E and W, 30% on N and 50% on S	• alignment 80% EW, with 10% shade • 15% of windows realigned from N to S

The base case scenario assumes that homes are constructed 55% in north-south alignment with 40% shade and 45% in east-west alignment with 22% shade. Window areas are distributed for NS houses as 10% north and south, 40% east and west. For homes with EW alignment, window areas are 10% east and west, 30% north and 50% south. The solar orientation scenario assumes that 80% of the homes are aligned east-west with 10% shade and 20% aligned north-south with 30% shade. The solar design scenario assumes that for the oriented homes 15% of the window area is relocated from the north side to the south side.

These design alternatives are listed as two separate measures for new single family construction. There may be additional benefits to solar access, including *infill benefits** to existing housing and encouragement of solar design and water heating. These benefits are more difficult to quantify and were not assessed.

4.7 Energy Conservation Measures

The delta UA values and associated costs were originally derived from the Council's models. Cost data for some measures were updated based on results from the company's multi-family weatherization program as documented by Portland Energy Conservation, Inc[7]. Details of the types of measures analyzed are listed in the worksheets of the appendices.

It should be noted that the delta UA values are not based on strict engineering calculations, as explained above. The Council used empirical values developed by Bonneville. They are supposed to represent actual values achieved in the field, taking into account voids in the insulation and other installer errors. Thus, the values are not linear in terms of R values. Some of the incremental measures required calculating the effective change in U value and interpolating between the points the Council used[8].

A few *energy conservation measures** (ECMs) were computed for this study. The cost and delta UA for re-roofing an existing mobile home came from interviews with CAP weatherization teams[9]. This measure appears to be too expensive on an energy basis but might be considered if a new roof was needed anyway. The setback thermostat was another case of a calculated measure. In this case, there were some estimates from Hood River for the annual energy savings[10]. This number needed to be divided by the regression slope (fuel factor corrected) to determine the equivalent delta UA. This value is listed in the worksheet even though the measure is not, strictly speaking, a measure that affects the envelope UA.

4.8 Residential Load Profiles

Load shapes of the conservation savings were derived primarily from monitored data. Plots of the normalized load shapes in the Northwest are shown in Figure 5 for weekdays and in Figure 6 for weekend days. Note that the normalization process sets the magnitude of the area under the curves to an annual sum of 1 MWh. Gradation units on the vertical axis are not shown since the curves have been normalized. One should compare the relative shapes of the curves rather than the magnitude. Because there is some random noise in the monitored data, the load shapes include some extreme observations. These points were not removed in order to reflect some of the real-world uncertainty around these values.

Also note that these shapes are actually derived for a program that would include energy conservation from water heating measures as well as space heating measures so that there is some impact even during the summer. Details of the program design are discussed in Part II of this report. The same load profile was assumed for a potential weatherization program in Utah. However, the potential resource for such a program is almost non-existent due to the prevalence of gas heating in Utah.

Load shapes for a new residential construction program in the Northwest are shown in Figures 7 and 8. The load shape is different from existing buildings due to the inclusion of more zonal systems in new construction. These systems have a more rounded load shape. New residential load shapes were not further developed for Utah since the amount of electrically heated construction is small.

4.9 Residential Worksheets

Figure 9 shows an estimate of potential savings in the year 2013 relative to existing stock space heat consumption. Figure 10 shows the same information by state. Figure 11 shows an estimate of the potential savings beyond local codes for new construction under the Medium economic growth scenario. Figure 12 summarizes the same information by state. Examples of the residential worksheets may be found in the appendices for Oregon, Washington, Montana and Utah. These take in to account the elements described in this section, such as takeback, delta UA values, and *incremental costs** for ECMs.*

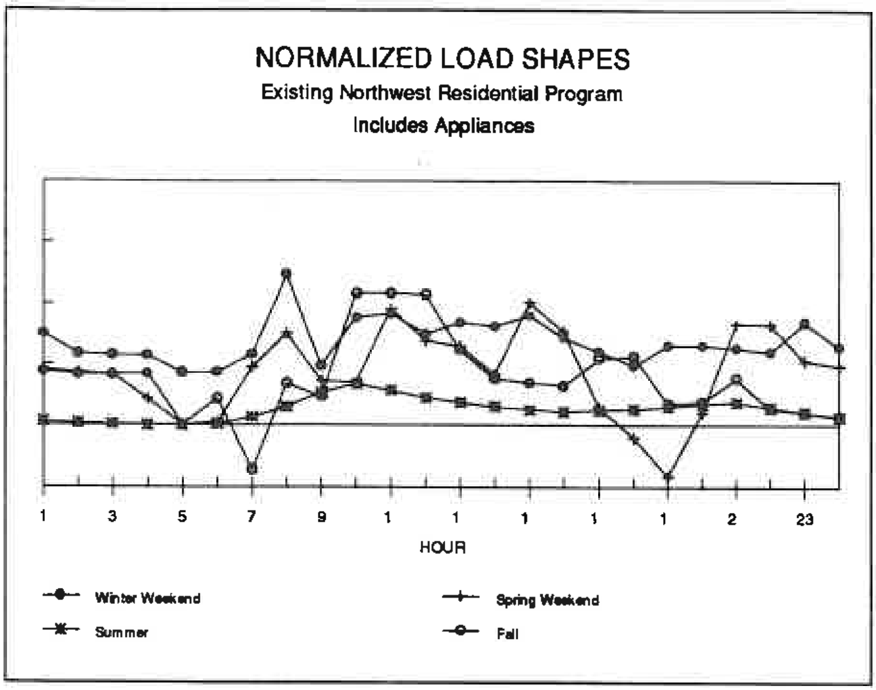


Figure 5—Nomalized Weekday Load Shape, Existing Residential Program

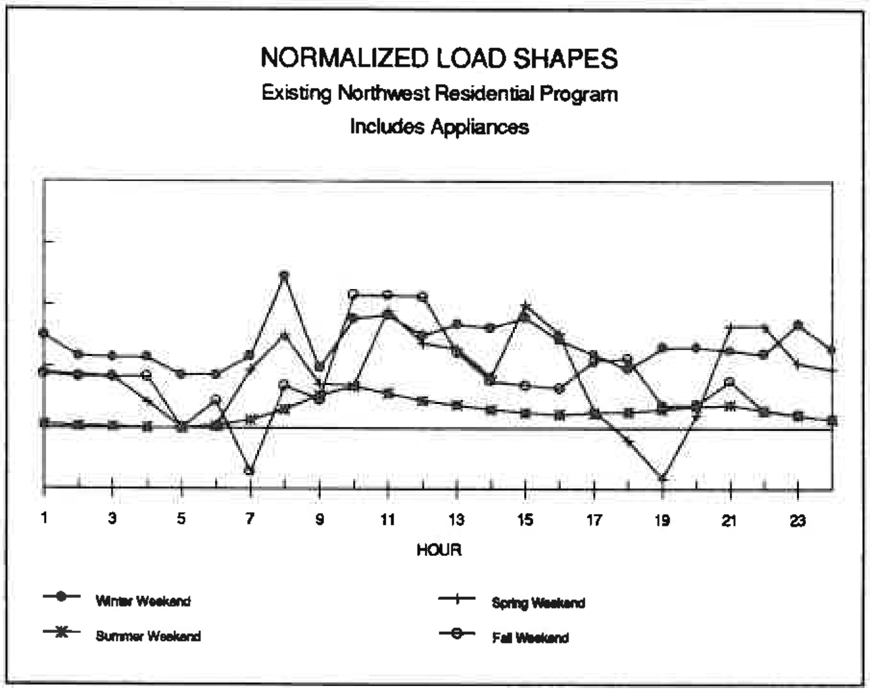


Figure 6—Normalized Weekend Load Shape, Existing Residential Program

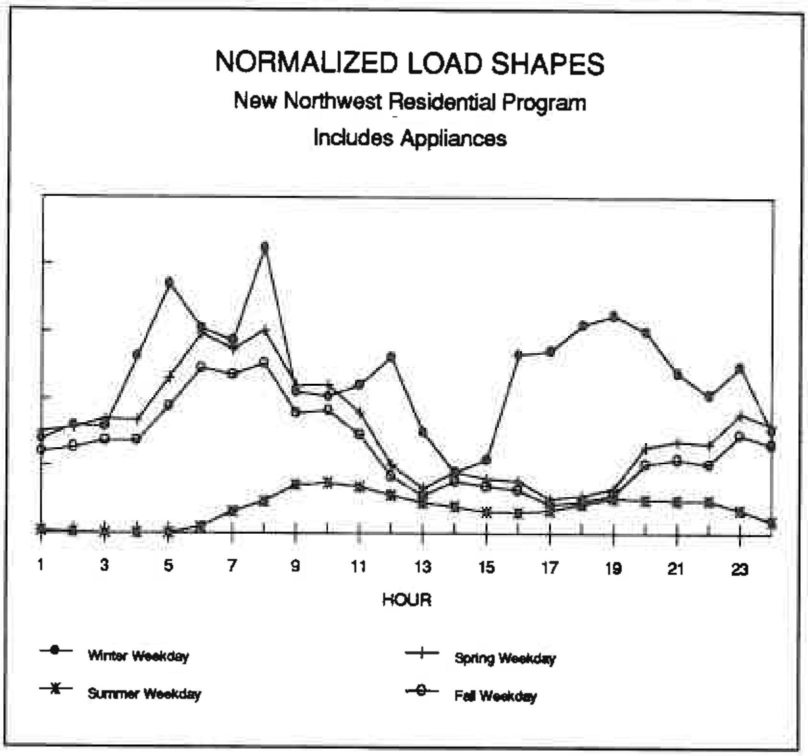


Figure 7—Nomalized Weekday Load Shape, Existing New Residential Program

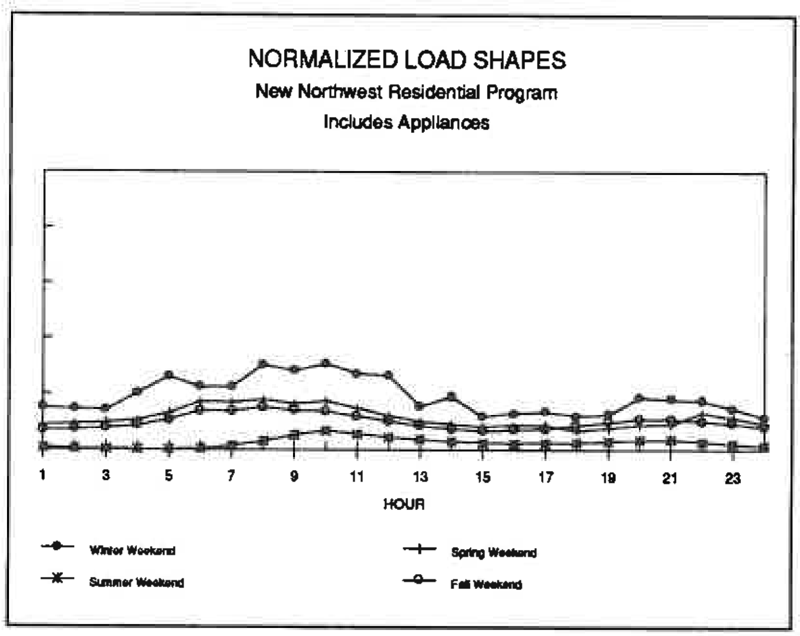


Figure 8—Normalized Weekend Load Shape, Existing New Residential Program

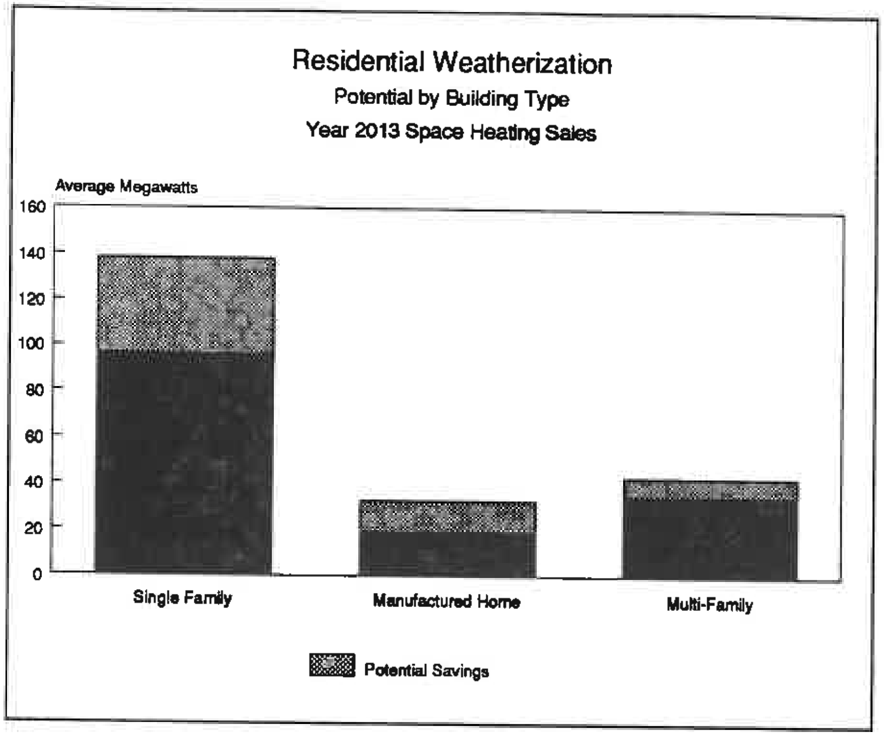


Figure 9—Estimate of Potential Weatherization Savings

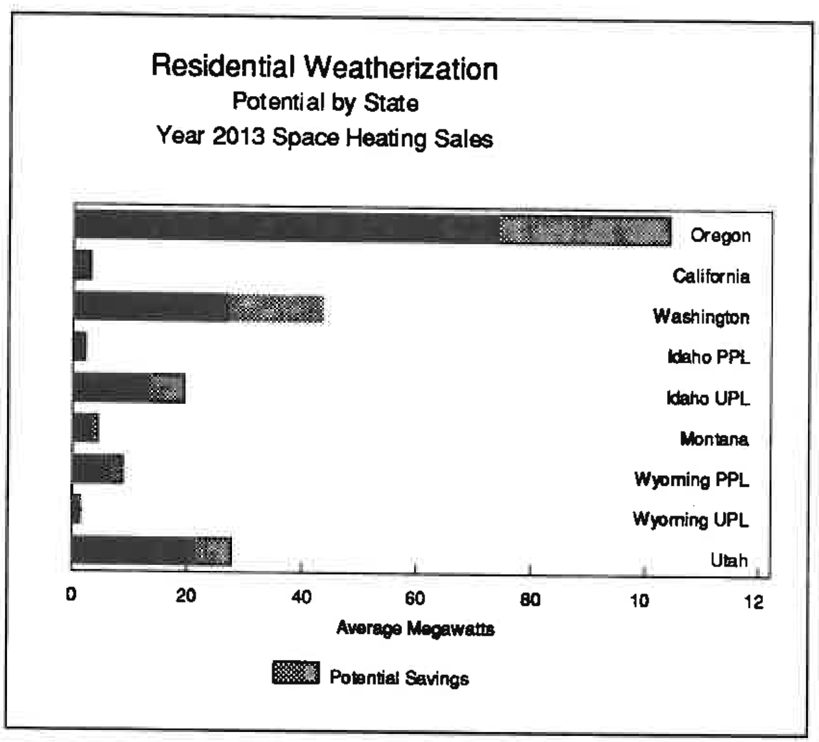


Figure 10—Residential Weatherization Potential, by State

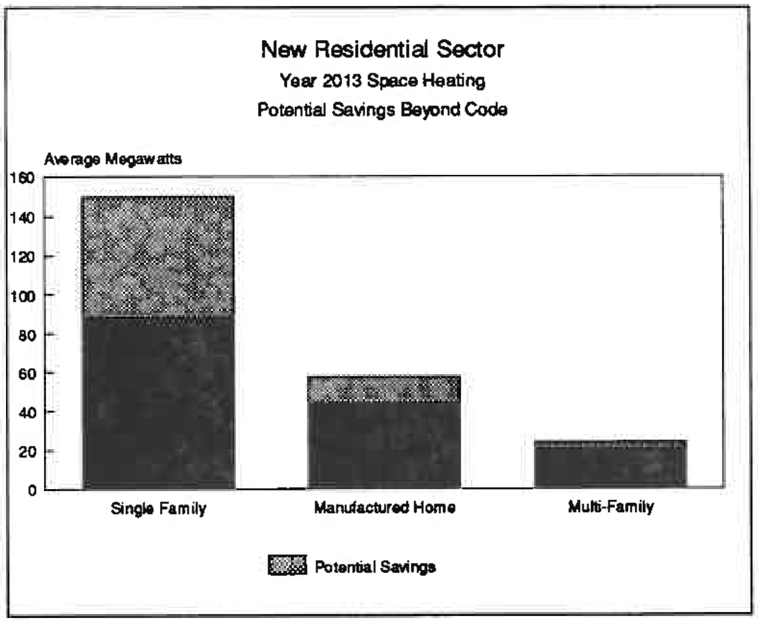


Figure 11—New Residential Potential Energy Savings Beyond Code

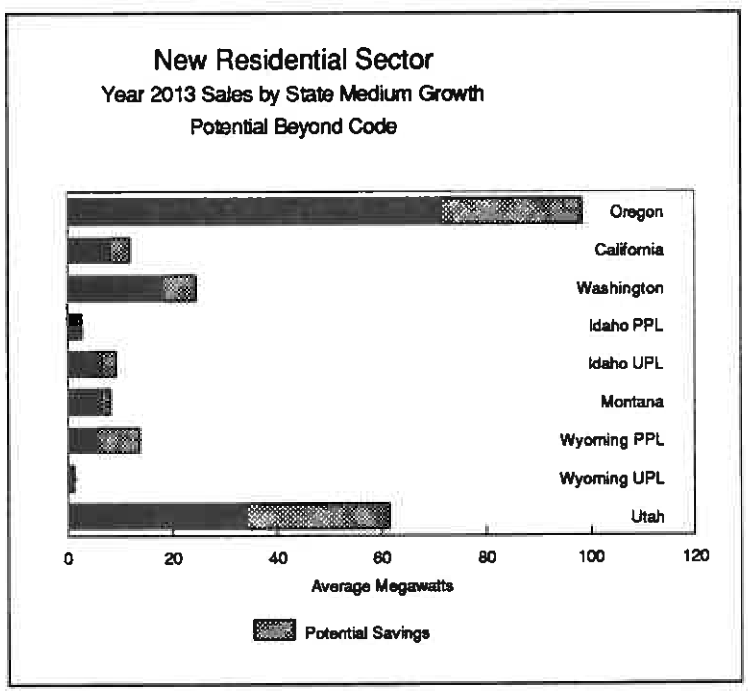


Figure 12—New Residential Sector Savings Potential Beyond Code, by State

SECTION 5.0 Residential Sector—Appliances

One of the problems in residential energy analysis is *disaggregation** of the residential loads into specific end uses or appliances. The disaggregation is necessary because the home is metered only at the whole house level. Breaking down residential consumption into end uses requires application of several tools.

5.1 Conditional Demand Modeling—Disaggregating Appliance Energy Use

Conditional demand models can be used for some end uses. The conditional demand model is used to estimate space heating, space cooling, water heating and a few other appliance loads. There are problems with this procedure. It is often the case that the regression model picks up *colinearity** between the presence of certain appliances. Thus, these results are supplemented with expert judgment.

The judgment takes the form of estimating typical appliance consumption from other references and multiplying by the *saturation** of the appliance. Saturation data are taken from the company's "Energy Decisions" surveys[11]. Since we are dealing with relatively small amounts of annual consumption, the assumed vacancy rate affects the results. The vacancy rate is larger than suggested by connect reports because empty homes can still have the electric service turned on. The most recent vacancy data came from the 1980 US Census, which is not a very recent survey. The company attempted to use census data to estimate the amount of bias in connect reports in order to refine the vacancy assumption[12]. The resulting appliance worksheet is shown in Table 11.

First, this table shows the saturations of the various electric appliances. Next, it shows the average consumption, which is the product of three factors: the typical consumption, the saturation of that particular appliance, and the occupancy rate (or 1 minus the vacancy rate).

The majority of estimates of consumption have been derived from the conditional demand model which isolates the impact of specific appliances. Thus, for example, the consumption of domestic hot water (DHW) does not count that used by the clothes washer and dishwasher which are listed separately. The last line shows the total annual average consumption for residential appliances in each state.

Table 11—Energy use for Residential Appliances

Electric Appliances—Saturation in 1992

	OR	WA	ID	MT	WY	CA	UP&L UT	UP&L ID	UP&L WY
DHW	83%	89%	91%	71%	30%	86%	19%	77%	36%
Refrigerator	103%	103%	100%	100%	100%	100%	100%	100%	100%
Freezer	58%	63%	63%	65%	64%	58%	48%	67%	61%
Clothes Dryer	81%	84%	82%	84%	82%	79%	69%	85%	76%
Range	92%	96%	93%	92%	77%	87%	84%	90%	73%
Hot Tub	6%	5%	6%	4%	4%	6%	2%	4%	2%
Well Pump	22%	26%	23%	31%	12%	31%	0%	0%	0%
Dishwasher	57%	60%	50%	57%	62%	51%	64%	52%	68%
Clothes washer	86%	89%	86%	88%	90%	87%	86%	90%	89%
Waterbed Heater	21%	20%	18%	20%	36%	23%	20%	22%	23%
Air Conditioner, wind	14%	36%	7%	7%	9%	11%	6%	4%	2%
Air Conditioner, central	15%	27%	2%	4%	5%	8%	19%	4%	2%
Air Conditioner, evaporative	5%	9%	3%	5%	31%	11%	54%	12%	6%
Lights	100%	100%	100%	100%	100%	100%	100%	100%	100%
Vacancy Rate for Electric Appliances	8%	8%	9%	9%	12%	9%	9%	9%	9%

Average Consumption (kWh/yr) corrected for Saturation and Vacancy Rate

	OR	WA	ID	MT	WY	CA	UP&L UT	UP&L ID	UP&L WY
DHW	3054	3506	3094	2619	1121	2724	423	2594	1382
Refrigerator	1358	1355	1295	1302	1261	1300	1295	1295	1295
Freezer	496	538	530	550	524	489	404	563	513
Clothes Dryer	621	643	618	636	602	597	520	641	573
Range	516	537	512	510	413	481	463	496	402
Hot Tub	142	118	140	94	91	140	47	93	47
Well Pump	286	337	294	398	149	397	50	300	300
Dishwasher	370	389	319	366	385	327	408	332	434
Clothes washer	504	520	495	509	504	502	495	518	512
Waterbed Heater	194	185	164	183	319	210	182	200	209
Air Conditioner, wind	64	165	32	32	40	50	19	18	9
Air Conditioner, central	222	398	31	33	71	117	227	43	29
Air Conditioner, evaporative	6	10	3	6	34	12	280	75	7
Lights	1629	1626	1624	1606	1559	1606	1604	1611	1604
Miscellaneous	1067	1555	719	1087	349	445	528	1476	841
Total Appliances	10529	11882	9870	9930	7420	9397	6944	10255	8157

The table estimates average consumption for appliances which is then compared to total average customer consumption in order to separate appliance from space heat consumption. Source for appliance saturation data is Company's Energy Decision Survey for 1992. The vacancy rates were based on 1980 US Census, they were refined using the Energy Decision survey data. The average consumption data presented on Table 11, were based on Conditional Demand Analysis study 1990. The values presented for average consumption are reduced for the saturation and vacancy rate.

The annual kWh consumption level for an average appliance is higher than figures presented on Table 11. The annual consumption of average appliance can be estimated using the following formula:

$$AAC = AC/(S * (1 - V))$$

where:

where:	AAC	is consumption of average appliance
	AC	is average consumption (from Table 11)
	S	is saturation rate (from Table 11)
	V	is vacancy rate (from Table 11)

Additional details on typical appliance kWh/yr can be found in Appendix E.

5.2 Appliance ECMs—Costs and Market Saturation Levels

Predicting the savings potential from new appliances is problematic. Should one assume current levels of technology or the improved levels expected in the future? Should one base costs on the incremental or total replacement? For the forecast, we applied different consumption estimates for new appliances to capture the effect of new efficiency standards. The old and new consumption estimates are shown in the appliance worksheets in Appendix E.

In our study, we included an ECM to represent "High Technology" refrigerators and freezers. This option represents new products expected within the twenty year planning horizon, although not available now. We also assigned the cost for new appliances as the incremental cost. Cost and savings for these appliances were taken from USDOE Draft Rulemaking Proceedings as developed by Lawrence Berkeley Laboratory[13]. These estimates result in a large technical potential estimate for the new appliance sector. Change out of old appliances before the end of their lifetime was assigned full replacement cost, which means the ECM would not be cost-effective. More efficient clothes dryers and dishwashers are also assumed as future appliance options.

Technical potential is currently estimated conservatively by assuming an 33% *penetration** overall of high-tech refrigerators and freezers. This reflects current experience that it is difficult to locate products with extremely high efficiency. Although such units are possible they are not readily available in today's marketplace. One would expect this assumption to change as more experience is gained regarding the market response to demand-side initiatives.

5.3 Interaction of Appliances and Space Heating Demand

Another complication in estimating the apportioned energy use among appliances is the interaction of appliances and space heating. To a certain extent, the waste heat from appliance inefficiency contributes to space heating. If the appliances are more efficient, some additional space heating will be required. In the case of extremely tight modern houses, the usability of appliance waste heat could be considerable. Estimates of the usability for space heat was taken from work done for the Council by Lawrence Berkeley Laboratory[14].

Details of the space heating interaction are shown in Table 12. In calculating the gross adjustment, the market share times the usability is taken for each market sector and summed to a weighted total. This weighted total times the fuel saturation gives the net adjustment factor. As an example of the result, in Oregon the net adjustment for refrigerator savings is 0.25. This means that 25% of the savings are estimated to be "taken back" in the form of increased space heating consumption. The net electric savings for appliance measures will depend on the saturation of electricity for space heating as well as the estimates of the usability of internal gains.

Table 12—Space Heat Interaction

Residential End Use Disaggregation
Space Heat Interaction Adjustment, Market Shares

	OR	WA	ID	MT	WY	CA	UP&L UT	UP&L ID	UP&L WY
Existing	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Existing Wx	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
Current New	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
MCS New	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28

Usability of Internal Gains from LBL TRNSYS Simulation
Gross Adjustment

	OR	WA	ID	MT	WY	CA	UP&L UT	UP&L ID	UP&L WY
Existing	0.62	0.64	0.64	0.69	0.64	0.62	0.60	0.64	0.69
Existing Wx	0.52	0.58	0.58	0.62	0.58	0.52	0.52	0.58	0.62
Current New	0.53	0.58	0.58	0.61	0.58	0.53	0.52	0.58	0.61
MCS New	0.46	0.46	0.46	0.51	0.46	0.46	0.39	0.46	0.51
Weighted Total	0.51	0.55	0.55	0.59	0.55	0.51	0.49	0.55	0.59
Space Heat Saturation	0.48	0.54	0.57	0.42	0.19	0.53	0.14	0.49	0.25
DHW Saturation	0.83	0.89	0.91	0.71	0.3	0.86	0.19	0.77	0.36
Net Adjustment Refrigerator	0.25	0.30	0.31	0.25	0.10	0.27	0.07	0.27	0.15
Net Adjustment Freezer	0.12	0.15	0.16	0.12	0.05	0.14	0.03	0.14	0.07
Net Adjustment DHW	0.20	0.24	0.26	0.15	0.03	0.23	0.01	0.19	0.05

5.4 Potential for Energy Savings with Appliances

The technical potential for appliances is very high—leaving one to wonder why more savings are not included in programs. The answer is that much of the potential is not immediately accessible. Water heat savings and lighting savings are considered within planned programs such as Long Term Super Good Cents and weatherization programs. Land use and design is a measure representing the passive cooling benefits of solar access. This resource is best addressed in the new construction program, although roof color and tree plantings are measures that can be considered for existing stock. The new residential construction program (Long Term Super Good Cents) recognizes these potential benefits but they are outside the traditional scope of what most utility programs have included in the past.

New Federal standards have recently been mandated for a variety of appliances. These savings are included in the planning forecasts—they are no longer available as programmatic savings. Finally, there is the category of products not yet available. A variety of product improvements have been identified as cost effective in the conservation supply curve worksheets. However, these products are not yet available on the U.S. market. One expects that more efficient products will appear during the twenty year planning horizon, but they are not yet available.

*Market transformation programs**, in cooperation with other utilities, represent one programmatic approach to accomplish these savings. PacifiCorp is already a member of a consortium group incenting the rapid deployment of more efficient refrigerators. Another possible example that may merit further investigation is horizontal axis clothes washers. The savings from the new washers include the clothes dryer savings shown in Table 13 resulting from high spin speed which extracts more water from the clothes.

Table 13—Energy Savings from Horizontal Axis Clothes Washers

Comparison	*Horizontal Axis Washing Machine*	*High Speed Spin Option*
Energy Savings	161 kWh per year	346 kWh per year
Cost (incremental)	$148	$51

5.5 Appliance Capacity Savings

The methodology for estimating hourly impacts was discussed in Section 3.0. The load shapes from appliance measures have been included in the residential programs. The dominant appliance measure is the savings from low-flow shower heads. The load shapes used are shown in Figure 13 and Figure 14 and were derived in this plan from monitored load shapes used by BPA.

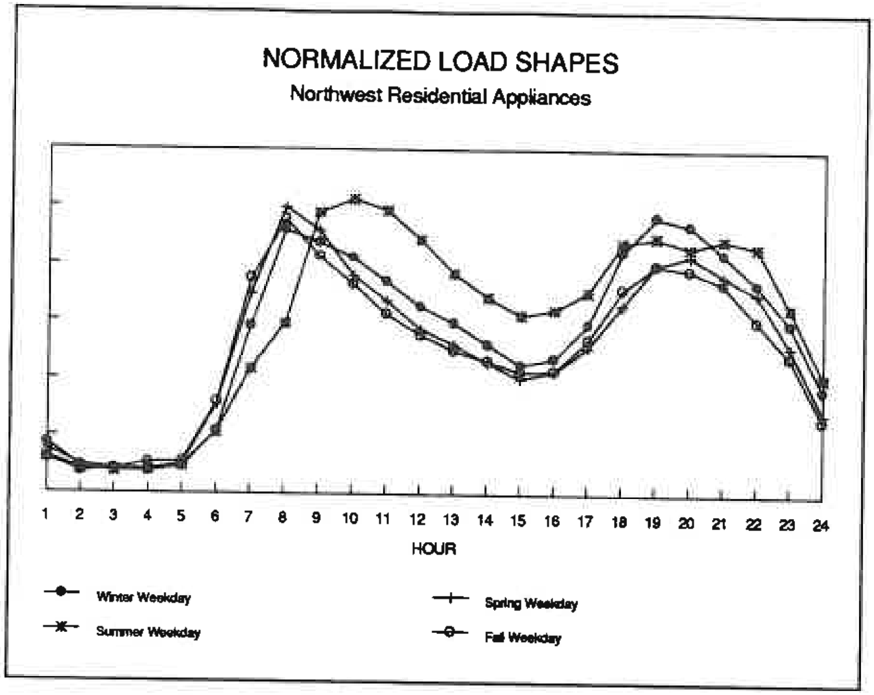


Figure 13—Normalized Weekday Load Shape, Residential Appliances

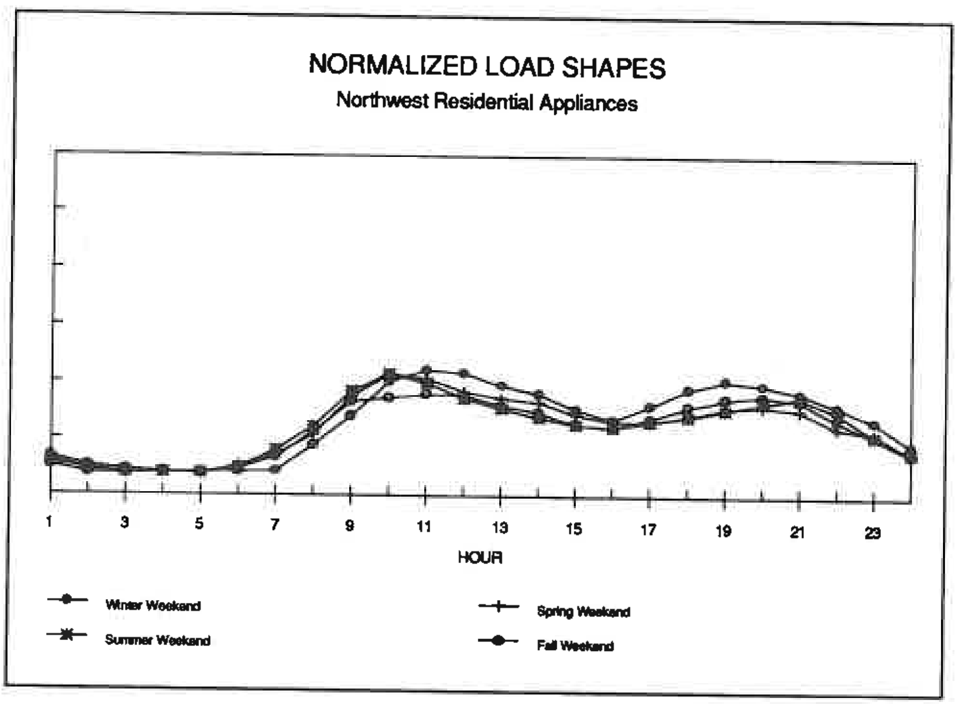


Figure 14—Normalized Weekend Load Shape, Residential Appliances

Another appliance option is the installation of load controls on appliances. The controls are designed to "lock out" the appliance during peak times unless overridden by the customer. The controls have little impact on energy but can save capacity during system peaks. The load shape for a direct load control program is shown in Figure 15. Note also that the usage "rebounds" with negative savings after the *time-out period** is over. To provide significant system benefit the time-out period was designed to extend over two periods during the day and is scheduled for later in the day during the summer.

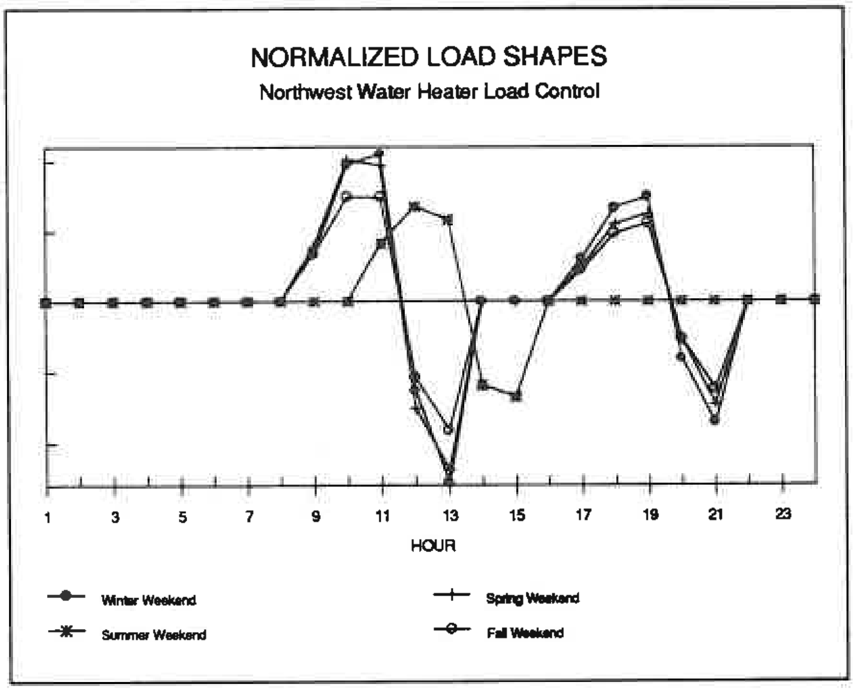


Figure 15—Representative Load Shape for Direct Load Control of a Water Heater

The load shapes for water heater load controls are the load shapes for water heater consumption during the time-out period. After the time-out period ends, the rebound is the amount of water heater consumption during the time-out period less the standby loss during that time. In other words, when one shuts off the water heater, one saves the energy that would normally have been consumed during that period. When the water heater comes back on, it immediately heats the cold water in the tank, consuming essentially the same amount of energy that was saved during the time-out period. The consumption has just been shifted to a later time. There is a slight energy savings in that any standby loss that occurred during the time-out period is not counted in the rebound consumption.

5.6 Residential Appliance Worksheets

Figure 16 summarizes potential savings estimates from appliances. Note that the older appliances are expected to die off and be replaced by more efficient ones. An example of the change in appliance stock included in the forecast is shown in Figure 17. Examples of the supply curve worksheets are shown for Oregon and Utah as representative states. There are two pages of potential measures, followed by a page that sorts the measures by levelized cost

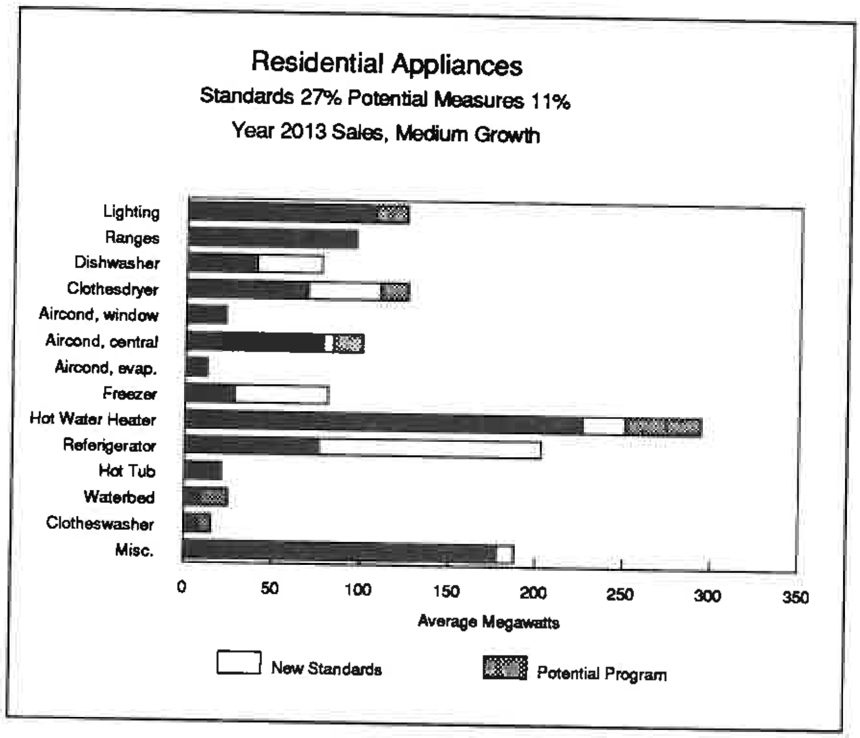


Figure 16—Potential Energy Savings from Appliances, Residential Sector

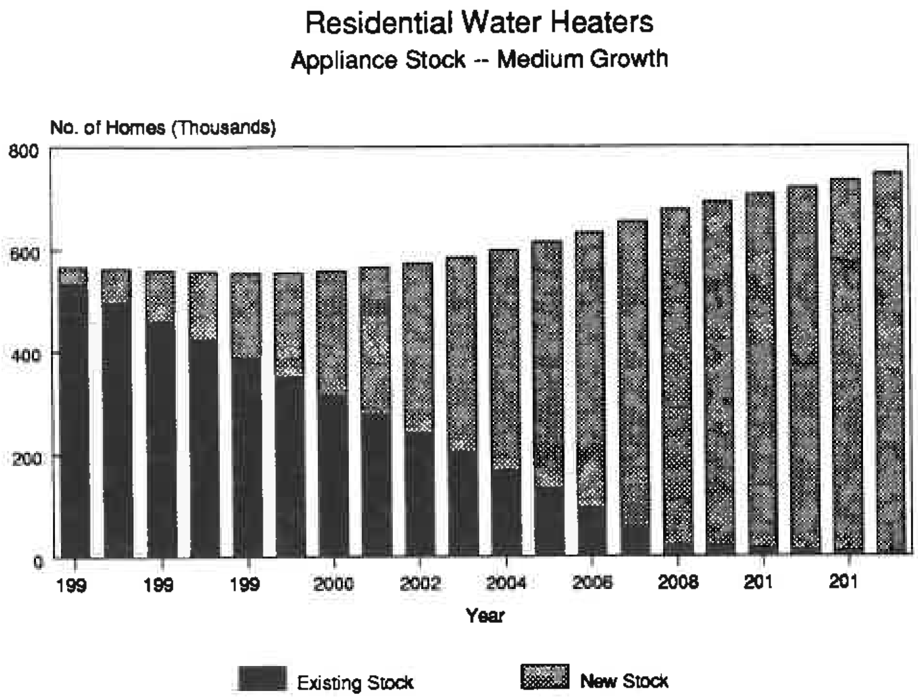


Figure 17—Residential Water Heaters, Change in Stock

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SECTION 6.0 Commercial Sector

The methodology for estimating energy savings in the commercial sector is based on a series of prototype buildings modeled for Bonneville using the DOE-2 program by United Industries Corporation (UIC)[15]. This work was updated by the original consultants under the name SBW Consulting, Inc., in 1990[16]; however we continued to refer to the analysis under the name UIC. The building model developed for the lodging segment was a 12-story hotel. This prototype was not appropriate to the company's service territory. A new prototype based on a 35-unit motel, originally modeled by Ecotope[17], was used for modeling this segment of the commercial market.

6.1 Commercial End-Use Splits

There was fairly extensive effort in identifying the end-use splits in these buildings. For the most part, the end-use splits agree with our marketing study[18]. Both these studies rely heavily on ELCAP commercial data. An additional set of end-use splits was supplied by, Oregon Department of Energy, based on an ODOE independent study. All these end-use splits are compared against the end use assumptions in the worksheets. We found it helpful to have a reality check when reviewing the ECMs. The company's end-use splits are similar to regional ones based on ELCAP monitoring and developed in the UIC models. The ODOE splits are somewhat different, due to a different source of data, but not inconsistent.

The new building worksheets (see Appendix F) include two end-use splits for reference. The current practice column is the one reported by UIC as current code in 1990. The MCS column is reported by UIC to represent the same buildings under 1992 versions of the MCS commercial code. Even though Oregon and Washington codes are considered to be MCS equivalent, they appear to be less energy efficient than the MCS level. This is demonstrated by the differences between the current practice and the MCS columns. New code hearings are currently underway to refine and improve the MCS. Any new changes are not yet included in the end use model.

The resulting ECM costs and savings from the UIC analysis are suitable for the prototype study. A few additional measures were added because they seemed too important to overlook. These included retrofit refrigeration upgrades and changeout of incandescent beyond halogen bulbs to compact fluorescent lights.

6.2 Baseline Assumptions

The proper level of baseline use for new buildings is fuzzy. New buildings are supposed to be at the MCS level. However, as previously discussed, it does not appear that current practice is in compliance. Therefore, a measure titled "current>MCS" (base is current practice and MCS is an energy-efficiency improvement) was included for end uses where an upgrade was implied. Acceptance of the commercial MCS can be modeled by choosing appropriate penetration rates for this measure.

The commercial building stock in the company's territory differs from that of most other utilities. The company serves many small, rural towns. As a result, the building stock is older and very small compared to other utilities. It also appears to be poorly insulated. Space heat is much higher than one would expect for commercial structures, even though electric space heat has low saturation. There is little space cooling, which rules out an energy bonus for measures that reduce internal gains such as reduction of lighting levels. Downsizing credits are also unlikely since they result primarily from savings for cooling equipment. Details of the space heating and cooling interactions are included as a table in the worksheets of Appendix F.

The worksheets list end-use split assumptions for commercial buildings. For reference, the UIC and ODOE splits are also listed, although not utilized in the calculations. Notice that cost, savings and acceptance factors are all based on square footage. Measures are classified into structure, lighting and equipment categories. At the bottom of each category is shown the total energy, fraction of appropriate end use and average cost for measures within a 55 mills/kWh ceiling.

The baseline consumption included in the forecast assumes that 85% of new buildings will comply with new commercial code in the Northwest states. The remaining 15% will be equivalent to current practice. Utah and Wyoming are assumed to continue at current practice levels. The recent National Energy Policy Act will require all states to adopt higher efficiency standards. However, this law was not enacted at the time of the planning study and the impacts have not been included in RAMPP-3.

6.3 Consideration of Climate Effects

Commercial buildings are only slightly sensitive to climate. This is because there is a low saturation of electric space heat and low cooling usage. Lighting and receptacle loads are not affected by climate. The climate adjustments from the UIC study are listed in Table 14 for existing buildings.

End uses for other climate zones are based on Zone 1 usage multiplied by the appropriate factor. Models were not rerun for all the different zones, the zone factors derived by UIC were used to adjust space heat and cooling to Zones 2 and 3. The models were run for Portland and Salt Lake as the two major cities.

There are other climate considerations which are not addressed. The amount of shell insulation in the base case building varies between climate zones. The variation is not always in line with code since it is dominated by what the local building community considers "accepted practice." Due to lack of resolution in the survey data, we did not attempt to adjust the base case shell insulation to different localities. A generic building is assumed based on the company's total commercial usage. For new buildings, an updated analysis by SBW Consulting served to define the baseline construction and measures.

Table 14—UIC Climate Adjustment Factors

Zone 2

Segment	Heating	Cooling	Ventilation
Office	1.38	1.85	1.45
Retail	1.28	2.72	1.15
Grocery	1.10	2.64	2.84
Restaurant	1.15	1.62	1.01
School	1.03	—	1.13
Hospital	1.15	1.40	1.01
Warehouse	1.39	1.56	1.22
Hotel	1.04	1.32	1.04

Zone 3

Segment	Heating	Cooling	Ventilation
Office	1.89	1.33	1.44
Retail	1.94	1.72	1.08
Grocery	1.48	1.64	2.84
Restaurant	1.56	1.19	1.00
School	1.26	—	1.09
Hospital	1.23	0.92	0.99
Warehouse	2.02	1.15	1.46
Hotel	1.21	1.98	1.98

6.4 Commercial Sector Capacity Savings

The methodology for estimating capacity savings was discussed in Section 3.0. For commercial sector, hourly loads were simulated for a variety of prototype buildings and then aggregated for programmatic impacts. Normalized load shapes are shown for new and existing commercial buildings in Appendix A. Note that these load profiles reflect the load shape of the conservation savings.

It is instructive to note that the fuel mix plays an important part in the load shape for this sector. Interactions between the conservation measures and space heating can change the demand profile. As an example consider the load profiles shown in Figure 18. Use of efficient lighting can actually increase consumption by a heat pump during certain hours. One might also notice that the loads in Utah lag those in the Northwest by one hour. As part of the planning process, all loads were assembled to match Pacific Standard Time.

6.5 Commercial Building Worksheets

Figure 19 shows savings potential by state for both vintages, existing and new. Existing buildings dominate in technical potential because there are more buildings in this category. Figure 20 summarizes consumption and potential savings for existing commercial stock. Savings estimate is based on savings available up to a 55 mill levelized cost ceiling. Figure 21 summarizes consumption and potential savings for new commercial buildings. Savings estimate is based on the 55 mill cost ceiling. Savings are lower because the new codes require more efficiency in the base case building. Examples of the commercial worksheets are shown for Oregon, Washington, Montana and Utah as representative states.

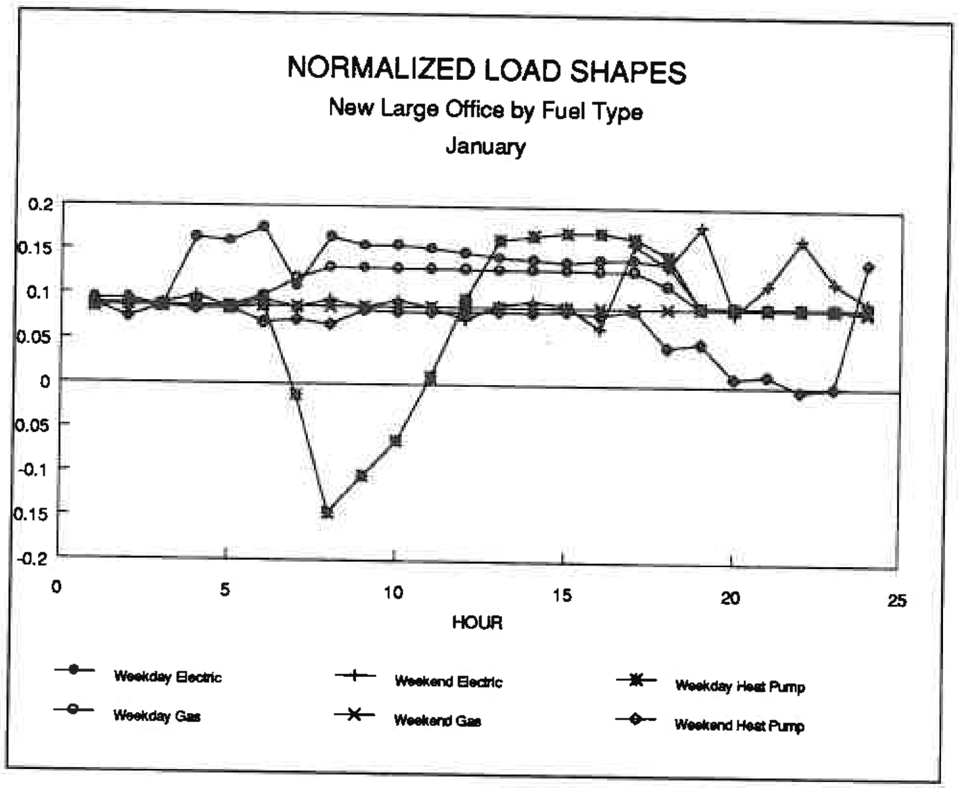

Figure 18—Normalized Load Shape for a New, Large Office in January

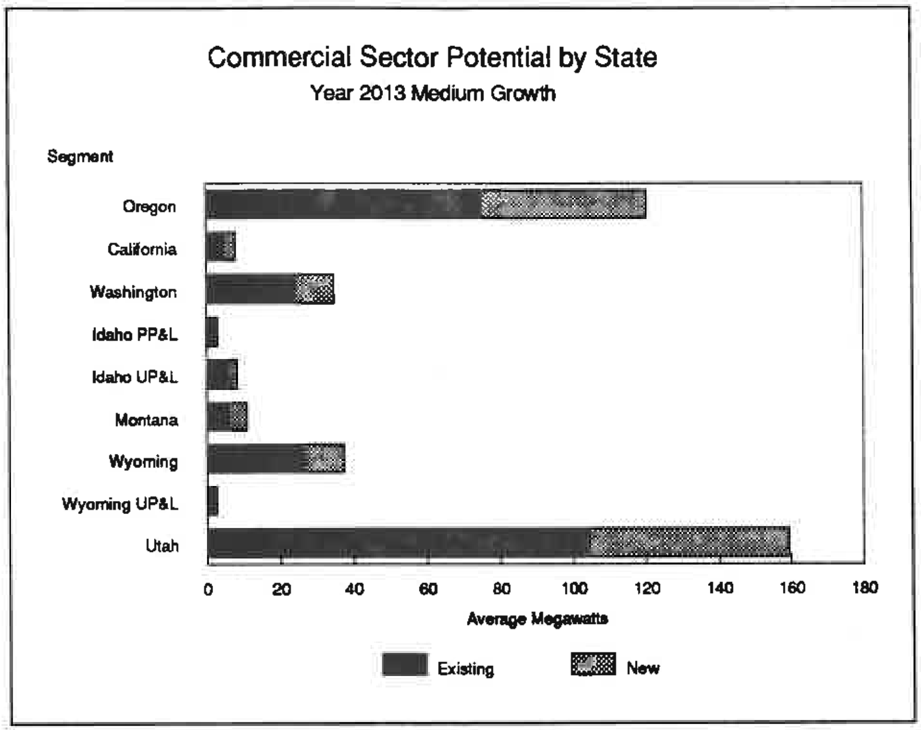

Figure 19—Commercial Sector Savings Potential, by State

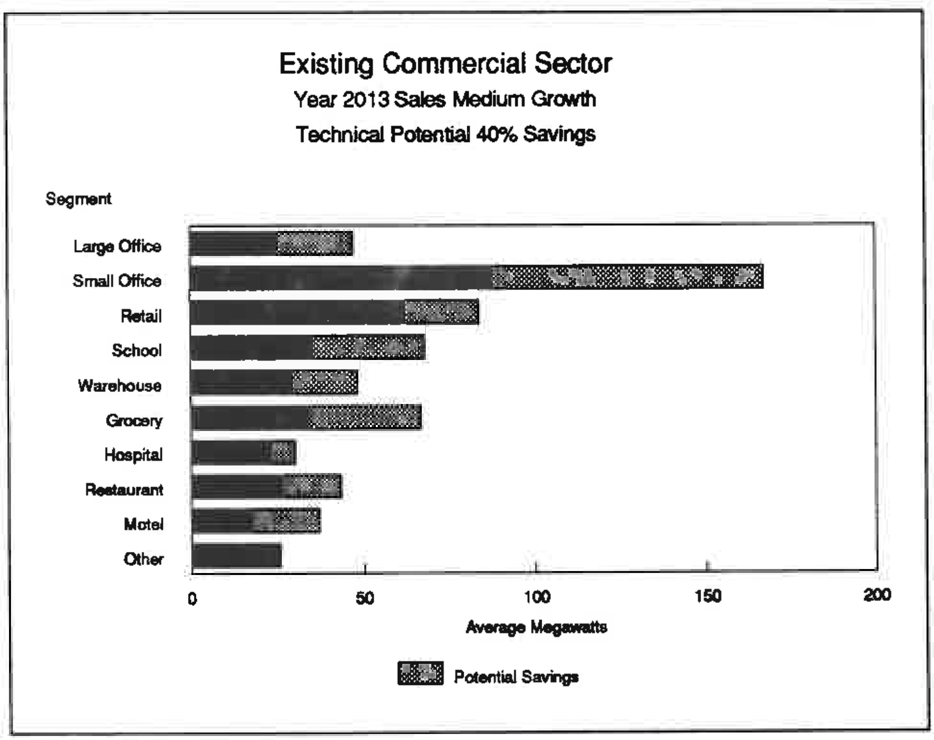

Figure 20—New Commercial Sector, Technical Potential at 40% Savings

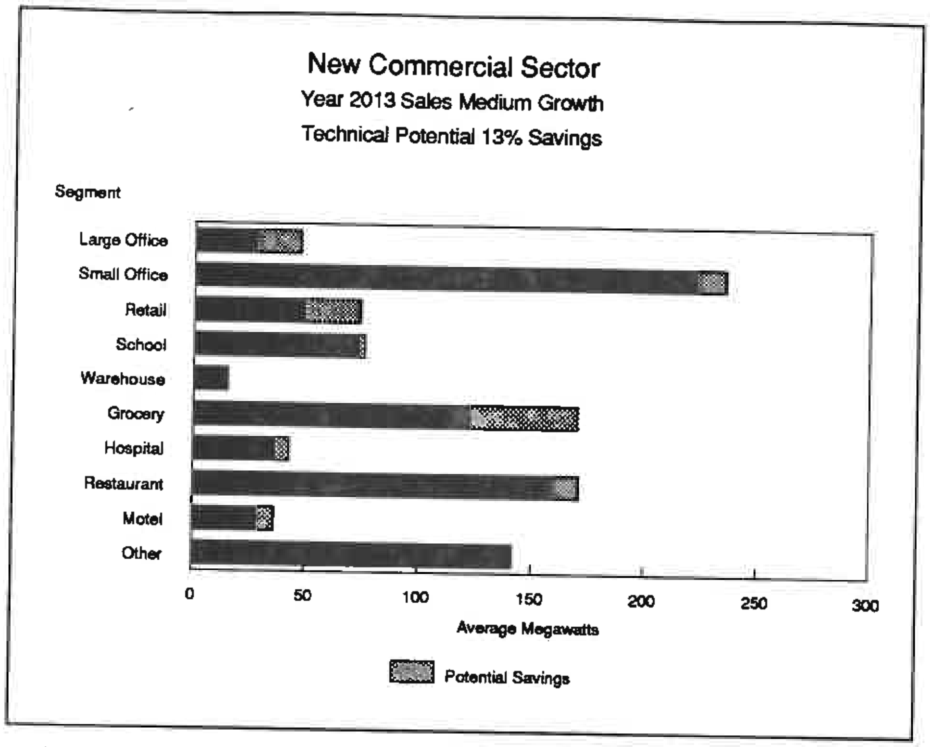

Figure 21—New Commercial Sector Technical Potential with 13% Savings

SECTION 7.0 Industrial Sector and Irrigation

Industrial end use analysis was conducted initially by Gail Katz, Momentum Engineering for RAMPP-1. Results were updated, specifically for UP&L territory, using various consultants' reports[19]. End uses in this sector were assigned on the basis of processes. Thus, energy usage was noted for a process, such as air compressors or pumping, not as motors, which are used in both cases.

Energy usage is expressed differently for the industrial sector than it is for the commercial and residential sectors. The econometric forecast supplies gross megawatt-hour sales without distinguishing between new and old facilities. Instead of computing the cost of each ECM, we estimated how much savings would be possible for a specific average cost. Thus, the industrial supply curve shows only three large step increases, with cut-off thresholds for each tier at 20, 40, and 55 mills/kWh. Given the lack of resolution for this sector, we did not see value in trying to be more specific.

7.1 Basis for Estimating the Costs of Industrial Demand Side Resources

The industrial cost supply estimate is based on the:

1. The 1990 industrial energy consumption by two digit Standard Industrial Classification (SIC) for the company's service territories in a six state region.

2. An energy use breakdown, by end use, from data from the Bonneville Power Administration (BPA), Industrial Test Program (ITP), a series of reports on energy use and conservation in different industries prepared by the Oregon Department of Energy (ODOE) Planning Division, the energy use breakdown in the Dun and Bradstreet database, and energy audits from contractor's reports as specified by Momentum Engineering.

   These data were modified to reflect industries in the territories served by the company. For example, primary metals (SIC 33) appears as a significant industry in the Oregon service territory. Regional energy use data for this SIC is heavily weighted towards the aluminum industry while national energy use data is heavily weighted towards the milling and forming processes found in rolling mills and cable manufacturers. The industries served by PacifiCorp in Oregon include several foundries and Teledyne Wah Chang, producing an overall energy profile that looks like a hybrid between a metals fabrication plant and a refining plant. Other adjustments were made such as increasing the energy use for pumping to allow for plant-owned well pumps n light of the predominantly rural nature of the company's service territory.

The energy use breakdown focused on the systems where there is known conservation potential.

3. The energy conservation measures were taken from the ITP reports, the ODOE reports, a list of projects submitted through a customized rebate program from an East Coast Utility, and contractor's files as specified by Momentum Engineering.

4. The energy conservation measures were divided into three groups based on the estimated levelized cost (0 to less than 20 mills/kWh, 20 to less than 40 mills/kWh, and 40 to 55 mills/kWh). Several measures were split among different brackets based on the available data. For example, the savings due to installing a variable speed drive on a pump or fan depends on the operation of the equipment. As a result, this measure will be in the low cost bracket on some equipment and the medium cost bracket on other equipment.

The conservation measures included are listed in Table 15.

Table 15—Industrial Sector Demand Side Measures

Lighting	• Incandescent to HPS or metal halide • Mercury to HPS or metal halide • Fluorescent in offices to electronic ballasts • VHO fluorescent to HPS or metal halide
Heating Ventilation and Air Conditioning	• Install improved controls on office HVAC • Install night shut off on shop plant HVAC • Replace electric unit heaters with radiant heaters
Compressed Air Systems	• Install multiple compressors for different pressure applications • Install low load unloader mechanisms • Install high efficiency blow-off nozzles • Install multiple compressors with a control system to stage operation • Install high speed electric grinders instead of pneumatic grinders • Install lead-lag control systems for multi-compressor operation to increase part-load compressor for the application • Install humidity controls on air dryers • Rework piping to decrease pressure drop • Install low pressure blowers for low pressure applications
Pumping Systems	• Install VSDs on pumping systems • Install multiple staged pumps for applications with varying flow rates • Install controls to stage existing pumps • Use pony motors for relatively constant loads with occasional peaks • Trim impellers on pumps to match load • Use special nozzles to reduce water use • Increase water recirculation and reuse
Pneumatic Conveying	• Replace pneumatic conveyors with mechanical conveyors
Refrigeration	• Install additional evaporative condensers to minimize condensing pressure • Replace Screw Oil Cooling with thermosyphon • Install staged controls • Install controls for variable suction pressure • Use incoming water for subcooling or precooling

7.2 Irrigation

Irrigation savings have been studied in the Northwest for some time. A rough estimate is that 15% from pump efficiency and another 15% from improved scheduling represent the upper end of technical potential. Farm pumps are often worn and mismatched to their applications. Scheduling irrigation to the exact point that crops need it can save water as well as pumping power. Estimates of the programmatic potential is derived from a consultant study prepared by Xenergy for PacifiCorp[20].

However, there are very serious constraints on the amount of the technical potential that is achievable. The company's program manager reports that farmers are highly risk-adverse when it comes to their crops. Although improved scheduling may save water without affecting yields, they are unlikely to be interested in experimenting with their livelihood. Thus, it is difficult to identify opportunities and persuade farmers to participate. In effect these barriers are legitimate *transaction costs** which need to be considered in developing irrigation conservation supply curves.

The company is currently conducting a pilot test of irrigation efficiency in California. Results will help determine the best ways to market approaches to improving irrigation efficiency.

7.3 Industrial Capacity

The methodology for estimating the load shape was discussed in Section 3.0. The resulting normalized load profiles are shown in Figure 22 for the mix of industrial sales. Note that the sales are dominated by large facilities with very flat usage. Operation with daily scheduling is apparent only in small industries and wood products which results in some load shape in the Northwest. There are few sales to these segments in Utah and Wyoming resulting in very flat sales. Irrigation has a different load shape with very strong seasonality. Irrigation peaks in the summer months and accounts for the majority of demand in some rural areas, notably southern Idaho. Normalized daily profile for irrigation is shown in Figure 23. The shape is fairly flat but the magnitude of irrigation consumption is very seasonal.

7.4 Industrial Worksheets

Figure 24 summarizes consumption and potential savings for industrial sector. Figure 25 shows savings potential by PacifiCorp Division and industrial segment. Note that responsibility for the PP&L territory in Wyoming has been transferred to UP&L. Similar information is shown by process end uses. Figure 26 shows energy consumption by process end uses within industrial segments. Figure 27 shows the potential for energy savings distributed by process end uses. Note that the largest potential is related to motors. Example worksheets for each specific industry can be found in the appendices.

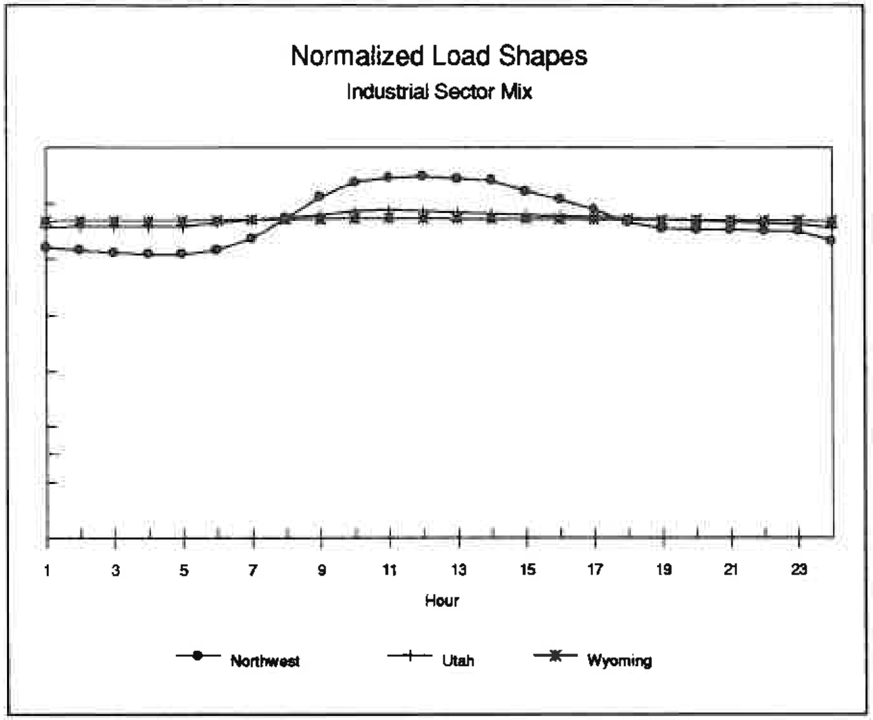

Figure 22—Normalized Industral Sector Load Profles

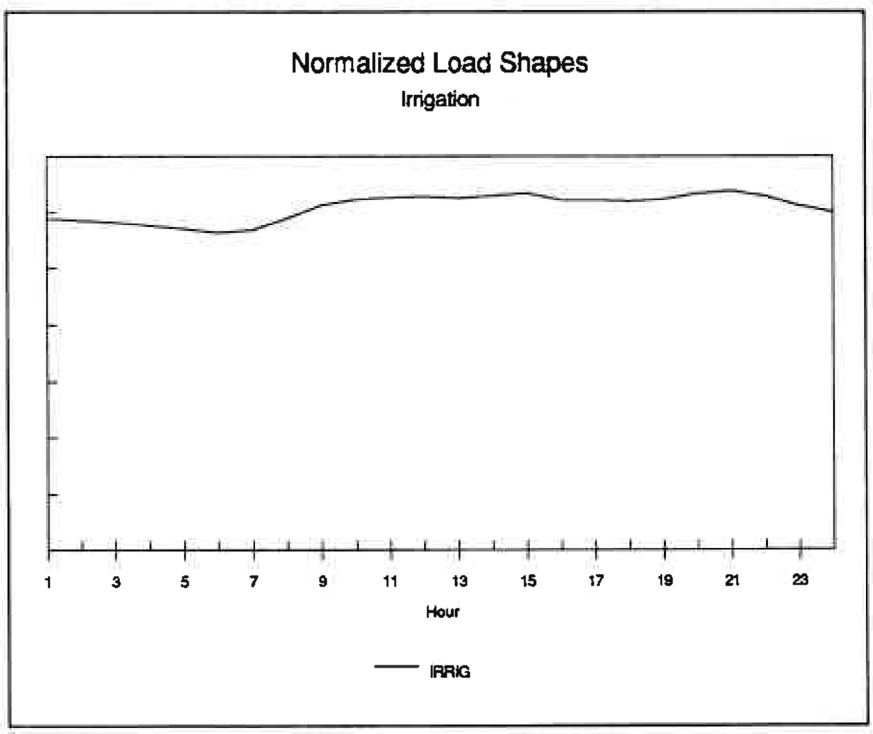

Figure 23—Normalized Load Shapes for Irrigation

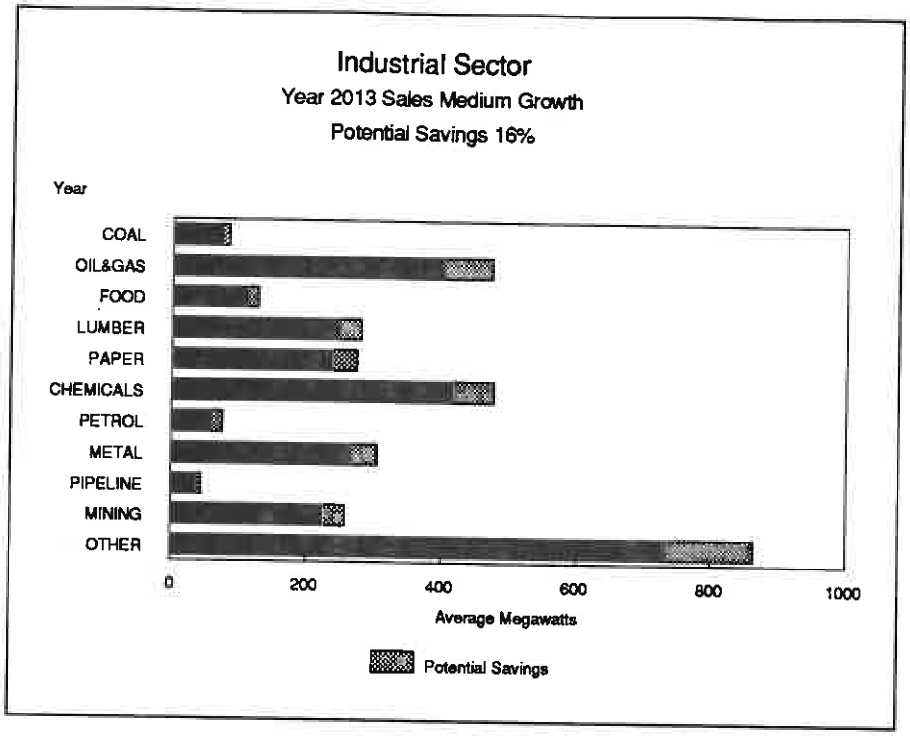

Figure 24—Industrial Sector Savings Potential

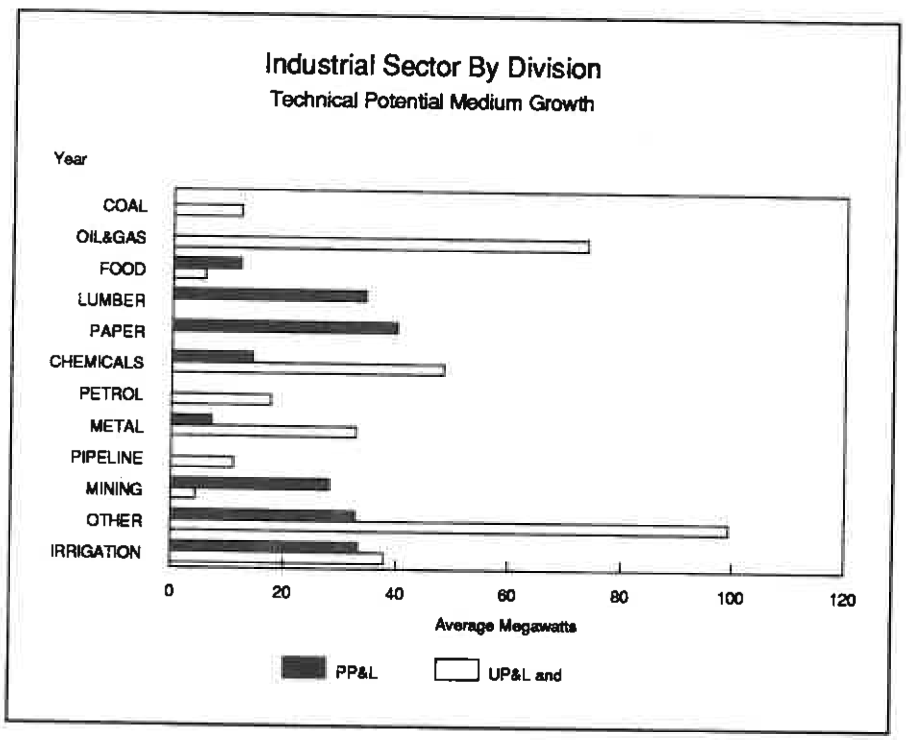

Figure 25—Industrial Sector Savings Potential by Company Division

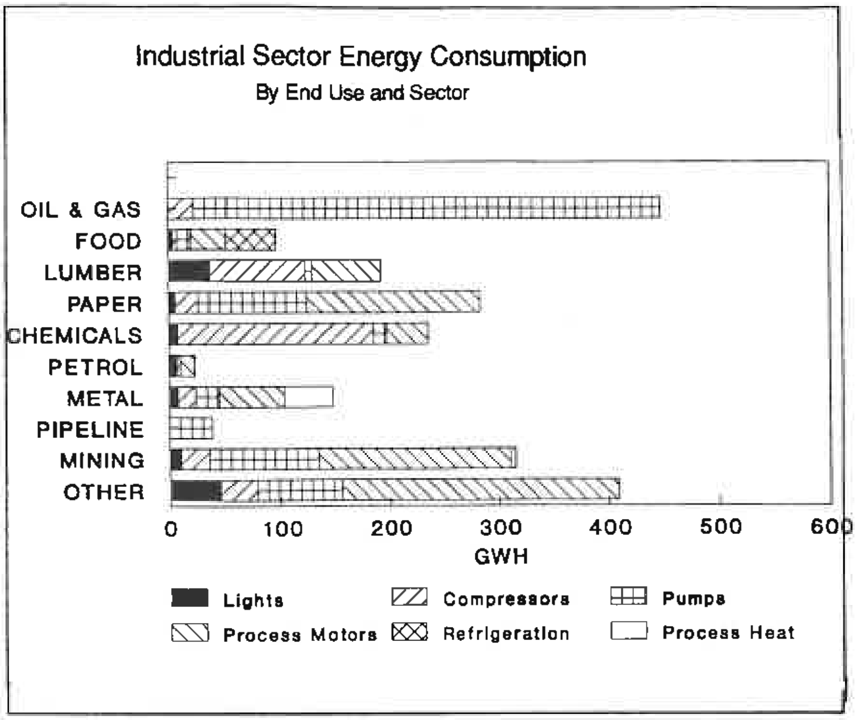

Figure 26—Industrial Savings Potential by End Use and Sector

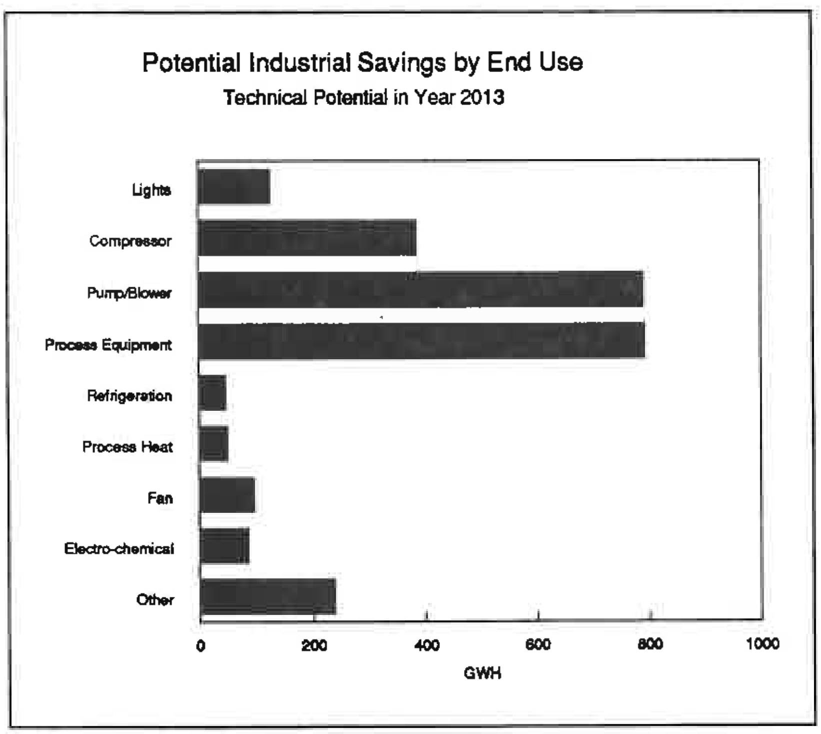

Figure 27—Potential Industrial Savings by End Use

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SECTION 8.0 Other Resources—Fuel Switching and Street Lighting

This section review's the company's analysis of fuel switching as a resource and briefly reviews the status of the company's street lighting program.

8.1 Fuel Switching as a Demand-Side Option

*Fuel switching** is defined as replacing the electrical space or water heating equipment in an existing customer's building with fossil fuel-fired equipment. Because this reduces the electrical utility load, it can be considered a potential resource. However, because another fuel rather than electricity is still being consumed, it is properly a *"load shedding"** option rather than energy conservation.

Fuel switching was analyzed as a potential demand side measure for RAMPP-2.

RAMPP-2 order required that company and the PUC staff hire an outside contractor and conduct fuel switching analysis. Company representatives were under the understanding from meetings with representatives from the Oregon Public Utility Commission and Oregon Department of Energy that the group decided that there was no need to select a contractor and conduct further analysis beyond the information provided to staff regarding the customers with gas space heat and electric water heat. The company was under the belief that it had met the RAMPP-2 order for the fuel switching analysis. PacifiCorp staff will follow-up with OPUC and ODOE staff to determine the status of this issue. Accordingly, the RAMPP-2 study is repeated here with no further additional analysis.

It is important to point out where fuel switching fits in a Least Cost Planning framework. Planning principles require that one look first at low-cost conservation as the first option. Fuel switching can then be considered for the remaining energy consumption. Note that, when examining the cost-effectiveness of the switch, the 10% cost advantage given conservation does not apply to load shedding.

Fuel switching could occur in any customer facility (residential, commercial or industrial) which currently uses electricity to provide heat but could use a fossil fuel instead. In connection with UM424 proceedings conducted by Oregon's Department of Energy and the Oregon PUC staff, the company looked at fuel switching for existing residential customers.

8.2 Analyzing Fuel Choices and the "Bin Model" for Energy Consumption

The Oregon Department of Energy (ODOE) used a computer model to analyze the energy use of existing homes with electric and fossil-fueled forced-air furnaces. An economic calculation sheet computed the comparative economics for the two fuel choices. In this case, the objective was to minimize the *net present value** (NPV) of the lifecycle cost. Lifecycle cost includes the initial cost of changing out the equipment, the NPV of operation and maintenance costs, as well as the NPV of fuel cost over a long time period. Results were examined for both a societal and a customer perspective. However, in keeping with Least Cost Planning, the societal perspective was emphasized. This perspective uses the marginal cost (*utility avoided cost**) of the two fuels in computing lifecycle cost. The NPV of lifecycle cost can also be expressed as a levelized cost for the saved electricity.

The energy consumption model, which is referred to as the *"Bin Model"**, has a manual entitled "A Simplified Energy Analysis Model Incorporating Duct Loss Impacts on Heating System Efficiency." This model is a Lotus 1-2-3 spreadsheet which uses bin weather data to estimate residential heating energy requirements. It then estimates how much primary energy, fuel or electricity, is required to meet both the heating energy requirement and the heating system duct and system losses. The "Bin Model" allows for explicit analysis of several load factors, envelope area and insulation, floor losses, air infiltration, distribution efficiency and internal heat gains including solar heat through the windows. The equations calculate the flow of heat into and out of a single heated space. Due to assumptions made for these variables, different modelers predict wide variations in energy usage.

Like other engineering models for estimating heating energy use, the "Bin Model" does not allow for occupant behavior such as closing off and not heating rooms and turning down the heating thermostat in response to high heating bills. Partly for this reason, engineering models typically over-estimate energy consumption when compared to actual billing data. It is important that the engineering model be "calibrated" or tuned to match typical consumption. To do so, it is necessary to adjust some of the engineering input assumptions to reflect empirical results.

In spite of these problems, an engineering model is the only available tool for comparing the impact of conservation followed by different heating systems, one electric and the other fossil fuel, in the a prototype home. Using the "Bin Model" it was determined how much electrical energy is avoided and how much gas energy must be purchased.

8.3 Cost-Effective Fuel Switching for Furnaces

To determine the cost effectiveness of removing a functioning electrical furnace and replacing it with a natural gas furnace, one would need to consider the fixed costs of demolition, the new furnace including flue venting and gas piping, and the variable cost of the purchased natural gas. The avoided cost to the company for not producing electricity includes avoided generation and a credit for avoided T&D cost but it does not include the 10% allowance for conservation.

The company has a commitment to pursuit of least cost planning principles in its acquisition of energy conservation and therefore no customer should be converted to another fuel until all cost-effective energy conservation has been installed.

Conservation such as added insulation and better windows can reduce the space heating energy usage of electric forced air customers by 2,000 to 3,000 kilowatt-hours per year.

Considering the costs and benefits itemized by ODOE, a single family prototype home with an existing electric furnace would need to use over 12,000 kilowatt-hours for space heating before it would be cost effective to convert to natural gas.

The economic break-even point can be determined graphically as shown in Figure 28. This figure shows the NPV of lifecycle cost for the two fuel choices at different levels of energy consumption. The point where the two lines cross over is the economic break-even point for fuel switching. Note that the lifecycle cost lines for electric and gas are close to being parallel. This implies a high sensitivity to initial assumptions—a small change in one line can shift the cross-over point dramatically.

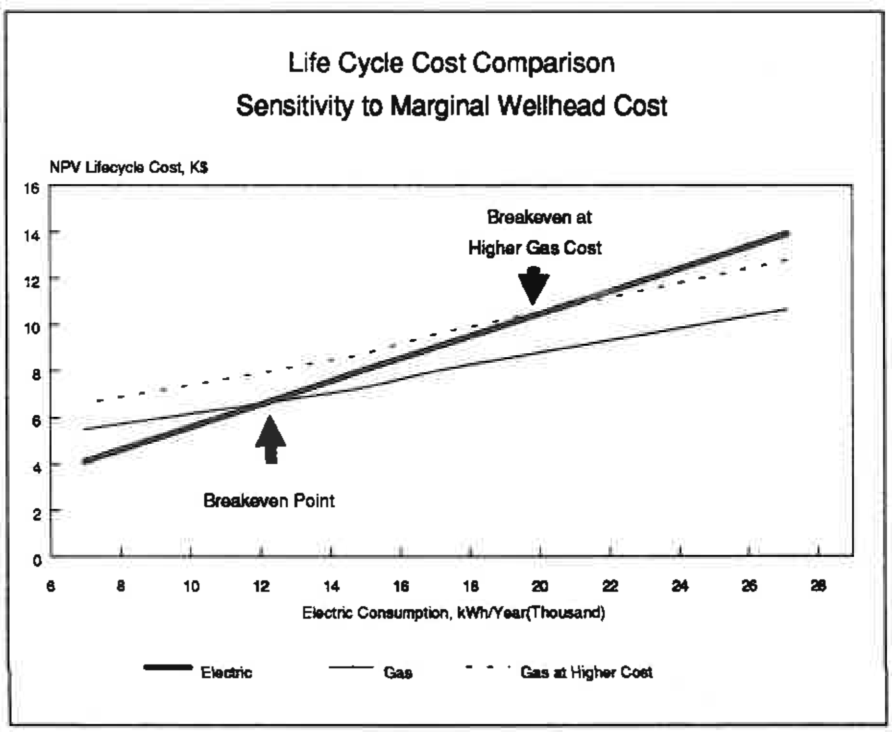

Figure 28—Break-even for Fuel Switching

The fuel switching analysis was performed under the RAMPP 2 assumptions, it was not updated for RAMPP-3.

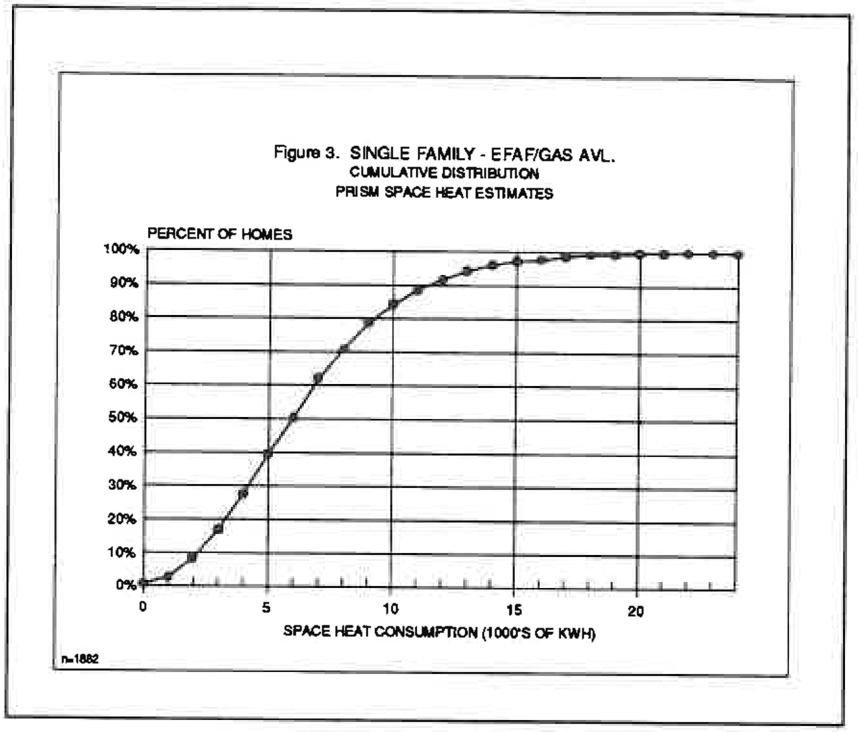

Figure 29—Distribution of Space Heat Consumption

The analysis showed that the break-even point for fuel switching would be 19,000 kWh if the price gas goes up by 30 percent. The analysis evaluated various levels of gas price increase and was used to illustrate the fact that the outcome of the analysis was sensitive to the gas price chosen. At a price 30% higher at the well-head, the break-even point moved to 19,000 kWh, a level well beyond all but the extreme points in our distribution of customer consumption.

Figure 29 shows the distribution of electric space heating energy usage for customers who might be candidates. This distribution is based on 1,882 customers who have electric forced- air furnaces, no evidence of wood heat and live where natural gas might be available. As derived from the historical billing data, 92% of these customers use less than 12,000 kilowatt-hours for space heating. That means a furnace conversion would be cost effective for only 8% of the customers. Assuming that 2,000 to 3,000 kilowatt-hours can be trimmed from the energy usage of these customers by installing energy conservation first, about 5% of customers would still be cost-effective candidates for space heat fuel switching. This small number of potential beneficiaries does not justify the development cost of creating a fuel switching program.

Levelized costs for a variety of prototype homes are shown in Table 16. These prototypes are intended to approximate quintile points of the distribution of the company's electric space heating customers. The same homes are first weatherized as indicated with "Wx". Note that the Least Cost approach of weatherizing the home first reduces the cost-effectiveness of subsequent fuel switching. Fuel switching as a resource would cost 60 to 100 mills/kWh in 1992 dollars. For comparison, the company's levelized avoided cost was estimated to be only about 40 mills/kWh in 1992.

Table 16—Levelized Cost for Fuel Switching

Under Different Economic Load Growth Scenarios

Usage Level	Electric Forced Air Furnace Annual kWh	Gas Forced Air Furnace Annual MMBTU	Fuel Switch Levelized Cost mills/kWh
High	17,035	93.53	41
Medium High	11,137	64.44	49
Medium	8,096	53.23	68
Medium Low	6,004	43.54	83
Low	3,490	28.41	124
Wx—High	7,712	46.59	60
Wx—Med High	7,091	43.09	63
Wx—Medium	5,441	38.63	89
Wx—Med Low	3,621	28.98	120
Wx—Low	3,490	28.41	124

8.4 Fuel Switching for Water Heaters

A similar case can be demonstrated for electric resistance water heating for residential customers. The economic cross-over point for water heating is about 4,300 kilowatt-hours per year at a cost of 40 mills/kilowatt-hour, based on recent computations by a Fuel Switching Technical Group[1]. Again, energy conservation is the company's first priority—water heating savings of 700 to 1,000 kilowatt-hours are possible. So, only customers with water heating energy usage over 5,000 kilowatt-hours (homes with large families) would benefit from a fuel switching program. Again the development, marketing, and administrative costs of a full scale fuel switching program for water heating could not be justified.

These results are expected to be similar for other areas of the company's service territory. Marginal costs for gas are expected to be similar since gas companies across the company's service territory are purchasing new supply from the same market. The company's marginal costs and equipment costs are the same for all areas served.

8.5 Street Lighting

The company operates a street lighting service in most of its territory. About 98% of street lights in PP&L and 75% in UP&L are owned by the company. This amounts to about 47,000 lamps in PP&L and 313,000 lamps in UP&L. Older mercury vapor lamps can be replaced by more efficient high pressure sodium (HPS) lamps, saving about 40%. However, the company has already changed out the majority of its lamps[2]. About 50% of lamps in PP&L and 20% in UP&L remain as mercury vapor lamps. The company has a policy of retrofitting mercury vapor with HPS during normal maintenance and replacement. Complete changeout of the lamps would result in estimated savings of about 4,500 MWh or about half an average megawatt. Given that the company already has a policy of replacing the lamps, accelerating the replacement is not a sufficiently large resource to consider this as a program opportunity.

SECTION 9.0 Supply Curves

Technical savings potentials from all the sectors are summarized in the following supply curves. Examples of the individual and combined curves are shown below. Figure 30 shows the combined supply curves for the medium economic growth forecast. Figure 31 shows the same information for individual sectors. Figure 32 shows the combined supply curves for the two divisions.

The next series of charts shows PP&L and UP&L combined under the medium economic growth scenario for different customer segments. Figure 33 shows the supply curve for residential appliances. This curve is very large but represents a lot of savings which remain theoretical, not achievable. Figure 34 shows the industrial supply curve. Figure 35 and Figure 36 shows the supply curve for existing commercial and new commercial building sectors. Figure 37 shows the potential for space heating in existing residences. Figure 38 shows the same for new residences.

Please note that the following graphs do not have same scale.

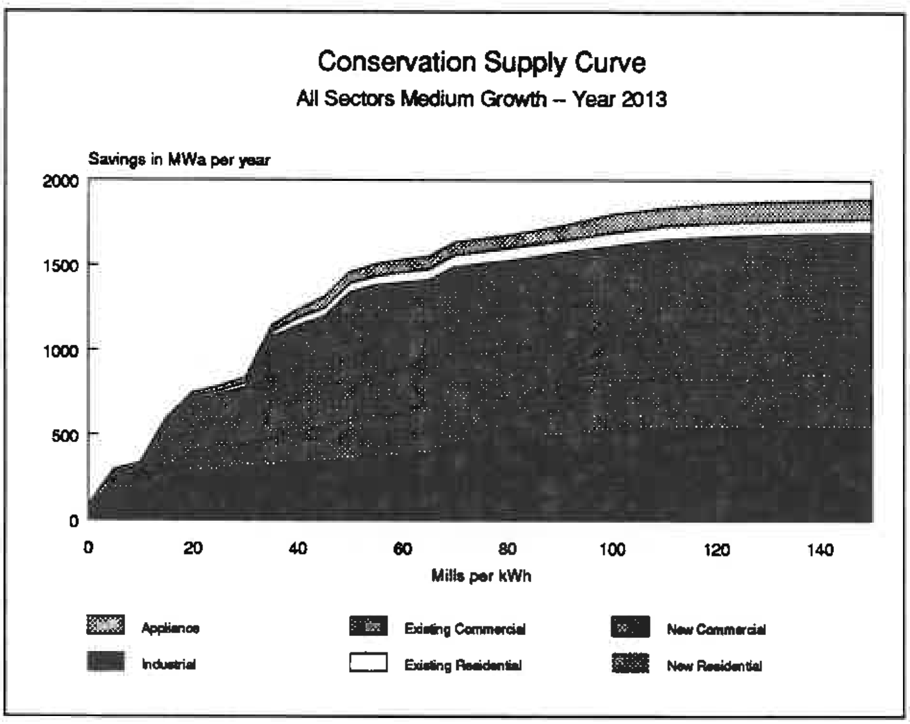

Figure 30—Combined DSR Supply Curve for Medium Economic Growth

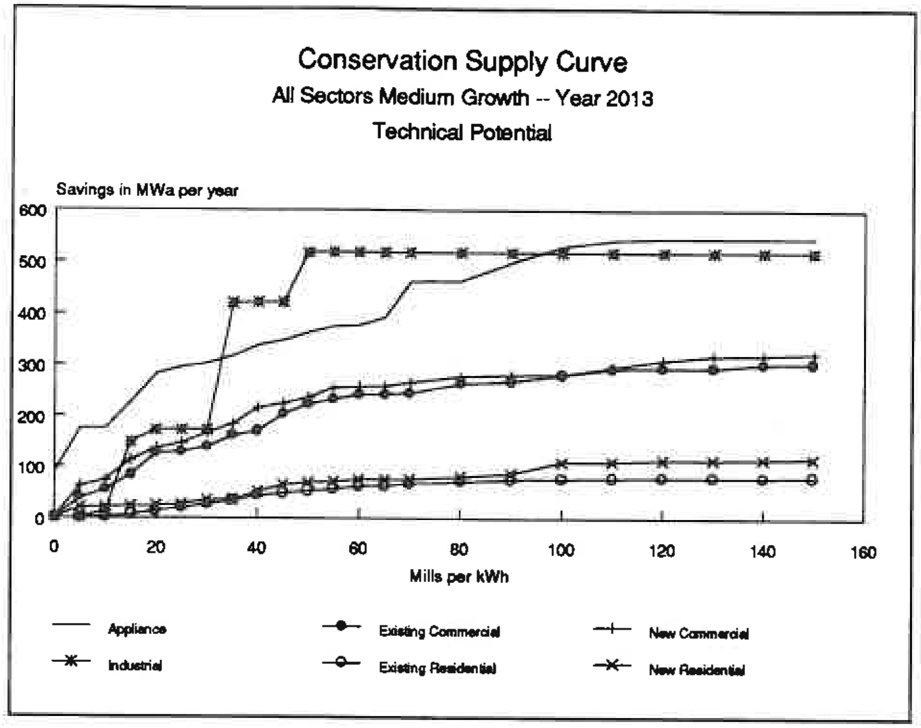

Figure 31—Supply Curves by Sector

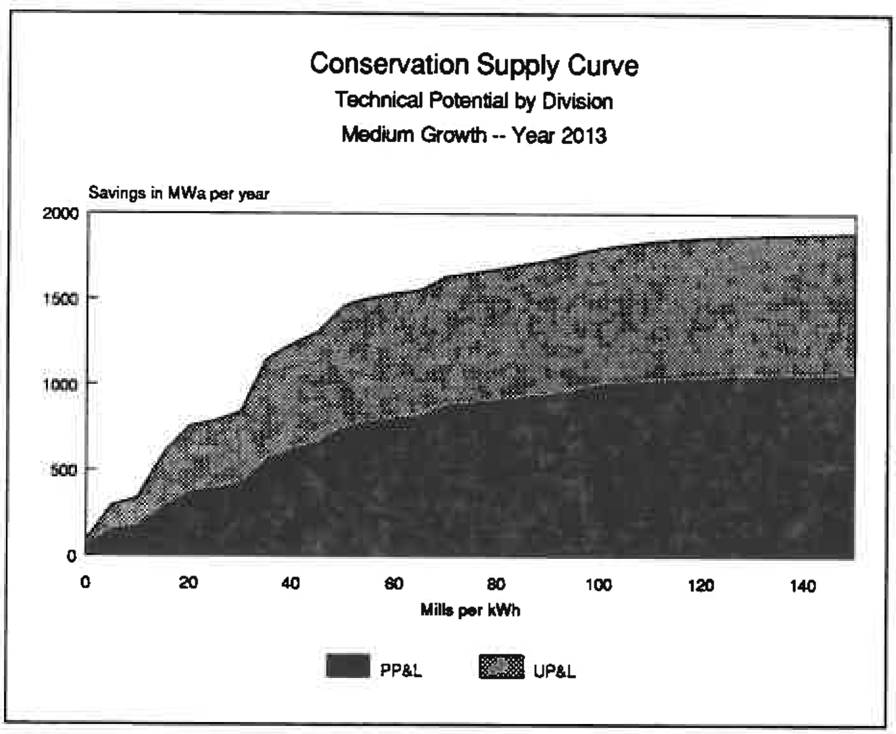

Figure 32—Supply Curves by Sector

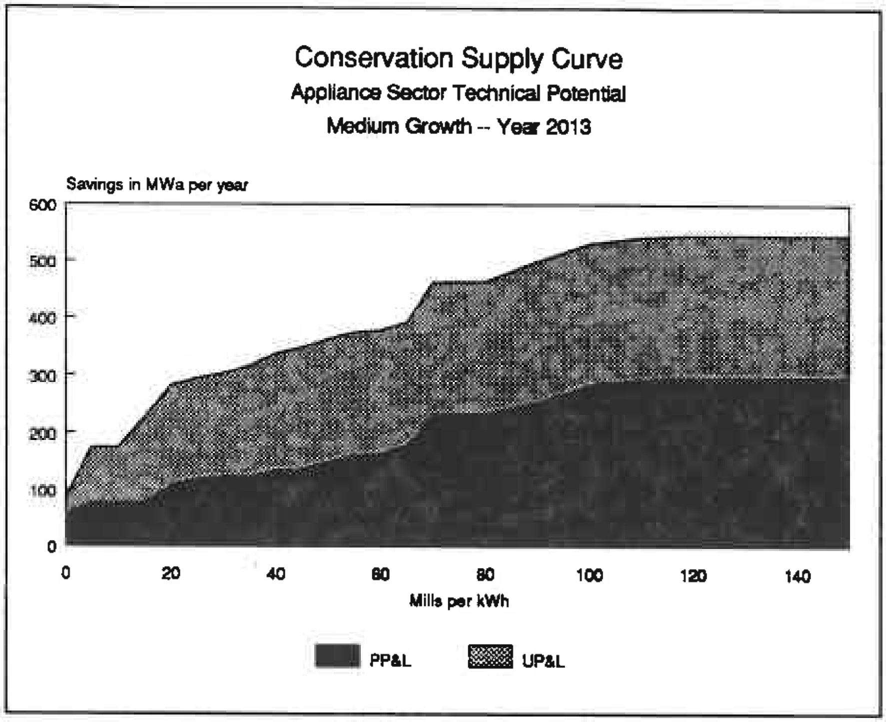

Figure 33—Supply Curve for Residential Appliances by Company Division

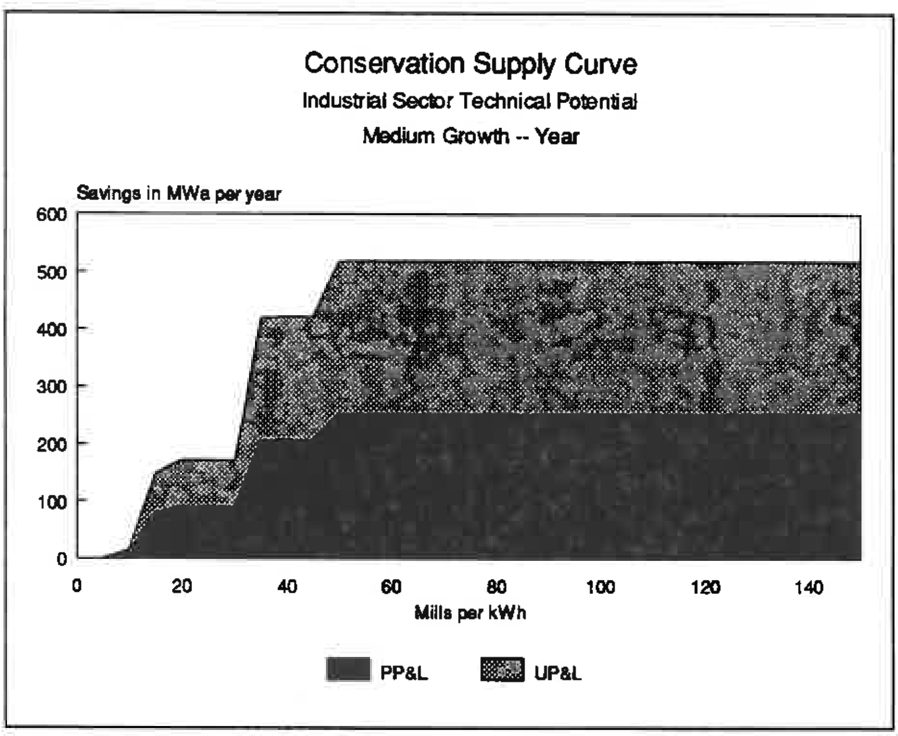

Figure 34—Supply Curve for the Industrial Sector

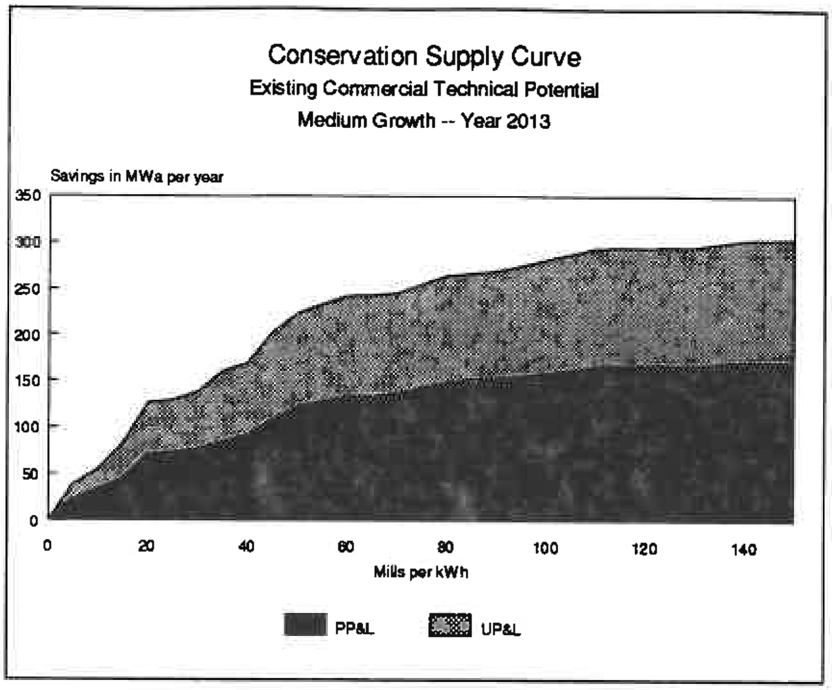

Figure 35—Supply Curve for the Existing Commercial Sector by Division

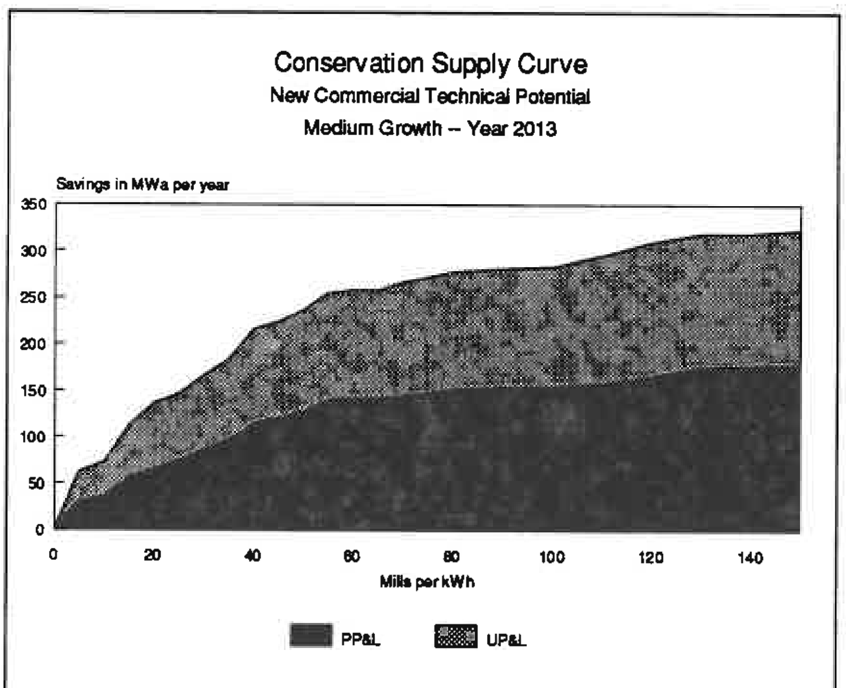

Figure 36—Supply Curve for the New Commercial Sector by Division

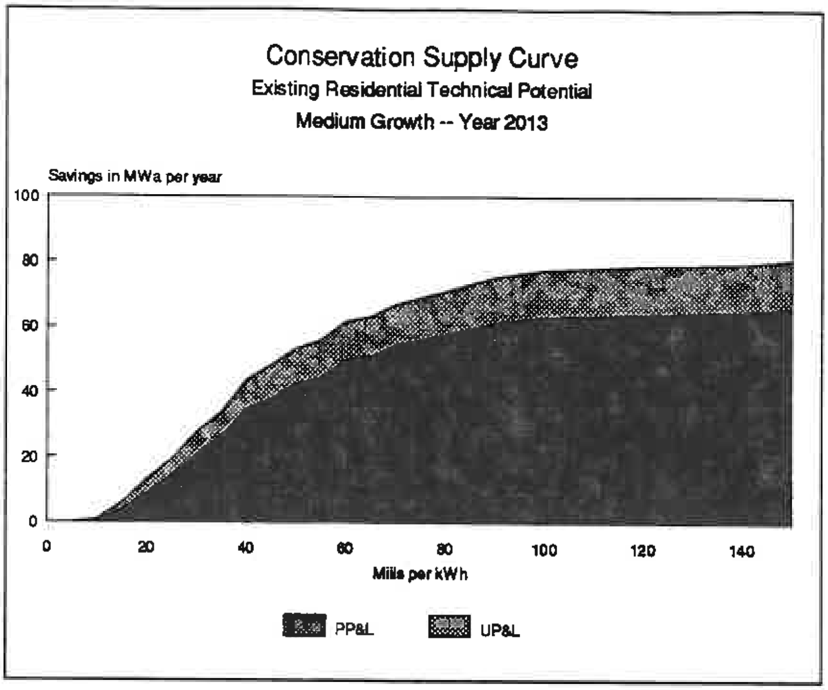

Figure 37—Existing Residential Supply Curve

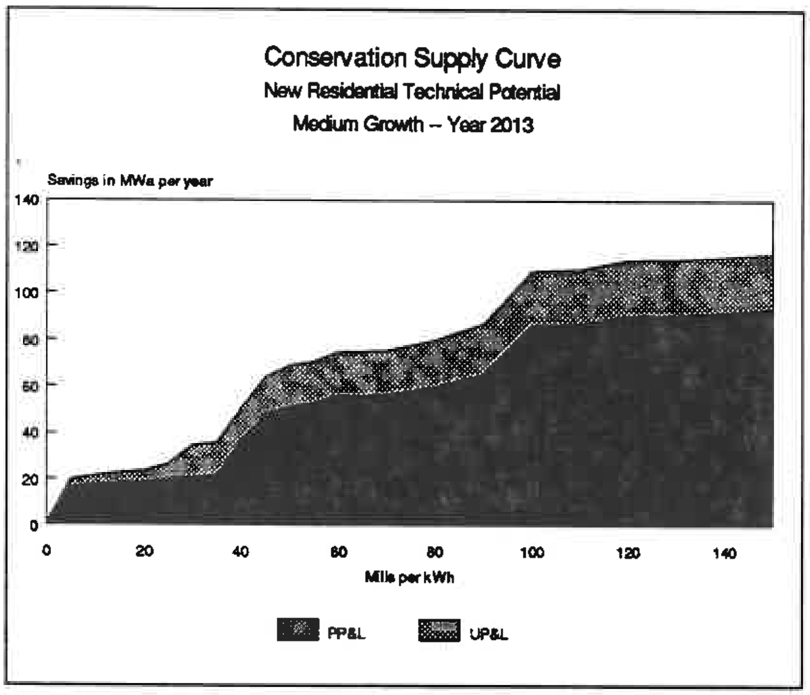

Figure 38—New Residential Supply Curve

9.1 Comparison of Technical Potential with NPPC Reports

The Northwest Power Planning Council (NPPC-1991) has produced the broadest planning document in the Northwest Region[1]. It is difficult to compare technical potential estimates because of the problems isolating the company from the rest of the Northwest Region. An attempt is made in Table 17 to compare the two planning methodologies. The comparison is based on the percentage of savings predicted and the amount of resource estimated for the company's share of the Northwest Region. The company's larger estimate of the potential resource is due primarily to a larger assumption about the forecasted customer demand. The company's conservation estimate is larger in estimates of industrial and irrigation potential. NPPC has a smaller estimate of industrial sales and a smaller estimate of the savings potential for that sector.

Table 17—Technical Potential Compared with NPPC Results

Northwest Power Planning Council versus PacifiCorp Supply Curve Model
Savings from RAMPP-3/NPPC 1991 Medium Supply Curves Medium mills/kWh

	Savings Fraction	PP&L Share MWa	Savings Fraction	NW tates MWa
Commercial Sector				
Existing	.29	120	.40	129
New	.23	57	.13	141
Subtotal	.27	177	.14	270
Residential Sector				
Existing SF	--	18	--	30
Existing MF	--	8	--	4
Existing MH	--	--	--	10
Subtotal Existing	.23	26	.19	44
New SF	--	8	--	47
New MF	--	6	--	3
New MH	--	13	--	3
Subtotal New	.46	27	.18	53
Water Heaters	.35	18	.26	67
Lights	.16	9	.10	8
Subtotal Residential Sector	.29	80	.14	172
Industrial Sector	.07	67	.16	254
Irrigation	.07	8	.30	45
***TOTAL*, All Sectors**	.17	332	.11	741

SECTION 10.0 Background Conservation and Lost Opportunities

The economic forecasts of customer energy demand are on "frozen efficiency", that is, without consideration of the amount of conservation customers will do on their own. This amount of energy is removed from the forecast to estimate the load that the company would otherwise have to supply. Thus, the background conservation must also be removed from utility programs to calculate the net resource delivered by programs. In most cases, the background is small so this is not a serious issue.

Lost opportunities are those conservation resources which will be cost-effective during their lifetime if installed now, but not if installed later as part of a more expensive retrofit. Thus, lost opportunities are measures which should be installed even during a generation surplus.

10.1 Assessment of Background Conservation, or "Gravity"

Background conservation was assessed by estimating the amount of conservation that customers would perceive as cost-effective based on their retail rates and high *implicit discount rate**. The implicit discount rate sets an economic proxy for observed customer behavior. If customers insist on simple payback within two years, they are discounting any savings beyond that point. This can be treated as if they have a very high discount rate. Of course, the reasons for their reluctance to participate are more likely to be entry barriers (transaction costs), lack of information, lack of a perceived significant benefit and other issues which are not purely economic.

An implicit discount rate of 60% nominal was used , for commercial and residential customers, to represent the various customer barriers (it is understood that not all these barriers are financial). Under these conditions only cheap measures (levelized cost of 8-10 mills/kWh) appear cost-effective. These measures are assumed to be deployed over the twenty year planning horizon. Background conservation estimate for industrial sector is implicitly included in the econometric model used for estimation of industrial forecast. No further adjustments were made.

For the residential sector, only air sealing improvements on the largest single family prototype meets the cost-effective criterion. Thus, very little weatherization is expected to occur though the customer's efforts alone. For new construction, MCS absorbs the conservation that people would do on their own. It should be noted that solar access estimates were defined relative to the amount that people would do on their own, so the background has already been accounted for.

For the commercial sector, there are many cost-effective measures. Because the existing commercial building stock is not efficient, there are many appropriate measures. There are also efficiency measures beyond the current code for new construction which would be cost effective. Thus, there is a certain amount of conservation produced by customers associated with new commercial construction. Under new efficiency codes, the mandated measures will likely absorb background savings, so this adjustment will be less important in future plans.

Table 18—Background Conservation Measures

	ECMs Included in Background Conservation	
	Existing	***New Construction***
Residential Large, single family	Tighten and reduce air infiltration (ACH)	—
Commercial Office	Lights, incand > PL HVAC, tune and adjust	Lights, incand > PL HVAC, upgrade heat pump
Retail	Lights, 34W fluor. Lights, ballast>elect.	HVAC, storage rad. heater
Warehouse	AC, temp. setback HVAC, tune and adjust	Lights, incand > PL HVAC, storage radiant heater
Grocery	Envel., tighten ACH Lights, incand > PL HVAC, refer case timer HVAC, tune and adjust	ights, parabolic reflector Lights, incand > PL
School	Envelope, tighten ACH Lights, 2 level switch	--
Hospital	Lights, T8 fluorescent Lights, incand>PL HVAC, temp. reset	Envelope, insulate walls Lights, incand > PL
Restaurant	Envelope, insulate roof	--
Lodging	Lights, effic. incand. Lights, incand > PL HVAC, temp. reset HVAC, low flow shower	HVAC, low flow shower

The amount of customer produced conservation is referred to as the "gravity" amount. It is included to some extent in all the economic forecasts but is not directly visible to resource planners. The measures applicable to the background conservation in the commercial sector are listed in Table 18. For the industrial sector, background efficiency is assumed to be included in the econometric trends embedded in the forecast model.

Table 19—Cost Induced Conservation in Forecast

Total Background Conservation
Average Megawatts (MWa) in Year 2014 at 10 mills/kWh or less
Based on Medium High Forecast, Merged Company

Sector	Existing Stock	New Construction	All Stock
Residential	0	0	0
Commercial	53.3	83.5	136.8
Industrial	—	—	—
Total	53.3	83.5	136.8

Table 19 lists an estimate of the conservation that consumers would do on their own. Outside of solar access, there are no low-cost opportunities in new residential construction not incorporated in building codes. (The amount of solar access in existing practice was included in the base case). The largest amount of such conservation occurs in the commercial sector. That is because there are many low-cost options. At least some of the customers should recognize those opportunities. The industrial sector is not included in this table because industrial "background" trends are already included in the econometric forecasting model. The amount of background conservation, including MCS, is shown below. The amounts are compared for the five economic growth scenarios in Figure 39.

10.2 Lost Opportunities

Lost opportunities occur in several ways. First, the long-lived structural components of new buildings should be constructed to long-run cost-effectiveness standards. This is currently the rationale behind the Super Good Cents program for residential MCS. No similar program exists for new commercial construction, even though the potential for savings is much greater. The company will participate to a limited extent in Bonneville's Energy Smart commercial program for new commercial buildings to access the commercial opportunities. The program design of Energy Smart may be inadequate to capture lost opportunities without incentive payments.

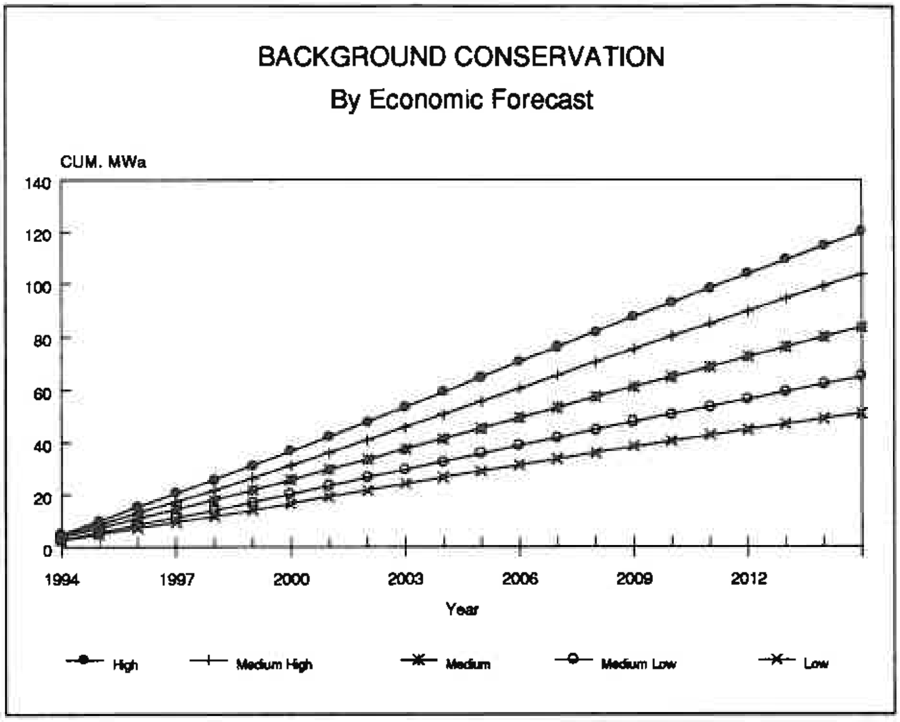

Figure 39—Background Forecast by Economic Growth Scenario

Additional lost opportunities occur during remodel and replacement of the commercial building stock. There is a constant turn-over of commercial sales spaces through remodeling. Installation of some measures will be much cheaper if included during remodel.

In addition, there is an on-going repair and replacement of equipment in existing buildings due to component breakdown. It is often more cost-effective to replace with efficient equipment during the repair than to attempt upgrading retroactively. Both repair and remodel opportunities need to be evaluated against the likelihood of event windows. If there is a possibility of another window of opportunity occurring before the conservation is needed, the opportunity is not actually lost. Thus, if commercial sales spaces are remodeled every five years and conservation is not needed for five.

- For this analysis, we included lost opportunities based on the following criteria:
- Years, the measure can be postponed to the next window of opportunity.

  Current installation costs less than 55 mills/kWh.
- Measure has a lifetime over 10 years.
- Retrofit costs will exceed 55 mills/kWh or the levelized cost will increase by at least 50% as a retrofit.
- The window of opportunity occurs on the average of 10 years or more.

The supply curve worksheets were used to calculate lost opportunities for most of the sectors. An exception is commercial repair and remodel. For these estimates, spreadsheets developed for Bonneville by Gail Katz, SJO, were applied. These spreadsheets allowed updating for the square footage and fuel saturations appropriate for the company territory. Only the small office and small retail sheets were used since the worksheet models of these building types provided good analytic resolution and this subsector is highly susceptible to repair and remodel activity.

10.3 Size of Potential Lost Opportunity

The bulk of the lost opportunities occur in the commercial sector . There is also a significant amount that appears during remodel and repair opportunities. Industrial sector opportunities are perhaps large but are not included in the above assessment. This is because industrial opportunities are quite site-specific and our level of knowledge is incomplete.

Some of the opportunity will occur even without utility programs as customers undertake conservation on their own. The amount of that background conservation is small since only the cheapest measures are attractive.

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PART II

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SECTION 11.0 Overview of Program Planning

This part of the Demand Side RAMPP-3 Technical Appendix covers sections addressing aspects of demand-side program planning. Sections 12.0 through 18.0 detail planning assumptions and steps in arriving at programmatic savings and cost estimates. The result of this planning effort is a specific two-year action plan with state-by-state goals by program area to be included in the company's integrated resource plan, RAMPP-3.

Figure 40 is a road map to help guide you through Part II of this report.

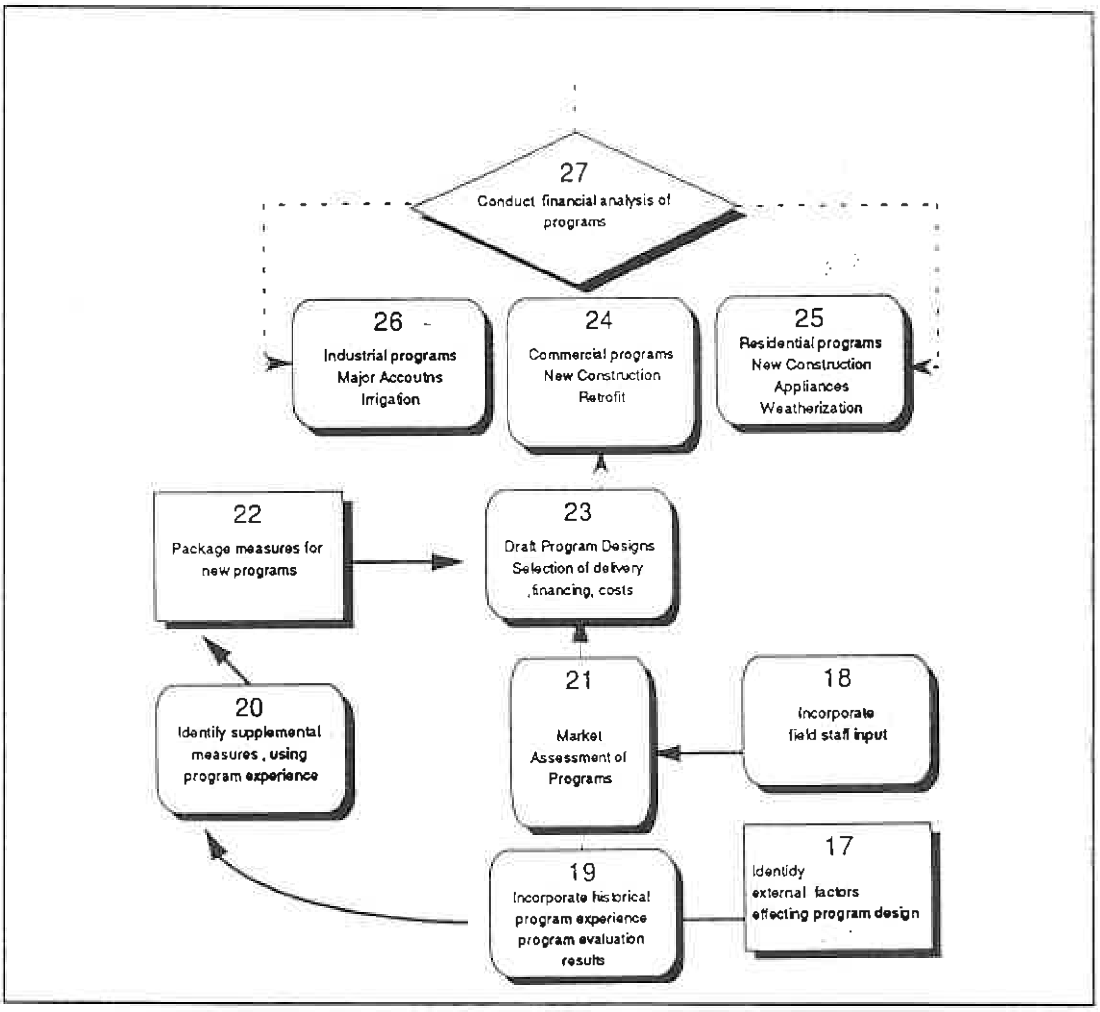

Figure 40—Program Planning Steps

SECTION 12.0 Demand Side Resource Opportunities

Customers use electricity for the end-use benefits it provides rather than for the energy itself. The customer end-use applications include, but are not limited to, space heating and cooling, water heating, indoor and outdoor lighting, and running motors. If these end-use applications can be accomplished using less energy more efficiently, then the surplus energy can be used in new applications. The end-use efficiency improvements provide energy resources to meet future needs. Figure 41 shows the company's typical electric energy consumption by major end-uses.

A number of factors influence the company's decisions on priorities of demand-side resource acquisition. These factors include cost of the resource, impact on customer prices, size of resource, ease of acquisition, lost opportunities, and others. The following will focus on the major factors influencing priority of acquisition within program development.

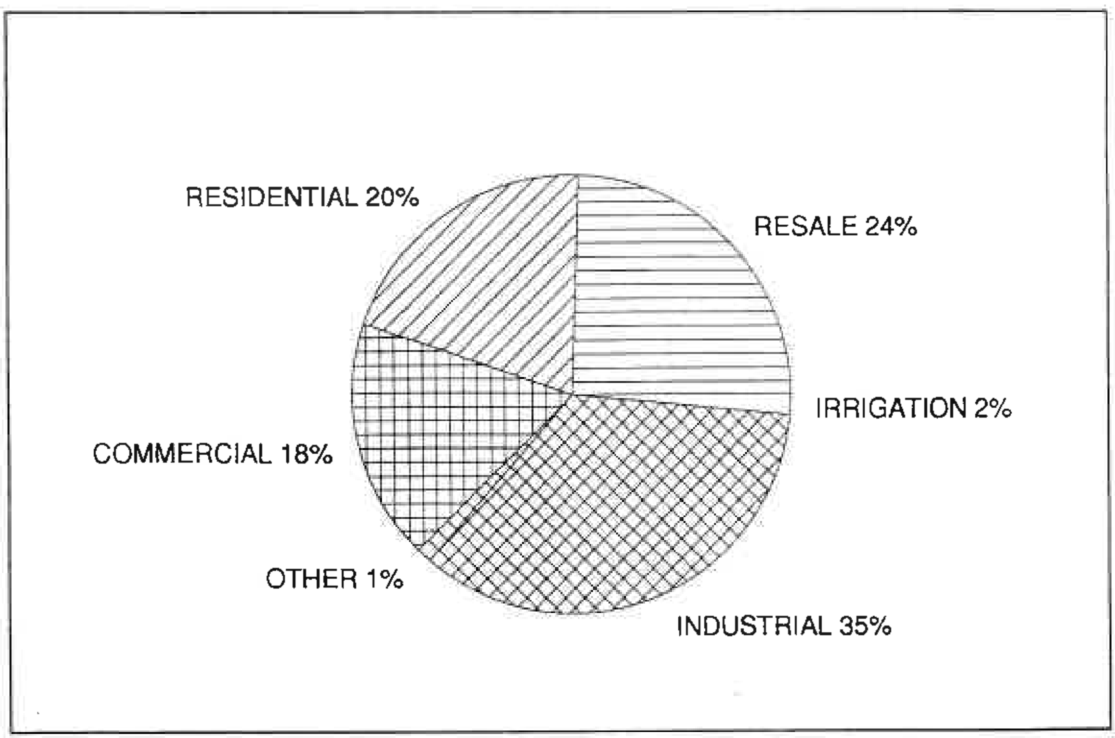

Figure 41—Energy End Use by Major Sector

12.1 Lost Opportunities

Program development activities at the company over the last several years have targeted acquisition of lost opportunity resources and plan to continue these efforts into the future.

Lost opportunities are conservation measures that will be cost-effective during their lifetime if installed now, but not if installed later as part of a more expensive retrofit. The bulk of lost opportunities, analysts found, occur in the commercial sector, both in new construction and building remodeling, where programs are not in place. Lost opportunities also occur in industrial new construction.

New construction is an example of a potential lost opportunity. Constructing buildings, which only meet existing energy codes, locks the building owner into paying energy bills that are higher than an energy efficient building. These bills remain higher for the life of the building. Some conservation measures are prohibitively expensive to add after the building is constructed. Lost opportunity type programs are beneficial over the long run to operate and even during a temporary period of generation surplus. Programs have been developed for residential new construction (SGC and MAP) and commercial new construction. Energy FinAnswer and FinAnswer 12,000 are examples of current programs in place to capture resource opportunities.

12.1.1 Cost Effectiveness

Another important question for lost opportunities is that of defining cost-effectiveness relative to the expected deficit date and new resource cost. To some extent, this will not be known until completion of the integration phase of the Least Cost Planning process. Then it will be necessary to identify and reconcile any differences between regional cost-effectiveness levels and those pertaining to the individual utility. The estimate of lost opportunities at this point is clearly preliminary.

12.1.2 Timing for Capturing Lost Opportunities

Normally within the context of an integrated resource planning process one would simply choose the least-cost resources first and prioritize program development based on this selection. However, lost opportunity resources are excluded from this decision criteria. If there is an expected need for the resource at a future time and the resource is cost effective over the lifetime then the resource should be captured at the point where the opportunity exists.

A crucial acquisition consideration is the *window of opportunity**, the time that an opportunity presents itself. Will there be another window or chance at the same opportunity before it is needed? If so, the opportunity could be safely postponed and not truly lost. As an example, commercial building spaces are frequently remodeled. For some measures, this means there are frequent opportunities. For other measures, there are not.

One finding from a Commercial Remodel Study done by the company suggests that there are significant current lost opportunities, but there was no technical estimate of the potential and therefore could not be included in this plan. If no lost opportunity programs were conducted, the company would be incurring an estimated 23 MWa per year of lost opportunities. Table 20 below shows estimates of lost opportunity resource potential, most of which will be covered by company programs in 1994.

As shown in Table 20, the largest lost opportunity potential exists the in commercial sector—both in new construction and building remodeling. The company has implemented the Energy FinAnswer program to cover new construction and has just recently implemented a commercial retrofit program in Oregon.

Table 20—Sources of Lost Opportunity Resources in 1994

Technical Potential, in MWa per Year

SECTOR	* TECHNICAL POTENTIAL, MWa	PROGRAM
New Residential Construction	1.3	Super Good Cents
New Manufactured Homes	1.4	MAP
Solar Access	0.6	Long Term Super Good Cents
Appliances, • Refrigerators • Freezers • Water Heaters	5.0	Long Term Super Good Cents
New Commercial Construction	11.3	Energy FinAnswer
Commercial Remodel	3.0	Energy FinAnswer—Retrofit
Commercial Repair And Replacement	0.8	Energy FinAnswer—Retrofit
Total Potential	*23.4*	

* Technical potential based Medium Forecast and 55 mills/kWh cost ceiling.

Lost opportunities also occur in industrial new construction. The company offers the Industrial Energy FinAnswer program to capture these resources. The technical potential for lost opportunities in industrial is not itemized in the forecasting methodology and there is currently no method to identify lost opportunities in advance.

12.2 Size of the Resource Opportunity

The technical potential provides a first step in identifying areas where programs could be developed. The potential shows where programs could be targeted for maximum effect, where opportunities lie and what some interactions may be. The technical potential is defined as all of the conservation that is physically possible.

The company has a technical potential for conservation of about 1450 MWa based on the medium forecast. The results by sector are shown in Table 21. As can be seen from Table 21, much of the resource potential is in the residential appliances, commercial new and existing and industrial.

The technical potential shown in Table 21 includes Model Conservation Standards and "background" conservation (74 MWa in commercial sector) which is assumed to occur in the company sales forecast. The amount of potential available for possible resource acquisition is the 1,452 MWa shown in Table 21 less MCS and "background" conservation of 74 MWa in commercial. The total technical potential available for resource acquisition is 1,378 MWa. Of course, not all this technical potential is achievable today. Much of the potential savings in appliances, for example, depends on the development and availability of high-efficiency appliances. Many of these high-efficiency appliances are currently available in Europe and Japan, but not available in the US market.

Table 21—Conservation Technical Potential
Average Megawatts in Year 2014

SECTOR	EXISTING STOCK MWa	TECHNICAL POTENTIAL, NEW CONSTRUCTION (MWa) * Based on Medium Forecast at 55 mills or less, total company.	ALL STOCK MWa
Residential • Space Heat • Appliances *subtotal*	 56 not applicable 56	 60 375 435	 116 375 491
Commercial	233	255	488
Industrial(Irrigation)	not applicable	not applicable	473
Total			1,452

12.3 Cost of Resources—Initial and Ongoing

In general, the supply curve methodology is to keep all cost calculations in real dollars and apply discounting with real discount rates. The discounting period for conservation measures is based on the lifetime of that measure so both initial and ongoing costs are accounted for in the analysis.

12.3.1 Base Cost

The base cost of the resource includes only the initial incremental cost of materials and labor for the energy efficiency measure installed at the time of program participation. This cost does not include administrative costs, maintenance costs, or replacement.

12.3.2 Operation and Maintenance Costs

Sometimes there are other cash flows to be considered. For example, O&M costs are computed as the net present value and added to the initial cost before levelizing. One case might be a lighting option where tubes and ballasts are replaced on different schedules. This option would require present valuing to capture the entire cost of one lifecycle.

O&M costs include increased space heating fuel when there is a space heating interaction. An example might occur with efficient lighting. When the new lights are installed, they reduce waste heat within the building. During the cooling season, this reduction is a benefit. However during the heating season, the heating plant needs to provide additional heat. This shows up as an increase in fuel costs for gas-heated buildings or a decrease in net savings for an electrically heated one. The increased fossil fuel is treated as an O&M cost. It is valued at current retail rates and treated with an effective discount rate that includes real price escalation.

Since the measures are all different, they have different replacement schedules and costs. The analysis is also complicated by the fact that long-term financial analysis requires itemizing a stream of expenditures over a 50-year period to capture end effects. To simplify calculation of replacement costs, all the measures were put into a consistent analysis period within each program. For example, all the commercial sector measures were given replacement treatment to bring the lifetime up to 30 years, which was the life of the longest- lived measures. In the industrial sector, all measures were treated with 15-year lives. To include these programs for 50-year analysis, the cost of the commercial program is duplicated at year 31. The industrial program cost is duplicated at years 16 and 31. This analysis convention is not meant to imply that we expect all these measures to be duplicated at customer expense forever. Rather it is intended to produce a stream of expenditures consistent with the "frozen efficiency" forecast assumption. The "frozen efficiency" assumption will be reconsidered as a planning assumption in the next planning phase and thought will be directed to a more realistic market substitution scenario.

As an example of the O&M calculations consider one case, an existing small office building in Oregon. This market segment has 42% saturation of electrical heating (including 17% heat pumps) and 58% saturation of cooling. Measures that reduce internal gains have a 55% space heat interaction and a 14% cooling interaction. Overall the net savings corrected for interactions and saturations are 89%. The measures considered for the supply curve are listed in Table 22:

Table 22—Frequency of Measure Replacement for an Existing Small Office Building,**Over 30 Years**

Measure	Replacement Occurrence
Insulate roof R4>R24	0
Insulate wall R5>R24	0
Windows SG>DG	0
Low-e windows	2
Solar window film	2
Lights T12mag>T8electronic	
Tube	4
Ballast	2
Exit signs ballast	4
Incandescent> halogen	2
Daylight dimming	2
Low ambient/task lights	
Bulb	4
Fixture	2
Occupancy sensor lights	2
Economizer	2
Optimum start timer	2
Air-to-air heat exchanger	2
Air sealing	6
Resistance> heat pump	2
Efficient heat pump upgrade	2

A similar set of replacement rates are built up for all the measures in each building and each market segment. These measures are then aggregated according to the square footage estimates in the forecast. The final result is a sum representing the average NPV of O&M for the customer without specificity as to all the different measures and interactions included.

12.4 Impact on Prices

The impact that demand-side resource programs have on future general price increases is an important consideration by the company in setting priorities for resource acquisition.

Demand-side resource programs can adversely impact prices because of lost revenues. When measured on a Total Resource Cost basis, demand-side options are typically lower cost than most supply-side options. Selecting the demand-side option results in a lower total revenue requirement (and thus lower average bills for customers), but can still increase unit electricity prices. This happens because increased energy efficiency results in lower electric usage and reduced electric revenues (lost revenues) to the utility. The company relies on customer payments to meet fixed expenses, such as paying for the transmission lines or previously constructed facilities. When some customers reduce purchases through conservation, prices must increase to provide the same amount of net revenue and cover the added conservation costs. Note that total costs will go down, so customers as a whole are better off. However, the people who benefit from an individual program and those who face higher prices are not necessarily the same. While conservation participants see reduced bills, non-participants could see increased bills. This becomes the central equity issue—is everyone treated fairly?

The company focuses on reducing total cost to serve all customers, while ensuring that equity considerations are considered. Several options exist to deal with the equity issue. If the utility operates multiple large programs, there can be some benefit for all—everyone a participant in something. To some extent the utility can lower the funding requirement by finding innovative ways to package a broader service to participating customers and thus recover program costs directly. The rate impacts can also be limited to the customer class which contains the predominant beneficiaries.

Concern for equity needs to taken in context. The current rate structure, by necessity, cannot produce perfect equity. The equity impacts caused by a broad conservation acquisition program can be substantial. Thus, before implementing a mechanism to ensure equity, one needs first to assess the problem as one looks at the equity impacts of an integrated plan.

12.5 Cost Effectiveness of Energy Efficiency Measures

Cost effectiveness of an individual demand-side resource measure is determined by comparing the incremental cost of the individual measure to a cost ceiling for planning purposes.

In selecting cost-effective measures to include in programs, it is necessary to determine the upper bound on measure costs, otherwise known as the measure cost effectiveness ceiling. More energy savings can be acquired if one continues to spend money. At some point, however, the diminishing returns from conservation are no longer cost-effective compared to other resource choices. Thus, there is an effective ceiling on the cost a utility would pay for any one measure.

The cost effectiveness ceiling is based on a current estimates of conservation cost-effectiveness. At the moment, the company enjoys sufficient resources to meet customer needs. Avoided cost is low, based primarily on the variable fuel cost to serve new growth with existing resources. Around 1996, however, new resources are expected to be needed. At that time, conservation programs will be scheduled for full deployment to provide new resources. The correct program strategy is to increase programs on a ramp-up schedule to be poised for full deployment.

During the period leading up to 1996, programs are being developed to best capture opportunities. Experience will be refined through market exploration. The period also serves as a time to build capability by developing the supply infrastructure. All these efforts will be focused on refining programs to be fully deployed during a period of higher avoided costs.

12.5.1 Determining a Cost Effectiveness Ceiling

The cost ceiling was selected based on preliminary estimates of conservation cost-effectiveness expected at the end of the RAMPP-2 process. The company uses current avoided costs to assess the value of demand-side resource acquisition programs. The cost effectiveness ceiling for planning purposes is 55 mills/kWh.

The cost ceiling is also affected by the lifetime and load factor of the savings under consideration. Although 55 mills/kWh is the reference case, that number is based on an assumed average lifetime of 15 years and load factor of 60%. When measures have longer lifetimes, it is appropriate to compare to a larger ceiling representing the value over the longer term. Table 23 shows the values used in the current study to assess the impact of different conservation cutoff ceilings. The rows indicate different lifetimes. The columns indicate a different reference cutoff ceiling. Thus, for example, the commercial sector measures include replacement costs to extend lifetimes to thirty years. Therefore, the actual cutoff point for the reference case is 59 mills not the 55 mills appropriate for fifteen year measures.

Determining the appropriate cost-effective ceiling is difficult because it is a function of future resource acquisitions. Because of uncertainty about the future, the precise cost-effective ceiling cannot be calculated. Since the ceiling influences resource choices, it might be necessary to iterate until an optimal solution is calculated. In practice, the ceiling is an estimate, based avoided costs from the most likely expected future.

Table 23—Conservation Ceiling Under Alternative Conditions, 1994 Dollars

Measure Life	30 mill	40 mill	55 mill	70 mill
5	0.024	0.032	**0.044**	0.056
10	0.028	0.037	**0.051**	0.064
15	0.030	0.040	**0.055**	0.070
20	0.032	0.043	**0.057**	0.073
30	0.035	0.046	**0.059**	0.072
40	0.036	0.048	**0.062**	0.074

12.5.2 Determining Incremental Measure Cost

To determine cost effectiveness what should be included in the cost of individual measures? Should program administrative costs be added with those measures? The procedure suggested by the Northwest Power Planning Council (NPPC) where incremental measure cost is based only on the cost of the physical measure and does not include administrative costs, was assumed in this planning analysis.

Consider an example—one is trying to decide if it is cost effective to add one more inch of insulation to an attic. The additional cost will be entirely due to the cost of the material and labor to install. There are no additional trips to the site, no additional inspections, no additional paperwork. So the administrative cost is not affected by the decision. One need only consider the incremental cost and savings of adding one more inch of insulation. This is the procedure followed by the NPPC.

Exceptions to this procedure can be imagined. For example, consider a measure consisting of retrofit heat pumps. This would be an entirely new program, requiring a different set of contractors, additional inspections and paperwork. In this case, the cost of the program should be recognized in the supply curves. For current work, however, entirely new programs of this type were not seriously pursued since they were too expensive to be cost effective.

It has been suggested that administrative cost is included in the supply-side alternative which defines the cost-effective ceiling. Therefore, it should be included on demand-side as well. This argument is not entirely correct because it fails to consider the inherent "lumpiness" in making these comparisons. Consider an engineer planning a thermal resource. There are a variety of optimizing decisions to make—should one include more efficient turbines or VSD motors, for example. The engineer will chose the optimal investment for the supply-side plant following the same sort of incremental logic. Administrative cost will be added to the completed design, corresponding to treating the whole package of measures in a demand-side program. Thus, the proper comparison is between whole programs on demand side and whole resources on supply side. The cost ceiling used to test incremental measures is only a proxy to assist that process.

12.6 Supplemental Measures

Measures are funded up to the cost-effective ceiling of 55 mills (cost-effective funding). Any costs funded above this limit are considered supplemental and are funded at a higher interest rate. In RAMPP-2 there was no assumption regarding supplemental measures because there were no plans at that time to provide this type of funding. Typically for a individual measure this funding is a small percentage of the overall funding. Historically this funding has been included within the Energy Service Charge (ESC) programs to achieve a depth of savings greater than what might have been possible otherwise.

The supplemental measure funding is assumed to be 30 percent of cost-effective measures with savings representing 20 percent of the cost-effective savings. The supplemental was added to the program plan because of an identified customer need and to achieve a greater depth of savings that might not be possible otherwise. In addition, it is assumed that higher program participation rates can be achieved through offering the supplemental funding. Although no studies have yet been done to verify this, indications from participant surveys show that the availability of supplemental funding did influence their decision to participate. Supplemental funding is available through the commercial programs and is limited to residential retrofit.

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SECTION 13.0 Demand Side Program Potential

This section looks at the transition from technical potential to programmatic potential. What assumptions were made along the way? What decrements in potential occurred as a result?

13.1 Calculating Program Potential from Technical Potential

The programmatic potential is determined as follows. Begin with an estimate of technical potential by program area. Add line losses to estimate the gross savings potential. Multiply by the effective penetration rate to get gross program potential. Subtract "free riders", if any, for net program potential. Examples are shown in Table 24.

Table 24—From Technical Potential to Programmatic Potential

Sector	Technical Potential		Line Loss		Gross Potential		Effective Penetration		Gross Program		Free Riders		Net Program
Existing Commercial	233	+	10.5%	=	257	x	.77	=	198	-	34	=	164
New Commercial	255	+	10.5%	=	282	x	.59	=	167	-	49	=	118
Industrial	473	+	6%	=	501	x	.55	=	275			=	275
Existing Residential	56	+	12%	=	63	x	.32	=	20			=	20
New Residential	60	+	12%	=	67	x	.43	=	29			=	29
Appliance	374	+	12%	=	419	x	.03	=	13			=	13
Totals	1,451				1,589								619

There are some problems disaggregating the residential sector savings. The programs include space heat and appliances melded together such that separation is difficult. The example shown shows shell and appliances separated with effective penetration rates of the programs. These penetrations are slightly different from those shown in the draft program worksheets. In this table, the penetrations are energy-weighted. In the worksheets, they were based on number of participants.

Please note that in the industrial sector the estimates of free riders are implicitly imbedded into the specification of the econometric equations used to forecast energy consumption. Since the econometric models consider efficiency investments pursued by the customer, their use in forecasting future consumption also implicitly takes these actions into account, therefore there is no attempt to separately account for free riders in the supply curves.

13.2 Programmatic Supply Curve

The conservation programs need to be considered in context. There are synergies and interactions between programs. For example, operating several programs at the same time allows some overlap in staff and marketing efforts. This reduces administrative costs. On the other hand, operation of a "cream-skimming" program would prevent capturing all the potential savings. This is because, after installing the cheapest measures, it would no longer be cost-effective to go back a second time to install other measures. Thus, blocks of conservation savings cannot be added together quite like supply-side options.

Nevertheless, for illustrative purposes, Figure 42 shows the programs as if they were combined in a demand-side resource stack. The illustration gives an idea of how the programs compare in terms of magnitude. One must be careful using this programmatic supply curve because it does not address issues of timing. For example, it would appear that a program for existing residential buildings would be implemented before a program for new buildings based on cost. But the new buildings represent lost opportunities if they are ignored. Therefore, the order in which programs are implemented cannot be based merely on cost considerations. Cost differences for complete programs appear to be minor. Most of the programs are estimated to cost around 30 mills/kWh.

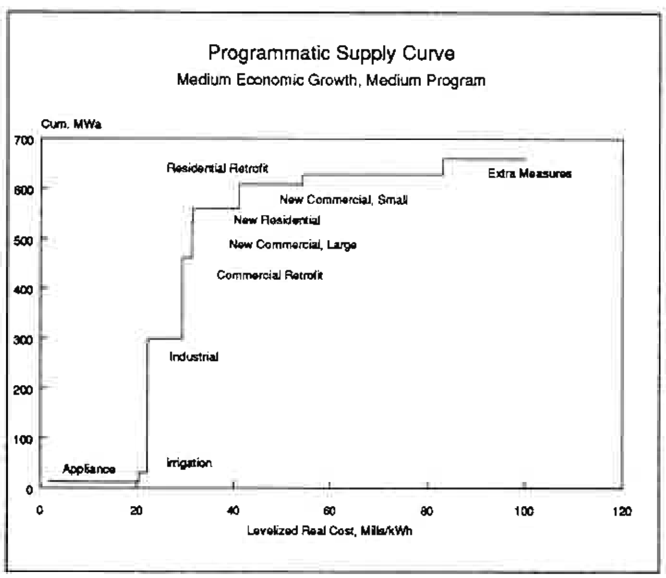

Figure 42—Demand-Side Resource Stack

SECTION 14.0 Demand Side Program Design

Over the 20 year planning horizon, DSR program design will evolve and change as the company learns more about how to efficiently and effectively deliver demand-side resources. The requirement to develop significant delivery capability means that even more programs will be offered in the future than are being offered now. Historically, the company has designed DSR programs as a package offering to the customer based on the customer needs and the opportunity for resource acquisition within the facility. In addition to packaging measures, the company will design or participate with others in offering single measures as a packaged offering. Future programs are assumed to include other appliances to consolidate and reduce costs of development and implementation through "piggybacked" operations. Program marketing will be enhanced by the increased visibility of conservation programs and consumer awareness.

14.1 Market Assessment

The company plans to continue efforts in assessing customer needs for energy efficient products and services. Future programs will be tailored to address specific market niches, which may not be defined along the traditional sectors of residential, commercial, industrial, or variations of these larger groups. In addition, the company plans to continue to design programs which overcome market barriers to participation in energy efficiency improvements, whether utility sponsored or not.

14.1.1 Market Segmentation and Target Markets

For long-term planning purposes the markets are not segmented to address specific customer needs, but rather classified by program area where opportunities for demand-side resource acquisition exist. The existing programs have typically not been highly segmented, but some efforts have been made to identify key decision makers by vertical market segment and SIC. Some segmentation also has been done in the residential sector to identify possible program participants based on lifestyle and demographic information regarding the resident. In the future, markets will need to be highly segmented in order to target customer needs and to design energy efficiency programs addressing those needs to achieve the high levels of participation assumed in the 20-year resource acquisition plan.

14.1.2 Market Barriers

Critics have wondered why the utility needs to be involved in redirecting energy investments. They suggest that the marketplace should be capable of finding its own direction through pricing mechanisms. They are reasons why this is not the case. Regulatory-controlled prices may not provide proper signals to consumers. Far more significant are major barriers and market imperfections. These barriers are partly financial, since consumers do not have access to capital at the long-term rates, which is available to utilities. In addition, there is a cost to the individual decision maker to include energy consideration in decisions that already include a number of factors. Consumers don't often consider energy decisions as investment decisions. There are costs to gather the information needed to do so. Furthermore, in many market segments, the equipment purchaser, the bill-payer and the end user are different people with very different motivations. Effective programs will be a marketing challenge. It will be necessary to understand participant's motivations and to tailor program offerings for maximum acceptance.

Another consumer problem is that only the most cost-effective purchases are likely to attract consumer interest. If consumers proceed, they may invest only in a part of the purchase. This leads to *"cream-skimming"** where only the most attractive options are considered. The danger is that other options, only slightly less attractive, might be overlooked. These other options would be cost-effective if done together, but not if a separate job is required. Thus, cream-skimming may create lost opportunities. Utility assistance can remove some of the market barriers and facilitate better conservation.

14.2 Program Measures

Each program consists of a "bundle" of conservation measures. The conservation measures were "bundled" using the following criteria:

- Each single measure, in the bundle, stands on its own cost and benefits.
- A bundle of measures is a logical group to put together.

For example, we do not bundle cost-effective high ceiling, high-intensity discharge lamps, with other lighting measures for an office building because these are not appropriate lighting techniques for offices. Our programs are designed to capture all cost-effective opportunities based on the operating characteristics of the site.

The "bundling" of measures were subject to the constraint that no single measure have a levelized cost greater than the cost-effective ceiling. This constraint prevents "luring" a program participant into an investment which cannot be justified as less costly than the alternative. Several conservation measures, such as high quality storm windows or heat pumps, will have additional value to the participant for other reasons than energy savings. In this case, the program would need to distinguish between the energy-justified and amenity-justified portions of the measure cost.

14.3 Program Implementation

Underlying the design of all programs in this planning process are the principles of minimizing lost opportunities, achieving high program participation levels in targeted segments, and ensuring equitable participation in programs by low income customers.

To address these goals, we make several overriding assumptions. Programs should specifically address the lost opportunities created in new construction or in new appliance purchases. Programs should not create lost opportunities in the course of the program operation. Lost opportunities occur when a program addresses only a few of the most cost- effective measures, leaving the less cost-effective, but still viable, measures. These measures will then be lost because they cannot justify the expense of an additional site visit.

The company is committed to assuring equal representation for low income customers. In practice, this means that the proportion of low income participants relative to all participants must be at least as great as the proportion of low income customers to all customers.

14.3.1 Delivery System

Utility sponsored DSR programs operate in a marketplace which is ever changing. This marketplace consists of several major components of the program delivery system. These include interactions between the utility, program participants (or decision makers), contractors, suppliers, government agencies and building designers. Programs targeting the new construction market must consider all these interactions, which must occur to efficiently and effectively deliver the program during program design, implementation, and operation stages. If any one element of this delivery system is not supportive, program results can be significantly reduced. Conversely, when all the delivery systems are integrated the program penetration in the market is high. The program can be successfully transformed to address more efficient end uses. At this point, the utility program may no longer be necessary.

14.3.2 Market Transformation

*Market transformation** can occur because of utility programs or other influences. A new construction code is an example of a mandated market transformation. The savings potential in market transformation lies in the fact that a change in the code can now eliminate the need for a program in the future. Other examples of market transformation occur with specific products. Near term programs may include some measures, such as efficient lighting or VSD motors, which are somewhat expensive now.

However, there is good reason to believe that significant cost reductions can result if a market for these products develops. When that happens the new products will tend to become the standard for all new installations. Thus, including some of these expensive measures in early years, may create "free" savings in later years as the market transformation takes place.

14.4 Program Cost

Program costs include incentives and program development and administration costs.

14.4.1 Administration

Planning for demand-side programs must include administrative costs as one component of the Total Resource Cost (TRC). The method used is to increase measure cost by a fixed percentage and use the resulting administration cost in the TRC calculations. Typically the cost of conservation programs is assumed to increase by 20% for administration.

The company's method of estimating program administrative costs is different. Explicit costs are estimated for each cost component identified as administration. The net increase in total resource cost is often lower than 20% for a mature demand-side program. There are several reasons for this difference.

First, the uniform percentage of added cost fails to recognize different levels of measure cost across programs. For example, residential sector measures cost more than commercial sector conservation. Thus, similar program costs in residential sector should be a smaller percentage of a larger number. On the other hand, in appliance programs the same administrative cost would be a high percentage because the measure cost is low.

Second, the assumption of high administrative cost may be true for programs in the initial stage of development. Initial programs contain large marketing and evaluation components. However, as programs become mature, the proportional share of these costs can be expected to decrease. Our long-term program planning anticipates market transformation and program synergies to occur. This means that the programs can be operated in the out years with proportionally smaller administrative outlays.

Table 25 shows the administrative cost components and total resource cost. The administrative percentage is calculated as an adder to the simple measure cost. Measure cost is not defined in precisely the same way in each program. For example, the new commercial program includes design cost as part of the measure cost. The commercial retrofit program includes audit/design work as part of the administrative adder. The residential programs include a variety of program mechanisms. Table 25 shows overhead for a weatherization program with full financing. Low income and partial loan programs would be different because the company only pays part of the measure costs.

Table 25—Long Term Program Administrative Cost

Program	Deferred Percentage	Expense Percentage
Industrial	4%	1%
New Commercial (FinAnswer-inc. Design)	38	1
New Commercial (12000)	27	1
Commercial Retrofit	20	1
Residential Retrofit	30	1
New Residential	16.5	16
Appliance	5	5
Load Control	15	5

It should be pointed out that these costs represent generalized programs for planning purposes. The actual expenditure decisions for these program areas will be determined as specific program initiatives are defined. RAMPP-3 DSR model does not assume a fixed administrative cost for all programs. The administrative cost percentage varies across the programs, it is, however, fixed over time for each program. Administrative cost is calculated as percentage of measure cost- excluding supplemental funding costs.

14.4.2 Energy Service Charge

The concept of *Energy Service Charge** is a response to equity concerns. There is an acknowledgment that non-participants should not be unnecessarily burdened. Moreover, there is recognition that conservation is a valuable service for which customers should expect to pay something. Therefore, it seems reasonable that participants should reimburse non-participants by returning a portion of their savings.

The Energy Service Charge is an additional service charge added to the billing meter. As such, it stays in place regardless of who operates the facility until it is fully paid off. This service charge has the advantage of minimizing administrative costs. The utility provides the customer with full up-front financing, offering the benefit of the utility's longer time perspective on payback. The customer retains a portion of the savings and so has a positive cash flow. The most recent design focuses on a low-interest loan approach which is repaid out of the energy savings.

14.4.3 Net Present Value (NPV) Program Multipliers

Costs of a program are calculated based on a revenue requirement model. That is, the total cost of the program must include whatever costs would show up in prices. The program costs are treated as an investment in the company's ratebase. The cost to service this investment is reflected in the prices customers will pay. Debt service is treated with the company's weighted average cost of capital, net of tax benefits. The company has determined that this cost represents an interest rate of 8.8% nominal or 5.2% real, after correcting for inflation. This interest rate is used as the discount rate in making present value calculations.

Tax considerations enter the revenue requirement in another way as well. The amount paid by customers for debt service must be increased to also cover corporate income taxes. For some programs, this results in an increase in the lifetime cost of the program. For other programs, there are tax benefits which can reduce the income tax requirement. The net program cost over a programmatic lifetime can be presented as a NPV multiplier term. The multiplier represents the amount that the cost must be increased or decreased to assure full recovery in prices. This multiplier is used in calculating the levelized cost of different programs. Some examples of the multiplier for different types of program operation are presented below in Table 26. The same NPV multiplier terms give equivalent levelized costs as using utility fixed charge rates. The fixed charge rates incorporate the same multipliers times the appropriate capital recovery factors.

The NPV multipliers have increased from those used in RAMPP-2. Federal guidelines require that the investment base for loan programs can only be amortized at the rate that the principle is repaid. Since payments in early years are primarily interest, this creates a decelerated amortization schedule. Of course, the NPV multipliers apply only to the utility investment and not to investment by the participants or third parties.

NPV multipliers are not used in development of the conservation supply curve at the measure level. This is because the program mechanism could be developed along several different paths. For that reason, a simple capital recovery factor is used for the economic screening that goes into developing an estimate of the technical potential. As programs are developed, the NPV multiplier is applied. Calculation of program cost is included in program worksheets discussed later.

Table 26—End of Year NPV Multipliers for Different Programs

Program Type	Amortization Term Years	NPV Multiplier
Deferred Expense	5	1.07938
	10	1.08531
	15	1.08987
6.5% Loan	10	1.28309
	15	1.37346

These NPV factors are applied to the "instant cost" or the sum of real expenditures. The total present value cost is computed as the sum of four components:

- (Loan investment) * (NPV multiplier)
- (Deferred expense) * (NPV multiplier)
- (Utility expense)
- (NPV of Customer cost)

The total present value cost is then annualized by multiplying the total cost times the appropriate capital recovery factor for the real discount rate and the analysis lifetime. The annualized cost is then divided by the annual energy savings achieved by the full program. The result is expressed in units of mills/kWh.

A similar calculation is provided for the levelized utility cost. For utility perspective, the customer cost is not included. Furthermore, the NPV of Energy Service Charge payments or loan payments is subtracted to provide a real present value sum of utility cost.

Utility cost net of ESC

Notice that the loan repayments do not fully compensate for all the utility costs due to taxes and other costs. The loan programs operate with the utility subsidizing the loans to bring down the interest rate. The cost of the subsidy is captured in the net present value of utility cost.

For planning purposes, programs are ranked in order of increasing TRC. TRC includes all programmatic administration costs. TRC assists planners in making rational choices based on those costs borne by society as a whole. The loan programs operate with the utility subsidizing the loans to bring down the interest rate. The cost of the subsidy is captured in the net present value of utility cost.

The 6.5% loan program is typical of some residential weatherization. The commercial and industrial loans have similar interest rates. The commercial retrofit program is expected to have higher interest rates. In this document, levelized costs are presented at several points. Levelized costs are presented for "instant" utility cost and TRC for the Long Term programs in Section 5.

14.5 Program Evaluation

The planning study is only as good as the information on which it is based. Often our knowledge is sketchy and incomplete. One of the tasks for the immediate future is to refine the planning tools and assumptions. Pilot programs serve a dual function. They allow implementation techniques to be tested. And they test assumptions about the end uses, opportunities and resource availabilities. In the next few years, conservation programs such as lost opportunity programs, include an explicit evaluation component for refining planning assumptions and implementation details.

14.5.1 Quality Control

Process and impact evaluations are planned for all existing DSR programs. Results from past evaluation work has provided insights into improving the quality of program operation and measure installation.

*Commissioning** is one of the tools used by the company to assure prolonged delivery of energy savings from the energy conservation measures. Commissioning is a set of procedures, responsibilities and methods involved in advancing a total system from a state of static installation to an integrated state of full working order in accordance with the design intent. At the same time, the building operating staff is instructed in system operations and maintenance.

Building commissioning is a process which occurs after measure installation and building occupancy, where measures are checked and tested through spot measurements to determine if they were installed properly and are operating according to manufacturer specifications. The company currently includes this service as part of its large new commercial building program, where savings are significant and the opportunity for a degradation in savings is high because of improper installation and/or building operation.

The current experience from Energy FinAnswer program shows that commissioning costs are 6% of measure costs- Energy FinAnswer evaluation 1992. In the planning assumptions for the FinAnswer program we have added 6 percent to the measure cost for commissioning activities. The costs associated with training and education of the building operator are included within the program costs associated with commissioning and verification. On-going costs associated with retraining were not included. We would be willing to consider inclusion of an assumption for RAMPP-4 and would look forward to guidance in this area as to an appropriate assumption to use.

The long-term plan assumes that once measures are installed and the building is occupied, savings persist over the life of the measures. Over time, costs are incurred by the customer to maintain and operate their building to the specified energy efficiency level. The company plans to assure that savings persist over the life of the building through a one-time building commissioning at completion of program participation, and by supporting educational efforts to train building maintenance personnel in proper building operation to ensure that savings persist.

These efforts will continue in the future.

14.5.2 Program Improvement

Demand-side programs are, by nature, diffuse. They involve thousands of independent actions. Program plans operate on fundamental assumptions of penetration rates, physical barriers and costs. The achievement of cost and penetration targets will require an explicit and timely evaluation component. Evaluation must be closely enough integrated with program operations and planning that it can accomplish the following:

1. Establish work and materials specifications updated yearly.

2. Provide monthly tracking reports on program progress vis-a-vis program plans.

3. Provide the capability for program evolution, mid course corrections, trouble shooting and general problem solving.

4. Establish an impact evaluation methodology and associated databases for credible yearly certification of program outputs.

5. Provide a yearly process evaluation with respect to general program effectiveness and participant satisfaction and motivation.

6. Identify marketable spin-off opportunities.

7. Provide feedback on demand-side planning assumptions.

14.5.3 Cost Control

A large demand-side program will involve hundreds of thousands of small transactions. There is potential for significant cost savings through economies of scale. On the other hand, there is potential for cost overruns through inadequate program oversight or planning. A primary cost control check lies in an explicit evaluation component in each program. Evaluation tracks cost-effectiveness and actively guides the evolution of improved effectiveness. Anticipating a high level of program activity mandates consideration of several cost control issues early in the design phase.

Some program areas, notably residential weatherization and retrofit lighting, will involve hundreds of thousands of replications. Learning curve theory suggests that the costs can be reduced after the first large number of initial projects. However, experience with crash programs does not show a price reduction when programs are forced into production at a high rate. Programs can access learning curve price reduction by careful attention to the bidding structure and to an ongoing program evaluation/improvement component.

Some program areas, notably residential weatherization and retrofit lighting, will involve hundreds of thousands of replications. Learning curve theory suggests that the costs can be reduced after the first large number of initial projects. However, experience with crash programs does not show a price reduction when programs are forced into production at a high rate. Programs can access learning curve price reduction by careful attention to the bidding structure and to an ongoing program evaluation/improvement component.

Program Cost-Effectiveness and Supplemental measure Costs

Program cost effectiveness also includes the cost of supplemental measures. The calculations for the commercial sector is presented here. Cost and savings from the supplemental measures is estimated as a percentage of estimated cost and savings of the cost-effective measures. Percentage adjustment is based on 1991, 1992 FinAnswer program evaluation results, and expected level of funding for supplemental measures over long term.

SMC = CMC * 0.30

SMS = CMS * 0.20

Where:

- SMC is the supplemental measures cost per square feet.
- CMC is cost-effective measures, bundled on a cost per square feet.
- SMS is the supplemental measures savings per square feet.
- CMS is cost-effective measures savings per square feet.
- 0.30 is the expected ratio of supplemental costs to cost effective costs.
- 0.20 is expected ratio of savings from supplemental measures to savings from cost-effective measures.

Costs and benefits used in the TRC are based on the costs for cost-effective measures and supplemental measures.

TMC = CMC * 1.3

*TMS = CMS * 1.2*

Where:

- TMC is total cost per square feet.
- TMS is total savings per square feet.

Program screening estimates the cost for total program including the supplemental and cost-effective measures.

SECTION 15.0 Demand Side Program Ramp Rate

Program planning proceeding from the technical potential estimate begins with an overview perspective on the entire level of program activity. This perspective can improve program efficiency by minimizing redundancy and maximizing helpful program interactions. The necessity for multi-year program planning is reinforced by program developments and ramp-up requirements of about 5 years for most programs.

Most programs operate in an environment dominated by yearly construction cycles. The full effect of any particular incentive or other program feature will require more than one yearly cycle to be integrated into the plans of the prospective participants. Program efficiencies associated with cumulative program recognition or with increased operation efficiencies will be evident only after program operation of at least three years.

Timing of these programs deserves special mention. It is assumed for the purpose of this scenario that developmental and lost opportunity programs begin immediately. The other programs represent optional or schedulable conservation. Although additional programs can be started earlier to provide flexibility, the acquisition phase will be implemented only when new resources are needed and when any cheaper resources have already been utilized. One of the outcomes of this planning process will be to define the extent that a full range of lost opportunities can now be undertaken consistent with prudent business practice given the current financial and operating environment.

Figure 43 shows the conservation supply curve for the medium growth scenario. The determination of the timing for schedulable resources will be an outcome from the later integration phase of the Least Cost Plan.

The company is committed to pursue the most cost-effective DSR options as compared to other resource options. We expect that both new and existing initiatives would strive to meet or exceed the internal standards. If additional DSR resources can be identified which meet the internal standards, the company will pursue them.

There are several alternative strategies to deal with risk. In order to be prepared to deliver large scale acquisition when needed, the company recognizes the need to capability build. Capability building means that initiatives are tried in advance of need. During 1993-1996 we are actively building capability in all sectors. These efforts will allow us to be poised for full deployment when the resource is required or to delay if the need does not arise. Either way, the strategy is one of being prepared by testing the market before full acquisition is needed.

In program planning capability building is recognized as a strategy to manage uncertainty and risk. The planned programs focus on lost opportunities and testing of schedulable demand-side resource acquisition. If growth is expected to be high, all programs would be ramped into full-scale acquisition. If growth is expected to be medium, only the relatively low-cost programs would proceed. If growth is expected to be low, conservation would continue to be ar lower levels. Figure 44 is an example of program ramp rate.

The lost opportunity/developmental phase makes use of the current surplus to develop capability. Figure 44 illustrates this concept. The goal is to create cost-effective program options which can be applied later during the acquisition phase. These programs also show the power of the market transformation where efficient new construction continues to deliver conservation even after the utility program has ended.

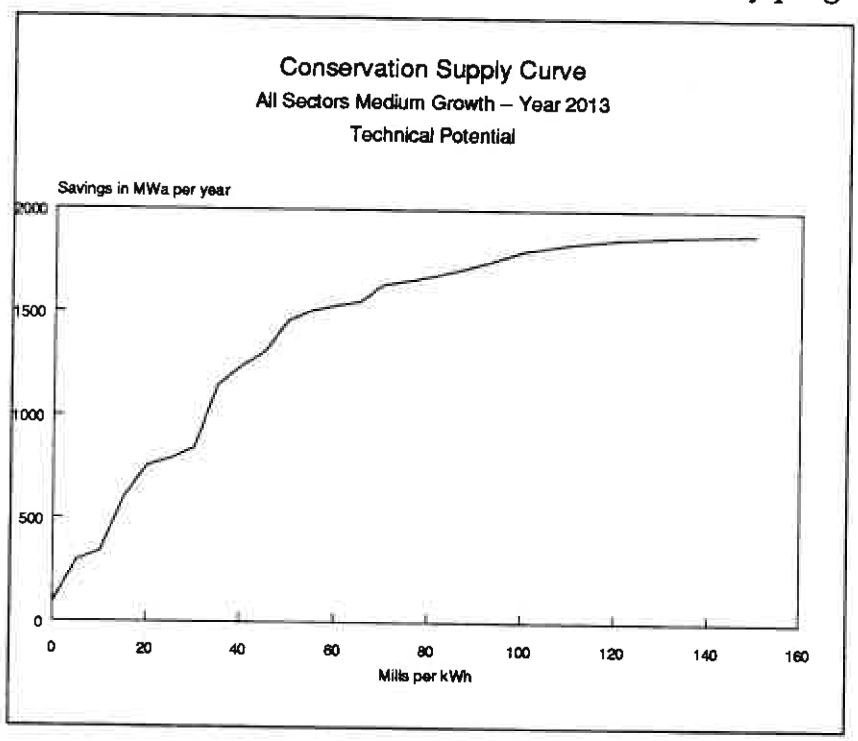

Figure 43—Demand-Side Resource Supply Curve for All Resources

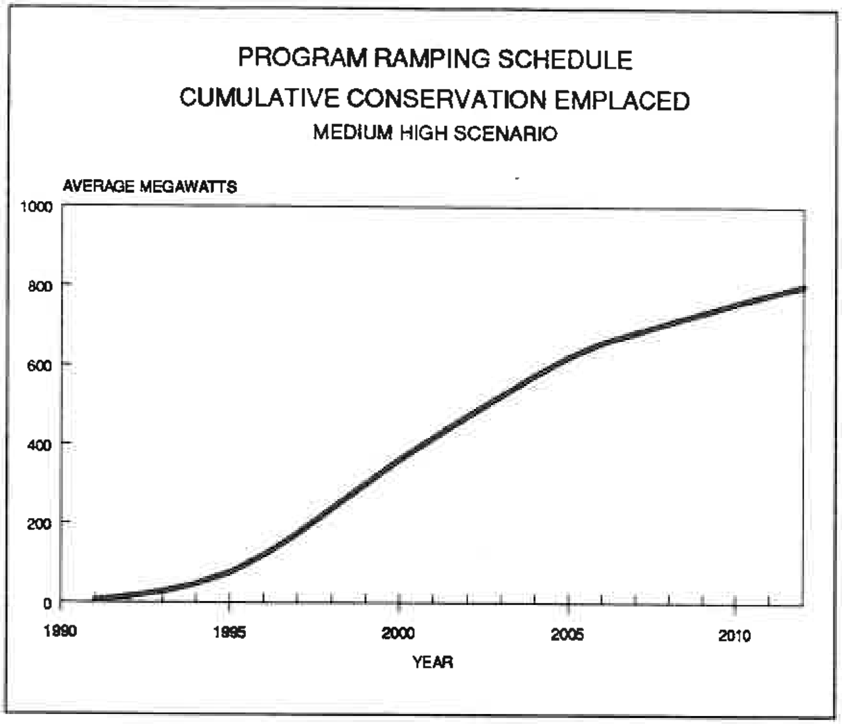

Figure 44—Demand-Side Resourcese Combined Ramp Rate

15.1 "Unconstrained" Run

For RAMPP-3, a new approach was conducted to assist development of ramp-up rates. The integration model was run in an "unconstrained" mode wherein the model selected the optimum program timing without consideration of logistic constraints. Of course, the result was not a realistic program implementation. However, the result provides some guidance for when resources should be available for full deployment. The program planning step then attempted to provide a ramp-up which would match the "unconstrained" resource selection within the limits of practicality.

Several program options were developed to investigate the impact of different ramp rates and program strategies. Those options were :

- MD Medium DSR rate, base case
- AD Accelerated DSR rate
- HD High DSR
- LD Low DSR
- A2 Second Accelerated Rate suggested by the Advisory Group

15.2 Logistic Constraints

Conservation programs are often thought to have a short lead time, able to be started and stopped as desired. In fact, there are constraints. Conservation is dependent on the perspectives of consumers, equipment suppliers and others. The programs will not succeed if programs are changed too often. Contractors cannot stay in business if program rates vary excessively. Thus, there are minimum viable levels necessary to maintain programs in an operational mode.

At the other extreme, there are constraints on how rapidly a large-scale program can be deployed. Suitable personnel need to be trained. Administrative costs may be difficult to control as programs become larger and more complex. Generally, higher programs rates will cost more. Thus, there is a maximum ramp up rate as well. Somehow the programs need to be managed so that the industry stays viable during the surplus. Then the industry needs to be sufficiently developed for ramp up when the surplus ends.

Assume, for illustrative purposes, that a decision is made to achieve all available conservation by about the year 2000. It takes several years to build up to a high level. Even at the maximum rate, it takes years to complete full acquisition. Much of the work during the first five years can be done in advance and then banked for a later decision on ramp up. Additional flexibility can come through spreading the major acquisition phase over longer or shorter time periods, although this may have some impact on unit costs.

SECTION 16.0 Demand Side Program Options

To integrate the demand-side resource measures with the supply-side options for IRP model integration runs, the DSR measures must be "bundled" into program options. For integrated resource planning purposes the company "bundles" these program options into the categories shown in Table 27.

Table 27—Program Categories

PROGRAM AREA
New Residential Construction
Residential Retrofit - Non-Low Income
Residential Retrofit - Low Income
Residential Appliances
Water Heater Load Control
New Commercial Construction
Commercial Retrofit
Industrial

These categories have been defined to capture the logical segments of customer types/applications in the market. Specific DSR programs currently offered by PacifiCorp such as Super Good Cents, MAP, or Energy FinAnswer, will likely evolve into new or revised programs or may not exist at some future point over the 20 year planning horizon. Therefore, the company has chosen the categories identified in Table 28 because programs offered to these customers will change over time, but these category names remain representative of the market sector target for DSR acquisition.

A brief summary of each program is given below. A detailed program description including year by year cost and yield estimates is provided in the next section.

Table 28—Summary Results

PROGRAM "Bundle"	UNIT TARGET		RESOURCE YIELD (1994-2013) MWa	REAL LEVELIZED COST (mills/kWh)		PROGRAM COST Millions, 94$	KEY PROGRAM FEATURES
	UNITS	DEFINITION	Include. T&D	TRC	UTILITY		
Appliance Retrofit	300,000	Homes	13	7	37	53	Lights, appliances in homes without electric space heat
Residential Retrofit	155,000	Homes	20	54	30	82	Weatherization cost sharing with customer via the ESC
Industrial	300	Facilities	275	23	5	388	Provide Technical Assistance Measure Financing
New Commercial	76,000	Buildings	118	33	17	236	Lost Opportunity Measure Financing
New Residential	176,000	Homes	29	31	12	53	Incremental above Model Conservation Standards
Commercial Retrofit	43,000	Buildings	164	29	8	417	Cost sharing via the ESC Measure Financing
Total			619	28	10	1,229	

A set of programs representing different ramp rates was assembled. The combinations of program alternatives that are included in each scenario are listed in Table 29 below.

Table 29—Demand-Side Resource Scenarios

DSR	APPLIANCES				RESIDENTIAL WEATHERIZATION								
SCENARIO	U	L	M	H	U	L	M	H	U				
Unconstrained	X				X				X				
Medium DSR			X				X				X		
Accelerated DSR			X				X					X	
High DSR				X				X					X
Low DSR		X				X				X			
Minimum DSR						X							

DSR	INDUSTRIAL			COMMERCIAL RETROFIT			NEW RESIDENTIAL CONSTRUCTION	LOAD CONTROL
SCENARIO	L	M	A	L	M	H	M	M
U		X			X		X	X
MD		X			X		X	X
AD			X		X		X	X
HD			X			X	X	X
LD	X			X				
MIN. DSR								

Definitions
HEADINGS: U=Unconstrained, M=Medium, A=Accelerated, H=High, L=Low.
WITHIN TABLE: X=Model Run

The sum of these programs is shown for five economic growth scenarios in Figure 45. In this case, each of the programs includes a medium level of demand-side resources although the economic forecast varies. During the planning study, alternative ramping rates and schedules were considered as well.

Figure 46 compares these alternatives for the medium economic growth case. The "unconstrained" case was discussed previously. It represents a hypothetical case used for planning purposes to determine that the proposed schedule fits within optimum parameters. However, the unconstrained case is not practical due to logistical constraints in mounting a large program over a short time interval.

The programs can be divided into lost opportunities, which depend primarily on the economic growth assumed, and scheduled programs, for which the ramp rate can be timed to the desired acquisition date. Lost opportunities under the five economic scenarios are shown in Figure 47. Schedulable program ramping is shown in Figure 48.

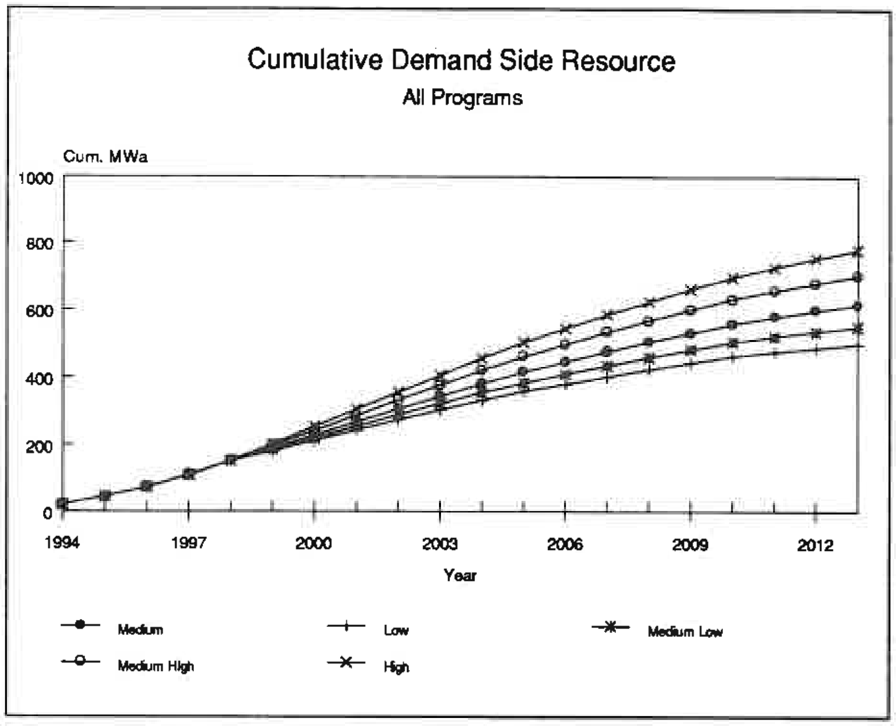

Figure 45—Cumulative Demand Side Resources, All Programs

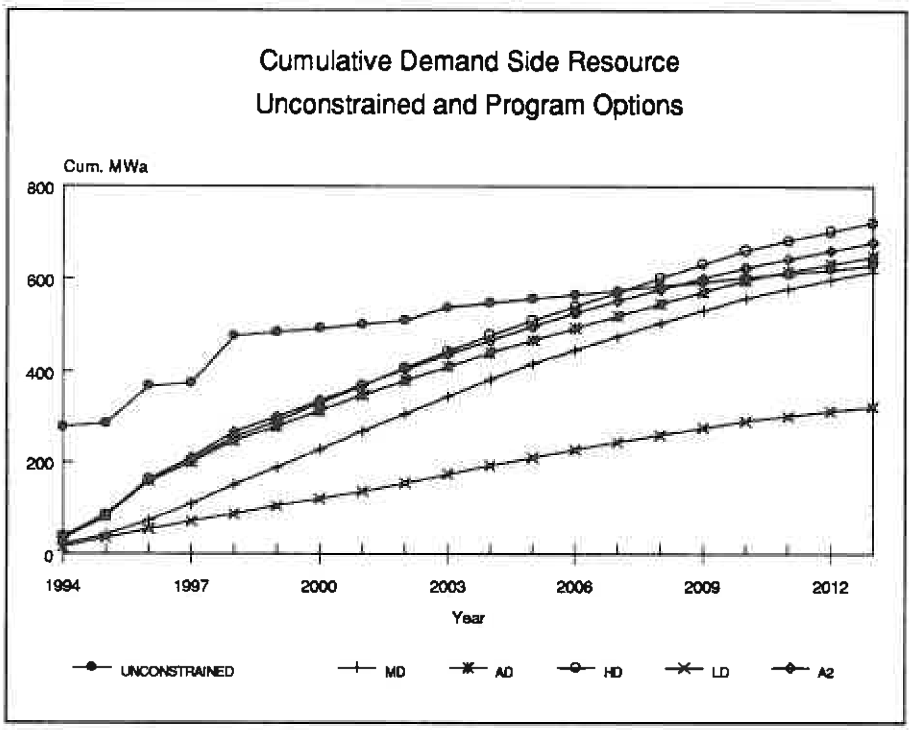

Figure 46—Cumulative Demand Side Resources, Unconstrained and Other Programs Options

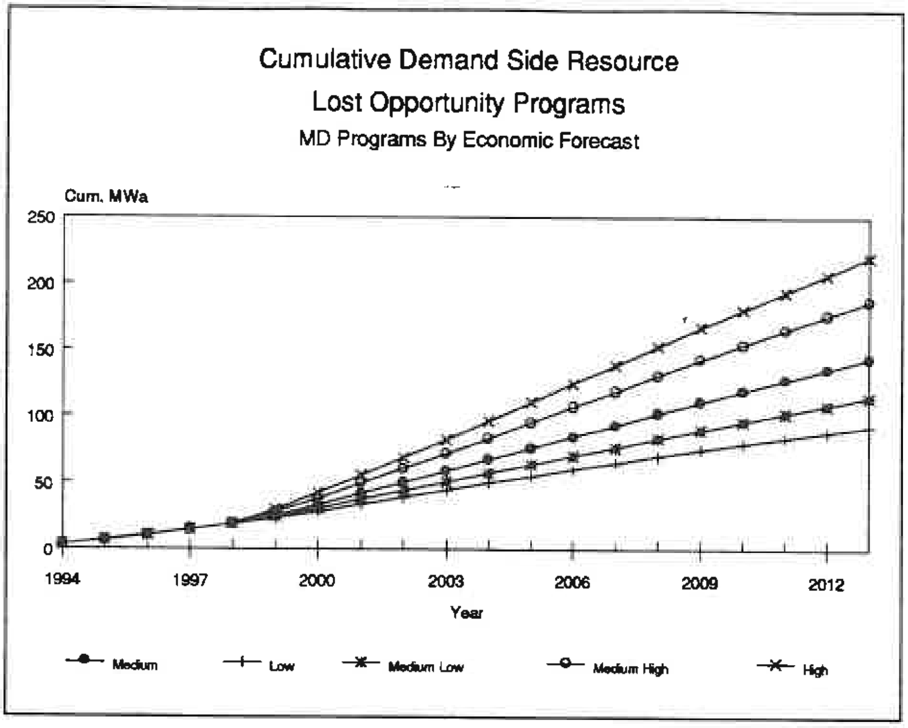

Figure 47—Cumulative Demand-Side Resource, Lost Opportunity Programs

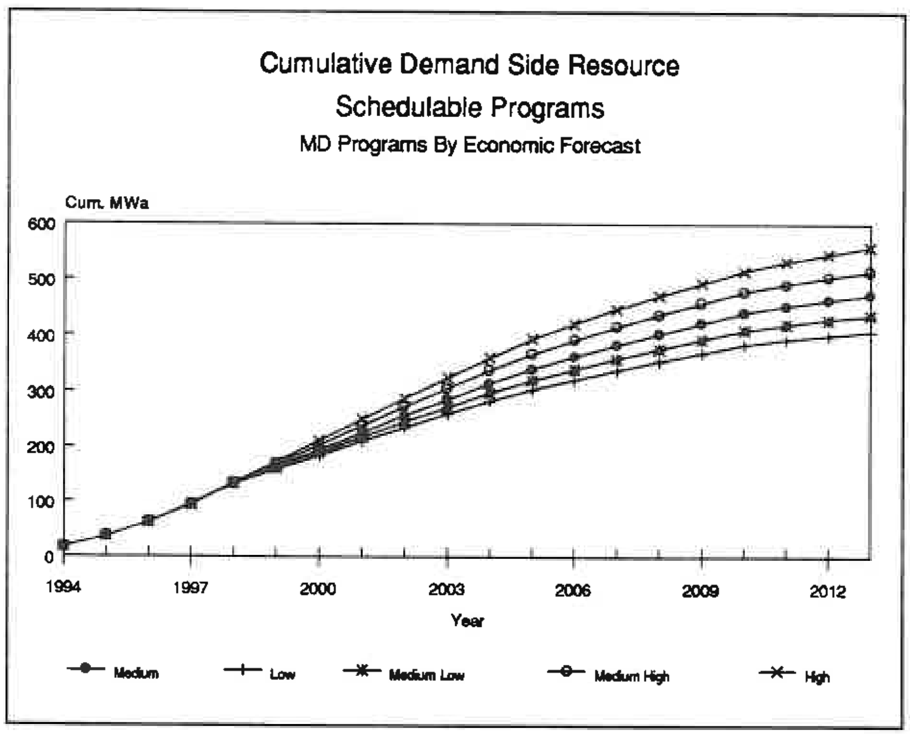

Figure 48— Cumulative Demand-Side Resource, Scheduable Programs

16.1 Residential Retrofit Program, Including the Low Income Component

This program targets residential retrofit in primarily Oregon, Washington, Idaho, Montana, and California. The program includes a low-income component to maintain equity in offering of weatherization services as mandated by several state jurisdictions in which the company serves.

The existing weatherization retrofit programs cover several markets. The low income component operates in all states except Wyoming and takes advantage of potential cost-sharing opportunities from other agencies. One of the residential weatherization programs is already operating in Washington and California. Several program concepts will be piloted in Oregon and launched in 1994. As residential programs are developed, they will absorb the existing loan and rebate programs under their umbrella. Together, both components maintain and strengthen residential retrofit capability by supporting a broad community cost share low-income weatherization program and by piloting a positive cash flow program to other customers.

16.1.1 Assumptions

The low income component would produce low income participation by offering $1200 toward the costs of full weatherization to be matched by other funding sources. An additional low-income program will seek contractors using a bidding process.

16.1.2 Plan Outline

The Washington pilot would test a "energy service charge" repayment of a low-interest loan against the meter of the weatherized home to secure the customer's cost share. This arrangement has no up-front cost to the customer and may represent a significant utility cost reduction to customers with high electric heating use. The pilot will maximize program benefits during early development stages. As the program develops, it will rely more on third-party financing arranged through the utility. Development will focus on improved tools and procedures to improve the ability to accurately estimate savings, manage installations and supervise the program.

Important research questions include verifying planning assumptions and the delivery mechanism. The company's previous experience consists of the Hood River Program. This program operated successfully but not cost-effectively. It remains to be seen how such a program can be managed to deal with all the logistics, management and coordination problems efficiently. In addition, the ability to successfully persuade customers to participate in large numbers needs to be tested.

The pilot program will operate initially in Washington and California. The Washington program anticipates delivering a free home energy audit and some simple conservation measures (low flow shower head). Half the recipients are targeted to accept a full weatherization package with company-provided financing. Program amounts assuming the medium program level are shown for the economic growth scenarios in

Figure 49. Since the program relies on existing building stock there is no difference due to economic growth. Alternative program levels for the medium economic growth case are shown in Figure 50. There is no difference between the medium and accelerated program alternatives.

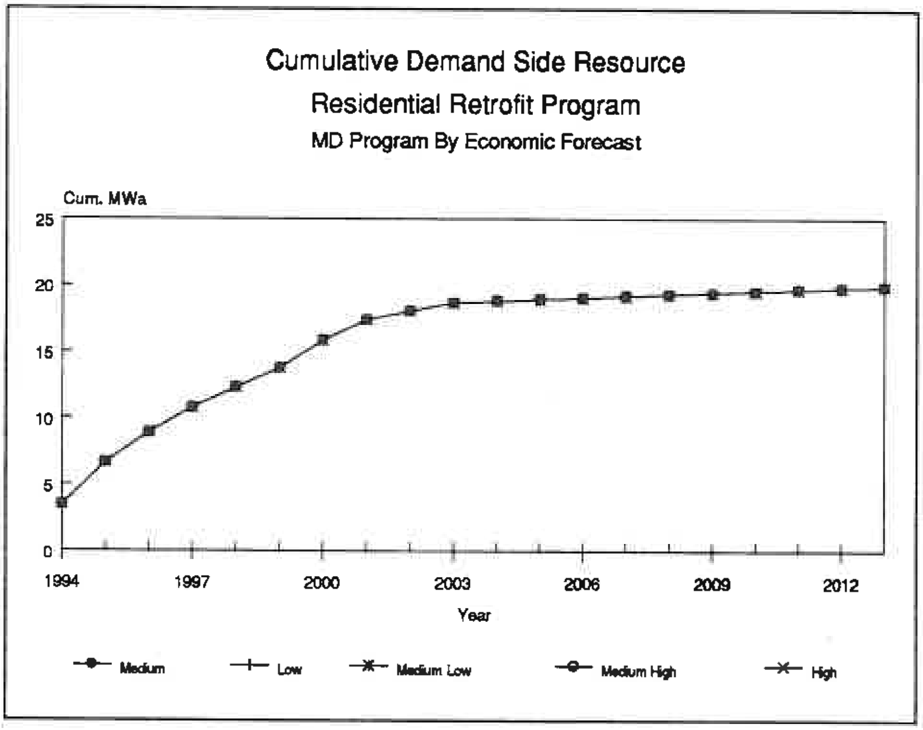

Figure 49— Cumulative Demand-Side Resource, Residential Retrofit

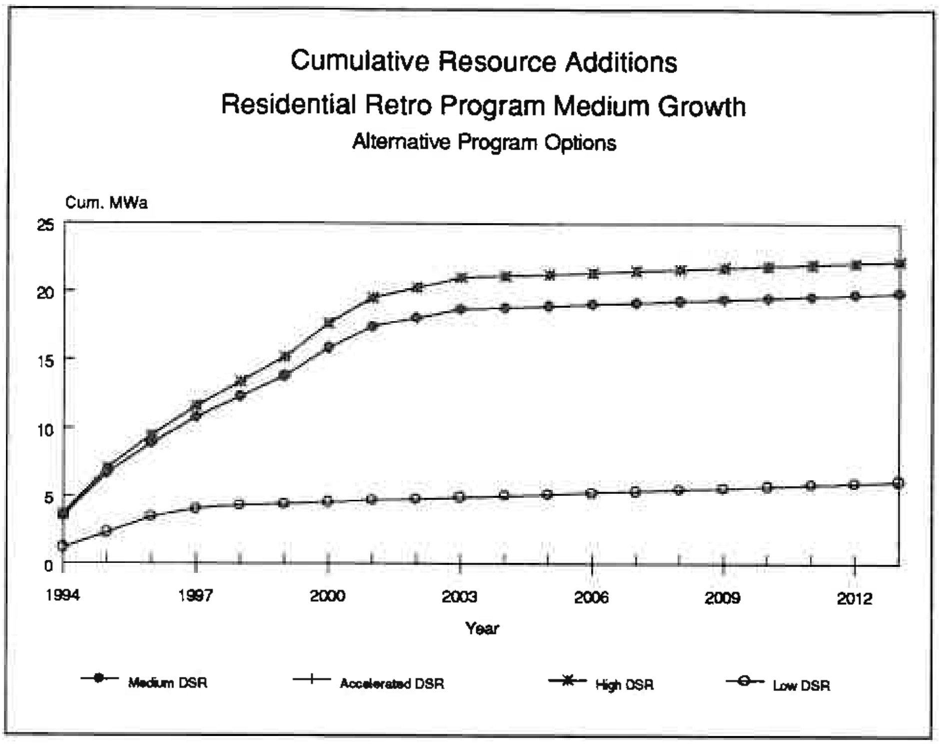

Figure 50—Cumulative Resource Additions, Residential Retrofit

16.2 New Residential Construction

This program, run from 1994 on, addresses lost opportunities by accelerating the efficiency transformation in new residential construction.

The New Residential Construction program targets electrically heated single and multi-family units constructed over the 20 year planning horizon. A Long Term Super Good Cents type program is being planned to continue to capture cost-effective opportunities beyond current building codes. The Long Term Program is enhanced to include solar orientation and daylighting. Emphasis is placed on transforming the new residential construction market to more efficient standards and increasing energy efficiency awareness of the home buyer for the 1990s.

The manufactured home component is addressed by supporting the Residential Manufactured Home Acquisition program (MAP). Under this program, utilities in the region would pay an incentive to manufacturers for efficient units. Manufacturers would change assembly practices so that all units are efficient. Because the incentive is paid at the manufacture level before dealer's markup costs, it achieves high impact with minimal cost. The strength of this demonstration program is expected to drive the HUD standards process, minimizing utility costs in the long term. This program has been assumed in the forecast since it affects all the appropriate housing stock. Consequently, it is not available as a potential resource program.

16.2.1 Assumptions

Program activity is dictated by the economic growth assumed. Penetration targets are expected to ramp up rapidly to high levels. See Table 30. The Long Term program, following new building codes, will have a more difficult time reaching high penetration targets. Please note that the penetration rates presented below are use the total number of new homes built between 1994 and 2013 as their denominator. Further detail on the year by year penetration rates is presented in appendix H page H-34.

Table 30—Long Term Super Good Cents Penetration Rate Assumptions

Medium Growth Scenario

	1994	1995	1996	1997	1998	1999	2000	2001	2013
% Program Penetration	0.5%	1.1%	1.8%	2.5%	3.4%	4.4%	5.7%	7.2%	26%

There are no alternative program designs planned as shown in Figure 51.

16.2.2 Plan Outline

Program resources under the economic growth scenarios are shown in Figure 52.

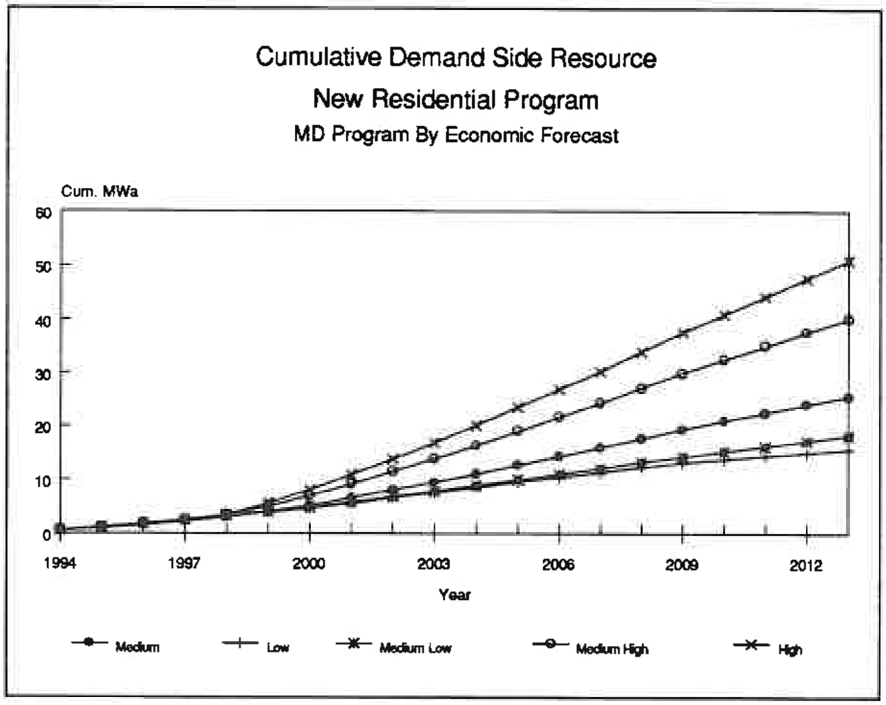

Figure 51—Cumulative Demand-Side Resource, New Residential Program

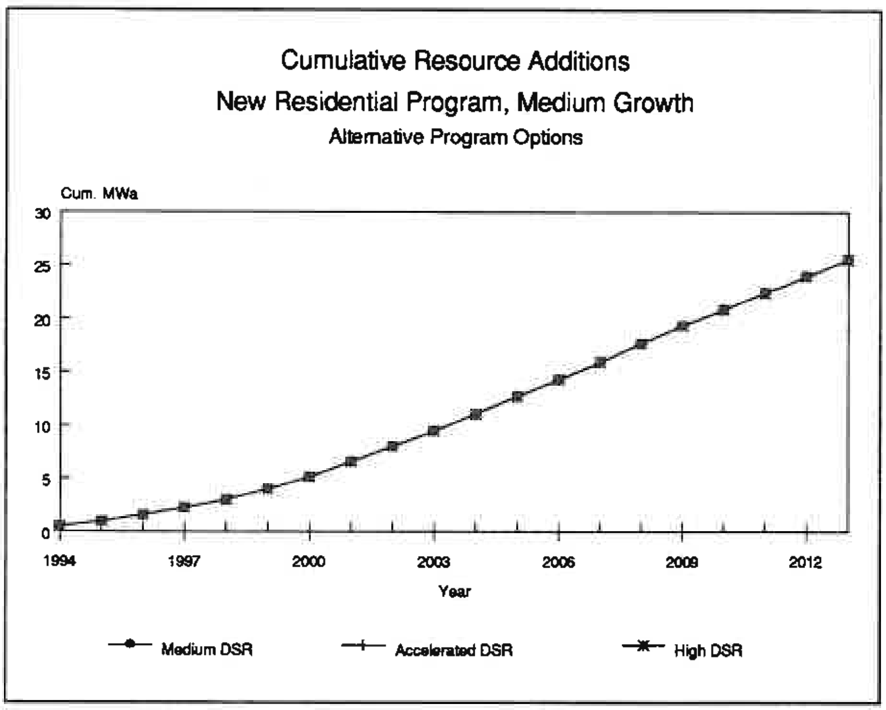

Figure 52— Cumulative Resource Additions, New Residential Program

16.3 Appliances

This program, run as an acquisition program in the late 1990s, is expected to have a high community profile.

As a retrofit measure, it targets customers who can benefit from compact fluorescent lighting, a water heater wrap and/or improved shower fixtures. This program develops or purchases in bulk high quality products and installs them with trained personnel.

16.3.1 Assumptions

The customer's 50% cost share (about $30) would be recovered through a one time charge. Financing for other measure offerings, such as solar water heaters, can be included for appropriate family sizes and in appropriate climate zones.

16.3.2 Plan Outline

The amount of savings from this program is small, although the cost is low. This program reaches a large number of customers, including those without electric space heat, but savings per home are small. Delay means that there are fewer untreated appliances for the program to address. This is because the older appliances are being retired and replaced with more modern ones. Program resource under the economic growth scenarios assuming a medium program level is shown in Figure 53. Alternative programs for the medium economic growth case are shown in Figure 54. The medium and accelerated cases are the same.

This program has the potential to be expanded to include other types of appliances. A large technical potential has been identified for the appliance sector. Unfortunately, the efficient appliances assumed for the supply curves are not yet available in large numbers on the local market. It is expected that ideas for an appliance program will be refined as more information becomes available. For that reason, this program may be more appropriately viewed as a place-holder for new appliance ideas.

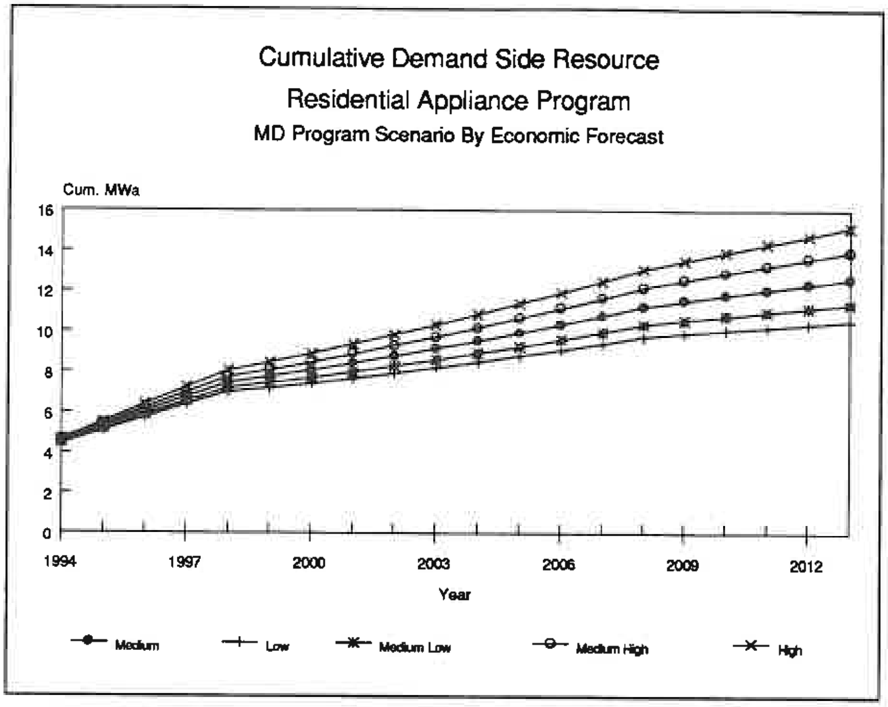

Figure 53—Cumulative Demand-Side Resource, Residential Appliance Program

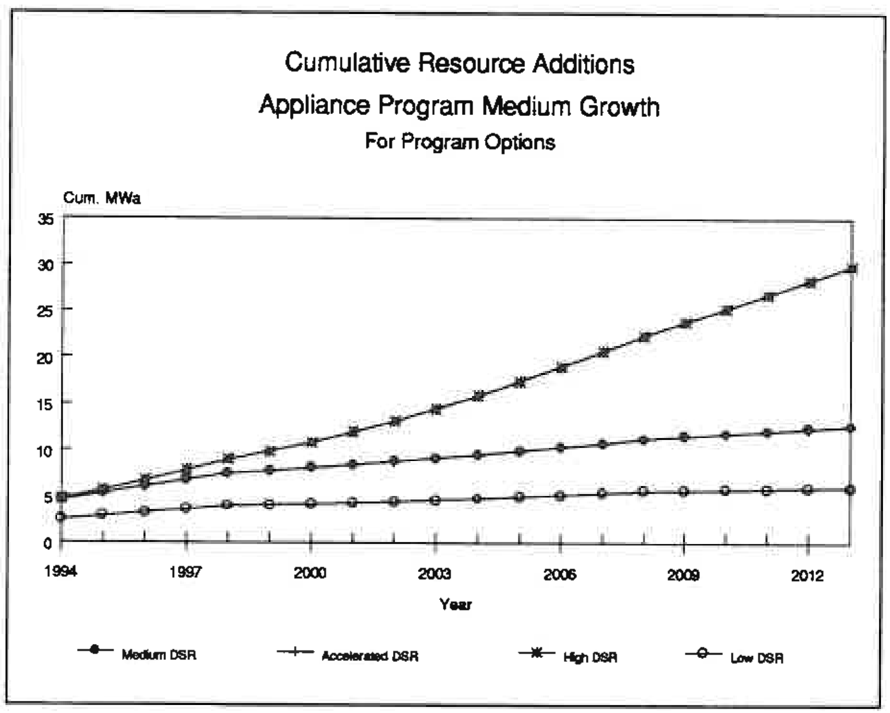

Figure 54—Cumulative Demand-Side Resource, Residential Appliance Program

16.4 Commercial Retrofit

This program would run five years prior to the estimated need for acquisition starting in 1994. A program will start by targeting large urban office buildings for maximum program gain. The retrofit of a major portion of the commercial space tests the viability of accessing a broad spectrum of commercial customers. This development effort also helps to validate or refine Pacific's least cost planning model for the commercial sector. As experience is gained, the program will be expanded to aid other offerings with a prescriptive approach for small buildings available.

16.4.1 Assumptions

Program starts in 1994. The retrofits will be on the basis of a low interest loan secured by an "energy service charge" on the meter. This pilot also develops the capability for audit and quality control management of a commercial retrofit program. An associated objective of this pilot will be to assure that retrofit lighting is superior to original in terms of quality and function and to explore the viability of a separate business service associated with advanced lighting technology and energy-related O&M services. A critical development task will be building the technical and managerial tools needed for large-scale deployment. The mature program must provide low-cost auditing, installation supervision and savings verification for thousands of small jobs. Development of these program components requires some time during early ramp-up.

16.4.2 Plan Outline

Program activity is similar in all the economic growth scenarios. Resource amounts under the economic scenarios assuming a medium level program are shown in Figure 55. Since the program relies on existing building stock there is no difference between economic growth scenarios. Alternative program levels for the medium economic growth case are shown in Figure 56.

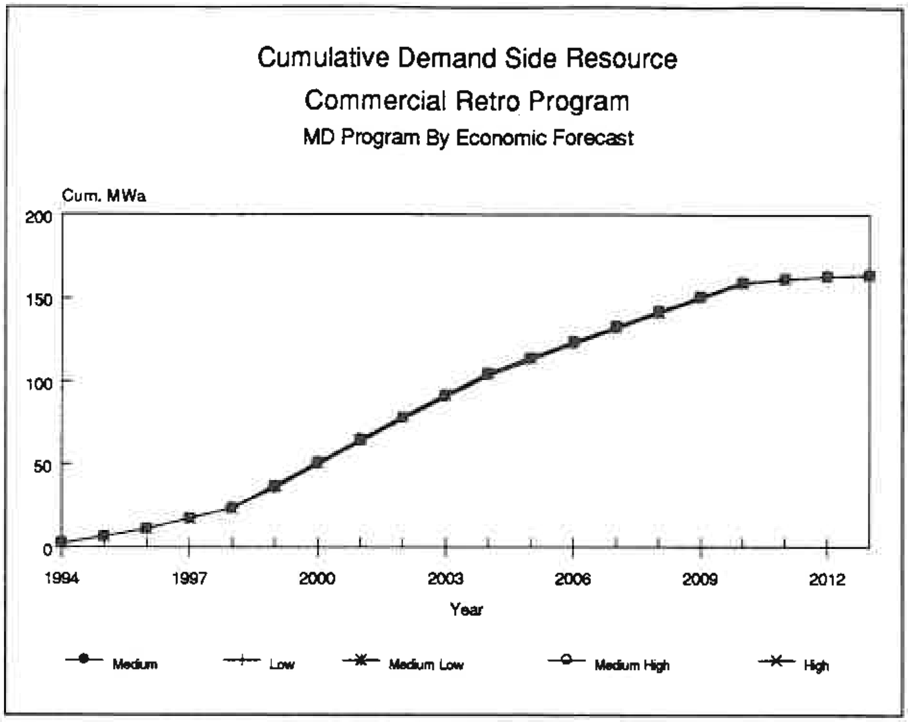

Figure 55—Demand-Side Resource, Commercial Retrofit Program

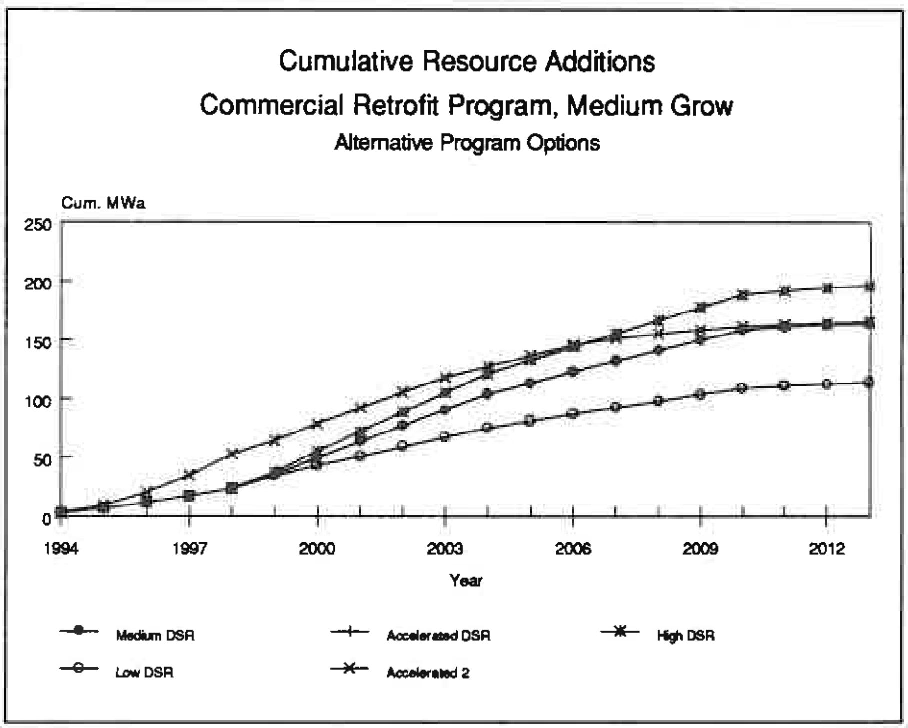

Figure 56—Cumulative Resources Additions, Commercial Retrofit

16.5 New Commercial Construction

This program, run from 1994 on, addresses lost opportunities by accelerating the energy efficiency transformation in new commercial construction. The program design is broken into a large commercial segment and a small commercial segment, similar to the existing program offerings—Energy FinAnswer for large buildings and FinAnswer 12,000 for smaller buildings. The program is highly flexible, permitting a variety of measures to be considered.

16.5.1 Assumptions

In this long-term plan, this program segment includes major remodels. Under the large building program, a design incentive of approximately $.20/sq.ft. and installation financing of approximately $1.00/sq. ft. are offered to qualifying new commercial construction.

Financing assistance is the primary incentive for participants. The program design anticipates that ESC utility financing will evolve such that a significant amount of the resource will be captured using third party financing.

For small buildings, there is a prescriptive measure offering which minimizes administration while capturing the most important resource opportunities.

16.5.2 Plan Outline

The supply, design and economic development communities are intensively networked to identify eligible projects and to reinforce the market transformation. Emphasis on this market transformation is essential to establishing the base of experience and consensus necessary for an improved commercial code. Even with a market transformation, the commercial MCS code upgrade scheduled for 1994 is expected to capture only about 40% of the identified technical potential. This is because of the technical complexities of implementing a commercial code. The remaining savings are expected to be cost effective enough to justify a long term program in the 1995-2013 time period, with the utility's role and incentive levels to be defined on the basis of the actual realized code.

Program activity level is primarily a function of the economic growth assumed, since the program ramps up rapidly to target 85% penetration. Program resource under the five economic scenarios is shown in Figure 57. Program alternatives under the medium economic growth scenario are shown in Figure 58.

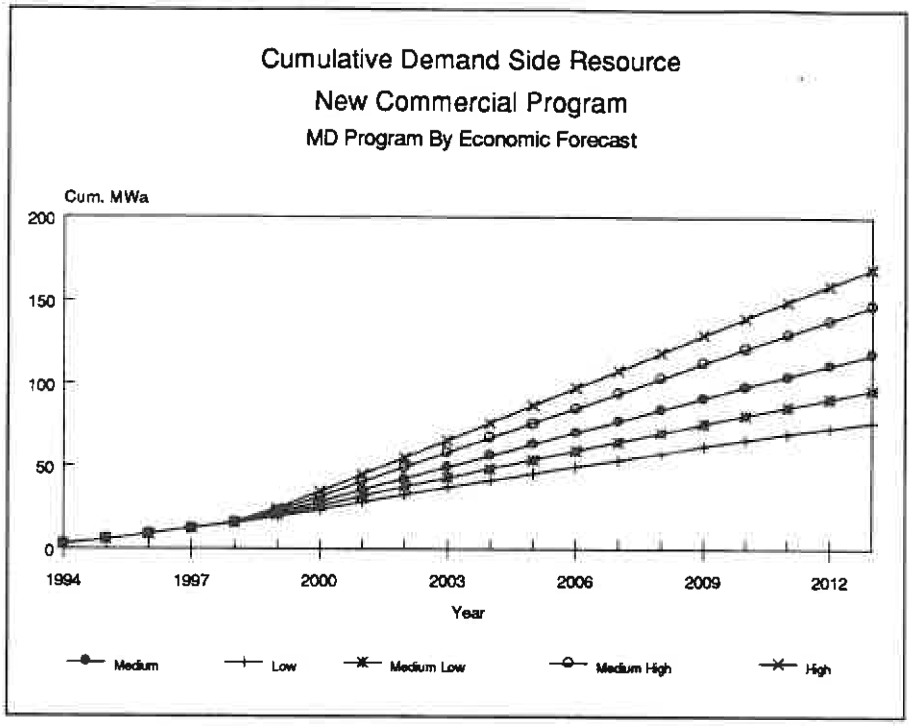

Figure 57—Demand-Side Resource, New Commercial Program

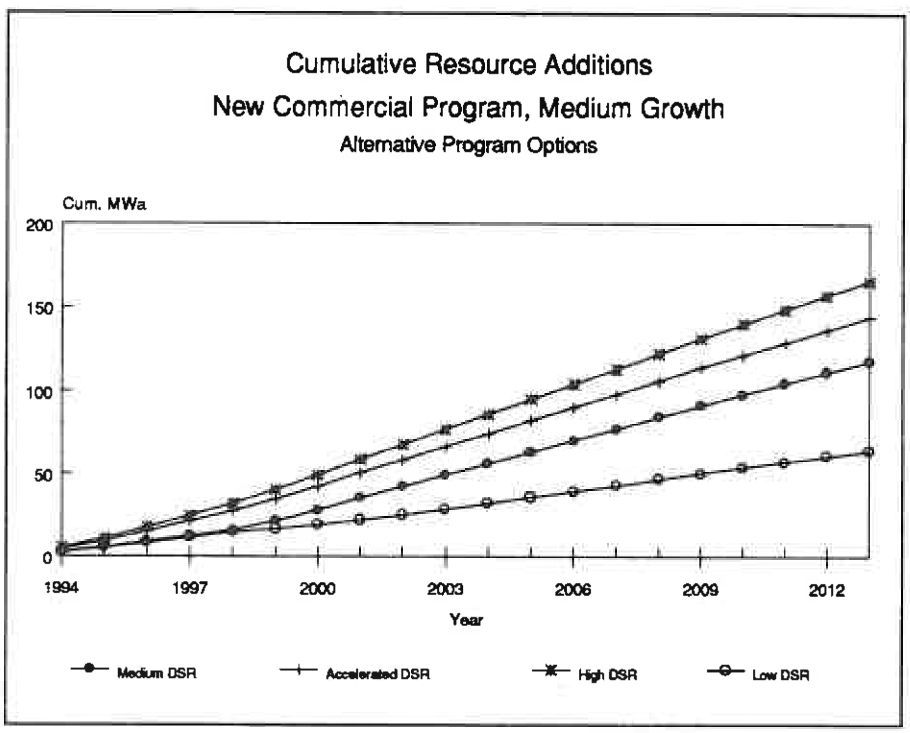

Figure 58—Cumulative Resource Additions, New Commercial Program

16.6 Industrial Program

This program seeks to build a strong liaison between the company and industrial customers. The company's current economic development role in new industrial includes the financing of electrical efficiency measures. The program tests and refines the "energy service charge" mechanism to implement a cost share relationship with the customer providing measure funding.

This program will provide funding assistance and engineering studies for electric energy efficiency improvements. Participants will receive non-energy benefits such as improvements in production processes. The program will develop a series of horizontal program offerings for industrial niche areas. Examples might include air compressor efficiency, lighting and HVAC, or efficient motors. The strategy is for the niche programs to serve as an entry for additional process efficiency improvements.

16.6.1 Assumptions

As currently planned, the financing will be at about the utility's cost of capital. The program design anticipates that a significant amount of the resource will be captured using third party finance.

The company anticipates that much of the resource will be identified by calls to energy service account managers. Account managers are utility employees who will work closely with large customers.

The program also develops an industrial sector least cost information base. This data can be used to apportion the resource into schedulable and lost opportunities components. The industrial pilot is also intended to have a market transformation benefit through accelerating the trend in industrial electrical efficiency.

16.6.2 Plan Outline

The achievable potential is limited by the amount of the market that can be expected to join the program. Based on results of current program offerings and economic standing of the industrial base, PacifiCorp has revised the estimate of the amount that can be achieved. The maximum market penetration rate has been reduced from 65% to 55% of the technical potential. This amount is still high relative to other planning groups since the company's estimate of the technical potential is somewhat higher.

Program activity level is highly influenced by the amount of economic growth assumed. Much of the increase in forecast load comes from industrial sector, so consequently there are more opportunities for savings with high growth rates. Ramping of the program is treated as a scheduled resource. The amount of resource under the five economic scenarios assuming a medium program level is shown in Figure 59. The amount under a medium economic growth but under alternative program options is shown in Figure 60.

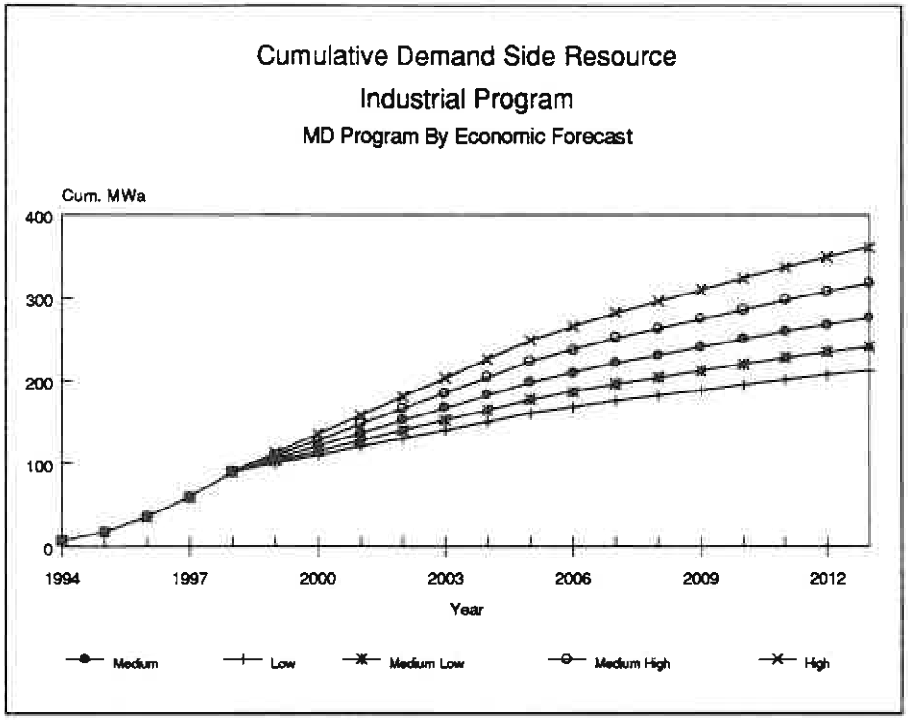

Figure 59—Demand–Side Resource, Industrial Program

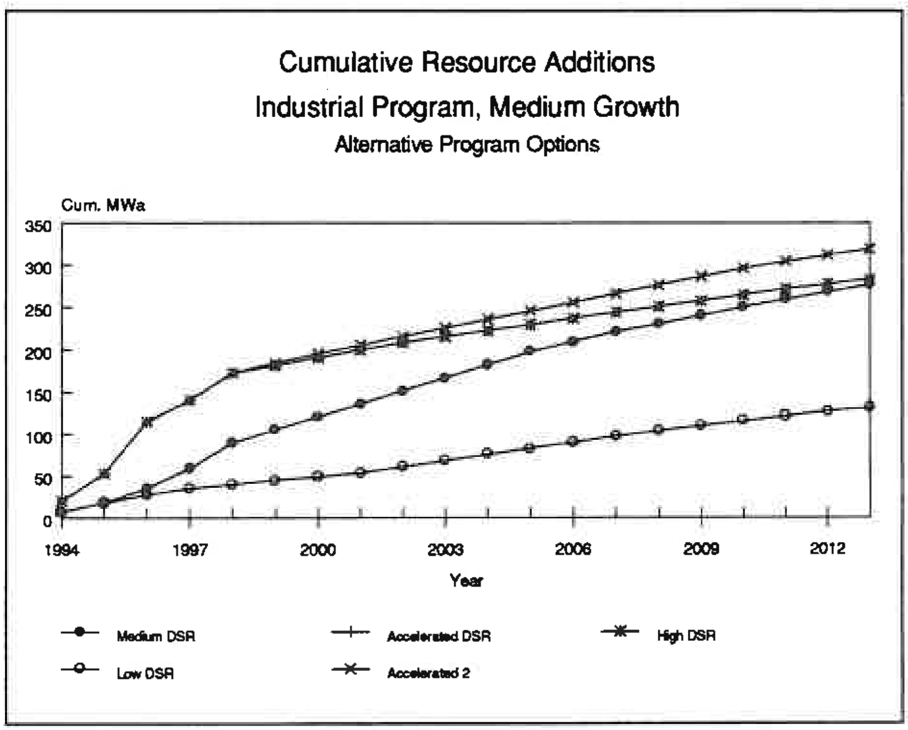

Figure 60—Cumulative Resource Addition, Industrial Program

16.7 Water Heater Load Control

The program is targeted specifically at water heater load control operated only for demand savings. The program would be implemented in the late 1990s, as need for additional capacity becomes apparent. This program would pay participants an incentive to accept load control on their water heater.

16.7.1 Assumptions

The program assumptions are as follows: installation cost is $250/unit for materials and labor to install stand-alone timing devices on water heaters. These devices will shut off the water heater during system peak times. As stand-alone devices, they do not depend on radio signals. Repair and replacement cost is assumed to be $70 after 10 years. Participants receive $24/year ($2/month) reduction on their electric bill for their cooperation. The incentive payment is the major program expense.

Some utilities have achieved reasonable participation on a voluntary basis. The participation for this program is expected to be about 19 percent, or 139,000 units by 2014.

A water heater program is only feasible in the Northwest since Utah tends to have gas water heaters.

16.7.2 Plan Outline

A useful experiment would be to determine what level of participation can be expected at a lower incentive amount. Capacity savings are estimated here as 1 kW in winter and 0.6 kW in summer. The program is not dependent on economic growth since it relies on existing stock as shown in Figure 61.

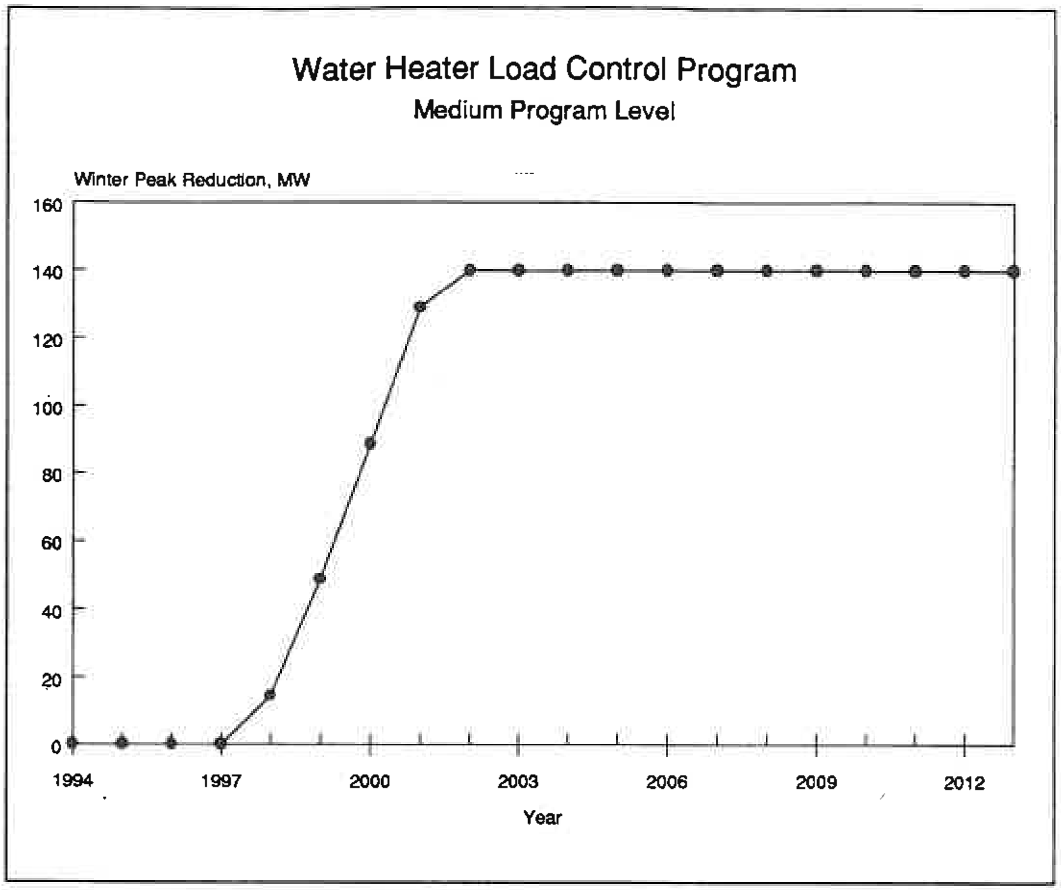

Figure 61—Water Heater Load Control Program

SECTION 17.0 Demand-Side Program Cost Effectiveness

Measures eligible for inclusion in programs are those measures determined to be cost effective when compared to the cost effectiveness ceiling- approximately of 55 mills/kWh. The eligible measures are included as a package, together with estimates for program delivery and administrative cost. The resulting program will have a cost based on the average of the measures and the overhead cost to deploy them. The program cost is compared to the cost of other resources using two cost effectiveness tests.

- **Total Resource Cost Test:**

  To screen and select demand-side resource options the company uses the Total Resource Cost (TRC) Test. The Total Resource Cost (TRC) test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. net of what?

  what about benefits?

- **Utility Cost Test:**

  Also of interest to the company is the net cost of the resource option to the utility, since these costs will be ultimately passed on to customers. For DSR programs, the utility can pay all or a part of the resource cost. When the utility covers only a portion of the resource cost then the remaining cost must be absorbed by the customer or government agencies.

  To determine utility impact the company uses the Utility Cost Test. The Utility Cost Test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the utility (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits, but the costs are defined more narrowly.

In addition , the company has analyzed DSR programs using financial analysis comparable to those used for other investments.

17.1 Financial Analysis and RAMPP-3 Cost Effectiveness Methodology

In the company's economic analysis process the focus is directed primarily at utility cost, cash flow, of the program and the impact on prices. This complements the RAMPP-3 focus which is primarily on the long term net present value of total resource cost- utility and customer cost- see table 31. For a typical supply-side resource there are no customer costs.

Table 31— RAMPP-3 Complemented with the Utility Economic Planning

RAMPP-3	Company Economic Criteria
Total Resource Cost Customer Cost Other Customer Benefits	Utility Cost
No lost revenues	Lost sales revenues
No IRR standard	IRR standard
Perfect regulation	Price Increase Assumptions (limited Regulatory Recovery)
Avoided Cost	Incremental Power Cost
Real levelized cost	Year-by-year costs
20 Year, Long Term Perspective	5 Year, Short Term Perspective

For Purposes of calculating the internal economic criteria, the company uses the change in the unleveraged (before financing), after tax cash flows with a particular program versus without that program to assess the incremental impact. Differential cash flows are discounted at the company cost of capital to determine the net present value (NPV) of the program. In doing this, a reduction in cash flows due to lost retail revenues is taken into account which is ignored in the RAMPP analysis. RAMPP uses levelized capital costs, which may be accurate on a net present value basis over the long term life of the asset, but are not indicative of the year-by-year earnings impacts.

Because of the differences in the way in which RAMPP looks at DSM programs versus the way that it is analyzed in the company economic criteria framework, some DSM programs look attractive from a RAMPP viewpoint while simultaneously not passing the company analysis.

These differences can yield different results on demand-side resource selection. This explains why the RAMPP medium case is 152 MWa of demand-side resource over the 1994 to 1998 short term planning horizon, and why only 143 MWa of demand-side resource is selected under the company screening criteria. This is discussed in more detail below.

17.2 Company Economic Analysis

The principal financial criteria used by the company to select resources are the:

- Internal Rate of Return (IRR) of the utilities' cash flow must exceed 9 percent.

- Real levelized program costs must be less than the company's incremental power cost after adjusting for line losses and adding 15 percent to account for the T&D investment deferral and the 10% conservation adder.

An IRR is the discount rate at which a stream of utility cash flows has a net present value of zero. The cash flows that are used are the unleveraged cash flows which means the cash flows after taxes, but before financing (e.g. before interest, principal payments, dividends, stock offerings, etc.). Financing costs are excluded is because these costs are included in the discount rate.

The IRR calculation has an advantage over the net present value approach because it provides a mechanism to prioritize capital. This is important to any capital intensive industry.

The cash flows are calculated by including all of the costs and savings (except financing costs and benefits) incurred by the company for investing in any particular DSR program. Any price changes that would result from the program being evaluated were not included in the analysis. The pricing assumption is held the same for each program or project when evaluating all capital expenditures including supply side resources. This method is commonly used by unregulated companies that operate in a competitive environment. This assumption is used for the following reasons:

1. DSR programs can be ranked and prioritized with other economic alternatives. If the economic analysis assumed that DSR costs could be recovered through increased prices, then the results may favor capital intensive, utility financed programs over a lower cost, third-party financed DSR program.
2. This methodology is consistent with the company's goal of being a low cost producer.
3. The electric business is becoming more competitive and market forces may not allow the company to increase prices even though our costs may justify this under regulatory treatment.
4. Assuming regulatory recovery of costs, any authorized investment would earn the allowed rate of return making it difficult to prioritize capital spending requirements despite the fact that some investments would increase prices while others would decrease prices.

When analyzing cash flows resulting from a DSR program, the company takes into account the following factors:

- The investment required by the program.

- Lost revenue as a result of a reduction in electric sales that otherwise would have occurred.

- Energy Service Charge interest and principal repayments are credited to the program.

- Bad debt expense is assumed to be 0.5 percent of the Energy Service Charge to account for uncollectables.

- Power cost savings are calculated as explained below.

In performing the analysis, the company uses a calculation of incremental power cost to measure the value to the system. This incremental power cost is used in evaluating decisions for either demand-side or supply-side resources. The company files a published avoided cost which establishes the price for purchasing power from qualifying facilities under PURPA. The QF avoided cost is filed approximately every two years in conjunction with RAMPP, or more frequently, as appropriate. The incremental power cost used in evaluating resource decisions internally differs from the published QF avoided cost in two ways.

1. The incremental power costs use the most recent information available about natural gas prices. When the company performed the evaluation of DSR programs in the fall of 1993, the best and most recent information was from our experience in the marketplace, and it appeared reasonable to assume that gas contracts were available with a nominal 5.1 percent escalation rate. These gas prices are similar to those now used in the Base Case of this report.
2. The incremental power costs use higher costs in the short run to reflect the value of power in the wholesale market. These values are included in the incremental power costs when evaluating supply side resources and are included in the DSR analysis for consistency.

An example of the calculations and a discussion are shown in Appendix J.

The Company also tested the overall price impact of the proposed programs and found that prices increased less than 1 percent compared to the case where no DSR was acquired. The company found this price increase to be acceptable. By its nature, this is not a test that is meaningful in evaluating individual DSR programs. It is unlikely that any particular DSR program would cause prices to rise that amount. This instead is a guideline for providing a check n the impact of DSR investments in total. Note that this guideline applies to year-by-year nominal prices rather than real levelized prices. In this test, the financial model is run assuming no DSR. From this analysis, the initial plans were returned to program planners to review cost and saving assumptions, especially in the residential sector. Costs were trimmed and savings reduced accordingly (supplemental measures and high cost resource measures dropped or reduced). Based on this reassessment the five year plans and two year action plan were modified to reflect the following programs discussed in the next section.

17. 4 Changes Between RAMPP2 and RAMPP3

Comparison of RAMPP-3 DSM to Strategic Goal of 170 MWa (1992 to 1996)

How does the RAMPP-3 action plan under the internal standards compare to the company strategic goal of 170 MWa by 1996?.

The attached table lays out the comparison between the current company planning efforts under RAMPP-3 and those assumed as part of the strategic goal of 170 MWa by 1996. The strategic goal of 170 MWa was an outgrowth of the strategic planning process that was conducted nearly simultaneously with the RAMPP-2 planning effort. The 170 MWa goal most closely reflects an adoption of the medium high growth scenario and an additional acquisition of DSM. The development of the strategic goal included an accounting of all conservation that would be captured. The table shows that the 170 MWa goal was comprised of 40 MWa of background conservation. For the commercial sector, this represented all conservation which could be obtained which yielded a payback of less than two years. The industrial sector also included low cost DSM that was embedded within the econometric model specifications used for the industrial sector.

In addition to the background conservation, there was an additional assumed acquisition of 13 MWa from a competitive bidding initiative. This allocation of additional acquisition was above and beyond the program activity included in RAMPP-2. Once adjusted for the background conservation and the additional bidding initiative, the net resource delivered under the strategic goal (117 MWa) roughly equaled the RAMPP-2 Medium High Scenario for program activity.

In order to compare the RAMPP-3 to RAMPP-2 results for the same time period, several adjustments are necessary. First and foremost, the forecasted growth rate was lower under RAMPP-3 medium case than for the medium high assumption used from RAMPP-2 (2.9% in RAMPP-2 versus 2.1% in RAMPP-3). This lower growth rate and overall level of kWh sales resulted in less potential for DSM activity. In total, there was a reduction of nearly 10,000,000 Mwh of industrial sales by 2013. In addition to the lower level of sales, some DSM formerly attributed to the programs in RAMPP-2 was incorporated into a reduction in base level of usage due to improvements in state building codes and appliance efficiency standards.

The three areas most impacted involved assumptions regarding residential new construction in Oregon, Washington and the presence of the MAP initiative. Appliance efficiency standards also reduced the base usage and therefore the amount of cost effective DSM that could be acquired due to the adoption of appliance efficiency standards. Overall, the combination of these factors, lower sales forecast, new residential building codes, and appliance efficiency standards, resulted in 17 MWa less of programmatic activity.

After adjusting the strategic goal of 170 MWa for the background conservation, the changes in planning assumptions for RAMPP-3 and the changes in building codes, the resulting net resource delivered is 100 MWa over the period 1992-96. One further adjustment requires the deduction of the actual conservation achievement during 1992 and 1993. On an installed basis, the company has put into place 25 MWa of conservation during 1992-93. After deducting the installed conservation the remaining program activity required during 1994-96 in order to achieve the strategic goal of 170 MWa is 75 MWa.

Under the internal standards the 1994-96 program activity would yield 69 Mwa or a variance of 6 MWa from the program activity path suggested by the strategic goal of 170 MWa.

PacifiCorp - *1992 to 1996 DSM acquisition*
All Resources are delivered to the system (adjusted for line losses)

Supplemental Funding not included in RAMPP-2 (page 97)

RAMPP2		1992-1996
	Medium Low	81
	Medium High	120
	Average Net Resource	101
Accelerated Plan (Strategic 170 MWa)		
	Gross Resource	170
	Background Conservation	40
	Competitive Bidding/ Wholesale	13
	Net Program Resource	117
Adjustments (-) subtractions		
RAMPP-3	RAMPP-2 to 3 Adjustment[1]	17
Installed DSM	Installed (92-93)	25
Rampp-3 Action Plan	Internal Standards (94-96)	69
Program Variance From 170 MWa Strategic Goal		<6>

[1] RAMPP-2 to RAMPP-3 adjustments include reductions in program potential due to new residential building codes in Oregon and Washington, new appliance efficiency standards due to the passage of the National Energy Policy Act and lower industrial / commercial potential due to a lower overall assumption regarding economic growth. The forecasted growth for industrial sales is nearly 10,000,000 Mwh less than the medium high RAMPP-2 forecast.

SECTION 18.0 Demand-Side Resource Two-Year Action Plan

The actions item specified in this section were developed through a series of meetings and reviews by company staff and management in November, 1993. They represent our best thinking on the correct course of actions to take with regard to developing demand-side programs and increasing program offerings throughout the Utah and Pacific service territories over the next two years. The company is committed to assuring achievement of these action items unless it becomes apparent over the next year that either one or more of the items should not be pursued because of changing circumstances.

18.1 Two-Year Acquisition Targets

The two year action plan MWh savings targets were developed initially by program planners based on research information, program experience through mid-1993, and assumptions about changes to programs which would impact future program performance. The company's economic criteria, which was discussed in the previous section, were applied to the initial program five year MWa savings and cost estimates.

The results of this analysis, tabulated in Appendix I, show that some programs were marginal or uneconomic. Most of these programs were primarily targeted at residential sector. Based on this new information, company program planners revisited the projections, modifying assumptions regarding program funding of measures and costs of services provided under the program downward and eliminating marginal measures from the programs. The change in the program projections resulted in a 9 MWa reduction in savings, from 152 MWa down to 143MWa. The MWa savings shown in the two year action plan is the first two years of the 143 MWa five-year company goal.

18.2 Action Plan

The following sections describe the elements of the Action Plan by program.

18.2.1 New Residential Buildings

The company's objective is to promote the adoption of Model Conservation Standards (MCS) into current code practices. In order to gain adoption of all cost-effective energy efficiency measures into state building codes, the company strives to influence adoption of MCS through capturing cost effective lost opportunities beyond the current building code standard, while working in collaboration with state and local agencies to gain adoption of model conservation standards into current code practice. The company will also work with local and state building code standard, while working in collaboration with state and local agencies to gain adoption of model conservation standards into current code practice. The company will also work with local and state building code agencies to improve builder compliance with existing codes and to overcome builder resistance to new code changes through program training.

The company will continue using the Super Good Cents program as a vehicle to improve builder awareness and familiarity with new technologies, materials, appliances and building practices. The company will also continue participation in the regional Manufactured Housing Acquisition program (MAP) as a vehicle to capture cost-effective lost opportunities above the current HUD standard. With adoption of a new HUD standard in 1994, this program will be revisited for cost effectiveness.

The Company plans to:

- *Revise and implement a new Super Good Cents program in Oregon, Washington, Idaho, Montana, and Wyoming in 1994.* The revised program will tie payments more closely to kWh savings obtained from individual residences.

- *Streamline the Super Good Cents program.* The program will reflect a more prescriptive design, targeting a 20 percent reduction in administrative overhead costs by 1995.

- *Continue participation in MAP for the states of Oregon, Washington, Idaho, Montana, and California in 1994.* Work with BPA and others to renegotiate with manufacturers the incentive payment adjusted for adoption of the new HUD standard expected by October 1994. Participate in renegotiation and implementation of a new regional contract with manufactured home suppliers and BPA after expiration of existing contract in April of 1996.

- *Continue to work with MAP collaborative group to improve program cost effectiveness.* Analyze cost effectiveness of measures which will be included in MAP homes beyond 1994.

- *Participate in a collaborative study of residential code compliance in Oregon.* The study will provide information on improving compliance and enforcement of the residential energy code in Oregon. The study will be completed in 1994.

- Participate and be knowledgeable about code development issues in Wyoming, Idaho, and Utah. Facilitate where possible adoption of an MCS equivalent code.

Work with other interested parties to educate builders on new Utah Model Energy Codes and other energy efficient construction practices which will yield higher compliance with state code.

18.2.2 Existing Residential

The company's objective in residential weatherization is to continue to offer the service to assist customers in improving the overall electric energy efficiency within their homes. The goal over the long term is to provide the customers with the necessary information and tools to enable them to conduct cost-effective weatherization activities. A key component of this strategy will be to increase our emphasis on providing energy education and information to customers.

The company plans to continue to offer residential weatherization alternatives for residential customers to acquire cost-effective energy efficiency opportunities and provide customer service options for customers. Company initiatives will place less emphasis on administratively expensive house-by-house weatherization activities. Efforts will focus on streamlining delivery and minimizing program overheads while maintaining quality installations. Additional efforts will focus on developing program initiatives which minimize impacts on non-participants and overall rates while delivering cost-effective energy efficiency resources.

The residential retrofit program cost was assumed to be 75 percent lower than the administrative cost of the Home Comfort program. The reduction in up front costs were largely due to the differences in approach to the market and the more simplified approach to the audit.

The company plans to:

- *Operate a residential retrofit program in Washington and California in 1994 and 1995.* Make revisions to weatherization program delivery to improve cost effectiveness.

- *Market test alternative financial assistance options such as third party finance, rebates, and the energy service charge.*

- Launch Super Good Cents Home Improvement Program in Oregon

- *Continue availability of company weatherization programs which are required by state statutes.*

- *Operate a direct install water heating retrofit program targeted at multi-family residences in Utah during 1994.* Conduct prototype test of measures to assure measures perform as deemed in Utah during the second quarter of 1994.

- *Operate a competitive bid, Pay-For-Performance low income program in Oregon to test as an alternative delivery system.*

- *Continue to offer low income weatherization programs and provide evaluations to regulatory agencies to demonstrate that low income programs are being assessed and action taken to improve program cost effectiveness.*
    - In Washington use a standardized audit and provide payments based on measure cost effectiveness. Continue to offer energy education to participants.
    - In Oregon provide a study to quantify benefits of energy education and arrearage impacts of the low income program.
- *Develop educational and informational literature to support improved information on home energy usage through:*
    - Brochures which provide energy efficiency tips.
    - Packets which provide guidance in performing a home energy audit.
    - Brochures which provide appliance purchase information.
- *Market test energy information displays in Oregon.* Determine the value of providing energy efficiency information which influences customer energy use decisions.

18.2.3 Appliances

The company's objective is to continue to transform the market toward more energy efficient appliances. The company's efforts to improve the efficiency of appliances include, but are not limited to, providing information on efficient appliances, incorporating efficient appliances into residential program designs, and working in collaboration with state and regional organizations to establish standards and to encourage the manufacture of energy efficient equipment.

In general, the company will encourage customers to purchase energy efficient appliances by providing educational information and providing minimum efficiency standards rather than providing technology-specific cash incentives. The most cost-effective way to influence market adoption of energy efficient appliances is through manufacturer programs and minimum efficiency standards.

The company plans to:

- *Rely on improved standards as the preferred way to achieve appliance energy savings.* Participate in collaborative efforts with other utilities through organizations such as the Western Utilities Consortium and others to improve the efficiency of new appliances.

- *Participate in collaboratives to adopt standards for technologies such as compact fluorescent lamps, horizontal axis washers and other new technologies.* Investigate possible technologies such as microwave dryers as a cost-effective alternative.

- *Maintain board membership in the Super Efficient Refrigerator Project.* Oversee implementation of the 1994 new model design and begin promotion of the refrigerators.

- *Continue to participate in BPA's Blue Clue program or a similar initiative, encouraging the purchase of energy efficient appliances.* In addition, develop home tuning and home maintenance tips for energy efficient performance. Extend Blue Clue or a similar informational initiative to Utah and Wyoming.

- *Conduct follow-up survey and verification of Oregon show head saturation program to determine applicability to other jurisdictions.*

- *Offer a saturation show head program for customers currently on schedule 5 in the State of Utah.*

- *Re-assess the cost effectiveness of radio communication direct control of electric water heaters as allowed under schedule 5.*

- *Continue installation of energy efficient water heaters (.93 or equivalent) through the Hassle Free Water Heater Guarantee Program.* Target installation of up to 3,500 tanks per year over the two year action plan. Encourage the installation of low flow show head, aerators, and pipe wrap, along with energy efficient tanks where applicable.

- *Pilot a water heater load control program starting in 1994 in Oregon as part of the company's automated distribution project.*

- *Execute a multifamily shower head program in Washington and Utah, as well as potentially extending the initiative to other jurisdictions.*

18.2.4 Commercial Retrofit

The company's objective in the commercial retrofit market is to develop the capability to deliver cost-effective conservation acquisition at the time of resource need. To be in a position to deliver the required resource identified in the plan, the company will pursue a strategy of capability building through experimentation of alternate program designs and delivery mechanisms.

The cornerstone of this effort will be in providing a comprehensive retrofit service which does not compromise program flexibility and the customers' choice in energy efficiency options. A key part of this flexibility will be in the auditing, quality control, and building operation and maintenance training. The company will continue to require the participant to pay the bulk of the energy efficiency improvement costs such that non-participant impacts are mitigated.

The company plans to:

- *Implement a comprehensive commercial retrofit program for buildings over 20,000 square feet in the State of Oregon in 1993.* Design the program to provide flexibility in addressing customer needs which could include items such as controls, lighting only, and building operation and maintenance (O&M) training. Establish building operating savings standards to guide building managers in efficient operation of their buildings.

- *Evaluate commercial retrofit program results in Oregon for 1994.* Recommend program revisions and assess feasibility for expansion to other jurisdictions in 1995.

- *Operate task team in 1994 to develop a small prescriptive commercial retrofit program for buildings under 20,000 square feet.* Assess feasibility of implementation before year end 1994 in Oregon.

- *Operate the EPA Green Lights program for company facilities.* Complete development of site inventory, environmental assessment, energy efficiency audit and prioritization by 1994 and begin installations in 1995 to be completed within five years.

- *Develop a comprehensive catalog of energy efficiency products available for commercial application.* Distribute catalog to company field personnel by year-end 1994.

- *Continue supporting the development of REMPRO program through the Everett and Portland Community College campuses as a tool to provide effective energy efficiency operation and maintenance building training for building managers.*
- *Participate in collaboratives to adopt standards for technologies such as motors and packaged air conditioning systems.*

18.2.5 New Commercial

The company will actively participate in the development of improved code standards as the preferred way to achieve energy savings over the long term in this market segment. One means will be participation in collaborative efforts with other utilities to gain adoption of new commercial energy codes and code enforcement. In the absence of adequate codes, maintain lost opportunity programs which address acquisition of energy efficiency above the current code.

The company will continue using the Energy FinAnswer programs as a tool to improve architect and engineer awareness and familiarity with new energy efficiency technologies, materials, appliances and building practices. The company will continue to require the participant to pay the bulk of the energy efficiency costs such that non-participant impacts are mitigated.

The company plans to:

- *Participate in code development and implementation design for new commercial codes in Oregon and Washington.* Participate in a collaborative effort to establish training and educational programs for commercial energy code compliance in Washington.

- *Conduct a detailed study to determine the impact of building code changes on energy efficiency in new commercial construction.* Complete a report which includes recommendations for changes to the Washington Energy FinAnswer Program in 1994 and the Oregon program in 1995.

- *Conduct a common practice survey for new commercial construction in areas of the service area not currently covered by research studies.*

- *Improve program cost effectiveness through streamlining.* Reduce administrative costs, change funding criteria, and improve program design. Reduce process steps in the commissioning (including inspection and performance testing) phase.

- *Improve leverage of trade ally networks (architects, design firms, contractors and others involved in the construction and building operation industries) through enhanced training and informational materials.* Complete a pilot building design study to influence architects to consider passive design features which will lower energy usage.

- *Complete study to verify savings and determine appropriate calibration of modeling tools for new construction energy savings estimates.*

- *In 1994 participate in a collaborative (LBL and BPA) study to quantify energy benefits of the commissioning process.*

- *Influence the adoption of commissioning standards through participation in a National Building Commissioning Association.* Provide funding to ASHRAE for commissioning guidelines group to establish protocols for incorporation into building code practices.

- *Establish protocols for commissioning Path B (defined as non-ESC participant, but installs recommended measures) program participants in 1994.*

- *Offer to commercial customers the Energy FinAnswer program, designed to improve new commercial building energy efficiency, in all jurisdictions served by the company.* Achieve the following penetration rates in new commercial construction:

Table 32—Targeted Penetration Rates

STATE	Large Buildings (over 12,000 sq ft)		Small Buildings (less than 12,000 sq ft)	
	1994	1995	1994	1995
Oregon	67%	70%	40%	45%
Washington	45%	65%	20%	30%
Idaho	45%	65%	20%	30%
Montana	35%	45%	35%	40%
California	45%	65%	35%	40%
Wyoming	35%	45%	35%	40%
Utah	67%	70%	20%	30%

18.2.6 Industrial and Irrigation

The company views this sector as a low-cost target market, and acquisition efforts will increase such that maximum benefits are achieved for both participants and non-participants. The company seeks to enhance relationships with its major industrial customers to capitalize on opportunities to provide energy efficient electric technologies and to demonstrate their viability in industrial processes. Programs are being designed to offer the maximum flexibility and recognize the many unique requirements of key industrial customers. The company will also focus on lost opportunity efficiency improvements as a priority.

The company plans to:

- *Offer the Energy FinAnswer program to industrial customers in Oregon, Washington, California, and Utah.* Expand the program to Idaho in 1994. Develop a feasibility assessment for expansion of the program to Montana and Wyoming during 1995.

- *Continue development of an industrial customer database which provides information to improve assessments of resource availability and cost.* Create major account plans for the top 100 customers, assessing opportunity and cost of resource acquisition.

- *Participate in collaborative effort with NPPC and others to complete Original Equipment Manufacturers (OEM) study.* The study will examine motor drive applications and how to influence efficiency improvements in this equipment category.

- *Add additional program options to address prescriptive path measures in industrial facilities.* Consider these two measures as possible candidates for prescriptive path: (1) motors, and (2) lights.

- *Operate commercial and industrial Pay-For-Performance contracts in Utah in 1994 as a comparison on cost effectiveness of alternative delivery systems.*

- *Improve cost effectiveness of Irrigation FinAnswer in California in 1994.* Examine alternative designs such as a prescriptive approach versus a custom approach.

- *Study irrigation options for customers in Idaho in 1994.*

- *Continue the ditch to pipe proposal for Oregon in 1994.*

- *Continue to offer the radio communication direct load control for irrigation pumps in Idaho and Utah.* Test the system and seek more participants if cost effective.

- *Participate in collaboratives to adopt standards for technologies such as motors and air conditioning systems and other new technologies.*

18.2.7 Other Demand-Side Resource Activities

The company has other DSR activities planned which benefit more than one sector or program, therefore these activities have been identified separately from the above sector action plans.

The company plans to:

- *Conduct a customer energy survey (Energy Decisions) in 1994 to collect demographic, equipment, housing and attitudes data.* The data will be analyzed to assess resource potential and assist in program design. Complete residential survey and assessment in 1994 and commercial survey and assessment in 1995.

- *Evaluate pay for performance agreements with contractors.* Assess this method for cost- effective DSM acquisition. Evaluate competitive bid process and make recommendations on how to improve the process.

- *Continue participation in Evaluation and other Advisory Groups as recommended by regulatory agencies to obtain external review and input into improvement of program evaluations and process.* (NW Evaluation Group, Utah Evaluation Collaborative, and Regional Evaluation Network).

- *Develop a comprehensive verification plan for determining accuracy of savings estimates which balances costs of verification with the commensurate risk and size of the project.* Collaborate with state agencies to receive input on development of the verification plan.

- *Conduct a free drivership/market transformation study for residential and commercial new construction and appliance improvements.*

- *Design, implement, and report on an automated meter reading, real time usage display, time of day pricing, and direct load control pilot project in conjunction with the automated distribution project in 1994/ 95.*

- *Study and report on the potential for a pilot experiment on local transmission and distribution deferral using DSM to reduce need for system upgrades to meet peak requirements on a localized level*

- *Conduct program process and impact evaluations to improve cost effectiveness.* Evaluations will be completed in the following program areas:

Table 33—Scheduled Program Evaluations

PROGRAM AREA	1994		1995	
	Process	Impact	Process	Impact
New Residential	√	√	√	√
Residential Weatherization	√	√	√	√
Appliances	√	√		
New Commercial	√	√	√	√
Retrofit Commercial			√	√
Industrial	√	√	√	√
Competitive Bid	√	√		

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Glossary of Demand-Side Resource Terms

achievable potential	The portion of the cost-effective technical potential that can be obtained given market constraints.
acquisition	The gain of a power resource, including demand-side and supply-side categories, in the form of energy or capacity.
amenity takeback	The amount of reduction in energy savings due to a customer choosing more amenity by increasing energy consumption.
avoided cost	The incremental costs to an electric utility of electric energy or capacity, or both, which, but for the purchase from the qualifying facility or qualifying utilities, the utility would generate itself or produce from another source. [Oregon Administrative Rule 860-29-010 (1)]
average megawatt	Average megawatt or average annual megawatt is a unit of electric consumption or production over a year. It is equivalent to the energy produced by the continuous use of one megawatt of capacity over a period of one year. (MWa = 8760 MWh)
background conservation	This is assessed by estimating the amount of conservation customers would perceive as cost-effective, based on their retail rates and high implicit discount rate. An amount of naturally occurring conservation.
baseline	A reference of actual or estimate energy use that serves as the basis for determining energy savings.
BIN Model	An energy consumption model, based on the number of hours per year that the temperature is in each 5 degree fahrenheit bin; a LOTUS 1-2-3 spreadsheet, incorporating duct loss impacts on heating system efficiency.

BTU/hr-°F	A unit of heat transfer (British Thermal Units per hour per one degree fahrenheit).
building type	A categorization of buildings based on type of activity performed in that structure (i.e., single family, multifamily, mobile home, office, retail, grocery, hospital).
capability building	A reference to the period of time needed to establish a fully operational DSM program and a DSM market infrastructure.
capacity	The maximum power that a machine or system can produce or carry under specified conditions. The capacity of generating equipment is generally expressed in kilowatts (kW) or megawatts (MW). Capacity as applied to transmission lines is the maximum load a line is capable of carrying under specified conditions.
capacity reserve margin	Percent of generation beyond expected peak load used to maintain the reliability of the electric utility's operating system.
capital recovery factors	A factor used to convert up-front cost of investment into equal payments over time. A mortgage rate. It varies depending on the life of measure and discount rate used.
climate adjustment factor	A number used to adjust the energy consumption and potential savings derived from one climate zone to fit another climate zone.
climate zone	Northwest Power Planning Council's separation of the region based on the number of heating days. Zone 1: 4000-6000 heating degree days (the mild maritime climate west of the Cascades and other temperate areas); Zone 2: 6000-8000 heating degree days (the eastern part of the region); and Zone 3; more than 8000 heating degree days (western Montana and higher elevations throughout the region).
competitive bid	A process of soliciting bids from outside providers for delivery of resources. For example, DSR services, or cogeneration conditional demand model. A statistical method of developing end-use consumption patterns from whole-house consumption data and appliance saturation data, demographic and household data, weather data, economic and market data.

conservation load factor	A ratio representing the energy savings compared to the peak reduction of a demand-side measure over a given period. (change in kill x 720/monthly kWh savings)
conservation measure	An action taken to reduce energy or to use energy more efficiently. For example, installing insulation, retrofitting energy-efficient lighting, or applying better energy system controls.
conservation supply curve	A presentation tool used to show the amount of electrical conservation available at various costs per conserved kWh.
cost-effective	An acceptable level of cost for a measure or a resource that meets or reduces electrical power demand by consumers. A resource or measure is cost-effective if its estimated incremental system cost is no greater than that of the least cost similarly reliable and available alternative or combination of alternatives.
cream skimming	A practice of selecting and installing conservation measures that have short payback periods, and ignoring conservation measures that are cost-effective but have a higher pay-back period.
daylighting	Using daylight as a substitute for artificial lighting.
daytype	A conservation modeling convention used to characterize energy use different days of a week. Peak day, week day, holiday and weekend days are typical daytypes.
demand	The level of electric capacity (power), in kilowatts or megawatts, that is needed at any given time.
demand side resources	Energy efficient end-use measures and services that decrease customers' energy consumption and peak load demand.
discount rate	The rate used in valuing cash flows to be received in the future. The rate used in a formula to convert future costs or benefits to their present value.

diversity factor	A derating factor applied to the demand savings derived from a prototypical modeling or an engineering analysis. It is designed to discount the sum of the individual savings from a group of buildings taking into account that all buildings do not have the same load profile; some are off when others are on so the average load is lower. As a result, diverse load shapes for groups of customers are smoother than for individual customers.
economic elasticity	A measure of a customer's responsiveness to a change in the prices. Price elasticity of demand for a product measures a customer's response to increase or decrease in price of the product.
end-use	A purpose or final use of energy. Residential end-use is primarily for space and water heating, lighting and appliances. In the commercial buildings heating, ventilation and air conditioning, lighting are major end-uses.
end-use energy	A final, discrete use of electrical energy, such as lighting, space heating and cooling, refrigeration, office equipment or any other discrete load.
energy conservation	The process of reducing energy consumption while meeting end-use needs of consumers.
energy efficiency	The ratio of the energy output by the end-use to the energy input.
Energy FinAnswer	An overall energy conservation program, offered by PacifiCorp; providing design assistance, energy analysis, financial incentive, and commissioning service to commercial and industrial customers.
energy service charge	Referred to as the ESC. ESC payments are a repayment of the financing included in a program participant's electricity bill. It is designed to increase the participants acceptance of the energy conservation measure and to reduce the portion of the cost paid for by other utility ratepayers.
Energy Smart Design	A BPA energy conservation program targeted to commercial and industrial sectors. Its main goal is to incorporate energy efficient systems and designs at the design phase of the building construction.

envelope area	The exterior area in a building. This area may consist of doors, walls, windows, roofs, floors plus partitions to unconditioned spaces.
equity impacts	The amount of a DSM program's cost that is born by non-participating customers or rate payers. Good programs have low equity impact.
FinAnswer 12000	PacifiCorp's new commercial construction program designed to meet the needs of smaller buildings, less than 12,000 square feet; using a prescriptive approach to estimating savings and cost.
"free riders"	Participants who would have adopted program-recommended energy conservation measures without a DSR program incentive.
"frozen efficiency"	An assumption that baseline buildings do not change energy use except when becoming a program participant. Economic forecasts of customer energy demand are based on "frozen efficiency," that is, without consideration of the amount of conservation customers will do on their own. This amount of energy is removed from the forecast to estimate the load the company would otherwise have to supply.
fuel switching	Replacing the original energy source (electrical) for space or water heat in an existing customer's building with a different energy source (fossil fuel).
"gravity"	The amount of customer-produced conservation independent of any DSM program.
heat loss coefficient	A unit describing the rate at which heat would be lost by a particular building per degree fahrenheit (BTU/hr-° F).
implicit discount rate	An estimated discount rate, combining financial and non-financial discounting factors.
incentive	Financial and non-financial assistance offered to the consumers in exchange for incorporation of energy efficient systems and design in their building construction, operation and maintenance.

incremental measure cost	The difference in the total cost between standard equipment and energy efficient equipment.
interactive measures	Measures with interdependent energy consumption and savings. For example, lighting and cooling and heating have an interactive effect; as lighting in a building becomes more efficient, there is less waste heat, cooling requirements for the building go down and heating requirements go up.
kilowatt-hour	The basic unit of electrical energy, equal to one kilowatt of power generated, or used, continuously for one hour.
least cost planning	Least cost planning or integrated resource planning, is a name given to the power planning strategy. The term "least-cost" refers to all costs, including: capital investments, labor and administrative costs, fuel costs, and maintenance costs. It can also include cost of environmental externalities.
levelized cost	The levelized cost of a measure is the present value of the measure's cost including incremental cost of the measure, and the operating cost, converted into a stream of equal annual payments. The levelized cost of a measure can be expressed in dollars, or mills, per kWh saved.
life cycle cost	The cost of energy including the initial cost of replacing the equipment, the net present value of operation and maintenance costs, and the net present value of fuel cost over the economic life of the equipment.
line loss	Percent of power lost, transferred to waste heat energy, during the transmission and distribution of power from the generation site to end-use site.
load	The amount of electricity used by a customer or group of customers during a specified time period.
load factor	A ratio or percentage which represents the portion of time when power is used.
load shapes	A load shape is a profile of a building's or facility's kilowatt demand over time, usually over the hours of the day, which can be derived from metered data. Typically utility system load shapes peak during the day and are reduced at night. Different types of businesses, industrial operations, and residential users show markedly different load shapes.

load shedding	A load management strategy. Consisting of dropping part of a customer's load based on prior agreement between the utility and the customer.
lost opportunities	Conservation resources which will be cost-effective during their lifetime if installed now, but not if installed later as part of a more expensive retrofit. Thus, lost opportunities are measures which should be installed even during a generation surplus.
lost revenues	That portion of the expected future revenue that may be lost if the expected levels of savings from the DSR activities are realized.
market barriers	Any real or perceived barrier to customer's buying energy conservation on their own. First cost, inadequate information, and perceived high risk of failure are examples of market barriers to energy conservation.
measure cost effectiveness ceiling	The highest cost that should be paid for savings from a particular measure.
megawatt	The electrical unit of power, equal to 1,000 kilowatts or one million watts.
mill	A tenth of one cent. A thousand mills equals one dollar. The cost of electricity is often expressed in mills per kilowatt-hour. (mills/kWh)
net present value	The equivalent present value of a future sum or stream of future investments or payments, when taking into account the discount rate, or interest rate. Net present value brings all money quantities to their value at the current time.
no losers test	Measures the impact of DSM programs on electric rates (also referred to as non-participant's test). In the calculation of ratepayer input measure (RIM) test the avoided supply costs, and any revenue gain are included in the benefit side. The costs include any increased supply costs, revenue loss, incentives, and program costs. The ESC revenue is a benefit or an offsetting negative cost.
normalized load shape	A load shape where the highest peak load is set as one and all other load values are less than one.

Pacific Northwest	According to the 1980 Northwest Power Act, the Pacific Northwest comprises Oregon, Washington, Idaho, and Montana west of the Continental Divide, as well as portions of Nevada, Utah, and Wyoming that are within the Columbia-Snake River Basin. The Pacific Northwest also includes any contiguous areas not more than 75 miles from the region defined above that are part of the service area of rural electric cooperative customers served by Bonneville Power Administration, on the effective date of the Act, whose distribution system serves both within and without the region.
passive cooling	Methods of providing cooling to a building without using energy sources. For example, window films, exterior shading, interior shading, natural ventilation, etc.
passive design features	Passive design elements are those which require no external energy source to be effective; for example, window films or windows on the south for winter, so low heat. Air conditioning equipment is a active design element.
peak load	The maximum electrical demand for power during a stated period of time. It may be the maximum instantaneous load or the maximum average load within a designated interval of the stated period of time.
peak savings	Reduction of the peak load by a conservation measure.
penetration rate	The market rate of adoption of a new technology, appliance or fuel type in a given year. For the conservation programs penetration rate is the annual share of a potential market for conservation that is targeted. Penetration rate can be expressed as a ratio of the number of participants in a program to the number of eligible customers for the program, with both the numerator and denominator defined in the same units.
prescriptive path	A simplified estimate of energy savings and measure cost based on matching the subject building to a prototype with known savings and costs. A prescriptive path meets the needs of less complex buildings.

PRISM	A mathematical model used to adjust billing data for homes to weather correct space heat and estimate energy savings between pre- and post-years for a DSR program.
program	Organized utility activities that are intended to affect the consumption and/or demand of particular group of customers electricity use.
program evaluation	The process of evaluating the performance of DSR programs. It consists of impact (savings) evaluation, process evaluation and market evaluation.
programmatic potential	Conservation potential given to a specified program penetration rate for a given period.
prototype	A composite representation of a customer's building or facility. Energy simulation is often used to estimate energy savings opportunity of various measures in prototypical buildings to establish guidelines for applying a simple prescriptive path to similar customer buildings.
R-value	A measure of thermal resistance. It is used to rate the insulating properties of materials. A lower R-value indicates less thermal resistance, thus more heat loss.
ramp rate	The speed by which a DSR program goes from start-up to full production.
real discount rate	Discount rate adjusted for the effect of inflation.
real levelized cost	The annual cost per unit of energy savings of a conservation measure over the life of the measure. The levelized cost is calculated by developing a discounted annual cost for purchasing and operating the measure which includes financing, discount and inflation factors divided by the annual energy savings (kWh).
"real term" costs	Costs in constant dollars.
receptacle load	Loads of appliances and devices plugged into convenience outlets or receptacles.
region	See Pacific Northwest.

retrofit	To install an energy conservation measure (piece of equipment or system) in an existing building or facility.
saturation	The ratio of the number of specific types of appliances or equipment to the total number of customers in that class or to the total number of appliances or equipment in use.
scheduled acquisition	Acquiring DSR on a pre-defined schedule.
sector	A large group of energy users with similar types of conservation or opportunities. Sectors include residential, commercial, industrial and agricultural.
solar access	The right to have an unobstructed view of the sun upon a piece of real estate such that useful heating can be gained by solar designs and solar equipment without fear of a neighbor blocking the sunlight.
standby loss	Water heater pipe and tank heat losses occurring while the heater is not being used. Standby heat loss is a function of hot water temperature, surface areas, ambient temperature and thermal resistance of insulation used.
Super Good Cents	A BPA and PacifiCorp residential program designed to increase energy efficiency of new homes.
supply-side options	Range of supply resources considered in the integrated resource planning. Supply side options include, conventional coal and gas-fired plants, renewable resources, etc.
supply-side resources	Resources which physically generate electrical power for the power grid (i.e., hydro, thermal, wind).
supply curve	A presentation tool that shows the amount of conservation resource potential at a given levelized price per conserved kWh.
takeback	Also known as "snapback" or "rebound." It refers to increase in energy use resulting from the customer choosing more amenity after participating in a DSR program.
technical potential	All of the conservation that is physically possible within a cost effectiveness limit.

total resource cost	The total cost to install and operate a resource. This cost includes: equipment cost, installation cost, utility implementation costs, and O & M costs.
U-value	Heat loss coefficient used to estimate heat loss of building per unit component area and temperature (BTU/hr-sf-°F).
UA-value	Overall heat loss coefficient for a building with all component areas combined into a single value (BTU/hr-°F).
"unconstrained" run	Model run which provides no constraints on how or when the model selects resources from the portfolio to meet system needs.
vertical market segment	Classification of commercial and industrial customers based on the four digit SIC codes.
WATTSUN	A computer program used to estimate the energy use of residential buildings.
window of opportunity	The time that an opportunity presents itself to make a resource acquisition at a lower cost than at other times.

APPENDIX A

NORMALIZED LOAD SHAPES

Existing Northwest Building Stock Mix

January

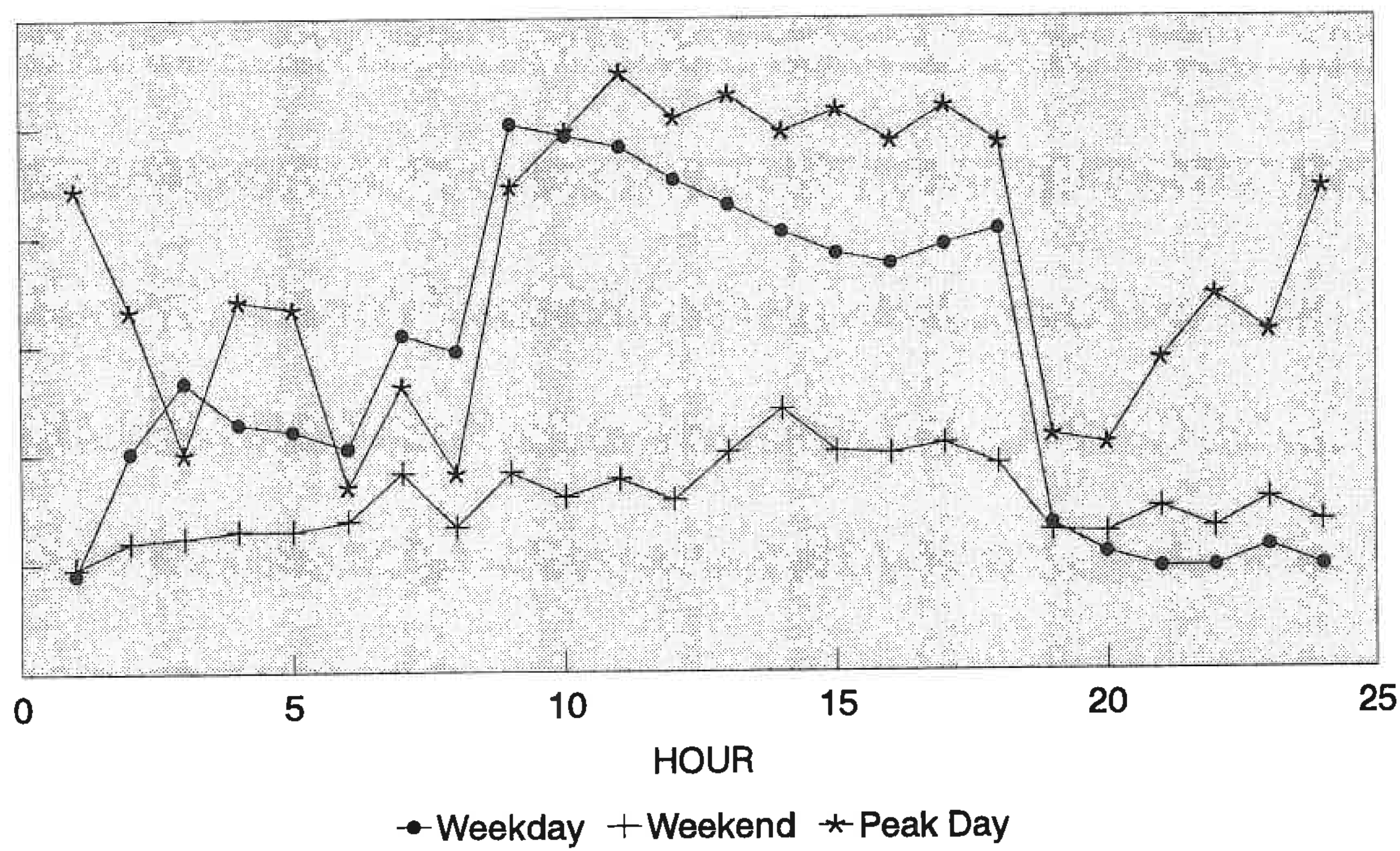

Fig. A-1 Existing Commercial Sector

NORMALIZED LOAD SHAPE
New Utah Building Stock Mix
October

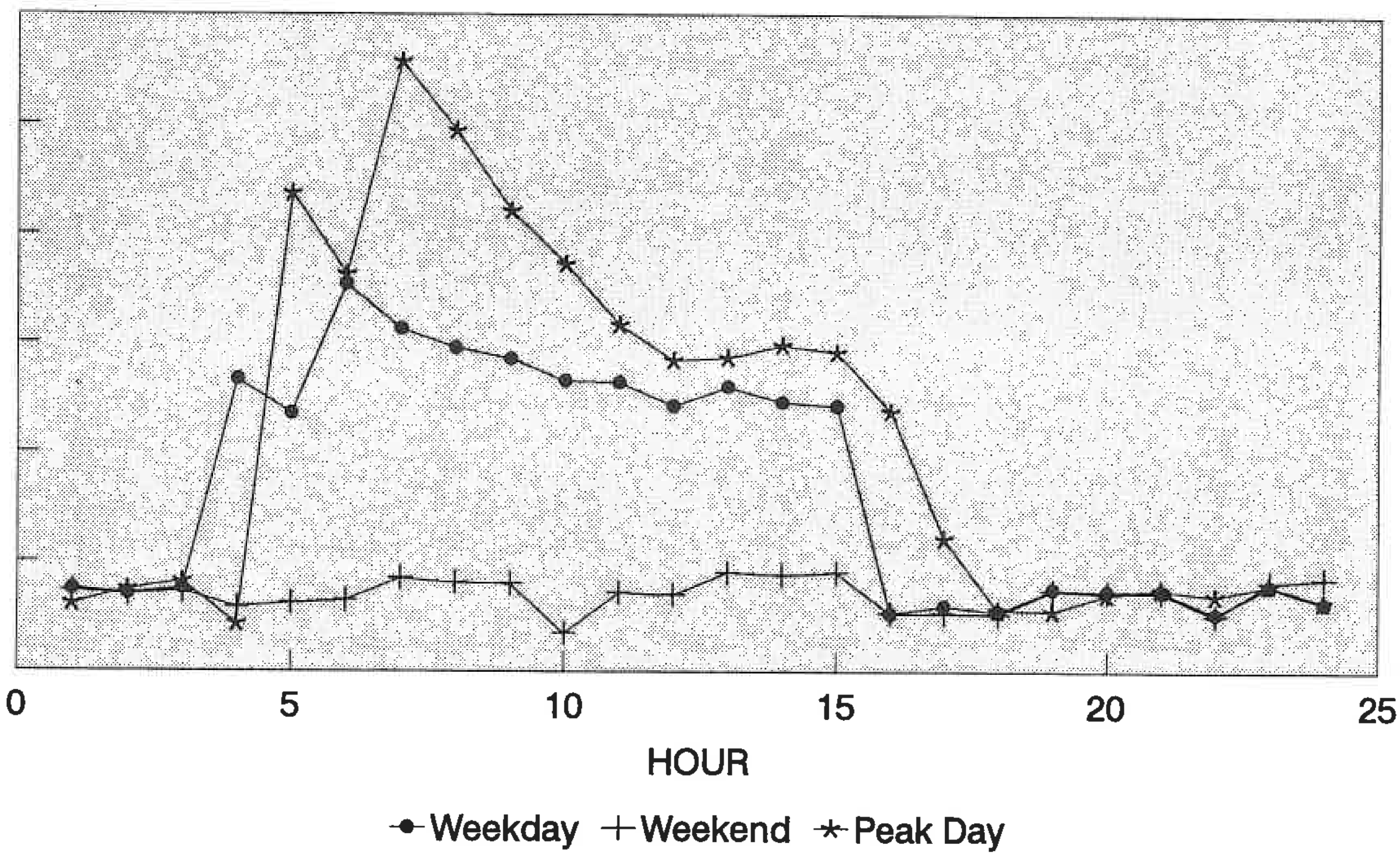

Fig. A-16 Commercial Sector

NORMALIZED LOAD SHAPES

Existing Utah Building Stock Mix

January

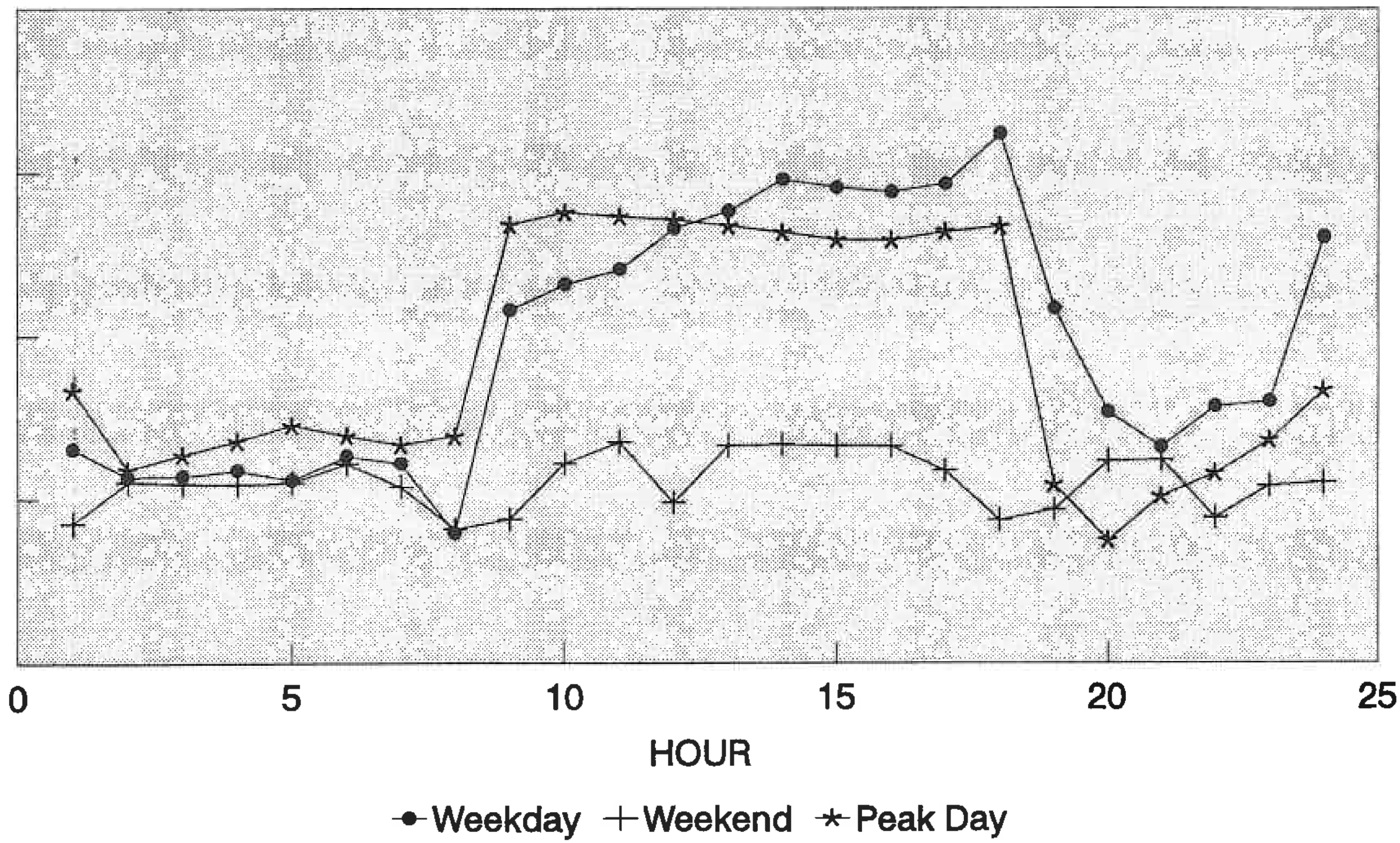

Fig. A-2 Existing Commercial Sector

NORMALIZED LOAD SHAPES

New Utah Building Stock Mix

January

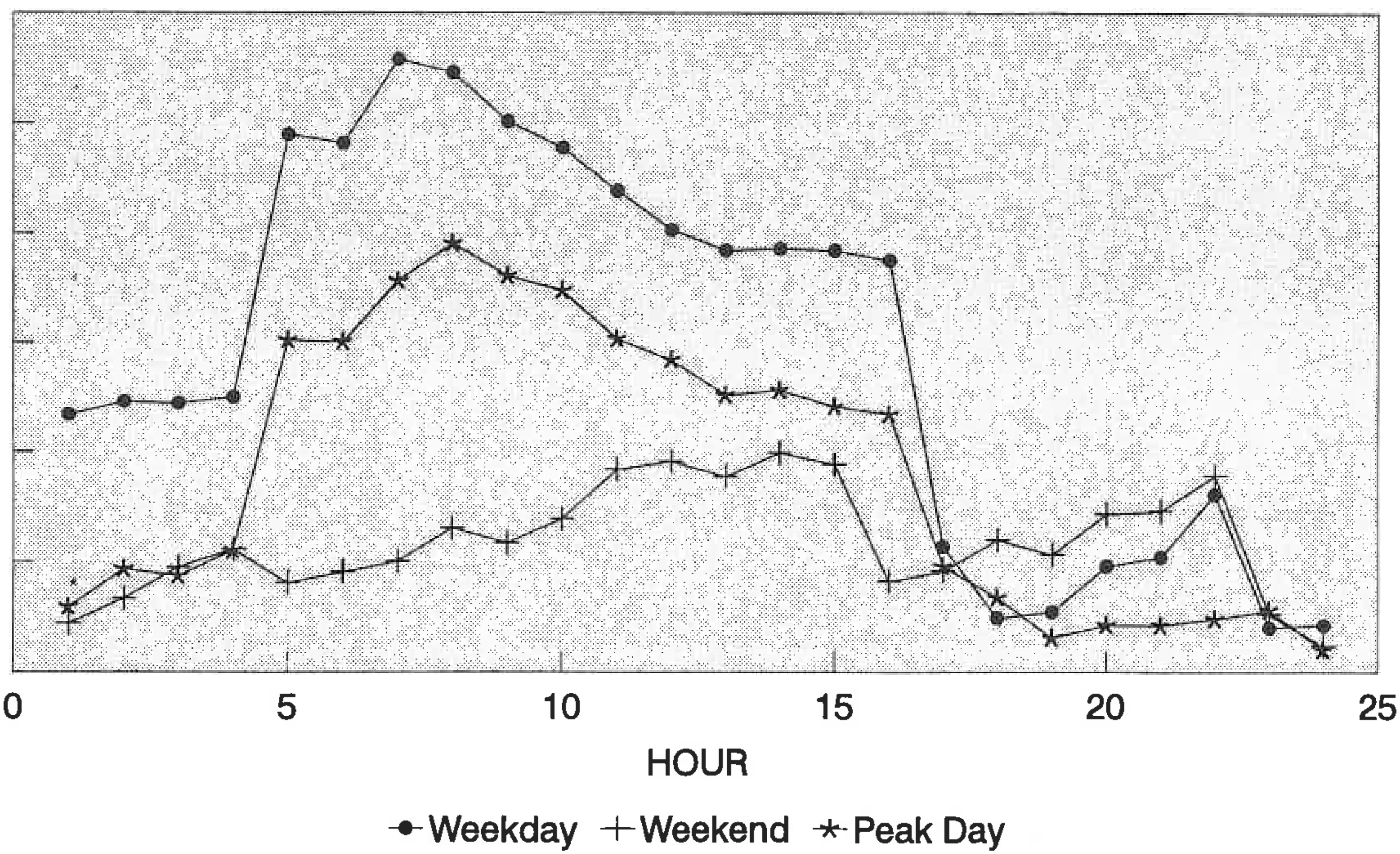

Fig. A-4 Commercial Sector

NORMALIZED LOAD SHAPES

New Northwest Building Stock Mix

January

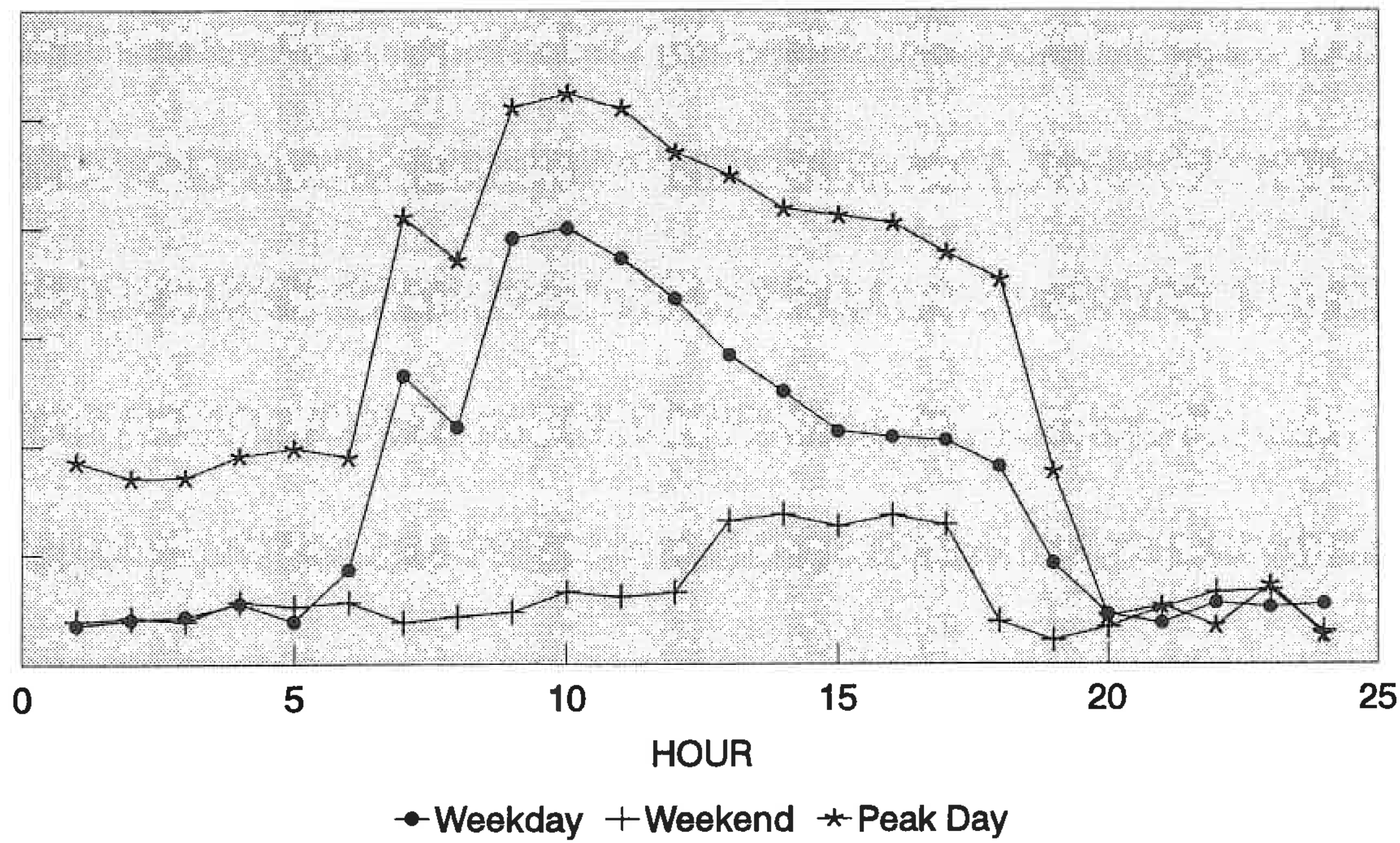

Fig. A-3 Commercial Sector

NORMALIZED LOAD SHAPES

Existing Utah Building Stock Mix

April

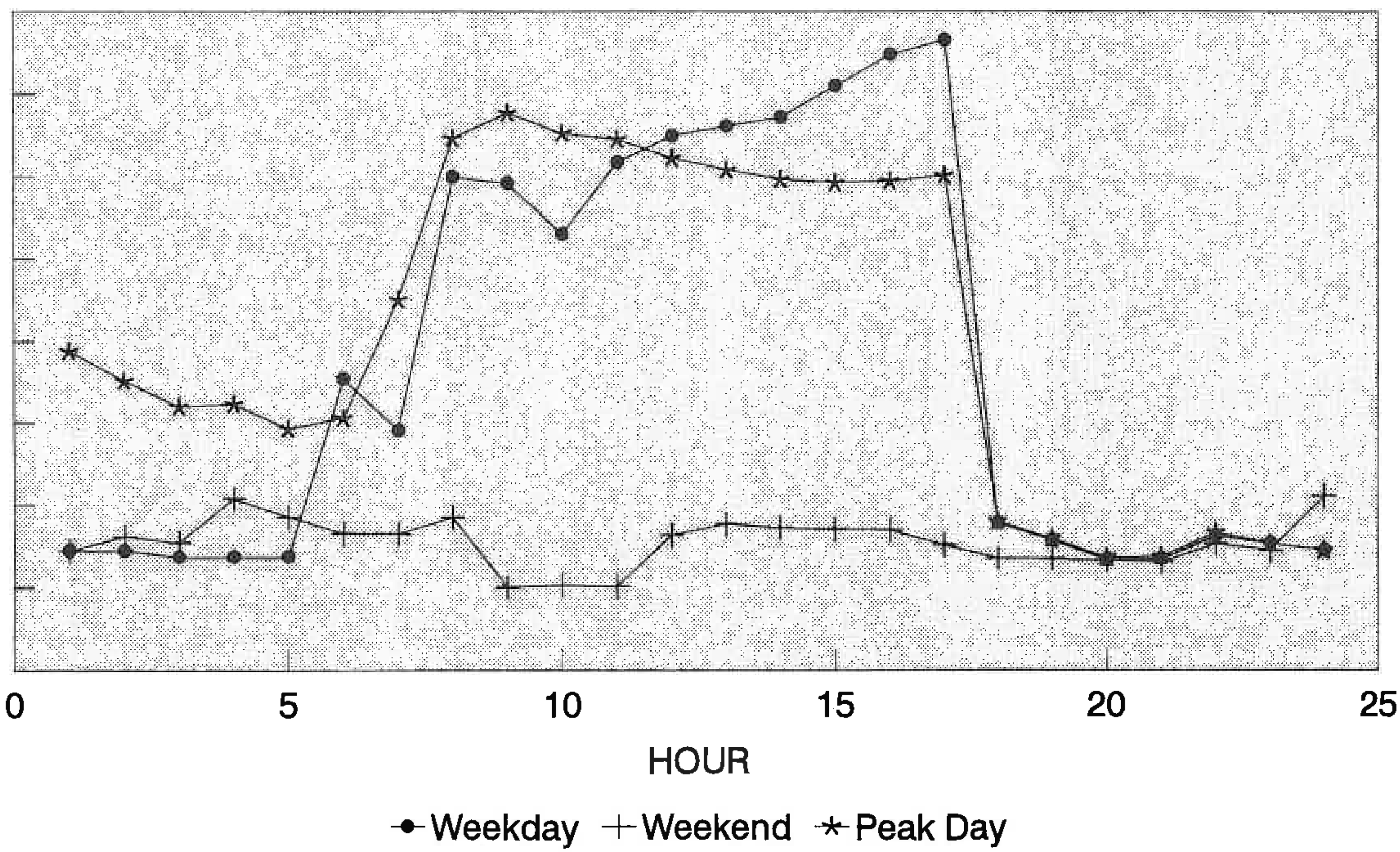

Fig. A-6 Existing Commercial Sector

NORMALIZED LOAD SHAPES
Existing Northwest Building Stock Mix
April

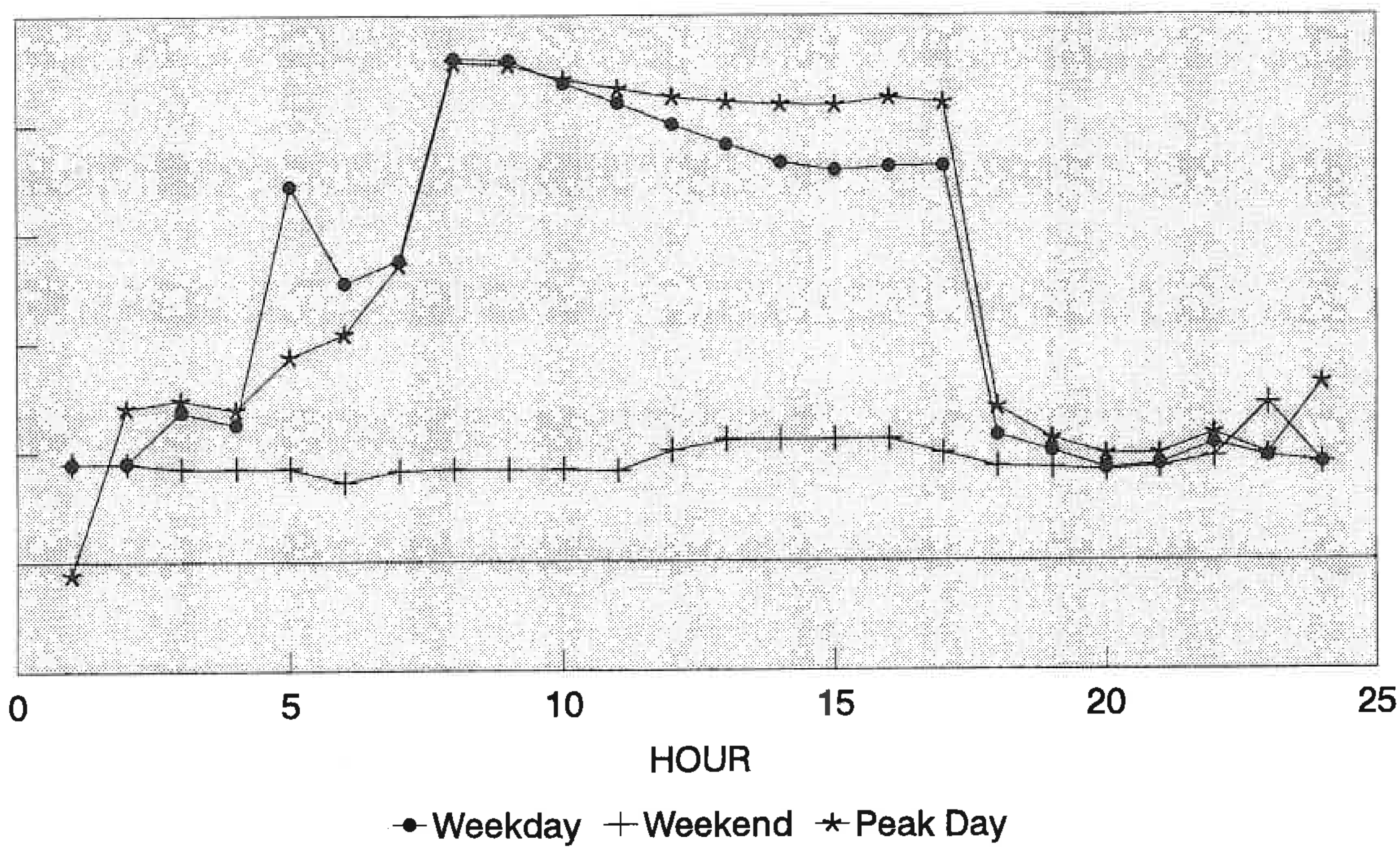

Fig. A-5 Existing Commercial Sector

NORMALIZED LOAD SHAPES

New Northwest Building Stock Mix

April

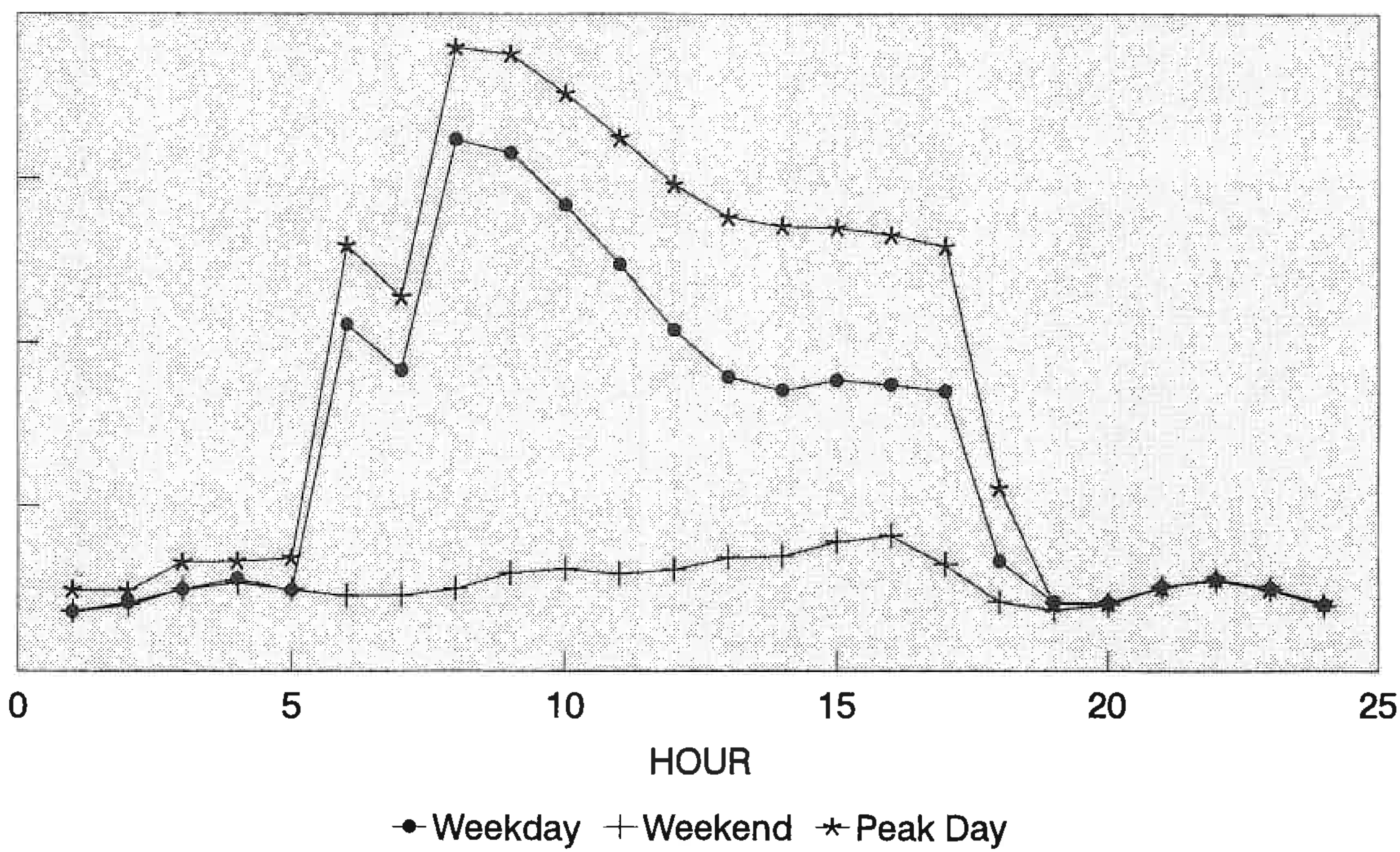

Fig. A-7 Commercial Sector

NORMALIZED LOAD SHAPES

New Utah Building Stock Mix

April

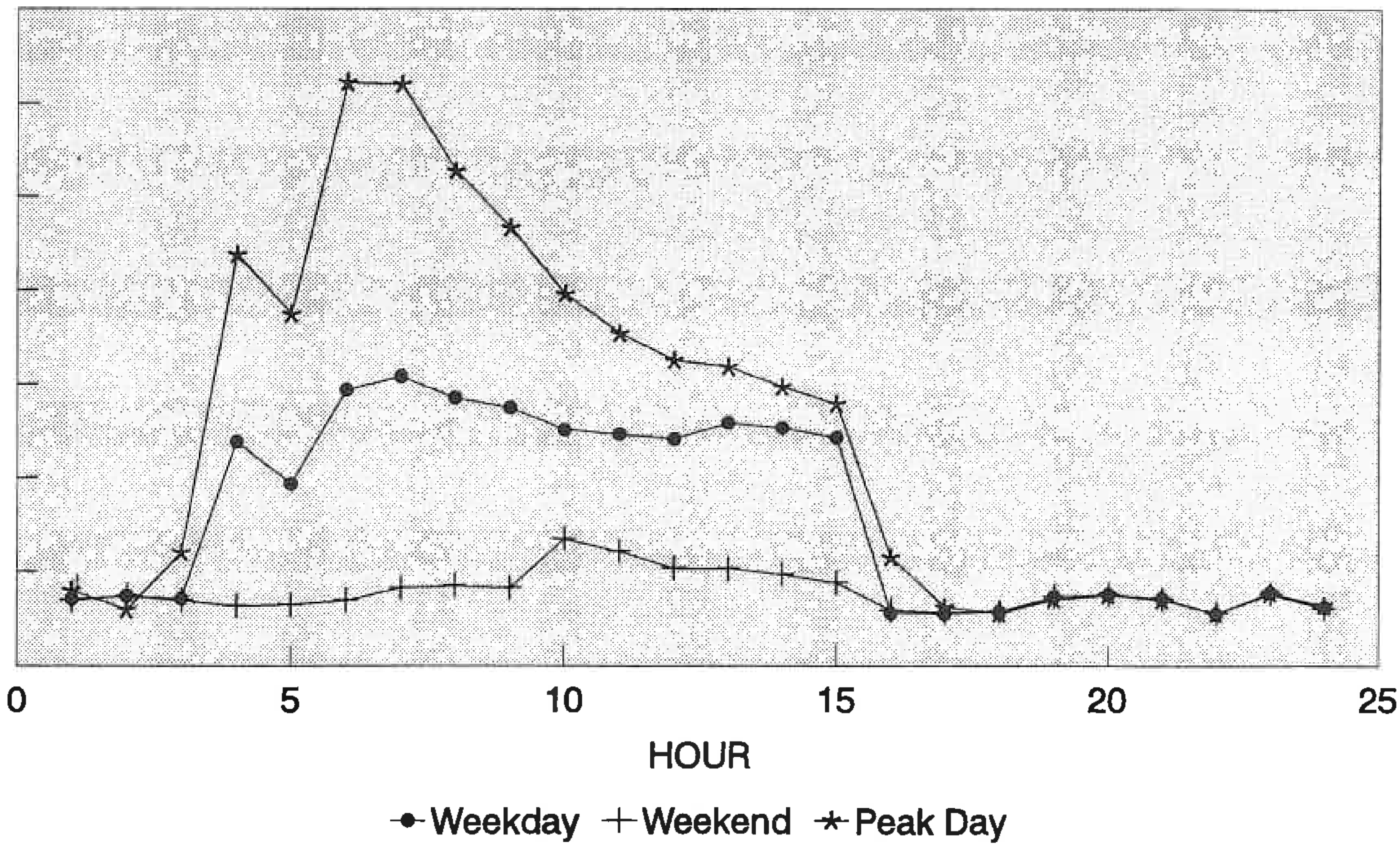

Fig. A-8 Commercial Sector

NORMALIZED LOAD SHAPE

Existing Northwest Building Stock Mix

August

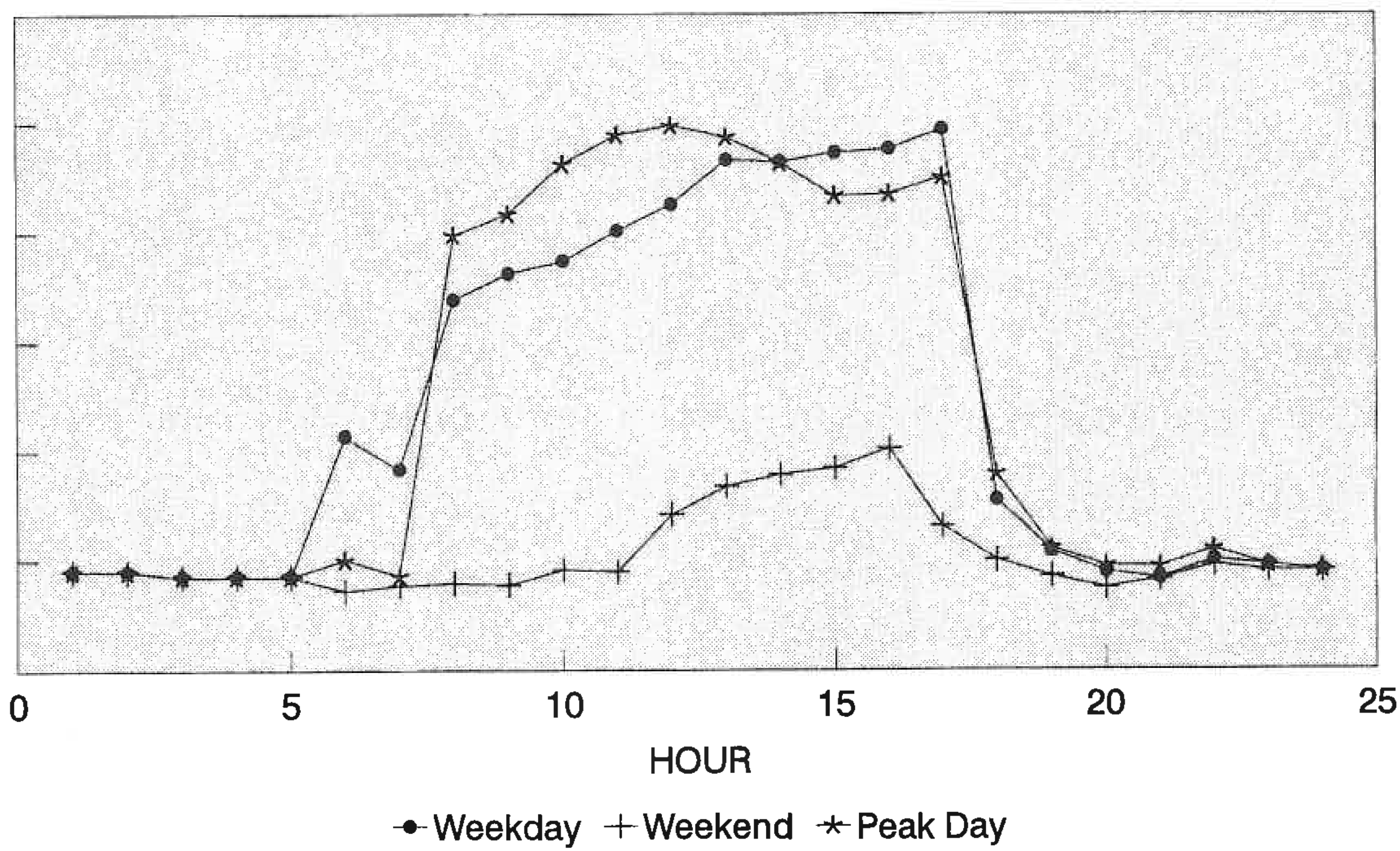

Fig. A-9 Existing Commercial Sector

NORMALIZED LOAD SHAPE

Existing Utah Building Stock Mix

August

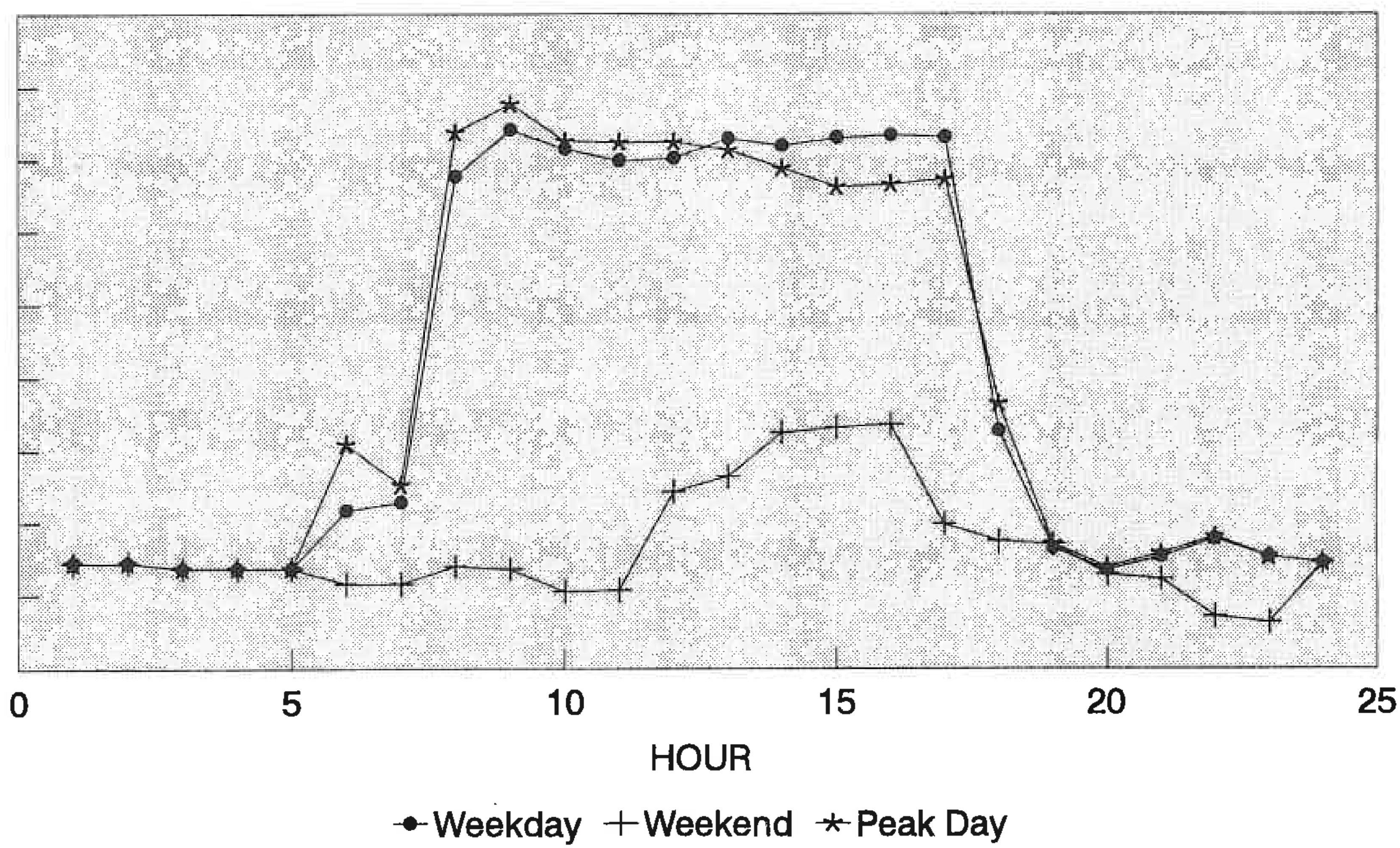

Fig. A-10 Existing Commercial Sector

NORMALIZED LOAD SHAPE
New Northwest Building Stock Mix
August

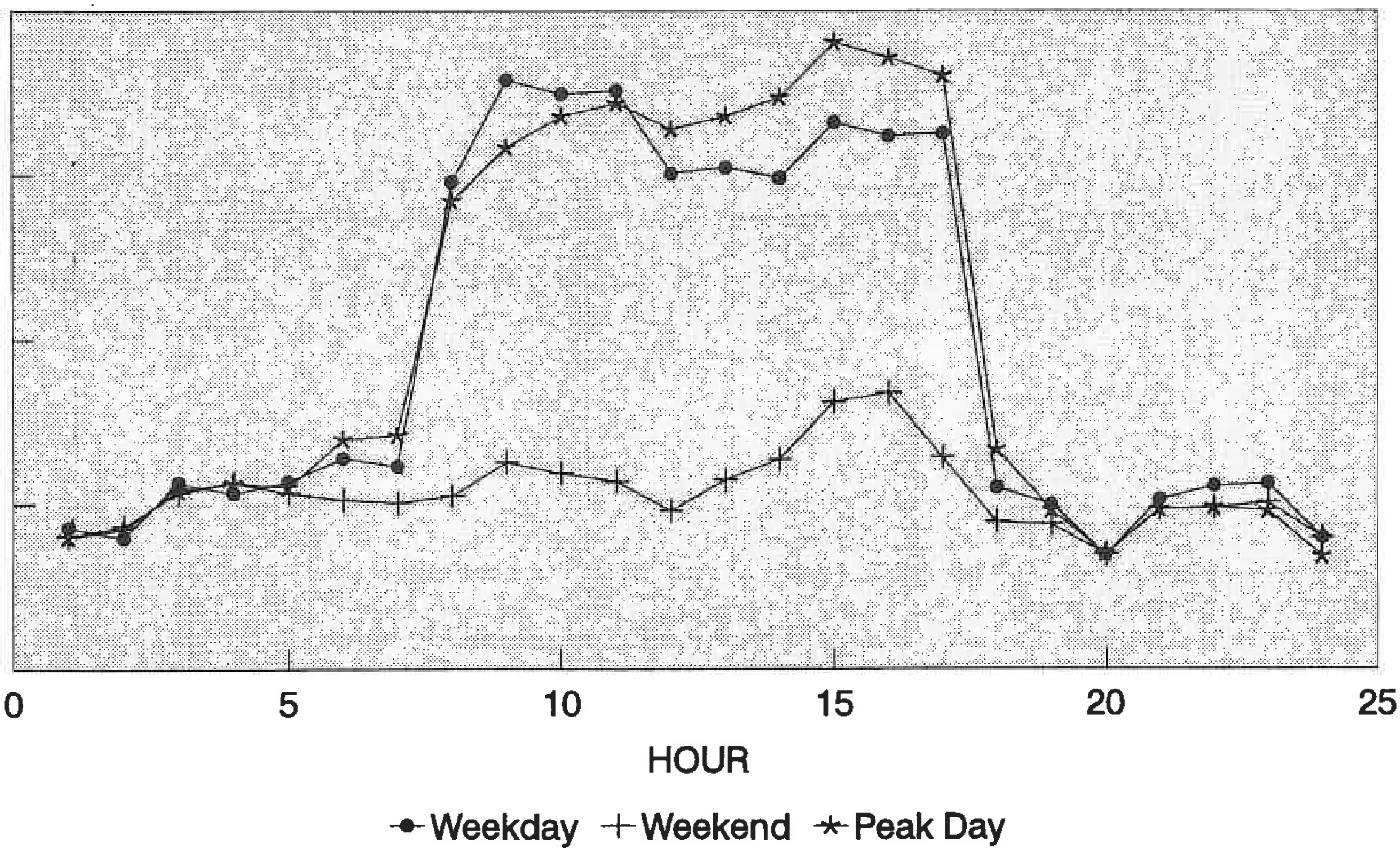

Fig. A-11 Commercial Sector

NORMALIZED LOAD SHAPE

New Utah Building Stock Mix

August

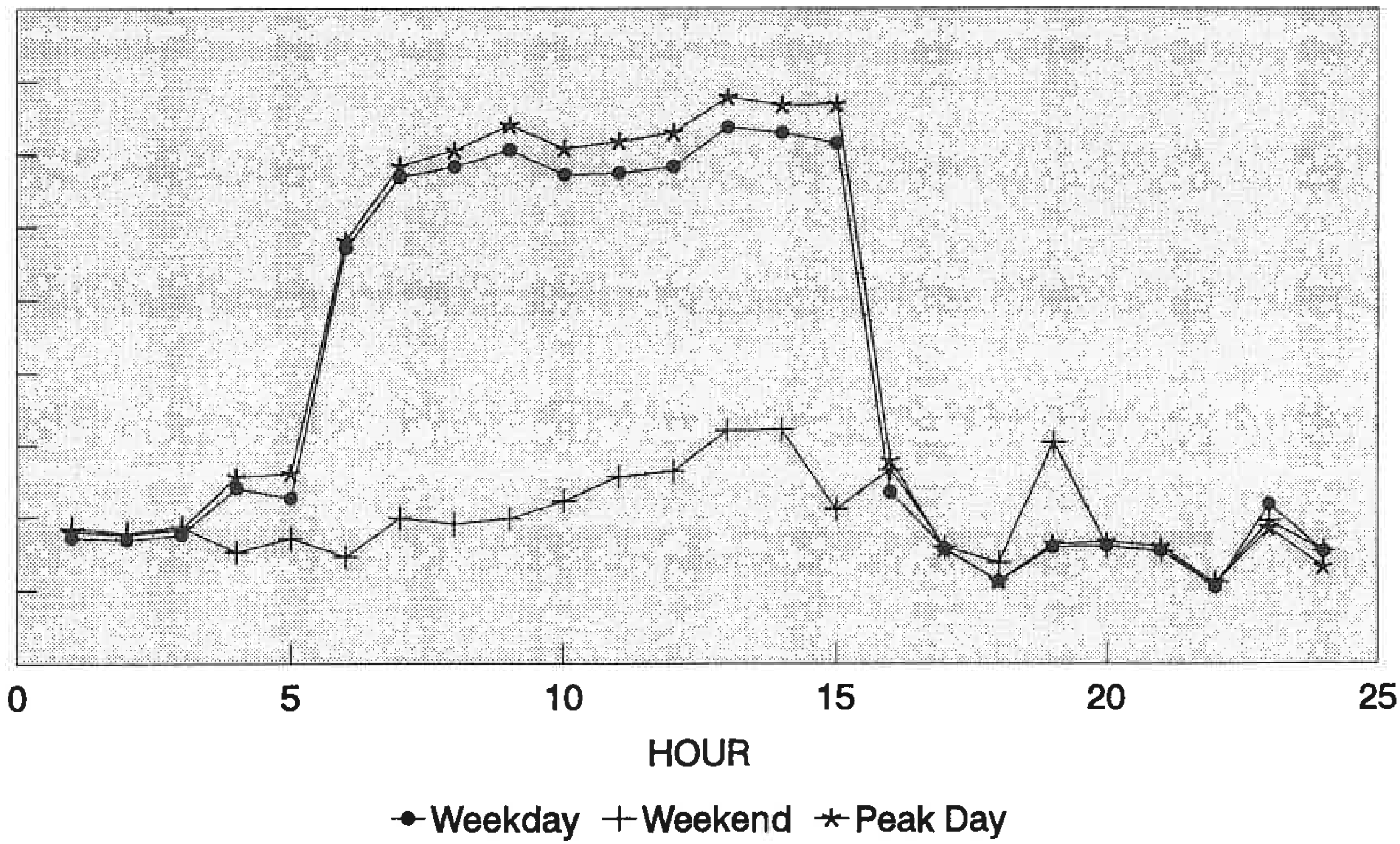

Fig. A-12 Commercial Sector

NORMALIZED LOAD SHAPE
Existing Northwest Building Stock Mix
October

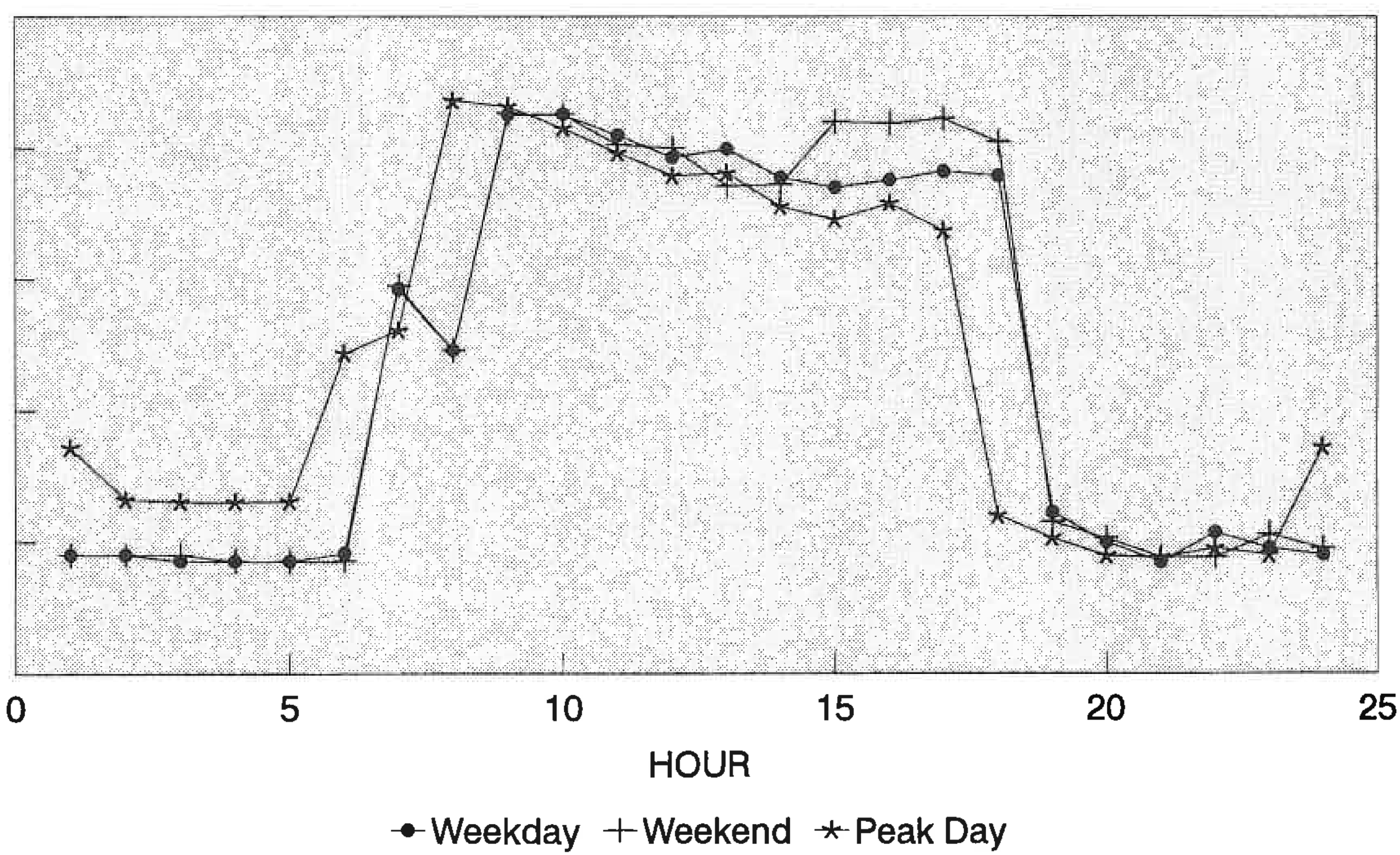

Fig. A-13 Existing Commercial Sector

NORMALIZED LOAD SHAPE

Existing Utah Building Stock Mix

October

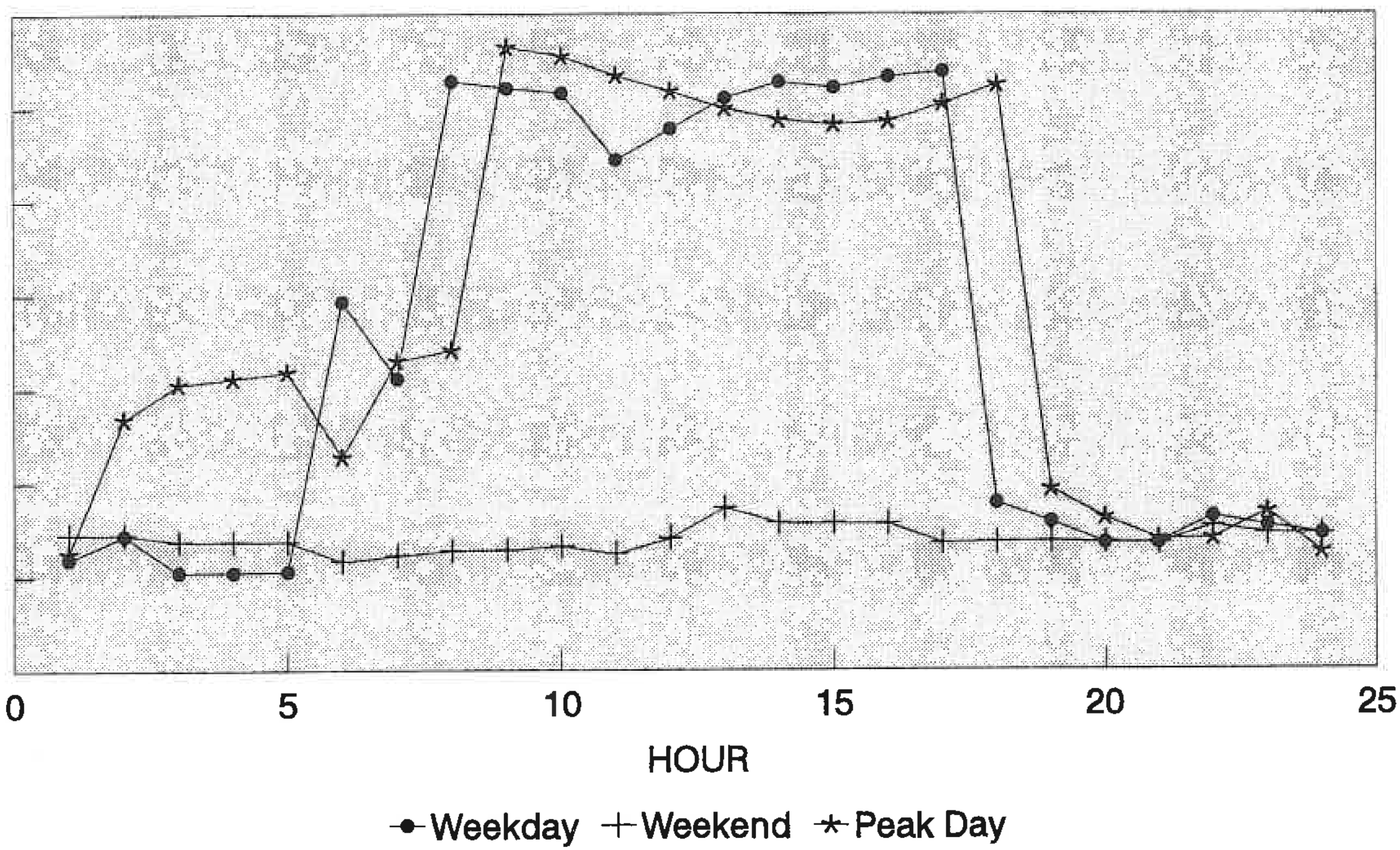

Fig. A-14 Existing Commercial Sector

NORMALIZED LOAD SHAPE
New Northwest Building Stock Mix
October

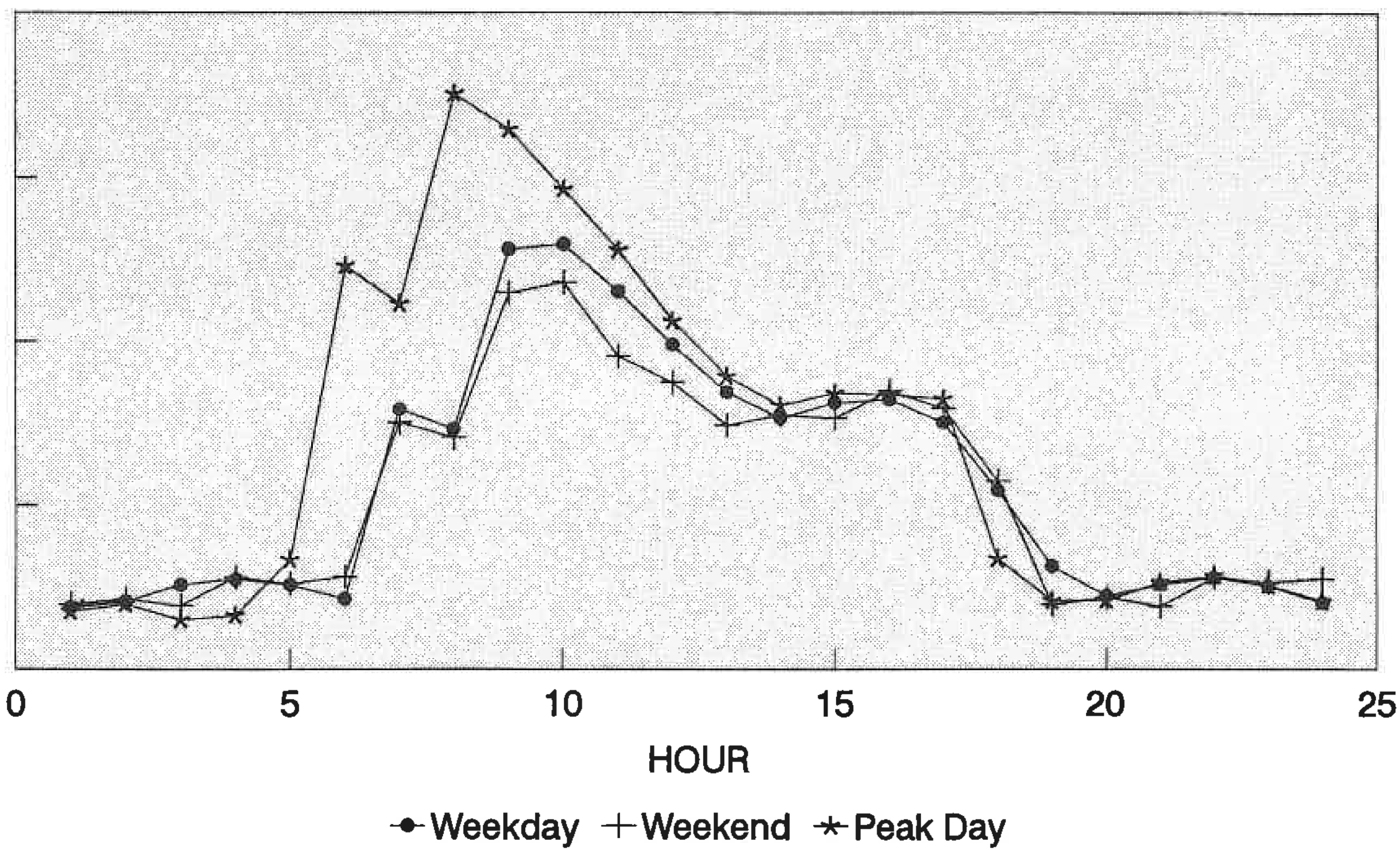

Fig. A-15 Commercial Sector

APPENDIX
B

Template for Residential Sector Appendices (B, C, D)

The worksheet structure for all the residential sector appendices, except for appliances, is similar, therefore only one template is shown for the appendices, B, C, and D. The first worksheet was chosen from appendix D to use as template for the appendix B and C.

Appendix D- Multifamiy Dwelling, Demand-Side Resources Worksheet

The following set of worksheets present assumptions and calculations used for the multi-family dwellings.

The worksheet identifier section, not labeled individually, includes name of state, the climate zone, vintage and size of the prototypical unit. The values presented in the other sections of the report could vary for each state, vintage, and climate zone. The prototypical multifamily unit analyzed is an 840 square foot unit.

The base consumption values.

A: Shows the number of multifamily apartments, in the year 2014. In this example or template worksheet, the number of units is 1,986. This means that we expect 1,986 units of current stock of multifamily units to be remaining.

B: Fuel factor is the adjustment factor derived from calibration of the modeled energy consumption to actual. The fuel factor is used in column P where the estimate of base use for the unit is calculated.

C: Take-back factor is used to adjust energy consumption due to customer take-back of savings. The savings from measures are reduced by (1- takeback factor) .

D: The energy use from the modeling is estimated using the following equation

Unit consumption (kWh/yr) = -3897.6 + 48.95 * UA

where:

-3897 is a constant value and
48.95 is the slope of line.

E: The slope of the line shows the magnitude of change in unit consumption for changes in UA.

F: The U value for the multifamily unit as a whole, UA, is calculated to be 279.8. This U value is used in column J as the baseline UA, rounded to the nearest whole number.

Columns G through I, summarize the results of the analysis presented in columns J through Q. The detailed analysis of columns J through Q will be discussed first and then column s O through I will be discussed.

J: This column shows the UA values, for the base building, and the energy conservation measure. The values presented here are inputs from the engineering analysis.

K: For the first measure Delta UA is the incremental change from the base case units' UA. All subsequent UAs' are incremental to the base case plus the previous UA.

L: First incremental cost of the measures, is the difference in cost of the energy conservation measure compared to the base case measure. The incremental cost figures include the replacement cost of the measure.

M: The measure life is not the actual operational or service life of the equipment but an analysis period. This measure life presented in this column is used to create common analysis platform for all the measures with varying measure lives.

N: Measure Acceptance is a percentage of the qualifying homes that the measure can be applied to. For the residential markets, this measure acceptance is based on study by Bardsley and Haslicher, reference number 2.

O: Penetration Rate is the percentage of market expected to be reached. At this point in the analysis technical potential is assumed to reach 100 percent of the market. The program penetration rates, which are less than 100 percent, will be discussed in the program section of the technical appendix.

P: The use (kwh/year), column P is the consumption level for the Base Unit with and without energy conservation measures. The consumption level is calculated using the following equation.: *Use = (D + E* J)* (1-B)*

This works for first line but doesn't work for subsequent lines

Where::

D	*is energy use conversion constant* (kwh/yr)
E	*is energy use conversion Slope* (kwy/(Btu/hr-F))/yr
J	*is composite U factor for the unit*
B	*is Fuel factor*

Q: The column savings is the incremental savings from each measure and is calculated as follows:

K

Savings = (D + E (J) * (1-B)* (1-C)* N * O*

This does not work

Where:

	D	*is energy use conversion constant* (kwy/yr)
	E	*is energy use conversion Slope* (kwh/Btu/hr-F))/yr
K	**J**	*is Delta UA factor for measure*
	B	*is fuel factor*
	C	*is take-back factor*
	N	*i s acceptance factor for measure*
	O	*is penetration rate*

Note that savings from each measure is the incremental savings, and will depend or will be influenced on savings from the other measures already installed.

R: The capital recovery factor use to levelize costs.

S: The variable levelized cost for each measures is calculated using the savings from the measure, the capital recovery factor and the annual savings.

T: The values of MW savings from each measure presented in the last column is for the total savings. The measure savings is calculated as follows:

*Measure savings (MW/yr) = A * Q / (8670 * 1000)*

where:
A *is the number of homes in sector matching prototype*
Q *is the savings per measure (kwh/yr)*
8760 *is number hours per year.*
1000 *is to convert from KW to MW.*

The savings and levelized costs are summarized in columns G-I, middle table, and are described below:

G: Average levelized cost is calculated using the measure savings in MW and the variable levelized cost for the measure. Average levelized costs are savings weighted average of variable levelized cost.

H: Same information as variable levelized cost.

I: Same information as annual savings (MW/yr) .

Appendix D - Multifamily Dwellings, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
DATE OF RUN: 02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	1,986	(A)
FUEL FACTOR	61.90%	(B)
TAKE-BACK FACTOR	30.00%	(C)
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-3897.60	(D)
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	48.95	(E)
BASE UA	279.8	(F)

Template for Residential Tables

STATE	**MONTANA**
CLIMATE ZONE	**3**
VINTAGE OF HOUSING	**EXISTING**
PROTOTYPE SIZE (SQFT)	**840**

(G) AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	ANNUAL MEASURE SAVINGS (MW/YR)	(H) LEVELIZED COST (mills/kWh)	(I) CUMULATIVE SAVINGS (MW/YR)
21.988	W1 WIND SG>STORM	0.059	21.988	0.059
28.371	WALLS R0>R11	0.032	39.987	0.091
48.569	W2 REPLACE SG> VINYL	0.074	73.379	0.165
60.139	ACH .6>.5	0.041	107.098	0.206
67.486	F1 FLOOR R0>R19	0.021	138.626	0.227
69.668	C2 CEIL R38>49 AFT C1	0.002	281.006	0.230
77.241	C1 CEIL R19>38	0.005	439.031	0.235
85.172	DOOR INSUL	0.004	591.384	0.238
96.645	CEILING R17>R49	0.005	610.681	0.244

input from engineering analys

CONSERVATION MEASURES	(J) UA (Btu/hr-F)	(K) DELTA U/A (Btu/hr-F)	(L) FIRST INCRMT. COST($)	(M) MEASURE LIFE(YRS)	(N) MEASURE ACCEPTANCE	(o) PENETRATION RATE	(P) USE (kWh/YR)	(Q) SAVINGS (kWh/YR)	(R) CAPITAL RECOVERY FACTOR	(S) VARIABLE LEVELIZED COST (mills/kWh)	(T) MEASURE SAVINGS (MW/YR)
BASE CASE	280	---	---	---	---	---	3734	---	---	---	---
W1 WIND SG>STORM	260	45.60	196.01	30	44%	100%	3474	260	0.067	21.988	0.059
WALLS R0>R11	249	43.88	343.02	30	25%	100%	3331	143	0.067	39.987	0.032
W2 RPLC SG> VINYL	224	57.00	817.67	30	44%	100%	3004	327	0.067	73.379	0.074
ACH .6>.5	210	13.77	288.30	30	100%	100%	2824	180	0.067	107.098	0.041
F1 FLOOR R0>R19	203	26.45	716.81	30	27%	100%	2730	94	0.067	138.626	0.021
C1 CEIL R19>38	201	5.42	464.96	30	30%	100%	2709	21	0.067	439.031	0.005
C2 CEIL R38>49 AFT C1	201	2.64	145.30	30	30%	100%	2699	10	0.067	281.006	0.002
DOOR INSUL	199	1.38	159.54	30	90%	100%	2682	16	0.067	591.384	0.004
CEILING R17>R49	197	5.99	715.11	30	30%	100%	2659	23	0.067	610.681	0.005

L × R / Q = S

(D+E*K)*(1-B)*(1-C)*N*O = Q

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
DATE OF RUN: 02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	1173
FUEL FACTOR	56%
TAKE-BACK FACTOR	30%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-4055.6
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	47.044

STATE	MONTANA
CLIMATE ZONE	3
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQFT)	850

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
	HEAT PUMP	0.000	0.000	
11.523	C1 CEIL R0>38	0.004	11.523	0.004
12.135	C5 CEIL R0>R49	0.004	12.719	0.008
25.431	F1 FLOOR R0>R19	0.047	27.756	0.056
28.130	WALLS R0>R11	0.031	32.923	0.087
33.698	ACH .7>.4	0.071	40.514	0.158
35.698	C6 CEIL R15>R49	0.023	49.481	0.181
38.104	C3 CEIL R15>R38	0.018	62.418	0.199
43.386	RPLC WNDW SG>VNYL	0.051	63.867	0.250
44.887	C7 CEIL R20>R49	0.012	77.295	0.261
48.029	CLOCK THERMOSTAT	0.025	81.108	0.286
48.855	WALLS R3>R11	0.006	86.626	0.292
49.589	C9 CEIL R38>49	0.005	89.491	0.298
49.863	C8 CEIL R37>49	0.002	91.278	0.300
53.276	DOOR INSUL	0.019	105.830	0.319
53.512	C3 CEIL R20>38	0.001	127.892	0.320
54.098	F2 FLOOR R11>R19	0.002	130.651	0.323
54.147	C4 CEIL R37>38	0.000	654.733	0.323

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	389.00	---	---	---	---	---	6239	---	---	0.000	0.000
C1 CEIL R0>38	386.91	209.10	612.35	50	1%	100%	6209	30	0.057	11.523	0.004
C5 CEIL R0>R49	384.72	219.05	708.10	50	1%	100%	6177	32	0.057	12.719	0.004
WALLS R0>R11	368.52	85.25	713.32	50	19%	100%	5944	234	0.057	32.923	0.031
F1 FLOOR R0>R19	344.04	76.50	539.65	50	32%	100%	5591	353	0.057	27.756	0.047
ACH .7>.4	307.32	36.72	321.31	30	100%	100%	5061	530	0.067	40.514	0.071
C6 CEIL R15>R49	295.47	45.60	573.44	50	26%	100%	4890	171	0.057	49.481	0.023
C3 CEIL R15>R38	286.21	35.60	564.74	50	26%	100%	4756	134	0.057	62.418	0.018
RPLC WNDW SG>VNYL	259.70	56.40	777.98	30	47%	100%	4374	382	0.067	63.867	0.051
C7 CEIL R20>R49	253.71	23.04	452.61	50	26%	100%	4288	86	0.057	77.295	0.012
WALLS R3>R11	250.47	32.40	713.32	50	10%	100%	4241	47	0.057	86.626	0.006
CLOCK THERMOSTAT	237.62	17.13	300.10	30	75%	100%	4056	185	0.067	81.108	0.025
C9 CEIL R38>49	234.84	9.95	226.30	50	28%	100%	4015	40	0.057	89.491	0.005
C8 CEIL R37>49	233.82	11.31	262.37	50	9%	100%	4001	15	0.057	91.278	0.002
DOOR INSUL	223.74	11.20	256.00	30	90%	100%	3855	145	0.067	105.830	0.019
C3 CEIL R20>38	223.21	13.09	425.47	50	4%	100%	3848	8	0.057	127.892	0.001
F2 FLOOR R11>R19	221.94	14.11	468.52	50	9%	100%	3830	18	0.057	130.651	0.002
C4 CEIL R37>38	221.93	1.36	226.30	50	1%	100%	3829	0	0.057	654.733	0.000
HEAT PUMP	221.93	4.59	2870.32	30	0%	100%	3829	0	0.067	0.000	0.000

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
DATE OF RUN: 02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	1063
FUEL FACTOR	71%
TAKE-BACK FACTOR	30%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-7353.2
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	52.6325

STATE	MONTANA
CLIMATE ZONE	3
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQFT)	1350

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	MEASURE SAVINGS (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
	HEAT PUMP	0.000	0.000	
22.950	DUCT SEAL/INSULATE	0.006	22.950	0.006
33.845	ACH .7>.4	0.075	34.676	0.081
34.300	WALLS R0>R11	0.022	35.956	0.103
36.857	F1 FLOOR R0>R19	0.065	40.913	0.168
38.508	C1 CEIL R8>38	0.009	68.770	0.177
39.951	C5 CEIL R8>49	0.008	70.259	0.185
47.090	RPLC WNDW SG>VNYL	0.040	79.959	0.226
50.171	CLOCK THERMOSTAT	0.022	81.108	0.248
51.938	C6 CEIL R13>49	0.014	84.243	0.262
53.530	C2 CEIL R13>38	0.013	84.599	0.275
54.042	C7 CEIL R21>49	0.001	152.909	0.277
56.137	F2 FLOOR R11>19	0.006	156.320	0.282
60.704	DOOR INSUL	0.013	160.101	0.295
61.139	C3 CEIL R21>38	0.001	163.219	0.297
61.327	C8 CEIL R37>49	0.000	202.178	0.297
63.101	C9 CEIL R38>49	0.003	237.337	0.300
67.097	WALLS R6>11	0.004	374.323	0.304

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	563.00	---	---	---	---	---	6416	---	---	0.000	0.000
WALLS R0>R11	545.78	132.44	890.33	50	13%	100%	6234	183	0.057	35.956	0.022
F1 FLOOR R0>R19	495.36	112.05	857.09	50	45%	100%	5699	535	0.057	40.913	0.065
DUCT SEAL/INSULATE	490.92	49.38	180.06	30	9%	100%	5651	47	0.067	22.950	0.006
ACH .7>.4	432.60	58.32	321.31	30	100%	100%	5033	619	0.067	34.676	0.075
C1 CEIL R8>38	425.48	64.67	831.49	50	11%	100%	4957	75	0.057	68.770	0.009
C5 CEIL R8>49	418.93	72.77	955.90	50	9%	100%	4888	69	0.057	70.259	0.008
RPLC WNDW SG>VNYL	387.64	89.40	1135.76	30	35%	100%	4556	332	0.067	79.959	0.040
C6 CEIL R13>49	377.10	55.49	873.98	50	19%	100%	4444	112	0.057	84.243	0.014
C2 CEIL R13>38	366.67	47.39	749.57	50	22%	100%	4333	111	0.057	84.599	0.013
CLOCK THERMOSTAT	349.21	23.29	300.10	30	75%	100%	4148	185	0.067	81.108	0.022
C7 CEIL R21>49	348.10	27.67	791.04	50	4%	100%	4136	12	0.057	152.909	0.001
F2 FLOOR R11>19	343.61	23.65	691.20	50	19%	100%	4088	48	0.057	156.320	0.006
C3 CEIL R21>38	342.63	19.58	597.50	50	5%	100%	4078	10	0.057	163.219	0.001
DOOR INSUL	332.55	11.20	284.90	30	90%	100%	3971	107	0.067	160.101	0.013
C8 CEIL R37>49	332.24	10.24	387.07	50	3%	100%	3968	3	0.057	202.178	0.000
C9 CEIL R38>49	329.89	8.10	359.42	50	29%	100%	3943	25	0.057	237.337	0.003
WALLS R6>11	326.86	12.13	848.92	50	25%	100%	3911	32	0.057	374.323	0.004
HEAT PUMP	326.86	8.96	2870.32	30	0%	100%	3911	0	0.067	0.000	0.000

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
DATE OF RUN: 02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	1097
FUEL FACTOR	70%
TAKE-BACK FACTOR	30%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-10593.4
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	52.0272

STATE	MONTANA
CLIMATE ZONE	3
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQFT)	2100

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	MEASURE SAVINGS (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
	HEAT PUMP	0.000	0.000	
	HEAT PUMP AFTER A/C	0.000	0.000	
20.198	ACH .7>.4	0.133	20.198	0.133
20.390	DUCT SEAL/INSULATE	0.012	22.514	0.145
25.101	WALLS R0>R11	0.067	35.271	0.212
39.875	REPLC WNDW SG>VNYL	0.156	59.960	0.368
42.319	CLOCK THERMOSTAT	0.023	81.108	0.392
42.925	C3 CEIL R17>49	0.005	86.671	0.397
43.208	C1 CEIL R17>38	0.002	101.200	0.399
43.552	C4 CEIL R19>49	0.002	106.753	0.401
43.704	C2 CEIL R19>38	0.001	145.834	0.402
44.271	C5 CEIL R35>49	0.002	146.770	0.404
47.958	DOOR INSUL	0.014	157.056	0.418
50.386	WALLS R6>11	0.003	367.143	0.421

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	835.00	---	---	---	---	---	9756	---	---	0.000	0.000
ACH .7>.4	736.78	98.22	321.31	30	100%	100%	8694	1062	0.067	20.198	0.133
DUCT SEAL/INSULATE	727.89	49.38	180.06	30	18%	100%	8598	96	0.067	22.514	0.012
WALLS R0>R11	678.27	198.47	1334.17	50	25%	100%	8061	537	0.057	35.271	0.067
RPLAC WNDW SG>VNYL	562.98	189.00	2159.83	50	61%	100%	6814	1247	0.057	59.960	0.156
C3 CEIL R17>49	558.97	28.64	473.09	50	14%	100%	6771	43	0.057	86.671	0.005
CLOCK THERMOSTAT	541.84	22.84	300.10	30	75%	100%	6585	185	0.067	81.108	0.023
C1 CEIL R17>38	540.41	20.44	394.24	50	7%	100%	6570	15	0.057	101.200	0.002
C4 CEIL R19>49	538.81	22.90	465.92	50	7%	100%	6552	17	0.057	106.753	0.002
C2 CEIL R19>38	538.37	14.70	408.58	50	3%	100%	6548	5	0.057	145.834	0.001
C5 CEIL R35>49	536.73	8.20	229.38	50	20%	100%	6530	18	0.057	146.770	0.002
DOOR INSUL	526.65	11.20	284.90	30	90%	100%	6421	109	0.067	157.056	0.014
HEAT PUMP AFTER A/C	526.65	14.03	757.76	30	0%	100%	6421	0	0.067	0.000	0.000
WALLS R6>11	524.28	18.18	1272.12	50	13%	100%	6395	26	0.057	367.143	0.003
HEAT PUMP	524.28	14.03	2870.32	30	0%	100%	6395	0	0.067	0.000	0.000

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014	# OF HOMES IN SECTOR MATCHING PROTOTYPE	53	STATE	MONTANA
DATE OF RUN: 02-Dec-93	FUEL FACTOR	0%	CLIMATE ZONE	3
	TAKE-BACK FACTOR	0%	VINTAGE OF HOUSING	NEW
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-6041.2	PROTOTYPE SIZE (SQ. FT.)	1344
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	29.4023		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
1.187	SOLAR ORIENT.	0.006	1.187	0.006
2.582	LTSGS WINDOWS	0.002	6.989	0.007
3.252	SOLAR WINDOWS	0.001	12.673	0.008
15.404	PASSIVE SOLAR DESIGN	0.003	52.948	0.010
32.250	LTSGS ENVELOPE	0.009	52.949	0.019
47.941	WALL R26 A>R40 BDW	0.003	152.848	0.022
65.417	CLASS 20 WINDOW	0.004	167.754	0.026
68.156	FLOOR R30>R38	0.001	199.624	0.026

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	292.00	---	---	---	---	---	2544	---	---	0.000	0.000
SOLAR ORIENT.	260.40	31.60	20.48	70	100%	100%	1615	929	0.054	1.187	0.006
SOLAR WINDOWS	257.44	2.96	20.48	70	100%	100%	1528	87	0.054	12.673	0.001
LTSGS WINDOWS	247.44	10.00	30.77	30	100%	100%	1234	294	0.067	6.989	0.002
LTSGS ENVELOPE	0.00	48.00	1388.03	70	100%	100%	0	1411	0.054	52.949	0.009
PASSIVE SOLAR DSGN	0.00	14.42	417.00	70	100%	100%	0	424	0.054	52.948	0.003
WALL R26 A>R40 BDW	0.00	16.00	1335.61	70	100%	100%	0	470	0.054	152.848	0.003
CLASS 20 WINDOW	0.00	21.00	1551.00	30	100%	100%	0	617	0.067	167.754	0.004
FLOOR R30>R38	0.00	3.00	327.07	70	100%	100%	0	88	0.054	199.624	0.001

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014	# OF HOMES IN SECTOR MATCHING PROTOTYPE	37	STATE	MONTANA
DATE OF RUN: 02-Dec-93	FUEL FACTOR	0%	CLIMATE ZONE	3
	TAKE-BACK FACTOR	0%	VINTAGE OF HOUSING	NEW
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-8731.9	PROTOTYPE SIZE (SQ. FT.)	1848
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	43.6286		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
1.151	SOLAR ORIENT.	0.004	1.151	0.004
1.497	SOLAR WINDOWS	0.002	2.141	0.006
3.802	INCRM. HEAT PUMP EFF.	0.000	39.724	0.007
25.452	LTSGS ENVELOPE	0.009	41.327	0.016
28.201	LTSGS WINDOWS	0.002	46.159	0.018
32.428	PASSIVE SOLAR DESIGN	0.002	77.466	0.020
43.942	WALL R26 A>R40 BDW	0.006	82.485	0.026
54.861	CLASS 20 WINDOW	0.005	111.124	0.031
56.799	FLOOR R30>R38	0.001	175.117	0.031

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	416.00	---	---	---	---	---	9418	---	---	0.000	0.000
SOLAR ORIENT.	394.04	21.96	20.48	70	100%	100%	8460	958	0.054	1.151	0.004
SOLAR WINDOWS	382.24	11.80	20.48	70	100%	100%	7945	515	0.054	2.141	0.002
LTSGS WINDOWS	369.24	13.00	392.02	30	100%	100%	7377	567	0.067	46.159	0.002
LTSGS ENVELOPE	320.24	49.00	1641.02	70	100%	100%	5240	2138	0.054	41.327	0.009
WALL R26 A>R40 BDW	288.24	32.00	2139.03	70	100%	100%	3844	1396	0.054	82.485	0.006
PASSIV SOLAR DSIGN	279.05	9.19	577.00	70	100%	100%	3443	401	0.054	77.466	0.002
CLASS 20 WINDOW	252.05	27.00	1960.11	30	100%	100%	2265	1178	0.067	111.124	0.005
FLOOR R30>R38	249.33	2.72	386.00	70	100%	100%	2146	119	0.054	175.117	0.001
INCRM. HEAT PMP EFF	247.16	17.79	461.58	30	12%	100%	2051	95	0.067	39.724	0.000

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014	# OF HOMES IN SECTOR MATCHING PROTOTYPE	1		STATE	MONTANA
DATE OF RUN: 02-Dec-93	FUEL FACTOR	0%		CLIMATE ZONE	3
	TAKE-BACK FACTOR	0%		VINTAGE OF HOUSING	NEW
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-10593.4		PROTOTYPE SIZE (SQ. FT.)	2352
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	51.1007			

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
0.735	SOLAR ORIENT.	0.000	0.735	0.000
0.964	SOLAR WINDOWS	0.000	1.403	0.000
18.018	LTSGS ENVELOPE	0.000	37.099	0.000
21.891	LTSGS WINDOWS	0.000	40.129	0.001
30.759	INCRM. HEAT PUMP EFF.	0.000	54.752	0.001
34.151	PASSIVE SOLAR DESIGN	0.000	85.441	0.001
40.494	WALL R26 A>R40 BDW	0.000	85.816	0.001
50.403	CLASS 20 WINDOW	0.000	95.003	0.001
51.220	FLOOR R30>R38	0.000	222.116	0.001

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	476.00	---	---	---	---	---	13731	---	---	0.000	0.000
SOLAR ORIENT.	446.63	29.37	20.48	70	100%	100%	12230	1501	0.054	0.735	0.000
SOLAR WINDOWS	431.25	15.38	20.48	70	100%	100%	11444	786	0.054	1.403	0.000
LTSGS ENVELOPE	391.25	40.00	1408.55	70	100%	100%	9400	2044	0.054	37.099	0.000
LTSGS WINDOWS	373.25	18.00	552.71	30	100%	100%	8480	920	0.067	40.129	0.000
INCRM. HEAT PMP EFF	335.27	16.14	461.58	15	235%	100%	6539	1941	0.098	54.752	0.000
WALL R26 A>R40 BDW	314.27	21.00	1710.54	70	100%	100%	5466	1073	0.054	85.816	0.000
CLASS 20 WINDOW	276.27	38.00	2762.39	30	100%	100%	3524	1942	0.067	95.003	0.000
PASSVE SOLAR DSGN	266.96	9.31	754.69	70	100%	100%	3049	476	0.054	85.441	0.000
FLOOR R30>R38	265.96	1.00	210.83	70	100%	100%	2997	51	0.054	222.116	0.000

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR:
2014
DATE OF RUN:
02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	24129
FUEL FACTOR	44%
TAKE-BACK FACTOR	30%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-4943
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	35.2623

STATE	**OREGON**
CLIMATE ZONE	**1**
VINTAGE OF HOUSING	**EXISTING**
PROTOTYPE SIZE (SQ. FT.)	**850**

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
11.981	C1 CEIL R0>38	0.080	11.981	0.080
12.617	C5 CEIL R0>R49	0.084	13.225	0.164
26.442	F1 FLOOR R0>R19	0.935	28.860	1.099
29.248	WALLS R0>R11	0.619	34.232	1.718
35.037	ACH .7>.4	1.403	42.125	3.121
37.117	C6 CEIL R15>R49	0.453	51.448	3.574
39.619	C3 CEIL R15>R38	0.354	64.899	3.928
45.111	RPLACE WNDW SG>VNYL	1.013	66.406	4.941
46.672	C7 CEIL R20>R49	0.229	80.368	5.169
49.767	CLOCK THERMOSTAT	0.510	81.108	5.680
50.626	WALLS R3>R11	0.124	90.070	5.804
51.390	C9 CEIL R38>49	0.106	93.049	5.910
51.675	C8 CEIL R37>49	0.039	94.907	5.949
55.224	DOOR INSUL	0.385	110.037	6.334
55.469	C3 CEIL R20>38	0.020	132.976	6.354
56.078	F2 FLOOR R11>R19	0.049	135.845	6.403
56.128	C4 CEIL R37>38	0.001	680.763	6.403
80.185	HEAT PUMP	0.054	2913.440	6.458

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVING (MW/YR)
BASE CASE	388.00	---	---	---	---	---	4911	---	---	0.000	0.000
C1 CEIL R0>38	385.91	209.10	612.35	50	1%	100%	4882	29	0.057	11.981	0.080
C5 CEIL R0>R49	383.72	219.05	708.10	50	1%	100%	4852	30	0.057	13.225	0.084
WALLS R0>R11	367.52	85.25	713.32	50	19%	100%	4627	225	0.057	34.232	0.619
F1 FLOOR R0>R19	343.04	76.50	539.65	50	32%	100%	4288	340	0.057	28.860	0.935
ACH .7>.4	306.32	36.72	321.31	30	100%	100%	3778	509	0.067	42.125	1.403
C6 CEIL R15>R49	294.47	45.60	573.44	50	26%	100%	3614	164	0.057	51.448	0.453
C3 CEIL R15>R38	285.21	35.60	564.74	50	26%	100%	3485	128	0.057	64.899	0.354
RPLC WNDW SG>VNYL	258.70	56.40	777.98	30	47%	100%	3118	368	0.067	66.406	1.013
C7 CEIL R20>R49	252.71	23.04	452.61	50	26%	100%	3034	83	0.057	80.368	0.229
WALLS R3>R11	249.47	32.40	713.32	50	10%	100%	2989	45	0.057	90.070	0.124
CLOCK THERMOSTAT	236.11	17.81	300.10	30	75%	100%	2804	185	0.067	81.108	0.510
C9 CEIL R38>49	233.33	9.95	226.30	50	28%	100%	2766	39	0.057	93.049	0.106
C8 CEIL R37>49	232.31	11.31	262.37	50	9%	100%	2751	14	0.057	94.907	0.039
DOOR INSUL	222.23	11.20	256.00	30	90%	100%	2612	140	0.067	110.037	0.385
C3 CEIL R20>38	221.70	13.09	425.47	50	4%	100%	2604	7	0.057	132.976	0.020
F2 FLOOR R11>R19	220.43	14.11	468.52	50	9%	100%	2587	18	0.057	135.845	0.049
C4 CEIL R37>38	220.42	1.36	226.30	50	1%	100%	2586	0	0.057	680.763	0.001
HEAT PUMP	219.00	4.74	2870.32	30	30%	100%	2567	20	0.067	2913.440	0.054

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR:
2014
DATE OF RUN:
02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	25540	STATE	OREGON
FUEL FACTOR	54%	CLIMATE ZONE	1
TAKE-BACK FACTOR	30%	VINTAGE OF HOUSING	EXISTING
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-6437.5	PROTOTYPE SIZE (SQ. FT.)	1350
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	35.6846		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
20.965	DUCT SEAL/INSULATE	0.151	20.965	0.151
30.918	ACH .7>.4	1.975	31.676	2.126
31.333	WALLS R0>R11	0.583	32.846	2.709
33.669	F1 FLOOR R0>R19	1.708	37.374	4.416
35.177	C1 CEIL R8>38	0.241	62.822	4.657
36.496	C5 CEIL R8>49	0.222	64.183	4.879
43.017	REPLCE WNDW SG>VNYL	1.060	73.043	5.938
44.942	C6 CEIL R13>49	0.357	76.956	6.296
46.659	C2 CEIL R13>38	0.353	77.282	6.649
49.248	CLOCK THERMOSTAT	0.540	81.108	7.189
49.717	C7 CEIL R21>49	0.037	139.683	7.226
51.637	F2 FLOOR R11>19	0.152	142.800	7.379
55.821	DOOR INSUL	0.341	146.254	7.720
56.220	C3 CEIL R21>38	0.033	149.102	7.753
56.392	C8 CEIL R37>49	0.010	184.692	7.764
58.019	C9 CEIL R38>49	0.080	216.809	7.843
61.689	WALLS R6>11	0.103	341.948	7.946
82.018	HEAT PUMP	0.075	2243.693	8.020

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVING (MW/YR)
BASE CASE	528.00	---	---	---	---	---	5768	---	---	0.000	0.000
WALLS R0>R11	510.78	132.44	890.33	50	13%	100%	5568	200	0.057	32.846	0.583
F1 FLOOR R0>R19	460.36	112.05	857.09	50	45%	100%	4982	586	0.057	37.374	1.708
DUCT SEAL/INSULATE	455.92	49.38	180.06	30	9%	100%	4931	52	0.067	20.965	0.151
ACH .7>.4	397.60	58.32	321.31	30	100%	100%	4253	677	0.067	31.676	1.975
C1 CEIL R8>38	390.48	64.67	831.49	50	11%	100%	4171	83	0.057	62.822	0.241
C5 CEIL R8>49	383.93	72.77	955.90	50	9%	100%	4094	76	0.057	64.183	0.222
RPLC WNDW SG>VNYL	352.64	89.40	1135.76	30	35%	100%	3731	363	0.067	73.043	1.060
C6 CEIL R13>49	342.10	55.49	873.98	50	19%	100%	3609	122	0.057	76.956	0.357
C2 CEIL R13>38	331.67	47.39	749.57	50	22%	100%	3487	121	0.057	77.282	0.353
CLOCK THERMOSTAT	315.72	21.27	300.10	30	75%	100%	3302	185	0.067	81.108	0.540
C7 CEIL R21>49	314.61	27.67	791.04	50	4%	100%	3289	13	0.057	139.683	0.037
F2 FLOOR R11>19	310.12	23.65	691.20	50	19%	100%	3237	52	0.057	142.800	0.152
C3 CEIL R21>38	309.14	19.58	597.50	50	5%	100%	3226	11	0.057	149.102	0.033
DOOR INSUL	299.06	11.20	284.90	30	90%	100%	3109	117	0.067	146.254	0.341
C8 CEIL R37>49	298.75	10.24	387.07	50	3%	100%	3105	4	0.057	184.692	0.010
C9 CEIL R38>49	296.40	8.10	359.42	50	29%	100%	3078	27	0.057	216.809	0.080
WALLS R6>11	293.37	12.13	848.92	50	25%	100%	3043	35	0.057	341.948	0.103
HEAT PUMP	291.16	7.36	2870.32	30	30%	100%	3017	26	0.067	2243.693	0.075

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
DATE OF RUN: 02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	20634
FUEL FACTOR	54%
TAKE-BACK FACTOR	30%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-8924.7
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	35.012

STATE	OREGON
CLIMATE ZONE	1
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	2100

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
19.253	ACH .7>.4	2.625	19.253	2.625
19.436	DUCT SEAL/INSULATE	0.238	21.460	2.863
23.927	WALLS R0>R11	1.326	33.621	4.189
38.010	REPLCE WNDW SG>VNYL	3.082	57.154	7.271
40.451	CLOCK THERMOSTAT	0.437	81.108	7.707
41.029	C3 CEIL R17>49	0.107	82.615	7.814
41.299	C1 CEIL R17>38	0.038	96.465	7.853
41.627	C4 CEIL R19>49	0.043	101.758	7.895
41.772	C2 CEIL R19>38	0.012	139.010	7.907
42.313	C5 CEIL R35>49	0.044	139.903	7.951
45.833	DOOR INSUL	0.269	149.707	8.220
47.835	HEAT PUMP AFTER A/C	0.055	348.733	8.275
50.124	WALLS R6>11	0.063	349.965	8.338
57.376	HEAT PUMP	0.048	1320.968	8.386

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVING (MW/YR)
BASE CASE	811.00	---	---	---	---	---	9015	---	---	0.000	0.000
ACH .7>.4	712.78	98.22	321.31	30	100%	100%	7900	1115	0.067	19.253	2.625
DUCT SEAL/INSULATE	703.89	49.38	180.06	30	18%	100%	7799	101	0.067	21.460	0.238
WALLS R0>R11	654.27	198.47	1334.17	50	25%	100%	7236	563	0.057	33.621	1.326
RPLC WNDW SG>VNYL	538.98	189.00	2159.83	50	61%	100%	5928	1308	0.057	57.154	3.082
C3 CEIL R17>49	534.97	28.64	473.09	50	14%	100%	5882	45	0.057	82.615	0.107
CLOCK THERMOSTAT	518.64	21.78	300.10	30	75%	100%	5697	185	0.067	81.108	0.437
C1 CEIL R17>38	517.21	20.44	394.24	50	7%	100%	5681	16	0.057	96.465	0.038
C4 CEIL R19>49	515.61	22.90	465.92	50	7%	100%	5663	18	0.057	101.758	0.043
C2 CEIL R19>38	515.17	14.70	408.58	50	3%	100%	5658	5	0.057	139.010	0.012
C5 CEIL R35>49	513.53	8.20	229.38	50	20%	100%	5639	19	0.057	139.903	0.044
DOOR INSUL	503.45	11.20	284.90	30	90%	100%	5525	114	0.067	149.707	0.269
HEAT PUMP AFTER A/C	501.40	12.79	757.76	30	16%	100%	5501	23	0.067	348.733	0.055
WALLS R6>11	499.04	18.18	1272.12	50	13%	100%	5475	27	0.057	349.965	0.063
HEAT PUMP	497.25	12.79	2870.32	30	14%	100%	5454	20	0.067	1320.968	0.048

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014

DATE OF RUN: 02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	670
FUEL FACTOR	0%
TAKE-BACK FACTOR	0%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-4186.4
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	27.436

STATE	**OREGON**
CLIMATE ZONE	**1**
VINTAGE OF HOUSING	**NEW**
PROTOTYPE SIZE (SQ. FT.)	**1344**

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
2.043	SOLAR ORIENT.	0.040	2.043	0.040
3.908	LTSGS WINDOWS	0.021	7.490	0.061
36.756	LTSGS ENVELOPE	0.101	56.744	0.162
46.351	INCRM. HEAT PUMP EFF.	0.017	136.084	0.179
64.872	WALL R26 A>R40 BDW	0.034	163.803	0.213
84.576	CLASS 20 WINDOW	0.044	179.777	0.257
89.109	PASSIVE SOLAR DESIGN	0.006	277.161	0.263

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	292.00	---	---	---	---	---	3825	---	---	0.000	0.000
SOLAR ORIENT.	272.79	19.21	20.00	70	100%	100%	3298	527	0.054	2.043	0.040
LTSGS WINDOWS	262.79	10.00	30.77	30	100%	100%	3024	274	0.067	7.490	0.021
LTSGS ENVELOPE	214.79	48.00	1388.03	70	100%	100%	1707	1317	0.054	56.744	0.101
CLASS 20 WINDOW	193.79	21.00	1551.00	30	100%	100%	1130	576	0.067	179.777	0.044
WALL R26 A>R40 BDW	177.79	16.00	1335.61	70	100%	100%	691	439	0.054	163.803	0.034
PASSV SOLAR DSGN	174.84	2.95	417.00	70	100%	100%	610	81	0.054	277.161	0.006
INCRM. HEAT PMP EFF	166.58	8.26	461.58	30	100%	100%	384	227	0.067	136.084	0.017

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014	# OF HOMES IN SECTOR MATCHING PROTOTYPE	673	STATE	OREGON
			CLIMATE ZONE	1
DATE OF RUN: 02-Dec-93	FUEL FACTOR	0%	VINTAGE OF HOUSING	NEW
			PROTOTYPE SIZE (SQ. FT.)	1848
	TAKE-BACK FACTOR	0%		
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-5239.4		
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	41.9538		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
1.882	SOLAR ORIENT.	0.044	1.882	0.044
2.545	SOLAR WINDOWS	0.021	3.930	0.065
31.189	LTSGS ENVELOPE	0.158	42.976	0.223
33.849	LTSGS WINDOWS	0.042	48.002	0.265
48.404	WALL R26 A>R40 BDW	0.103	85.778	0.368
61.249	CLASS 20 WINDOW	0.087	115.561	0.455
62.440	INCRM. HEAT PUMP EFF.	0.009	125.881	0.464
66.693	PASSIVE SOLAR DESIGN	0.006	383.506	0.470

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	416.00	---	---	---	---	---	12213	---	---	0.000	0.000
SOLAR ORIENT.	402.37	13.63	20.00	70	100%	100%	11641	572	0.054	1.882	0.044
SOLAR WINDOWS	395.83	6.53	20.00	70	100%	100%	11367	274	0.054	3.930	0.021
LTSGS WINDOWS	382.83	13.00	392.02	30	100%	100%	10822	545	0.067	48.002	0.042
LTSGS ENVELOPE	333.83	49.00	1641.02	70	100%	100%	8766	2056	0.054	42.976	0.158
INCRM. HEAT PMP EFF	331.18	5.84	461.58	30	45%	100%	8655	111	0.067	125.881	0.009
WALL R26 A>R40 BDW	299.18	32.00	2139.03	70	100%	100%	7313	1343	0.054	85.778	0.103
CLASS 20 WINDOW	272.18	27.00	1960.11	30	100%	100%	6180	1133	0.067	115.561	0.087
PASSV SOLAR DSGN	270.25	1.93	577.00	70	100%	100%	6099	81	0.054	383.506	0.006

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014	# OF HOMES IN SECTOR MATCHING PROTOTYPE	1863	STATE	OREGON
DATE OF RUN: 02-Dec-93	FUEL FACTOR	0%	CLIMATE ZONE	1
	TAKE-BACK FACTOR	0%	VINTAGE OF HOUSING	NEW
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-5808.6	PROTOTYPE SIZE (SQ. FT.)	2352
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	48.6069		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
1.040	SOLAR ORIENT.	0.220	1.040	0.220
1.440	SOLAR WINDOWS	0.098	2.341	0.318
22.675	LTSGS ENVELOPE	0.414	39.003	0.732
26.632	LTSGS WINDOWS	0.186	42.188	0.918
28.584	INCRM. HEAT PUMP EFF.	0.041	71.748	0.959
39.961	WALL R26 A>R40 BDW	0.217	90.219	1.176
54.962	CLASS 20 WINDOW	0.393	99.877	1.569
59.834	PASSIVE SOLAR DESIGN	0.013	634.204	1.582

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	497.00	---	---	---	---	---	18349	---	---	0.000	0.000
SOLAR ORIENT.	475.71	21.29	20.00	70	100%	100%	17314	1035	0.054	1.040	0.220
SOLAR WINDOWS	466.24	9.46	20.00	70	100%	100%	16854	460	0.054	2.341	0.098
LTSGS ENVELOPE	426.24	40.00	1408.55	70	100%	100%	14910	1944	0.054	39.003	0.414
LTSGS WINDOWS	408.24	18.00	552.71	30	100%	100%	14035	875	0.067	42.188	0.186
INCRM. HEAT PMP EFF	404.23	8.84	461.58	30	45%	100%	13840	195	0.067	71.748	0.041
WALL R26 A>R40 BDW	383.23	21.00	1710.54	70	100%	100%	12819	1021	0.054	90.219	0.217
CLASS 20 WINDOW	345.23	38.00	2762.39	30	100%	100%	10972	1847	0.067	99.877	0.393
PASSV SOLAR DSGN	343.94	1.29	737.00	70	100%	100%	10909	63	0.054	634.204	0.013

Appendix B - Single Family Homes, Demand-Side Resources

FOR THE YEAR: 2014
DATE OF RUN: 02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	6643
FUEL FACTOR	73%
TAKE-BACK FACTOR	0%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-5031.3
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	45.4327

STATE	UTAH
CLIMATE ZONE	2
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	850

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
0.871	SOLAR ORIENT.	0.144	0.871	0.144
1.235	SOLAR WINDOWS	0.059	2.119	0.203
23.890	CODE>LTSGS ENVELOPE	0.215	45.289	0.419
34.795	CLASS 50>LTSGS WINDW	0.114	74.714	0.533
34.979	INCRM. HEAT PUMP EFF.	0.002	88.074	0.535
46.023	WALL R26 A>R40 BDW	0.054	155.769	0.589
49.155	PASSIVE SOLAR DESIGN	0.016	166.297	0.605
61.901	CLASS 20 WINDOW	0.071	170.960	0.675

Appendix B - Single Family Homes, Demand-Side Resources

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	406.00	---	---	---	---	---	3595	---	---	0.000	0.000
C1 CEIL R0>38	403.91	209.10	612.35	50	1%	100%	3570	25	0.057	13.650	0.019
C5 CEIL R0>R49	401.72	219.05	708.10	50	1%	100%	3543	27	0.057	15.067	0.020
WALLS R0>R11	385.52	85.25	713.32	50	19%	100%	3346	197	0.057	39.001	0.150
F1 FLOOR R0>R19	361.04	76.50	539.65	50	32%	100%	3048	298	0.057	32.880	0.226
ACH .7>.4	324.32	36.72	321.31	30	100%	100%	2601	447	0.067	47.993	0.339
C6 CEIL R15>R49	312.47	45.60	573.44	50	26%	100%	2456	144	0.057	58.615	0.109
C3 CEIL R15>R38	303.21	35.60	564.74	50	26%	100%	2343	113	0.057	73.940	0.085
RPLC WNDW SG>VNYL	276.70	56.40	777.98	30	47%	100%	2021	323	0.067	75.657	0.245
C7 CEIL R20>R49	270.71	23.04	452.61	50	26%	100%	1948	73	0.057	91.564	0.055
WALLS R3>R11	267.47	32.40	713.32	50	10%	100%	1908	39	0.057	102.618	0.030
CLOCK THERMOSTAT	245.73	28.99	300.10	30	75%	100%	1644	265	0.067	56.775	0.201
C9 CEIL R38>49	242.94	9.95	226.30	50	28%	100%	1610	34	0.057	106.012	0.026
C8 CEIL R37>49	241.92	11.31	262.37	50	9%	100%	1597	12	0.057	108.128	0.009
DOOR INSUL	231.84	11.20	256.00	30	90%	100%	1475	123	0.067	125.367	0.093
C3 CEIL R20>38	231.32	13.09	425.47	50	4%	100%	1468	6	0.057	151.501	0.005
F2 FLOOR R11>R19	230.05	14.11	468.52	50	9%	100%	1453	15	0.057	154.769	0.012
C4 CEIL R37>38	230.04	1.36	226.30	50	1%	100%	1453	0	0.057	775.599	0.000
HEAT PUMP	227.62	8.04	2870.32	30	30%	100%	1423	29	0.067	1956.970	0.022

FOR THE YEAR:
2014
DATE OF RUN:
02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	4954
FUEL FACTOR	73%
TAKE-BACK FACTOR	0%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-6626.5
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	45.5724

STATE	UTAH
CLIMATE ZONE	2
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	1350

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
0.609	SOLAR WINDOWS	0.116	0.609	0.116
0.985	SOLAR ORIENT.	0.028	2.564	0.144
28.995	CODE>LTSGS ENVELOPE	0.165	53.374	0.309
31.844	PASSIVE SOLAR DESIGN	0.036	55.971	0.346
38.741	CLASS 50>LTSGS WINDOW	0.116	59.245	0.462
39.144	INCRM. HEAT PUMP EFF.	0.005	79.448	0.466
46.326	WALL R26 A>R40 BDW	0.091	83.066	0.558
54.276	CLASS 20 WINDOW	0.077	111.906	0.634

Appendix B - Single Family Homes, Demand-Side Resources

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	587.00	---	---	---	---	---	5393	---	---	0.000	0.000
WALLS R0>R11	569.78	132.44	890.33	50	13%	100%	5183	210	0.057	31.238	0.119
F1 FLOOR R0>R19	519.36	112.05	857.09	50	45%	100%	4567	616	0.057	35.544	0.348
DUCT SEAL/INSULATE	514.92	49.38	180.06	30	9%	100%	4513	54	0.067	19.939	0.031
ACH .7>.4	456.60	58.32	321.31	30	100%	100%	3801	712	0.067	30.125	0.403
C1 CEIL R8>38	449.48	64.67	831.49	50	11%	100%	3714	87	0.057	59.745	0.049
C5 CEIL R8>49	442.93	72.77	955.90	50	9%	100%	3634	80	0.057	61.040	0.045
RPLC WNDW SG>VNYL	411.64	89.40	1135.76	30	35%	100%	3252	382	0.067	69.467	0.216
C6 CEIL R13>49	401.10	55.49	873.98	50	19%	100%	3123	129	0.057	73.188	0.073
C2 CEIL R13>38	390.67	47.39	749.57	50	22%	100%	2996	127	0.057	73.498	0.072
CLOCK THERMOSTAT	369.00	28.90	300.10	30	75%	100%	2731	265	0.067	56.775	0.150
C7 CEIL R21>49	367.89	27.67	791.04	50	4%	100%	2717	14	0.057	132.843	0.008
F2 FLOOR R11>19	363.40	23.65	691.20	50	19%	100%	2662	55	0.057	135.807	0.031
C3 CEIL R21>38	362.42	19.58	597.50	50	5%	100%	2650	12	0.057	141.801	0.007
DOOR INSUL	352.34	11.20	284.90	30	90%	100%	2527	123	0.067	139.092	0.070
C8 CEIL R37>49	352.03	10.24	387.07	50	3%	100%	2524	4	0.057	175.648	0.002
C9 CEIL R38>49	349.68	8.10	359.42	50	29%	100%	2495	29	0.057	206.192	0.016
WALLS R6>11	346.65	12.13	848.92	50	25%	100%	2458	37	0.057	325.203	0.021
HEAT PUMP	343.11	11.79	2870.32	30	30%	100%	2415	43	0.067	1331.288	0.024

Appendix B - Single Family Homes, Demand-Side Resources

FOR THE YEAR:	2014
DATE OF RUN:	02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	4181
FUEL FACTOR	73%
TAKE-BACK FACTOR	0%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-9506.6
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	44.9853

STATE	**UTAH**
CLIMATE ZONE	**2**
VINTAGE OF HOUSING	**EXISTING**
PROTOTYPE SIZE (SQ. FT.)	**2100**

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
0.424	SOLAR WINDOWS	0.449	0.424	0.449
0.681	SOLAR ORIENT.	0.110	1.731	0.559
10.001	CLASS 50>LTSGS WINDOW	0.388	23.411	0.947
16.913	CODE>LTSGS ENVELOPE	0.787	25.228	1.734
19.346	PASSIVE SOLAR DESIGN	0.144	48.570	1.879
19.689	INCRM. HEAT PUMP EFF.	0.017	56.874	1.896
25.749	WALL R26 A>R40 BDW	0.186	87.602	2.082
35.651	CLASS 20 WINDOW	0.336	96.980	2.418

Appendix B - Single Family Homes, Demand-Side Resources

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	852.00	---	---	---	---	---	7666	---	---	0.000	0.000
ACH .7>.4	753.78	98.22	321.31	30	100%	100%	6491	1175	0.067	18.257	0.561
DUCT SEAL/INSULATE	744.89	49.38	180.06	30	18%	100%	6385	106	0.067	20.351	0.051
WALLS R0>R11	695.27	198.47	1334.17	50	25%	100%	5791	594	0.057	31.882	0.283
RPLC WNDW SG>VNYL	579.98	189.00	2159.83	50	61%	100%	4411	1380	0.057	54.199	0.658
C3 CEIL R17>49	575.97	28.64	473.09	50	14%	100%	4363	48	0.057	78.344	0.023
CLOCK THERMOSTAT	553.85	29.50	300.10	30	75%	100%	4099	265	0.067	56.775	0.126
C1 CEIL R17>38	552.42	20.44	394.24	50	7%	100%	4082	17	0.057	91.478	0.008
C4 CEIL R19>49	550.82	22.90	465.92	50	7%	100%	4062	19	0.057	96.496	0.009
C2 CEIL R19>38	550.37	14.70	408.58	50	3%	100%	4057	5	0.057	131.823	0.003
C5 CEIL R35>49	548.73	8.20	229.38	50	20%	100%	4037	20	0.057	132.669	0.009
DOOR INSUL	538.65	11.20	284.90	30	90%	100%	3917	121	0.067	141.966	0.058
HEAT PUMP AFTER A/C	533.09	18.54	757.76	30	30%	100%	3850	67	0.067	228.158	0.032
WALLS R6>11	530.73	18.18	1272.12	50	13%	100%	3822	28	0.057	331.870	0.013
HEAT PUMP	530.73	18.54	2870.32	30	0%	100%	3822	0	0.067	0.000	0.000

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014	# OF HOMES IN SECTOR MATCHING PROTOTYPE	1022	STATE	UTAH
DATE OF RUN: 02-Dec-93	FUEL FACTOR	0%	CLIMATE ZONE	2
	TAKE-BACK FACTOR	0%	VINTAGE OF HOUSING	NEW
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-5031.3	PROTOTYPE SIZE (SQ. FT.)	1344
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	28.8509		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
0.871	SOLAR ORIENT.	0.144	0.871	0.144
1.235	SOLAR WINDOWS	0.059	2.119	0.203
23.890	CODE>LTSGS ENVELOPE	0.215	45.289	0.419
34.795	CLASS 50>LTSGS WNDWS	0.114	74.714	0.533
34.979	INCRM. HEAT PUMP EFF.	0.002	88.074	0.535
46.023	WALL R26 A>R40 BDW	0.054	155.769	0.589
49.155	PASSIVE SOLAR DESIGN	0.016	166.297	0.605
61.901	CLASS 20 WINDOW	0.071	170.960	0.675

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	420.00	---	---	---	---	---	7086	---	---	0.000	0.000
SOLAR ORIENT.	377.16	42.84	20.00	70	100%	100%	5850	1236	0.054	0.871	0.144
SOLAR WINDOWS	359.55	17.61	20.00	70	100%	100%	5342	508	0.054	2.119	0.059
CODE>LTSGS ENVLP	295.55	64.00	1553.27	70	100%	100%	3496	1846	0.054	45.289	0.215
CLSS 50>LTSGS WDW	261.55	34.00	1097.43	30	100%	100%	2515	981	0.067	74.714	0.114
PASSV SOLAR DSGN	256.87	4.68	417.00	70	100%	100%	2380	135	0.054	166.297	0.016
WALL R26 A>R40 BDW	240.87	16.00	1335.61	70	100%	100%	1918	462	0.054	155.769	0.054
CLASS 20 WINDOW	219.87	21.00	1551.00	30	100%	100%	1312	606	0.067	170.960	0.071
INCRM. HEAT PMP EFF	219.32	12.13	461.58	30	5%	100%	1296	16	0.067	88.074	0.002

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR:	# OF HOMES IN SECTOR MATCHING PROTOTYPE	576	STATE	UTAH
2014			CLIMATE ZONE	2
DATE OF RUN:	FUEL FACTOR	0%	VINTAGE OF HOUSING	NEW
02-Dec-93			PROTOTYPE SIZE (SQ. FT.)	1848
	TAKE-BACK FACTOR	0%		
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-6543.6		
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	43.3237		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
0.609	SOLAR WINDOWS	0.116	0.609	0.116
0.985	SOLAR ORIENT.	0.028	2.564	0.144
28.995	CODE>LTSGS ENVELOPE	0.165	53.374	0.309
31.844	PASSIVE SOLAR DESIGN	0.036	55.971	0.346
38.741	CLASS 50>LTSGS WINDWS	0.116	59.245	0.462
39.144	INCRM. HEAT PUMP EFF	0.005	79.448	0.466
46.326	WALL R26 A>R40 BDW	0.091	83.066	0.558
54.276	CLASS 20 WINDOW	0.077	111.906	0.634

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	455.00	---	---	---	---	---	13169	---	---	0.000	0.000
SOLAR ORIENT.	445.31	9.69	20.00	70	100%	100%	12749	420	0.054	2.564	0.028
SOLAR WINDOWS	404.52	40.79	20.00	70	100%	100%	10982	1767	0.054	0.609	0.116
CODE>LTSGS ENVLP	346.52	58.00	2491.17	70	100%	100%	8469	2513	0.054	53.374	0.165
CLSS 50>LTSGS WDW	305.72	40.80	1568.09	30	100%	100%	6701	1768	0.067	59.245	0.116
PASSV SOLAR DSGN	292.91	12.81	577.00	70	100%	100%	6146	555	0.054	55.971	0.036
INCRM. HEAT PMP EFF	291.29	8.96	461.58	30	18%	100%	6076	70	0.067	79.448	0.005
WALL R26 A>R40 BDW	259.29	32.00	2139.03	70	100%	100%	4690	1386	0.054	83.066	0.091
CLASS 20 WINDOW	232.29	27.00	1960.11	30	100%	100%	3520	1170	0.067	111.906	0.077

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014	# OF HOMES IN SECTOR MATCHING PROTOTYPE	1548		STATE	UTAH
DATE OF RUN: 02-Dec-93	FUEL FACTOR	0%		CLIMATE ZONE	2
	TAKE-BACK FACTOR	0%		VINTAGE OF HOUSING	NEW
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-7223.2		PROTOTYPE SIZE (SQ. FT.)	2352
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	50.0591			

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
0.424	SOLAR WINDOWS	0.449	0.424	0.449
0.681	SOLAR ORIENT.	0.110	1.731	0.559
10.001	CLASS 50>LTSGS WINDOW	0.388	23.411	0.947
16.913	CODE>LTSGS ENVELOPE	0.787	25.228	1.734
19.346	PASSIVE SOLAR DESIGN	0.144	48.570	1.879
19.689	INCRM. HEAT PUMP EFF.	0.017	56.874	1.896
25.749	WALL R26 A>R40 BDW	0.186	87.602	2.082
35.651	CLASS 20 WINDOW	0.336	96.980	2.418

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	551.00	---	---	---	---	---	20359	---	---	0.000	0.000
SOLAR ORIENT.	538.57	12.43	20.00	70	100%	100%	19737	622	0.054	1.731	0.110
SOLAR WINDOWS	487.83	50.74	20.00	70	100%	100%	17197	2540	0.054	0.424	0.449
CODE>LTSGS ENVLP	398.83	89.00	2087.75	70	100%	100%	12742	4455	0.054	25.228	0.787
CLSS 50>LTSGS WDW	354.93	43.90	770.37	30	100%	100%	10545	2198	0.067	23.411	0.388
PASSV SOLAR DSGN	338.62	16.32	737.00	70	100%	100%	9728	817	0.054	48.570	0.144
INCRM. HEAT PMP EFF	336.66	10.83	461.58	30	18%	100%	9629	98	0.067	56.874	0.017
WALL R26 A>R40 BDW	315.66	21.00	1710.54	70	100%	100%	8578	1051	0.054	87.602	0.186
CLASS 20 WINDOW	277.66	38.00	2762.39	30	100%	100%	6676	1902	0.067	96.980	0.336

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
DATE OF RUN: 02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	8529
FUEL FACTOR	8%
TAKE-BACK FACTOR	30%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-4943
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	35.2623

STATE	**WASHINGTON**
CLIMATE ZONE	**2**
VINTAGE OF HOUSING	**EXISTING**
PROTOTYPE SIZE (SQ. FT.)	**850**

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
7.335	C1 CEIL R0>38	0.046	7.335	0.046
7.724	C5 CEIL R0>R49	0.048	8.096	0.094
16.188	F1 FLOOR R0>R19	0.540	17.668	0.635
17.906	WALLS R0>R11	0.357	20.957	0.992
21.450	ACH .7>.4	0.810	25.789	1.802
22.723	C6 CEIL R15>R49	0.262	31.496	2.064
24.255	C3 CEIL R15>R38	0.204	39.731	2.268
27.617	RPLC WNDW SG>VNYL	0.585	40.654	2.853
28.572	C7 CEIL R20>R49	0.132	49.201	2.985
29.194	WALLS R3>R11	0.071	55.141	3.056
29.741	C9 CEIL R38>49	0.061	56.965	3.118
29.944	C8 CEIL R37>49	0.022	58.102	3.140
32.419	DOOR INSUL	0.222	67.365	3.363
34.899	CLOCK THERMOSTAT	0.180	81.108	3.543
35.050	C3 CEIL R20>38	0.012	81.408	3.555
35.426	F2 FLOOR R11>R19	0.028	83.164	3.583
35.458	C4 CEIL R37>38	0.000	416.763	3.583
50.806	HEAT PUMP	0.020	2848.783	3.603

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	388.00	---	---	---	---	---	8022	---	---	0.000	0.000
C1 CEIL R0>38	385.91	209.10	612.35	50	1%	100%	7975	47	0.057	7.335	0.046
C5 CEIL R0>R49	383.72	219.05	708.10	50	1%	100%	7925	50	0.057	8.096	0.048
WALLS R0>R11	367.52	85.25	713.32	50	19%	100%	7558	367	0.057	20.957	0.357
F1 FLOOR R0>R19	343.04	76.50	539.65	50	32%	100%	7003	555	0.057	17.668	0.540
ACH .7>.4	306.32	36.72	321.31	30	100%	100%	6171	832	0.067	25.789	0.810
C6 CEIL R15>R49	294.47	45.60	573.44	50	26%	100%	5903	269	0.057	31.496	0.262
C3 CEIL R15>R38	285.21	35.60	564.74	50	26%	100%	5693	210	0.057	39.731	0.204
RPLC WNDW SG>VNYL	258.70	56.40	777.98	30	47%	100%	5092	601	0.067	40.654	0.585
C7 CEIL R20>R49	252.71	23.04	452.61	50	26%	100%	4957	136	0.057	49.201	0.132
WALLS R3>R11	249.47	32.40	713.32	50	10%	100%	4883	73	0.057	55.141	0.071
CLOCK THERMOSTAT	241.29	10.90	300.10	30	75%	100%	4698	185	0.067	81.108	0.180
C9 CEIL R38>49	238.51	9.95	226.30	50	28%	100%	4635	63	0.057	56.965	0.061
C8 CEIL R37>49	237.49	11.31	262.37	50	9%	100%	4612	23	0.057	58.102	0.022
DOOR INSUL	227.41	11.20	256.00	30	90%	100%	4383	228	0.067	67.365	0.222
C3 CEIL R20>38	226.88	13.09	425.47	50	4%	100%	4371	12	0.057	81.408	0.012
F2 FLOOR R11>R19	225.61	14.11	468.52	50	9%	100%	4343	29	0.057	83.164	0.028
C4 CEIL R37>38	225.60	1.36	226.30	50	1%	100%	4342	0	0.057	416.763	0.000
HEAT PUMP	224.71	2.97	2870.32	30	30%	100%	4322	20	0.067	2848.783	0.020

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR:	# OF HOMES IN SECTOR MATCHING PROTOTYPE	8583	STATE	WASHINGTON
2014			CLIMATE ZONE	2
DATE OF RUN:	FUEL FACTOR	31%	VINTAGE OF HOUSING	EXISTING
02-Dec-93			PROTOTYPE SIZE (SQ. FT.)	1350
	TAKE-BACK FACTOR	30%		
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-6437.5		
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	35.6846		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
14.191	DUCT SEAL/INSULATE	0.075	14.191	0.075
20.927	ACH .7>.4	0.981	21.440	1.055
21.208	WALLS R0>R11	0.289	22.232	1.345
22.789	F1 FLOOR R0>R19	0.848	25.297	2.193
23.810	C1 CEIL R8>38	0.120	42.521	2.312
24.702	C5 CEIL R8>49	0.110	43.442	2.422
29.116	RPLC WNDW SG>VNYL	0.526	49.440	2.948
30.419	C6 CEIL R13>49	0.177	52.088	3.126
31.582	C2 CEIL R13>38	0.175	52.309	3.301
34.164	CLOCK THERMOSTAT	0.182	81.108	3.483
34.485	C7 CEIL R21>49	0.019	94.546	3.501
35.798	F2 FLOOR R11>19	0.076	96.655	3.577
38.657	DOOR INSUL	0.169	98.993	3.746
38.929	C3 CEIL R21>38	0.016	100.921	3.763
39.047	C8 CEIL R37>49	0.005	125.010	3.768
40.165	C9 CEIL R38>49	0.039	146.749	3.807
42.693	WALLS R6>11	0.051	231.449	3.858
56.919	HEAT PUMP	0.026	2205.332	3.884

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	528.00	---	---	---	---	---	8522	---	---	0.000	0.000
WALLS R0>R11	510.78	132.44	890.33	50	13%	100%	8226	295	0.057	22.232	0.289
F1 FLOOR R0>R19	460.36	112.05	857.09	50	45%	100%	7361	865	0.057	25.297	0.848
DUCT SEAL/INSULATE	455.92	49.38	180.06	30	9%	100%	7285	76	0.067	14.191	0.075
ACH .7>.4	397.60	58.32	321.31	30	100%	100%	6284	1001	0.067	21.440	0.981
C1 CEIL R8>38	390.48	64.67	831.49	50	11%	100%	6162	122	0.057	42.521	0.120
C5 CEIL R8>49	383.93	72.77	955.90	50	9%	100%	6049	112	0.057	43.442	0.110
RPLC WNDW SG>VNYL	352.64	89.40	1135.76	30	35%	100%	5512	537	0.067	49.440	0.526
C6 CEIL R13>49	342.10	55.49	873.98	50	19%	100%	5331	181	0.057	52.088	0.177
C2 CEIL R13>38	331.67	47.39	749.57	50	22%	100%	5152	179	0.057	52.309	0.175
CLOCK THERMOSTAT	320.87	14.40	300.10	30	75%	100%	4967	185	0.067	81.108	0.182
C7 CEIL R21>49	319.77	27.67	791.04	50	4%	100%	4948	19	0.057	94.546	0.019
F2 FLOOR R11>19	315.27	23.65	691.20	50	19%	100%	4871	77	0.057	96.655	0.076
C3 CEIL R21>38	314.30	19.58	597.50	50	5%	100%	4854	17	0.057	100.921	0.016
DOOR INSUL	304.22	11.20	284.90	30	90%	100%	4681	173	0.067	98.993	0.169
C8 CEIL R37>49	303.91	10.24	387.07	50	3%	100%	4676	5	0.057	125.010	0.005
C9 CEIL R38>49	301.56	8.10	359.42	50	29%	100%	4636	40	0.057	146.749	0.039
WALLS R6>11	298.53	12.13	848.92	50	25%	100%	4584	52	0.057	231.449	0.051
HEAT PUMP	297.01	5.07	2870.32	30	30%	100%	4558	26	0.067	2205.332	0.026

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR:
2014
DATE OF RUN:
02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	9599
FUEL FACTOR	28%
TAKE-BACK FACTOR	30%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-8924.7
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	35.012

STATE	**WASHINGTON**
CLIMATE ZONE	**2**
VINTAGE OF HOUSING	**EXISTING**
PROTOTYPE SIZE (SQ. FT.)	**2100**

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
	HEAT PUMP	0.000	0.000	
12.450	ACH .7>.4	1.889	12.450	1.889
12.568	DUCT SEAL/INSULATE	0.171	13.877	2.060
15.472	WALLS R0>R11	0.954	21.741	3.014
24.579	REPLACE WINDOW SG>VIN'	2.217	36.959	5.231
24.998	C3 CEIL R17>49	0.077	53.423	5.308
25.191	C1 CEIL R17>38	0.028	62.379	5.335
25.424	C4 CEIL R19>49	0.031	65.801	5.366
27.454	CLOCK THERMOSTAT	0.203	81.108	5.569
27.549	C2 CEIL R19>38	0.008	89.891	5.578
27.903	C5 CEIL R35>49	0.032	90.468	5.609
30.205	DOOR INSUL	0.194	96.808	5.803
31.728	WALLS R6>11	0.045	226.304	5.848
34.290	HEAT PUMP AFTER A/C	0.048	344.781	5.897

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	811.00	---	---	---	---	---	13941	---	---	0.000	0.000
ACH .7>.4	712.78	98.22	321.31	30	100%	100%	12217	1724	0.067	12.450	1.889
DUCT SEAL/INSULATE	703.89	49.38	180.06	30	18%	100%	12061	156	0.067	13.877	0.171
WALLS R0>R11	654.27	198.47	1334.17	50	25%	100%	11190	871	0.057	21.741	0.954
RPLC WNDW SG>VNYL	538.98	189.00	2159.83	50	61%	100%	9167	2023	0.057	36.959	2.217
C3 CEIL R17>49	534.97	28.64	473.09	50	14%	100%	9097	70	0.057	53.423	0.077
CLOCK THERMOSTAT	524.41	14.08	300.10	30	75%	100%	8912	185	0.067	81.108	0.203
C1 CEIL R17>38	522.98	20.44	394.24	50	7%	100%	8886	25	0.057	62.379	0.028
C4 CEIL R19>49	521.38	22.90	465.92	50	7%	100%	8858	28	0.057	65.801	0.031
C2 CEIL R19>38	520.94	14.70	408.58	50	3%	100%	8851	8	0.057	89.891	0.008
C5 CEIL R35>49	519.30	8.20	229.38	50	20%	100%	8822	29	0.057	90.468	0.032
DOOR INSUL	509.22	11.20	284.90	30	90%	100%	8645	177	0.067	96.808	0.194
HEAT PUMP AFTER A/C	506.71	8.36	757.76	30	30%	100%	8601	44	0.067	344.781	0.048
WALLS R6>11	504.35	18.18	1272.12	50	13%	100%	8559	41	0.057	226.304	0.045
HEAT PUMP	504.35	8.36	2870.32	30	0%	100%	8559	0	0.067	0.000	0.000

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014	# OF HOMES IN SECTOR MATCHING PROTOTYPE	219	STATE	WASHINGTON
			CLIMATE ZONE	2
DATE OF RUN: 02-Dec-93	FUEL FACTOR	0%	VINTAGE OF HOUSING	NEW
			PROTOTYPE SIZE (SQ. FT.)	1344
	TAKE-BACK FACTOR	0%		
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-4186.4		
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	27.436		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
2.043	SOLAR ORIENT.	0.013	2.043	0.013
3.908	LTSGS WINDOWS	0.007	7.490	0.020
36.756	LTSGS ENVELOPE	0.033	56.744	0.053
46.351	INCRM. HEAT PUMP EFF.	0.006	136.084	0.059
64.872	WALL R26 A>R40 BDW	0.011	163.803	0.070
84.576	CLASS 20 WINDOW	0.014	179.777	0.084
89.109	PASSIVE SOLAR DESIGN	0.002	277.161	0.086

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	292.00	---	---	---	---	---	3825	---	---	0.000	0.000
SOLAR ORIENT.	272.79	19.21	20.00	70	100%	100%	3298	527	0.054	2.043	0.013
LTSGS WINDOWS	262.79	10.00	30.77	30	100%	100%	3024	274	0.067	7.490	0.007
LTSGS ENVELOPE	214.79	48.00	1388.03	70	100%	100%	1707	1317	0.054	56.744	0.033
CLASS 20 WINDOW	193.79	21.00	1551.00	30	100%	100%	1130	576	0.067	179.777	0.014
WALL R26 A>R40 BDW	177.79	16.00	1335.61	70	100%	100%	691	439	0.054	163.803	0.011
PSSV SOLAR DSGN	174.84	2.95	417.00	70	100%	100%	610	81	0.054	277.161	0.002
INCRM. HEAT PMP EFF	166.58	8.26	461.58	30	100%	100%	384	227	0.067	136.084	0.006

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR:	# OF HOMES IN SECTOR MATCHING PROTOTYPE	174	STATE	WASHINGTON
2014			CLIMATE ZONE	2
DATE OF RUN:	FUEL FACTOR	0%	VINTAGE OF HOUSING	NEW
02-Dec-93			PROTOTYPE SIZE (SQ. FT.)	1848
	TAKE-BACK FACTOR	0%		
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-5239.4		
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	41.9538		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
1.882	SOLAR ORIENT.	0.011	1.882	0.011
2.545	SOLAR WINDOWS	0.005	3.930	0.017
31.189	LTSGS ENVELOPE	0.041	42.976	0.058
33.849	LTSGS WINDOWS	0.011	48.002	0.068
48.404	WALL R26 A>R40 BDW	0.027	85.778	0.095
61.249	CLASS 20 WINDOW	0.022	115.561	0.118
62.187	INCRM. HEAT PUMP EFF.	0.002	125.881	0.119
66.460	PASSIVE SOLAR DESIGN	0.002	383.506	0.121

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	416.00	---	---	---	---	---	12213	---	---	0.000	0.000
SOLAR ORIENT.	402.37	13.63	20.00	70	100%	100%	11641	572	0.054	1.882	0.011
SOLAR WINDOWS	395.83	6.53	20.00	70	100%	100%	11367	274	0.054	3.930	0.005
LTSGS WINDOWS	382.83	13.00	392.02	30	100%	100%	10822	545	0.067	48.002	0.011
LTSGS ENVELOPE	333.83	49.00	1641.02	70	100%	100%	8766	2056	0.054	42.976	0.041
INCRM. HEAT PMP EFF	331.76	5.84	461.58	30	36%	100%	8679	87	0.067	125.881	0.002
WALL R26 A>R40 BDW	299.76	32.00	2139.03	70	100%	100%	7337	1343	0.054	85.778	0.027
CLASS 20 WINDOW	272.76	27.00	1960.11	30	100%	100%	6204	1133	0.067	115.561	0.022
PSSV SOLAR DSGN	270.83	1.93	577.00	70	100%	100%	6123	81	0.054	383.506	0.002

Appendix B - Single Family Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014	# OF HOMES IN SECTOR MATCHING PROTOTYPE	568	STATE	WASHINGTON
			CLIMATE ZONE	2
DATE OF RUN: 02-Dec-93	FUEL FACTOR	0%	VINTAGE OF HOUSING	NEW
			PROTOTYPE SIZE (SQ. FT.)	2352
	TAKE-BACK FACTOR	0%		
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-5808.6		
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	48.6069		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
1.040	SOLAR ORIENT.	0.067	1.040	0.067
1.440	SOLAR WINDOWS	0.030	2.341	0.097
22.675	LTSGS ENVELOPE	0.126	39.003	0.223
26.632	LTSGS WINDOWS	0.057	42.188	0.280
28.177	INCRM. HEAT PUMP EFF	0.010	71.748	0.290
39.717	WALL R26 A>R40 BDW	0.066	90.219	0.356
54.866	CLASS 20 WINDOW	0.120	99.877	0.476
59.766	PASSIVE SOLAR DESIGN	0.004	634.204	0.480

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	497.00	---	---	---	---	---	18349	---	---	0.000	0.000
SOLAR ORIENT.	475.71	21.29	20.00	70	100%	100%	17314	1035	0.054	1.040	0.067
SOLAR WINDOWS	466.24	9.46	20.00	70	100%	100%	16854	460	0.054	2.341	0.030
LTSGS ENVELOPE	426.24	40.00	1408.55	70	100%	100%	14910	1944	0.054	39.003	0.126
LTSGS WINDOWS	408.24	18.00	552.71	30	100%	100%	14035	875	0.067	42.188	0.057
INCRM. HEAT PMP EFF	405.10	8.84	461.58	30	36%	100%	13882	153	0.067	71.748	0.010
WALL R26 A>R40 BDW	384.10	21.00	1710.54	70	100%	100%	12861	1021	0.054	90.219	0.066
CLASS 20 WINDOW	346.10	38.00	2762.39	30	100%	100%	11014	1847	0.067	99.877	0.120
PSSV SOLAR DSGN	344.81	1.29	737.00	70	100%	100%	10952	63	0.054	634.204	0.004

APPENDIX C

Appendix C - Mobile Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
DATA OF RUN: 02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	946
FUEL FACTOR	69.30%
TAKE-BACK FACTOR	30.00%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-5124.80
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	52.36

STATE	MONTANA
CLIMATE ZONE	3
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQFT)	924

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVINGS (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
28.680	WEATHERSTRIP	0.007	28.680	0.007
29.714	BLOW WALL R4>R11	0.098	29.786	0.105
33.483	BLOW BELLY R2>R30	0.105	37.246	0.210
33.880	DUCT SEALING	0.010	42.429	0.220
39.545	BLOW CLING R19>R30	0.057	61.489	0.277
44.809	REPLACE WNDW U>.40	0.070	65.480	0.347
47.234	ROOF CAP> R30	0.012	115.657	0.359

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA UA (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	ANNUAL MEASURE SAVINGS (MW/YR)
BASE CASE	463	---	---	---	---	---	5869	---	---	---	---
WEATHERSTRIP	457	18.70	$90.37	30	30%	100%	5806	63	0.067	28.680	0.007
BLOW BELLY R2>R30	371	101.00	633.86	30	86%	100%	4833	973	0.067	37.246	0.105
DUCT SEALING	363	11.46	81.92	30	70%	100%	4743	90	0.067	42.429	0.010
BLOW WALL R4>R11	282	162.00	813.06	30	50%	100%	3834	909	0.067	29.786	0.098
RPLC WNDWS U>.40	224	86.50	954.36	30	67%	100%	3182	652	0.067	65.480	0.070
BLOW CEIL R19>R30	177	101.20	1048.50	30	46%	100%	2656	526	0.067	61.489	0.057
ROOF CAP> R30	167	101.20	1972.16	30	10%	100%	2542	114	0.067	115.657	0.012

Appendix C - Mobile Homes, Demand-Side Resources Worksheet

FOR THE YEAR:	# OF HOMES IN SECTOR MATCHING PROTOTYPE	1		STATE	MONTANA
2014				CLIMATE ZONE	3
DATA OF RUN:	FUEL FACTOR	0.00%		VINTAGE OF HOUSING	NEW
02-Dec-93				PROTOTYPE SIZE (SQ. FT.)	924
	TAKE-BACK FACTOR	0.00%			
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-5124.80			
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	52.36			

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVINGS (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
29.758	WALL R19>R21	0.000	29.758	0.000
31.869	ATTIC R38>R49	0.000	36.090	0.000
66.988	CLASS 20 WINDOWS	0.000	82.039	0.000

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	ANNUAL MEASURE SAVINGS (MW/YR)
BASE CASE	200	---	---	---	---	---	5348	---	---	0.000	0.000
WALL R19>R21	196	4.00	$107.12	45	100%	100%	5138	209	0.058	29.758	0.000
ATTIC R38>R49	194	2.00	64.96	45	100%	100%	5033	105	0.058	36.090	0.000
CLASS 20 WINDOWS	180	14.00	1033.62	45	100%	100%	4300	733	0.058	82.039	0.000

Appendix C - Mobile Homes, Demand-Side Resources Worksheet

FOR THE YEAR:
2014
DATA OF RUN:
02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	1
FUEL FACTOR	0.00%
TAKE-BACK FACTOR	0.00%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-6848.60
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	52.66

STATE	MONTANA
CLIMATE ZONE	3
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	1344

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVINGS (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
	HEAT PUMP W/O AC	0.000	0.000	
7.831	HEAT PUMP AFTER AC CRED	0.000	7.831	0.000
15.352	WALL R19>R21	0.000	28.963	0.000
23.614	ATTIC R38>R49	0.000	54.567	0.000
66.737	CLASS 20 WINDOWS	0.000	92.321	0.000

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	ANNUAL MEASURE SAVINGS (MW/YR)
BASE CASE	293	---	---	---	---	---	8580	---	---	0.000	0.000
HT PMP AFTR AC CRDT	286	120.65	$744.91	30	6%	100%	8198	381	0.067	7.831	0.000
WALL R19>R21	282	4.00	104.84	45	100%	100%	7988	211	0.058	28.963	0.000
HEAT PUMP W/O AC	282	119.00	3280.55	30	0%	100%	7988	0	0.067	0.000	0.000
ATTIC R38>R49	279	3.00	148.15	45	100%	100%	7830	158	0.058	54.567	0.000
CLASS 20 WINDOWS	255	24.00	1747.01	30	100%	100%	6566	1264	0.067	92.321	0.000

Appendix C - Mobile Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014	# OF HOMES IN SECTOR MATCHING PROTOTYPE	22,972	STATE	OREGON
DATA OF RUN: 02-Dec-93	FUEL FACTOR	54.40%	CLIMATE ZONE	1
	TAKE-BACK FACTOR	30.00%	VINTAGE OF HOUSING	EXISTING
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-3692.60	PROTOTYPE SIZE (SQ. FT.)	924
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	29.04		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVINGS (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
28.565	DUCT SEALING	0.176	28.565	0.176
31.297	WEATHERSTRIP	0.136	34.820	0.312
35.438	BLOW WALL R4>R11	1.784	36.162	2.096
40.280	BLOW BELLY R7>R30	2.055	45.219	4.151
45.249	REPLACE WINDOWS U>.40	1.428	59.691	5.579
49.453	BLOW CEILING R7>R30	0.925	74.799	6.504
52.772	ROOF CAP> R30	0.245	140.692	6.750

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	ANNUAL MEASURE SAVINGS (MW/YR)
BASE CASE	539	---	---	---	---	---	5453	---	---	0.000	0.000
DUCT SEALING	532	20.66	$81.92	30	35%	100%	5386	67	0.067	28.565	0.176
BLOW WALL R4>R11	458	162.00	813.06	30	45%	100%	4706	680	0.067	36.162	1.784
WEATHERSTRIP	453	18.70	90.37	30	30%	100%	4654	52	0.067	34.820	0.136
BLOW BELLY R7>R30	368	101.00	633.86	30	84%	100%	3870	784	0.067	45.219	2.055
RPLC WNDWS U>.40	309	115.20	954.36	30	51%	100%	3326	545	0.067	59.691	1.428
BLOW CEILING R7>R30	271	101.00	1048.50	30	38%	100%	2973	353	0.067	74.799	0.925
ROOF CAP> R30	261	101.00	1972.16	30	10%	100%	2879	94	0.067	140.692	0.245

Appendix C - Mobile Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014	# OF HOMES IN SECTOR MATCHING PROTOTYPE	680		STATE	OREGON
DATA OF RUN: 02-Dec-93	FUEL FACTOR	0.00%		CLIMATE ZONE	1
	TAKE-BACK FACTOR	0.00%		VINTAGE OF HOUSING	NEW
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-3692.60		PROTOTYPE SIZE (SQ. FT.)	924
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	29.04			

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVINGS (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
	HEAT PUMP W/O AC	0.000	0.000	
53.663	WALL R19>R21	0.009	53.663	0.009
57.469	ATTIC R38>R49	0.005	65.081	0.014
80.125	HEAT PUMP AFTER AC CRED	0.005	143.289	0.018
122.984	CLASS 20 WINDOWS	0.032	147.940	0.050

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	ANNUAL MEASURE SAVINGS (MW/YR)
BASE CASE	200	---	---	---	---	---	2115	---	---	0.000	0.000
WALL R19>R21	196	4.00	$107.12	45	100%	100%	1999	116	0.058	53.663	0.009
ATTIC R38>R49	194	2.00	64.96	45	100%	100%	1941	58	0.058	65.081	0.005
CLASS 20 WINDOWS	180	14.00	1033.62	45	100%	100%	1534	407	0.058	147.940	0.032
HT PMP AFTR AC CRDT	178	11.96	744.91	30	18%	100%	1472	62	0.067	143.289	0.005
HEAT PUMP W/O AC	178	3.72	3280.55	30	0%	100%	1472	0	0.067	0.000	0.000

Appendix C - Mobile Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
DATA OF RUN: 02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	943
FUEL FACTOR	0.00%
TAKE-BACK FACTOR	0.00%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-4940.60
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	29.73

STATE	OREGON
CLIMATE ZONE	1
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	1344

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVINGS (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
	HEAT PUMP W/O AC	0.000	0.000	
13.869	HEAT PUMP AFTER AC CRED	0.070	13.869	0.070
19.690	WALL R19>R21	0.013	51.295	0.082
27.729	ATTIC R38>R49	0.010	96.643	0.092
89.544	CLASS 20 WINDOWS	0.077	163.507	0.169

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	ANNUAL MEASURE SAVINGS (MW/YR)
BASE CASE	293	---	---	---	---	---	3771	---	---	0.000	0.000
HT PMP AFTR AC CRDT	271	120.65	$744.91	30	18%	100%	3125	646	0.067	13.869	0.070
WALL R19>R21	267	4.00	104.84	45	100%	100%	3006	119	0.058	51.295	0.013
HEAT PUMP W/O AC	267	119.00	3280.55	30	0%	100%	3006	0	0.067	0.000	0.000
ATTIC R38>R49	264	3.00	148.15	45	100%	100%	2917	89	0.058	96.643	0.010
CLASS 20 WINDOWS	240	24.00	1747.01	30	100%	100%	2203	714	0.067	163.507	0.077

Appendix C - Mobile Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014	# OF HOMES IN SECTOR MATCHING PROTOTYPE	1,110		STATE	UTAH
				CLIMATE ZONE	2
DATA OF RUN: 02-Dec-93	FUEL FACTOR	11.80%		VINTAGE OF HOUSING	EXISTING
				PROTOTYPE SIZE (SQ. FT.)	924
	TAKE-BACK FACTOR	30.00%			
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-4548.30			
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	44.91			

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVINGS (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
11.639	WEATHERSTRIP	0.020	11.639	0.797
12.055	BLOW WALL R4>R11	0.258	12.087	0.931
12.207	DUCT SEALING	0.016	14.768	0.931
13.668	BLOW BELLY R7>R30	0.297	15.115	0.931
15.295	REPLACE WINDOWS U>.40	0.206	19.952	0.931
16.689	BLOW CEILING R7>R30	0.134	25.002	0.967
17.803	ROOF CAP> R30	0.035	47.027	0.967

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	ANNUAL MEASURE SAVINGS (MW/YR)
BASE CASE	539	---	---	---	---	---	17340	---	---	0.000	0.000
DUCT SEALING	534	13.36	$81.92	30	35%	100%	17210	130	0.067	14.768	0.016
BLOW WALL R4>R11	461	162.00	813.06	30	45%	100%	15175	2035	0.067	12.087	0.258
WEATHERSTRIP	455	18.70	90.37	30	30%	100%	15020	156	0.067	11.639	0.020
BLOW BELLY R7>R30	371	101.00	633.86	30	84%	100%	12676	2344	0.067	15.115	0.297
RPLAC WNDWS U>.40	312	115.20	954.36	30	51%	100%	11046	1629	0.067	19.952	0.206
BLOW CEILING R7>R30	274	101.00	1048.50	30	38%	100%	9991	1056	0.067	25.002	0.134
ROOF CAP> R30	264	101.00	1972.16	30	10%	100%	9711	280	0.067	47.027	0.035

Appendix C - Mobile Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014	# OF HOMES IN SECTOR MATCHING PROTOTYPE	526	STATE	UTAH
DATA OF RUN: 02-Dec-93	FUEL FACTOR	0.00%	CLIMATE ZONE	2
	TAKE-BACK FACTOR	0.00%	VINTAGE OF HOUSING	NEW
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-4548.30	PROTOTYPE SIZE (SQ. FT.)	924
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	44.91		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVINGS (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
	HEAT PUMP AFTER AC CRDT	0.000	0.000	
25.098	HUD STANDARD>MAP	0.348	25.098	0.348
25.327	CURRENT>NEW HUD STND	0.138	25.908	0.485
25.531	WALL R19>R21	0.011	34.694	0.496
25.709	ATTIC R38>R49	0.005	42.076	0.502
26.827	HEAT PUMP W/O AC	0.015	63.350	0.517
31.511	CLASS 20 WINDOWS	0.038	95.646	0.555

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	ANNUAL MEASURE SAVINGS (MW/YR)
BASE CASE	373	---	---	---	---	---	12204	---	---	0.000	0.000
CRNT>NEW HUD STND	322	51.00	$1,019.94	45	100%	100%	9914	2291	0.058	25.908	0.138
HUD STANDARD>MAP	193	129.00	2499.14	45	100%	100%	4120	5794	0.058	25.098	0.348
HT PMP AFTR AC CRDT	193	79.47	744.91	30	0%	100%	4120	0	0.067	0.000	0.000
WALL R19>R21	189	4.00	107.12	45	100%	100%	3940	180	0.058	34.694	0.011
ATTIC R38>R49	187	2.00	64.96	45	100%	100%	3850	90	0.058	42.076	0.005
HEAT PUMP W/O AC	181	77.00	3280.55	30	7%	100%	3595	256	0.067	63.350	0.015
CLASS 20 WINDOWS	167	14.00	1033.62	45	100%	100%	2966	629	0.058	95.646	0.038

Appendix C - Mobile Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
DATA OF RUN: 02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	923
FUEL FACTOR	0.00%
TAKE-BACK FACTOR	0.00%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-6179.20
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	45.44

STATE	UTAH
CLIMATE ZONE	2
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	1344

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVINGS (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
	HEAT PUMP AFTER AC CRDT	0.000	0.000	
	0	0.000	0.000	
	0	0.000	0.000	
13.385	CURRENT>NEW HUD STND	0.776	13.385	0.776
19.502	HUD STANDARD>MAP	0.943	24.532	1.719
19.657	WALL R19>R21	0.019	33.561	1.738
20.299	HEAT PUMP W/O AC	0.029	58.544	1.767
20.645	ATTIC R38>R49	0.014	63.231	1.782
25.876	CLASS 20 WINDOWS	0.115	106.979	1.896

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	ANNUAL MEASURE SAVINGS (MW/YR)
BASE CASE	566	---	---	---	---	---	19540	---	---	0.000	0.000
CRNT>NEW HUD STND	404	162.00	$1,693.45	45	100%	100%	12179	7361	0.058	13.385	0.776
HUD STANDARD>MAP	207	197.00	3774.36	45	100%	100%	3227	8952	0.058	24.532	0.943
HT PMP AFTR AC CRDT	207	85.24	744.91	30	0%	100%	3227	0	0.067	0.000	0.000
WALL R19>R21	203	4.00	104.84	45	100%	100%	3045	182	0.058	33.561	0.019
ATTIC R38>R49	200	3.00	148.15	45	100%	100%	2909	136	0.058	63.231	0.014
HEAT PUMP W/O AC	194	82.35	3280.55	30	7%	100%	2632	277	0.067	58.544	0.029
CLASS 20 WINDOWS	170	24.00	1747.01	30	100%	100%	1541	1091	0.067	106.979	0.115

Appendix C - Mobile Homes, Demand-Side Resources Worksheet

FOR THE YEAR: 2014	# OF HOMES IN SECTOR MATCHING PROTOTYPE	7,694	STATE	WASHINGTON
DATA OF RUN: 02-Dec-93	FUEL FACTOR	29.20%	CLIMATE ZONE	2
	TAKE-BACK FACTOR	30.00%	VINTAGE OF HOUSING	EXISTING
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-3692.60	PROTOTYPE SIZE (SQ. FT.)	924
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	29.04		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVINGS (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
18.398	DUCT SEALING	0.091	18.398	0.091
20.158	WEATHERSTRIP	0.071	22.426	0.162
22.824	BLOW WALL R4>R11	0.928	23.291	1.090
25.943	BLOW BELLY R7>R30	1.069	29.124	2.158
29.143	REPLACE WINDOWS U>.40	0.743	38.445	2.901
31.851	BLOW CEILING R7>R30	0.481	48.176	3.382
33.989	ROOF CAP> R30	0.128	90.615	3.510

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	ANNUAL MEASURE SAVINGS (MW/YR)
BASE CASE	539	---	---	---	---	---	8467	---	---	0.000	0.000
DUCT SEALING	532	20.66	$81.92	30	35%	100%	8362	104	0.067	18.398	0.091
BLOW WALL R4>R11	458	162.00	813.06	30	45%	100%	7306	1056	0.067	23.291	0.928
WEATHERSTRIP	453	18.70	90.37	30	30%	100%	7226	81	0.067	22.426	0.071
BLOW BELLY R7>R30	368	101.00	633.86	30	84%	100%	6009	1217	0.067	29.124	1.069
RPLC WNDWS U>.40	309	115.20	954.36	30	51%	100%	5164	845	0.067	38.445	0.743
BLOW CEILING R7>R30	271	101.00	1048.50	30	38%	100%	4616	548	0.067	48.176	0.481
ROOF CAP> R30	261	101.00	1972.16	30	10%	100%	4470	145	0.067	90.615	0.128

FOR THE YEAR:	# OF HOMES IN SECTOR MATCHING PROTOTYPE	449	STATE	WASHINGTON
2014			CLIMATE ZONE	2
DATA OF RUN:	FUEL FACTOR	0.00%	VINTAGE OF HOUSING	NEW
02-Dec-93			PROTOTYPE SIZE (SQ. FT.)	924
	TAKE-BACK FACTOR	0.00%		
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-3692.60		
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	29.04		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVINGS (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
	HEAT PUMP W/O AC	0.000	0.000	
20.803	HEAT PUMP AFTER AC CRED	0.011	20.803	0.011
32.237	WALL R19>R21	0.006	53.663	0.017
37.104	ATTIC R38>R49	0.003	65.081	0.020
93.537	CLASS 20 WINDOWS	0.021	147.940	0.041

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	ANNUAL MEASURE SAVINGS (MW/YR)
BASE CASE	200	---	---	---	---	---	2115	---	---	0.000	0.000
HT PMP AFTR AC CRDT	193	82.35	$744.91	30	9%	100%	1897	218	0.067	20.803	0.011
WALL R19>R21	189	4.00	107.12	45	100%	100%	1781	116	0.058	53.663	0.006
ATTIC R38>R49	187	2.00	64.96	45	100%	100%	1723	58	0.058	65.081	0.003
HEAT PUMP W/O AC	187	79.88	3280.55	30	0%	100%	1723	0	0.067	0.000	0.000
CLASS 20 WINDOWS	173	14.00	1033.62	45	100%	100%	1316	407	0.058	147.940	0.021

Appendix C - Mobile Homes, Demand-Side Resources

FOR THE YEAR:	# OF HOMES IN SECTOR MATCHING PROTOTYPE	533		STATE	WASHINGTON
2014				CLIMATE ZONE	2
DATA OF RUN:	FUEL FACTOR	0.00%		VINTAGE OF HOUSING	NEW
02-Dec-93				PROTOTYPE SIZE (SQ. FT.)	1344
	TAKE-BACK FACTOR	0.00%			
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-4940.60			
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	29.73			

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVINGS (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
	HEAT PUMP W/O AC	0.000	0.000	
13.869	HEAT PUMP AFTER AC CRED	0.020	13.869	0.020
23.865	WALL R19>R21	0.007	51.295	0.027
36.010	ATTIC R38>R49	0.005	96.643	0.033
108.906	CLASS 20 WINDOWS	0.043	163.507	0.076

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	ANNUAL MEASURE SAVINGS (MW/YR)
BASE CASE	293	---	---	---	---	---	3771	---	---	0.000	0.000
HT PMP AFTR AC CRDT	282	120.65	$744.91	30	9%	100%	3444	326	0.067	13.869	0.020
WALL R19>R21	278	4.00	104.84	45	100%	100%	3325	119	0.058	51.295	0.007
HEAT PUMP W/O AC	278	119.00	3280.55	30	0%	100%	3325	0	0.067	0.000	0.000
ATTIC R38>R49	275	3.00	148.15	45	100%	100%	3236	89	0.058	96.643	0.005
CLASS 20 WINDOWS	251	24.00	1747.01	30	100%	100%	2523	714	0.067	163.507	0.043

APPENDIX D

FOR THE YEAR: 2014
DATE OF RUN: 02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	1,986	(A)
FUEL FACTOR	61.90%	(B)
TAKE-BACK FACTOR	30.00%	(C)
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-3897.60	(D)
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	48.95	(E)
BASE UA	279.8	(F)

Template for Residential Tables

STATE	MONTANA
CLIMATE ZONE	3
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQFT)	840

(G) AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	ANNUAL MEASURE SAVINGS (MW/YR)	(H) LEVELIZED COST (mills/kWh)	(I) CUMULATIVE SAVINGS (MW/YR)
21.988	W1 WIND SG>STORM	0.059	21.988	0.059
28.371	WALLS R0>R11	0.032	39.987	0.091
48.569	W2 REPLACE SG> VINYL	0.074	73.379	0.165
60.139	ACH .6>.5	0.041	107.098	0.206
67.486	F1 FLOOR R0>R19	0.021	138.626	0.227
69.668	C2 CEIL R38>49 AFT C1	0.002	281.006	0.230
77.241	C1 CEIL R19>38	0.005	439.031	0.235
85.172	DOOR INSUL	0.004	591.384	0.238
96.645	CEILING R17>R49	0.005	610.681	0.244

CONSERVATION MEASURES	(J) UA (Btu/hr-F)	(K) DELTA U/A (Btu/hr-F)	(L) FIRST INCRMT. COST($)	(M) MEASURE LIFE(YRS)	(N) MEASURE ACCEPTANCE	(o) PENETRATION RATE	(P) USE (kWh/YR)	(Q) SAVINGS (kWh/YR)	(R) CAPITAL RECOVERY FACTOR	(S) VARIABLE LEVELIZED COST (mills/kWh)	(T) MEASURE SAVINGS (MW/YR)
BASE CASE	280	---	---	---	---	---	3734	---	---	---	---
W1 WIND SG>STORM	260	45.60	196.01	30	44%	100%	3474	260	0.067	21.988	0.059
WALLS R0>R11	249	43.88	343.02	30	25%	100%	3331	143	0.067	39.987	0.032
W2 RPLC SG> VINYL	224	57.00	817.67	30	44%	100%	3004	327	0.067	73.379	0.074
ACH .6>.5	210	13.77	288.30	30	100%	100%	2824	180	0.067	107.098	0.041
F1 FLOOR R0>R19	203	26.45	716.81	30	27%	100%	2730	94	0.067	138.626	0.021
C1 CEIL R19>38	201	5.42	464.96	30	30%	100%	2709	21	0.067	439.031	0.005
C2 CEIL R38>49 AFT C1	201	2.64	145.30	30	30%	100%	2699	10	0.067	281.006	0.002
DOOR INSUL	199	1.38	159.54	30	90%	100%	2682	16	0.067	591.384	0.004
CEILING R17>R49	197	5.99	715.11	30	30%	100%	2659	23	0.067	610.681	0.005

Appendix D - Multifamily Dwellings, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
DATE OF RUN: 02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	377
FUEL FACTOR	0.00%
TAKE-BACK FACTOR	0.00%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-262.30
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	44.25
BASE UA	202.92

STATE	MONTANA
CLIMATE ZONE	3
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	840

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	ANNUAL MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
40.733	WALL R26 A>R40 BDW	0.014	40.733	0.014
41.254	LTSGS ENVELOPE	0.017	41.670	0.031
42.276	LTSGS WINDOWS	0.011	45.221	0.042
46.657	FLOOR R30>R48	0.003	110.916	0.045
67.998	CLASS 20 WINDOW	0.022	111.927	0.066

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVING (MW/YR)
BASE CASE	203	---	---	---	---	---	8717	---	---	---	---
LTSGS ENVELOPE	194	9.08	311.11	70	100%	100%	8315	402	0.054	41.670	0.017
LTSGS WINDOWS	188	5.67	169.80	30	100%	100%	8064	251	0.067	45.221	0.011
WALL R26 A>R40 BDW	181	7.25	242.73	70	100%	100%	7744	321	0.054	40.733	0.014
FLOOR R30>R48	179	1.50	136.75	70	100%	100%	7677	66	0.054	110.916	0.003
CLASS 20 WINDOW	168	11.42	846.72	30	100%	100%	7172	505	0.067	111.927	0.022

Appendix D - Multifamily Dwellings, Demand-Side Resources Worksheet

FOR THE YEAR: 2014	# OF HOMES IN SECTOR MATCHING PROTOTYPE	32,758	STATE	OREGON
DATE OF RUN: 02-Dec-93	FUEL FACTOR	33.50%	CLIMATE ZONE	1
	TAKE-BACK FACTOR	30.00%	VINTAGE OF HOUSING	EXISTING
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-3165.10	PROTOTYPE SIZE (SQ. FT.)	840
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	31.29		
	BASE UA	279.8		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	ANNUAL MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
19.707	W1 WIND SG>STORM	1.083	19.707	1.083
25.428	WALLS R0>R11	0.595	35.839	1.678
43.530	W2 REPLACE SG> VINYL	1.366	65.766	3.044
53.900	ACH .6>.5	0.750	95.986	3.794
60.485	F1 FLOOR R0>R19	0.392	124.244	4.186
62.440	C2 CEIL R38>49 AFT C1	0.043	251.852	4.230
69.227	C1 CEIL R19>38	0.089	393.482	4.318
76.336	DOOR INSUL	0.068	530.029	4.386
86.618	CEILING R17>R49	0.098	547.324	4.484

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	280	---	---	---	---	---	3718	---	---	---	---
W1 WIND SG>STORM	260	45.60	196.01	30	44%	100%	3428	290	0.067	19.707	1.083
WALLS R0>R11	249	43.88	343.02	30	25%	100%	3269	159	0.067	35.839	0.595
W2 RPLC SG> VNYL	224	57.00	817.67	30	44%	100%	2904	365	0.067	65.766	1.366
ACH .6>.5	210	13.77	288.30	30	100%	100%	2703	201	0.067	95.986	0.750
F1 FLOOR R0>R19	203	26.45	716.81	30	27%	100%	2598	105	0.067	124.244	0.392
C1 CEIL R19>38	201	5.42	464.96	30	30%	100%	2575	24	0.067	393.482	0.089
C2 CEIL R38>49 AFT C1	201	2.64	145.30	30	30%	100%	2563	12	0.067	251.852	0.043
DOOR INSUL	199	1.38	159.54	30	90%	100%	2545	18	0.067	530.029	0.068
CEILING R17>R49	197	5.99	715.11	30	30%	100%	2519	26	0.067	547.324	0.098

Appendix D - Multifamily Dwellings, Demand-Side Resources Worksheet

FOR THE YEAR: 2014	# OF HOMES IN SECTOR MATCHING PROTOTYPE	850		STATE	OREGON
DATE OF RUN: 02-Dec-93	FUEL FACTOR	0.00%		CLIMATE ZONE	1
	TAKE-BACK FACTOR	0.00%		VINTAGE OF HOUSING	NEW
	ENERGY USE CONVERSION CONSTANT (kWh/YR)	-168.60		PROTOTYPE SIZE (SQ. FT.)	840
	ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	22.54			
	BASE UA	132			

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	ANNUAL MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
79.963	WALL R26 A>R40 BDW	0.016	79.963	0.016
80.986	LTSGS ENVELOPE	0.020	81.803	0.036
82.992	LTSGS WINDOWS	0.012	88.775	0.048
91.593	FLOOR R30>R48	0.003	217.741	0.051
133.489	CLASS 20 WINDOW	0.025	219.726	0.076

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	132	---	---	---	---	---	2807	---	---	---	---
LTSGS ENVELOPE	123	9.08	311.11	70	100%	100%	2602	205	0.054	81.803	0.020
LTSGS WINDOWS	117	5.67	169.80	30	100%	100%	2474	128	0.067	88.775	0.012
WALL R26 A>R40 BDW	110	7.25	242.73	70	100%	100%	2311	163	0.054	79.963	0.016
CLASS 20 WINDOW	99	11.42	846.72	30	100%	100%	2054	257	0.067	219.726	0.025
FLOOR R30>R48	97	1.50	136.75	70	100%	100%	2020	34	0.054	217.741	0.003

Appendix D - Multifamily Dwellings, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
DATE OF RUN: 02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	16,567
FUEL FACTOR	20.70%
TAKE-BACK FACTOR	30.00%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-3897.60
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	48.95
BASE UA	279.8

STATE	UTAH
CLIMATE ZONE	2
VINTAGE OF HOUSING	EXISTING
PROTOTYPE SIZE (SQ. FT.)	840

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	ANNUAL MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
10.564	W1 WIND SG>STORM	1.022	10.564	1.022
13.631	WALLS R0>R11	0.561	19.212	1.583
23.335	W2 REPLACE SG> VINYL	1.289	35.255	2.872
28.894	ACH .6>.5	0.708	51.455	3.580
32.424	F1 FLOOR R0>R19	0.370	66.604	3.949
33.472	C2 CEIL R38>49 AFT C1	0.041	135.011	3.990
37.111	C1 CEIL R19>38	0.084	210.934	4.074
40.921	DOOR INSUL	0.064	284.133	4.138
46.434	CEILING R17>R49	0.092	293.404	4.230

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	280	---	---	---	---	---	7771	---	---	---	---
W1 WIND SG>STORM	260	45.60	196.01	30	44%	100%	7231	540	0.067	10.564	1.022
WALLS R0>R11	249	43.88	343.02	30	25%	100%	6934	297	0.067	19.212	0.561
W2 RPLC SG> VINYL	224	57.00	817.67	30	44%	100%	6252	682	0.067	35.255	1.289
ACH .6>.5	210	13.77	288.30	30	100%	100%	5878	374	0.067	51.455	0.708
F1 FLOOR R0>R19	203	26.45	716.81	30	27%	100%	5682	195	0.067	66.604	0.370
C1 CEIL R19>38	201	5.42	464.96	30	30%	100%	5638	44	0.067	210.934	0.084
C2 CEIL R38>49 AFT C1	201	2.64	145.30	30	30%	100%	5617	22	0.067	135.011	0.041
DOOR INSUL	199	1.38	159.54	30	90%	100%	5583	34	0.067	284.133	0.064
CEILING R17>R49	197	5.99	715.11	30	30%	100%	5534	49	0.067	293.404	0.092

Appendix D - Multifamily Dwellings, Demand-Side Resources Worksheet

FOR THE YEAR:
2014
DATE OF RUN:
02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	608
FUEL FACTOR	0.00%
TAKE-BACK FACTOR	0.00%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-234.10
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	37.82
BASE UA	150.25

STATE	UTAH
CLIMATE ZONE	2
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	840

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	ANNUAL MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
47.662	WALL R26 A>R40 BDW	0.019	47.662	0.019
48.271	CURRENT>LTSGS ENVELOPE	0.024	48.758	0.043
61.101	CLASS 50>LTSGS WINDOWS	0.042	74.064	0.085
64.131	FLOOR R30>R48	0.004	129.783	0.089
80.932	CLASS 20 WINDOW	0.030	130.966	0.119

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	150	---	---	---	---	---	5448	---	---	---	---
CRRNT>LTSGS ENVLP	141	9.08	311.11	70	100%	100%	5105	344	0.054	48.758	0.024
CLSS 50>LTSGS WDWS	125	16.17	678.06	30	100%	100%	4493	611	0.067	74.064	0.042
WALL R26 A>R40 BDW	118	7.25	242.73	70	100%	100%	4219	274	0.054	47.662	0.019
FLOOR R30>R48	116	1.50	136.75	70	100%	100%	4162	57	0.054	129.783	0.004
CLASS 20 WINDOW	105	11.42	846.72	30	100%	100%	3731	432	0.067	130.966	0.030

(311.11 * .054)/344 = LC

Appendix D - Multifamily Dwellings, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
DATE OF RUN: 02-Dec-93

OF HOMES IN SECTOR MATCHING PROTOTYPE 8,073

FUEL FACTOR 4.70%

TAKE-BACK FACTOR 30.00%

ENERGY USE CONVERSION CONSTANT (kWh/YR) -3165.10
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR 31.29
BASE UA 279.8

STATE WASHINGTON
CLIMATE ZONE 2
VINTAGE OF HOUSING EXISTING
PROTOTYPE SIZE (SQ. FT.) 840

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	ANNUAL MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
13.751	W1 WIND SG>STORM	0.382	13.751	0.382
17.744	WALLS R0>R11	0.210	25.008	0.593
30.375	W2 REPLACE SG> VINYL	0.482	45.891	1.075
37.611	ACH .6>.5	0.265	66.979	1.340
42.206	F1 FLOOR R0>R19	0.138	86.697	1.479
43.571	C2 CEIL R38>49 AFT C1	0.015	175.742	1.494
48.307	C1 CEIL R19>38	0.031	274.571	1.525
53.267	DOOR INSUL	0.024	369.852	1.549
60.442	CEILING R17>R49	0.035	381.921	1.584

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	280	---	---	---	---	---	5328	---	---	---	---
W1 WIND SG>STORM	260	45.60	196.01	30	44%	100%	4913	415	0.067	13.751	0.382
WALLS R0>R11	249	43.88	343.02	30	25%	100%	4685	228	0.067	25.008	0.210
W2 REPLC SG> VINYL	224	57.00	817.67	30	44%	100%	4161	524	0.067	45.891	0.482
ACH .6>.5	210	13.77	288.30	30	100%	100%	3874	287	0.067	66.979	0.265
F1 FLOOR R0>R19	203	26.45	716.81	30	27%	100%	3724	150	0.067	86.697	0.138
C1 CEIL R19>38	201	5.42	464.96	30	30%	100%	3690	34	0.067	274.571	0.031
C2 CEIL R38>49 AFT C1	201	2.64	145.30	30	30%	100%	3673	17	0.067	175.742	0.015
DOOR INSUL	199	1.38	159.54	30	90%	100%	3647	26	0.067	369.852	0.024
CEILING R17>R49	197	5.99	715.11	30	30%	100%	3610	38	0.067	381.921	0.035

Appendix D - Multifamily Dwellings, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
DATE OF RUN: 02-Dec-93

# OF HOMES IN SECTOR MATCHING PROTOTYPE	(16)
FUEL FACTOR	0.00%
TAKE-BACK FACTOR	0.00%
ENERGY USE CONVERSION CONSTANT (kWh/YR)	-168.60
ENERGY USE CONVERSION SLOPE (kWh/(Btu/hr-F))/YR	22.54
BASE UA	132

STATE	WASHINGTON
CLIMATE ZONE	2
VINTAGE OF HOUSING	NEW
PROTOTYPE SIZE (SQ. FT.)	840

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	ANNUAL MEASURE SAVINGS (MW/YR)	LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
79.963	WALL R26 A>R40 BDW	0.000	79.963	0.000
80.986	LTSGS ENVELOPE	0.000	81.803	-0.001
82.992	LTSGS WINDOWS	0.000	88.775	-0.001
91.593	FLOOR R30>R48	0.000	217.741	-0.001
133.489	CLASS 20 WINDOW	0.000	219.726	-0.001

CONSERVATION MEASURES	UA (Btu/hr-F)	DELTA U/A (Btu/hr-F)	FIRST INCRMT. COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	USE (kWh/YR)	SAVINGS (kWh/YR)	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
BASE CASE	132	---	---	---	---	---	2807	---	---	---	---
LTSGS ENVELOPE	123	9.08	311.11	70	100%	100%	2602	205	0.054	81.803	0.000
LTSGS WINDOWS	117	5.67	169.80	30	100%	100%	2474	128	0.067	88.775	0.000
WALL R26 A>R40 BDW	110	7.25	242.73	70	100%	100%	2311	163	0.054	79.963	0.000
CLASS 20 WINDOW	99	11.42	846.72	30	100%	100%	2054	257	0.067	219.726	0.000
FLOOR R30>R48	97	1.50	136.75	70	100%	100%	2020	34	0.054	217.741	0.000

APPENDIX
E

Appendix E: Residential Appliances

Residential appliance information is presented on two sheets which are identified as E-1 and E-2.

The residential appliance sheets for new homes in the state of Oregon are used as the template.

A: Number of Appliances: The values presented in this column show the number of appliances installed in new homes, between 1993 and 2014. The total lighting customers are equal to the number of new residential additions between 1993 to 2014. The number of appliances are calculated as follows:

$N_A = n_A + R_A$

Where:

N_A *is the number of new appliances by appliance type sub A*

n_A *is equal to number of new appliances in new homes by appliance type*

R_A *is equal to number of new appliances in existing homes by appliance type*

The other variables on the worksheets have the same definitions as those in appendix B.

Appendix E - Residential Appliances, End-Use Consumption

APPLIANCES - OREGON

FIRST YEAR OF DATA	1993 APPLIANCE ENERGY USE (kWh/Year)	
	OLD	NEW
Lighting	1,629	1,629
Ranges	561	561
Dishwashers	649	317
Clothesdryers	767	519
Air conditioners, window	461	438
Air conditioners, central	1,479	1,405
Air conditioners, evap.	115	115
Freezers	856	364
Waterheaters	3,679	3,401
Refrigerators	1,318	580
Hot tub	2,366	2,366
Well pump	1,300	1,300
Waterbed	925	925
Clotheswasher	586	527
Miscellaneous	1,067	1,067

APPLIANCES - UTAH

FIRST YEAR OF DATA	1993 APPLIANCE ENERGY USE (kWh/Year)	
	OLD	NEW
Lighting	1,604	1,604
Ranges	551	551
Dishwashers	638	312
Clothesdryers	754	511
Air conditioners, window	320	304
Air conditioners, central	1,194	1,134
Air conditioners, evap.	517	517
Freezers	841	359
Waterheaters	2,228	3,077
Refrigerators	1,295	570
Hot tub	2,325	2,325
Well pump	1,277	1,277
Waterbed	909	909
Clotheswasher	575	518
Miscellaneous	528	528

Appendix E - Residential Appliances, Demand-Side Resources Worksheet

FOR THE YEAR:		(A)
2014	Total lighting customers	150,259
DATE OF RUN:	Total number of ranges	424,969
03-Dec-93	Total number of dishwashers	270,546
	Total number of clothesdryers	412,486
	Total number of air conditioners, window	165,261
	Total number of air conditioners, central	202,735
	Total number of air conditioners, evaporative	57,344
	Total number of freezers	279,003
	Total number of hot waterheaters	346,229
	Total number of refrigerators	424,996
	Total number of hot tubs	26,396
	Total number of well pumps	90,947
	Total number of waterbeds	63,794
	Total number of clotheswashers	412,466

STATE	OREGON
CLIMATE ZONE	1
VINTAGE OF HOUSING	NEW

Template for Residential Appliances

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	ANNUAL MEASURE SAVINGS (MW/YR)	LEVELIZED MEASURE COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
-25.477	LOW FLOW SHOWERHEAD	15.933	-25.477	15.933
-22.475	INCRM. HORIZ. AXIS WASHER	7.573	-16.159	23.506
-17.777	DISHWASHER MEASURES	7.393	-2.838	30.899
-13.264	ORIENTATION	8.542	3.058	39.441
-4.443	HORIZNTL WASH/HIGH SPIN	16.322	16.872	55.763
-1.587	ROOF COLOR, LANDSCAPING	6.572	22.649	62.335
1.089	CLOTHESWASHER MEASURES	4.614	37.246	66.948
2.412	FIRST 3 INCAND. > PL	2.060	45.408	69.009
5.033	1993 FREEZER> 1998 STAND.	4.210	47.994	73.219
8.961	1993 REFER> 1998 STAND.	6.548	52.877	79.766
9.799	INSULATED BEDFRAME	1.474	55.179	81.241
13.674	NEW .95 TANK	6.482	62.246	87.722
14.828	ADD.3 INCAND. > PL	2.060	63.964	89.782
27.645	EXHAUST AIR HP DHW	29.357	66.842	119.140
31.963	DRYER MEASURES	10.446	81.210	129.586
40.886	SOLAR DHW	22.473	92.337	152.059
41.755	EFFICIENT AC UPGRADE	1.157	156.005	153.216
94.320	1998 REFER> HI TECH	11.998	765.580	165.214
139.869	1998 REFER> HI TECH	11.982	767.912	177.197
163.708	1998 FREEZER> HI TECH	6.692	794.901	183.889
189.819	H.P. DHW	6.450	934.219	190.339

Appendix E - Residential Appliances, Demand-Side Resources Worksheet

MEASURES APPLICABLE TO:	SAVINGS (kWh/YR)	FIRST INCRMT. COST($)	O & M COST($)	MEASURE LIFE(YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
ALL LIGHTING									
FIRST 3 INCAND. > PL	120.19	76.47	-20.70	15	100%	100%	0.098	45.408	2.060
ADD 3 INCAND. > PL	120.19	99.27	-20.70	15	100%	100%	0.098	63.964	2.060
ALL DISHWASHERS									
DISHWASHER MEASURES	288.60	74.19	-81.35	12	83%	100%	0.114	-2.838	7.393
ALL CLOTHESDRYERS									
DRYER MEASURES	222.00	157.72	0.00	12	100%	100%	0.114	81.210	10.446
HORIZTL WASH/HIGH SPIN	346.88	51.20	0.00	12	100%	100%	0.114	16.872	16.322
ALL CLOTHESWASHERS.									
CLOTHESWASHER MSURS	98.05	31.95	0.00	12	100%	100%	0.114	37.246	4.614
INCRM. HORIZ. AXIS WSHR	160.95	147.46	-170.21	12	100%	100%	0.114	-16.159	7.573
ALL COOLING									
ORIENTATION	352.09	20.00	0.00	70	50%	100%	0.054	3.058	8.542
ROOF COLOR, LANDSCPNG	270.88	113.96	0.00	70	50%	100%	0.054	22.649	6.572
ALL AIR CONDITIONERS									
EFFICIENT AC UPGRADE	71.49	113.96	0.00	15	70%	100%	0.098	156.005	1.157
ALL FREEZERS									
1993 FREEZER> 1998 STAND	106.60	46.72	5.56	15	100%	100%	0.098	47.994	4.210
1998 FREEZER> HI TECH	169.44	1367.52	8.83	15	100%	100%	0.098	794.901	6.692
ALL WATERHEATERS									
NEW .95 TANK	205.13	94.59	17.12	12	80%	100%	0.114	62.246	6.482
LOW FLOW SHOWERHEAD	576.28	13.00	-163.03	15	70%	100%	0.098	-25.477	15.933
H.P. DHW	494.88	1139.60	113.96	3	33%	100%	0.369	934.219	6.450
SOLAR DHW	1724.20	1945.60	0.00	20	33%	100%	0.082	92.337	22.473
EXHAUST AIR HP DHW	2252.38	1424.50	113.96	15	33%	100%	0.098	66.842	29.357
ALL REFRIGERATORS									
1993 REFER> 1998 STAND.	135.05	56.98	15.99	15	100%	100%	0.098	52.877	6.548
1998 REFER> HI TECH	247.15	1909.97	29.43	15	100%	100%	0.098	767.912	11.982
1998 REFER> HI TECH	247.47	1909.97	26.05	15	100%	100%	0.098	765.580	11.998
ALL WATERBEDS									
INSULATED BEDFRAME	607.73	270.70	71.96	15	33%	100%	0.098	55.179	1.474

Appendix E - Residential Appliances, Demand-Side Resources Worksheet

FOR THE YEAR:	Total lighting customers	240,943	STATE	UTAH
2014	Total number of ranges	633,102	CLIMATE ZONE	2
DATE OF RUN:	Total number of dishwashers	419,261	VINTAGE OF HOUSING	NEW
03-Dec-93	Total number of clothesdryers	598,574		
	Total number of air conditioners, window	101,248		
	Total number of air conditioners, central	262,174		
	Total number of air conditioners, evaporative	633,220		
	Total number of freezers	370,699		
	Total number of hot waterheaters	87,624		
	Total number of refrigerators	633,220		
	Total number of hot tubs	25,307		
	Total number of well pumps	30,834		
	Total number of waterbeds	112,975		
	Total number of clotheswashers	617,786		

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES	ANNUAL MEASURE SAVINGS (MW/YR)	LEVELIZED MEASURE COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
-25.926	LOW FLOW SHOWERHEAD	3.963	-25.926	3.963
-18.930	INCRM. HORIZ. AXIS WASHER	11.147	-16.443	15.109
-12.080	DISHWASHER MEASURES	11.258	-2.888	26.368
-2.122	ORIENTATION	66.056	1.853	92.424
3.501	ROOF COLOR, LANDSCAPING	50.821	13.725	143.245
5.411	HORIZONTAL WASH/HIGH SPIN	23.276	17.169	166.521
5.979	FIRST 3 INCAND. > PL	4.136	28.840	170.657
7.904	1993 REFER> 1998 STAND.	12.213	34.806	182.871
8.409	INSULATED BEDFRAME	3.268	36.644	186.139
9.447	CLOTHESWASHER MEASURES	6.791	37.902	192.930
10.165	ADD 3 INCAND. > PL	4.136	43.662	197.066
10.511	NEW .95 TANK	1.989	44.775	199.054
10.705	1993 FREEZER> 1998 STAND.	1.047	47.598	200.102
12.292	SOLAR DHW	5.779	67.252	205.880
14.201	EXHAUST AIR HP DHW	7.301	68.019	213.182
18.671	DRYER MEASURES	14.897	82.639	228.078
22.756	AC> INDIRECT EVAP. COOLER	5.549	190.689	233.627
23.635	EFFICIENT AC UPGRADE	1.187	196.733	234.814
74.129	1998 REFER> HI TECH	22.744	595.428	257.558
116.778	1998 REFER> HI TECH	22.774	599.114	280.332
120.856	1998 FREEZER> HI TECH	1.664	807.652	281.996
125.549	H.P. DHW	1.604	950.662	283.600

400 kWh

Appendix E - Residential Appliances, Demand-Side Resources Worksheet

MEASURES APPLICABLE TO:	SAVINGS (KWH/YR)	FIRST INCRMT. COST($)	O & M COST ($)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVINGS (MW/YR)
ALL LIGHTING									
FIRST 3 INCAND. > PL	150.48	76.47	-32.13	15	100%	100%	0.098	28.840	4.136
ADD 3 INCAND. > PL	150.48	99.27	-32.13	15	100%	100%	0.098	43.662	4.136
ALL DISHWASHERS									
DISHWASHER MEASURES	283.61	74.19	-81.35	12	83%	100%	0.114	-2.888	11.258
ALL CLOTHESDRYERS									
DRYER MEASURES	218.16	157.72	0.00	12	100%	100%	0.114	82.639	14.897
HORZNTL WASH/HIGH SPIN	340.88	51.20	0.00	12	100%	100%	0.114	17.169	23.276
ALL CLOTHESWASHERS									
CLOTHESWASHER MEASRS	96.35	31.95	0.00	12	100%	100%	0.114	37.902	6.791
INCRM. HORIZ. AXIS WASHR	158.17	147.46	-170.21	12	100%	100%	0.114	-16.443	11.147
ALL COOLING									
ORIENTATION	581.00	20.00	0.00	70	100%	100%	0.054	1.853	66.056
ROOF COLOR, LANDSCPNG	447.00	113.96	0.00	70	100%	100%	0.054	13.725	50.821
ALL AIR CONDITIONERS									
EFFICIENT AC UPGRADE	56.69	113.96	0.00	15	70%	100%	0.098	196.733	1.187
AC> INDIRECT EVAP. COOLR	618.40	1092.60	112.41	15	30%	100%	0.098	190.689	5.549
ALL FREEZERS									
1993 FREEZER> 1998 STAND.	104.75	46.72	4.23	15	100%	100%	0.098	47.598	1.047
1998 FREEZER> HI TECH	166.51	1367.52	6.72	15	100%	100%	0.098	807.652	1.664
ALL WATERHEATERS									
NEW .95 TANK	248.70	94.59	2.83	12	80%	100%	0.114	44.775	1.989
LOW FLOW SHOWERHEAD	566.31	13.00	-163.03	15	70%	100%	0.098	-25.926	3.963
H.P. DHW	486.32	1139.60	113.96	3	33%	100%	0.369	950.662	1.604
SOLAR DHW	3613.28	2969.60	0.00	20	16%	100%	0.082	67.252	5.779
EXHAUST AIR HP DHW	2213.42	1424.50	113.96	15	33%	100%	0.098	68.019	7.301
ALL REFRIGERATORS									
1993 REFER> 1998 STAND.	169.07	56.98	3.15	15	100%	100%	0.098	34.806	12.213
1998 REFER> HI TECH	314.86	1909.97	5.80	15	100%	100%	0.098	595.428	22.744
1998 REFER> HI TECH	315.27	1909.97	20.17	15	100%	100%	0.098	599.114	22.774
ALL WATERBEDS									
INSULATED BEDFRAME	760.83	270.70	14.19	15	33%	100%	0.098	36.644	3.268

incremental cost!!

Breakdown of Appliance Consumption (KWH/YR)

TYPICAL USAGE KWH/yr	DWH SF	DWH MF	DWH MH	DWH Adjustment	DHW RAMPP-3 KWH/yr	DHW Weighted by Housing type. Excludes, Cloth& dishwashing RAMPP3 Formula
Oregon	4345	2712	3527	0	3977	(4345*0.71+2712*0.16+3527*0.13)
Washington	4549	3200	3805	0	4268	(4549*0.71+3200*0.17+3805*0.13)
Idaho-(Pacific Division)	4107	2995	2123	0	3740	(4107*0.78+2995*0.08+2123*0.14)
Montana	4392	3114	3269	0	4036	(4392*0.7+3114*0.12+3269*0.18)
Wyoming	4577	3284	3284	0	4223	(4577*0.71+3284*0.14+3424*0.15)
California	4337	2566	3598	-500	3473	(4337*0.71+2566*0.11+3598*0.17-500)
Utah	2769	1768	2652	0	2451	(2769*0.62+2652*0.07+1768*0.31)
Idaho-(Utah Division)	3182	2652	1768	1000	3707	(3182*0.62+2652*0.07+1768*0.31+1000)
Wyoming-(Utah Division)	4577	3424	3284		4223	(4577*0.71+3284*0.14+3424*0.15)
Source Key:	1	1	1	Judgement	Weighted	Formula

Breakdown of Appliance Consumption (KWH/YR)

TYPICAL USAGE KWH/yr	AC Window SF	AC Window MF	AC Window MH	AC Window	AIR CONDITIONER, WINDOW weighted by % of housing units Formula
Oregon	515	439	474	498	(515*0.71+439*0.16+474*0.13)
Washington	515	439	474	498	(515*0.71+439*0.16+474*0.13)
Idaho-(Pacific Division)	515	439	474	503	(515*0.78+439*0.08+474*0.14)
Montana	515	439	474	499	(515*0.7+439*0.12+474*0.18)
Wyoming	515	439	474	498	(515*0.71+439*0.14+474*0.15)
California	515	439	474	498	(515*0.71+439*0.16+474*0.13)
Utah	503	439	474	352	503*0.7
Idaho-(Utah Division)	503	439	474	503	503
Wyoming-(Utah Division)	515	439	474	498	(515*0.71+439*0.16+474*0.13)
Source Key:	1	1	1	Weighted	Formula

Please note that kwh consumption for Oregon was used for all the other states, except for Utah and Idaho.

Breakdown of Appliance Consumption (KWH/YR)

TYPICAL USAGE KWH/yr	CAC Weigted Ave RAMPP	CAC Revisded SF	CAC Revisded MF	CAC Revisded MH	CAC Formula RAMPP
Oregon	1599	2066	439	474	(2066*0.71+439*0.16+474*0.13)
Washington	1599	2066	439	474	(2066*0.71+439*0.16+474*0.13)
Idaho-(Pacific Division)	1713	2066	439	474	(2066*0.78+439*0.08+474*0.14)
Montana	896	1160	472	345	(1160*0.7+472*0.04+345*0.19)
Wyoming	1599	2066	439	474	(2066*0.71+439*0.14+474*0.15)
California	1600	2066	439	474	(2066*0.71+439*0.12+474*0.17)
Utah	1313	2181	274	0	(2181*0.84+274*0.16)*0.7
Idaho-(Utah Division)	1185	1385	439	0	(1385*0.82+274*0.18)
Wyoming-(Utah Division)	1599	2066	439	474	(2066*0.71+439*0.14+474*0.15)
Source Key:		1	1	1	Formula

Breakdown of Appliance Consumption (KWH/YR)

TYPICAL USAGE KWH/yr	AC -EVAP RAMPP 3	AC-EVAP SF	AC-EVAP MF	AC-EVAP MH	AIR CONDITIONER, EVAP Evaporative (set at 25% AC Window) Unless estimated directly (Utah)
		25% of AC window Consumption			
Oregon	124	129	110	119	+AC/4
Washington	124	129	110	119	+AC/4
Idaho-(Pacific Division)	126	129	110	119	+AC/4
Montana	125	129	110	119	+AC/4
Wyoming	125	129	110	119	+AC/4
California	124	129	110	119	+AC/4
Utah	576	789	NA	1495	(789*0.85+1495*0.15)*(1-I88)*0.7
Idaho-(Utah Division)	694	789	NA	1495	(789*0.71+0*0.16+1495*0.13)*(1-I88)
Wyoming-(Utah Division)	124	129	110	119	+AC/4
Source Key:		1,2	Calculated	1,2	Formula
Utah Numbers from Supplemetal Analysis Conditional Demand Model 1991- other hand written notes.					

NA: Not Available

Analysis of Appliance Energy Consumption (KWH/YR)

Breakdown of Appliance Consumption (KWH/YR)

TYPICAL USAGE KWH/yr	Lighting Sf	Lighting MF & MH	LIGHTING kWh/yr Weighted Average	LIGHTS kWh/yr
Oregon	1868	1500	1761	(1868*0.71+1500*0.29)
Washington	1868	1500	1761	(1868*0.71+1500*0.29)
Idaho-(Pacific Division)	1868	1500	1787	(1868*0.78+1500*0.22)
Montana	1868	1500	1758	(1868*0.7+1500*0.3)
Wyoming	1868	1500	1761	(1868*0.71+1500*0.29)
California	1868	1500	1761	(1868*0.71+1500*0.29)
Utah	1868	1500	1765	(1868*0.72+1500*0.28)
Idaho-(Utah Division)	1868	1500	1772	(1868*0.74+1500*0.26)
Wyoming-(Utah Division)	1868	1500	1765	(1868*0.72+1500*0.28)
Source Key:	3	3	Calculated	Formula

NA: Not Available

Breakdown of Appliance Consumption (KWH/YR)

TYPICAL USAGE KWH/yr	REFRIG.	FREEZER	CLOTHES Dryer	RANGE	HOT TUB	WELL Pump	Dish Washer	CLOTHES Washer	WATERBED heater
Oregon	1425	925	829	606	2558	1405	702	633	1000
Washington	1425	925	829	606	2558	1405	702	633	1000
Idaho-(Pacific Division)	1425	925	829	606	2558	1405	702	633	1000
Montana	1425	925	829	606	2558	1405	702	633	1000
Wyoming	1425	925	829	606	2558	1405	702	633	1000
California	1425	925	829	606	2558	1405	702	633	1000
Utah	1425	925	829	606	2558	1405	702	633	1000
Idaho-(Utah Division)	1425	925	829	606	2558	1405	702	633	1000
Wyoming-(Utah Division)	1425	925	829	606	2558	1405	702	633	1000
Source Key:	3	3	3	3	1	1	3	3	3

Source Key descriptions:

1) Conditional Demand Analysis By Betsy Strong, BRG, December 1990.
2) Conditional Demand Analysis March 1991,
3) Various reports, not specified yet.
4) PacifiCorp Energy Decisions 1992

APPENDIX
F

Appendix F- Commercial Buildings, Demand-Side Resources Worksheets

Explanation of terms and calculations in the template worksheet.

This worksheet shows the baseline building energy characteristics, first cost and savings assumptions for commercial buildings. Columns A-D show baseline energy consumption assumptions. The information presented in the worksheet is for a prototypical, representative, building and not for an actual building. The order of explanation of each column follows the flow of information.

D: This column shows the average kWh per square feet consumption for each enduse in that building type. This information comes from the United Industries Corporations report and is used to break up the water heating consumption into gas and electric.

C: This column shows the average kWh per square feet usage by enduse. The values in this column are used in the subsequent calculations in the worksheet.

B: This column shows the saturation rate of electrical enduses. For example 37.0 percent saturation rate indicates that 37 percent of space heating in fast-food establishments, in Oregon is electric. The appliance saturations are broken down further in column I, under measure acceptance .

A: This column shows the kWh/sf baseline electric consumption for each enduse. It is calculated by multiplying column C and B.

The measure identifiers are abbreviated, but are self-explanatory, so they will not be discussed. For each measure there are incremental cost, O&M costs, energy savings, and measure life, levelized cost, effective savings.

E: Incremental cost of measure, expressed in 1994 $/sf.

F: Operation and maintenance cost of the measure, including the replacement costs.

G: Energy savings from the measure expressed in kWh/sf.

H: This measure life is not the actual operational or service life of the equipment. For most measures, the actual effective measure life is often shorter. This measure life presented in this column is used to create a common analysis platform for all the measures with varying measure lives. It is used to calculate the number of replacements during the analysis period.

I: Measure acceptance, is the same as percent saturation rate for the enduse. For example, measure acceptance for building envelop measures effecting heating , i.e. Roof insulation is same as saturation rate for heating, 37 percent. For water heating however, the measure acceptance is equal to saturation rate for measure times the ratio of all fuels (kWh/sf) and current UIC prototype. In the example the acceptance factor for water heating measures is 19 percent which is equal to (.48 *(3.43 / 8.76)).

J: This column shows the levelized cost for each measure. The base cost is used along with net present value of O&M including replacement costs, columns E and F, and multiply it by capital recovery factor and divide the results by the annual savings from column G.

K: This column shows those measures that were found to be cost effective. The effective savings is calculated by multiplying the energy savings from the measure, column G, and the measure acceptance, column I.

In this column we also perform the measure cost-effectiveness screening.
We compare the levelized cost for the measures , column J, and the levelized avoided cost for a 30 year measure. The savings for those measure that are cost effective are shown column K.

L: Measure cost in dollars per square foot for cost effective measures.

M: O&M cost for cost effective measure.

For each enduse the savings, costs, cost effective measures are averaged and shown in the row labeled Total. The levelized cost of measures is weighted by the savings from the measure. For Example, for case of building lighting, the total levelized cost is $ 0.0336 per kWh, and is calculated as follows:

$$(0.0498 * 2.3834 + 0.0187 * 2.5962) / (2.3834 + 2.5962)$$

All the cost-effective measures are aggregated for the building type and the result is presented in the columns labeled O, P, Q, R ,S.

Template for Appendix F

EXISTING	2,624	SQFT
STATE:		OREGON
ZONE:		0
BUILDING TYPE:		FAST FOOD
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA:		1993

ABSOLUTE ENERGY USE BY END USE	(A) ELEC (kWh/SF)	(B) PERCENT SATUR.	(C) ALL FUELS (kWh/SF)	(D) CURRENT UIC PROTOTYPE (kWh/SF)
HEATING	11.36	37.0%	30.71	29.40
COOLING	0.96	73.0%	1.32	5.05
VENTILATION	8.60	100.0%	8.60	6.29
WATER HEAT	1.65	48.0%	3.43	8.76
REFRIGERATION	3.00	100.0%	3.00	
LIGHTING	8.79	100.0%	8.79	7.60
MISC.	1.05	30.0%	3.49	55.82
TOTAL	35.41	61.9%	59.34	112.92

	(E) BASE COST ($/SF)	(F) O & M COSTS ($/SF)	(G) ENERGY SAVINGS (kWh/SF)	(H) MEASURE LIFE (YRS)	(I) MEASURE ACCEPTANCE	(J) LEVEL COST ($/kWh)	(K) EFFECTIVE SAVINGS (kWh/SF)	(L) COST $/SQFT	(M) O&M $/SQFT
BUILDING ENVELOPE MEASURES									
INSULATE ROOF R6>R26 *94	0.5854	0.0000	3.3880	30	37%	0.0115	1.2535	0.2166	0.0000
INSULATE WALL R7>R19 *94	6.2039	0.0000	4.1761	30	37%	0.0991			
EFF. WNDWS SG>LOW E *94	3.1818	0.0000	2.0991	30	37%	0.1011			
SOLAR FILM *94	0.4356	0.7729	0.8899	30	73%	0.0906			
					TOTAL % OF ENDUSE	0.0115	1.2535 10.2%	0.2166	0.0000
BUILDING LIGHTING MEASURES									
FLUORESCENT>T8 *94	1.0106	0.7676	2.3834	30	100%	0.0498	2.3834	1.0106	0.7676
INCANDESCENT>PL *94	0.3960	0.3321	2.5962	30	100%	0.0187	2.5962	0.3960	0.3321
					TOTAL % OF ENDUSE	0.0336	4.9797 56.7%	1.4065	1.0997
BUILDING EQUIPMENT MEASURES									
AAHX (DINING RM) *94	1.1135	0.5189	1.1490	30	37%	0.0948			
HI Ef H PMP (DIN RM) *94	4.5804	1.0672	3.6631	30	37%	0.1028			
HW HEAT RECOVERY *94	1.0590	0.4935	8.7652	30	19%	0.0118	1.6474	0.1990	0.0927
HW BLANKET Same *94	0.0220	0.0212	0.0469	30	19%	0.0615	0.0088	0.0041	0.0040
HW TIME CLOCK *94	0.0240	0.0087	0.0202	30	19%	0.1080			
FREEZER STRP CURTN *94	0.1173	0.5311	1.5812	30	100%	0.0274	1.5812	0.1173	0.5311
ECONOMIZER *94	1.8321	0.8538	1.9966	30	73%	0.0897			
					TOTAL % OF ENDUSE	0.0195	3.2374 12.2%	0.3205	0.6279
						(O)	(P)	(Q)	(R)
					GRAND TOTAL	0.0259	9.4706	1.9436	1.7276
							(S) *26.7%*		

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	4.60	46.5%	9.87	10.00
COOLING	3.22	91.4%	3.49	3.70
VENTILATION	10.90	100.0%	10.90	10.90
WATER HEAT	7.22	82.0%	8.80	8.80
REFRIGERATION	15.10	100.0%	15.10	15.10
LIGHTING	13.68	100.0%	13.07	17.10
MISC.	13.12	92.9%	6.50	57.30
TOTAL	67.83	100.1%	67.73	122.90

NEW	2,624	SQFT
STATE		OREGON
CLIMATE ZONE		0
BUILDING TYPE		FAST FOOD
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE									
MEASURES									
CURRENT PRACTICE>MCS '94	0.0340	0.0000	0.1330	70	0%	0.0138	0.0000	0.0000	0.0000
ROOF R19>R30 same '94	0.2622	0.0000	0.3136	30	20%	0.0558	0.0627	0.0524	0.0000
SOLAR FILM '94	0.4356	0.7729	0.6753	30	75%	0.1194			
WINDOWS LOW E '94	0.8256	0.2983	0.4992	30	20%	0.1502			
					TOTAL %	0.0558	0.0627	0.0524	0.0000
					OF ENDUSE		0.8%		
BUILDING LIGHTING									
MEASURES									
CURRENT PRACTICE>MCS '94	0.2598	-0.6837	4.0266	30	0%	-0.0070	0.0000	0.0000	0.0000
FLUORESCENT>T8 Elec '94	0.5205	0.6386	1.6159	30	100%	0.0479	1.6159	0.5205	0.6386
EXIT SIGNS '94	0.0773	-0.1152	0.1601	30	100%	-0.0158	0.1601	0.0773	-0.1152
					TOTAL %	0.0421	1.7759	0.5978	0.5234
					OF ENDUSE		10.4%		
BUILDING EQUIPMENT									
MEASURES									
CURRENT PRACTICE>MCS '94	0.2795	0.1302	0.2100	30	0%	0.1302			
FRZR STRIP CURTAIN '94	0.1173	0.5311	1.5354	30	100%	0.0282	1.5354	0.1173	0.5311
HW HEAT RECOVERY '94	1.0590	0.4935	8.7652	30	36%	0.0118	3.1117	0.3759	0.1752
BATHRM EXHST HT RCVRY '94	0.5165	0.2407	0.7535	30	47%	0.0670			
KITCHEN EXHST HT RCVRY '94	5.2250	2.4348	10.0528	30	47%	0.0508	4.6746	2.4296	1.1322
ECONOMIZER '94	1.3741	0.6403	1.0392	30	91%	0.1293			
					TOTAL %	0.0341	9.3217	2.9229	1.8385
					OF ENDUSE		8.8%		
					GRAND TOTAL	0.0355	11.1603	3.5731	2.3618
							9.1%		

APPENDIX F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS (kWh/SF)	CURRENT UIC PROTOTYPE (kWh/SF)
HEATING	7.45	55.0%	13.54	7.99
COOLING	0.04	63.0%	0.07	0.86
VENTILATION	2.30	100.0%	2.30	0.83
WATER HEAT	0.30	74.0%	0.40	1.42
REFRIGERATION	15.00	100.0%	15.00	
LIGHTING	12.75	100.0%	12.75	16.39
MISC.	10.20	99.0%	10.30	30.16
TOTAL	48.04	88.4%	54.36	57.65

EXISTING	26,052	SQFT
STATE		OREGON
CLIMATE ZONE		0
BUILDING TYPE		GROCERY
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
INSULATE ROOF R3>R22 '94	0.6009	0.0000	2.0888	30	55%	0.0192	1.1489	0.3305	0.0000
INSULATE WALL R5>R24 '94	2.8322	0.0000	2.3311	30	55%	0.0811			
EFF. WINDOWS SG>DG '94	0.5775	0.0000	0.5663	30	55%	0.0680			
WEATHERSTRIP ACH '94	0.0117	0.0113	0.1381	30	55%	0.0111	0.0760	0.0065	0.0062
					TOTAL %	0.0187	1.2248	0.3370	0.0062
					OF ENDUSE		16.4%		
BUILDING LIGHTING MEASURES									
PARAB REFLCT (SALE) '94	0.8841	0.0372	3.2251	30	100%	0.0191	3.2251	0.8841	0.0372
2 LEVEL SWITCHING '94	0.2856	0.1620	1.9029	30	100%	0.0157	1.9029	0.2856	0.1620
INCAND>HALOGEN IR '94	0.0111	0.5460	1.0802	30	100%	0.0344	1.0802	0.0111	0.5460
					TOTAL %	0.0207	6.2082	1.1808	0.7452
					OF ENDUSE		48.7%		
BUILDING EQUIPMENT MEASURES									
REFER CASE COVERS '94	0.3288	0.1532	4.2391	30	100%	0.0076	4.2391	0.3288	0.1532
REFER CASE TIMER '94	0.0252	0.0117	2.4183	30	100%	0.0010	2.4183	0.0252	0.0117
HW HEAT RECOVERY '94	0.2768	0.1290	1.4145	30	74%	0.0191	1.0467	0.2048	0.0955
HW BLANKET '94	0.0128	0.0123	0.0800	30	74%	0.0210	0.0592	0.0095	0.0091
REDUCE MINIMUM AIR '94	0.0185	0.0459	0.5286	30	55%	0.0081	0.2907	0.0102	0.0252
REFIGERATION PUMP '94	0.8203	0.3822	5.0000	30	100%	0.0160	5.0000	0.8203	0.3822
FREEZER STRIP CURTAIN '94	0.0242	0.0113	0.2069	30	100%	0.0114	0.2069	0.0242	0.0113
RESISTANCE>HEAT PUMP '94	3.1120	0.7251	1.9174	30	41%	0.1335			
EXHAUST HEAT RCVRY '94	0.3166	0.1476	0.8891	30	55%	0.0348	0.4890	0.1742	0.0812
					TOTAL %	0.0115	13.7499	1.5970	0.7694
					OF ENDUSE		39.0%		
					GRAND TOTAL	0.0146	21.1830	3.1148	1.5208
							44.1%		

APPENDIX F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	1.38	66.1%	2.09	2.10
COOLING	0.09	95.5%	0.09	0.10
VENTILATION	4.10	100.0%	4.10	4.10
WATER HEAT	0.23	76.9%	0.30	0.30
REFRIGERATION	43.30	100.0%	43.30	43.30
LIGHTING	14.50	100.0%	14.50	14.50
MISC.	5.20	100.0%	5.20	5.20
TOTAL	68.80	98.9%	69.59	69.60

NEW	26,052	SQFT
STATE		OREGON
CLIMATE ZONE		0
BUILDING TYPE		GROCERY
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE									
MEASURES									
CURRENT PRACTICE>MCS '94	0.0098	0	0.0080	30	0%	0.0819			
ROOF R19>R30 same '94	1.4860	0.0000	1.2051	30	66%	0.0823			
LOW E WINDOWS same '94	0.0793	0.0000	0.1660	30	66%	0.0319	0.1097	0.0524	0.0000
					TOTAL %	0.0319	0.1097	0.0524	0.0000
					OF ENDUSE		7.4%		
BUILDING LIGHTING									
MEASURES									
CURRENT PRACTICE>MCS									
FLUORESCENT>T8 Elec '94	0.1515	0.7437	1.8931	30	100%	0.0315	1.8931	0.1515	0.7437
INCANDESCENT>HALOGEN '94	0.0111	0.1930	0.4313	30	100%	0.0316	0.4313	0.0111	0.1930
EXIT SIGNS '94	0.0350	-0.0551	0.0699	30	100%	-0.0192	0.0699	0.0350	-0.0551
					TOTAL %	0.0301	2.3944	0.1976	0.8816
					OF ENDUSE		16.5%		
BUILDING EQUIPMENT									
MEASURES									
CURRENT PRACTICE>MCS '94	0.0242	0.0113	0.0070	30	0%	0.3387			
DHW HEAT RECOVER same '94	0.2642	0.1231	0.3000	30	77%	0.0861			
REFER FLOATING HEAD '94	0.0807	0.0776	4.7150	30	100%	0.0022	4.7150	0.0807	0.0776
REFER CASE COVERS '94	0.3597	0.3462	0.9520	30	100%	0.0495	0.9520	0.3597	0.3462
RFR ANTI-SWEAT TIMER '94	0.1156	0.1112	5.2650	30	100%	0.0029	5.2650	0.1156	0.1112
MECH SUBCOOLING '94	0.1359	0.1308	0.9320	30	100%	0.0191	0.9320	0.1359	0.1308
HOT GAS DEFROST '94	0.1678	0.1614	2.4110	30	100%	0.0091	2.4110	0.1678	0.1614
REFER PUMP AFT #3 '94	0.9965	0.9589	0.9220	30	100%	0.1415			
EFF FAN MOTORS '94	0.2768	0.2664	2.5890	30	100%	0.0140	2.5890	0.2768	0.2664
					TOTAL %	0.0088	16.8640	1.1364	1.0936
					OF ENDUSE		31.0%		
					GRAND TOTAL	0.0116	19.3681	1.3864	1.9752
							28.1%		

Appendix F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS (kWh/SF)	CURRENT UIC PROTOTYPE (kWh/SF)
HEATING	4.26	34.0%	12.54	36.00
COOLING	0.77	82.0%	0.94	2.29
VENTILATION	3.03	100.0%	3.03	6.82
WATER HEAT	2.33	33.0%	7.07	1.80
REFRIGERATION				
LIGHTING	7.88	100.0%	7.88	8.85
MISC.	0.64	85.2%	0.75	4.69
TOTAL	18.91	58.7%	32.21	60.45

EXISTING	272,000	SQFT
STATE		OREGON
CLIMATE ZONE		0
BUILDING TYPE		HOSPITAL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE									
MEASURES									
ROOF INSUL. R7>R23 *94	0.1093	0.0000	0.7885	30	12%	0.0092	0.0934	0.0129	0.0000
EFF. WINDOWS SG>DG *94	0.8203	0.2963	0.5999	20	12%	0.1522			
					TOTAL % OF ENDUSE	0.0092	0.0934 1.9%	0.0129	0.0000
BUILDING LIGHTING									
MEASURES									
T-12/Mag>T8 Elect *94	0.7912	0.4362	0.7389	30	100%	0.1108			
INCANDESCENT>PL *94	0.0583	0.0945	0.5838	30	100%	0.0175	0.5838	0.0583	0.0945
OUTSIDE LIGHTS Same *94	0.0006	-0.0097	0.0173	30	100%	-0.0350	0.0173	0.0006	-0.0097
					TOTAL % OF ENDUSE	0.0160	0.6010 7.6%	0.0589	0.0849
BUILDING EQUIPMENT									
MEASURES									
TEMP RESET *94	0.0422	0.0406	2.3263	30	34%	0.0024	0.7909	0.0143	0.0138
AAHX *94	0.3761	0.1753	3.3899	30	34%	0.0109	1.1526	0.1279	0.0596
FAN MOTORS *94	0.1022	0.0476	0.1231	30	100%	0.0812			
VAV same *94	1.9604	0.9135	0.4300	30	34%	0.4459			
HEAT RECOVER DHW same *94	0.0193	0.0090	3.0000	30	25%	0.0006	0.7425	0.0048	0.0022
					TOTAL % OF ENDUSE	0.0055	2.6860 24.4%	0.1470	0.0756
					GRAND TOTAL	0.0075	3.3804 17.9%	0.2189	0.1605

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	16.26	76.1%	21.37	21.40
COOLING	1.23	82.0%	1.50	1.50
VENTILATION	6.00	100.0%	6.00	6.00
WATER HEAT	1.26	89.7%	1.40	1.40
REFRIGERATION	0.00			
LIGHTING	7.59	100.0%	7.36	8.90
MISC.	4.43	85.2%	5.20	5.20
TOTAL	36.77	85.9%	42.83	44.40

NEW	272,000	SQFT
STATE		OREGON
CLIMATE ZONE		0
BUILDING TYPE		HOSPITAL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
CURRENT PRACTICE>MCS '94	0.0266	0.0000	0.0320	30	0%	0.0554	0.0000	0.0000	0.0000
INSULATE WALLS R5>R24 '94	0.1034	0.0000	0.1699	30	57%	0.0406	0.0970	0.0590	0.0000
LOW E WINDOWS '94	0.2826	0.0000	0.4117	30	57%	0.0458	0.2350	0.1613	0.0000
					TOTAL %	0.0443	0.3319	0.2203	0.0000
					OF ENDUSE		1.9%		
BUILDING LIGHTING MEASURES									
CURRENT PRACTICE>MCS '94	0.1358	0.2542	1.5386	30	0%	0.0169	0.0000	0.0000	0.0000
EXIT SIGNS '94	0.0675	-0.1005	0.1078	30	100%	-0.0204	0.1078	0.0675	-0.1005
OUTDOOR LIGHTS same '94	-0.0003	-0.0092	0.0173	30	100%	-0.0365	0.0173	-0.0003	-0.0092
FLUORESCENT>T8 Elec '94	0.1728	0.2274	0.6212	30	100%	0.0430	0.6212	0.1728	0.2274
INCAND>HALOGEN IR '94	0.0038	0.1027	0.1812	30	100%	0.0392	0.1812	0.0038	0.1027
AMBIENT/TASK AFT #1 '94	-0.0029	-0.0129	0.1644	30	75%	-0.0064	0.1233	-0.0021	-0.0097
DAYLIGHT DIM AFT #2 '94	0.0852	0.0495	0.1614	30	75%	0.0557	0.1211	0.0639	0.0371
OCCUP SENSOR AFT #3 '94	0.0839	0.0919	0.1830	30	75%	0.0641			
					TOTAL %	0.0315	1.1718	0.3055	0.2479
					OF ENDUSE		13.2%		
BUILDING EQUIPMENT MEASURES									
AAHX same '94	0.4178	0.1947	3.3969	30	62%	0.0120	2.0891	0.2569	0.1197
CHILLER STRNER CYCLE '94	0.1809	0.0843	0.4390	30	62%	0.0403	0.2700	0.1112	0.0518
HEAT RCVERY DHW same '94	0.5794	0.2700	0.7000	30	67%	0.0809			
EVAP COOLER '94	0.4382	0.2042	0.4390	30	62%	0.0976			
					TOTAL %	0.0153	2.3591	0.3682	0.1716
					OF ENDUSE		8.1%		
					GRAND TOTAL	0.0227	3.8629	0.8940	0.4195
							10.1%		

Appendix F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS (kWh/SF)	CURRENT UIC PROTOTYPE (kWh/SF)
HEATING	4.85	58.0%	8.37	9.17
COOLING	0.64	51.0%	1.25	0.49
VENTILATION	2.23	100.0%	2.23	0.03
WATER HEAT	1.26	45.0%	2.80	6.02
REFRIGERATION		100.0%		
LIGHTING	4.74	100.0%	4.74	3.72
MISC.	1.03	67.7%	1.52	1.94
TOTAL	14.75	70.5%	20.91	21.37

EXISTING	11,664	SQFT
STATE		OREGON
CLIMATE ZONE		0
BUILDING TYPE		HOTEL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
ROOF INSUL. R7>R27 *94	0.2311	0.0000	0.7509	30	58%	0.0205	0.4355	0.1341	0.0000
WALL INSUL. R2>R11 *94	0.2408	0.0000	3.5652	30	58%	0.0045	2.0678	0.1397	0.0000
WINDOW SG>DG *94	0.2016	0.0728	0.9382	30	58%	0.0195	0.5441	0.1169	0.0422
					TOTAL %	0.0095	3.0475	0.3907	0.0422
					OF ENDUSE		55.5%		
BUILDING LIGHTING MEASURES									
INCANDESCENT>PL *94	0.5720	-1.0868	0.4177	30	100%	-0.0822	0.4177	0.5720	-1.0868
FLUORESCENT>T8 *94	0.1265	0.0240	0.4607	30	100%	0.0218	0.4607	0.1265	0.0240
EXTERNAL>HPS *94	0.0766	0.0187	0.1740	30	100%	0.0365	0.1740	0.0766	0.0187
					TOTAL %	-0.0171	1.0524	0.7750	-1.0441
					OF ENDUSE		22.2%		
BUILDING EQUIPMENT MEASURES									
EFFICIENT THERMOSTAT *94	0.3460	0.1612	1.1130	30	44%	0.0304	0.4842	0.1505	0.0701
LOW FLOW SHOWER *94	0.0473	-0.0842	2.1652	30	38%	-0.0011	0.8282	0.0181	-0.0322
DHW & PIPE INSULATION *94	0.0270	0.0260	0.6331	30	38%	0.0056	0.2421	0.0103	0.0099
					TOTAL %	0.0097	1.5545	0.1789	0.0479
					OF ENDUSE		15.5%		
					GRAND TOTAL	0.0046	5.5544	1.3446	-0.9540
							38.3%		

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	2.96	69.1%	4.23	4.55
COOLING	0.25	51.0%	0.49	0.50
VENTILATION	0.02	100.0%	0.02	0.02
WATER HEAT	4.06	96.8%	3.87	6.03
COOKING	0.00	100.0%		
LIGHTING	3.43	100.0%	3.40	3.63
MISC.	1.31	67.7%	1.94	1.94
TOTAL	12.03	70.5%	13.95	16.67

NEW	11,664	SQFT
STATE		OREGON
CLIMATE ZONE		0
BUILDING TYPE		HOTEL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE									
MEASURES									
CURRENT CODE>MCS '94	0.2653	0.0000	0.3091	30	0%	0.0573			
LOW E WINDOW U65>U39 '94	0.2507	0.0000	0.6371	30	69%	0.0262	0.4402	0.1732	0.0000
INSULATE ROOF R19>R38 '94	0.1273	0.0000	0.2826	30	69%	0.0300	0.1953	0.0879	0.0000
INSULATE WALL R19>R24 '94	0.3722	0.0000	0.5637	30	69%	0.0440	0.3895	0.2572	0.0000
					TOTAL %	0.0337	1.0250	0.5183	0.0000
					OF ENDUSE		30.2%		
BUILDING LIGHTING									
MEASURES									
CODE>MCS 1/2 Inc>PL '94	0.8563	-0.5762	0.2232	30	0%	0.0837			
INCN>PL Second 1/2 '94	0.8563	-0.5762	0.2232	30	100%	0.0837			
HPS EXTERIOR LIGHTS '94	0.0476	0.1473	0.1740	30	100%	0.0747			
					TOTAL %	0.0000	0.0000	0.0000	0.0000
					OF ENDUSE		0.0%		
BUILDING EQUIPMENT									
MEASURES									
LOW FLOW SHOWER '94	0.0473	-0.3690	2.1652	30	0%	-0.0099	0.0000	0.0000	0.0000
DHW & PIPE INSULATION '94	0.0270	0.0260	0.6331	30	77%	0.0056	0.4902	0.0209	0.0201
					TOTAL %	0.0056	0.4902	0.0209	0.0201
					OF ENDUSE		6.0%		
					GRAND TOTAL	0.0246	1.5152	0.5393	0.0201
							12.9%		

Appendix F - Commercial Building, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS (kWh/SF)	CURRENT UIC PROTOTYPE (kWh/SF)
HEATING	4.19	29.4%	14.25	14.16
COOLING	1.46	100.0%	1.46	1.70
VENTILATION	4.30	100.0%	4.30	5.34
WATER HEAT	0.82	75.2%	1.09	0.20
REFRIGERATION	0.00			
LIGHTING	6.56	100.0%	6.56	10.50
MISC.	0.35	85.5%	0.41	3.12
TOTAL	17.68	62.6%	28.07	35.02

EXISTING	408,000	SQFT
STATE		OREGON
CLIMATE ZONE		0
BUILDING TYPE		LG OFFICE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE									
MEASURES									
INSUL. ROOF R6>R24 '94	0.0250	0.0000	0.1044	30	22%	0.0160	0.0230	0.0055	0.0000
					TOTAL %	0.0160	0.0230	0.0055	0.0000
					OF ENDUSE		0.4%		
BUILDING LIGHTING									
MEASURES									
40W FLUOR>T8 Elec Bal '94	1.3890	0.3215	2.0357	30	100%	0.0561	2.0357	1.3890	0.3215
INCANDESCENT>PL '94	0.1075	-0.0154	0.4128	30	100%	0.0149	0.4128	0.1075	-0.0154
EXIT SIGNS '94	0.0569	-0.0993	0.1710	30	100%	-0.0165	0.1710	0.0569	-0.0993
OCCUP SENSOR AFT #1 '94	0.2108	0.2464	0.9504	30	75%	0.0321	0.7128	0.1581	0.1848
AMBIENT/TASK AFT #4 '94	0.8105	-0.0634	0.7117	30	75%	0.0700			
DAYLIGHT DIM AFT #5 '94	0.3022	0.1380	0.1382	30	75%	0.2125			
					TOTAL %	0.0421	3.3323	1.7115	0.3916
					OF ENDUSE		50.8%		
BUILDING EQUIPMENT									
MEASURES									
TEMP RESET FOR MLTZN '94	0.0141	0.0066	1.4713	30	29%	0.0009	0.4326	0.0041	0.0019
EFF FAN Motor 1800rpm '94	0.1407	0.0656	0.1014	30	100%	0.1357			
TUNE & ADJUST same '94	0.0012	0.0030	0.0177	30	29%	0.0159	0.0052	0.0004	0.0009
TRAV RETROFIT same '94	1.9313	-1.7174	3.9798	30	100%	0.0036	3.9798	1.9313	-1.7174
					TOTAL %	0.0033	4.4176	1.9357	-1.7145
					OF ENDUSE		39.7%		
					GRAND TOTAL	0.0200	7.7729	3.6528	-1.3230
							44.0%		

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	2.51	49.8%	4.99	5.30
COOLING	0.60	100.0%	0.60	0.60
VENTILATION	1.80	100.0%	1.80	1.80
WATER HEAT	0.15	75.2%	0.20	0.20
REFRIGERATION	0.00			
LIGHTING	6.55	100.0%	6.35	7.70
MISC.	3.08	85.5%	3.60	3.60
TOTAL	14.69	62.6%	17.54	19.20

NEW	408,000	SQFT
STATE		OREGON
CLIMATE ZONE		0
BUILDING TYPE		LG OFFICE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
CURRENT PRACTICE>MCS *94	0.0751	0	0.3340	30	0.0%	0.0150	0.0000	0.0000	0.0000
LOW E. WINDOWS *94	0.8929	0.3226	0.5615	20	49.8%	0.1770			
					TOTAL %	0.0000	0.0000	0.0000	0.0000
					OF ENDUSE		0.0%		
BUILDING LIGHTING MEASURES									
CRRNT PRACTICE>MCS *94	0.2533	-0.2116	1.3537	30	0.00%	0.0021	0.0000	0.0000	0.0000
T8 FLUOR./ELECTRONIC *94	0.0723	0.0289	0.4856	30	100.00%	0.0139	0.4856	0.0723	0.0289
EXIT SIGNS *94	0.0569	-0.1050	0.1708	30	100.00%	-0.0188	0.1708	0.0569	-0.1050
OCC SENSOR AFTER #2 *94	0.2108	0.2161	1.0674	30	100.00%	0.0267	1.0674	0.2108	0.2161
AMBIENT/TSK AFTER #4 *94	0.8105	-0.0748	0.9133	30	100.00%	0.0537	0.9133	0.8105	-0.0748
DAYLT DIM AFTER #5 *94	0.3022	0.0236	0.2237	30	100.00%	0.0972			
					TOTAL %	0.0308	2.6371	1.1504	0.0653
					OF ENDUSE		34.2%		
BUILDING EQUIPMENT MEASURES									
CURRENT PRACTICE>MCS									
VSD MOTORS *94	0.0542	0.0253	0.0913	30	100%	0.0581	0.0913	0.0542	0.0253
TRAV CNTRLS *same 94	1.9313	-0.3342	1.9540	30	100%	0.0545	1.9540	1.9313	-0.3342
EVAP. COOLING	0.6695	0.3164	0.1912	30	100%	0.3439			
					TOTAL %	0.0547	2.0453	1.9855	-0.3089
					OF ENDUSE		47.4%		
					GRAND TOTAL	0.0412	4.6825	3.1359	-0.2437
							39.0%		

Appendix F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	2.94	42.0%	7.00	7.18
COOLING	1.10	58.0%	1.89	1.98
VENTILATION	1.14	100.0%	1.14	1.14
WATER HEAT	0.36	66.0%	0.54	0.54
REFRIGERATION				
LIGHTING	7.45	100.0%	7.45	7.00
MISC.	0.43	85.5%	0.50	0.50
TOTAL	13.42	72.5%	18.52	18.34

EXISTING	4,880	SQFT
STATE		OREGON
CLIMATE ZONE		0
BUILDING TYPE		OFFICE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
INSULATE ROOF R4>R24 *94	0.3005	0	1.2518	30	42.0%	0.0160	0.5258	0.1262	0.0000
INSUL. WALL R5>R24 *94	5.8235	0	2.1645	30	42.0%	0.1795			
WINDOWS SG>DG *94	1.7109	0	1.5990	30	42.0%	0.0714			
LOW E. WINDOWS *94	1.3860	0.6459	0.4689	30	42.0%	0.2891			
SOLAR FILM *94	0.4691	0.2186	0.5357	30	58.0%	0.0856			
					TOTAL %	0.0160	0.5258	0.1262	0.0000
					OF ENDUSE		13.0%		
BUILDING LIGHTING MEASURES									
4L-T12 Mag>T8-4L Elec *94	0.8482	0.3791	1.0612	30	100.00%	0.0772			
EXIT SIGNS *94	0.0525	-0.0762	0.1426	30	100.00%	-0.0111	0.1426	0.0525	-0.0762
INCAN > 90 W HALOGEN *94	-0.0002	0.0286	0.0854	30	100.00%	0.0222	0.0854	-0.0002	0.0286
DAYLIGHT DIM AFT #1 *94	0.6007	0.1638	1.1239	30	100.00%	0.0454	1.1239	0.6007	0.1638
AMBIENT/TASK AFT #2 *94	1.0364	0.0979	0.7373	30	100.00%	0.1026			
OCCUP SENSOR AFT #3 *94	0.2407	0.1174	0.0733	30	100.00%	0.3261			
					TOTAL %	0.0380	1.3519	0.6530	0.1162
					OF ENDUSE		18.1%		
BUILDING EQUIPMENT MEASURES									
ECONOMIZER *94	0.4926	0.2295	0.6629	30	58.00%	0.0727			
OPTIMUM START TIMER *94	0.2799	0.1304	0.6873	30	31.50%	0.0398	0.2165	0.0882	0.0411
AAHX *94	0.1744	0.0813	1.0680	30	31.50%	0.0160	0.3364	0.0549	0.0256
REDUCE OUTSIDE AIR Same *94	0.0118	0.0294	1.0348	30	31.50%	0.0027	0.3260	0.0037	0.0093
RESISTANCE>HEAT PUMP *94	2.0131	0.9381	4.8840	30	46.01%	0.0403	2.2471	0.9262	0.4316
EFF HEAT PUMP *94	0.7389	0.3443	0.5154	30	17.00%	0.1402			
					TOTAL %	0.0337	3.1260	1.0731	0.5076
					OF ENDUSE		52.4%		
					GRAND TOTAL	0.0330	5.0037	1.8523	0.6237
							37.3%		

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	3.64	50.7%	7.00	7.18
COOLING	1.77	89.5%	1.89	1.98
VENTILATION	1.14	100.0%	1.14	1.14
WATER HEAT	0.43	80.3%	0.54	0.54
REFRIGERATION	0.00			
LIGHTING	7.00	100.0%	7.28	7.00
MISC.	0.43	85.5%	0.50	0.50
TOTAL	14.41	78.6%	18.35	18.34

NEW	4,880	SQFT
STATE		OREGON
CLIMATE ZONE		0
BUILDING TYPE		OFFICE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
CURRENT PRACTICE>MCS "94	0.0661	0	0.1830	30	0.0%	0.0241	0.0000	0.0000	0.0000
INSUL. WALL R11>R16 "94	0.4037	0	0.8743	30	50.7%	0.0308	0.4433	0.2047	0.0000
INSULATE ROOF R13>R30 "94	0.1421	0	0.2767	30	50.7%	0.0343	0.1403	0.0720	0.0000
INSULATE ROOF R30>R38 "94	0.0383	0	0.0548	30	50.7%	0.0467	0.0278	0.0194	0.0000
LOW E. WINDOWS "94	1.3957	0.5042	1.0110	30	100.0%	0.1254			
					TOTAL % OF ENDUSE	0.0323	0.6114 11.3%	0.2961	0.0000
BUILDING LIGHTING MEASURES									
CURRENT PRACTICE>MCS "94	0.2812	-0.1040	1.2971	30	0.00%	0.0091	0.0000	0.0000	0.0000
T8 FLUORESCENT/ELECT "94	0.2459	0.0494	0.4620	30	100.00%	0.0426	0.4620	0.2459	0.0494
EXIT SIGNS "94	0.0525	-0.0862	0.1497	30	100.00%	-0.0150	0.1497	0.0525	-0.0862
DAYLIGHT DIM AFT #1 "94	0.6007	0.0971	1.2787	30	100.00%	0.0364	1.2787	0.6007	0.0971
AMBIENT/TASK AFT #2 "94	1.0364	0.0361	0.6332	30	100.00%	0.1130			
OCCPNCY SENSOR AFT #3 "94	0.2407	0.0025	0.0494	30	100.00%	0.3285			
					TOTAL % OF ENDUSE	0.0339	1.8904 27.0%	0.8990	0.0603
BUILDING EQUIPMENT MEASURES									
CURRENT PRACTICE>MCS "94	0.1076	0.0502	0.0889	30	0.00%	0.1184			
ECONOMIZER "94	0.4926	0.2295	0.6629	30	89.50%	0.0727			
OPTIM STRT TMR same "94	0.2799	0.1304	0.6873	30	38.03%	0.0398	0.2613	0.1064	0.0496
AAHX same "94	0.1744	0.0813	1.0680	30	38.03%	0.0160	0.4061	0.0663	0.0309
REDUCE OUTSDE AIR same"94	0.0118	0.0055	1.0348	30	38.03%	0.0011	0.3935	0.0045	0.0021
EFF HEAT PUMP same "94	0.7389	0.3443	0.5154	30	20.28%	0.1402			
					TOTAL % OF ENDUSE	0.0163	1.0610 14.3%	0.1772	0.0826
					GRAND TOTAL	0.0284	3.5627 24.7%	1.3724	0.1429

Appendix F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS (kWh/SF)	CURRENT UIC PROTOTYPE (kWh/SF)
HEATING	5.14	35.60%	14.45	4.79
COOLING	1.43	63.00%	2.27	0.90
VENTILATION	5.88	100.00%	5.88	1.00
WATER HEAT	0.09	74.00%	0.12	0.42
REFRIGERATION				
LIGHTING	6.71	100.00%	6.71	8.62
MISC.	0.61	95.20%	0.64	1.14
TOTAL	19.86	66.05%	30.07	16.87

EXISTING	13,125	SQFT
STATE		OREGON
CLIMATE ZONE		0
BUILDING TYPE		RETAIL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
INSULATE ROOF R7>R20 *94	0.6009	0.0000	2.6233	30	27%	0.0153	0.7004	0.1604	0.0000
INSULATE WALL R3>R22 *94	2.3877	0.0000	1.2182	30	27%	0.1308			
LOW E. WINDOWS *94	0.6761	0.0000	0.5581	30	27%	0.0808			
WEATHERSTRIP ACH *94	0.0131	0.0000	0.0040	10	27%	0.4256			
					TOTAL %	0.0153	0.7004	0.1604	0.0000
					OF ENDUSE		10.7%		
BUILDING LIGHTING MEASURES									
EXIT SIGNS *94	0.0260	-0.0324	0.0336	30	100%	-0.0126	0.0336	0.0260	-0.0324
DAYLIGHT DIM *94	0.0528	0.0688	0.8230	30	100%	0.0099	0.8230	0.0528	0.0688
FLUORESCENT>T8 *94	0.5749	0.6479	1.7451	30	100%	0.0467	1.7451	0.5749	0.6479
INCANDESCENT>HALOGEN *94	0.0132	0.4544	1.0005	30	100%	0.0312	1.0005	0.0132	0.4544
					TOTAL %	0.0334	3.6021	0.6669	1.1388
					OF ENDUSE		53.7%		
BUILDING EQUIPMENT MEASURES									
AAHX *94	0.2017	0.0000	0.5739	14.0	27%	0.0360	0.1532	0.0539	0.0000
RESISTANCE > HEAT PUMP *94	1.8491	0.0000	2.8524	15.0	5%	0.0634			
DHW BLANKET (Timer) *94	0.0048	0.0000	0.0315	10.0	56%	0.0200	0.0175	0.0027	0.0000
					TOTAL %	0.0344	0.1707	0.0565	0.0000
					OF ENDUSE		1.3%		
					GRAND TOTAL	0.0306	4.4733	0.8839	1.1388
							22.5%		

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS PROTOTYPE (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	0.31	40.2%	0.70	1.10
COOLING	0.41	63.0%	0.65	0.70
VENTILATION	1.60	100.0%	1.60	1.60
WATER HEAT	0.04	98.4%	0.04	0.04
REFRIGERATION	0.00			
LIGHTING	8.93	100.0%	8.88	9.20
MISC.	0.94	85.2%	1.10	1.10
TOTAL	12.23	68.5%	12.97	13.74

NEW	13,124	SQFT
STATE		OREGON
CLIMATE ZONE		0
BUILDING TYPE		RETAIL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE									
MEASURES									
CURRENT CODE>MCS *94	0.1079	0	0.3970	30	0%	0.0181	0.0000	0.0000	0.0000
DG>LOW E WINDOWS *94	0.1754	0.0634	0.1174	20	40%	0.1663			
					TOTAL %	0.0000	0.0000	0.0000	0.0000
					OF ENDUSE		0.0%		
BUILDING LIGHTING									
MEASURES									
CURRENT CODE>MCS *94	0.0356	-0.0455	0.3199	30	0%	-0.0021	0.0000	0.0000	0.0000
FLUORESCENT>T8 Elec *94	0.1501	0.4356	1.9407	30	100%	0.0201	1.9407	0.1501	0.4356
INCAN>HALOGEN IR *94	0.0178	0.4190	1.0004	30	100%	0.0291	1.0004	0.0178	0.4190
DAYLIGHT DIM AFT #1 *94	0.0528	0.0601	0.6831	30	100%	0.0110	0.6831	0.0528	0.0601
EXIT SIGNS *94	0.0260	-0.0453	0.0820	30	100%	-0.0157	0.0820	0.0260	-0.0453
					TOTAL %	0.0000	0.0000	0.0000	0.0000
					OF ENDUSE		0.0%		
BUILDING EQUIPMENT									
MEASURES									
CURRENT PRACTICE>MCS *94	0.0879	0.0410	0.0500	30	0%	0.1720			
AAHX *94	0.2017	0.0940	0.5162	30	30%	0.0382	0.1556	0.0608	0.0283
EFF H PUMP same *94	0.6868	0.3201	0.1978	30	8%	0.3396			
RADIANT HTRS same *94	0.0325	0.0151	0.0754	30	30%	0.0421	0.0227	0.0098	0.0046
					TOTAL %	0.0387	0.1784	0.0706	0.0329
					OF ENDUSE		84.2%		
					GRAND TOTAL	0.0209	3.8845	0.3173	0.9022
							41.3%		

Appendix F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS (kWh/SF)	CURRENT UIC PROTOTYPE (kWh/SF)
HEATING	3.65	20.0%	18.24	15.45
COOLING	0.03	42.0%	0.07	0.00
VENTILATION	1.46	100.0%	1.46	1.09
WATER HEAT	0.15	59.0%	0.25	0.55
REFRIGERATION				
LIGHTING	4.72	100.0%	4.72	3.92
MISC.	0.50	88.5%	0.56	0.92
TOTAL	10.51	41.5%	25.30	21.93

EXISTING	67,784	SQFT
STATE		OREGON
CLIMATE ZONE		0
BUILDING TYPE		SCHOOL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
INSULATE ROOF R7> R27 *94	0.546	0.000	2.2842	30	20%	0.0160	0.4568	0.1093	0.0000
LOW E WINDOWS *94	2.212	0.799	2.0334	30	20%	0.0988			
INSULATE WALLS R4>R23 *94	2.973	0.000	1.9553	30	20%	0.1014			
WEATHERSTRIP ACH *94	0.242	0.233	2.3545	30	20%	0.0135	0.4709	0.0484	0.0466
					TOTAL %	0.0147	0.9277	0.1577	0.0466
					OF ENDUSE		25.2%		
BUILDING LIGHTING MEASURES									
T-12/Mag>T8 4L Elec *94	0.8484	0.3351	1.5359	30	100%	0.0514	1.5359	0.8484	0.3351
INCANDESCENT>PL *94	0.1311	0.0410	0.3955	30	100%	0.0290	0.3955	0.1311	0.0410
EXIT SIGNS *94	0.0673	-0.0922	0.1327	30	100%	-0.0125	0.1327	0.0673	-0.0922
OCCUP SENSOR AFT #1 *94	0.1849	0.1164	0.2747	30	100%	0.0732			
DAYLIGHT DIM AFT #1 *94	0.0979	0.0519	0.0568	30	100%	0.1758			
					TOTAL %	0.0430	2.0641	1.0468	0.2839
					OF ENDUSE		43.7%		
BUILDING EQUIPMENT MEASURES									
ADJUST OUTSIDE AIR *94	0.030	0.074	1.9237	30.0	20%	0.0036	0.3847	0.0060	0.0148
DHW BLANKET *94	0.003	0.003	0.0680	30.0	44%	0.0062	0.0301	0.0014	0.0014
					TOTAL %	0.0038	0.4148	0.0074	0.0162
					OF ENDUSE		7.2%		
					GRAND TOTAL	00.0305	03.4067	01.2118	00.3467
							32.4%		

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	2.42	26.90%	8.98	9.10
COOLING	0.00	42.00%	0.00	0.00
VENTILATION	2.21	100.00%	2.22	2.20
WATER HEAT	1.47	98.10%	1.50	1.50
REFRIGERATION	0.00			
LIGHTING	4.54	100.00%	4.43	5.20
MISC.	1.15	88.50%	1.30	1.30
TOTAL	11.80	64.05%	18.42	19.30

NEW	277,200	SQFT
STATE		OREGON
CLIMATE ZONE		0
BUILDING TYPE		SCHOOL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
CURRENT PRACTICE>MCS '94	0.0037	0.0000	0.0298	30	0%	0.0083	0.0000	0.0000	0.0000
INSUL ROOF R19> R38 '94	0.0641	0.0000	0.1299	30	27%	0.0329	0.0349	0.0172	0.0000
INSULATE WALLS R6>R19 '94	0.0634	0.0000	0.1176	30	27%	0.0360	0.0316	0.0171	0.0000
LOW E WINDOWS U.46 '94	0.0435	0.0000	0.0696	30	27%	0.0417	0.0187	0.0117	0.0000
					TOTAL %	0.0360	0.0853	0.0460	0.0000
					OF ENDUSE		3.5%		
BUILDING LIGHTING MEASURES									
CURRENT PRACTICE>MCS '94	-0.0363	-0.0697	0.1755	30	0%	-0.0403	0.0000	0.0000	0.0000
FLUORESCENT>T8 Elec '94	0.0344	0.0939	0.2110	30	100%	0.0406	0.2110	0.0344	0.0939
EXIT SIGNS '94	0.0165	-0.0234	0.0328	30	100%	-0.0141	0.0328	0.0165	-0.0234
OCCUP SENSOR AFT #1 '94	0.0452	0.0512	0.0920	30	100%	0.0700			
DAYLIGHT DIM AFT #2 '94	0.0239	0.0124	0.0144	30	100%	0.1677			
					TOTAL %	0.0332	0.2438	0.0508	0.0705
					OF ENDUSE		4.7%		
BUILDING EQUIPMENT MEASURES									
62-89 VENTILATION	0.0011	0.0005	-0.0080	30	0%	-0.0132	0.0000	0.0000	0.0000
VSD MOTORS '94	0.0183	0.0085	0.0569	30	75%	0.0314	0.0427	0.0137	0.0064
EMCS CONTROLS '94	0.2895	0.0515	0.2346	30	27%	0.0970			
					TOTAL %	0.0314	0.0427	0.0137	0.0064
					OF ENDUSE		0.6%		
					GRAND TOTAL	0.0336	0.3718	0.1106	0.0769
							3.0%		

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS (kWh/SF)	CURRENT UIC PROTOTYPE (kWh/SF)
HEATING	2.72	38.0%	7.16	6.33
COOLING	0.04	52.0%	0.07	0.22
VENTILATION	0.03	100.0%	0.03	0.19
WATER HEAT	0.01	62.0%	0.02	0.15
REFRIGERATION	5.00	100.0%	5.00	
LIGHTING	3.29	100.0%	3.29	3.50
MISC.	3.02	97.6%	3.09	1.72
TOTAL	14.11	75.6%	18.66	12.11

EXISTING	18,025 SQFT
STATE	OREGON
CLIMATE ZONE	0
BUILDING TYPE	WAREHOUSE
LIFE OF PROTOTYPE BUILDING	70
INITIAL YEAR OF DATA	1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
INSULATED ROOF R2>R20 '94	0.5459	0.000	2.5987	30	38%	0.0140	0.9875	0.2074	0.0000
INSULATED WALL R2>R20 '94	1.8460	0.000	1.8849	30	38%	0.0653			
LOW E WINDOWS SG>DG '94	0.5768	0.2084	0.2900	30	38%	0.1806			
WEATHERSTRIP ACH '94	0.0393	0.0378	0.1460	30	38%	0.0352	0.0555	0.0149	0.0144
					TOTAL % OF ENDUSE	0.0151	1.0430 37.8%	0.2224	0.0144
BUILDING LIGHTING MEASU4RES									
OFFICE FLUORESCENT>T8 '94	0.1163	0.050	0.2164	30	100%	0.0512	0.2164	0.1163	0.0499
STOR DELMP/Reflec '94	0.1312	0.024	0.2710	30	100%	0.0382	0.2710	0.1312	0.0240
INCAN>HALOGEN, HID '94	0.0003	0.040	0.3331	30	100%	0.0080	0.3331	0.0003	0.0397
					TOTAL % OF ENDUSE	0.0294	0.8205 24.9%	0.2478	0.1136
BUILDING EQUIPMENT MEASURES									
REDUCE OUTSIDE AIR '94	0.0047	0.0116	0.1283	30	38%	0.0084	0.0487	0.0018	0.0044
TEMP SETBACK '94	0.0818	0.0788	1.4371	30	38%	0.0075	0.5461	0.0311	0.0299
RADIANT HEATERS '94	0.9790	0.4562	2.4596	30	38%	0.0389	0.9346	0.3720	0.1734
AAHX '94	0.1621	0.0755	0.1218	30	38%	0.1302			
RESIST> HP (OFFICE) '94	0.2448	0.1141	0.6382	30	20%	0.0375	0.1292	0.0496	0.0231
EFFICIENT REFER. '94 Same	0.7054	0.3287	3.5000	30	38%	0.0197	1.3300	0.2680	0.1249
DESTRATIFIERS '94	0.1346	0.0627	1.5504	30	38%	0.0085	0.5892	0.0511	0.0238
DHW BLANKET '94	0.0030	0.0014	0.0229	30	47%	0.0127	0.0107	0.0014	0.0006
ECONOMIZER (OFFICE) '94	0.0667	0.0311	0.0798	30	39%	0.0817			
					TOTAL % OF ENDUSE	0.0215	3.5885 33.2%	0.7750	0.3802
					GRAND TOTAL	0.0215	5.4521 38.6%	1.2452	0.5082

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	0.46	47.0%	0.93	1.20
COOLING	0.10	52.0%	0.19	0.20
VENTILATION	0.30	100.0%	0.30	0.30
WATER HEAT	0.19	96.5%	0.20	0.20
REFRIGERATION	4.00	100.0%	4.00	4.00
LIGHTING	2.31	100.0%	2.13	3.30
MISC.	1.17	97.6%	1.20	1.20
TOTAL	8.52	95.3%	8.95	10.40

NEW	18,025	SQFT
STATE		OREGON
CLIMATE ZONE		0
BUILDING TYPE		WAREHOUSE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
CURRENT PRACTICE>MCS '94	0.1022	0	0.2700	30	0%	0.0252	0.0000	0.0000	0.0000
INSULTED WALL R11>R16 '94	0.2397	0.000	0.1665	30	47%	0.0960			
LOW E WINDOWS '94	0.1798	0.000	0.0832	30	47%	0.1442			
INSULATE ROOF>R30 '92	0.2426	0.000	0.1126	30	47%	0.1437			
					TOTAL %	0.0000	0.0000	0.0000	0.0000
					OF ENDUSE		0.0%		
BUILDING LIGHTING MEASURES									
CURRENT PRACTICE>MCS '94	-0.0164	-0.1823	1.1705	30	0%	-0.0113	0.0000	0.0000	0.0000
EXIT SIGNS '94	0.0284	-0.0499	0.0755	30	100%	-0.0190	0.0755	0.0284	-0.0499
OCCUP SENSOR '94	0.0391	0.0637	0.5531	30	100%	0.0124	0.5531	0.0391	0.0637
AMB/TASK LIGHT AFT #1 '94	0.1007	-0.0051	0.1689	30	100%	0.0378	0.1689	0.1007	-0.0051
DAYLIGHT DIM AFT #2 '94	0.0656	0.0347	0.0833	30	100%	0.0803			
					TOTAL %	0.0148	0.7975	0.1682	0.0087
					OF ENDUSE		24.2%		
BUILDING EQUIPMENT MEASURES									
CURRENT PRACTICE>MCS '94	0.0175	0.0081	0.0140	30	0%	0.1223			
EFFICIENT REFER. same '94	0.7008	0.3265	3.5000	30	75%	0.0196	2.6250	0.5256	0.2449
ECONOMIZER '94	0.0667	0.0311	0.0920	30	39%	0.0709			
					TOTAL %	0.0196	2.6250	0.5256	0.2449
					OF ENDUSE		39.7%		
					GRAND TOTAL	0.0185	3.4225	0.6938	0.2536
							34.5%		

Appendix F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELECT (kWh/SF)	PERCENT SATUR.	ALL FUELS (kWh/SF)	CURRENT UIC PROTOTYPE (kWh/SF)
HEATING	10.75	35.0%	30.71	32.64
COOLING	1.03	78.0%	1.32	9.24
VENTILATION	8.60	100.0%	8.60	6.42
WATER HEAT	2.81	82.0%	3.43	8.76
REFRIGERATION	3.00	100.0%	3.00	
LIGHTING	8.79	100.0%	8.79	17.60
MISC.	1.05	30.0%	3.49	55.82
TOTAL	36.03	61.9%	59.34	130.48

EXISTING	2,624	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		FAST FOOD
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
INSULATE ROOF R6>R26 *94	0.5854	0.0000	3.7606	30	35%	0.0104	1.3162	0.2049	0.0000
INSULATE WALL R7>R19 *94	6.2039	0.0000	4.6354	30	35%	0.0893			
EFF. WINDOWS SG>LOW E *94	3.1818	1.1495	2.3300	30	35%	0.1240			
SOLAR FILM *94	0.6923	1.2283	3.2569	30	78%	0.0393	2.5404	0.5400	0.9581
					TOTAL %	0.0295	3.8566	0.7448	0.9581
					OF ENDUSE		32.7%		
BUILDING LIGHTING MEASURES									
FLUORESCENT>T8 *94	1.0106	0.8004	2.5253	30	100%	0.0478	2.5253	1.0106	0.8004
INCANDESCENT>PL *94	0.3960	0.3680	2.7507	30	100%	0.0185	2.7507	0.3960	0.3680
					TOTAL %	0.0326	5.2760	1.4065	1.1684
					OF ENDUSE		60.0%		
AAHX (DINING RM) *94	1.1135	0.5189	1.2754	30	35%	0.0854			
Hi Ef H PMP (DIN RM) *94	4.5804	1.0672	4.0661	30	35%	0.0927			
HW HEAT RECOVERY *94	1.0590	0.4935	8.7652	30	32%	0.0118	2.8143	0.3400	0.1584
HW BLANKET Same *94	0.0220	0.0212	0.0469	30	32%	0.0615			
HW TIME CLOCK *94	0.0240	0.0087	0.0202	30	32%	0.1080			
FREEZER STRIP CURTAIN *94	0.1173	0.5311	1.5812	30	100%	0.0274	1.5812	0.1173	0.5311
ECONOMIZER *94	1.8321	0.8538	3.6537	30	78%	0.0490	2.8499	1.4291	0.6659
					TOTAL %	0.0298	7.2454	1.8864	1.3555
					OF ENDUSE		26.6%		
					GRAND TOTAL	0.0306	16.3779	4.0378	3.4819
							45.5%		

ABSOLUTE ENERGY USE BY END USE	ELECT (kWh/SF)	PERCENT SATUR.	ALL FUELS MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	8.50	45.2%	18.78	18.90
COOLING	4.95	98.7%	4.97	5.30
VENTILATION	11.00	100.0%	11.00	11.00
WATER HEAT	7.79	88.5%	8.80	8.80
REFRIGERATION	15.10	100.0%	15.10	15.10
LIGHTING	14.01	100.0%	13.46	17.10
MISC.	13.12	92.9%	6.50	57.30
TOTAL	74.47	94.7%	78.61	133.50

NEW	2,624	SQFT
STATE		UTAH
ZONE:		0
BUILDING TYPE		FAST FOOD
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE									
MEASURES									
CURRENT PRACTICE>MCS '94	0.0340	0.0000	0.1200	70	45%	0.0152	0.0543	0.0154	0.0000
ROOF R19>R30 same '94	0.2622	0.0000	0.3607	30	45%	0.0485	0.1630	0.1185	0.0000
SOLAR FILM XIR '94	0.6747	1.1972	2.1880	30	99%	0.0571	2.1595	0.6660	1.1816
WINDOWS LOW E '94	0.8256	0.2983	0.5741	30	45%	0.1306			
					TOTAL %	0.0555	2.3768	0.7999	1.1816
					OF ENDUSE		17.3%		
BUILDING LIGHTING									
MEASURES									
CURRENT PRACTICE>MCS '94	0.2598	-0.4311	3.7119	30	100%	-0.0031	3.7119	0.2598	-0.4311
FLUORESCENT>T8 Elec '94	0.5205	0.7537	1.6655	30	100%	0.0510	1.6655	0.5205	0.7537
EXIT SIGNS '94	0.0773	-0.1039	0.1646	30	100%	-0.0108	0.1646	0.0773	-0.1039
					TOTAL %	0.0130	5.5421	0.8576	0.2187
					OF ENDUSE		32.4%		
CURRENT PRACTICE>MCS '94	0.2795	0.1302	0.3312	30	45%	0.0825			
FRZR STRIP CURTAIN '94	0.1173	0.5077	1.5354	30	100%	0.0272	1.5354	0.1173	0.5077
HW HEAT RECOVERY '94	1.0590	0.4935	8.7652	30	43%	0.0118	3.7954	0.4586	0.2137
EXHAUST HEAT RECOVERY '94	0.5165	0.2407	17.9905	30	45%	0.0028	8.1317	0.2335	0.1088
Heat Rec EXHAUST HOOD '94	5.2250	2.4348	16.7293	30	45%	0.0305	7.5617	2.3617	1.1005
ECONOMIZER '94	1.3741	0.6403	0.6606	30	99%	0.2034			
					TOTAL %	0.0162	21.0242	3.1710	1.9307
					OF ENDUSE		19.2%		
					GRAND TOTAL	0.0188	28.9431	4.8285	3.3311
							22.9%		

Appendix F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELECT (kWh/SF)	PERCENT SATUR.	ALL FUELS (kWh/SF)	CURRENT UIC PROTOTYPE (kWh/SF)
HEATING	9.07	67.0%	13.54	8.78
COOLING	0.07	100.0%	0.07	2.30
VENTILATION	2.30	100.0%	2.30	0.83
WATER HEAT	0.27	67.0%	0.40	1.42
REFRIGERATION	15.00	100.0%	15.00	
LIGHTING	12.75	100.0%	12.75	16.39
MISC.	10.20	99.0%	10.30	30.16
TOTAL	49.66	91.4%	54.36	59.88

EXISTING	26,052	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		GROCERY
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
INSULATE ROOF R3>R22 *94	0.6009	0.0000	2.2977	30	67%	0.0174	1.5395	0.4026	0.0000
INSULATE WALL R5>R24 *94	2.8322	0.0000	2.5642	30	67%	0.0737			
EFF. WINDOWS SG>DG *94	0.5775	0.2086	0.6229	30	67%	0.0842			
WEATHERSTRIP ACH *94	0.0117	0.0113	0.1519	30	67%	0.0101	0.1018	0.0079	0.0076
					TOTAL %	0.0170	1.6412	0.4105	0.0076
					OF ENDUSE		18.0%		
BUILDING LIGHTING MEASURES									
PARAB REFLCT (SALE) *94	0.8841	-0.0266	3.2251	30	100%	0.0177	3.2251	0.8841	-0.0266
2 LEVEL SWITCHING *94	0.2856	0.1245	1.9029	30	100%	0.0144	1.9029	0.2856	0.1245
INCAND>HALOGEN IR *94	0.0111	0.5246	1.0802	30	100%	0.0331	1.0802	0.0111	0.5246
					TOTAL %	0.0194	6.2082	1.1808	0.6225
					OF ENDUSE		48.7%		
BUILDING EQUIPMENT MEASURES									
REFER CASE COVERS *94	0.3288	0.1532	4.2391	30	100%	0.0076	4.2391	0.3288	0.1532
REFER CASE TIMER *94	0.0252	0.0117	2.4183	30	100%	0.0010	2.4183	0.0252	0.0117
HW HEAT RECOVERY *94	0.2768	0.1290	1.4145	30	67%	0.0191	0.9477	0.1855	0.0864
HW BLANKET *94	0.0128	0.0123	0.0800	30	67%	0.0210	0.0536	0.0086	0.0083
REDUCE MINIMUM AIR *94	0.0185	0.0459	0.5815	30	67%	0.0074	0.3896	0.0124	0.0307
REFIGERATION PUMP *94	0.8203	0.3822	5.0000	30	100%	0.0160	5.0000	0.8203	0.3822
FREEZER STRIP CURTAIN *94	0.0242	0.0113	0.2069	30	100%	0.0114	0.2069	0.0242	0.0113
RESISTANCE>HEAT PUMP *94	3.1120	1.4501	1.9174	30	50%	0.1587			
EXHAUST HEAT RECOVERY *94	0.3166	0.1476	0.9781	30	67%	0.0317	0.6553	0.2122	0.0989
					TOTAL %	0.0115	13.9105	1.6170	0.7827
					OF ENDUSE		37.7%		
					GRAND TOTAL	0.0142	21.7599	3.2082	1.4128
							43.8%		

ABSOLUTE ENERGY USE BY END USE	ELECT (kWh/SF)	PERCENT SATUR.	ALL FUELS MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	0.82	37.2%	2.19	2.20
COOLING	0.28	98.7%	0.28	0.30
VENTILATION	4.20	100.0%	4.20	4.20
WATER HEAT	0.28	92.3%	0.30	0.30
REFRIGERATION	42.90	100.0%	42.90	42.90
LIGHTING	14.50	100.0%	14.50	14.50
MISC.	5.20	100.0%	5.20	5.20
TOTAL	68.17	98.0%	69.57	69.60

NEW	26,052	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		GROCERY
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
CURRENT PRACTICE>MCS '94	0.0098	0	0.0080	30	37%	0.0819			
ROOF R19>R30 same '94	1.4860	0.0000	1.3256	30	37%	0.0748			
LOW E WINDOWS same '94	0.0793	0.0286	0.1826	30	37%	0.0394	0.0679	0.0295	0.0107
					TOTAL %	0.0394	0.0679	0.0295	0.0107
					OF ENDUSE		6.1%		
BUILDING LIGHTING MEASURES									
CURRENT PRACTICE>MCS									
FLUORESCENT>T8 Elec '94	0.1515	0.7623	2.2284	30	100%	0.0274	2.2284	0.1515	0.7623
INCANDESCENT>HALOGEN '94	0.0111	0.1972	0.5077	30	100%	0.0274	0.5077	0.0111	0.1972
EXIT SIGNS '94	0.0350	-0.0544	0.0823	30	100%	-0.0157	0.0823	0.0350	-0.0544
					TOTAL %	0.0261	2.8184	0.1976	0.9051
					OF ENDUSE		19.4%		
BUILDING EQUIPMENT MEASURES									
CURRENT PRACTICE>MCS '94	0.0242	0.0113	0.0070	30	99%	0.3387			
DHW HEAT RECOVER same '94	0.2642	0.1231	0.3000	30	92%	0.0861			
REFER FLOATING HEAD '94	0.0807	0.0776	4.7150	30	100%	0.0022	4.7150	0.0807	0.0776
REFER CASE COVERS '94	0.3597	0.3462	0.9520	30	100%	0.0495	0.9520	0.3597	0.3462
RFR ANTI-SWEAT TIMER '94	0.1156	0.1112	5.2650	30	100%	0.0029	5.2650	0.1156	0.1112
MECHANICAL SUBCOOLING '94	0.1359	0.1308	0.9320	30	100%	0.0191	0.9320	0.1359	0.1308
HOT GAS DEFROST '94	0.1678	0.1614	2.4110	30	100%	0.0091	2.4110	0.1678	0.1614
REFER PUMP AFT #3 '94	0.9965	0.9589	0.9220	30	100%	0.1415			
EFF FAN MOTORS '94	0.2768	0.2664	2.5890	30	100%	0.0140	2.5890	0.2768	0.2664
					TOTAL %	0.0088	16.8640	1.1364	1.0935
					OF ENDUSE		31.4%		
					GRAND TOTAL	0.0114	19.7503	1.3635	2.0093
							29.0%		

Appendix F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS (kWh/SF)	CURRENT UIC PROTOTYPE (kWh/SF)
HEATING	6.65	53.0%	12.54	43.55
COOLING	0.38	40.0%	0.94	3.20
VENTILATION	3.03	100.0%	3.03	7.02
WATER HEAT	4.74	67.0%	7.07	1.80
REFRIGERATION				
LIGHTING	7.88	100.0%	7.88	8.85
MISC.	0.64	85.2%	0.75	4.69
TOTAL	23.32	72.4%	32.21	69.11

EXISTING	272,000	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		HOSPITAL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE									
MEASURES									
ROOF INSUL. R7>R23 *94	0.1093	0.0000	0.8910	30	15%	0.0082	0.1360	0.0167	0.0000
EFF. WINDOWS SG>DG *94	0.8203	0.2963	0.6779	30	15%	0.1099			
					TOTAL %	0.0082	0.1360	0.0167	0.0000
					OF ENDUSE		1.9%		
BUILDING LIGHTING									
MEASURES									
T-12/Mag>T8 Elect *94	0.7912	0.4094	0.5842	30	100%	0.1371			
INCANDESCENT>PL *94	0.0583	0.0733	0.4615	30	100%	0.0190	0.4615	0.0583	0.0733
OUTSIDE LIGHTS Same *94	0.0006	-0.0097	0.0173	30	100%	-0.0350	0.0173	0.0006	-0.0097
					TOTAL %	0.0171	0.4788	0.0589	0.0637
					OF ENDUSE		6.1%		
BUILDING EQUIPMENT									
MEASURES									
TEMP RESET *94	0.0422	0.0406	2.6287	30	53%	0.0021	1.3932	0.0224	0.0215
AAHX *94	0.3761	0.1753	3.8306	30	53%	0.0096	2.0302	0.1994	0.0929
FAN MOTORS *94	0.1022	0.0476	0.0973	30	100%	0.1026			
HEAT RECOVER DHW same *94	0.0193	0.0090	3.0000	30	50%	0.0006	1.5075	0.0097	0.0045
					TOTAL %	0.0047	4.9309	0.2314	0.1189
					OF ENDUSE		31.9%		
					GRAND TOTAL	0.0059	5.5457	0.3070	0.1826
							23.8%		

Appendix F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	16.77	64.2%	26.12	26.20
COOLING	1.42	83.8%	1.70	1.70
VENTILATION	6.10	100.0%	6.10	6.10
WATER HEAT	1.26	89.9%	1.40	1.40
REFRIGERATION	0.00			
LIGHTING	7.57	100.0%	7.33	8.90
MISC.	4.43	85.2%	5.20	5.20
TOTAL	37.56	78.5%	47.85	49.50

NEW	272,000	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		HOSPITAL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
CURRENT PRACTICE>MCS *94	0.0266	0.0000	0.0840	30	64%	0.0211	0.0539	0.0171	0.0000
INSULATE WALLS R5>R24 *94	0.1034	0.0000	0.2035	30	48%	0.0339	0.0980	0.0498	0.0000
LOW E WINDOWS *94	0.2826	0.1021	0.4222	30	48%	0.0608			
					TOTAL %	0.0294	0.1519	0.0669	0.0000
					OF ENDUSE		0.8%		
BUILDING LIGHTING MEASURES									
CURRENT PRACTICE>MCS *94	0.1358	0.3160	1.5572	30	100%	0.0194	1.5572	0.1358	0.3160
EXIT SIGNS *94	0.0675	-0.0962	0.1091	30	100%	-0.0175	0.1091	0.0675	-0.0962
OUTDOOR LIGHTS same *94	-0.0003	-0.0092	0.0173	30	100%	-0.0365	0.0173	-0.0003	-0.0092
FLUORESCENT>T8 Elec *94	0.1728	0.2532	0.6374	30	100%	0.0446	0.6374	0.1728	0.2532
INCAND>HALOGEN IR *94	0.0038	0.1103	0.1834	30	100%	0.0415	0.1834	0.0038	0.1103
AMBIENT/TASK AFT #1 *94	-0.0029	-0.0055	0.1742	30	75%	-0.0032	0.1306	-0.0021	-0.0041
DAYLIGHT DIM AFT #2 *94	0.0852	0.0574	0.1760	30	75%	0.0540	0.1320	0.0639	0.0430
OCCUP SENSOR AFT #3 *94	0.0839	0.0998	0.1902	30	75%	0.0644			
					TOTAL %	0.0254	2.7671	0.4413	0.6132
					OF ENDUSE		31.1%		
BUILDING EQUIPMENT MEASURES									
AAHX same *94	0.4178	0.1947	3.9065	30	48%	0.0105	1.8810	0.2012	0.0937
HEAT RECOVER DHW same *94	0.5794	0.2700	0.7000	30	67%	0.0809			
EVAP COOLER *94	0.4382	0.0066	0.5040	30	63%	0.0589			
					TOTAL %	0.0105	1.8810	0.2012	0.0937
					OF ENDUSE		6.3%		
					GRAND TOTAL	0.0197	4.7999	0.7093	0.7069
							12.4%		

Appendix F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS (kWh/SF)	CURRENT UIC PROTOTYPE (kWh/SF)
HEATING	6.86	82.0%	8.37	11.72
COOLING	0.53	42.0%	1.25	0.64
VENTILATION	2.23	100.0%	2.23	0.04
WATER HEAT	2.32	83.0%	2.80	6.02
REFRIGERATION		100.0%		
LIGHTING	4.74	100.0%	4.74	3.72
MISC.	1.03	67.7%	1.52	1.94
TOTAL	17.71	84.7%	20.91	24.08

EXISTING	11,664	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		HOTEL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE									
MEASURES									
ROOF INSUL. R7>R27 *94	0.2311	0.0000	0.9432	30	82%	0.0163	0.7735	0.1895	0.0000
WALL INSUL. R2>R11 *94	0.2408	0.0000	4.4359	30	82%	0.0036	3.6374	0.1974	0.0000
WINDOW SG>DG *94	0.2016	0.0728	1.1317	30	82%	0.0162	0.9280	0.1653	0.0597
					TOTAL %	0.0076	5.3389	0.5523	0.0597
					OF ENDUSE		72.2%		
BUILDING LIGHTING									
MEASURES									
INCANDESCENT>PL *94	0.5720	-1.0907	0.3939	30	100%	-0.0879	0.3939	0.5720	-1.0907
FLUORESCENT>T8 *94	0.1265	0.0196	0.4345	30	100%	0.0224	0.4345	0.1265	0.0196
EXTERNAL>HPS *94	0.0766	0.0187	0.1740	30	100%	0.0365	0.1740	0.0766	0.0187
					TOTAL %	-0.0185	1.0023	0.7750	-1.0524
					OF ENDUSE		21.1%		
BUILDING EQUIPMENT									
MEASURES									
EFFICIENT THERMOSTAT *94	0.3460	0.1612	1.1130	30	25%	0.0304	0.2782	0.0865	0.0403
LOW FLOW SHOWER *94	0.0473	-0.4145	2.1652	30	60%	-0.0113	1.2991	0.0284	-0.2487
DHW & PIPE INSULATION *94	0.0270	0.0260	0.6331	30	40%	0.0056	0.2532	0.0108	0.0104
					TOTAL %	-0.0026	1.8306	0.1257	-0.1980
					OF ENDUSE		14.1%		
					GRAND TOTAL	0.0021	8.1718	1.4530	-1.1907
							46.1%		

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	0.40	8.8%	4.23	6.00
COOLING	0.49	96.4%	0.49	0.63
VENTILATION	0.02	100.0%	0.02	0.02
WATER HEAT	5.60	92.8%	6.03	6.03
REFRIGERATION	0.00	100.0%		
LIGHTING	3.43	100.0%	3.40	3.63
MISC.	1.31	67.7%	1.94	1.94
TOTAL	11.25	84.7%	16.11	18.25

NEW	11,664	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		HOTEL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
CURRENT CODE>MCS '94	0.2653	0.0000	0.4311	30	8.8%	0.0411	0.0379	0.0233	0.0000
LOW E WINDOW U65>U39 '94	0.2507	0.0906	0.7918	30	8.8%	0.0287	0.0697	0.0221	0.0080
INSULATE ROOF R19>R38 '94	0.1273	0.0000	0.3575	30	8.8%	0.0237	0.0315	0.0112	0.0000
INSULATE WALL R19>R24 '94	0.3722	0.0000	0.7152	30	8.8%	0.0347	0.0629	0.0328	0.0000
					TOTAL %	0.0321	0.2020	0.0894	0.0080
					OF ENDUSE		17.8%		
BUILDING LIGHTING MEASURES									
CODE>MCS 1/2 Inc>PL '94	0.8563	-0.5740	0.2576	30	100%	0.0731			
INCN>PL Second 1/2 '94	0.8563	-0.5740	0.2576	30	100%	0.0731			
HPS EXTERIOR LIGHTS '94	0.0476	0.1473	0.1740	30	100%	0.0747			
					TOTAL %	0.0000	0.0000	0.0000	0.0000
					OF ENDUSE		0.0%		
BUILDING EQUIPMENT MEASURES									
LOW FLOW SHOWER '94	0.0473	-0.4145	2.1652	30	74.2%	-0.0113	1.6075	0.0351	-0.3077
DHW & PIPE INSULATION '94	0.0270	0.0260	0.6331	30	74.2%	0.0056	0.4700	0.0201	0.0193
					TOTAL %	-0.0075	2.0774	0.0552	-0.2884
					OF ENDUSE		17.6%		
					GRAND TOTAL	-0.0040	2.2794	0.1445	-0.2805
							14.7%		

Appendix F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELECT (kWh/SF)	PERCENT SATUR.	ALL FUELS (kWh/SF)	CURRENT UIC PROTOTYPE (kWh/SF)
HEATING	3.14	22.0%	14.25	12.46
COOLING	1.46	100.0%	1.46	2.57
VENTILATION	4.30	100.0%	4.30	5.55
WATER HEAT	0.41	38.0%	1.09	0.20
REFRIGERATION	0.00			
LIGHTING	6.56	100.0%	6.56	10.50
MISC.	0.35	85.5%	0.41	3.12
TOTAL	16.22	57.8%	28.07	34.40

EXISTING	408,000	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		LG OFFICE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
INSUL. ROOF R6>R24 *94	0.0250	0.0000	0.0919	30	17%	0.0182	0.0152	0.0041	0.0000
W1 WINDOW SG>DG	0.0173	0.0063	0.0168	30	17%	0.0936			
W2 LOW E. WINDOWS AFT W1	0.0040	0.0015	0.0049	30	17%	0.0740			
					TOTAL %	0.0182	0.0152	0.0041	0.0000
					OF ENDUSE		0.3%		
BUILDING LIGHTING MEASURES									
40W FLUOR>T8 Elec Bal *94	1.3890	0.3145	2.1112	30	100%	0.0538	2.1112	1.3890	0.3145
INCANDESCENT>PL *94	0.1075	-0.0169	0.4281	30	100%	0.0141	0.4281	0.1075	-0.0169
EXIT SIGNS *94	0.0569	-0.0999	0.1773	30	100%	-0.0162	0.1773	0.0569	-0.0999
OCCUP SENSOR AFT #1 *94	0.2108	0.2432	0.9857	30	75%	0.0307	0.7392	0.1581	0.1824
AMBIENT/TASK AFT #4 *94	0.8105	-0.0651	0.7381	30	75%	0.0674			
DAYLIGHT DIM AFT #5 *94	0.3022	0.1377	0.1433	30	75%	0.2047			
					TOTAL %	0.0404	3.4559	1.7115	0.3801
					OF ENDUSE		52.7%		
BUILDING EQUIPMENT MEASURES									
TEMP RESET FOR MLTZN *94	0.0141	0.0066	0.0155	30	22%	0.0886			
EFF FAN Motor 1800rpm *94	0.1407	0.0656	0.0089	30	100%	1.5453			
TUNE & ADJUST same *94	0.0112	0.0279	0.0177	30	22%	0.1475			
TRAV RETROFIT same *94	1.9313	-1.1114	3.5580	30	100%	0.0154	3.5580	1.9313	-1.1114
EFF CHLR CHANGEOUT *94	0.1642	0.0765	0.0015	30	75%	10.5030			
					TOTAL %	0.0154	3.5580	1.9313	-1.1114
					OF ENDUSE		36.8%		
					GRAND TOTAL	0.0277	7.0291	3.6469	-0.7313
							43.3%		

ABSOLUTE ENERGY USE BY END USE	ELECT (kWh/SF)	PERCENT SATUR.	ALL FUELS MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	1.97	39.3%	4.97	5.00
COOLING	0.70	100.0%	0.70	0.70
VENTILATION	2.10	100.0%	2.10	2.10
WATER HEAT	0.15	75.2%	0.20	0.20
REFRIGERATION	0.00			
LIGHTING	7.70	100.0%	6.16	7.70
MISC.	3.08	85.5%	3.60	3.60
TOTAL	15.69	88.5%	17.73	19.30

NEW	408,000	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		LG OFFICE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE									
MEASURES									
CURRENT PRACTICE>MCS *94	0.0751	0	0.0320	25	39.3%	0.1702			
LOW E. WINDOWS *94	0.8929	0.3226	0.2016	20	39.3%	0.4929			
					TOTAL %	0.0000	0.0000	0.0000	0.0000
					OF ENDUSE		0.0%		
BUILDING LIGHTING									
MEASURES									
CRRNT PRACTICE>MCS *94	0.2533	-0.2112	1.4081	30	100.00%	0.0020	1.4081	0.2533	-0.2112
T8 FLUOR./ELECTRONIC *94	0.0723	0.0332	0.8449	30	100.00%	0.0083	0.8449	0.0723	0.0332
EXIT SIGNS *94	0.0569	-0.1049	0.1777	30	100.00%	-0.0180	0.1777	0.0569	-0.1049
OCC SENSOR AFTER #2 *94	0.2108	0.2233	1.6665	30	100.00%	0.0174	1.6665	0.2108	0.2233
AMBIENT/TSK AFTER #4 *94	0.8105	-0.0704	1.2803	30	100.00%	0.0386	1.2803	0.8105	-0.0704
DAYLT DIM AFTER #5 *94	0.3022	0.0237	0.2317	30	100.00%	0.0938			
					TOTAL %	0.0158	5.3775	1.4037	-0.1301
					OF ENDUSE		69.8%		
BUILDING EQUIPMENT									
MEASURES									
CURRENT PRACTICE>MCS									
VSD MOTORS *94	0.0542	0.0253	0.1877	30	100%	0.0282	0.1877	0.0542	0.0253
TRAV CNTRLS *same 94	1.9313	-0.3875	1.9010	30	100%	0.0542	1.9010	1.9313	-0.3875
EVAP COOLING	0.5616	0.0044	0.2112	30	75%	0.1788			
					TOTAL %	0.0518	2.0887	1.9855	-0.3623
					OF ENDUSE		22.3%		
					GRAND TOTAL	0.0259	7.4662	3.3892	-0.4923
							43.7%		

Appendix F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	2.95	32.0%	9.22	9.41
COOLING	1.20	30.0%	3.99	4.08
VENTILATION	1.77	100.0%	1.77	1.77
WATER HEAT	0.41	76.0%	0.54	0.54
REFRIGERATION				
LIGHTING	7.11	100.0%	7.11	7.00
MISC.	0.43	85.5%	0.50	0.50
TOTAL	13.87	60.0%	23.13	23.29

EXISTING	4,880	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		OFFICE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE									
MEASURES									
INSULATE ROOF R4>R24 '94	0.3005	0	1.6399	30	32.0%	0.0122	0.5248	0.0962	0.0000
INSUL. WALL R5>R24 '94	5.8235	0	2.8356	30	32.0%	0.1370			
WINDOWS SG>DG '94	1.7109	0.6181	2.0947	30	32.0%	0.0742			
LOW E. WINDOWS '94	1.3860	0.5007	0.6142	30	32.0%	0.2049			
SOLAR FILM '94	0.5716	1.0142	2.2069	30	30.0%	0.0479	0.6621	0.1715	0.3043
					TOTAL %	0.0321	1.1868	0.2677	0.3043
					OF ENDUSE		28.6%		
BUILDING LIGHTING									
MEASURES									
4L-T12 Mag>T8-4L Elec '94	0.8482	0.2808	1.7438	30	100.00%	0.0432	1.7438	0.8482	0.2808
EXIT SIGNS '94	0.0525	-0.0894	0.1533	30	100.00%	-0.0161	0.1533	0.0525	-0.0894
INCAN > 90 W HALOGEN '94	-0.0002	0.0207	0.0918	30	100.00%	0.0149	0.0918	-0.0002	0.0207
DAYLIGHT DIM AFT #1 '94	0.6007	0.0526	1.0628	30	100.00%	0.0410	1.0628	0.6007	0.0526
AMBIENT/TASK AFT #2 '94	1.0364	0.0249	0.6974	30	100.00%	0.1015			
OCCUP SENSOR AFT #3 '94	0.2407	0.1102	0.0693	30	100.00%	0.3377			
					TOTAL %	0.0386	3.0518	1.5012	0.2647
					OF ENDUSE		42.9%		
BUILDING EQUIPMENT									
MEASURES									
ECONOMIZER '94	0.4926	0.2295	1.3656	30	30.00%	0.0353	0.4097	0.1478	0.0689
OPTIMUM START TIMER '94	0.2799	0.1304	0.9004	30	24.00%	0.0304	0.2161	0.0672	0.0313
AAHX '94	0.1744	0.0813	1.3991	30	24.00%	0.0122	0.3358	0.0419	0.0195
REDUCE OUTSIDE AIR Same '94	0.0118	0.0055	1.3556	30	24.00%	0.0009	0.3254	0.0028	0.0013
RESISTANCE>HEAT PUMP '94	2.0131	0.4691	4.8840	30	44.32%	0.0339	2.1646	0.8922	0.2079
EFF HEAT PUMP '94	0.7389	0.3443	0.5154	30	7.00%	0.1402			
					TOTAL %	0.0286	3.4515	1.1519	0.3289
					OF ENDUSE		51.1%		
					GRAND TOTAL	0.0331	7.6901	2.9207	0.8978
							55.4%		

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	2.31	51.0%	4.53	4.60
COOLING	2.01	96.6%	2.06	2.20
VENTILATION	1.27	100.0%	1.10	2.20
WATER HEAT	0.42	82.2%	0.50	0.54
REFRIGERATION	0.00			
LIGHTING	6.14	100.0%	6.17	6.00
MISC.	0.80	85.5%	0.50	3.40
TOTAL	12.95	87.2%	14.85	18.94

NEW	4,880	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		OFFICE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE									
MEASURES									
CURRENT PRACTICE>MCS '94	0.0661	0	0.0900	30	51.0%	0.0490	0.0459	0.0337	0.0000
INSUL. WALL R11>R16 '94	0.4037	0	0.2276	30	51.0%	0.1183			
INSULATE ROOF R13>R30 '94	0.1421	0	0.1801	30	51.0%	0.0526	0.0919	0.0725	0.0000
INSULATE ROOF R30>R38 '94	0.0383	0	0.0599	30	51.0%	0.0427	0.0306	0.0195	0.0000
LOW E. WINDOWS '94	1.3957	0.5042	1.1885	30	100.0%	0.1066			
					TOTAL %	0.0498	0.1683	0.1257	0.0000
					OF ENDUSE		3.8%		
BUILDING LIGHTING									
MEASURES									
CURRENT PRACTICE>MCS '94	0.2812	-0.1080	1.2502	30	100.00%	0.0092	1.2502	0.2812	-0.1080
T8 FLUORESCENT/ELECT '94	0.2459	0.0480	0.4453	30	100.00%	0.0440	0.4453	0.2459	0.0480
EXIT SIGNS '94	0.0525	-0.0867	0.1443	30	100.00%	-0.0158	0.1443	0.0525	-0.0867
DAYLIGHT DIM AFT #1 '94	0.6007	0.0929	1.2325	30	100.00%	0.0375	1.2325	0.6007	0.0929
AMBIENT/TASK AFT #2 '94	1.0364	0.0342	0.6103	30	100.00%	0.1170			
OCCPNCY SENSOR AFT #3 '94	0.2407	0.0024	0.0476	30	100.00%	0.3406			
					TOTAL %	0.0245	3.0724	1.1802	-0.0537
					OF ENDUSE		51.2%		
BUILDING EQUIPMENT									
MEASURES									
CURRENT PRACTICE>MCS '94	0.1076	0.0502	0.1410	30	100.00%	0.0747			
ECONOMIZER '94	0.4926	0.2295	0.7160	30	96.60%	0.0673			
OPTIM STRT TMR same '94	0.2799	0.1304	0.7114	30	38.25%	0.0385	0.2721	0.1071	0.0499
AAHX same '94	0.1744	0.0813	1.1054	30	38.25%	0.0154	0.4228	0.0667	0.0311
REDUCE OUTSDE AIR same '94	0.0118	0.0055	1.0711	30	38.25%	0.0011	0.4097	0.0045	0.0021
EFF HEAT PUMP same '94	0.7389	0.1722	0.7731	30	25.50%	0.0786			
					TOTAL %	0.0158	1.1046	0.1783	0.0831
					OF ENDUSE		10.5%		
					GRAND TOTAL	0.0232	4.3453	1.4842	0.0293
							26.3%		

Appendix F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS (kWh/SF)	CURRENT UIC PROTOTYPE (kWh/SF)
HEATING	3.76	26.00%	14.45	5.70
COOLING	1.18	52.00%	2.27	2.48
VENTILATION	5.88	100.00%	5.88	1.15
WATER HEAT	0.07	59.00%	0.12	0.42
REFRIGERATION				
LIGHTING	6.71	100.00%	6.71	8.62
MISC.	0.61	95.20%	0.64	1.14
TOTAL	18.21	60.56%	30.07	19.51

EXISTING	13,125	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		RETAIL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE									
MEASURES									
INSULATE ROOF R7>R20 *94	0.6009	0.0000	3.1217	30	20%	0.0128	0.6087	0.1172	0.0000
INSULATE WALL R3>R22 *94	2.3877	0.0000	1.4497	30	20%	0.1099			
LOW E. WINDOWS *94	0.6761	0.2443	0.6641	30	20%	0.0925			
WEATHERSTRIP ACH *94	0.0131	0.0126	0.0048	30	20%	0.3576			
					TOTAL %	0.0128	0.6087	0.1172	0.0000
					OF ENDUSE		12.3%		
BUILDING LIGHTING									
MEASURES									
EXIT SIGNS *94	0.0260	-0.0315	0.0371	30	100%	-0.0099	0.0371	0.0260	-0.0315
DAYLIGHT DIM *94	0.0528	0.0918	0.9319	30	100%	0.0104	0.9319	0.0528	0.0918
FLUORESCENT>T8 *94	0.5749	0.6944	1.9524	30	100%	0.0434	1.9524	0.5749	0.6944
INCANDESCENT>HALOGEN *94	0.0132	0.4796	1.1042	30	100%	0.0298	1.1042	0.0132	0.4796
					TOTAL %	0.0315	4.0255	0.6669	1.2343
					OF ENDUSE		60.0%		
BUILDING EQUIPMENT									
MEASURES									
AAHX *94	0.2017	0.0940	0.6830	30	20%	0.0289	0.1332	0.0393	0.0183
RESISTANCE > HEAT PUMP *94	1.8491	0.4308	2.8524	30	0%	0.0533	0.0000	0.0000	0.0000
DHW BLANKET (Timer) *94	0.0048	0.0022	0.0315	30	44%	0.0149	0.0139	0.0021	0.0010
					TOTAL %	0.0276	0.1471	0.0415	0.0193
					OF ENDUSE		1.3%		
					GRAND TOTAL	0.0290	4.7814	0.8256	1.2536
							26.3%		

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS PROTOTYPE (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	0.31	31.40%	0.98	1.00
COOLING	1.10	84.00%	1.29	1.40
VENTILATION	1.70	100.00%	1.70	1.70
WATER HEAT	0.04	97.20%	0.04	0.04
REFRIGERATION	0.00			
LIGHTING	8.97	100.00%	8.93	9.20
MISC.	0.94	85.20%	1.10	1.10
TOTAL	13.05	68.50%	14.04	14.44

NEW	13,124	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		RETAIL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COST ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
CURRENT CODE>MCS '94	0.1079	0	0.0230	30	31%	0.3128			
DG>LOW E WINDOWS '94	0.1754	0.0634	0.1503	30	31%	0.1060			
					TOTAL %	0.0000	0.0000	0.0000	0.0000
					OF ENDUSE		0.0%		
BUILDING LIGHTING MEASURES									
CURRENT CODE>MCS '94	0.0356	-0.0386	0.3812	30	100%	-0.0005	0.3812	0.0356	-0.0386
FLUORESCENT>T8 Elec '94	0.1501	0.4753	2.2817	30	100%	0.0183	2.2817	0.1501	0.4753
INCAN>HALOGEN IR '94	0.0178	0.4395	1.1571	30	100%	0.0264	1.1571	0.0178	0.4395
DAYLIGHT DIM AFT #1 '94	0.0528	0.0747	0.8106	30	100%	0.0105	0.8106	0.0528	0.0747
EXIT SIGNS '94	0.0260	-0.0437	0.0948	30	100%	-0.0124	0.0948	0.0260	-0.0437
					TOTAL %	0.0168	4.7254	0.2823	0.9073
					OF ENDUSE		51.4%		
BUILDING EQUIPMENT MEASURES									
CURRENT PRACTICE>MCS '94	0.0879	0.0410	0.0140	30	31%	0.6131			
AAHX '94	0.2017	0.0940	0.6607	30	24%	0.0299	0.1556	0.0475	0.0221
EFF H PUMP same '94	0.6868	0.1600	0.1978	30	8%	0.2856			
RADIANT HTRS same '94	0.0325	0.0151	0.0966	30	24%	0.0329	0.0227	0.0077	0.0036
					TOTAL %	0.0303	0.1783	0.0552	0.0257
					OF ENDUSE		25.8%		
					GRAND TOTAL	0.0173	4.9037	0.3375	0.9330
							49.6%		

Appendix F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS (kWh/SF)	CURRENT UIC PROTOTYPE (kWh/SF)
HEATING	9.12	50.0%	18.24	16.07
COOLING	0.01	18.0%	0.07	0.00
VENTILATION	1.46	100.0%	1.46	1.18
WATER HEAT	0.14	56.0%	0.25	0.55
REFRIGERATION				
LIGHTING	4.72	100.0%	4.72	3.92
MISC.	0.50	88.5%	0.56	0.92
TOTAL	15.95	63.0%	25.30	22.64

EXISTING	67,784	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		SCHOOL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE									
MEASURES									
INSULATE ROOF R7> R27 '94	0.546	0.000	2.3756	30	50%	0.0153	1.1878	0.2732	0.0000
LOW E WINDOWS '94	2.212	0.799	2.1147	30	50%	0.0950			
INSULATE WALLS R4>R23 '94	2.973	0.000	2.0335	30	50%	0.0975			
WEATHERSTRIP ACH '94	0.242	0.233	2.4487	30	50%	0.0129	1.2243	0.1211	0.1165
					TOTAL %	0.0141	2.4121	0.3942	0.1165
					OF ENDUSE		26.4%		
BUILDING LIGHTING									
MEASURES									
T-12/Mag>T8 4L Elec '94	0.8484	0.2706	1.3557	30	100%	0.0551	1.3557	0.8484	0.2706
INCANDESCENT>PL '94	0.1311	0.0244	0.3491	30	100%	0.0297	0.3491	0.1311	0.0244
EXIT SIGNS '94	0.0673	-0.0978	0.1171	30	100%	-0.0174	0.1171	0.0673	-0.0978
OCCUP SENSOR AFT #1 '94	0.1849	0.1049	0.2425	30	100%	0.0797			
DAYLIGHT DIM AFT #1 '94	0.0979	0.0495	0.0501	30	100%	0.1960			
					TOTAL %	0.0455	1.8219	1.0468	0.1972
					OF ENDUSE		38.6%		
BUILDING EQUIPMENT									
MEASURES									
ADJUST OUTSIDE AIR '94	0.030	0.080	2.0006	30	50%	0.0036	1.0003	0.0149	0.0398
DHW BLANKET '94	0.003	0.003	0.0680	30	42%	0.0062	0.0286	0.0013	0.0013
					TOTAL %	0.0037	1.0289	0.0162	0.0411
					OF ENDUSE		9.2%		
					GRAND TOTAL	0.0230	5.2629	1.4572	0.3547
							33.0%		

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	1.88	16.50%	11.40	11.50
COOLING	0.10	32.00%	0.30	0.30
VENTILATION	2.22	100.00%	2.22	2.20
WATER HEAT	1.38	91.70%	1.50	1.50
REFRIGERATION	0.00			
LIGHTING	4.53	100.00%	4.41	5.20
MISC.	1.15	88.50%	1.30	1.30
TOTAL	11.25	53.26%	21.13	22.00

NEW	277,200	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		SCHOOL
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
CURRENT PRACTICE>MCS '94	0.0037	0.0000	0.0237	30	17%	0.0104	0.0039	0.0006	0.0000
INSUL ROOF R19> R38 '94	0.0641	0.0000	0.1570	30	17%	0.0272	0.0259	0.0106	0.0000
INSULATE WALLS R6>R19 '94	0.0634	0.0000	0.1329	30	17%	0.0318	0.0219	0.0105	0.0000
INSUL WALLS>R24 AFT #3'94	0.0503	0.0000	0.0910	30	17%	0.0368	0.0150	0.0083	0.0000
LOW E WINDOWS U.46 '94	0.0435	0.0157	0.0747	30	17%	0.0529	0.0123	0.0072	0.0026
					TOTAL %	0.0335	0.0791	0.0371	0.0026
					OF ENDUSE		4.0%		
BUILDING LIGHTING MEASURES									
CURRENT PRACTICE>MCS '94	-0.0363	-0.0677	0.1845	30	100%	-0.0376	0.1845	-0.0363	-0.0677
FLUORESCENT>T8 Elec '94	0.0344	0.0972	0.2248	30	100%	0.0391	0.2248	0.0344	0.0972
EXIT SIGNS '94	0.0165	-0.0229	0.0341	30	100%	-0.0126	0.0341	0.0165	-0.0229
OCCUP SENSOR AFT #1 '94	0.0452	0.0526	0.0973	30	100%	0.0671			
DAYLIGHT DIM AFT #2 '94	0.0239	0.0131	0.0213	30	100%	0.1161			
					TOTAL %	0.0032	0.4434	0.0146	0.0065
					OF ENDUSE		8.5%		
BUILDING EQUIPMENT MEASURES									
62-89 VENTILATION	0.0011	0.0005	-0.0042	30	0%	-0.0255	0.0000	0.0000	0.0000
VSD MOTORS '94	0.0183	0.0085	0.0581	30	75%	0.0307	0.0436	0.0137	0.0064
EMCS CONTROLS '94	0.2895	0.0492	0.2461	30	17%	0.0918			
					TOTAL %	0.0307	0.0436	0.0137	0.0064
					OF ENDUSE		0.7%		
					GRAND TOTAL	0.0095	0.5660	0.0654	0.0155
							4.8%		

Appendix F - Commercial Buildings, Demand-Side Resources Worksheets

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS (kWh/SF)	CURRENT UIC PROTOTYPE (kWh/SF)
HEATING	1.58	22.0%	7.16	8.30
COOLING	0.03	38.0%	0.07	0.38
VENTILATION	0.03	100.0%	0.03	0.23
WATER HEAT	0.01	56.0%	0.02	0.15
REFRIGERATION	5.00	100.0%	5.00	
LIGHTING	3.29	100.0%	3.29	3.50
MISC.	3.02	97.6%	3.09	1.72
TOTAL	12.96	69.5%	18.66	14.28

EXISTING	18,025	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		WAREHOUSE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
INSULATED ROOF R2>R20 *94	0.5459	0.000	3.4043	30	22%	0.0107	0.7490	0.1201	0.0000
INSULATED WALL R2>R20 *94	1.8460	0.000	2.4693	30	22%	0.0499	0.5432	0.4061	0.0000
LOW E WINDOWS SG>DG *94	0.5768	0.208	0.3799	30	22%	0.1379			
WEATHERSTRIP ACH *94	0.0393	0.038	0.1912	30	22%	0.0269	0.0421	0.0086	0.0083
					TOTAL %	0.0272	1.3343	0.5349	0.0083
					OF ENDUSE		82.9%		
BUILDING LIGHTING MEASURES									
OFFICE FLUORESCENT>T8 *94	0.1163	0.062	0.2238	30	100%	0.0530	0.2238	0.1163	0.0616
STOR DELMP/Reflec *94	0.1312	0.040	0.2803	30	100%	0.0409	0.2803	0.1312	0.0404
INCAN>HALOGEN, HID *94	0.0003	0.060	0.3445	30	100%	0.0117	0.3445	0.0003	0.0599
					TOTAL %	0.0322	0.8485	0.2478	0.1619
					OF ENDUSE		25.8%		
BUILDING EQUIPMENT MEASURES									
REDUCE OUTSIDE AIR *94	0.0047	0.012	0.1680	30	22%	0.0064	0.0370	0.0010	0.0025
TEMP SETBACK *94	0.0818	0.079	1.8826	30	22%	0.0057	0.4142	0.0180	0.0173
RADIANT HEATERS *94	0.9790	0.456	3.2221	30	22%	0.0297	0.7089	0.2154	0.1004
AAHX *94	0.1621	0.076	0.1595	30	22%	0.0994			
RESIST> HP (OFFICE) *94	0.2448	0.114	0.6382	30	17%	0.0375	0.1053	0.0404	0.0188
EFFICIENT REFER. *94 Same	0.7054	0.329	3.5000	30	22%	0.0197	0.7700	0.1552	0.0723
DESTRATIFIERS *94	0.1346	0.063	2.0310	30	22%	0.0065	0.4468	0.0296	0.0138
DHW BLANKET *94	0.0030	0.003	0.0229	30	42%	0.0170	0.0096	0.0012	0.0012
ECONOMIZER (OFFICE) *94	0.0667	0.031	0.1381	30	29%	0.0472	0.0394	0.0190	0.0089
					TOTAL %	0.0188	2.5311	0.4798	0.2352
					OF ENDUSE		26.2%		
					GRAND TOTAL	0.0236	4.7139	1.2625	0.4055
							36.4%		

ABSOLUTE ENERGY USE BY END USE	ELEC (kWh/SF)	PERCENT SATUR.	ALL FUELS MCS (kWh/SF)	CURRENT PRACTICE (kWh/SF)
HEATING	0.14	5.3%	2.68	2.70
COOLING	0.16	85.8%	0.19	0.20
VENTILATION	0.40	100.0%	0.40	0.40
WATER HEAT	0.19	96.1%	0.20	0.20
REFRIGERATION	4.00	100.0%	4.00	4.00
LIGHTING	2.28	100.0%	2.10	3.30
MISC.	1.17	97.6%	1.20	1.20
TOTAL	8.35	77.5%	10.77	12.00

NEW	18,025	SQFT
STATE		UTAH
CLIMATE ZONE		0
BUILDING TYPE		WAREHOUSE
LIFE OF PROTOTYPE BUILDING		70
INITIAL YEAR OF DATA		1993

	BASE COST ($/SF)	O & M COSTS ($/SF)	ENERGY SAVINGS (kWh/SF)	MEASURE LIFE (YRS)	MEASURE ACCEPTANCE	LEVEL COST ($/kWh)	EFFECTIVE SAVINGS (kWh/SF)	COST $/SQFT	O&M $/SQFT
BUILDING ENVELOPE MEASURES									
CURRENT PRACTICE>MCS '94	0.1022	0	0.0190	30	5%	0.3592			
INSUL WALL R11>R24 '94	0.3865	0.000	0.0349	30	5%	0.7394			
LOW E WINDOWS '94	0.1798	0.065	0.0136	30	5%	1.2003			
INSULATE ROOF>R30 '92	0.2426	0.000	0.0202	30	5%	0.8012			
					TOTAL %	0.0000	0.0000	0.0000	0.0000
					OF ENDUSE		0.0%		
BUILDING LIGHTING MEASURES									
CURRENT PRACTICE>MCS '94	-0.0164	-0.0620	1.2268	30	100%	-0.0043	1.2268	-0.0164	-0.0620
EXIT SIGNS '94	0.0284	-0.0422	0.0791	30	100%	-0.0116	0.0791	0.0284	-0.0422
OCCUP SENSOR '94	0.0391	0.1205	0.5797	30	100%	0.0184	0.5797	0.0391	0.1205
AMB/TASK LIGHT AFT #1 '94	0.1007	0.0123	0.1663	30	100%	0.0453	0.1663	0.1007	0.0123
DAYLIGHT DIM AFT #2 '94	0.0656	0.0437	0.0873	30	100%	0.0834			
					TOTAL %	0.0059	2.0519	0.1518	0.0286
					OF ENDUSE		62.2%		
BUILDING EQUIPMENT MEASURES									
CURRENT PRACTICE>MCS '94	0.0175	0.0081	0.0140	30	5%	0.1223			
EFFICIENT REFER. same '94	0.7008	0.3265	3.5000	30	75%	0.0196	2.6250	0.5256	0.2449
ECONOMIZER '94	0.0667	0.0311	0.1435	30	64%	0.0454	0.0923	0.0429	0.0200
					TOTAL %	0.0205	2.7174	0.5685	0.2649
					OF ENDUSE		45.3%		
					GRAND TOTAL	0.0142	4.7692	0.7203	0.2935
							51.3%		

APPENDIX G

Appendix G - Industrial Sector Demand-Side Resources Worksheet

Explanation of the calculations and terms used in appendix G.

Columns A-E are summary information. Columns F-M are background data for columns A-E. To follow calculation flows start with the detail on page 2, columns F-M and move to columns A-E.

There are three levels of analysis for each measure: measure name-1, measure name-2, measure name-3.

F: First Cost is expressed in 1994 dollars per MWh per year

G: This column shows what percentage of the sector's total electrical energy is consumed by that enduse.

H: This column shows the technical potential for savings reduction for each measure. It is expressed in form of percentage of enduse consumption.

I: This column calculates the total savings potential for the measure in MWH/yr. The savings potential for each measure is equal to:

*MW used in sector = G * H* Megawatts used in sector*

where:

G	*is % power usage by enduse*
H	*is % technical potential savings from measure*

J: Measure acceptance, is the percentage of market the measure can be applied to.

K: Penetration Rates are presented as a percentage of market expected to reach. The analysis deals with technical potential and assumes 100 percent market penetration. The program penetration rates, which are less than 100 percent, will be discussed in the program section of the technical appendix.

L: Capital recovery factor was determined based on cost of capital and measure life.

M: Measure savings is equal to potential savings for each measure (MWh/year) divided by 8760. the data from column M, ranked by average levelized cost, is used in column C

C: Annual Measures Savings, in MW per year.

B: Ranked Measures, Ranked based on per unit average levelized cost. Ranking of the measures is based on the levelized cost calculation shown in column A.

D: Variable Levelized cost is equal to:

First cost * capital recovery factor.

Note that the first cost is expressed in Mills/kwh, so the annual savings drops out of the numerator and denominator.

A: Average Levelized cost is calculated based on the savings and costs shown in columns F,I,and L. Average levelized costs are weighted by the savings for each measure.

E: Cumulative Savings : The sum of savings from columns C and E with a one measure lag. 0.69+.277= .977 Example is as follows:

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
DATE OF RUN: 13-Jan-94

TOTAL NUMBER OF MEGAWATTS USED IN SECTOR: 486,101

Template for Appendix G-1

STATE: OREGON

SECTOR: FOOD

(A) AVERAGE LEVELIZED COST (mills/kWh)	(B) RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	(C) ANNUAL MEASURE SAVING (MW/YR)	(D) VARIABLE LEVELIZED COST (mills/kWh)	(E) CUMULATIVE SAVINGS (MW/YR)
12.705	LOW TEMP REFRIG 1	0.699	12.705	0.699
12.705	LIGHTING 1	0.277	12.705	0.977
12.705	PUMPS 1	0.277	12.705	1.254
12.705	DRYING (FANS) 1	0.033	12.705	1.287
12.705	OTHER PROCESS 1	0.350	12.705	1.637
12.705	HVAC 1	0.044	12.705	1.681
12.705	AIR COMPRESSORS 1	0.133	12.705	1.815
12.705	MED TEMP REFRIG 1	0.200	12.705	2.014
20.513	LOW TEMP REFRIG 2	1.398	31.762	3.413
21.808	LIGHTING 2	0.444	31.762	3.857
21.865	HVAC 2	0.022	31.762	3.879
21.907	DRYING (ELECTRIC) 2	0.017	31.762	3.895
23.614	OTHER PROCESS 2	0.816	31.762	4.711
24.050	MED TEMP REFRIG 2	0.266	31.762	4.978
24.251	AIR COMPRESSORS 2	0.133	31.762	5.111
24.371	DRYING (FANS) 2	0.083	31.762	5.194
25.084	PUMPS 2	0.555	31.762	5.749
25.974	MED TEMP REFRIG 3	0.266	45.172	6.015
27.973	LOW TEMP REFRIG 3	0.699	45.172	6.714
28.142	AIR COMPRESSORS 3	0.067	45.172	6.781
28.483	PUMPS 3	0.139	45.172	6.920
29.286	OTHER PROCESS 3	0.350	45.172	7.269
29.394	DRYING (FANS) 3	0.050	45.172	7.319
29.859	LIGHTING 3	0.222	45.172	7.541
29.948	HVAC 3	0.044	45.172	7.586

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

Template for Industrial Sector

CONSERVATION MEASURE	(F) FIRST COST ($/MWh/Yr)	(G) PERCENT OF POWER USED BY MEASURE	(H) SAVINGS % REDUCTION	(I) POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	(J) MEASURE ACCEPTANCE	(K) PENETRATION RATE	(L) CAPITAL RECOVERY FACTOR	(M) VARIABLE LEVELIZED COST (mills/kWh)	(N) MEASURE SAVING (MWa/YR)
AIR COMPRESSORS 1	$129.83	4.00%	6.00%	1,167	15	100%	100%	0.098	12.705	0.133
AIR COMPRESSORS 2	$324.56	4.00%	6.00%	1,167	15	100%	100%	0.098	31.762	0.133
AIR COMPRESSORS 3	$461.60	4.00%	3.00%	583	15	100%	100%	0.098	45.172	0.067
DRYING (ELECTRIC) 1	$129.83	1.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
DRYING (ELECTRIC) 2	$324.56	1.00%	3.00%	146	15	100%	100%	0.098	31.762	0.017
DRYING (ELECTRIC) 3	$461.60	1.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
DRYING (FANS) 1	$129.83	3.00%	2.00%	292	15	100%	100%	0.098	12.705	0.033
DRYING (FANS) 2	$324.56	3.00%	5.00%	729	15	100%	100%	0.098	31.762	0.083
DRYING (FANS) 3	$461.60	3.00%	3.00%	437	15	100%	100%	0.098	45.172	0.050
HVAC 1	$129.83	2.00%	4.00%	389	15	100%	100%	0.098	12.705	0.044
HVAC 2	$324.56	2.00%	2.00%	194	15	100%	100%	0.098	31.762	0.022
HVAC 3	$461.60	2.00%	4.00%	389	15	100%	100%	0.098	45.172	0.044
LIGHTING 1	$129.83	10.00%	5.00%	2,431	15	100%	100%	0.098	12.705	0.277
LIGHTING 2	$324.56	10.00%	8.00%	3,889	15	100%	100%	0.098	31.762	0.444
LIGHTING 3	$461.60	10.00%	4.00%	1,944	15	100%	100%	0.098	45.172	0.222
LOW TEMP REFRIG 1	$129.83	42.00%	3.00%	6,125	15	100%	100%	0.098	12.705	0.699
LOW TEMP REFRIG 2	$324.56	42.00%	6.00%	12,250	15	100%	100%	0.098	31.762	1.398
LOW TEMP REFRIG 3	$461.60	42.00%	3.00%	6,125	15	100%	100%	0.098	45.172	0.699
MED TEMP REFRIG 1	$129.83	12.00%	3.00%	1,750	15	100%	100%	0.098	12.705	0.200
MED TEMP REFRIG 2	$324.56	12.00%	4.00%	2,333	15	100%	100%	0.098	31.762	0.266
MED TEMP REFRIG 3	$461.60	12.00%	4.00%	2,333	15	100%	100%	0.098	45.172	0.266
OTHER PROCESS 1	$129.83	21.00%	3.00%	3,062	15	100%	100%	0.098	12.705	0.350
OTHER PROCESS 2	$324.56	21.00%	7.00%	7,146	15	100%	100%	0.098	31.762	0.816
OTHER PROCESS 3	$461.60	21.00%	3.00%	3,062	15	100%	100%	0.098	45.172	0.350
PUMPS 1	$129.83	5.00%	10.00%	2,431	15	100%	100%	0.098	12.705	0.277
PUMPS 2	$324.56	5.00%	20.00%	4,861	15	100%	100%	0.098	31.762	0.555
PUMPS 3	$461.60	5.00%	5.00%	1,215	15	100%	100%	0.098	45.172	0.139

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

CONSERVATION MEASURE	FIRST COST ($/MWh/Yr)	PERCENT OF POWER USED BY MEASURE	SAVINGS % REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVING (MWa/YR)
AIR COMPRESSORS 1	$129.83	4.00%	6.00%	1,167	15	100%	100%	0.098	12.705	0.133
AIR COMPRESSORS 2	$324.56	4.00%	6.00%	1,167	15	100%	100%	0.098	31.762	0.133
AIR COMPRESSORS 3	$461.60	4.00%	3.00%	583	15	100%	100%	0.098	45.172	0.067
DRYING (ELECTRIC) 1	$129.83	1.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
DRYING (ELECTRIC) 2	$324.56	1.00%	3.00%	146	15	100%	100%	0.098	31.762	0.017
DRYING (ELECTRIC) 3	$461.60	1.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
DRYING (FANS) 1	$129.83	3.00%	2.00%	292	15	100%	100%	0.098	12.705	0.033
DRYING (FANS) 2	$324.56	3.00%	5.00%	729	15	100%	100%	0.098	31.762	0.083
DRYING (FANS) 3	$461.60	3.00%	3.00%	437	15	100%	100%	0.098	45.172	0.050
HVAC 1	$129.83	2.00%	4.00%	389	15	100%	100%	0.098	12.705	0.044
HVAC 2	$324.56	2.00%	2.00%	194	15	100%	100%	0.098	31.762	0.022
HVAC 3	$461.60	2.00%	4.00%	389	15	100%	100%	0.098	45.172	0.044
LIGHTING 1	$129.83	10.00%	5.00%	2,431	15	100%	100%	0.098	12.705	0.277
LIGHTING 2	$324.56	10.00%	8.00%	3,889	15	100%	100%	0.098	31.762	0.444
LIGHTING 3	$461.60	10.00%	4.00%	1,944	15	100%	100%	0.098	45.172	0.222
LOW TEMP REFRIG 1	$129.83	42.00%	3.00%	6,125	15	100%	100%	0.098	12.705	0.699
LOW TEMP REFRIG 2	$324.56	42.00%	6.00%	12,250	15	100%	100%	0.098	31.762	1.398
LOW TEMP REFRIG 3	$461.60	42.00%	3.00%	6,125	15	100%	100%	0.098	45.172	0.699
MED TEMP REFRIG 1	$129.83	12.00%	3.00%	1,750	15	100%	100%	0.098	12.705	0.200
MED TEMP REFRIG 2	$324.56	12.00%	4.00%	2,333	15	100%	100%	0.098	31.762	0.266
MED TEMP REFRIG 3	$461.60	12.00%	4.00%	2,333	15	100%	100%	0.098	45.172	0.266
OTHER PROCESS 1	$129.83	21.00%	3.00%	3,062	15	100%	100%	0.098	12.705	0.350
OTHER PROCESS 2	$324.56	21.00%	7.00%	7,146	15	100%	100%	0.098	31.762	0.816
OTHER PROCESS 3	$461.60	21.00%	3.00%	3,062	15	100%	100%	0.098	45.172	0.350
PUMPS 1	$129.83	5.00%	10.00%	2,431	15	100%	100%	0.098	12.705	0.277
PUMPS 2	$324.56	5.00%	20.00%	4,861	15	100%	100%	0.098	31.762	0.555
PUMPS 3	$461.60	5.00%	5.00%	1,215	15	100%	100%	0.098	45.172	0.139

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

FOR THE YEAR:
2014
DATE OF RUN:
13-Jan-94

TOTAL NUMBER OF MEGAWATTS USED IN SECTOR: 1,905,168

STATE OREGON

SECTOR LUMBER

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVING (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
12.705	HVAC 1	0.087	12.705	0.087
12.705	AIR COMPRESSORS 1	1.566	12.705	1.653
12.705	LIGHTING 1	1.196	12.705	2.849
12.705	PNEUMATIC CONVEYING	2.610	12.705	5.459
12.705	OTHER PROCESS 1	1.957	12.705	7.416
12.705	BOILER AUXILIARIES 1	0.652	12.705	8.069
12.705	POLLUTION CONTROL 1	0.065	12.705	8.134
12.705	DRYING (FANS) 1	0.435	12.705	8.569
12.705	PUMPS 1	0.652	12.705	9.221
14.643	BOILER AUXILIARIES 2	1.044	31.762	10.265
19.914	OTHER PROCESS 2	4.567	31.762	14.832
19.949	HVAC 2	0.043	31.762	14.876
21.074	AIR COMPRESSORS 2	1.566	31.762	16.442
22.188	LIGHTING 2	1.914	31.762	18.356
22.621	DRYING (FANS) 2	0.870	31.762	19.226
22.621	PUMPS 2	0.000	31.762	19.226
22.652	POLLUTION CONTROL 2	0.065	31.762	19.291
22.814	CONVEYORS 2	0.348	31.762	19.639
23.863	PNEUMATIC CONVEYING	2.610	31.762	22.249
24.742	LIGHTING 3	0.957	45.172	23.206
24.818	HVAC 3	0.087	45.172	23.293
25.044	BOILER AUXILIARIES 3	0.261	45.172	23.554
25.337	PNEUMATIC CONVEYING	0.348	45.172	23.902
25.966	AIR COMPRESSORS 3	0.783	45.172	24.685
26.299	DRYING (FANS) 3	0.435	45.172	25.120
26.299	PUMPS 3	0.000	45.172	25.120

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

CONSERVATION MEASURE	FIRST COST ($/MWh/Yr)	PERCENT OF POWER USED BY MEASURE	SAVINGS % REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVING (MWa/YR)
AIR COMPRESSORS 1	$129.8255	12.00%	6.00%	13,717	15	100%	100%	0.098	12.705	1.566
AIR COMPRESSORS 2	$324.5638	12.00%	6.00%	13,717	15	100%	100%	0.098	31.762	1.566
AIR COMPRESSORS 3	$461.6019	12.00%	3.00%	6,859	15	100%	100%	0.098	45.172	0.783
BOILER AUXILIARIES 1	$129.8255	6.00%	5.00%	5,716	15	100%	100%	0.098	12.705	0.652
BOILER AUXILIARIES 2	$324.5638	6.00%	8.00%	9,145	15	100%	100%	0.098	31.762	1.044
BOILER AUXILIARIES 3	$461.6019	6.00%	2.00%	2,286	15	100%	100%	0.098	45.172	0.261
CHIPPERS 1	$129.8255	8.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
CHIPPERS 2	$324.5638	8.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
CHIPPERS 3	$461.6019	8.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
CONVEYORS 1	$129.8255	8.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
CONVEYORS 2	$324.5638	8.00%	2.00%	3,048	15	100%	100%	0.098	31.762	0.348
CONVEYORS 3	$461.6019	8.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
DRYING (FANS) 1	$129.8255	10.00%	2.00%	3,810	15	100%	100%	0.098	12.705	0.435
DRYING (FANS) 2	$324.5638	10.00%	4.00%	7,621	15	100%	100%	0.098	31.762	0.870
DRYING (FANS) 3	$461.6019	10.00%	2.00%	3,810	15	100%	100%	0.098	45.172	0.435
HVAC 1	$129.8255	1.00%	4.00%	762	15	100%	100%	0.098	12.705	0.087
HVAC 2	$324.5638	1.00%	2.00%	381	15	100%	100%	0.098	31.762	0.043
HVAC 3	$461.6019	1.00%	4.00%	762	15	100%	100%	0.098	45.172	0.087
LIGHTING 1	$129.8255	11.00%	5.00%	10,478	15	100%	100%	0.098	12.705	1.196
LIGHTING 2	$324.5638	11.00%	8.00%	16,765	15	100%	100%	0.098	31.762	1.914
LIGHTING 3	$461.6019	11.00%	4.00%	8,383	15	100%	100%	0.098	45.172	0.957
OTHER PROCESS 1	$129.8255	30.00%	3.00%	17,147	15	100%	100%	0.098	12.705	1.957
OTHER PROCESS 2	$324.5638	30.00%	7.00%	40,009	15	100%	100%	0.098	31.762	4.567
OTHER PROCESS 3	$461.6019	30.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
PNEUMATIC CONVEYING 1	$129.8255	8.00%	15.00%	22,862	15	100%	100%	0.098	12.705	2.610
PNEUMATIC CONVEYING 2	$324.5638	8.00%	15.00%	22,862	15	100%	100%	0.098	31.762	2.610
PNEUMATIC CONVEYING 3	$461.6019	8.00%	2.00%	3,048	15	100%	100%	0.098	45.172	0.348
POLLUTION CONTROL 1	$129.8255	3.00%	1.00%	572	15	100%	100%	0.098	12.705	0.065
POLLUTION CONTROL 2	$324.5638	3.00%	1.00%	572	15	100%	100%	0.098	31.762	0.065
POLLUTION CONTROL 3	$461.6019	3.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
PUMPS 1	$129.8255	3.00%	10.00%	5,716	15	100%	100%	0.098	12.705	0.652
PUMPS 2	$324.5638	3.00%	20.00%	11,431	15	100%		0.098	31.762	0.000
PUMPS 3	$461.6019	3.00%	5.00%	2,858	15	100%		0.098	45.172	0.000

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
TOTAL NUMBER OF MEGAWATTS USED IN SECTOR 382,880
STATE OREGON
DATE OF RUN: 13-Jan-94
SECTOR METAL

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVING (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
12.705	LIGHTING 1	0.109	12.705	0.109
12.705	POLLUTION CONTROL 1	0.092	12.705	0.201
12.705	ARC FURNACES 1	0.070	12.705	0.271
12.705	OTHER PROCESS 1	0.590	12.705	0.861
12.705	PUMPS 1	0.262	12.705	1.123
12.705	AIR COMPRESSORS 1	0.262	12.705	1.386
12.705	INDUCTION FURNACES 1	0.170	12.705	1.556
12.705	HVAC 1	0.035	12.705	1.591
12.705	HEAT TREAT 1	0.070	12.705	1.661
12.903	HVAC 2	0.017	31.762	1.678
17.393	PUMPS 2	0.524	31.762	2.203
17.618	HEAT TREAT 2	0.035	31.762	2.238
18.643	LIGHTING 2	0.175	31.762	2.413
22.548	INDUCTION FURNACES 2	1.023	31.762	3.435
23.769	ARC FURNACES 2	0.524	31.762	3.960
24.265	AIR COMPRESSORS 2	0.262	31.762	4.222
26.109	OTHER PROCESS 2	1.377	31.762	5.599
26.545	PUMPS 3	0.131	45.172	5.730
26.962	AIR COMPRESSORS 3	0.131	45.172	5.861
28.284	POLLUTION CONTROL 3	0.459	45.172	6.320
29.726	OTHER PROCESS 3	0.590	45.172	6.910
29.919	LIGHTING 3	0.087	45.172	6.998
29.995	HVAC 3	0.035	45.172	7.033

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

CONSERVATION MEASURE	FIRST COST ($/MWh/Yr)	PERCENT OF POWER USED BY MEASURE %	SAVINGS REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVING (MWa/YR)
AIR COMPRESSORS 1	$129.8255	10.00%	6.00%	2,297	15	100%	100%	0.098	12.705	0.262
AIR COMPRESSORS 2	$324.5638	10.00%	6.00%	2,297	15	100%	100%	0.098	31.762	0.262
AIR COMPRESSORS 3	$461.6019	10.00%	3.00%	1,149	15	100%	100%	0.098	45.172	0.131
ARC FURNACES 1	$129.8255	8.00%	2.00%	613	15	100%	100%	0.098	12.705	0.070
ARC FURNACES 2	$324.5638	8.00%	15.00%	4,595	15	100%	100%	0.098	31.762	0.524
ARC FURNACES 3	$461.6019	8.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
HEAT TREAT 1	$129.8255	4.00%	4.00%	613	15	100%	100%	0.098	12.705	0.070
HEAT TREAT 2	$324.5638	4.00%	2.00%	306	15	100%	100%	0.098	31.762	0.035
HEAT TREAT 3	$461.6019	4.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
HVAC 1	$129.8255	2.00%	4.00%	306	15	100%	100%	0.098	12.705	0.035
HVAC 2	$324.5638	2.00%	2.00%	153	15	100%	100%	0.098	31.762	0.017
HVAC 3	$461.6019	2.00%	4.00%	306	15	100%	100%	0.098	45.172	0.035
INDUCTION FURNACES 1	$129.8255	13.00%	3.00%	1,493	15	100%	100%	0.098	12.705	0.170
INDUCTION FURNACES 2	$324.5638	13.00%	18.00%	8,959	15	100%	100%	0.098	31.762	1.023
INDUCTION FURNACES 3	$461.6019	13.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
LIGHTING 1	$129.8255	5.00%	5.00%	957	15	100%	100%	0.098	12.705	0.109
LIGHTING 2	$324.5638	5.00%	8.00%	1,532	15	100%	100%	0.098	31.762	0.175
LIGHTING 3	$461.6019	5.00%	4.00%	766	15	100%	100%	0.098	45.172	0.087
OTHER PROCESS 1	$129.8255	45.00%	3.00%	5,169	15	100%	100%	0.098	12.705	0.590
OTHER PROCESS 2	$324.5638	45.00%	7.00%	12,061	15	100%	100%	0.098	31.762	1.377
OTHER PROCESS 3	$461.6019	45.00%	3.00%	5,169	15	100%	100%	0.098	45.172	0.590
POLLUTION CONTROL 1	$129.8255	7.00%	3.00%	804	15	100%	100%	0.098	12.705	0.092
POLLUTION CONTROL 2	$324.5638	7.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
POLLUTION CONTROL 3	$461.6019	7.00%	15.00%	4,020	15	100%	100%	0.098	45.172	0.459
PUMPS 1	$129.8255	6.00%	10.00%	2,297	15	100%	100%	0.098	12.705	0.262
PUMPS 2	$324.5638	6.00%	20.00%	4,595	15	100%	100%	0.098	31.762	0.524
PUMPS 3	$461.6019	6.00%	5.00%	1,149	15	100%	100%	0.098	45.172	0.131

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
DATE OF RUN: 13-Jan-94

TOTAL NUMBER OF MEGAWATTS USED IN SECTOR 886,618

STATE OREGON
SECTOR OTHER

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVING (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
12.705	AIR COMPRESSORS 1	0.486	12.705	0.486
12.705	OTHER PROCESS 1	2.186	12.705	2.672
12.705	HVAC 1	0.081	12.705	2.753
12.705	LIGHTING 1	0.506	12.705	3.259
12.705	PUMPS 1	0.810	12.705	4.069
23.306	OTHER PROCESS 2	5.101	31.762	9.170
23.731	AIR COMPRESSORS 2	0.486	31.762	9.656
24.885	PUMPS 2	1.619	31.762	11.275
24.909	HVAC 2	0.040	31.762	11.316
25.367	LIGHTING 2	0.810	31.762	12.125
26.007	LIGHTING 3	0.405	45.172	12.530
26.130	HVAC 3	0.081	45.172	12.611
28.943	OTHER PROCESS 3	2.186	45.172	14.797
29.375	PUMPS 3	0.405	45.172	15.202
29.624	AIR COMPRESSORS 3	0.243	45.172	15.445

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

CONSERVATION MEASURE	FIRST COST ($/MWh/Yr)	PERCENT OF POWER USED BY MEASURE	% SAVINGS REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVING (MWa/YR)
AIR COMPRESSORS 1	$129.8255	8.00%	6.00%	4,256	15	100%	100%	0.098	12.705	0.486
AIR COMPRESSORS 2	$324.5638	8.00%	6.00%	4,256	15	100%	100%	0.098	31.762	0.486
AIR COMPRESSORS 3	$461.6019	8.00%	3.00%	2,128	15	100%	100%	0.098	45.172	0.243
HVAC 1	$129.8255	2.00%	4.00%	709	15	100%	100%	0.098	12.705	0.081
HVAC 2	$324.5638	2.00%	2.00%	355	15	100%	100%	0.098	31.762	0.040
HVAC 3	$461.6019	2.00%	4.00%	709	15	100%	100%	0.098	45.172	0.081
LIGHTING 1	$129.8255	10.00%	5.00%	4,433	15	100%	100%	0.098	12.705	0.506
LIGHTING 2	$324.5638	10.00%	8.00%	7,093	15	100%	100%	0.098	31.762	0.810
LIGHTING 3	$461.6019	10.00%	4.00%	3,546	15	100%	100%	0.098	45.172	0.405
OTHER PROCESS 1	$129.8255	72.00%	3.00%	19,151	15	100%	100%	0.098	12.705	2.186
OTHER PROCESS 2	$324.5638	72.00%	7.00%	44,686	15	100%	100%	0.098	31.762	5.101
OTHER PROCESS 3	$461.6019	72.00%	3.00%	19,151	15	100%	100%	0.098	45.172	2.186
PUMPS 1	$129.8255	8.00%	10.00%	7,093	15	100%	100%	0.098	12.705	0.810
PUMPS 2	$324.5638	8.00%	20.00%	14,186	15	100%	100%	0.098	31.762	1.619
PUMPS 3	$461.6019	8.00%	5.00%	3,546	15	100%	100%	0.098	45.172	0.405

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

FOR THE YEAR: 2014
TOTAL NUMBER OF MEGAWATTS USED IN SECTOR 1,771,224
STATE OREGON
DATE OF RUN: 13-Jan-94
SECTOR PAPER

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVING (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
12.705	OTHER FANS 1	0.404	12.705	0.404
12.705	POLLUTION CONTROL 1	0.061	12.705	0.465
12.705	PNEUMATIC CONVEYING	0.607	12.705	1.072
12.705	AIR COMPRESSORS 1	0.364	12.705	1.436
12.705	LIGHTING 1	0.202	12.705	1.638
12.705	HVAC 1	0.081	12.705	1.719
12.705	PUMPS 1	3.235	12.705	4.954
12.705	BOILER AUXILIARIES 1	0.162	12.705	5.116
12.705	OTHER PROCESS	6.369	12.705	11.485
16.364	OTHER PROCESS 1	2.730	31.762	14.214
21.181	PUMPS 2	6.470	31.762	20.684
21.201	HVAC 2	0.040	31.762	20.725
21.283	BOILER AUXILIARIES 2	0.162	31.762	20.887
21.283	REFINING 2	0.000	31.762	20.887
21.579	PNEUMATIC CONVEYING	0.607	31.762	21.493
21.948	DRYING (FANS) 2	0.809	31.762	22.302
22.088	LIGHTING 2	0.324	31.762	22.626
22.422	OTHER FANS 2	0.809	31.762	23.434
22.612	AIR COMPRESSORS 2	0.485	31.762	23.920
22.688	PNEUMATIC CONVEYING	0.081	45.172	24.000
24.984	OTHER PROCESS 3	2.730	45.172	26.730
26.136	PUMPS 3	1.618	45.172	28.348
26.244	LIGHTING 3	0.162	45.172	28.509
26.364	AIR COMPRESSORS 3	0.182	45.172	28.691
26.417	HVAC 3	0.081	45.172	28.772
26.469	BOILER AUXILIARIES 3	0.081	45.172	28.853
26.979	OTHER FANS 3	0.809	45.172	29.662

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

CONSERVATION MEASURE	FIRST COST ($/MWh/Yr)	PERCENT OF POWER USED BY MEASURE	SAVINGS % REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVING (MWa/YR)
AIR COMPRESSORS 1	$129.8255	3.00%	6.00%	3,188	15	100%	100%	0.098	12.705	0.364
AIR COMPRESSORS 2	$324.5638	3.00%	8.00%	4,251	15	100%	100%	0.098	31.762	0.485
AIR COMPRESSORS 3	$461.6019	3.00%	3.00%	1,594	15	100%	100%	0.098	45.172	0.182
BOILER AUXILIARIES 1	$129.8255	2.00%	4.00%	1,417	15	100%	100%	0.098	12.705	0.162
BOILER AUXILIARIES 2	$324.5638	2.00%	4.00%	1,417	15	100%	100%	0.098	31.762	0.162
BOILER AUXILIARIES 3	$461.6019	2.00%	2.00%	708	15	100%	100%	0.098	45.172	0.081
DRYING (FANS) 1	$129.8255	8.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
DRYING (FANS) 2	$324.5638	8.00%	5.00%	7,085	15	100%	100%	0.098	31.762	0.809
DRYING (FANS) 3	$461.6019	8.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
HVAC 1	$129.8255	1.00%	4.00%	708	15	100%	100%	0.098	12.705	0.081
HVAC 2	$324.5638	1.00%	2.00%	354	15	100%	100%	0.098	31.762	0.040
HVAC 3	$461.6019	1.00%	4.00%	708	15	100%	100%	0.098	45.172	0.081
LIGHTING 1	$129.8255	2.00%	5.00%	1,771	15	100%	100%	0.098	12.705	0.202
LIGHTING 2	$324.5638	2.00%	8.00%	2,834	15	100%	100%	0.098	31.762	0.324
LIGHTING 3	$461.6019	2.00%	4.00%	1,417	15	100%	100%	0.098	45.172	0.162
OTHER FANS 1	$129.8255	5.00%	4.00%	3,542	15	100%	100%	0.098	12.705	0.404
OTHER FANS 2	$324.5638	5.00%	8.00%	7,085	15	100%	100%	0.098	31.762	0.809
OTHER FANS 3	$461.6019	5.00%	8.00%	7,085	15	100%	100%	0.098	45.172	0.809
OTHER PROCESS	$129.8255	45.00%	7.00%	55,794	15	100%	100%	0.098	12.705	6.369
OTHER PROCESS 1	$324.5638	45.00%	3.00%	23,912	15	100%	100%	0.098	31.762	2.730
OTHER PROCESS 3	$461.6019	45.00%	3.00%	23,912	15	100%	100%	0.098	45.172	2.730
PNEUMATIC CONVEYING 1	$129.8255	2.00%	15.00%	5,314	15	100%	100%	0.098	12.705	0.607
PNEUMATIC CONVEYING 2	$324.5638	2.00%	15.00%	5,314	15	100%	100%	0.098	31.762	0.607
PNEUMATIC CONVEYING 3	$461.6019	2.00%	2.00%	708	15	100%	100%	0.098	45.172	0.081
POLLUTION CONTROL 1	$129.8255	3.00%	1.00%	531	15	100%	100%	0.098	12.705	0.061
POLLUTION CONTROL 2	$324.5638	3.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
POLLUTION CONTROL 3	$461.6019	3.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
PUMPS 1	$129.8255	16.00%	10.00%	28,340	15	100%	100%	0.098	12.705	3.235
PUMPS 2	$324.5638	16.00%	20.00%	56,679	15	100%	100%	0.098	31.762	6.470
PUMPS 3	$461.6019	16.00%	5.00%	14,170	15	100%	100%	0.098	45.172	1.618
REFINING 1	$129.8255	13.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
REFINING 2	$324.5638	13.00%	10.00%	23,026	15	100%		0.098	31.762	0.000
REFINING 3	$461.6019	13.00%	0.00%	0	15	100%		0.098	0.000	0.000

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

OR THE YEAR: 2014
DATE OF RUN: 13-Jan-94

TOTAL NUMBER OF MEGAWATTS USED IN SECTOR 1,225,850

STATE UTAH
SECTOR CHEMICALS

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVING (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
12.705	DRIVEPOWER1	0.386	12.705	0.386
12.705	PUMPS 1	0.154	12.705	0.540
12.705	LIGHTING 1	0.105	12.705	0.645
12.705	POLLUTION CONTROL 1	0.008	12.705	0.654
12.705	DRYING (FANS) 1	0.157	12.705	0.810
12.705	AIR COMPRESSORS 1	3.014	12.705	3.824
12.705	HVAC 1	0.022	12.705	3.847
14.117	PUMPS 2	0.308	31.762	4.155
14.164	AGITATION 2	0.011	31.762	4.166
14.211	HVAC 2	0.011	31.762	4.177
21.568	AIR COMPRESSORS 2	3.014	31.762	7.191
25.001	ELECTROCHEMICAL 2	3.652	31.762	10.844
25.520	DRIVEPOWER2	0.901	31.762	11.745
25.608	LIGHTING 2	0.168	31.762	11.913
25.804	DRYING (FANS) 2	0.392	31.762	12.305
26.393	DRIVEPOWER3	0.386	45.172	12.691
28.387	AIR COMPRESSORS 3	1.507	45.172	14.198
28.436	AGITATION 3	0.042	45.172	14.240
28.559	LIGHTING 3	0.105	45.172	14.345
29.337	DRYING (FANS) 3	0.705	45.172	15.050
29.418	PUMPS 3	0.077	45.172	15.127
29.441	HVAC 3	0.022	45.172	15.150

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

CONSERVATION MEASURI	FIRST COST ($/MWh/Yr)	PERCENT OF POWER USED BY MEASURE %	SAVINGS REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVING (MWa/YR)
AIR COMPRESSORS 1	$129.8255	35.90%	6.00%	26,405	15	100%	100%	0.098	12.705	3.014
AIR COMPRESSORS 2	$324.5638	35.90%	6.00%	26,405	15	100%	100%	0.098	31.762	3.014
AIR COMPRESSORS 3	$461.6019	35.90%	3.00%	13,202	15	100%	100%	0.098	45.172	1.507
DRYING (FANS) 1	$129.8255	5.60%	2.00%	1,373	15	100%	100%	0.098	12.705	0.157
DRYING (FANS) 2	$324.5638	5.60%	5.00%	3,432	15	100%	100%	0.098	31.762	0.392
DRYING (FANS) 3	$461.6019	5.60%	9.00%	6,178	15	100%	100%	0.098	45.172	0.705
ELECTROCHEMICAL 1	$129.8255	52.20%	0.00%	0	15	100%	100%	0.098	0.000	0.000
ELECTROCHEMICAL 2	$324.5638	52.20%	5.00%	31,995	15	100%	100%	0.098	31.762	3.652
ELECTROCHEMICAL 3	$461.6019	52.20%	0.00%	0	15	100%	100%	0.098	0.000	0.000
HVAC 1	$129.8255	0.40%	4.00%	196	15	100%	100%	0.098	12.705	0.022
HVAC 2	$324.5638	0.40%	2.00%	98	15	100%	100%	0.098	31.762	0.011
HVAC 3	$461.6019	0.40%	4.00%	196	15	100%	100%	0.098	45.172	0.022
LIGHTING 1	$129.8255	1.50%	5.00%	919	15	100%	100%	0.098	12.705	0.105
LIGHTING 2	$324.5638	1.50%	8.00%	1,471	15	100%	100%	0.098	31.762	0.168
LIGHTING 3	$461.6019	1.50%	5.00%	919	15	100%	100%	0.098	45.172	0.105
DRIVEPOWER1	$129.8255	9.20%	3.00%	3,383	15	100%	100%	0.098	12.705	0.386
DRIVEPOWER2	$324.5638	9.20%	7.00%	7,894	15	100%	100%	0.098	31.762	0.901
DRIVEPOWER3	$461.6019	9.20%	3.00%	3,383	15	100%	100%	0.098	45.172	0.386
POLLUTION CONTROL 1	$129.8255	0.60%	1.00%	74	15	100%	100%	0.098	12.705	0.008
POLLUTION CONTROL 2	$324.5638	0.60%	0.00%	0	15	100%	100%	0.098	0.000	0.000
POLLUTION CONTROL 3	$461.6019	0.60%	0.00%	0	15	100%	100%	0.098	0.000	0.000
PUMPS 1	$129.8255	1.10%	10.00%	1,348	15	100%	100%	0.098	12.705	0.154
PUMPS 2	$324.5638	1.10%	20.00%	2,697	15	100%	100%	0.098	31.762	0.308
PUMPS 3	$461.6019	1.10%	5.00%	674	15	100%	100%	0.098	45.172	0.077
AGITATION 1	$129.8255	0.20%	0.00%	0	15	100%	100%	0.098	0.000	0.000
AGITATION 2	$324.5638	0.20%	4.00%	98	15	100%	100%	0.098	31.762	0.011
AGITATION 3	$461.6019	0.20%	15.00%	368	15	100%	100%	0.098	45.172	0.042

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

FOR THE YEAR: 2014

DATE OF RUN: 13-Jan-94

TOTAL NUMBER OF MEGAWATTS USED IN SECTOR 289,947

STATE UTAH

SECTOR COAL

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVING (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
12.705	HOISTING1	0.119	12.705	0.119
12.705	PUMPS1	0.212	12.705	0.331
12.705	CONVEYORS1	0.616	12.705	0.947
12.705	HVAC1	0.265	12.705	1.211
12.705	AIR COMPRESSOR1	0.457	12.705	1.668
12.705	OTHER PROCESS1	0.212	12.705	1.880
12.705	LIGHTING1	0.050	12.705	1.930
15.004	PUMPS2	0.265	31.762	2.194
18.180	CONVEYORS2	0.513	31.762	2.707
18.813	HVAC2	0.132	31.762	2.840
19.035	LIGHTING2	0.050	31.762	2.890
19.698	OTHER PROCESS2	0.159	31.762	3.048
20.042	HOISTING2	0.089	31.762	3.138
21.531	AIR COMPRESSOR2	0.457	31.762	3.595
22.944	AIR COMPRESSOR3	0.228	45.172	3.823
23.172	LIGHTING3	0.040	45.172	3.863
24.584	HVAC3	0.265	45.172	4.127
25.347	OTHER PROCESS3	0.159	45.172	4.286
26.675	CONVEYORS3	0.308	45.172	4.594
27.028	HOISTING3	0.089	45.172	4.684
27.527	PUMPS3	0.132	45.172	4.816

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

CONSERVATION MEASURE	FIRST COST ($/MWh/Yr)	PERCENT OF POWER USED BY MEASURE %	SAVINGS REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVING (MWa/YR)
LIGHTING1	$129.8255	3.00%	5.00%	435	15	100%	100%	0.098	12.705	0.050
LIGHTING2	$324.5638	3.00%	5.00%	435	15	100%	100%	0.098	31.762	0.050
LIGHTING3	$461.6019	3.00%	4.00%	348	15	100%	100%	0.098	45.172	0.040
HVAC1	$129.8255	10.00%	8.00%	2,320	15	100%	100%	0.098	12.705	0.265
HVAC2	$324.5638	10.00%	4.00%	1,160	15	100%	100%	0.098	31.762	0.132
HVAC3	$461.6019	10.00%	8.00%	2,320	15	100%	100%	0.098	45.172	0.265
AIR COMPRESSOR1	$129.8255	23.00%	6.00%	4,001	15	100%	100%	0.098	12.705	0.457
AIR COMPRESSOR2	$324.5638	23.00%	6.00%	4,001	15	100%	100%	0.098	31.762	0.457
AIR COMPRESSOR3	$461.6019	23.00%	3.00%	2,001	15	100%	100%	0.098	45.172	0.228
PUMPS1	$129.8255	8.00%	8.00%	1,856	15	100%	100%	0.098	12.705	0.212
PUMPS2	$324.5638	8.00%	10.00%	2,320	15	100%	100%	0.098	31.762	0.265
PUMPS3	$461.6019	8.00%	5.00%	1,160	15	100%	100%	0.098	45.172	0.132
CONVEYORS1	$129.8255	31.00%	6.00%	5,393	15	100%	100%	0.098	12.705	0.616
CONVEYORS2	$324.5638	31.00%	5.00%	4,494	15	100%	100%	0.098	31.762	0.513
CONVEYORS3	$461.6019	31.00%	3.00%	2,697	15	100%	100%	0.098	45.172	0.308
HOISTING1	$129.8255	9.00%	4.00%	1,044	15	100%	100%	0.098	12.705	0.119
HOISTING2	$324.5638	9.00%	3.00%	783	15	100%	100%	0.098	31.762	0.089
HOISTING3	$461.6019	9.00%	3.00%	783	15	100%	100%	0.098	45.172	0.089
OTHER PROCESS1	$129.8255	16.00%	4.00%	1,856	15	100%	100%	0.098	12.705	0.212
OTHER PROCESS2	$324.5638	16.00%	3.00%	1,392	15	100%	100%	0.098	31.762	0.159
OTHER PROCESS3	$461.6019	16.00%	3.00%	1,392	15	100%	100%	0.098	45.172	0.159

FOR THE YEAR: 2014
DATE OF RUN: 13-Jan-94

TOTAL NUMBER OF MEGAWATTS USED IN SECTOR 266,444

STATE UTAH
SECTOR MINING

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVING (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
12.705	DRIVEPOWER1	0.718	12.705	0.718
12.705	ELECTROCHEMICAL1	0.046	12.705	0.763
12.705	PROCESS HEAT1	0.049	12.705	0.812
12.705	PUMPS1	0.462	12.705	1.274
12.705	LIGHTING1	0.046	12.705	1.320
12.705	AIR COMPRESSOR1	0.036	12.705	1.357
12.705	CONVEYORS1	0.182	12.705	1.539
12.705	HVAC1	0.049	12.705	1.588
12.992	HVAC2	0.024	31.762	1.612
14.610	CONVEYORS2	0.152	31.762	1.764
14.958	AIR COMPRESSOR2	0.036	31.762	1.801
15.292	ELECTROCHEMICAL2	0.036	31.762	1.837
15.400	PROCESS HEAT2	0.012	31.762	1.849
19.089	DRIVEPOWER2	0.538	31.762	2.388
19.327	LIGHTING2	0.046	31.762	2.433
21.713	PUMPS2	0.578	31.762	3.011
21.808	PROCESS HEAT3	0.012	45.172	3.023
21.948	AIR COMPRESSOR3	0.018	45.172	3.042
22.223	LIGHTING3	0.036	45.172	3.078
22.581	HVAC3	0.049	45.172	3.127
22.841	ELECTROCHEMICAL3	0.036	45.172	3.163
26.089	DRIVEPOWER3	0.538	45.172	3.702
26.548	CONVEYORS3	0.091	45.172	3.793
27.867	PUMPS3	0.289	45.172	4.082

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

CONSERVATION MEASURE	FIRST COST ($/MWh/Yr)	PERCENT OF POWER USED BY MEASURE %	SAVINGS REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVING (MWa/YR)
LIGHTING1	$129.8255	3.00%	5.00%	400	15	100%	100%	0.098	12.705	0.046
LIGHTING2	$324.5638	3.00%	5.00%	400	15	100%	100%	0.098	31.762	0.046
LIGHTING3	$461.6019	3.00%	4.00%	320	15	100%	100%	0.098	45.172	0.036
HVAC1	$129.8255	2.00%	8.00%	426	15	100%	100%	0.098	12.705	0.049
HVAC2	$324.5638	2.00%	4.00%	213	15	100%	100%	0.098	31.762	0.024
HVAC3	$461.6019	2.00%	8.00%	426	15	100%	100%	0.098	45.172	0.049
AIR COMPRESSOR1	$129.8255	2.00%	6.00%	320	15	100%	100%	0.098	12.705	0.036
AIR COMPRESSOR2	$324.5638	2.00%	6.00%	320	15	100%	100%	0.098	31.762	0.036
AIR COMPRESSOR3	$461.6019	2.00%	3.00%	160	15	100%	100%	0.098	45.172	0.018
PUMPS1	$129.8255	19.00%	8.00%	4,050	15	100%	100%	0.098	12.705	0.462
PUMPS2	$324.5638	19.00%	10.00%	5,062	15	100%	100%	0.098	31.762	0.578
PUMPS3	$461.6019	19.00%	5.00%	2,531	15	100%	100%	0.098	45.172	0.289
CONVEYORS1	$129.8255	10.00%	6.00%	1,599	15	100%	100%	0.098	12.705	0.182
CONVEYORS2	$324.5638	10.00%	5.00%	1,332	15	100%	100%	0.098	31.762	0.152
CONVEYORS3	$461.6019	10.00%	3.00%	799	15	100%	100%	0.098	45.172	0.091
DRIVEPOWER1	$129.8255	59.00%	4.00%	6,288	15	100%	100%	0.098	12.705	0.718
DRIVEPOWER2	$324.5638	59.00%	3.00%	4,716	15	100%	100%	0.098	31.762	0.538
DRIVEPOWER3	$461.6019	59.00%	3.00%	4,716	15	100%	100%	0.098	45.172	0.538
PROCESS HEAT1	$129.8255	4.00%	4.00%	426	15	100%	100%	0.098	12.705	0.049
PROCESS HEAT2	$324.5638	4.00%	1.00%	107	15	100%	100%	0.098	31.762	0.012
PROCESS HEAT3	$461.6019	4.00%	1.00%	107	15	100%	100%	0.098	45.172	0.012
ELECTROCHEMICAL1	$129.8255	3.00%	5.00%	400	15	100%	100%	0.098	12.705	0.046
ELECTROCHEMICAL2	$324.5638	3.00%	4.00%	320	15	100%	100%	0.098	31.762	0.036
ELECTROCHEMICAL3	$461.6019	3.00%	4.00%	320	15	100%	100%	0.098	45.172	0.036

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

FOR THE YEAR: 2014

DATE OF RUN: 13-Jan-94

TOTAL NUMBER OF MEGAWATTS USED IN SECTOR 187,089

STATE UTAH

SECTOR OIL&GAS

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVING (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
12.705	WELL PUMPS1	0.256	12.705	0.256
12.705	OTHER PROCESS1	0.224	12.705	0.481
12.705	REINJECTION PUMPS1	0.449	12.705	0.929
12.705	GAS COMPRESSORS1	0.032	12.705	0.961
13.896	GAS COMPRESSORS2	0.064	31.762	1.025
21.553	REINJECTION PUMPS2	0.769	31.762	1.794
23.354	WELL PUMPS2	0.384	31.762	2.178
24.585	OTHER PROCESS2	0.374	31.762	2.552
26.881	REINJECTION PUMPS3	0.320	45.172	2.873
27.083	GAS COMPRESSORS3	0.032	45.172	2.905
28.380	OTHER PROCESS3	0.224	45.172	3.129
29.352	WELL PUMPS3	0.192	45.172	3.321

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

CONSERVATION MEASURE	FIRST COST ($/MWh/Yr)	PERCENT OF POWER USED BY MEASURE	% SAVINGS REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVING (MWa/YR)
WELL PUMPS1	$129.8255	30.00%	4.00%	2,245	15	100%	100%	0.098	12.705	0.256
WELL PUMPS2	$324.5638	30.00%	6.00%	3,368	15	100%	100%	0.098	31.762	0.384
WELL PUMPS3	$461.6019	30.00%	3.00%	1,684	15	100%	100%	0.098	45.172	0.192
REINJECTION PUMPS1	$129.8255	30.00%	7.00%	3,929	15	100%	100%	0.098	12.705	0.449
REINJECTION PUMPS2	$324.5638	30.00%	12.00%	6,735	15	100%	100%	0.098	31.762	0.769
REINJECTION PUMPS3	$461.6019	30.00%	5.00%	2,806	15	100%	100%	0.098	45.172	0.320
GAS COMPRESSORS1	$129.8255	5.00%	3.00%	281	15	100%	100%	0.098	12.705	0.032
GAS COMPRESSORS2	$324.5638	5.00%	6.00%	561	15	100%	100%	0.098	31.762	0.064
GAS COMPRESSORS3	$461.6019	5.00%	3.00%	281	15	100%	100%	0.098	45.172	0.032
OTHER PROCESS1	$129.8255	35.00%	3.00%	1,964	15	100%	100%	0.098	12.705	0.224
OTHER PROCESS2	$324.5638	35.00%	5.00%	3,274	15	100%	100%	0.098	31.762	0.374
OTHER PROCESS3	$461.6019	35.00%	3.00%	1,964	15	100%	100%	0.098	45.172	0.224

FOR THE YEAR: 2014
DATE OF RUN: 13-Jan-94

TOTAL NUMBER OF MEGAWATTS USED IN SECTOR 439,625

STATE UTAH
SECTOR PETROL

AVERAGE LEVELIZED COST (mills/kWh)	RANKED MEASURES (LEAST UNIT LEVELIZED COST (VLC) CRITERIA)	ANNUAL MEASURE SAVING (MW/YR)	VARIABLE LEVELIZED COST (mills/kWh)	CUMULATIVE SAVINGS (MW/YR)
12.705	POLLUTION CONTROL 1	0.025	12.705	0.025
12.705	HVAC 1	0.060	12.705	0.085
12.705	OTHER PROCESS 1	0.301	12.705	0.386
12.705	AIR COMPRESSORS 1	0.090	12.705	0.477
12.705	PUMPS 1	2.258	12.705	2.735
12.705	DRYING (FANS) 1	0.090	12.705	2.825
12.705	LIGHTING 1	0.176	12.705	3.001
13.673	AGITATION 2	0.161	31.762	3.162
15.149	LIGHTING 2	0.281	31.762	3.443
16.172	DRYING (FANS) 2	0.226	31.762	3.669
18.678	OTHER PROCESS 2	0.703	31.762	4.371
25.327	PUMPS 2	4.517	31.762	8.888
25.392	AIR COMPRESSORS 2	0.090	31.762	8.978
25.413	HVAC 2	0.030	31.762	9.008
25.716	LIGHTING 3	0.141	45.172	9.149
25.812	AIR COMPRESSORS 3	0.045	45.172	9.194
26.632	DRYING (FANS) 3	0.407	45.172	9.600
27.196	OTHER PROCESS 3	0.301	45.172	9.902
28.226	AGITATION 3	0.602	45.172	10.504
28.323	HVAC 3	0.060	45.172	10.564
29.950	PUMPS 3	1.129	45.172	11.693

Appendix G - Industrial Sector, Demand-Side Resources Worksheet

CONSERVATION MEASURE	FIRST COST ($/MWh/Yr)	PERCENT OF POWER USED BY MEASURE %	SAVINGS REDUCTION	POTENTIAL SAVINGS (MWh/YR)	MEASURE LIFE	MEASURE ACCEPTANCE	PENETRATION RATE	CAPITAL RECOVERY FACTOR	VARIABLE LEVELIZED COST (mills/kWh)	MEASURE SAVING (MWa/YR)
AIR COMPRESSORS 1	$129.8255	3.00%	6.00%	791	15	100%	100%	0.098	12.705	0.090
AIR COMPRESSORS 2	$324.5638	3.00%	6.00%	791	15	100%	100%	0.098	31.762	0.090
AIR COMPRESSORS 3	$461.6019	3.00%	3.00%	396	15	100%	100%	0.098	45.172	0.045
DRYING (FANS) 1	$129.8255	9.00%	2.00%	791	15	100%	100%	0.098	12.705	0.090
DRYING (FANS) 2	$324.5638	9.00%	5.00%	1,978	15	100%	100%	0.098	31.762	0.226
DRYING (FANS) 3	$461.6019	9.00%	9.00%	3,561	15	100%	100%	0.098	45.172	0.407
HVAC 1	$129.8255	3.00%	4.00%	528	15	100%	100%	0.098	12.705	0.060
HVAC 2	$324.5638	3.00%	2.00%	264	15	100%	100%	0.098	31.762	0.030
HVAC 3	$461.6019	3.00%	4.00%	528	15	100%	100%	0.098	45.172	0.060
LIGHTING 1	$129.8255	7.00%	5.00%	1,539	15	100%	100%	0.098	12.705	0.176
LIGHTING 2	$324.5638	7.00%	8.00%	2,462	15	100%	100%	0.098	31.762	0.281
LIGHTING 3	$461.6019	7.00%	4.00%	1,231	15	100%	100%	0.098	45.172	0.141
OTHER PROCESS 1	$129.8255	20.00%	3.00%	2,638	15	100%	100%	0.098	12.705	0.301
OTHER PROCESS 2	$324.5638	20.00%	7.00%	6,155	15	100%	100%	0.098	31.762	0.703
OTHER PROCESS 3	$461.6019	20.00%	3.00%	2,638	15	100%	100%	0.098	45.172	0.301
POLLUTION CONTROL 1	$129.8255	5.00%	1.00%	220	15	100%	100%	0.098	12.705	0.025
POLLUTION CONTROL 2	$324.5638	5.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
POLLUTION CONTROL 3	$461.6019	5.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
PUMPS 1	$129.8255	45.00%	10.00%	19,783	15	100%	100%	0.098	12.705	2.258
PUMPS 2	$324.5638	45.00%	20.00%	39,566	15	100%	100%	0.098	31.762	4.517
PUMPS 3	$461.6019	45.00%	5.00%	9,892	15	100%	100%	0.098	45.172	1.129
AGITATION 1	$129.8255	8.00%	0.00%	0	15	100%	100%	0.098	0.000	0.000
AGITATION 2	$324.5638	8.00%	4.00%	1,407	15	100%	100%	0.098	31.762	0.161
AGITATION 3	$461.6019	8.00%	15.00%	5,276	15	100%	100%	0.098	45.172	0.602

Appendix
H

Please note:

That in this appendix the program data for Wyoming-Pacific is included in the Pacific division total. This is in contrast to the Action Plan were Wyoming- Pacific is included in the Utah division total.

Appendix H- Program Summaries

Explanations for the commercial program worksheets.

Commercial program work-sheets consist of 12 tables. The commercial retrofit program is used to explain data relationships.

First table, labeled "SUMMARY REPORT" shows the measure, utility, and customer costs and savings for the company. Tables 2-12 show costs and savings at the state level. Note that all of the costs are in constant 1994 dollars, unless stated otherwise. The following section goes through a column by column discussion of all of the summary table data columns.

Summary Report Table

The summary report table is divided in two parts, cumulative and incremental.

Column A) Cumulative Energy MWa, the data presented in this column is net energy savings, calculated as

C/8760
where C is net energy savings MWH..

The gross savings, presented in column E are net of free-riders. The net megawatt average figures are also adjusted for transmission and distribution losses, they include T&D losses.

Column B) Capacity MW, the values presented in this column show the winter system peak capacity savings. It is calculated as:

A/.43
where
A is net energy MWa
.43 is the capacity factor

Column C) Net Energy Savings (MWh), the values presented in this column are gross savings minus free-riders. Gross savings is presented in column E. Free rider savings is not presented in this table, but can be found in page H-5 in the state level tables.

Column D) Gross savings (MWa) are calculated as Gross MWh savings divided by 8760. Gross savings are presented in column E.

Column E) Gross Savings MWh The values presented in this column are equal to:

*E= G * s*
where
G is the incremental gross savings for each state
s is the Supplemental savings added (15 percent).

The values for incremental gross savings for each state can be found on page H-3.

Column F) 3rd party financing; the values presented in this column are calculated as:

*F =measure cost * O*

where:

O *is other financing ratio*

Other financing ratio for this program is zero for 1994-1998, and 50 percent for 1999-2013.

Column G) Utility Financing, the values in this column are calculated as

*G=measure cost *(1-O)*

where:

O *is other financing ratio*

Other financing ratio for this program is zero for 1994-1998, and 50 percent for 1999-2013.

Column H) Utility Expense; the values in his column are calculated as

*H=measure cost *Administrative adder, expense*

Administrative adder expense is assumed to be 1 percent.
Please note that deferred component of administrative cost is part of column L.

Column I) Net present value of Customer costs is calculated as

*I= T * P*

where

T *is sum of net present customer cost for each state*

P *is the penetration rate for the program*

Values for T can be found on page H-7, labeled NPV O&M costs.
Values for P can be found on page H-11.

Column J) Real ESC revenue, is calculated as

*J=pmt(I, n, Measure cost *(1+d))*

Where

I *is ESC loan rate,*

n *is duration of loan,*

d *is design and audit adder,*

The ESC payment are calculated for cost of measure including the design and audit cost (19 percent). Payment assumed to occur over a 15 year average repayment period, at 9.2 percent. The values presented in the column J keep track of the ESC charges for the pervious period.

Column K) Measure cost; the values presented in this column are calculated as:

*Total Measure Cost= Measure cost *(1+s+d)*

Where:

s *is the supplemental measures percentage (30 %)*

d *is design and audit adder*

The measure cost for each state is presented in page H-9. Multiplying the measure costs on page H-9 by 1.49 calculates the total measure cost figures presented on column K.

Column L) Deferred overhead cost is calculated using two equations. For the 1994-1998 period the overhead cost is calculated as:

L= Deferred cost - utility finance
Deferred cost for each state is presented on page H-10
Utility finance is presented in column G

For the 1999-2013 period the deferred cost is calculated as:

*L= Measure cost * Deferred administrative adder*
Measure cost is presented on page H-9
Deferred administrative adder is assumed to be 20 %.

Column M) The Penetration Rate by year and for each state is presented on page H-11.
Column N) Participation, expressed in 1000 sqf, for commercial programs. The breakdown for each state can be found on page H-12.

Appendix H - Commercial New Construction Programs

The definitions and methodology used in the commercial new construction are similar to those presented for the commercial retrofit. The commercial new construction is divided into the Energy FinAnswer 12,000 for commercial prescriptive projects, and the energy FinAnswer for energy use modeled projects. For the Energy FinAnswer 12,000 program, calculations of the NPV of customer cost is different than the commercial retrofit or the commercial FinAnswer calculations for NPV customer costs. In the calculations for the commercial FinAnswer 12,000 the value of estimated gas savings are included in the customers net present value of costs.

Appendix H- Program Summaries

Explanation for the Residential Home Comfort program.

A: Energy MWa. The data presented in this column is calculated as net savings (MWH) divided by 8760.

B: Net energy savings (MWh) is calculated as sum of the annual gross energy savings presented. There are no reductions for free-riders in this program.

C: Incremental Gross Energy Savings (MWh), is annual energy savings from the program.

D: 3rd Party Finance, no third party finance is considered for this program.

E: Utility Finance, is the total of deferred utility expenditure. The values presented for 1994-1997 are based on the expected expenses, from the 5 year plan. The utility expense for 1998 is assumed to be fifty percent of total measure cost.

F: Utility Expense is equal to 30 percent of total measure cost.

G: NPV customer cost, is calculated as follows:

*NPV CC= -.27 * I * C + K * n*

where:

I	*is net present value of interest (.0349)*
C	*is the measure cost*
K	*is net present value of customer cost/residence*
n	*Number of participating residences*

H: Real ESC revenue is calculated as

@pmt (K, r, t)

where

K	*is measure cost*
r	*is ESC loan rate (1.3 percent)*
t	*is ESC load term*

I: Total Measure cost is calculated as ($2800 * n) where n is number of participants, and $2,800 dollars is average cost per home weatherization.

J: Deferred Overhead Cost, is calculated as follows:
total measure cost multiplied by the deferred portion of the overhead expenses (2 percent)

J * 2% where J: Total measure cost & 2% overhead expense.

Appendix H- Program Summaries

Explanation for the Low Income program

Note that the savings and cost presented in the "SUMMARY REPORT" table includes savings and costs for the Low Income demand side bidding in Oregon and Utah.

A: Net Energy MWa is calculated as ***Net energy savings / 8760***

B: Net Energy Savings, is calculated as ***Gross energy - Savings takeback*** .
Takeback per residence is estimated to be about 1430 kWh. Gross energy savings per residence is 2773 kWh per year.

C: Gross MWa is equal to Cumulative gross energy savings /8760.

D: Cumulative gross energy savings is equal to net energy savings plus the takeback.

E: No 3rd Party Financing.

F: No Utility Financing provided.

G: Utility Expense, is equal to sum of the expense for the low income program plus the expenses for the demand side bid in Oregon and Utah. For years 1999-2013 utility expense is calculated as follows:

Utility expense = E * C * n
Where

E	***is expense percent of measure cost (.39)***
C	***is measure cost per residence ($1200)***
n	***is number of completed jobs***

H: NPV customer cost is calculated as follows:

(CC + NPV c) * n + (NPV c * nB)
Where

CC	***is Cost share portion of measure cost ($1000)***
NPV c	***is net present value of customer savings/unit***
n	***is number of completed jobs***
nB	***is number of completed bid jobs***

NPV c is estimated to be about -112 dollars, a reduction in customers costs.

I: Real ESC Revenue, not applicable to this program.

J: Total Measure cost is equal to $1200 * number of completed jobs.

K: Deferred over head cost is calculated as follows:

$$Uc - .67 * C$$

where

Uc *is sum of utility deferred costs*

C *is measure cost*

Uc is sum of utility deferred cost for the low income program, presented on page H-8, and the utility deferred costs for the two demand side bidding projects. The utility deferred cost for the demand side bids for each residence is calculated as an initial payment of $227 dollars per residence and a progress payment of 10 percent of the initial payment.

L: Low income jobs completed are homes weatherized which received a $1,200 grant from the utility.

Appendix H- Program Summaries

Explanations for Residential Retrofit Programs without Oregon Statutory programs

The values presented in this summary report table are aggregated values for the weatherization, low income weatherization, Home comfort program (California, Washington) and Super Good Cents Retrofit for Oregon. The low income weatherization savings include the savings from the DS bidding in Oregon and Utah.

Net energy savings are equal to gross energy savings in the four programs minus the savings takeback in the low income program, discussed in the section on low income program.

Explanation for data presented in the Industrial Program Worksheets

A: Cumulative Energy Savings (MWa) is calculated as:

$$CE= (P * L * (e * F))/8760$$

where

CE	**is culmulative energy savings (MWa)**
P	**is penetration rate the program in the given year**
L	**is line loss factor**
e	**is percentage of energy savings possible for that sector**
F	**is forecast of energy use for the industrial sector**
8760	**is the hours in a year**

Ramp rate

How do these differ

The above calculation is performed for each state and each industrial SIC.

B: Capacity Saving (MW), is calculated as follows:

$$CS=CE /.96$$

where

CS	**is capacity savings**
CE	**is cumulative energy savings (MWa)**
.96	**is load factor for industrial programs**

G: Utility Finance is calculated as:

$$UF=(1-f) * K * (1+a)$$

where

f	**is finance ratio, 50 percent.**
K	**is measure cost**
a	**is administrative cost percent, expense**

I: NPV customer cost is calculated as:

$$CC=I * K * (1+ad)$$

where

CC	**is customer cost NPV**
I	**is penetration rate of the program**
ad	**is the administrative cost percentage, deferred (4%)**
K	**is the measure cost**

Utility deferred cost is calculated as:

$$UD=(S/E) * (1-f) * K$$

Where

UD	**is utility deferred cost**
S	**is incremental energy savings for the state,**
E	**is incremental energy savings for company**
f	**is finance ratio, 50 percent**
K	**is measure cost**

Above calculation is performed for each sector.

K: Measure cost is calculated as:

$MC = p * (c * F)$

where

MC	**is measure cost**
p	**is the annual penetration rate for the program**
c	**is average cost per kWh of savings, for the sector**
F	**is forecasted energy consumption for the sector**

COMMERCIAL RETROFIT
SUMMARY REPORT
ALL COSTS IN REAL $, INCLUDES LINE LOSSES

	CUMULATIVE				INCREMENTAL									
YEAR	ENERGY MWa	CAPACITY MW	NET ENERGY Savings MWh	GROSS MWa	GROSS ENERGY MWh	3rd Party FINANCE k$	UTILITY FINANCE k$	UTILITY EXPENSE k$	NPV CUSTOMER O & M k$	REAL ESC REVENUE, k$	MEASURE COST k$	DEFERRED OVERHEAD k$	PENETRA-TION RATE	PARTICIPATION k SQFT
1994	2.5	5.8	21,957	2.9	25,650	$0	$5,950	$0	$604	$889	$10,994	$2,556	1%	2,240
1995	6.8	15.7	59,216	8.0	44,336	$0	$9,402	$0	$1,297	$2,264	$16,322	$3,553	2%	4,813
1996	11.3	26.3	98,961	13.5	48,380	$0	$9,929	$0	$1,543	$3,673	$15,736	$2,549	4%	5,726
1997	17.3	40.2	151,494	20.9	64,515	$0	$10,411	$0	$1,789	$5,107	$16,595	$2,636	6%	6,639
1998	23.2	54.0	203,304	28.4	66,245	$0	$13,368	$0	$2,482	$6,936	$21,330	$2,273	9%	9,212
1999	35.2	81.9	308,418	43.4	130,965	$20,937	$20,937	$281	$7,610	$10,906	$41,875	$5,621	13%	13,026
2000	49.3	114.7	432,130	61.2	156,129	$24,585	$24,585	$330	$9,417	$15,477	$49,170	$6,600	18%	15,612
2001	63.2	147.0	553,619	79.0	156,129	$24,585	$24,585	$330	$9,417	$19,897	$49,170	$6,600	23%	15,612
2002	76.8	178.6	672,884	96.9	156,129	$24,585	$24,585	$330	$9,417	$24,173	$49,170	$6,600	28%	15,612
2003	90.2	209.7	789,926	114.7	156,129	$24,585	$24,585	$330	$9,417	$28,307	$49,170	$6,600	33%	15,612
2004	103.3	240.2	904,743	132.5	156,129	$24,585	$24,585	$330	$9,417	$32,306	$49,170	$6,600	38%	15,612
2005	112.9	262.5	988,775	146.0	118,209	$18,440	$18,440	$248	$8,238	$34,941	$36,881	$4,950	41%	11,236
2006	122.3	284.4	1,071,262	159.5	118,209	$18,440	$18,440	$248	$8,238	$37,490	$36,881	$4,950	45%	11,236
2007	131.5	305.9	1,152,204	173.0	118,209	$18,440	$18,440	$248	$8,238	$39,954	$36,881	$4,950	48%	11,236
2008	140.6	327.0	1,231,602	186.5	118,209	$18,440	$18,440	$248	$8,238	$41,907	$36,881	$4,950	52%	11,236
2009	149.5	347.6	1,309,454	200.0	118,209	$18,440	$18,440	$248	$8,238	$42,934	$36,881	$4,950	55%	11,236
2010	158.2	367.9	1,385,761	213.5	118,209	$18,440	$18,440	$248	$8,238	$43,046	$36,881	$4,950	59%	11,236
2011	160.7	373.7	1,407,690	218.9	48,002	$7,349	$7,349	$99	$3,088	$39,956	$14,697	$1,973	60%	4,846
2012	162.4	377.7	1,422,822	223.5	39,614	$6,133	$6,133	$82	$2,486	$35,570	$12,266	$1,646	61%	3,984
2013	163.4	380.0	1,431,332	227.0	31,226	$4,917	$4,917	$66	$1,883	$31,745	$9,834	$1,320	62%	3,122
TOTAL	163.4	380.0	1,431,332	227.0	1,988,831	$272,903	$321,963	$3,663	$119,299		$626,784	$86,831	62%	199,088
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)

DISCOUNT RATE	5.2%
TOTAL RESOURCE (	29.3
UTILITY COST	8.1
UTAH %	40%
WEIGHTED LIFE	30.0

ESC LOAN RATE	9.2%
AVE. ANNUAL ESC REVENUE, k$	$41,032
DESIGN/AUDIT COST ADDER	19%
ADMINISTRATIVE ADDER, DEFERRED	20%
ADMINISTRATIVE ADDER, EXPENSE	1%

FRACTION OF NET SALES	25%
SUPPLEMENTAL SAVED ADDED	15%
SUPPLEMENTAL COST ADDED	30%
OTHER FINANCE	50%

Appendix H - Program Summaries: Medium Case Forecast

COMMERCIAL RETROFIT
CUM. NET SAVINGS, MWa

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	1.7	0.8	2.5
1995	4.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	4.9	1.9	6.8
1996	8.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.1	8.2	3.1	11.3
1997	11.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	11.8	5.5	17.3
1998	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.2	16.0	7.2	23.2
1999	20.1	0.1	0.5	0.0	0.1	0.1	0.6	0.0	13.5	21.6	13.7	35.2
2000	24.2	0.4	1.9	0.1	0.4	0.4	2.0	0.1	19.7	29.0	20.3	49.3
2001	28.1	0.7	3.2	0.2	0.8	0.8	3.4	0.2	25.9	36.4	26.8	63.2
2002	31.9	1.0	4.5	0.3	1.1	1.1	4.8	0.3	31.9	43.6	33.3	76.8
2003	35.6	1.3	5.8	0.4	1.4	1.4	6.1	0.4	37.9	50.6	39.6	90.2
2004	39.3	1.6	7.0	0.5	1.6	1.6	7.4	0.5	43.7	57.4	45.8	103.3
2005	39.5	1.8	8.3	0.6	1.9	1.9	8.7	0.6	49.5	60.9	52.0	112.9
2006	39.8	2.1	9.5	0.7	2.2	2.2	10.0	0.6	55.2	64.3	58.0	122.3
2007	40.0	2.4	10.7	0.8	2.5	2.5	11.2	0.7	60.8	67.5	64.0	131.5
2008	40.2	2.6	11.8	0.9	2.8	2.7	12.5	0.8	66.3	70.8	69.8	140.6
2009	40.4	2.9	13.0	0.9	3.0	3.0	13.7	0.9	71.7	73.9	75.6	149.5
2010	40.6	3.1	14.1	1.0	3.3	3.2	14.8	0.9	77.0	76.9	81.3	158.2
2011	40.7	3.3	14.7	1.1	3.4	3.4	15.5	1.0	77.6	78.6	82.0	160.7
2012	40.9	3.3	15.1	1.1	3.5	3.4	15.8	1.0	78.2	79.7	82.7	162.4
2013	41.0	3.4	15.2	1.1	3.5	3.4	15.9	1.0	78.8	80.0	83.4	163.4
Total	41.0	3.4	15.2	1.1	3.5	3.4	15.9	1.0	78.8	80.0	83.4	163.4

COMMERCIAL RETROFIT
CUM. CAPACITY, MW ANNUAL AVE.

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	3.7	1.9	5.6
1995	10.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.7	10.3	4.7	15.1
1996	17.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.7	17.5	7.7	25.2
1997	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.9	25.0	13.9	38.9
1998	34.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.9	34.1	17.9	52.1
1999	42.9	0.3	1.2	0.1	0.3	0.3	1.3	0.1	33.7	46.0	34.1	80.1
2000	51.4	0.9	4.0	0.3	1.1	0.9	4.6	0.3	49.3	62.2	50.7	112.9
2001	59.7	1.5	6.8	0.5	1.9	1.6	7.9	0.5	64.6	78.1	67.1	145.1
2002	67.9	2.1	9.6	0.7	2.6	2.3	11.1	0.8	79.7	93.6	83.2	176.8
2003	75.8	2.7	12.3	0.9	3.4	2.9	14.2	1.0	94.6	108.8	99.0	207.8
2004	83.5	3.3	15.0	1.1	4.1	3.5	17.3	1.2	109.3	123.7	114.6	238.3
2005	84.1	3.9	17.6	1.3	4.8	4.1	20.3	1.4	123.7	131.3	130.0	261.2
2006	84.6	4.5	20.2	1.5	5.5	4.7	23.3	1.6	138.0	138.7	145.1	283.8
2007	85.1	5.0	22.7	1.6	6.2	5.3	26.2	1.8	152.0	145.9	160.0	305.9
2008	85.6	5.6	25.2	1.8	6.9	5.8	29.0	2.0	165.7	153.0	174.6	327.6
2009	86.0	6.1	27.6	2.0	7.6	6.4	31.8	2.2	179.3	159.9	189.0	348.9
2010	86.4	6.6	30.0	2.2	8.2	6.9	34.5	2.3	192.6	166.6	203.1	369.8
2011	86.7	6.9	31.3	2.3	8.6	7.2	36.0	2.4	194.1	170.4	205.1	375.5
2012	87.0	7.1	32.1	2.3	8.8	7.3	36.8	2.5	195.6	172.7	206.9	379.5
2013	87.2	7.1	32.3	2.4	8.8	7.3	37.1	2.5	197.1	173.5	208.4	381.8
Total	87.2	7.1	32.3	2.4	8.8	7.3	37.1	2.5	197.1	173.5	208.4	381.8

COMMERCIAL RETROFIT
INCREMENTAL GROSS SAVINGS, MWh

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	15,641	0	0	0	0	0	0	0	6,664	15,641	6,664	22,304
1995	28,585	0	0	0	0	0	0	0	9,968	28,585	9,968	38,553
1996	31,611	0	0	0	0	0	0	0	10,458	31,611	10,458	42,069
1997	34,637	0	0	0	0	0	0	0	21,463	34,637	21,463	56,100
1998	43,295	0	0	0	0	0	0	0	14,309	43,295	14,309	57,604
1999	41,218	1,112	5,020	362	1,187	1,214	5,341	352	58,076	54,266	59,616	113,882
2000	41,218	2,781	12,549	905	2,968	3,035	13,352	881	58,076	73,840	61,925	135,764
2001	41,218	2,781	12,549	905	2,968	3,035	13,352	881	58,076	73,840	61,925	135,764
2002	41,218	2,781	12,549	905	2,968	3,035	13,352	881	58,076	73,840	61,925	135,764
2003	41,218	2,781	12,549	905	2,968	3,035	13,352	881	58,076	73,840	61,925	135,764
2004	41,218	2,781	12,549	905	2,968	3,035	13,352	881	58,076	73,840	61,925	135,764
2005	8,244	2,781	12,549	905	2,968	3,035	13,352	881	58,076	40,866	61,925	102,790
2006	8,244	2,781	12,549	905	2,968	3,035	13,352	881	58,076	40,866	61,925	102,790
2007	8,244	2,781	12,549	905	2,968	3,035	13,352	881	58,076	40,866	61,925	102,790
2008	8,244	2,781	12,549	905	2,968	3,035	13,352	881	58,076	40,866	61,925	102,790
2009	8,244	2,781	12,549	905	2,968	3,035	13,352	881	58,076	40,866	61,925	102,790
2010	8,244	2,781	12,549	905	2,968	3,035	13,352	881	58,076	40,866	61,925	102,790
2011	8,244	1,668	7,529	543	1,781	1,821	8,011	528	11,615	27,817	13,924	41,741
2012	8,244	1,112	5,020	362	1,187	1,214	5,341	352	11,615	21,292	13,155	34,447
2013	8,244	556	2,510	181	594	607	2,670	176	11,615	14,768	12,385	27,153
Total	475,266	35,038	158,118	11,406	37,393	38,239	168,237	11,096	794,625	886,305	843,113	1,729,418

COMMERCIAL RETROFIT
CUMULATIVE FREE RIDERSHIP, MWH

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	348	0	0	0	0	0	0	0	0	348	0	348
1995	1,641	0	0	0	0	0	0	0	0	1,641	0	1,641
1996	3,965	0	0	0	0	0	0	0	0	3,965	0	3,965
1997	7,532	0	0	0	0	0	0	0	0	7,532	0	7,532
1998	13,326	0	0	0	0	0	0	0	0	13,326	0	13,326
1999	18,517	59	265	18	69	85	303	25	2,754	19,247	2,848	22,095
2000	24,557	237	1,060	73	274	339	1,211	101	6,295	27,477	6,670	34,147
2001	31,445	458	2,044	140	529	655	2,335	195	10,623	37,076	11,346	48,422
2002	39,182	720	3,217	221	832	1,030	3,676	307	15,737	48,046	16,876	64,922
2003	47,767	1,025	4,579	314	1,185	1,467	5,233	436	21,639	60,385	23,260	83,645
2004	57,201	1,373	6,131	421	1,586	1,964	7,006	584	28,327	74,095	30,497	104,592
2005	63,071	1,763	7,872	540	2,037	2,521	8,995	750	35,802	84,761	38,589	123,350
2006	69,110	2,195	9,802	673	2,536	3,139	11,201	934	44,064	96,119	47,534	143,653
2007	75,320	2,669	11,921	818	3,084	3,818	13,622	1,136	53,113	108,168	57,333	165,502
2008	81,699	3,186	14,229	977	3,681	4,557	16,260	1,356	62,949	120,909	67,986	188,895
2009	88,248	3,745	16,727	1,148	4,328	5,357	19,114	1,594	73,571	134,340	79,493	213,833
2010	94,966	4,347	19,414	1,333	5,023	6,218	22,185	1,850	84,981	148,462	91,854	240,316
2011	101,854	4,830	21,571	1,481	5,581	6,909	24,650	2,056	91,197	161,295	98,834	260,128
2012	108,912	5,254	23,464	1,611	6,070	7,515	26,812	2,236	97,571	173,567	105,877	279,444
2013	116,140	5,605	25,034	1,718	6,477	8,018	28,607	2,386	104,102	185,122	112,964	298,086
Total	116,140	5,605	25,034	1,718	6,477	8,018	28,607	2,386	104,102	185,122	112,964	298,086

COMMERCIAL RETROFIT
EXPENSE, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1995	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1996	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1997	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1998	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1999	$103	$2	$10	$1	$3	$3	$12	$1	$145	$132	$149	$281
2000	$103	$6	$26	$2	$7	$7	$31	$3	$145	$175	$155	$330
2001	$103	$6	$26	$2	$7	$7	$31	$3	$145	$175	$155	$330
2002	$103	$6	$26	$2	$7	$7	$31	$3	$145	$175	$155	$330
2003	$103	$6	$26	$2	$7	$7	$31	$3	$145	$175	$155	$330
2004	$103	$6	$26	$2	$7	$7	$31	$3	$145	$175	$155	$330
2005	$21	$6	$26	$2	$7	$7	$31	$3	$145	$92	$155	$248
2006	$21	$6	$26	$2	$7	$7	$31	$3	$145	$92	$155	$248
2007	$21	$6	$26	$2	$7	$7	$31	$3	$145	$92	$155	$248
2008	$21	$6	$26	$2	$7	$7	$31	$3	$145	$92	$155	$248
2009	$21	$6	$26	$2	$7	$7	$31	$3	$145	$92	$155	$248
2010	$21	$6	$26	$2	$7	$7	$31	$3	$145	$92	$155	$248
2011	$21	$3	$16	$1	$4	$4	$18	$2	$29	$64	$35	$99
2012	$21	$2	$10	$1	$3	$3	$12	$1	$29	$49	$33	$82
2013	$21	$1	$5	$0	$1	$1	$6	$1	$29	$35	$31	$66
Total	$804	$73	$326	$27	$94	$89	$387	$32	$1,831	$1,706	$1,957	$3,663

COMMERCIAL RETROFIT
NPV CUSTOMER O&M COST, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$604	$0	$0	$0	$0	$0	$0	$0	$0	$604	$0	$604
1995	$1,297	$0	$0	$0	$0	$0	$0	$0	$0	$1,297	$0	$1,297
1996	$1,543	$0	$0	$0	$0	$0	$0	$0	$0	$1,543	$0	$1,543
1997	$1,789	$0	$0	$0	$0	$0	$0	$0	$0	$1,789	$0	$1,789
1998	$2,482	$0	$0	$0	$0	$0	$0	$0	$0	$2,482	$0	$2,482
1999	$1,474	$78	$430	$34	$111	$137	$369	$46	$4,931	$2,522	$5,088	$7,610
2000	$1,474	$196	$1,074	$86	$276	$343	$923	$114	$4,931	$4,095	$5,322	$9,417
2001	$1,474	$196	$1,074	$86	$276	$343	$923	$114	$4,931	$4,095	$5,322	$9,417
2002	$1,474	$196	$1,074	$86	$276	$343	$923	$114	$4,931	$4,095	$5,322	$9,417
2003	$1,474	$196	$1,074	$86	$276	$343	$923	$114	$4,931	$4,095	$5,322	$9,417
2004	$1,474	$196	$1,074	$86	$276	$343	$923	$114	$4,931	$4,095	$5,322	$9,417
2005	$295	$196	$1,074	$86	$276	$343	$923	$114	$4,931	$2,916	$5,322	$8,238
2006	$295	$196	$1,074	$86	$276	$343	$923	$114	$4,931	$2,916	$5,322	$8,238
2007	$295	$196	$1,074	$86	$276	$343	$923	$114	$4,931	$2,916	$5,322	$8,238
2008	$295	$196	$1,074	$86	$276	$343	$923	$114	$4,931	$2,916	$5,322	$8,238
2009	$295	$196	$1,074	$86	$276	$343	$923	$114	$4,931	$2,916	$5,322	$8,238
2010	$295	$196	$1,074	$86	$276	$343	$923	$114	$4,931	$2,916	$5,322	$8,238
2011	$295	$117	$645	$51	$166	$206	$554	$69	$986	$1,868	$1,221	$3,088
2012	$295	$78	$430	$34	$111	$137	$369	$46	$986	$1,343	$1,143	$2,486
2013	$295	$39	$215	$17	$55	$69	$185	$23	$986	$819	$1,064	$1,883
Total	$19,207	$2,464	$13,538	$1,078	$3,481	$4,325	$11,628	$1,442	$62,135	$52,241	$67,058	$119,299

Appendix H - Program Summaries: Medium Case Forecast

COMMERCIAL RETROFIT
INCREMENTAL ESC REVENUE, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$889	$0	$0	$0	$0	$0	$0	$0	$0	$889	$0	$889
1995	$1,404	$0	$0	$0	$0	$0	$0	$0	$0	$1,404	$0	$1,404
1996	$1,483	$0	$0	$0	$0	$0	$0	$0	$0	$1,483	$0	$1,483
1997	$1,555	$0	$0	$0	$0	$0	$0	$0	$0	$1,555	$0	$1,555
1998	$1,997	$0	$0	$0	$0	$0	$0	$0	$0	$1,997	$0	$1,997
1999	$1,540	$35	$154	$13	$45	$42	$184	$15	$2,170	$1,968	$2,230	$4,198
2000	$1,540	$87	$386	$32	$112	$106	$459	$38	$2,170	$2,610	$2,320	$4,929
2001	$1,540	$87	$386	$32	$112	$106	$459	$38	$2,170	$2,610	$2,320	$4,929
2002	$1,540	$87	$386	$32	$112	$106	$459	$38	$2,170	$2,610	$2,320	$4,929
2003	$1,540	$87	$386	$32	$112	$106	$459	$38	$2,170	$2,610	$2,320	$4,929
2004	$1,540	$87	$386	$32	$112	$106	$459	$38	$2,170	$2,610	$2,320	$4,929
2005	$308	$87	$386	$32	$112	$106	$459	$38	$2,170	$1,378	$2,320	$3,697
2006	$308	$87	$386	$32	$112	$106	$459	$38	$2,170	$1,378	$2,320	$3,697
2007	$308	$87	$386	$32	$112	$106	$459	$38	$2,170	$1,378	$2,320	$3,697
2008	$308	$87	$386	$32	$112	$106	$459	$38	$2,170	$1,378	$2,320	$3,697
2009	$308	$87	$386	$32	$112	$106	$459	$38	$2,170	$1,378	$2,320	$3,697
2010	$308	$87	$386	$32	$112	$106	$459	$38	$2,170	$1,378	$2,320	$3,697
2011	$308	$52	$232	$19	$67	$64	$275	$23	$434	$950	$524	$1,473
2012	$308	$35	$154	$13	$45	$42	$184	$15	$434	$736	$494	$1,230
2013	$308	$17	$77	$6	$22	$21	$92	$8	$434	$522	$464	$986

COMMERCIAL RETROFIT
MEASURE COST, K$
NET OF DESIGN & AUDIT COSTS AND SUPPLEMENTAL MEASURES

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$5,950	$0	$0	$0	$0	$0	$0	$0	$1,428	$5,950	$1,428	$7,378
1995	$9,402	$0	$0	$0	$0	$0	$0	$0	$1,553	$9,402	$1,553	$10,955
1996	$9,929	$0	$0	$0	$0	$0	$0	$0	$632	$9,929	$632	$10,561
1997	$10,411	$0	$0	$0	$0	$0	$0	$0	$727	$10,411	$727	$11,138
1998	$13,368	$0	$0	$0	$0	$0	$0	$0	$947	$13,368	$947	$14,315
1999	$10,310	$232	$1,034	$85	$299	$284	$1,229	$101	$14,530	$13,174	$14,930	$28,104
2000	$10,310	$580	$2,586	$213	$747	$710	$3,071	$253	$14,530	$17,469	$15,531	$33,000
2001	$10,310	$580	$2,586	$213	$747	$710	$3,071	$253	$14,530	$17,469	$15,531	$33,000
2002	$10,310	$580	$2,586	$213	$747	$710	$3,071	$253	$14,530	$17,469	$15,531	$33,000
2003	$10,310	$580	$2,586	$213	$747	$710	$3,071	$253	$14,530	$17,469	$15,531	$33,000
2004	$10,310	$580	$2,586	$213	$747	$710	$3,071	$253	$14,530	$17,469	$15,531	$33,000
2005	$2,062	$580	$2,586	$213	$747	$710	$3,071	$253	$14,530	$9,222	$15,531	$24,752
2006	$2,062	$580	$2,586	$213	$747	$710	$3,071	$253	$14,530	$9,222	$15,531	$24,752
2007	$2,062	$580	$2,586	$213	$747	$710	$3,071	$253	$14,530	$9,222	$15,531	$24,752
2008	$2,062	$580	$2,586	$213	$747	$710	$3,071	$253	$14,530	$9,222	$15,531	$24,752
2009	$2,062	$580	$2,586	$213	$747	$710	$3,071	$253	$14,530	$9,222	$15,531	$24,752
2010	$2,062	$580	$2,586	$213	$747	$710	$3,071	$253	$14,530	$9,222	$15,531	$24,752
2011	$2,062	$348	$1,551	$128	$448	$426	$1,843	$152	$2,906	$6,358	$3,506	$9,864
2012	$2,062	$232	$1,034	$85	$299	$284	$1,229	$101	$2,906	$4,926	$3,306	$8,232
2013	$2,062	$116	$517	$43	$149	$142	$614	$51	$2,906	$3,494	$3,106	$6,600
Total	$129,476	$7,307	$32,579	$2,685	$9,413	$8,940	$38,700	$3,193	$188,366	$219,687	$200,973	$420,660

COMMERCIAL RETROFIT
DEFERRED COST, K$
COSTS IN NOMINAL $'S

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$7,078	$0	$0	$0	$0	$0	$0	$0	$1,428	$7,078	$1,428	$8,506
1995	$11,402	$0	$0	$0	$0	$0	$0	$0	$1,553	$11,402	$1,553	$12,955
1996	$11,846	$0	$0	$0	$0	$0	$0	$0	$632	$11,846	$632	$12,478
1997	$12,320	$0	$0	$0	$0	$0	$0	$0	$727	$12,320	$727	$13,047
1998	$14,693	$0	$0	$0	$0	$0	$0	$0	$947	$14,693	$947	$15,641
1999	$4,021	$90	$403	$33	$117	$111	$479	$40	$5,667	$5,138	$5,823	$10,961
2000	$4,021	$226	$1,008	$83	$291	$277	$1,198	$99	$5,667	$6,813	$6,057	$12,870
2001	$4,021	$226	$1,008	$83	$291	$277	$1,198	$99	$5,667	$6,813	$6,057	$12,870
2002	$4,021	$226	$1,008	$83	$291	$277	$1,198	$99	$5,667	$6,813	$6,057	$12,870
2003	$4,021	$226	$1,008	$83	$291	$277	$1,198	$99	$5,667	$6,813	$6,057	$12,870
2004	$4,021	$226	$1,008	$83	$291	$277	$1,198	$99	$5,667	$6,813	$6,057	$12,870
2005	$804	$226	$1,008	$83	$291	$277	$1,198	$99	$5,667	$3,596	$6,057	$9,653
2006	$804	$226	$1,008	$83	$291	$277	$1,198	$99	$5,667	$3,596	$6,057	$9,653
2007	$804	$226	$1,008	$83	$291	$277	$1,198	$99	$5,667	$3,596	$6,057	$9,653
2008	$804	$226	$1,008	$83	$291	$277	$1,198	$99	$5,667	$3,596	$6,057	$9,653
2009	$804	$226	$1,008	$83	$291	$277	$1,198	$99	$5,667	$3,596	$6,057	$9,653
2010	$804	$226	$1,008	$83	$291	$277	$1,198	$99	$5,667	$3,596	$6,057	$9,653
2011	$804	$136	$605	$50	$175	$166	$719	$59	$1,133	$2,480	$1,367	$3,847
2012	$804	$90	$403	$33	$117	$111	$479	$40	$1,133	$1,921	$1,289	$3,210
2013	$804	$45	$202	$17	$58	$55	$240	$20	$1,133	$1,363	$1,211	$2,574
Total	$88,702	$2,850	$12,706	$1,047	$3,671	$3,487	$15,093	$1,245	$76,688	$123,885	$81,605	$205,489

COMMERCIAL RETROFIT
PROGRAM PENETRATION

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah
1994	2.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1995	4.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1996	5.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1997	6.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1998	8.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1999	5.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	5.0%
2000	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
2001	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
2002	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
2003	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
2004	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
2005	1.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
2006	1.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
2007	1.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
2008	1.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
2009	1.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
2010	1.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
2011	1.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	1.0%
2012	1.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	1.0%
2013	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Total	65.2%	63.0%	63.0%	63.0%	63.0%	63.0%	63.0%	63.0%	63.0%

Appendix H - Program Summaries: Medium Case Forecast

COMMERCIAL RETROFIT
PARTICIPATION, 1000 SQFT

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	2,240	0	0	0	0	0	0	0	0	2,240	0	2,240
1995	4,813	0	0	0	0	0	0	0	0	4,813	0	4,813
1996	5,726	0	0	0	0	0	0	0	0	5,726	0	5,726
1997	6,639	0	0	0	0	0	0	0	0	6,639	0	6,639
1998	9,212	0	0	0	0	0	0	0	0	9,212	0	9,212
1999	5,469	132	705	35	120	126	563	44	5,832	7,030	5,996	13,026
2000	5,469	330	1,762	87	299	314	1,407	110	5,832	9,370	6,242	15,612
2001	5,469	330	1,762	87	299	314	1,407	110	5,832	9,370	6,242	15,612
2002	5,469	330	1,762	87	299	314	1,407	110	5,832	9,370	6,242	15,612
2003	5,469	330	1,762	87	299	314	1,407	110	5,832	9,370	6,242	15,612
2004	5,469	330	1,762	87	299	314	1,407	110	5,832	9,370	6,242	15,612
2005	1,094	330	1,762	87	299	314	1,407	110	5,832	4,994	6,242	11,236
2006	1,094	330	1,762	87	299	314	1,407	110	5,832	4,994	6,242	11,236
2007	1,094	330	1,762	87	299	314	1,407	110	5,832	4,994	6,242	11,236
2008	1,094	330	1,762	87	299	314	1,407	110	5,832	4,994	6,242	11,236
2009	1,094	330	1,762	87	299	314	1,407	110	5,832	4,994	6,242	11,236
2010	1,094	330	1,762	87	299	314	1,407	110	5,832	4,994	6,242	11,236
2011	1,094	198	1,057	52	180	189	844	66	1,166	3,434	1,412	4,846
2012	1,094	132	705	35	120	126	563	44	1,166	2,654	1,330	3,984
2013	1,094	66	352	17	60	63	281	22	1,166	1,874	1,248	3,122
Total	71,293	4,158	22,197	1,099	3,772	3,961	17,729	1,392	73,487	120,437	78,650	199,088

NEW COMMERCIAL (FINANSWER)

SUMMARY REPORT

ALL COSTS IN REAL $, INCLUDES LINE LOSSES

	CUMULATIVE				INCREMENTAL									
YEAR	ENERGY MWa	CAPACITY MW	NET ENERGY Savings MWh	GROSS MWa	GROSS ENERGY MWh	3rd Party FINANCE k$	UTILITY FINANCE k$	UTILITY EXPENSE k$	NPV CUSTOMER O & M k$	REAL ESC REVENUE, k$	TOTAL MEASURE COST k$	DEFERRED OVERHEAD k$	PENETRA-TION RATE	PARTICIPATION k SQFT
1994	2.5	4.5	21,853	2.6	23,199	$0	$11,028	$99	$359	$705	$8,703	$2,325	17%	3,580
1995	5.2	9.4	45,128	5.5	25,202	$0	$10,997	$119	$460	$1,347	$8,212	$2,785	20%	3,879
1996	8.0	14.5	69,881	8.6	26,873	$0	$11,261	$126	$547	$1,989	$8,467	$2,794	20%	4,163
1997	10.8	19.7	94,905	11.7	27,628	$0	$11,196	$124	$588	$2,606	$8,418	$2,779	22%	4,283
1998	13.6	24.8	119,564	14.9	27,628	$0	$10,957	$122	$631	$3,180	$8,141	$2,816	22%	4,283
1999	17.8	32.4	156,218	20.9	52,894	$0	$17,296	$151	$3,501	$4,100	$12,647	$4,649	41%	8,834
2000	22.2	40.4	194,835	27.3	55,530	$0	$17,712	$155	$3,789	$5,014	$12,949	$4,763	41%	9,021
2001	27.0	49.0	236,189	33.8	57,569	$0	$18,074	$159	$4,014	$5,920	$13,216	$4,858	42%	9,171
2002	31.4	57.1	274,919	40.2	55,459	$0	$17,802	$159	$3,788	$6,780	$13,020	$4,783	42%	8,942
2003	36.0	65.4	315,096	46.7	56,891	$0	$17,935	$160	$3,960	$7,620	$13,114	$4,822	42%	8,979
2004	40.6	73.8	355,346	53.2	56,848	$0	$18,003	$161	$3,954	$8,436	$13,165	$4,837	42%	8,950
2005	45.1	82.0	395,197	59.6	56,620	$0	$18,096	$162	$3,905	$9,231	$13,237	$4,860	42%	8,881
2006	49.7	90.4	435,445	66.1	56,941	$0	$17,961	$161	$3,968	$9,992	$13,137	$4,824	42%	8,774
2007	54.2	98.5	474,688	72.6	56,554	$0	$17,769	$159	$3,948	$10,716	$12,989	$4,779	43%	8,623
2008	58.9	107.1	516,154	79.3	58,435	$0	$18,153	$163	$4,146	$11,440	$13,281	$4,873	43%	8,775
2009	63.6	115.6	557,089	85.8	57,240	$0	$17,798	$159	$4,036	$11,692	$13,025	$4,773	43%	8,538
2010	68.0	123.7	595,866	92.1	55,027	$0	$17,218	$152	$3,826	$11,925	$12,594	$4,624	43%	8,188
2011	72.4	131.6	634,261	98.3	54,748	$0	$17,089	$150	$3,809	$12,130	$12,498	$4,591	43%	8,079
2012	76.8	139.7	672,865	104.6	54,969	$0	$17,077	$150	$3,842	$12,330	$12,487	$4,590	43%	8,030
2013	81.2	147.7	711,643	110.9	54,902	$0	$16,999	$150	$3,849	$12,532	$12,433	$4,566	44%	7,943
TOTAL	81.2	147.7	711,643	110.9	971,159	$0	$320,422	$2,941	$60,921		$235,734	$84,688	44%	149,916

DISCOUNT RATE	5.2%
TOTAL RESOURCE COST	31.2
UTILITY COST	15.9
UTAH %	45%
WEIGHTED LIFE	30.0

ESC LOAN RATE	7.8%
AVE. ANNUAL ESC REVENUE, k$	$28,530
DESIGN/AUDIT COST ADDER	0%
ADMINISTRATIVE ADDER, DEFERRED	38%
ADMINISTRATIVE ADDER, EXPENSE	1%

FRACTION OF NET SALES	0%
SUPPLEMENTAL SAVED ADDED	11%
SUPPLEMENTAL COST ADDED	42%
OTHER FINANCE	0%

NEW COMMERCIAL (FINANSWER)
PROGRAM PENETRATION

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah
1994	10.6%	9.0%	1.8%	0.0%	2.6%	3.3%	3.3%	0.0%	6.9%
1995	12.7%	8.1%	3.5%	0.0%	3.4%	4.1%	4.3%	0.0%	11.3%
1996	14.3%	10.2%	3.6%	0.0%	4.8%	4.9%	4.4%	0.0%	14.1%
1997	15.1%	10.2%	4.7%	0.0%	6.0%	5.6%	4.9%	0.0%	19.3%
1998	15.1%	12.1%	5.1%	0.0%	6.4%	6.1%	5.5%	0.0%	21.8%
1999	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2000	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2001	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2002	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2003	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2004	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2005	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2006	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2007	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2008	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2009	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2010	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2011	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2012	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2013	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%

NEW COMMERCIAL (FINANSWER)
CUMULATIVE FREE RIDERSHIP, MWH

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	620	35	23	0	16	27	69	0	558	773	574	1,347
1995	735	27	57	0	19	33	95	0	960	948	979	1,927
1996	802	38	55	0	27	38	99	0	1,061	1,032	1,088	2,119
1997	898	36	74	0	35	44	108	0	1,408	1,161	1,443	2,604
1998	970	76	87	0	33	55	135	0	1,613	1,323	1,646	2,969
1999	4,956	497	1,283	185	380	699	1,826	156	6,259	9,445	6,796	16,240
2000	5,216	525	1,287	187	377	729	1,810	149	6,632	9,754	7,158	16,912
2001	5,340	543	1,289	184	373	746	1,785	145	5,811	9,886	6,330	16,216
2002	5,334	550	1,284	179	365	750	1,755	141	6,369	9,853	6,876	16,729
2003	5,544	567	1,295	180	367	777	1,738	138	6,108	10,101	6,612	16,714
2004	5,618	578	1,300	178	364	789	1,720	131	5,921	10,183	6,416	16,599
2005	5,433	577	1,282	172	350	780	1,684	123	6,367	9,929	6,840	16,769
2006	5,259	578	1,267	166	338	775	1,652	116	6,543	9,696	6,997	16,693
2007	5,576	602	1,274	168	339	823	1,645	111	6,774	10,088	7,224	17,312
2008	5,287	594	1,260	160	325	798	1,613	106	6,827	9,712	7,258	16,969
2009	4,869	565	1,231	146	304	737	1,572	100	6,780	9,120	7,184	16,305
2010	4,805	559	1,219	137	298	725	1,552	94	6,861	8,997	7,253	16,250
2011	4,830	563	1,215	129	296	728	1,538	91	6,964	9,002	7,351	16,353
2012	4,863	573	1,191	121	290	744	1,521	86	6,977	9,012	7,353	16,365
2013	4,708	575	1,169	109	281	738	1,501	81	6,961	8,801	7,323	16,123
Total	4,708	575	1,169	109	281	738	1,501	81	6,961	8,801	7,323	16,123

Appendix H - Program Summaries: Medium Case Forecast

NEW COMMERCIAL (FINANSWER)
INCREMENTAL GROSS SAVINGS, MWh

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	6,222	294	1,095	0	517	86	356	0	12,331	8,053	12,847	20,900
1995	6,501	425	1,581	0	746	110	459	0	12,883	9,075	13,629	22,704
1996	6,778	491	1,824	0	861	158	662	0	13,435	9,914	14,296	24,210
1997	6,964	491	1,824	0	861	183	763	0	13,803	10,226	14,664	24,890
1998	6,964	491	1,824	0	861	183	763	0	13,803	10,226	14,664	24,890
1999	16,656	1,145	4,209	481	914	1,741	4,339	343	17,824	28,571	19,081	47,653
2000	17,050	1,199	4,214	469	905	1,781	4,308	338	19,764	29,021	21,007	50,027
2001	17,785	1,260	4,213	475	900	1,861	4,273	323	20,775	29,867	21,998	51,864
2002	18,102	1,296	4,205	467	890	1,904	4,214	314	18,570	30,188	19,775	49,963
2003	18,020	1,309	4,173	455	873	1,913	4,144	306	20,060	30,014	21,238	51,253
2004	18,597	1,344	4,191	456	877	1,986	4,104	299	19,361	30,677	20,538	51,215
2005	18,802	1,364	4,194	452	873	2,017	4,061	285	18,961	30,890	20,119	51,009
2006	18,184	1,358	4,117	437	839	1,992	3,975	265	20,133	30,062	21,237	51,299
2007	17,615	1,354	4,043	420	808	1,980	3,896	249	20,586	29,307	21,643	50,950
2008	18,528	1,407	4,041	425	813	2,108	3,879	240	21,202	30,388	22,256	52,644
2009	17,621	1,381	3,974	405	778	2,043	3,802	227	21,338	29,225	22,343	51,568
2010	16,316	1,308	3,859	368	725	1,883	3,702	214	21,199	27,436	22,138	49,574
2011	16,062	1,288	3,798	345	707	1,852	3,653	202	21,417	26,997	22,325	49,323
2012	16,074	1,292	3,759	324	701	1,864	3,617	196	21,696	26,929	22,593	49,522
2013	16,101	1,313	3,664	302	686	1,906	3,575	183	21,730	26,861	22,600	49,461
Total	294,942	21,807	68,801	6,279	16,136	29,551	62,546	3,984	370,872	483,926	390,992	874,918

NEW COMMERCIAL (FINANSWER)
MEASURE COST, K$
NET OF DESIGN & AUDIT COSTS AND SUPPLEMENTAL MEASURES

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$1,794	$85	$315	$0	$153	$25	$103	$0	$3,655	$2,322	$3,807	$6,129
1995	$1,629	$106	$396	$0	$192	$27	$115	$0	$3,318	$2,273	$3,510	$5,783
1996	$1,643	$119	$442	$0	$214	$38	$161	$0	$3,346	$2,402	$3,560	$5,962
1997	$1,633	$115	$427	$0	$207	$43	$179	$0	$3,325	$2,396	$3,532	$5,928
1998	$1,579	$111	$413	$0	$200	$41	$173	$0	$3,216	$2,317	$3,416	$5,733
1999	$3,626	$156	$722	$65	$106	$269	$523	$41	$3,398	$5,361	$3,545	$8,906
2000	$3,672	$160	$722	$65	$105	$274	$517	$41	$3,564	$5,409	$3,710	$9,119
2001	$3,772	$166	$720	$67	$105	$283	$511	$39	$3,644	$5,519	$3,788	$9,307
2002	$3,810	$168	$717	$66	$105	$288	$503	$38	$3,474	$5,552	$3,616	$9,169
2003	$3,786	$168	$711	$65	$103	$288	$494	$38	$3,584	$5,511	$3,724	$9,235
2004	$3,864	$171	$711	$65	$104	$296	$488	$37	$3,536	$5,595	$3,676	$9,271
2005	$3,908	$172	$711	$64	$104	$299	$482	$35	$3,547	$5,636	$3,685	$9,322
2006	$3,805	$170	$696	$63	$100	$294	$472	$32	$3,620	$5,499	$3,753	$9,252
2007	$3,714	$168	$680	$61	$96	$291	$462	$30	$3,645	$5,376	$3,771	$9,147
2008	$3,851	$173	$676	$61	$97	$306	$458	$30	$3,701	$5,525	$3,827	$9,353
2009	$3,713	$169	$662	$59	$93	$295	$449	$28	$3,706	$5,346	$3,827	$9,173
2010	$3,505	$159	$640	$54	$86	$273	$438	$26	$3,687	$5,069	$3,800	$8,869
2011	$3,450	$155	$627	$52	$84	$267	$432	$25	$3,710	$4,982	$3,819	$8,801
2012	$3,435	$155	$616	$49	$83	$266	$427	$24	$3,738	$4,948	$3,845	$8,794
2013	$3,421	$156	$599	$47	$81	$269	$421	$22	$3,739	$4,913	$3,843	$8,756
Total	$63,609	$3,002	$12,203	$903	$2,417	$4,432	$7,806	$486	$71,152	$91,954	$74,055	$166,010

NEW COMMERCIAL (FINANSWER)
NPV CUSTOMER O&M COST, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$202	$7	$9	$0	$3	$7	$13	$0	$117	$238	$120	$359
1995	$234	$7	$14	$0	$5	$7	$15	$0	$177	$278	$182	$460
1996	$257	$8	$19	$0	$6	$8	$17	$0	$232	$309	$238	$547
1997	$262	$8	$23	$0	$8	$8	$20	$0	$258	$322	$266	$588
1998	$277	$10	$26	$0	$8	$9	$22	$0	$279	$344	$287	$631
1999	$1,485	$104	$413	$45	$86	$132	$347	$29	$861	$2,526	$975	$3,501
2000	$1,535	$111	$413	$43	$84	$137	$347	$28	$1,091	$2,586	$1,203	$3,789
2001	$1,624	$118	$413	$43	$84	$146	$347	$27	$1,214	$2,690	$1,325	$4,014
2002	$1,663	$122	$413	$42	$83	$151	$343	$26	$945	$2,735	$1,053	$3,788
2003	$1,658	$124	$410	$41	$81	$153	$339	$25	$1,130	$2,724	$1,236	$3,960
2004	$1,727	$129	$412	$41	$81	$161	$337	$24	$1,042	$2,807	$1,147	$3,954
2005	$1,745	$131	$413	$40	$81	$165	$336	$23	$971	$2,830	$1,074	$3,905
2006	$1,677	$131	$405	$39	$77	$164	$329	$21	$1,124	$2,745	$1,223	$3,968
2007	$1,613	$132	$399	$37	$75	$164	$322	$20	$1,186	$2,667	$1,281	$3,948
2008	$1,718	$138	$400	$38	$75	$178	$324	$19	$1,257	$2,795	$1,351	$4,146
2009	$1,614	$136	$394	$36	$72	$173	$317	$19	$1,277	$2,669	$1,367	$4,036
2010	$1,468	$128	$384	$32	$67	$157	$308	$18	$1,265	$2,477	$1,349	$3,826
2011	$1,444	$127	$379	$29	$65	$155	$305	$17	$1,287	$2,439	$1,370	$3,809
2012	$1,451	$128	$376	$27	$65	$158	$304	$16	$1,318	$2,443	$1,399	$3,842
2013	$1,461	$130	$367	$24	$64	$163	$301	$15	$1,323	$2,447	$1,402	$3,849
Total	$25,116	$1,929	$6,083	$556	$1,169	$2,396	$4,992	$325	$18,354	$41,072	$19,849	$60,921

NEW COMMERCIAL (FINANSWER)
PARTICIPATION, 1000 SQFT

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	1,053	47	162	0	65	14	109	0	2,130	1,384	2,195	3,580
1995	1,100	68	234	0	94	18	141	0	2,226	1,560	2,319	3,879
1996	1,147	78	270	0	108	26	203	0	2,331	1,724	2,439	4,163
1997	1,178	78	270	0	108	30	234	0	2,385	1,790	2,493	4,283
1998	1,178	78	270	0	108	30	234	0	2,385	1,790	2,493	4,283
1999	3,123	184	830	64	175	256	974	57	3,171	5,431	3,403	8,834
2000	3,159	188	828	63	174	260	958	58	3,332	5,456	3,565	9,021
2001	3,244	194	824	66	175	268	943	56	3,403	5,538	3,633	9,171
2002	3,263	196	818	65	174	271	925	56	3,175	5,537	3,405	8,942
2003	3,222	195	808	64	171	269	905	55	3,290	5,462	3,517	8,979
2004	3,280	197	806	64	173	276	889	55	3,210	5,512	3,438	8,950
2005	3,284	198	802	63	174	277	874	52	3,157	5,498	3,383	8,881
2006	3,166	194	783	61	168	271	853	46	3,232	5,328	3,446	8,774
2007	3,062	192	762	59	161	268	833	42	3,245	5,175	3,448	8,623
2008	3,176	196	754	59	162	280	821	40	3,286	5,287	3,488	8,775
2009	3,023	191	735	56	154	269	802	37	3,271	5,076	3,462	8,538
2010	2,815	179	707	52	141	249	780	34	3,230	4,782	3,405	8,188
2011	2,760	175	689	49	136	244	765	30	3,232	4,680	3,399	8,079
2012	2,741	174	673	47	133	242	751	30	3,238	4,628	3,401	8,030
2013	2,723	174	649	44	129	244	737	26	3,216	4,572	3,372	7,943
Total	51,696	3,175	12,673	875	2,884	4,062	13,730	674	60,145	86,212	63,704	149,916

NEW COMMERCIAL (FINANSWER)
DEFERRED COST, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$2,201	$88	$315	$0	$188	$32	$146	$0	$3,144	$2,781	$3,332	$6,114
1995	$2,044	$111	$396	$0	$234	$36	$165	$0	$4,331	$2,751	$4,565	$7,316
1996	$2,060	$123	$442	$0	$259	$48	$223	$0	$4,193	$2,897	$4,451	$7,348
1997	$2,048	$119	$427	$0	$251	$53	$247	$0	$4,168	$2,895	$4,419	$7,314
1998	$1,986	$115	$413	$0	$243	$52	$240	$0	$4,042	$2,806	$4,285	$7,091
1999	$5,003	$153	$997	$90	$146	$371	$721	$57	$4,689	$7,336	$4,892	$12,228
2000	$5,067	$157	$996	$89	$146	$378	$713	$56	$4,918	$7,401	$5,120	$12,521
2001	$5,205	$162	$994	$93	$145	$391	$705	$54	$5,028	$7,550	$5,227	$12,778
2002	$5,258	$165	$990	$91	$144	$397	$694	$53	$4,793	$7,595	$4,991	$12,586
2003	$5,224	$165	$981	$89	$142	$397	$682	$52	$4,945	$7,538	$5,139	$12,677
2004	$5,332	$168	$981	$90	$143	$408	$673	$51	$4,879	$7,653	$5,073	$12,726
2005	$5,393	$169	$981	$89	$143	$413	$665	$48	$4,894	$7,709	$5,086	$12,795
2006	$5,250	$167	$960	$86	$138	$406	$651	$45	$4,996	$7,521	$5,179	$12,699
2007	$5,125	$165	$938	$84	$132	$402	$638	$42	$5,030	$7,352	$5,205	$12,556
2008	$5,314	$170	$932	$85	$134	$422	$632	$41	$5,107	$7,556	$5,282	$12,837
2009	$5,123	$166	$913	$81	$128	$407	$620	$38	$5,114	$7,310	$5,281	$12,591
2010	$4,837	$156	$884	$75	$119	$377	$605	$36	$5,089	$6,932	$5,243	$12,176
2011	$4,761	$152	$865	$71	$116	$368	$596	$34	$5,120	$6,813	$5,270	$12,083
2012	$4,741	$152	$851	$68	$115	$367	$589	$33	$5,159	$6,767	$5,307	$12,074
2013	$4,721	$153	$827	$65	$112	$371	$581	$31	$5,160	$6,718	$5,303	$12,021
Total	$86,695	$2,974	$16,083	$1,246	$3,177	$6,097	$10,785	$671	$94,801	$123,880	$98,650	$222,529

NEW COMMERCIAL (FINANSWER)
EXPENSE, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$0	$19	$79	$0	$0	$0	$0	$0	$0	$99	$0	$99
1995	$0	$23	$96	$0	$0	$0	$0	$0	$0	$119	$0	$119
1996	$0	$24	$102	$0	$0	$0	$0	$0	$0	$126	$0	$126
1997	$0	$23	$100	$0	$0	$0	$0	$0	$0	$124	$0	$124
1998	$0	$23	$99	$0	$0	$0	$0	$0	$0	$122	$0	$122
1999	$36	$64	$7	$1	$1	$3	$5	$0	$34	$116	$35	$151
2000	$37	$66	$7	$1	$1	$3	$5	$0	$36	$118	$37	$155
2001	$38	$68	$7	$1	$1	$3	$5	$0	$36	$121	$38	$159
2002	$38	$69	$7	$1	$1	$3	$5	$0	$35	$123	$36	$159
2003	$38	$69	$7	$1	$1	$3	$5	$0	$36	$122	$37	$160
2004	$39	$70	$7	$1	$1	$3	$5	$0	$35	$124	$37	$161
2005	$39	$71	$7	$1	$1	$3	$5	$0	$35	$125	$37	$162
2006	$38	$70	$7	$1	$1	$3	$5	$0	$36	$123	$38	$161
2007	$37	$69	$7	$1	$1	$3	$5	$0	$36	$121	$38	$159
2008	$39	$71	$7	$1	$1	$3	$5	$0	$37	$125	$38	$163
2009	$37	$69	$7	$1	$1	$3	$5	$0	$37	$121	$38	$159
2010	$35	$65	$6	$1	$1	$3	$4	$0	$37	$114	$38	$152
2011	$34	$64	$6	$1	$1	$3	$4	$0	$37	$112	$38	$150
2012	$34	$63	$6	$0	$1	$3	$4	$0	$37	$111	$38	$150
2013	$34	$64	$6	$0	$1	$3	$4	$0	$37	$112	$38	$150
Total	$553	$1,124	$579	$9	$15	$43	$71	$5	$543	$2,379	$562	$2,941

NEW COMMERCIAL (FINANSWER)
INCREMENTAL ESC REVENUE, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$206	$10	$36	$0	$18	$3	$12	$0	$420	$267	$438	$705
1995	$400	$22	$83	$0	$40	$6	$25	$0	$815	$538	$856	$1,393
1996	$602	$37	$138	$0	$67	$11	$45	$0	$1,227	$833	$1,294	$2,127
1997	$810	$52	$192	$0	$93	$16	$68	$0	$1,650	$1,138	$1,743	$2,881
1998	$1,018	$66	$246	$0	$119	$22	$91	$0	$2,073	$1,443	$2,192	$3,635
1999	$1,511	$87	$345	$9	$134	$58	$162	$6	$2,535	$2,172	$2,674	$4,846
2000	$2,027	$110	$446	$18	$149	$97	$235	$11	$3,036	$2,932	$3,196	$6,128
2001	$2,575	$134	$551	$28	$164	$138	$309	$17	$3,566	$3,735	$3,747	$7,481
2002	$3,148	$159	$659	$38	$180	$181	$384	$23	$4,088	$4,569	$4,290	$8,860
2003	$3,737	$185	$769	$48	$196	$226	$461	$29	$4,645	$5,426	$4,869	$10,295
2004	$4,358	$213	$883	$58	$212	$274	$540	$35	$5,213	$6,325	$5,460	$11,785
2005	$5,007	$242	$1,002	$69	$229	$323	$620	$40	$5,803	$7,262	$6,072	$13,335
2006	$5,661	$271	$1,121	$80	$247	$374	$701	$46	$6,425	$8,207	$6,717	$14,924
2007	$6,321	$301	$1,242	$90	$264	$426	$783	$51	$7,072	$9,162	$7,387	$16,550
2008	$7,029	$332	$1,366	$102	$282	$482	$867	$57	$7,752	$10,177	$8,091	$18,268
2009	$7,527	$355	$1,456	$113	$282	$535	$941	$62	$8,036	$10,926	$8,380	$19,306
2010	$8,022	$373	$1,534	$123	$276	$585	$1,013	$67	$8,366	$11,651	$8,708	$20,360
2011	$8,521	$390	$1,607	$134	$266	$635	$1,081	$72	$8,708	$12,368	$9,046	$21,414
2012	$9,035	$408	$1,682	$144	$258	$685	$1,148	$77	$9,070	$13,102	$9,405	$22,507
2013	$9,570	$428	$1,758	$155	$249	$738	$1,216	$82	$9,459	$13,865	$9,790	$23,654

ENERGY FINANSWER 12,000
SUMMARY REPORT
ALL COSTS IN REAL $, INCLUDES LINE LOSSES

	CUMULATIVE					INCREMENTAL								
YEAR	ENERGY MWa	CAPACITY MW	NET ENERGY Savings MWh	REAL ESC REV, k$	GROSS MWa	GROSS ENERGY MWh	3rd Party FINANCE k$	UTILITY FINANCE k$	UTILITY EXPENSE k$	NPV CUSTOMER O & M k$	TOTAL MEASURE COST k$	DEFERRED OVERHEAD k$	PENETRATION RATE	PARTICIPATION k SQFT
1994	0.4	0.7	3,216	$188	0.5	4,448	$0	$1,577	$12	$298	$1,240	$337	0.27%	1,152
1995	0.8	1.5	3,901	$421	1.2	5,767	$0	$2,004	$16	$375	$1,575	$428	0.35%	1,485
1996	1.4	2.5	4,881	$693	2.0	7,051	$0	$2,401	$19	$446	$1,887	$513	0.38%	1,819
1997	2.0	3.6	5,417	$996	2.9	8,169	$0	$2,725	$21	$490	$2,142	$583	0.41%	2,109
1998	2.6	4.8	5,540	$1,305	3.9	8,863	$0	$2,867	$23	$532	$2,254	$613	0.41%	2,289
1999	4.3	7.8	14,772	$2,512	6.5	22,964	$0	$10,478	$82	$1,385	$8,238	$2,241	1.17%	6,281
2000	6.3	11.5	17,792	$3,895	9.7	27,306	$0	$12,289	$97	$1,716	$9,661	$2,628	1.28%	7,304
2001	8.5	15.4	18,667	$5,253	12.8	27,871	$0	$12,452	$98	$1,812	$9,789	$2,663	1.18%	7,343
2002	10.5	19.1	17,612	$6,532	15.9	26,857	$0	$12,172	$96	$1,731	$9,569	$2,603	1.05%	7,164
2003	12.5	22.8	17,988	$7,768	19.0	27,145	$0	$12,165	$96	$1,802	$9,563	$2,601	0.96%	7,092
2004	14.6	26.5	17,915	$8,962	22.1	26,984	$0	$12,150	$96	$1,809	$9,552	$2,598	0.89%	7,050
2005	16.6	30.2	17,718	$10,106	25.1	26,695	$0	$12,064	$95	$1,799	$9,485	$2,580	0.82%	6,960
2006	18.6	33.8	17,620	$11,187	28.1	26,473	$0	$11,844	$93	$1,827	$9,312	$2,533	0.73%	6,760
2007	20.6	37.4	17,114	$12,204	31.1	26,062	$0	$11,608	$91	$1,822	$9,126	$2,482	0.66%	6,564
2008	22.6	41.1	17,903	$13,214	34.2	26,664	$0	$11,834	$93	$1,912	$9,303	$2,531	0.64%	6,635
2009	24.6	44.7	17,430	$14,035	37.1	25,927	$0	$11,477	$90	$1,872	$9,023	$2,454	0.57%	6,375
2010	26.5	48.1	16,389	$14,739	40.0	24,817	$0	$10,982	$86	$1,789	$8,634	$2,348	0.49%	6,041
2011	28.3	51.5	16,189	$15,376	42.8	24,570	$0	$10,859	$85	$1,788	$8,537	$2,322	0.46%	5,918
2012	30.2	54.9	16,228	$15,962	45.6	24,495	$0	$10,804	$85	$1,809	$8,494	$2,310	0.44%	5,833
2013	32.0	58.2	16,117	$16,504	48.3	24,235	$0	$10,678	$84	$1,819	$8,395	$2,283	0.41%	5,703
TOTAL	32.0	58.2	16,117		48.3	423,364	$0	$185,430	$1,458	$28,832	$145,778	$39,652	0.41%	107,878

DISCOUNT RATE	5.2%
TOTAL RESOURCE (	41.0
UTILITY COST	22.4
UTAH %	41%
WEIGHTED LIFE	30.0

ESC LOAN RATE	7.45%
AVE. ANNUAL ESC REVENUE, k$	$17,390
DESIGN/AUDIT COST ADDER	0%
ADMINISTRATIVE ADDER, DEFERRED	27%
ADMINISTRATIVE ADDER, EXPENSE	1%

FRACTION OF NET SALES
SUPPLEMENTAL SAVED ADDED
SUPPLEMENTAL COST ADDED
OTHER FINANCE

Where is supplemental

ENERGY FINANSWER 12,000
PROGRAM PENETRATION

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah
1994	19.4%	17.9%	3.4%	0.0%	6.1%	7.6%	4.1%	0.0%	12.2%
1995	24.0%	15.7%	7.3%	0.0%	7.8%	9.6%	5.3%	0.0%	19.5%
1996	27.2%	19.6%	6.9%	0.0%	11.2%	11.4%	5.5%	0.0%	24.7%
1997	29.6%	19.0%	9.4%	0.0%	13.9%	13.1%	6.1%	0.0%	33.3%
1998	30.2%	24.5%	10.2%	0.0%	14.6%	14.2%	6.9%	0.0%	37.2%
1999	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%	65.0%
2000	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2001	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2002	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2003	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2004	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2005	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2006	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2007	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2008	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2009	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2010	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2011	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2012	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%
2013	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%	75.0%

ENERGY FINANSWER 12,000
CUMULATIVE FREE RIDERSHIP, MWH

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	324	16	7	0	11	24	98	0	752	469	763	1,231
1995	390	13	21	0	13	30	136	0	1,263	590	1,276	1,866
1996	421	19	19	0	18	36	141	0	1,516	636	1,534	2,170
1997	470	15	26	0	23	42	153	0	2,023	706	2,046	2,752
1998	517	33	31	0	21	53	191	0	2,477	825	2,498	3,323
1999	1,114	87	199	84	91	245	1,774	104	4,494	3,503	4,688	8,191
2000	1,302	102	228	100	103	293	2,014	114	5,258	4,039	5,476	9,515
2001	1,292	102	226	99	101	298	1,975	115	4,997	3,992	5,212	9,204
2002	1,261	100	222	97	97	298	1,933	114	5,122	3,912	5,333	9,245
2003	1,268	101	221	97	97	307	1,900	115	5,051	3,894	5,263	9,157
2004	1,253	101	220	97	95	310	1,871	109	5,012	3,852	5,216	9,069
2005	1,196	98	214	94	89	306	1,827	99	5,055	3,734	5,243	8,977
2006	1,148	95	207	92	83	302	1,785	93	5,048	3,629	5,224	8,854
2007	1,179	97	205	92	83	318	1,760	92	5,121	3,651	5,296	8,948
2008	1,111	93	199	89	77	307	1,721	87	5,077	3,520	5,241	8,761
2009	1,031	85	190	83	69	284	1,675	81	5,000	3,347	5,150	8,497
2010	1,007	81	185	79	66	277	1,643	77	5,013	3,273	5,155	8,428
2011	995	80	180	76	64	276	1,616	77	5,018	3,223	5,159	8,381
2012	981	79	173	72	61	279	1,588	71	4,962	3,173	5,094	8,267
2013	941	77	166	67	57	275	1,559	66	4,910	3,086	5,033	8,118
Total	941	77	166	67	57	275	1,559	66	4,910	3,086	5,033	8,118

Appendix H - Program Summaries: Medium Case Forecast

ENERGY FINANSWER 12,000
INCREMENTAL GROSS SAVINGS, MWh

YEAR	Oregon	California	Washingtog	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	2,239	67	96	0	35	77	178	0	1,791	2,656	1,826	4,483
1995	2,519	77	144	0	48	88	205	0	2,686	3,032	2,735	5,767
1996	2,798	86	191	0	65	99	230	0	3,582	3,404	3,647	7,051
1997	2,910	95	240	0	81	111	255	0	4,477	3,610	4,559	8,169
1998	3,078	105	264	0	89	121	281	0	4,926	3,848	5,015	8,863
1999	7,170	480	1,852	202	337	631	2,952	192	9,149	13,286	9,678	22,964
2000	8,360	564	2,104	229	383	743	3,360	223	11,341	15,360	11,947	27,306
2001	8,588	581	2,066	234	379	777	3,312	214	11,721	15,557	12,313	27,871
2002	8,609	588	2,023	231	372	796	3,250	213	10,775	15,497	11,360	26,857
2003	8,453	584	1,963	227	360	802	3,184	211	11,361	15,212	11,933	27,145
2004	8,603	591	1,937	228	360	833	3,134	211	11,088	15,325	11,659	26,984
2005	8,566	594	1,899	227	357	849	3,089	201	10,914	15,224	11,472	26,695
2006	8,184	581	1,809	221	336	841	3,016	185	11,300	14,652	11,821	26,473
2007	7,850	571	1,724	214	318	838	2,947	175	11,426	14,143	11,919	26,062
2008	8,169	588	1,685	216	320	893	2,912	172	11,710	14,462	12,202	26,664
2009	7,677	567	1,603	208	300	870	2,846	163	11,695	13,770	12,157	25,927
2010	7,051	523	1,493	192	270	805	2,768	154	11,560	12,833	11,984	24,817
2011	6,898	506	1,418	183	259	792	2,718	145	11,650	12,516	12,054	24,570
2012	6,849	500	1,357	174	254	799	2,676	145	11,743	12,354	12,141	24,495
2013	6,796	502	1,262	164	244	819	2,632	135	11,681	12,176	12,059	24,235
Total	131,364	8,748	27,129	3,148	5,166	12,585	45,945	2,738	186,577	228,919	194,481	423,399

ENERGY FINANSWER 12,000
MEASURE COST, K$
NET OF DESIGN & AUDIT COSTS AND SUPPLEMENTAL MEASURES

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$498	$20	$29	$0	$10	$23	$56	$0	$557	$625	$567	$1,192
1995	$541	$22	$42	$0	$15	$26	$61	$0	$807	$693	$822	$1,515
1996	$582	$24	$54	$0	$19	$28	$67	$0	$1,041	$755	$1,060	$1,815
1997	$585	$26	$65	$0	$23	$30	$72	$0	$1,259	$778	$1,281	$2,060
1998	$599	$28	$70	$0	$24	$32	$76	$0	$1,339	$804	$1,363	$2,167
1999	$2,821	$184	$597	$63	$98	$140	$980	$57	$2,982	$4,784	$3,137	$7,921
2000	$3,281	$215	$682	$72	$113	$164	$1,113	$66	$3,584	$5,527	$3,763	$9,290
2001	$3,359	$220	$673	$75	$112	$171	$1,095	$63	$3,644	$5,593	$3,820	$9,412
2002	$3,361	$222	$663	$74	$111	$174	$1,074	$64	$3,459	$5,568	$3,633	$9,201
2003	$3,299	$220	$648	$73	$108	$175	$1,052	$63	$3,559	$5,466	$3,730	$9,195
2004	$3,350	$223	$643	$73	$108	$180	$1,034	$64	$3,511	$5,502	$3,683	$9,185
2005	$3,333	$223	$635	$73	$108	$183	$1,018	$61	$3,487	$5,465	$3,655	$9,120
2006	$3,191	$218	$611	$71	$103	$180	$995	$55	$3,530	$5,265	$3,688	$8,953
2007	$3,068	$214	$587	$69	$98	$179	$972	$52	$3,536	$5,089	$3,686	$8,775
2008	$3,184	$220	$578	$69	$99	$189	$959	$51	$3,597	$5,198	$3,747	$8,946
2009	$3,003	$212	$556	$67	$94	$183	$938	$48	$3,576	$4,958	$3,718	$8,676
2010	$2,775	$195	$526	$62	$85	$169	$913	$46	$3,530	$4,641	$3,661	$8,302
2011	$2,720	$188	$506	$59	$82	$166	$896	$43	$3,548	$4,536	$3,673	$8,209
2012	$2,702	$186	$489	$57	$81	$166	$882	$43	$3,562	$4,482	$3,686	$8,167
2013	$2,682	$186	$464	$54	$78	$169	$867	$40	$3,532	$4,422	$3,650	$8,072
Total	$48,934	$3,247	$9,116	$1,009	$1,567	$2,726	$15,119	$816	$57,638	$80,150	$60,021	$140,171

.37/kWh

.31/kWh

less savings than OR
but higher cost

Appendix H - Program Summaries: Medium Case Forecast

ENERGY FINANSWER 12,000
NPV CUSTOMER O&M COST, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$192	$6	$8	$0	$3	$5	$8	$0	$75	$220	$77	$298
1995	$225	$6	$13	$0	$4	$5	$10	$0	$111	$260	$115	$375
1996	$252	$7	$17	$0	$5	$6	$11	$0	$149	$292	$154	$446
1997	$266	$7	$22	$0	$6	$6	$12	$0	$171	$313	$177	$490
1998	$286	$9	$24	$0	$7	$7	$14	$0	$186	$339	$192	$532
1999	$648	$38	$159	$17	$25	$38	$142	$7	$310	$1,042	$342	$1,385
2000	$771	$46	$182	$19	$29	$45	$165	$8	$451	$1,229	$487	$1,716
2001	$811	$49	$181	$19	$28	$48	$165	$8	$503	$1,273	$539	$1,812
2002	$831	$51	$179	$18	$28	$50	$164	$7	$403	$1,293	$438	$1,731
2003	$830	$52	$175	$18	$27	$51	$163	$7	$479	$1,289	$514	$1,802
2004	$863	$54	$175	$18	$27	$53	$163	$7	$448	$1,326	$483	$1,809
2005	$875	$55	$173	$18	$27	$55	$163	$7	$427	$1,339	$460	$1,799
2006	$847	$55	$168	$18	$26	$54	$161	$6	$492	$1,303	$524	$1,827
2007	$821	$55	$163	$17	$25	$55	$159	$6	$521	$1,270	$552	$1,822
2008	$872	$58	$162	$17	$25	$59	$160	$6	$553	$1,328	$584	$1,912
2009	$828	$57	$157	$17	$24	$58	$158	$6	$566	$1,275	$596	$1,872
2010	$766	$55	$150	$15	$22	$54	$154	$6	$567	$1,194	$595	$1,789
2011	$758	$54	$146	$14	$22	$53	$154	$5	$581	$1,180	$608	$1,788
2012	$763	$55	$143	$13	$22	$54	$154	$5	$599	$1,183	$626	$1,809
2013	$770	$56	$137	$12	$21	$57	$154	$5	$607	$1,186	$633	$1,819
Total	$13,275	$824	$2,536	$252	$403	$813	$2,433	$96	$8,200	$20,134	$8,698	$28,832

ENERGY FINANSWER 12,000
PARTICIPATION, 1000 SQFT

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	569	17	24	0	8	20	47	0	468	676	476	1,152
1995	640	19	36	0	13	22	53	0	702	771	714	1,485
1996	711	22	49	0	17	25	60	0	935	866	952	1,819
1997	739	24	61	0	21	28	67	0	1,169	919	1,190	2,109
1998	782	27	67	0	23	31	73	0	1,286	979	1,309	2,289
1999	2,193	148	615	38	93	89	828	45	2,230	3,913	2,368	6,281
2000	2,537	172	696	44	106	105	938	54	2,651	4,493	2,811	7,304
2001	2,582	176	681	46	105	108	921	51	2,674	4,513	2,831	7,343
2002	2,566	176	664	45	103	109	901	52	2,549	4,460	2,704	7,164
2003	2,500	173	641	44	100	109	879	52	2,595	4,346	2,746	7,092
2004	2,520	174	629	44	100	111	862	52	2,557	4,340	2,710	7,050
2005	2,488	173	613	44	100	112	846	49	2,535	4,276	2,684	6,960
2006	2,360	168	580	43	94	109	824	44	2,538	4,084	2,676	6,760
2007	2,251	163	548	42	88	107	803	41	2,522	3,913	2,652	6,564
2008	2,319	167	531	42	89	112	789	41	2,546	3,959	2,676	6,635
2009	2,166	159	500	40	83	107	768	38	2,513	3,741	2,634	6,375
2010	1,980	145	460	37	74	98	746	36	2,465	3,466	2,575	6,041
2011	1,924	138	431	36	70	95	729	33	2,462	3,353	2,565	5,918
2012	1,894	135	406	34	68	94	714	33	2,453	3,278	2,555	5,833
2013	1,862	134	371	33	65	94	699	30	2,415	3,193	2,510	5,703
Total	37,582	2,511	8,602	612	1,422	1,685	12,547	652	42,265	63,539	44,339	107,878

Appendix H - Program Summaries: Medium Case Forecast

ENERGY FINANSWER 12,000
DEFERRED COST, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$0	$0	$0	$0	$0	$0	$0	$0	$635	$0	$635	$635
1995	$905	$28	$52	$0	$17	$32	$74	$0	$965	$1,089	$982	$2,072
1996	$1,018	$31	$70	$0	$24	$36	$84	$0	$1,304	$1,239	$1,328	$2,567
1997	$1,073	$35	$88	$0	$30	$41	$94	$0	$1,651	$1,331	$1,681	$3,012
1998	$1,138	$39	$97	$0	$33	$45	$104	$0	$1,821	$1,423	$1,854	$3,277
1999	$3,867	$259	$999	$109	$182	$340	$1,592	$104	$0	$7,165	$285	$7,451
2000	$4,598	$310	$1,157	$126	$210	$409	$1,848	$123	$6,238	$8,448	$6,571	$15,019
2001	$4,849	$328	$1,166	$132	$214	$439	$1,870	$121	$6,617	$8,783	$6,952	$15,735
2002	$5,098	$348	$1,198	$137	$220	$472	$1,925	$126	$6,381	$9,178	$6,727	$15,905
2003	$5,118	$353	$1,189	$137	$218	$486	$1,928	$128	$6,879	$9,210	$7,225	$16,435
2004	$5,411	$372	$1,218	$143	$227	$524	$1,971	$133	$6,975	$9,640	$7,334	$16,974
2005	$5,592	$387	$1,240	$148	$233	$554	$2,017	$131	$7,125	$9,938	$7,489	$17,427
2006	$5,469	$388	$1,209	$147	$225	$562	$2,015	$123	$7,552	$9,792	$7,900	$17,691
2007	$5,400	$392	$1,186	$147	$219	$576	$2,027	$120	$7,860	$9,729	$8,199	$17,928
2008	$5,789	$417	$1,194	$153	$227	$633	$2,064	$122	$8,299	$10,250	$8,648	$18,898
2009	$5,611	$414	$1,172	$152	$219	$636	$2,080	$119	$8,548	$10,065	$8,886	$18,951
2010	$5,327	$395	$1,128	$145	$204	$608	$2,092	$116	$8,734	$9,696	$9,054	$18,750
2011	$5,382	$395	$1,107	$142	$202	$618	$2,121	$113	$9,090	$9,766	$9,406	$19,171
2012	$5,514	$402	$1,093	$140	$204	$643	$2,155	$116	$9,455	$9,947	$9,776	$19,723
2013	$5,652	$417	$1,049	$137	$203	$681	$2,189	$112	$9,714	$10,126	$10,029	$20,155
Total	$82,813	$5,713	$17,611	$2,096	$3,310	$8,335	$30,248	$1,807	$115,843	$146,816	$120,961	$267,777

ENERGY FINANSWER 12,000
EXPENSE, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$0	$5	$12	$0	$0	$0	$0	$0	$0	$17	$0	$17
1995	$0	$5	$12	$0	$0	$0	$0	$0	$0	$17	$0	$17
1996	$0	$5	$12	$0	$0	$0	$0	$0	$0	$17	$0	$17
1997	$0	$5	$13	$0	$0	$0	$0	$0	$0	$18	$0	$18
1998	$0	$5	$13	$0	$0	$0	$0	$0	$0	$18	$0	$18
1999	$15	$1	$3	$0	$1	$1	$5	$0	$16	$26	$17	$42
2000	$18	$1	$4	$0	$1	$1	$6	$0	$19	$30	$20	$50
2001	$18	$1	$4	$0	$1	$1	$6	$0	$19	$30	$20	$50
2002	$18	$1	$4	$0	$1	$1	$6	$0	$19	$30	$19	$49
2003	$18	$1	$3	$0	$1	$1	$6	$0	$19	$29	$20	$49
2004	$18	$1	$3	$0	$1	$1	$6	$0	$19	$29	$20	$49
2005	$18	$1	$3	$0	$1	$1	$5	$0	$19	$29	$20	$49
2006	$17	$1	$3	$0	$1	$1	$5	$0	$19	$28	$20	$48
2007	$16	$1	$3	$0	$1	$1	$5	$0	$19	$27	$20	$47
2008	$17	$1	$3	$0	$1	$1	$5	$0	$19	$28	$20	$48
2009	$16	$1	$3	$0	$1	$1	$5	$0	$19	$27	$20	$46
2010	$15	$1	$3	$0	$0	$1	$5	$0	$19	$25	$20	$44
2011	$15	$1	$3	$0	$0	$1	$5	$0	$19	$24	$20	$44
2012	$14	$1	$3	$0	$0	$1	$5	$0	$19	$24	$20	$44
2013	$14	$1	$2	$0	$0	$1	$5	$0	$19	$24	$20	$43
Total	$247	$41	$109	$5	$8	$14	$79	$4	$282	$496	$294	$790

ENERGY FINANSWER 12,000
INCREMENTAL ESC REVENUE, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$79	$3	$5	$0	$2	$4	$9	$0	$88	$99	$89	$188
1995	$85	$4	$7	$0	$2	$4	$10	$0	$127	$109	$130	$239
1996	$92	$4	$9	$0	$3	$4	$11	$0	$164	$119	$167	$286
1997	$92	$4	$10	$0	$4	$5	$11	$0	$199	$123	$202	$325
1998	$94	$4	$11	$0	$4	$5	$12	$0	$211	$127	$215	$342
1999	$445	$29	$94	$10	$16	$22	$155	$9	$471	$755	$495	$1,250
2000	$518	$34	$108	$11	$18	$26	$176	$10	$565	$872	$594	$1,466
2001	$530	$35	$106	$12	$18	$27	$173	$10	$575	$883	$603	$1,485
2002	$530	$35	$105	$12	$17	$27	$169	$10	$546	$879	$573	$1,452
2003	$521	$35	$102	$11	$17	$28	$166	$10	$562	$863	$589	$1,451
2004	$529	$35	$101	$11	$17	$28	$163	$10	$554	$868	$581	$1,449
2005	$526	$35	$100	$11	$17	$29	$161	$10	$550	$862	$577	$1,439
2006	$504	$34	$96	$11	$16	$28	$157	$9	$557	$831	$582	$1,413
2007	$484	$34	$93	$11	$15	$28	$153	$8	$558	$803	$582	$1,385
2008	$502	$35	$91	$11	$16	$30	$151	$8	$568	$820	$591	$1,412
2009	$474	$33	$88	$11	$15	$29	$148	$8	$564	$782	$587	$1,369
2010	$438	$31	$83	$10	$13	$27	$144	$7	$557	$732	$578	$1,310
2011	$429	$30	$80	$9	$13	$26	$141	$7	$560	$716	$580	$1,295
2012	$426	$29	$77	$9	$13	$26	$139	$7	$562	$707	$582	$1,289
2013	$423	$29	$73	$9	$12	$27	$137	$6	$557	$698	$576	$1,274
Total	$7,722	$512	$1,439	$159	$247	$430	$2,386	$129	$9,095	$12,648	$9,471	$22,119

SUPER GOOD CENTS
SUMMARY REPORT
ALL COSTS IN REAL $, INCLUDES LINE LOSSES

	CUMULATIVE			INCREMENTAL									CUMULATIVE
YEAR	NET ENERGY MWa	NET ENERGY SAVINGS MWh	GROSS MWa	GROSS ENERGY MWh	3rd Party FINANCE k$	UTILITY FINANCE k$	UTILITY EXPENSE k$	NPV CUSTOMER O & M k$	INCENTIVE COST k$	TOTAL MEASURE COST k$	DEFERRED OVERHEAD k$	PENETRA-TION RATE	PARTICIPATION SF & MF HOMES
1994	0.5	4,434	0.5	4,434	$0	$0	$1,000	($895)	$2,408	$2,270	$1,380	28.1%	1,496
1995	1.1	9,512	1.1	5,078	$0	$0	$987	($878)	$2,661	$2,679	$1,362	33.7%	3,190
1996	1.7	15,218	1.7	5,705	$0	$0	$970	($878)	$2,904	$3,042	$1,347	38.7%	5,095
1997	2.5	21,822	2.5	6,604	$0	$0	$967	($893)	$3,255	$3,548	$1,332	43.6%	7,298
1998	3.4	29,510	3.4	7,688	$0	$0	$976	($892)	$3,663	$4,161	$1,317	48.5%	9,854
1999	4.5	39,017	4.5	9,507	$0	$0	$670	($821)	$4,780	$5,958	$983	48.8%	12,831
2000	5.8	50,393	5.8	11,376	$0	$0	$959	$4,771	$0	$7,188	$0	49.1%	16,369
2001	7.4	64,429	7.4	14,036	$0	$0	$1,157	$5,919	$0	$8,906	$0	48.8%	20,731
2002	9.0	78,620	9.0	14,190	$0	$0	$1,434	$5,958	$0	$8,978	$0	48.4%	25,083
2003	10.6	92,881	10.6	14,261	$0	$0	$1,445	$5,972	$0	$9,006	$0	47.3%	29,394
2004	12.4	108,386	12.4	15,505	$0	$0	$1,450	$6,505	$0	$9,809	$0	46.4%	34,062
2005	14.2	124,495	14.2	16,109	$0	$0	$1,579	$6,752	$0	$10,182	$0	45.3%	38,872
2006	16.0	140,238	16.0	15,743	$0	$0	$1,639	$6,580	$0	$9,928	$0	43.7%	43,524
2007	17.8	156,037	17.8	15,799	$0	$0	$1,598	$6,597	$0	$9,957	$0	42.3%	48,154
2008	19.8	173,527	19.8	17,489	$0	$0	$1,603	$7,342	$0	$11,072	$0	41.4%	53,307
2009	21.7	189,818	21.7	16,291	$0	$0	$1,783	$6,817	$0	$10,288	$0	39.9%	58,040
2010	23.4	204,668	23.4	14,851	$0	$0	$1,656	$6,186	$0	$9,341	$0	38.1%	62,289
2011	25.1	219,595	25.1	14,926	$0	$0	$1,504	$6,218	$0	$9,389	$0	37.0%	66,540
2012	26.8	234,728	26.8	15,134	$0	$0	$1,512	$6,313	$0	$9,531	$0	36.1%	70,842
2013	28.5	249,896	28.5	15,168	$0	$0	$1,535	$6,334	$0	$9,562	$0	35.6%	75,147
TOTAL	28.5	249,896	28.5	249,896	$0	$0	$26,426	$83,007		$154,796	$7,722	36%	

TOTAL RESOURCE COST	30.7
UTILITY COST	12.1
WEIGHTED LIFE	44.8

ADMINISTRATIVE ADDER, DEFERRED	16.5%
ADMINISTRATIVE ADDER, EXPENSE	16.1%

SUPER GOOD CENTS
PROGRAM PENETRATION

	Super Good Cents Beyond Code		SGC Beyond MCS	Added Program SGC	Manufactured Housing Programs		
YEAR	OR, WA, ID	CA	MT	WY	HUD Standard	MAP	SGC - MH UT, WY
1994	30.0%	15.0%	15.0%	20.0%		100.0%	30.0%
1995	35.0%	25.0%	25.0%	25.0%	100.0%	100.0%	35.0%
1996	40.0%	30.0%	30.0%	30.0%	100.0%	100.0%	40.0%
1997	45.0%	35.0%	35.0%	35.0%	100.0%	100.0%	45.0%
1998	50.0%	40.0%	40.0%	40.0%	100.0%	100.0%	50.0%
1999	50.0%	45.0%	45.0%	45.0%	100.0%	100.0%	50.0%
2000	50.0%	50.0%	50.0%	50.0%	100.0%	100.0%	50.0%
2001	50.0%	50.0%	50.0%	50.0%	100.0%	100.0%	50.0%
2002	50.0%	50.0%	50.0%	50.0%	100.0%	100.0%	50.0%
2003	50.0%	50.0%	50.0%	50.0%	100.0%	100.0%	50.0%
2004	50.0%	50.0%	50.0%	50.0%	100.0%	100.0%	50.0%
2005	50.0%	50.0%	50.0%	50.0%	100.0%	100.0%	50.0%
2006	50.0%	50.0%	50.0%	50.0%	100.0%	100.0%	50.0%
2007	50.0%	50.0%	50.0%	50.0%	100.0%	100.0%	50.0%
2008	50.0%	50.0%	50.0%	50.0%	100.0%	100.0%	50.0%
2009	50.0%	50.0%	50.0%	50.0%	100.0%	100.0%	50.0%
2010	50.0%	50.0%	50.0%	50.0%	100.0%	100.0%	50.0%
2011	50.0%	50.0%	50.0%	50.0%	100.0%	100.0%	50.0%
2012	50.0%	50.0%	50.0%	50.0%	100.0%	100.0%	50.0%
2013	50.0%	50.0%	50.0%	50.0%	100.0%	100.0%	50.0%
Total	950.0%	890.0%	890.0%	895.0%	1900.0%	2000.0%	950.0%

SUPER GOOD CENTS
SINGLE-FAMILY DWELLING PARTICIPANTS

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	813	45	108	12	38	14	17	3	0	1,010	41	1,051
1995	902	74	119	18	50	14	27	5	0	1,154	55	1,209
1996	1,030	93	126	20	44	16	31	7	0	1,316	51	1,367
1997	1,199	114	140	23	52	16	37	8	0	1,528	60	1,588
1998	1,396	134	160	27	62	18	46	10	0	1,780	71	1,852
1999	1,451	174	354	37	85	24	51	8	0	2,089	93	2,183
2000	1,683	224	422	48	113	28	80	9	0	2,484	122	2,606
2001	2,131	282	466	53	128	40	106	12	0	3,077	140	3,216
2002	2,085	295	549	53	140	36	102	9	0	3,118	149	3,266
2003	2,029	317	556	51	140	36	118	12	0	3,106	152	3,258
2004	2,212	343	588	54	159	43	133	14	0	3,371	172	3,543
2005	2,278	355	599	55	174	46	149	14	0	3,479	188	3,667
2006	2,179	356	583	53	178	45	157	13	0	3,372	190	3,562
2007	2,150	362	583	53	183	48	168	14	0	3,364	197	3,560
2008	2,454	396	605	57	199	56	182	17	0	3,748	216	3,963
2009	2,213	375	570	53	197	50	187	20	0	3,447	216	3,663
2010	1,959	340	533	47	186	42	187	19	0	3,107	204	3,311
2011	1,962	340	526	47	187	44	195	20	0	3,112	207	3,319
2012	1,991	346	526	47	192	45	200	21	0	3,153	213	3,366
2013	2,002	356	501	44	192	48	205	22	0	3,155	214	3,369
Total	36,114	5,318	8,611	848	2,695	704	2,374	253	0	53,969	2,947	56,916

Appendix H - Program Summaries: Medium Case Forecast

SUPER GOOD CENTS
MULTI-FAMILY PARTICIPANTS

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	335	10	59	5	5	24	9	0	0	441	5	446
1995	356	9	48	8	7	35	21	0	0	477	7	484
1996	398	7	44	8	6	46	29	0	0	532	6	538
1997	455	6	42	10	8	57	36	0	0	607	8	615
1998	518	5	44	12	10	70	46	0	0	694	10	704
1999	526	5	87	16	14	98	50	0	0	781	14	795
2000	597	4	90	20	20	124	79	0	0	913	20	932
2001	736	3	88	22	23	174	101	0	0	1,124	23	1,146
2002	702	1	91	22	26	152	94	0	0	1,060	26	1,086
2003	666	1	81	21	27	156	104	0	0	1,027	27	1,054
2004	708	1	74	21	32	178	113	0	0	1,094	32	1,126
2005	710	1	67	22	37	188	120	0	0	1,107	37	1,144
2006	665	1	55	21	40	187	123	0	0	1,050	40	1,090
2007	642	1	47	20	43	194	125	0	0	1,028	43	1,070
2008	718	1	40	22	48	230	134	0	0	1,143	48	1,190
2009	635	1	30	20	49	204	133	0	0	1,021	49	1,070
2010	552	1	20	17	47	171	131	0	0	891	47	938
2011	545	1	13	18	49	175	134	0	0	884	49	933
2012	543	1	6	17	52	183	137	0	0	885	52	937
2013	538	1	-2	17	52	194	138	0	0	884	52	936
Total	11,543	53	1,018	335	592	2,836	1,853	0	0	17,639	592	18,231

SUPER GOOD CENTS
MEASURE COST, K$
NET OF DESIGN & AUDIT COSTS AND SUPPLEMENTAL MEASURES

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$1,653	$91	$220	$34	$98	$46	$113	$15	$0	$2,156	$114	$2,270
1995	$1,834	$150	$242	$51	$130	$54	$193	$26	$0	$2,523	$156	$2,679
1996	$2,094	$189	$256	$56	$114	$66	$231	$36	$0	$2,892	$150	$3,042
1997	$2,438	$232	$285	$65	$136	$74	$279	$41	$0	$3,371	$177	$3,548
1998	$2,838	$272	$325	$76	$162	$87	$349	$51	$0	$3,948	$213	$4,161
1999	$3,750	$430	$905	$110	$241	$158	$328	$35	$0	$5,682	$276	$5,958
2000	$4,348	$554	$1,079	$140	$321	$195	$514	$37	$0	$6,830	$358	$7,188
2001	$5,500	$697	$1,189	$156	$364	$275	$673	$51	$0	$8,491	$415	$8,906
2002	$5,375	$728	$1,398	$156	$398	$243	$640	$39	$0	$8,541	$437	$8,978
2003	$5,228	$784	$1,415	$149	$401	$248	$731	$50	$0	$8,555	$451	$9,006
2004	$5,695	$847	$1,493	$157	$454	$288	$816	$59	$0	$9,296	$513	$9,809
2005	$5,858	$876	$1,519	$160	$500	$305	$903	$61	$0	$9,621	$561	$10,182
2006	$5,600	$880	$1,479	$155	$512	$302	$946	$55	$0	$9,361	$567	$9,928
2007	$5,523	$895	$1,477	$155	$528	$317	$1,001	$61	$0	$9,367	$590	$9,957
2008	$6,298	$978	$1,530	$166	$576	$374	$1,077	$74	$0	$10,423	$650	$11,072
2009	$5,678	$927	$1,442	$153	$572	$333	$1,098	$86	$0	$9,631	$657	$10,288
2010	$5,022	$841	$1,346	$137	$540	$280	$1,094	$81	$0	$8,720	$621	$9,341
2011	$5,027	$839	$1,327	$135	$545	$288	$1,140	$88	$0	$8,756	$633	$9,389
2012	$5,099	$856	$1,325	$137	$561	$298	$1,164	$92	$0	$8,879	$652	$9,531
2013	$5,125	$880	$1,262	$128	$563	$317	$1,190	$96	$0	$8,903	$659	$9,562
Total	$89,982	$12,947	$21,514	$2,474	$7,714	$4,549	$14,480	$1,135	$0	$145,946	$8,849	$154,796

Appendix H - Program Summaries: Medium Case Forecast

SUPER GOOD CENTS
DEFERRED COST, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$3,020	$97	$0	$58	$152	$105	$85	$15	$0	$3,365	$166	$3,532
1995	$3,111	$148	$0	$71	$177	$114	$119	$20	$0	$3,564	$197	$3,761
1996	$3,301	$178	$0	$75	$156	$124	$130	$23	$0	$3,808	$178	$3,987
1997	$3,555	$210	$0	$78	$168	$129	$144	$24	$0	$4,116	$192	$4,308
1998	$3,841	$238	$0	$84	$182	$139	$163	$27	$0	$4,465	$209	$4,674
1999	$3,194	$352	$765	$84	$180	$109	$86	$10	$0	$4,590	$190	$4,780
2000	$1,325	$171	$337	$40	$89	$43	$0	$0	$0	$1,915	$89	$2,004
2001	$1,675	$215	$370	$44	$101	$60	$0	$0	$0	$2,364	$101	$2,465
2002	$1,636	$224	$433	$44	$111	$53	$0	$0	$0	$2,390	$111	$2,501
2003	$1,590	$241	$437	$42	$111	$54	$0	$0	$0	$2,364	$111	$2,475
2004	$1,730	$261	$460	$44	$126	$63	$0	$0	$0	$2,558	$126	$2,684
2005	$1,778	$270	$467	$45	$138	$67	$0	$0	$0	$2,627	$138	$2,765
2006	$1,699	$271	$453	$44	$142	$66	$0	$0	$0	$2,533	$142	$2,674
2007	$1,674	$275	$451	$44	$146	$70	$0	$0	$0	$2,515	$146	$2,661
2008	$1,908	$301	$467	$47	$159	$82	$0	$0	$0	$2,805	$159	$2,964
2009	$1,719	$285	$439	$43	$158	$73	$0	$0	$0	$2,560	$158	$2,718
2010	$1,520	$259	$409	$39	$149	$62	$0	$0	$0	$2,288	$149	$2,437
2011	$1,521	$258	$402	$38	$150	$63	$0	$0	$0	$2,283	$150	$2,433
2012	$1,542	$263	$401	$39	$155	$66	$0	$0	$0	$2,310	$155	$2,464
2013	$1,549	$271	$381	$36	$155	$70	$0	$0	$0	$2,307	$155	$2,462
Total	$42,888	$4,788	$6,669	$1,040	$2,905	$1,614	$727	$119	$0	$57,726	$3,024	$60,750

SUPER GOOD CENTS
INCREMENTAL ENERGY, MWh

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	3265.1	110.7	509.4	73.4	175.5	143.4	142.3	14.3	0.0	4244.3	189.8	4434.1
1995	3580.2	166.0	510.5	106.2	234.8	187.5	266.5	26.3	0.0	4816.9	261.1	5078.0
1996	4063.6	199.9	519.5	120.8	207.4	233.8	327.5	32.9	0.0	5465.2	240.3	5705.4
1997	4705.1	240.6	556.8	137.8	246.8	277.8	400.9	38.4	0.0	6319.0	285.2	6604.2
1998	5444.8	280.1	622.3	160.4	292.9	334.3	504.8	48.3	0.0	7346.7	341.2	7687.9
1999	5646.8	735.5	1602.3	183.6	376.9	215.9	662.2	84.0	0.0	9046.4	460.9	9507.2
2000	6537.8	944.0	1894.7	234.1	502.3	222.2	1041.2	0.0	0.0	10873.9	502.3	11376.2
2001	8258.3	1186.1	2076.0	261.6	569.6	319.1	1365.5	0.0	0.0	13466.7	569.6	14036.3
2002	8059.7	1237.3	2426.5	261.6	622.9	277.4	1305.0	0.0	0.0	13567.5	622.9	14190.4
2003	7827.4	1331.8	2444.3	248.6	626.4	282.9	1499.5	0.0	0.0	13634.4	626.4	14260.9
2004	8514.8	1438.9	2567.7	262.3	711.3	329.2	1681.0	0.0	0.0	14793.8	711.3	15505.1
2005	8748.0	1489.3	2603.7	267.3	781.4	349.9	1869.5	0.0	0.0	15327.6	781.4	16109.0
2006	8352.2	1495.6	2522.9	259.4	801.8	345.2	1966.2	0.0	0.0	14941.4	801.8	15743.2
2007	8228.3	1520.8	2511.3	258.6	827.1	363.8	2089.5	0.0	0.0	14972.2	827.1	15799.3
2008	9374.9	1661.4	2592.0	278.1	901.4	427.8	2253.7	0.0	0.0	16588.0	901.4	17489.5
2009	8444.0	1575.3	2433.5	255.7	895.2	382.3	2304.7	0.0	0.0	15395.6	895.2	16290.8
2010	7462.2	1428.4	2264.5	228.3	846.2	321.2	2300.0	0.0	0.0	14004.5	846.2	14850.7
2011	7465.1	1426.3	2225.6	226.8	853.2	330.5	2399.0	0.0	0.0	14073.2	853.2	14926.4
2012	7565.6	1453.6	2213.9	228.3	877.8	341.4	2453.0	0.0	0.0	14255.8	877.8	15133.6
2013	7598.7	1495.6	2100.8	214.6	880.6	363.8	2514.0	0.0	0.0	14287.4	880.6	15168.1
Total	7598.7	1495.6	2100.8	214.6	880.6	363.8	2514.0	0.0	0.0	14287.4	880.6	15168.1

Appendix H - Program Summaries: Medium Case Forecast

LOW INCOME -- ALL STATES
SUMMARY REPORT
ALL COSTS IN REAL $, INCLUDES LINE LOSSES

	CUMULATIVE				INCREMENTAL							
YEAR	NET ENERGY MWa	NET ENERGY Savings MWh	GROSS MWa	GROSS ENERGY MWh	3rd Party FINANCE k$	UTILITY FINANCE k$	UTILITY EXPENSE k$	NPV CUSTOMER O & M k$	REAL ESC REVENUE k$	TOTAL MEASURE COST k$	DEFERRED OVERHEAD k$	JOBS COMPLETED
1994	2.1	18,626	0.0	40,153	$0	$0	$707	$707	$0	$1,895	($107)	1,579
1995	2.9	25,475	0.0	38,035	$0	$0	$686	$686	$0	$1,739	$951	1,449
1996	3.7	32,424	0.0	51,346	$0	$0	$738	$738	$0	$1,739	$951	1,449
1997	3.9	34,564	0.0	55,558	$0	$0	$716	$716	$0	$1,739	$1,287	1,449
1998	4.2	36,705	0.0	59,771	$0	$0	$695	$695	$0	$1,739	$1,287	1,449
1999	4.3	37,771	0.0	61,866	$0	$0	$337	$337	$0	$864	$639	720
2000	4.4	38,837	0.0	63,962	$0	$0	$337	$337	$0	$864	$639	720
2001	4.6	39,902	0.0	66,057	$0	$0	$337	$337	$0	$864	$639	720
2002	4.7	40,968	0.0	68,153	$0	$0	$337	$337	$0	$864	$639	720
2003	4.8	42,034	0.0	70,248	$0	$0	$337	$337	$0	$864	$639	720
2004	4.9	43,100	0.0	72,344	$0	$0	$337	$337	$0	$864	$639	720
2005	5.0	44,166	0.0	74,439	$0	$0	$337	$337	$0	$864	$639	720
2006	5.2	45,232	0.0	76,535	$0	$0	$337	$337	$0	$864	$639	720
2007	5.3	46,298	0.0	78,630	$0	$0	$337	$337	$0	$864	$639	720
2008	5.4	47,364	0.0	80,726	$0	$0	$337	$337	$0	$864	$639	720
2009	5.5	48,430	0.0	82,821	$0	$0	$337	$337	$0	$864	$639	720
2010	4.3	37,704	0.0	73,125	$0	$0	$337	$337	$0	$864	$639	720
2011	4.4	38,770	0.0	75,220	$0	$0	$337	$337	$0	$864	$639	720
2012	4.5	39,836	0.0	77,316	$0	$0	$337	$337	$0	$864	$639	720
2013	4.7	40,902	0.0	79,411	$0	$0	$337	$337	$0	$864	$639	720
TOTAL	4.7	40,902	0.0		$0	$0	$8,597	$8,597		$21,810	$13,958	18,175
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)

DISCOUNT RATE	5.2%
TOTAL RESOURCE COS	29.3
UTILITY COST	8.1
UTAH %	40%
WEIGHTED LIFE	30.0

ESC LOAN RATE	9.2%
AVE. ANNUAL ESC REVENUE, k$	$41,032
DESIGN/AUDIT COST ADDER	19%
ADMINISTRATIVE ADDER, DEFERRED	20%
ADMINISTRATIVE ADDER, EXPENSE	1%

FRACTION OF NET SALE	25%
SUPP. SAVED ADDED	15%
SUPP. COST ADDED	30%
OTHER FINANCE	50%

LOW INCOME -- ALL STATES
PARTICIPANTS

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	630	125	392	32	65	35	0	0	300	1,214	365	1,579
1995	1,130	250	784	64	130	70	0	0	600	2,298	730	3,028
1996	1,630	375	1,176	96	195	105	0	0	900	3,382	1,095	4,477
1997	2,130	500	1,568	128	260	140	0	0	1,200	4,466	1,460	5,926
1998	2,630	625	1,960	160	325	175	0	0	1,500	5,550	1,825	7,375
1999	2,945	700	2,160	176	358	192	0	0	1,563	6,174	1,921	8,095
2000	3,260	775	2,360	193	392	210	0	0	1,626	6,797	2,018	8,815
2001	3,574	850	2,560	209	425	227	0	0	1,689	7,421	2,114	9,535
2002	3,889	925	2,759	226	459	245	0	0	1,752	8,044	2,211	10,255
2003	4,204	1,000	2,959	242	492	262	0	0	1,815	8,668	2,307	10,975
2004	4,519	1,075	3,159	259	526	280	0	0	1,878	9,291	2,404	11,695
2005	4,833	1,150	3,359	275	559	297	0	0	1,941	9,915	2,500	12,415
2006	5,148	1,225	3,559	292	593	315	0	0	2,004	10,539	2,596	13,135
2007	5,463	1,300	3,759	308	626	332	0	0	2,067	11,162	2,693	13,855
2008	5,778	1,374	3,959	325	660	350	0	0	2,130	11,786	2,789	14,575
2009	6,093	1,449	4,158	341	693	367	0	0	2,193	12,409	2,886	15,295
2010	6,407	1,524	4,358	358	727	385	0	0	2,255	13,033	2,982	16,015
2011	6,722	1,599	4,558	374	760	402	0	0	2,318	13,656	3,079	16,735
2012	7,037	1,674	4,758	391	794	420	0	0	2,381	14,280	3,175	17,455
2013	7,352	1,749	4,958	407	827	437	0	0	2,444	14,904	3,271	18,175
Total	85,374	20,244	59,263	4,859	9,867	5,249	0	0	34,555	174,988	44,422	219,410

LOW INCOME -- ALL STATES
DEFERRED COST, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$824	$125	$0	$41	$85	$57	$0	$0	$520	$1,046	$604	$1,651
1995	$640	$121	$0	$43	$84	$55	$0	$0	$504	$859	$588	$1,446
1996	$726	$140	$0	$47	$93	$60	$0	$0	$531	$974	$624	$1,598
1997	$704	$136	$0	$46	$91	$58	$0	$0	$515	$944	$605	$1,550
1998	$683	$131	$0	$45	$88	$57	$0	$0	$499	$916	$587	$1,503
1999	$320	$76	$203	$17	$34	$18	$0	$0	$64	$634	$98	$732
2000	$320	$76	$203	$17	$34	$18	$0	$0	$64	$634	$98	$732
2001	$320	$76	$203	$17	$34	$18	$0	$0	$64	$634	$98	$732
2002	$320	$76	$203	$17	$34	$18	$0	$0	$64	$634	$98	$732
2003	$320	$76	$203	$17	$34	$18	$0	$0	$64	$634	$98	$732
2004	$320	$76	$203	$17	$34	$18	$0	$0	$64	$634	$98	$732
2005	$320	$76	$203	$17	$34	$18	$0	$0	$64	$634	$98	$732
2006	$320	$76	$203	$17	$34	$18	$0	$0	$64	$634	$98	$732
2007	$320	$76	$203	$17	$34	$18	$0	$0	$64	$634	$98	$732
2008	$320	$76	$203	$17	$34	$18	$0	$0	$64	$634	$98	$732
2009	$320	$76	$203	$17	$34	$18	$0	$0	$64	$634	$98	$732
2010	$320	$76	$203	$17	$34	$18	$0	$0	$64	$634	$98	$732
2011	$320	$76	$203	$17	$34	$18	$0	$0	$64	$634	$98	$732
2012	$320	$76	$203	$17	$34	$18	$0	$0	$64	$634	$98	$732
2013	$320	$76	$203	$17	$34	$18	$0	$0	$64	$634	$98	$732
Total	$8,376	$1,795	$3,046	$472	$950	$553	$0	$0	$3,528	$14,242	$4,478	$18,720

LOW INCOME -- ALL STATES
EXPENSE, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$0	$29	$678	$0	$0	$0	$0	$0	$0	$707	$0	$707
1995	$0	$28	$657	$0	$0	$0	$0	$0	$0	$686	$0	$686
1996	$0	$36	$702	$0	$0	$0	$0	$0	$0	$738	$0	$738
1997	$0	$35	$681	$0	$0	$0	$0	$0	$0	$716	$0	$716
1998	$0	$35	$661	$0	$0	$0	$0	$0	$0	$695	$0	$695
1999	$147	$35	$94	$8	$16	$8	$0	$0	$29	$292	$45	$337
2000	$147	$35	$94	$8	$16	$8	$0	$0	$29	$292	$45	$337
2001	$147	$35	$94	$8	$16	$8	$0	$0	$29	$292	$45	$337
2002	$147	$35	$94	$8	$16	$8	$0	$0	$29	$292	$45	$337
2003	$147	$35	$94	$8	$16	$8	$0	$0	$29	$292	$45	$337
2004	$147	$35	$94	$8	$16	$8	$0	$0	$29	$292	$45	$337
2005	$147	$35	$94	$8	$16	$8	$0	$0	$29	$292	$45	$337
2006	$147	$35	$94	$8	$16	$8	$0	$0	$29	$292	$45	$337
2007	$147	$35	$94	$8	$16	$8	$0	$0	$29	$292	$45	$337
2008	$147	$35	$94	$8	$16	$8	$0	$0	$29	$292	$45	$337
2009	$147	$35	$94	$8	$16	$8	$0	$0	$29	$292	$45	$337
2010	$147	$35	$94	$8	$16	$8	$0	$0	$29	$292	$45	$337
2011	$147	$35	$94	$8	$16	$8	$0	$0	$29	$292	$45	$337
2012	$147	$35	$94	$8	$16	$8	$0	$0	$29	$292	$45	$337
2013	$147	$35	$94	$8	$16	$8	$0	$0	$29	$292	$45	$337
Total	$2,210	$689	$4,783	$116	$235	$123	$0	$0	$442	$7,920	$677	$8,597

LOW INCOME -- ALL STATES
CUM. NET SAVINGS, MWa

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	853.8	134.1	885.4	34.3	67.7	47.4	0.0	0.0	395.0	1955.2	462.7	2417.9
1995	1531.5	268.2	1569.1	68.7	135.5	94.9	0.0	0.0	789.9	3532.4	925.4	4457.8
1996	2209.1	402.3	2353.1	103.0	203.2	142.3	0.0	0.0	1184.9	5209.9	1388.1	6598.0
1997	2886.7	536.5	3137.1	137.3	271.0	189.7	0.0	0.0	1579.8	6887.4	1850.8	8738.2
1998	3564.4	670.6	3921.1	171.7	338.7	237.2	0.0	0.0	1974.8	8564.9	2313.5	10878.4
1999	3991.0	751.0	4320.9	189.4	373.6	260.9	0.0	0.0	2057.7	9513.1	2431.3	11944.4
2000	4417.6	831.4	4720.6	207.1	408.5	284.6	0.0	0.0	2140.5	10461.2	2549.1	13010.3
2001	4844.2	911.8	5120.3	224.7	443.4	308.3	0.0	0.0	2223.4	11409.4	2666.8	14076.2
2002	5270.9	992.2	5520.0	242.4	478.3	332.0	0.0	0.0	2306.3	12357.5	2784.6	15142.1
2003	5697.5	1072.7	5919.7	260.1	513.2	355.7	0.0	0.0	2389.2	13305.7	2902.4	16208.0
2004	6124.1	1153.1	6319.5	277.8	548.1	379.4	0.0	0.0	2472.1	14253.8	3020.2	17274.0
2005	6550.7	1233.5	6719.2	295.5	583.0	403.1	0.0	0.0	2555.0	15202.0	3137.9	18339.9
2006	6977.3	1313.9	7118.9	313.2	617.9	426.8	0.0	0.0	2637.8	16150.1	3255.7	19405.8
2007	7403.9	1394.3	7518.6	330.9	652.7	450.5	0.0	0.0	2720.7	17098.2	3373.5	20471.7
2008	7830.6	1474.7	7918.4	348.6	687.6	474.2	0.0	0.0	2803.6	18046.4	3491.3	21537.6
2009	8257.2	1555.1	8318.1	366.3	722.5	497.9	0.0	0.0	2886.5	18994.5	3609.0	22603.6
2010	8683.8	1635.5	8717.8	384.0	757.4	521.6	0.0	0.0	2969.4	19942.7	3726.8	23669.5
2011	9110.4	1716.0	9117.5	401.7	792.3	545.3	0.0	0.0	3052.3	20890.8	3844.6	24735.4
2012	9537.0	1796.4	9517.2	419.3	827.2	569.0	0.0	0.0	3135.1	21839.0	3962.3	25801.3
2013	9963.6	1876.8	9917.0	437.0	862.1	592.7	0.0	0.0	3218.0	22787.1	4080.1	26867.2
Total	9963.6	1876.8	9917.0	437.0	862.1	592.7	0.0	0.0	3218.0	22787.1	4080.1	26867.2

SUPER GOOD CENTS RETRO

SUMMARY REPORT

ALL COSTS IN REAL $, INCLUDES LINE LOSSES

	CUMULATIVE			INCREMENTAL									
YEAR	NET ENERGY MWa	NET ENERGY SAVINGS MWh	GROSS MWa	GROSS ENERGY MWh	3rd Party FINANCE k$	UTILITY FINANCE k$	UTILITY EXPENSE k$	NPV CUSTOMER O&M k$	REAL ESC REVENUE k$	TOTAL MEASURE COST k$	DEFERRED OVERHEAD k$	PENETRATION RATE	PARTICIPATION HOMES
1994	0.8	7,307	0.8	7,307	$2,632	$0	$95	($351)	$0	$2,632	$2,614	2.60%	1,460
1995	1.7	15,311	1.7	8,004	$2,885	$0	$226	($385)	$0	$2,885	$2,595	2.85%	1,600
1996	2.7	23,315	2.7	8,004	$2,885	$0	$223	($385)	$0	$2,885	$2,533	2.85%	1,600
1997	3.8	33,322	3.8	10,007	$3,606	$0	$831	($481)	$0	$3,606	$2,326	2.85%	2,000
1998	4.9	43,329	4.9	10,007	$3,606	$0	$813	($481)	$0	$3,606	$2,268	2.85%	2,000
1999	6.3	55,331	6.3	12,002	$4,333	$0	$715	($578)	$0	$4,333	$2,002	2.85%	2,403
2000	8.3	72,281	8.3	16,950	$6,120	$0	$1,010	($817)	$0	$6,120	$2,827	2.85%	3,394
2001	9.7	85,081	9.7	12,800	$4,626	$0	$763	($617)	$0	$4,626	$2,137	2.85%	2,566
2002	10.2	89,583	10.2	4,502	$1,638	$0	$270	($219)	$0	$1,638	$757	2.85%	908
2003	10.7	94,084	10.7	4,502	$1,638	$0	$270	($219)	$0	$1,638	$757	2.85%	908
2004	10.7	94,084	10.7	0	$0	$0	$0	$0	$0	$0	$0	2.85%	0
2005	10.7	94,084	10.7	0	$0	$0	$0	$0	$0	$0	$0	2.85%	0
2006	10.7	94,084	10.7	0	$0	$0	$0	$0	$0	$0	$0	2.85%	0
2007	10.7	94,084	10.7	0	$0	$0	$0	$0	$0	$0	$0	2.85%	0
2008	10.7	94,084	10.7	0	$0	$0	$0	$0	$0	$0	$0	2.85%	0
2009	10.7	94,084	10.7	0	$0	$0	$0	$0	$0	$0	$0	2.85%	0
2010	10.7	94,084	10.7	0	$0	$0	$0	$0	$0	$0	$0	2.85%	0
2011	10.7	94,084	10.7	0	$0	$0	$0	$0	$0	$0	$0	2.85%	0
2012	10.7	94,084	10.7	0	$0	$0	$0	$0	$0	$0	$0	2.85%	0
2013	10.7	94,084	10.7	0	$0	$0	$0	$0	$0	$0	$0	2.85%	0
TOTAL	10.7	94,084	10.7	94,084	$33,968	$0	$5,216	($4,534)		$33,968	$20,816	3%	18,840

DISCOUNT RATE	
TOTAL RESOURCE COS	19.9
UTILITY COST	23.0
UTAH %	
WEIGHTED LIFE	

ESC loan rate	NA
ESC Term	10
Overhead %.def	46%
Expense %	17%

NPV OF ESC	0.6472
NPV OF 6.5%INTERST	0.0000
NPV OF 9% INTERST	0.2643

SUPER GOOD CENTS RETRO
PROGRAM PENETRATION

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah
1994	0.8%	21.3%	0.0%	0.0%	0.2%	0.4%	0.0%	0.0%	0.0%
1995	0.8%	21.3%	0.0%	0.0%	0.4%	0.8%	0.0%	0.0%	0.0%
1996	0.8%	21.3%	0.0%	0.0%	0.4%	0.8%	0.0%	0.0%	0.0%
1997	0.8%	21.3%	1.0%	0.0%	0.4%	0.8%	0.0%	0.0%	0.0%
1998	0.8%	21.3%	1.0%	0.0%	0.4%	0.8%	0.0%	0.0%	0.0%
1999	1.0%	0.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	0.0%
2000	1.5%	0.0%	1.0%	1.5%	1.5%	1.5%	1.5%	1.5%	0.0%
2001	1.0%	0.0%	1.0%	1.5%	1.5%	1.5%	1.5%	1.5%	0.0%
2002	0.0%	0.0%	1.0%	1.5%	1.5%	1.5%	1.5%	1.5%	0.0%
2003	0.0%	0.0%	1.0%	1.5%	1.5%	1.5%	1.5%	1.5%	0.0%
2004	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2005	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2006	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2007	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2008	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2009	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2010	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2011	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2012	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2013	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	7.7%	106.3%	6.9%	7.0%	8.7%	10.6%	7.0%	7.0%	0.0%

SUPER GOOD CENTS RETRO
INCREMENTAL GROSS SAVINGS, MWh

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	7,011	0	0	0	146	150	0	0	0	7,161	146	7,307
1995	7,011	401	0	0	292	300	0	0	0	7,712	292	8,004
1996	7,011	401	0	0	292	300	0	0	0	7,712	292	8,004
1997	7,011	401	2,003	0	292	300	0	0	0	9,715	292	10,007
1998	7,011	401	2,003	0	292	300	0	0	0	9,715	292	10,007
1999	8,299	0	2,107	149	755	373	264	55	0	11,192	810	12,002
2000	12,448	0	2,107	223	1,133	560	395	83	0	15,734	1,216	16,950
2001	8,299	0	2,107	223	1,133	560	395	83	0	11,585	1,216	12,800
2002	0	0	2,107	223	1,133	560	395	83	0	3,286	1,216	4,502
2003	0	0	2,107	223	1,133	560	395	83	0	3,286	1,216	4,502
2004	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0	0
Total	64,100	1,602	14,542	1,042	6,601	3,965	1,846	385	0	87,098	6,986	94,084

SUPER GOOD CENTS RETRO
PARTICIPATION

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	1,400	0	0	0	30	30	0	0	0	1,430	30	1,460
1995	1,400	80	0	0	60	60	0	0	0	1,540	60	1,600
1996	1,400	80	0	0	60	60	0	0	0	1,540	60	1,600
1997	1,400	80	400	0	60	60	0	0	0	1,940	60	2,000
1998	1,400	80	400	0	60	60	0	0	0	1,940	60	2,000
1999	1,657	0	421	30	155	75	54	11	0	2,236	167	2,403
2000	2,486	0	421	45	233	112	81	17	0	3,144	250	3,394
2001	1,657	0	421	45	233	112	81	17	0	2,316	250	2,566
2002	0	0	421	45	233	112	81	17	0	658	250	908
2003	0	0	421	45	233	112	81	17	0	658	250	908
2004	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0	0
Total	12,800	320	2,904	208	1,357	792	379	79	0	17,403	1,436	18,840

WEATHERIZATION LOANS

SUMMARY REPORT

ALL COSTS IN REAL $, INCLUDES LINE LOSSES

	CUMULATIVE			INCREMENTAL									
YEAR	ENERGY MWa	NET ENERGY Savings MWh	GROSS MWa	GROSS ENERGY MWh	0% UTILITY FINANCE k$	6.5% UTILITY FINANCE k$	UTILITY EXPENSE k$	UTILITY REBATE k$	NPV CUSTOMER O & M k$	TOTAL MEASURE COST k$	DEFERRED OVERHEAD k$	LOAN PAYMENTS k$	JOBS COMPLETED
1994	0.4	3,116	0.4	3,116	$345	$159	$122	$233	$909	$1,646	$400	$93	1,038
1995	0.7	6,231	0.7	3,116	$345	$159	$122	$233	$909	$1,646	$400	$180	1,038
1996	1.1	9,347	1.1	3,116	$345	$159	$122	$233	$909	$1,646	$400	$262	1,038
1997	1.4	12,462	1.4	3,116	$345	$159	$122	$233	$909	$1,646	$400	$337	1,038
1998	1.4	12,462	1.4	0									
1999	1.4	12,462	1.4	0									
2000	1.4	12,462	1.4	0									
2001	1.4	12,462	1.4	0									
2002	1.4	12,462	1.4	0									
2003	1.4	12,462	1.4	0									
2004	1.4	12,462	1.4	0									
2005	1.4	12,462	1.4	0									
2006	1.4	12,462	1.4	0									
2007	1.4	12,462	1.4	0									
2008	1.4	12,462	1.4	0									
2009	1.4	12,462	1.4	0									
2010	1.4	12,462	1.4	0									
2011	1.4	12,462	1.4	0									
2012	1.4	12,462	1.4	0									
2013	1.4	12,462	1.4	0									
TOTAL	1.4	12,462	1.4	12,462	$1,379	$636	$490	$931		$6,583	$1,599	$872	4,152

DISCOUNT RATE	5.2%
TOTAL RESOURCE COS	41.1
UTILITY COST	19.4
NOMINAL RATE	9%
WEIGHTED LIFE	0.0

Appendix H - Program Summaries: Medium Case Forecast

HOME COMFORT
SUMMARY REPORT
ALL COSTS IN REAL $, INCLUDES LINE LOSSES

	CUMULATIVE		INCREMENTAL									
YEAR	ENERGY MWa	NET ENERGY Savings MWh	GROSS ENERGY MWh	3rd Party FINANCE k$	UTILITY FINANCE k$	UTILITY EXPENSE k$	NPV CUSTOMER COST k$	REAL ESC REVENUE, k$	TOTAL MEASURE COST k$	DEFERRED OVERHEAD k$	PENETRATION RATE	JOBS COMPLETED
1994	1.5	13,255	13,255	$0	$0	$1,939	($310)	$1,150	$6,283	$19	9%	2,242
1995	2.6	23,140	9,885	$0	$0	$1,393	($230)	$1,979	$4,532	$19	7%	1,672
1996	2.8	24,421	1,281	$0	$0	$246	($30)	$2,083	$568	$12	1%	217
1997	2.9	25,702	1,281	$0	$0	$241	($29)	$2,183	$549	$12	1%	217
1998	3.1	26,786	1,084	$0	$0	$214	($25)	$2,266	$450	$11	1%	183
1999	3.1	26,786	0	$0	$0	$0	$0	$1,116	$0	$0	0%	0
2000	3.1	26,786	0	$0	$0	$0	$0	$287	$0	$0	0%	0
2001	3.1	26,786	0	$0	$0	$0	$0	$183	$0	$0	0%	0
2002	3.1	26,786	0	$0	$0	$0	$0	$82	$0	$0	0%	0
2003	3.1	26,786	0	$0	$0	$0	$0	$0	$0	$0	0%	0
2004	3.1	26,786	0	$0	$0	$0	$0	$0	$0	$0	0%	0
2005	3.1	26,786	0	$0	$0	$0	$0	$0	$0	$0	0%	0
2006	3.1	26,786	0	$0	$0	$0	$0	$0	$0	$0	0%	0
2007	3.1	26,786	0	$0	$0	$0	$0	$0	$0	$0	0%	0
2008	3.1	26,786	0	$0	$0	$0	$0	$0	$0	$0	0%	0
2009	3.1	26,786	0	$0	$0	$0	$0	$0	$0	$0	0%	0
2010	3.1	26,786	0	$0	$0	$0	$0	$0	$0	$0	0%	0
2011	3.1	26,786	0	$0	$0	$0	$0	$0	$0	$0	0%	0
2012	3.1	26,786	0	$0	$0	$0	$0	$0	$0	$0	0%	0
2013	3.1	26,786	0	$0	$0	$0	$0	$0	$0	$0	0%	0
TOTAL	3.1	26,786	26,786	$0	$0	$4,032	($624)		$12,382	$73	0%	4,531

DISCOUNT RATE	0.0%	
TOTAL RESOURCE COST	52.2	mills/kWh
UTILITY COST	22.6	mills/kWh
UTAH %	0%	
WEIGHTED LIFE	23.0	

ESC LOAN RATE	1.3%
ESC TERM	5.7
OVERHEAD, DEFERRED	2%
OVERHEAD, EXPENSE	45%

RESIDENTIAL RETROFIT PROGRAMS, W/O OR. STATUTORY PROGRAMS

SUMMARY REPORT

ALL COSTS IN REAL $, INCLUDES LINE LOSSES

	CUMULATIVE				INCREMENTAL										
YEAR	AVERAGE PEAK SAVINGS MW	GROSS ENERGY MWh	NET ENERGY Savings MWh	GROSS MWa	GROSS MWh	3rd Party FINANCE k$	UTILITY FINANCE k$	UTILITY EXPENSE k$	NPV CUSTOMER O & M k$	REAL ESC REVENUE, k$	TOTAL MEASURE COST k$	DEFERRED OVERHEAD k$	CUMULATIVE PENETRATION RATE	AUDITS W/O JOBS	PATION JOBS COMPLETED
1994	6.5	61,656	40,129	4.6	61,656	$0	$6,283	$2,863	$1,910	$1,152	$11,004	$8,145	8%	12,039	7,260
1995	10.7	78,367	65,807	7.5	16,711	$0	$4,532	$2,427	$3,267	$1,983	$9,349	$5,469	13%	8,635	6,700
1996	13.5	101,904	82,983	9.5	23,537	$0	$568	$1,330	$3,468	$2,089	$5,385	$5,711	16%	652	5,245
1997	15.9	118,346	97,352	11.1	16,441	$0	$549	$1,910	$4,429	$2,192	$6,088	$4,597	18%	652	5,645
1998	18.2	134,590	111,524	12.7	16,244	$0	$450	$1,844	$4,433	$2,276	$5,988	$4,168	20%	585	4,573
1999	20.3	148,688	124,592	14.2	14,098	$0	$0	$1,174	$4,441	$1,124	$5,390	$3,664	22%	0	4,064
2000	23.3	167,733	142,608	16.3	19,045	$0	$0	$1,469	$5,989	$293	$7,177	$4,486	24%	13	5,055
2001	25.5	182,629	156,474	17.9	14,896	$0	$0	$1,223	$4,694	$187	$5,684	$3,724	26%	2,553	4,227
2002	26.4	189,226	162,042	18.5	6,597	$0	$0	$730	$2,105	$84	$2,696	$1,558	28%	1,514	2,569
2003	27.3	195,823	167,609	19.1	6,597	$0	$0	$730	$2,105	$0	$2,696	$1,558	29%	0	2,569
2004	27.5	197,919	168,675	19.3	2,096	$0	$0	$459	$686	$0	$1,058	$801	30%	0	1,661
2005	27.7	200,014	169,741	19.4	2,096	$0	$0	$459	$686	$0	$1,058	$801	30%	0	1,661
2006	27.9	202,110	170,807	19.5	2,096	$0	$0	$459	$686	$0	$1,058	$801	31%	0	1,661
2007	28.0	204,205	171,873	19.6	2,096	$0	$0	$459	$686	$0	$1,058	$801	32%	0	1,661
2008	28.2	206,301	172,939	19.7	2,096	$0	$0	$459	$686	$0	$1,058	$801	32%	0	1,661
2009	28.4	208,396	174,005	19.9	2,096	$0	$0	$459	$686	$0	$1,058	$801	34%	1,819	1,661
2010	26.6	198,700	163,279	18.6	(9,696)	$0	$0	$459	$686	$0	$1,058	$801	35%	1,805	1,661
2011	26.8	200,795	164,345	18.8	2,096	$0	$0	$459	$686	$0	$1,058	$801	36%	1,789	1,661
2012	27.0	202,891	165,411	18.9	2,096	$0	$0	$459	$686	$0	$1,058	$801	38%	1,775	1,661
2013	27.1	204,986	166,476	19.0	2,096	$0	$0	$459	$686	$0	$1,058	$801	39%	1,761	1,661
TOTAL	27.1	204,986	166,476	19.0	204,986	$0	$12,382	$20,293	$43,704		$72,035	$51,088	39%	35,592	64,517

DISCOUNT RATE	
TOTAL RESOURCE COST	54.2
UTILITY COST	30.4
UTAH %	
WEIGHTED LIFE	23.0

DEMAND SIDE BIDDING IN OREGON
SUMMARY REPORT
ALL COSTS IN REAL $, INCLUDES LINE LOSSES

	CUMULATIVE				INCREMENTAL								
YEAR	ENERGY MWa	CAPACITY MW	NET ENERGY Savings MWh	GROSS MWa	GROSS ENERGY MWh	3rd Party FINANCE k$	UTILITY FINANCE k$	UTILITY EXPENSE k$	NPV CUSTOMER O & M k$	INITIAL PAYMENT k$	PROGRES S PAYMENTS k$	DEFERRED OVERHEAD k$	PARTICIPA-TION HOMES
1994	0.5	0.0	4,416	0.5	4,416	$0	$0	$0	($309)	$627	$0	$40	2,755
1995	1.1	0.0	9,225	1.1	4,809	$0	$0	$0	($336)	$683	$63	$40	3,000
1996	1.6	0.0	14,034	1.6	4,809	$0	$0	$0	($336)	$683	$131	$40	3,000
1997	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$199	$5	0
1998	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$199	$5	0
1999	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$513	$5	0
2000	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$478	$5	0
2001	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$410	$5	0
2002	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$0	$0	0
2003	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$0	$0	0
2004	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$0	$0	0
2005	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$0	$0	0
2006	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$0	$0	0
2007	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$0	$0	0
2008	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$0	$0	0
2009	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$0	$0	0
2010	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$0	$0	0
2011	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$0	$0	0
2012	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$0	$0	0
2013	1.6	0.0	14,034	1.6	0	$0	$0	$0	$0	$0	$0	$0	0
TOTAL	1.6	0.0	14,034	1.6	14,034	$0	$0	$0	($981)		$1,993	$145	8,755

DISCOUNT RATE	
TOTAL RESOURCE COST	37.0
UTILITY COST	42.9
UTAH %	40%
WEIGHTED LIFE	

DEMAND SIDE BIDDING IN UTAH
SUMMARY REPORT
ALL COSTS IN REAL $, INCLUDES LINE LOSSES

	CUMULATIVE				INCREMENTAL								
YEAR	ENERGY MWa	CAPACITY MW	NET ENERGY Savings MWh	GROSS MWa	GROSS ENERGY MWh	3rd Party FINANCE k$	UTILITY FINANCE k$	UTILITY EXPENSE k$	NPV CUSTOMER O & M k$	INITIAL PAYMENT k$	PROGRES S PAYMENTS k$	DEFERRED OVERHEAD k$	PARTICIPA-TION HOMES
1994	1.3	0.0	11,792	1.3	11,792	$0	$0	$0	($1,201)	$2,655	$0	$0	10,720
1995	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
1996	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
1997	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
1998	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
1999	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
2000	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
2001	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
2002	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
2003	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
2004	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
2005	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
2006	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
2007	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
2008	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
2009	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
2010	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
2011	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
2012	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
2013	1.3	0.0	11,792	1.3	0	$0	$0	$0	$0	$0	$0	$0	0
TOTAL	1.3	0.0	11,792	1.3	11,792	$0	$0	$0	($1,201)		$0	$0	10,720

DISCOUNT RATE	
TOTAL RESOURCE COS	-9.1
UTILITY COST	-17.6
UTAH %	40%
WEIGHTED LIFE	

Appendix H - Program Summaries: Medium Case Forecast

WATER HEATER CONTROLLER PROGRAM
SUMMARY REPORT
ALL COSTS IN REAL $, INCLUDES LINE LOSSES

	CUMULATIVE			INCREMENTAL									
YEAR	ENERGY MWa	WINTER PEAK SAVINGS MW	SUMMER PEAK SAVINGS MW	GROSS ENERGY MWh	3rd Party FINANCE k$	UTILITY FINANCE k$	UTILITY EXPENSE k$	NPV CUSTOMER O & M k$	REAL ESC REVENUE k$	INCENTIVE PAYMENT k$	DEFERRED OVERHEAD k$	CUM. PENETRATION RATE	PARTICIPATION (INCREM. JOBS COMPLETED)
1994	0.0	0.0	0	0	$0	$0	$0	$0	$0	$0	$0	0%	0
1995	0.0	0.0	0	0	$0	$0	$0	$0	$0	$0	$0	0%	0
1996	0.0	0.0	0	0	$0	$0	$0	$0	$0	$0	$0	0%	0
1997	0.0	0.0	0	0	$0	$0	$0	$0	$0	$0	$0	0%	0
1998	0.0	14.5	9	0	$0	$0	$181	$0	$0	$174	$4,162	2%	14,478
1999	0.0	48.7	29	0	$0	$0	$428	$0	$0	$585	$9,846	7%	34,248
2000	0.0	88.5	53	0	$0	$0	$498	$0	$0	$1,062	$11,444	12%	39,806
2001	0.0	129.1	77	0	$0	$0	$508	$0	$0	$1,550	$11,677	18%	40,614
2002	0.0	139.8	84	0	$0	$0	$133	$0	$0	$1,677	$3,054	19%	10,624
2003	0.0	139.8	84	0	$0	$0	$0	$0	$0	$1,677	$0	19%	0
2004	0.0	139.8	84	0	$0	$0	$0	$0	$0	$1,677	$0	19%	0
2005	0.0	139.8	84	0	$0	$0	$0	$0	$0	$1,677	$0	19%	0
2006	0.0	139.8	84	0	$0	$0	$0	$0	$0	$1,677	$0	19%	0
2007	0.0	139.8	84	0	$0	$0	$0	$0	$0	$1,677	$0	19%	0
2008	0.0	139.8	84	0	$0	$0	$0	$0	$0	$1,677	$0	19%	0
2009	0.0	139.8	84	0	$0	$0	$0	$0	$0	$1,677	$0	19%	0
2010	0.0	139.8	84	0	$0	$0	$0	$0	$0	$1,677	$0	19%	0
2011	0.0	139.8	84	0	$0	$0	$0	$0	$0	$1,677	$0	19%	0
2012	0.0	139.8	84	0	$0	$0	$0	$0	$0	$1,677	$0	19%	0
2013	0.0	139.8	84	0	$0	$0	$0	$0	$0	$1,677	$0	19%	0
TOTAL	0.0	139.8	84	0	$0	$0	$1,747	$0		$23,497	$40,184	19%	139,770

DISCOUNT RATE	
TOTAL RESOURCE COS	37.3
UTILITY COST	37.3
UTAH %	0%
WEIGHTED LIFE	

ESC LOAN RATE	
AVE. ANNUAL ESC REVENUE, k$	
DESIGN/AUDIT COST ADDER	
ADMINISTRATIVE ADDER, DEFERR	15%
ADMINISTRATIVE ADDER, EXPENS	5%

WATER HEATER CONTROLLER PROGRAM
PROGRAM PENETRATION

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah
1994	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1995	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1996	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1997	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1998	5.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1999	10.0%	5.0%	5.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2000	10.0%	10.0%	10.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2001	10.0%	10.0%	10.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2002	0.0%	10.0%	10.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2003	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2004	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2005	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2006	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2007	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2008	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2009	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2010	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2011	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2012	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2013	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	35.0%	35.0%	35.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

WATER HEATER CONTROLLER PROGRAM
PARTICIPATION

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	0	0	0	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0	0	0	0
1996	0	0	0	0	0	0	0	0	0	0	0	0
1997	0	0	0	0	0	0	0	0	0	0	0	0
1998	14,478	0	0	0	0	0	0	0	0	14,478	0	14,478
1999	29,238	1,286	3,724	0	0	0	0	0	0	34,248	0	34,248
2000	29,638	2,596	7,572	0	0	0	0	0	0	39,806	0	39,806
2001	30,245	2,641	7,728	0	0	0	0	0	0	40,614	0	40,614
2002	0	2,692	7,932	0	0	0	0	0	0	10,624	0	10,624
2003	0	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0	0
Total	103,599	9,214	26,957	0	0	0	0	0	0	139,770	0	139,770

APPLIANCE RETROFIT FOR OTHER CUSTOMERS
INCLUDES OREGON H-PRO HEAT PUMPS THRU 1998
SUMMARY REPORT
ALL COSTS IN REAL $, INCLUDES LINE LOSSES

	CUMULATIVE				INCREMENTAL									
YEAR	ENERGY MWa	CAPACITY MW	NET ENERGY Savings MWh	GROSS MWa	GROSS ENERGY MWh	3rd Party FINANCE k$	UTILITY FINANCE k$	UTILITY EXPENSE k$	NPV CUSTOMER COST k$	REAL ESC REVENUE k$	TOTAL MEASURE COST k$	DEFERRED OVERHEAD k$	PENETRATION RATE	# OF HOMES
1994	4.6	8.8	39,960	0.0	0	$0	$0	$1,162	($6,854)	$0	$11,809	$9,466	7.0%	115,077
1995	5.3	10.2	46,496	0.0	0	$0	$0	$660	($2,991)	$0	$2,618	$1,796	0.9%	15,175
1996	6.0	11.6	52,868	0.0	0	$0	$0	$657	($2,775)	$0	$2,593	$1,767	0.9%	15,175
1997	6.8	13.0	59,136	0.0	0	$0	$0	$618	($2,558)	$0	$2,578	$1,743	0.9%	15,175
1998	7.5	14.3	65,295	0.0	0	$0	$0	$616	($2,341)	$0	$2,559	$1,720	0.9%	15,175
1999	7.8	14.9	67,896	0.0	0	$0	$0	$36	($1,818)	$0	$713	$475	0.2%	15,175
2000	8.1	15.5	70,756	0.0	0	$0	$0	$36	($1,620)	$0	$725	$472	0.2%	15,175
2001	8.4	16.2	73,834	0.0	0	$0	$0	$36	($1,420)	$0	$727	$476	0.2%	15,175
2002	8.8	16.9	76,931	0.0	0	$0	$0	$34	($1,226)	$0	$682	$450	0.2%	15,175
2003	9.2	17.6	80,158	0.0	0	$0	$0	$33	($1,031)	$0	$658	$424	0.2%	15,175
2004	9.5	18.3	83,563	0.0	0	$0	$0	$32	($835)	$0	$641	$411	0.2%	15,175
2005	9.9	19.1	87,112	0.0	0	$0	$0	$31	($640)	$0	$616	$391	0.2%	15,175
2006	10.4	19.9	90,760	0.0	0	$0	$0	$29	($447)	$0	$583	$363	0.2%	15,175
2007	10.8	20.8	94,531	0.0	0	$0	$0	$28	($253)	$0	$554	$339	0.2%	15,175
2008	11.2	21.6	98,536	0.0	0	$0	$0	$27	($57)	$0	$549	$332	0.2%	15,175
2009	11.5	22.2	100,999	0.0	0	$0	$0	$26	($40)	$0	$527	$316	0.2%	15,175
2010	11.8	22.7	103,380	0.0	0	$0	$0	$25	($23)	$0	$505	$299	0.2%	15,175
2011	12.1	23.2	105,793	0.0	0	$0	$0	$25	($4)	$0	$504	$296	0.2%	15,175
2012	12.4	23.8	108,244	0.0	0	$0	$0	$25	$15	$0	$504	$295	0.2%	15,175
2013	12.6	24.3	110,692	0.0	0	$0	$0	$25	$34	$0	$498	$292	0.2%	15,175
TOTAL	12.6	24.3	110,692	0.0	0	$0	$0	$4,163	($26,883)	$0	$31,143	$22,123	13.8%	403,400

DISCOUNT RATE	5.2%
TOTAL RESOURCE COST	29.3
UTILITY COST	8.1
UTAH %	40%
LIFETIME	7.0

ESC LOAN RATE	9.2%
AVE. ANNUAL ESC REVENUE, k$	$41,032
DESIGN/AUDIT COST ADDER	19%
ADMINISTRATIVE ADDER, DEFERRED	20%
ADMINISTRATIVE ADDER, EXPENSE	1%

FRACTION OF NET SALES	25%
SUPPLEMENTAL SAVED ADDED	15%
SUPPLEMENTAL COST ADDED	30%
OTHER FINANCE	50%

Appendix H - Program Summaries: Medium Case Forecast

APPLIANCE RETROFIT FOR OTHER CUSTOMERS
PROGRAM PENETRATION

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah
1994	9.719%	8.405%	9.403%	9.624%	9.787%	9.780%	9.704%	9.744%	9.568%
1995	1.488%	2.070%	1.041%	1.130%	1.179%	1.122%	1.084%	1.083%	1.093%
1996	1.492%	2.045%	1.024%	1.121%	1.116%	1.115%	1.067%	1.081%	1.077%
1997	1.502%	2.059%	1.013%	1.117%	1.109%	1.107%	1.056%	1.078%	1.072%
1998	1.513%	2.084%	1.006%	1.110%	1.102%	1.100%	1.052%	1.085%	1.051%
1999	0.182%	1.439%	0.208%	0.267%	0.222%	0.206%	0.103%	0.097%	0.220%
2000	0.205%	1.624%	0.231%	0.327%	0.268%	0.222%	0.132%	0.090%	0.271%
2001	0.252%	1.997%	0.240%	0.358%	0.278%	0.298%	0.153%	0.108%	0.271%
2002	0.240%	1.897%	0.267%	0.348%	0.272%	0.246%	0.129%	0.086%	0.238%
2003	0.226%	1.790%	0.260%	0.319%	0.249%	0.242%	0.131%	0.096%	0.261%
2004	0.240%	1.897%	0.266%	0.333%	0.257%	0.266%	0.131%	0.103%	0.262%
2005	0.240%	1.899%	0.266%	0.327%	0.260%	0.272%	0.131%	0.099%	0.262%
2006	0.224%	1.772%	0.255%	0.308%	0.249%	0.262%	0.126%	0.090%	0.264%
2007	0.216%	1.711%	0.252%	0.297%	0.242%	0.266%	0.123%	0.092%	0.267%
2008	0.242%	1.915%	0.260%	0.320%	0.252%	0.309%	0.126%	0.106%	0.282%
2009	0.214%	1.697%	0.243%	0.288%	0.239%	0.270%	0.121%	0.111%	0.272%
2010	0.187%	1.478%	0.226%	0.247%	0.219%	0.223%	0.116%	0.108%	0.265%
2011	0.185%	1.462%	0.222%	0.248%	0.216%	0.226%	0.116%	0.108%	0.270%
2012	0.185%	1.464%	0.221%	0.242%	0.216%	0.234%	0.116%	0.113%	0.275%
2013	0.184%	1.457%	0.210%	0.230%	0.212%	0.247%	0.115%	0.109%	0.270%

APPLIANCE RETROFIT FOR OTHER CUSTOMERS
INCREMENTAL GROSS SAVINGS, MWh

YEAR	Oregon (w/o showers)	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah
1994	8,211	2,494	7,026	589	2,506	1,666	3,431	433	13,605
1995	1,841	437	1,024	90	354	250	534	66	1,940
1996	1,842	423	980	87	331	243	518	64	1,883
1997	1,851	414	944	84	320	236	507	63	1,850
1998	1,861	405	914	81	311	230	502	62	1,791
1999	462	239	504	44	142	118	236	27	828
2000	490	260	540	48	159	125	265	27	945
2001	546	299	564	51	169	143	293	29	983
2002	532	297	602	51	177	137	296	28	977
2003	516	297	607	50	180	140	316	30	1,092
2004	532	310	621	51	191	148	336	31	1,185
2005	533	314	627	51	199	152	354	32	1,287
2006	514	307	621	51	203	152	367	32	1,400
2007	505	305	621	50	207	155	379	33	1,515
2008	536	325	630	53	215	165	393	34	1,654
2009	504	209	279	25	100	73	161	14	1,097
2010	471	187	264	23	95	63	158	14	1,104
2011	469	185	261	23	94	64	159	14	1,143
2012	470	186	260	22	95	65	160	15	1,177
2013	469	187	250	22	95	67	160	15	1,182
Total	23,155	8,080	18,141	1,548	6,145	4,394	9,526	1,064	38,638

APPLIANCE RETROFIT FOR OTHER CUSTOMERS
MEASURE COST, K$

YEAR	Oregon (w/o showers)	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah
1994	$4,195	$439	$1,216	$103	$472	$317	$827	$97	$4,144
1995	$1,299	$101	$240	$21	$93	$60	$138	$17	$649
1996	$1,320	$97	$228	$20	$87	$58	$134	$16	$633
1997	$1,342	$94	$217	$19	$84	$56	$129	$16	$621
1998	$1,367	$90	$206	$18	$80	$53	$126	$15	$604
1999	$148	$56	$112	$10	$41	$27	$51	$6	$262
2000	$156	$56	$106	$9	$40	$26	$50	$6	$275
2001	$172	$60	$99	$9	$38	$25	$49	$6	$268
2002	$168	$56	$93	$8	$35	$23	$45	$5	$248
2003	$163	$52	$85	$8	$32	$21	$43	$5	$250
2004	$168	$51	$78	$7	$29	$20	$40	$5	$243
2005	$168	$49	$70	$6	$27	$18	$38	$4	$236
2006	$163	$45	$62	$6	$24	$16	$35	$4	$230
2007	$160	$41	$54	$5	$21	$14	$32	$3	$224
2008	$169	$42	$47	$4	$19	$13	$30	$3	$222
2009	$160	$38	$45	$4	$18	$12	$29	$3	$218
2010	$151	$34	$43	$4	$17	$11	$29	$3	$214
2011	$150	$33	$42	$4	$17	$11	$29	$3	$216
2012	$150	$33	$41	$4	$16	$11	$28	$3	$217
2013	$150	$33	$39	$3	$16	$11	$28	$3	$215
Total	$11,920	$1,501	$3,123	$270	$1,205	$803	$1,910	$223	$10,187

APPLIANCE RETROFIT FOR OTHER CUSTOMERS
NPV O&M COST, K$

YEAR	Oregon (w/o showers)	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah
1994	($363)	($619)	($1,814)	($151)	($637)	($410)	($660)	($89)	($2,110)
1995	($2)	($302)	($885)	($74)	($308)	($198)	($301)	($41)	($880)
1996	($1)	($280)	($820)	($68)	($286)	($183)	($279)	($38)	($818)
1997	($1)	($259)	($755)	($63)	($263)	($169)	($258)	($35)	($756)
1998	$0	($237)	($689)	($58)	($240)	($154)	($236)	($32)	($694)
1999	$39	($192)	($556)	($46)	($194)	($124)	($187)	($26)	($531)
2000	$40	($172)	($496)	($42)	($173)	($111)	($168)	($23)	($475)
2001	$43	($153)	($437)	($37)	($153)	($98)	($148)	($20)	($419)
2002	$43	($133)	($377)	($32)	($132)	($85)	($128)	($18)	($363)
2003	$42	($113)	($318)	($27)	($112)	($72)	($109)	($15)	($307)
2004	$43	($93)	($259)	($22)	($92)	($59)	($89)	($12)	($252)
2005	$43	($74)	($200)	($17)	($71)	($46)	($70)	($10)	($196)
2006	$42	($54)	($141)	($12)	($51)	($33)	($50)	($7)	($141)
2007	$41	($35)	($82)	($7)	($31)	($20)	($31)	($4)	($85)
2008	$43	($15)	($22)	($2)	($11)	($7)	($12)	($1)	($30)
2009	$41	($13)	($18)	($2)	($8)	($5)	($10)	($1)	($24)
2010	$40	($10)	($13)	($2)	($6)	($4)	($8)	($1)	($18)
2011	$40	($7)	($9)	($1)	($4)	($3)	($6)	($1)	($13)
2012	$40	($5)	($4)	($1)	($2)	($1)	($4)	($1)	($7)
2013	$40	($2)	$1	$0	$0	$0	($2)	$0	($2)
Total	$251	($2,768)	($7,893)	($663)	($2,777)	($1,780)	($2,756)	($376)	($8,120)

APPLIANCE RETROFIT FOR OTHER CUSTOMERS
PARTICIPATION, # of Homes

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah
1994	40,073	3,776	9,068	775	3,773	2,595	8,277	926	45,812
1995	6,136	930	1,004	91	454	298	924	103	5,235
1996	6,153	919	988	90	430	296	910	103	5,156
1997	6,192	925	977	90	427	294	900	102	5,134
1998	6,239	936	970	89	425	292	897	103	5,034
1999	749	647	200	22	86	55	88	9	1,053
2000	845	730	223	26	104	59	113	9	1,296
2001	1,040	897	231	29	107	79	130	10	1,296
2002	988	852	258	28	105	65	110	8	1,142
2003	932	804	251	26	96	64	112	9	1,249
2004	988	852	257	27	99	71	112	10	1,256
2005	989	853	257	26	100	72	112	9	1,253
2006	923	796	246	25	96	70	108	9	1,266
2007	891	769	243	24	93	71	105	9	1,281
2008	998	861	251	26	97	82	107	10	1,351
2009	884	763	234	23	92	72	104	11	1,302
2010	770	664	218	20	84	59	99	10	1,267
2011	762	657	214	20	83	60	99	10	1,293
2012	763	658	214	20	83	62	99	11	1,315
2013	759	654	203	19	82	66	98	10	1,293
Total	78,076	18,943	16,507	1,494	6,918	4,780	13,503	1,482	85,283

APPLIANCE RETROFIT FOR OTHER CUSTOMERS
INCREMENTAL INCENTIVE, K$

YEAR	Oregon (w/o showers)	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah
1994	$3,547	$410	$1,147	$97	$448	$301	$803	$94	$3,851
1995	$616	$74	$176	$15	$70	$46	$116	$14	$380
1996	$600	$72	$169	$15	$66	$45	$113	$13	$376
1997	$585	$70	$162	$14	$64	$43	$111	$13	$371
1998	$571	$68	$156	$14	$62	$42	$108	$13	$366
1999	$252	$35	$66	$6	$25	$16	$35	$4	$0
2000	$248	$36	$64	$6	$25	$16	$36	$4	$0
2001	$251	$40	$62	$6	$25	$17	$37	$4	$0
2002	$235	$38	$61	$6	$23	$15	$34	$4	$0
2003	$220	$36	$57	$5	$22	$14	$33	$4	$0
2004	$212	$36	$54	$5	$21	$14	$32	$4	$0
2005	$201	$35	$51	$5	$20	$13	$31	$3	$0
2006	$185	$33	$47	$4	$18	$13	$30	$3	$0
2007	$171	$31	$44	$4	$17	$12	$29	$3	$0
2008	$167	$33	$42	$4	$16	$12	$28	$3	$0
2009	$158	$30	$40	$4	$16	$11	$28	$3	$0
2010	$149	$27	$39	$3	$15	$10	$27	$3	$0
2011	$147	$27	$38	$3	$15	$10	$27	$3	$0
2012	$146	$27	$38	$3	$15	$10	$27	$3	$0
2013	$145	$26	$37	$3	$15	$10	$27	$3	$0

Appendix H - Program Summaries: Medium Case Forecast

APPLIANCE RETROFIT FOR OTHER CUSTOMERS
PEAK, MW INCL LINE LOSS

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah
1994	1.6	0.5	1.3	0.1	0.5	0.3	0.7	0.1	2.6
1995	1.9	0.6	1.5	0.1	0.5	0.4	0.8	0.1	3.0
1996	2.3	0.6	1.7	0.1	0.6	0.4	0.9	0.1	3.3
1997	2.6	0.7	1.9	0.2	0.7	0.5	0.9	0.1	3.7
1998	3.0	0.8	2.1	0.2	0.7	0.5	1.0	0.1	4.0
1999	3.1	0.8	2.2	0.2	0.8	0.5	1.1	0.1	4.2
2000	3.2	0.9	2.3	0.2	0.8	0.5	1.1	0.1	4.3
2001	3.3	0.9	2.4	0.2	0.8	0.6	1.2	0.1	4.5
2002	3.4	1.0	2.5	0.2	0.9	0.6	1.3	0.2	4.7
2003	3.5	1.1	2.6	0.2	0.9	0.6	1.3	0.2	4.9
2004	3.6	1.1	2.7	0.2	0.9	0.7	1.4	0.2	5.2
2005	3.7	1.2	2.8	0.2	1.0	0.7	1.4	0.2	5.4
2006	3.8	1.2	3.0	0.3	1.0	0.7	1.5	0.2	5.7
2007	3.9	1.3	3.1	0.3	1.0	0.7	1.6	0.2	6.0
2008	4.0	1.4	3.2	0.3	1.1	0.8	1.7	0.2	6.3
2009	4.0	1.4	3.3	0.3	1.1	0.8	1.7	0.2	6.5
2010	4.1	1.4	3.3	0.3	1.1	0.8	1.7	0.2	6.7
2011	4.2	1.5	3.4	0.3	1.1	0.8	1.8	0.2	6.9
2012	4.3	1.5	3.4	0.3	1.2	0.8	1.8	0.2	7.1
2013	4.4	1.5	3.5	0.3	1.2	0.8	1.8	0.2	7.4
Total	4.4	1.5	3.5	0.3	1.2	0.8	1.8	0.2	7.4

INDUSTRIAL
SUMMARY REPORT
ALL COSTS IN REAL $, INCLUDES LINE LOSSES

	CUMULATIVE				INCREMENTAL									
YEAR	ENERGY MWa	CAPACITY MW	NET ENERGY Savings MWh	GROSS MWa	GROSS ENERGY MWh	3rd Party FINANCE k$	UTILITY FINANCE k$	UTILITY EXPENSE k$	NPV CUSTOMER O & M k$	REAL ESC REVENUE, k$	TOTAL MEASURE COST k$	DEFERRED OVERHEAD k$	PENETRA-TION RATE	NUMBER OF PARTICIPANT S
1994	6.7	7.0	58,684	0.0	58,684	$0	$5,662	$591	$0	$682	$5,662	$4,685	1.42%	20
1995	17.6	18.3	154,263	0.0	95,580	$0	$7,039	$729	$0	$1,507	$7,039	$11,564	2.31%	32
1996	35.3	36.8	309,543	0.0	155,279	$0	$8,417	$822	$0	$2,471	$8,417	$21,275	3.75%	52
1997	59.0	61.5	516,833	0.0	207,290	$0	$9,794	$960	$0	$3,569	$9,794	$27,184	5.01%	69
1998	89.4	93.1	782,776	0.0	265,944	$0	$11,171	$1,053	$0	$4,797	$11,171	$32,699	6.42%	89
1999	104.2	108.5	912,570	0.0	129,793	$18,114	$18,114	$348	$0	$8,834	$34,834	$1,393	3.13%	43
2000	119.0	123.9	1,042,363	0.0	129,793	$18,114	$18,114	$348	$0	$12,738	$34,834	$1,393	3.13%	43
2001	133.8	139.4	1,172,157	0.0	129,793	$18,114	$18,114	$348	$0	$16,514	$34,834	$1,393	3.13%	43
2002	148.6	154.8	1,301,950	0.0	129,793	$18,114	$18,114	$348	$0	$20,166	$34,834	$1,393	3.13%	43
2003	163.4	170.3	1,431,743	0.0	129,793	$18,114	$18,114	$348	$0	$23,698	$34,834	$1,393	3.13%	43
2004	178.3	185.7	1,561,537	0.0	129,793	$18,114	$18,114	$348	$0	$27,113	$34,834	$1,393	3.13%	43
2005	193.1	201.1	1,691,330	0.0	129,793	$18,114	$18,114	$348	$0	$30,417	$34,834	$1,393	3.13%	43
2006	204.2	212.7	1,788,639	0.0	97,309	$13,511	$13,511	$260	$0	$32,545	$25,984	$1,039	2.35%	32
2007	215.3	224.3	1,885,948	0.0	97,309	$13,511	$13,511	$260	$0	$34,604	$25,984	$1,039	2.35%	32
2008	224.3	233.6	1,964,677	0.0	78,730	$10,777	$10,777	$207	$5,662	$35,962	$20,726	$829	1.90%	26
2009	233.3	243.0	2,043,407	0.0	78,730	$10,777	$10,777	$207	$7,039	$36,862	$20,726	$829	1.90%	26
2010	242.3	252.3	2,122,136	0.0	78,730	$10,777	$10,777	$207	$8,417	$37,233	$20,726	$829	1.90%	26
2011	251.2	261.7	2,200,866	0.0	78,730	$10,777	$10,777	$207	$9,794	$37,025	$20,726	$829	1.90%	26
2012	259.1	269.9	2,269,640	0.0	68,774	$9,381	$9,381	$180	$11,171	$35,903	$18,041	$722	1.66%	23
2013	266.9	278.1	2,338,414	0.0	68,774	$9,381	$9,381	$180	$34,834	$34,094	$18,041	$722	1.66%	23
TOTAL	266.9	278.1	2,338,414	0.0	2,338,414	$215,692	$257,776	$8,303	$76,918		$456,876	$113,999	2%	779
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)

DISCOUNT RATE	5.2%
TOTAL RESOURCE COST	23.0
UTILITY COST	4.8
UTAH %	50%
ECM TERM	15.0

ESC LOAN RATE	8.5%
AVE. ANNUAL ESC REVENUE, k$	$59,258
DESIGN/AUDIT COST ADDER	19%
ADMINISTRATIVE ADDER, DEFERRED	20%
ADMINISTRATIVE ADDER, EXPENSE	1%

PROGRAM SAVINGS, % OF SALES=	7.7%
ADMIN OVERHEAD%=	4%
ADMIN EXPENSE%=	1%
WEIGHTED LIFETIME=	20.7
PERCENT OTHER FINANCE	50%

Appendix H - Program Summaries: Medium Case Forecast

INDUSTRIAL
PROGRAM PENETRATION

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah
1994	2.2%	20.4%	3.3%	0.0%	0.0%	0.0%	0.9%	0.0%	1.6%
1995	3.9%	20.4%	4.2%	0.0%	0.0%	0.0%	0.8%	0.0%	3.1%
1996	4.1%	20.4%	5.2%	0.0%	0.0%	0.0%	3.4%	0.0%	5.2%
1997	6.4%	20.4%	6.1%	0.0%	0.0%	0.0%	4.5%	0.0%	6.6%
1998	9.6%	20.4%	7.1%	0.0%	0.0%	0.0%	5.5%	0.0%	8.1%
1999	3.0%	0.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
2000	3.0%	0.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
2001	3.0%	0.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
2002	3.0%	0.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
2003	3.0%	0.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
2004	3.0%	0.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
2005	3.0%	0.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
2006	1.0%	0.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.0%
2007	1.0%	0.0%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.0%
2008	1.0%	0.0%	1.0%	3.0%	3.0%	3.0%	3.0%	3.0%	1.0%
2009	1.0%	0.0%	1.0%	3.0%	3.0%	3.0%	3.0%	3.0%	1.0%
2010	1.0%	0.0%	1.0%	3.0%	3.0%	3.0%	3.0%	3.0%	1.0%
2011	1.0%	0.0%	1.0%	3.0%	3.0%	3.0%	3.0%	3.0%	1.0%
2012	1.0%	0.0%	1.0%	3.0%	3.0%	3.0%	2.0%	3.0%	1.0%
2013	1.0%	0.0%	1.0%	3.0%	3.0%	3.0%	2.0%	3.0%	1.0%
Total	55.1%	102.1%	49.9%	45.0%	45.0%	45.0%	58.1%	45.0%	55.6%

INDUSTRIAL
INCREMENTAL GROSS SAVINGS, MWh

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	16,638	2,243	7,768	0	0	0	8,120	0	23,914	34,770	23,914	58,684
1995	29,193	2,243	9,987	0	0	0	7,631	0	46,525	49,055	46,525	95,580
1996	31,082	2,243	12,207	0	0	0	31,407	0	78,340	76,939	78,340	155,279
1997	48,515	2,243	14,426	0	0	0	41,154	0	100,951	106,339	100,951	207,290
1998	72,590	2,243	16,646	0	0	0	50,902	0	123,562	142,381	123,562	265,944
1999	24,786	0	5,237	462	10,675	1,097	29,867	9,788	47,882	61,448	68,345	129,793
2000	24,786	0	5,237	462	10,675	1,097	29,867	9,788	47,882	61,448	68,345	129,793
2001	24,786	0	5,237	462	10,675	1,097	29,867	9,788	47,882	61,448	68,345	129,793
2002	24,786	0	5,237	462	10,675	1,097	29,867	9,788	47,882	61,448	68,345	129,793
2003	24,786	0	5,237	462	10,675	1,097	29,867	9,788	47,882	61,448	68,345	129,793
2004	24,786	0	5,237	462	10,675	1,097	29,867	9,788	47,882	61,448	68,345	129,793
2005	24,786	0	5,237	462	10,675	1,097	29,867	9,788	47,882	61,448	68,345	129,793
2006	8,262	0	5,237	462	10,675	1,097	29,867	9,788	31,921	44,924	52,384	97,309
2007	8,262	0	5,237	462	10,675	1,097	29,867	9,788	31,921	44,924	52,384	97,309
2008	8,262	0	2,618	462	10,675	1,097	29,867	9,788	15,961	42,306	36,424	78,730
2009	8,262	0	2,618	462	10,675	1,097	29,867	9,788	15,961	42,306	36,424	78,730
2010	8,262	0	2,618	462	10,675	1,097	29,867	9,788	15,961	42,306	36,424	78,730
2011	8,262	0	2,618	462	10,675	1,097	29,867	9,788	15,961	42,306	36,424	78,730
2012	8,262	0	2,618	462	10,675	1,097	19,911	9,788	15,961	32,350	36,424	68,774
2013	8,262	0	2,618	462	10,675	1,097	19,911	9,788	15,961	32,350	36,424	68,774
Total	437,619	11,217	123,873	6,925	160,123	16,453	567,306	146,824	868,074	1,163,393	1,175,021	2,338,414

INDUSTRIAL
MEASURE COST, K$
NET OF DESIGN & AUDIT COSTS AND SUPPLEMENTAL MEASURES

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$1,530	$306	$1,071	$0	$0	$0	$612	$0	$2,142	$3,520	$2,142	$5,662
1995	$1,683	$306	$1,377	$0	$0	$0	$918	$0	$2,755	$4,285	$2,755	$7,039
1996	$1,836	$306	$1,683	$0	$0	$0	$1,224	$0	$3,367	$5,050	$3,367	$8,417
1997	$1,989	$306	$1,989	$0	$0	$0	$1,530	$0	$3,979	$5,815	$3,979	$9,794
1998	$2,142	$306	$2,295	$0	$0	$0	$1,836	$0	$4,591	$6,580	$4,591	$11,171
1999	$6,474	$0	$1,369	$77	$2,141	$281	$8,055	$2,834	$13,605	$16,255	$18,580	$34,834
2000	$6,474	$0	$1,369	$77	$2,141	$281	$8,055	$2,834	$13,605	$16,255	$18,580	$34,834
2001	$6,474	$0	$1,369	$77	$2,141	$281	$8,055	$2,834	$13,605	$16,255	$18,580	$34,834
2002	$6,474	$0	$1,369	$77	$2,141	$281	$8,055	$2,834	$13,605	$16,255	$18,580	$34,834
2003	$6,474	$0	$1,369	$77	$2,141	$281	$8,055	$2,834	$13,605	$16,255	$18,580	$34,834
2004	$6,474	$0	$1,369	$77	$2,141	$281	$8,055	$2,834	$13,605	$16,255	$18,580	$34,834
2005	$6,474	$0	$1,369	$77	$2,141	$281	$8,055	$2,834	$13,605	$16,255	$18,580	$34,834
2006	$2,158	$0	$1,369	$77	$2,141	$281	$8,055	$2,834	$9,070	$11,939	$14,045	$25,984
2007	$2,158	$0	$1,369	$77	$2,141	$281	$8,055	$2,834	$9,070	$11,939	$14,045	$25,984
2008	$2,158	$0	$684	$39	$2,141	$281	$8,055	$2,834	$4,535	$11,216	$9,510	$20,726
2009	$2,158	$0	$684	$39	$2,141	$281	$8,055	$2,834	$4,535	$11,216	$9,510	$20,726
2010	$2,158	$0	$684	$39	$2,141	$281	$8,055	$2,834	$4,535	$11,216	$9,510	$20,726
2011	$2,158	$0	$684	$39	$2,141	$281	$8,055	$2,834	$4,535	$11,216	$9,510	$20,726
2012	$2,158	$0	$684	$39	$2,141	$281	$5,370	$2,834	$4,535	$8,531	$9,510	$18,041
2013	$2,158	$0	$684	$39	$2,141	$281	$5,370	$2,834	$4,535	$8,531	$9,510	$18,041
Total	$71,761	$1,530	$24,842	$925	$32,116	$4,208	$121,571	$42,506	$157,416	$224,837	$232,038	$456,876

INDUSTRIAL
DEFERRED COST, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$2,996	$306	$1,071	$0	$0	$0	$1,479	$0	$4,495	$5,852	$4,495	$10,348
1995	$5,166	$306	$1,377	$0	$0	$0	$3,187	$0	$8,567	$10,037	$8,567	$18,604
1996	$8,190	$306	$1,683	$0	$0	$0	$5,460	$0	$14,053	$15,639	$14,053	$29,692
1997	$10,075	$306	$1,989	$0	$0	$0	$6,971	$0	$17,638	$19,341	$17,638	$36,979
1998	$11,843	$306	$2,295	$0	$0	$0	$8,401	$0	$21,024	$22,846	$21,024	$43,870
1999	$4,089	$0	$864	$76	$1,761	$181	$4,927	$1,615	$7,898	$10,136	$11,274	$21,410
2000	$4,228	$0	$893	$79	$1,821	$187	$5,094	$1,669	$8,167	$10,481	$11,657	$22,138
2001	$4,371	$0	$924	$81	$1,883	$193	$5,267	$1,726	$8,445	$10,837	$12,053	$22,890
2002	$4,520	$0	$955	$84	$1,947	$200	$5,446	$1,785	$8,732	$11,206	$12,463	$23,669
2003	$4,674	$0	$987	$87	$2,013	$207	$5,632	$1,846	$9,028	$11,587	$12,887	$24,473
2004	$4,833	$0	$1,021	$90	$2,081	$214	$5,823	$1,908	$9,335	$11,980	$13,325	$25,306
2005	$4,997	$0	$1,056	$93	$2,152	$221	$6,021	$1,973	$9,653	$12,388	$13,778	$26,166
2006	$1,714	$0	$1,086	$96	$2,214	$227	$6,194	$2,030	$6,620	$9,317	$10,864	$20,181
2007	$1,772	$0	$1,123	$99	$2,289	$235	$6,405	$2,099	$6,845	$9,634	$11,234	$20,867
2008	$1,806	$0	$572	$101	$2,334	$240	$6,529	$2,140	$3,489	$9,248	$7,962	$17,211
2009	$1,868	$0	$592	$104	$2,413	$248	$6,751	$2,213	$3,608	$9,563	$8,233	$17,796
2010	$1,931	$0	$612	$108	$2,495	$256	$6,981	$2,288	$3,730	$9,888	$8,513	$18,401
2011	$1,997	$0	$633	$112	$2,580	$265	$7,218	$2,366	$3,857	$10,224	$8,803	$19,027
2012	$2,057	$0	$652	$115	$2,658	$273	$4,958	$2,437	$3,974	$8,055	$9,070	$17,125
2013	$2,127	$0	$674	$119	$2,748	$282	$5,127	$2,520	$4,109	$8,329	$9,378	$17,707
Total	$85,252	$1,530	$21,060	$1,444	$33,388	$3,431	$113,870	$30,615	$163,269	$226,587	$227,272	$453,859

Appendix H - Program Summaries: Medium Case Forecast

INDUSTRIAL
EXPENSE, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$165	$33	$115	$0	$0	$0	$66	$0	$212	$379	$212	$591
1995	$179	$33	$147	$0	$0	$0	$98	$0	$273	$456	$273	$729
1996	$184	$31	$169	$0	$0	$0	$123	$0	$316	$506	$316	$822
1997	$199	$31	$199	$0	$0	$0	$153	$0	$377	$582	$377	$960
1998	$206	$29	$221	$0	$0	$0	$177	$0	$420	$633	$420	$1,053
1999	$67	$0	$14	$1	$29	$3	$80	$26	$129	$165	$183	$348
2000	$67	$0	$14	$1	$29	$3	$80	$26	$129	$165	$183	$348
2001	$67	$0	$14	$1	$29	$3	$80	$26	$129	$165	$183	$348
2002	$67	$0	$14	$1	$29	$3	$80	$26	$129	$165	$183	$348
2003	$67	$0	$14	$1	$29	$3	$80	$26	$129	$165	$183	$348
2004	$67	$0	$14	$1	$29	$3	$80	$26	$129	$165	$183	$348
2005	$67	$0	$14	$1	$29	$3	$80	$26	$129	$165	$183	$348
2006	$22	$0	$14	$1	$29	$3	$80	$26	$85	$120	$140	$260
2007	$22	$0	$14	$1	$29	$3	$80	$26	$85	$120	$140	$260
2008	$22	$0	$7	$1	$28	$3	$79	$26	$42	$111	$96	$207
2009	$22	$0	$7	$1	$28	$3	$79	$26	$42	$111	$96	$207
2010	$22	$0	$7	$1	$28	$3	$79	$26	$42	$111	$96	$207
2011	$22	$0	$7	$1	$28	$3	$79	$26	$42	$111	$96	$207
2012	$22	$0	$7	$1	$28	$3	$52	$26	$42	$85	$96	$180
2013	$22	$0	$7	$1	$28	$3	$52	$26	$42	$85	$96	$180
Total	$1,573	$156	$1,018	$18	$426	$44	$1,756	$391	$2,920	$4,566	$3,737	$8,303

INDUSTRIAL
INCREMENTAL ESC REVENUE, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$184	$37	$129	$0	$0	$0	$74	$0	$258	$424	$258	$682
1995	$394	$75	$300	$0	$0	$0	$188	$0	$601	$957	$601	$1,558
1996	$630	$114	$517	$0	$0	$0	$346	$0	$1,034	$1,608	$1,034	$2,642
1997	$895	$155	$782	$0	$0	$0	$549	$0	$1,564	$2,382	$1,564	$3,946
1998	$1,190	$197	$1,098	$0	$0	$0	$802	$0	$2,196	$3,288	$2,196	$5,484
1999	$2,111	$197	$1,293	$11	$305	$40	$1,949	$403	$4,132	$5,601	$4,841	$10,442
2000	$3,064	$197	$1,494	$22	$620	$81	$3,134	$820	$6,135	$7,993	$7,575	$15,568
2001	$4,049	$197	$1,703	$34	$946	$124	$4,360	$1,252	$8,205	$10,467	$10,402	$20,869
2002	$5,068	$197	$1,918	$46	$1,283	$168	$5,627	$1,697	$10,346	$13,025	$13,326	$26,350
2003	$6,121	$197	$2,141	$59	$1,631	$214	$6,938	$2,159	$12,559	$15,669	$16,349	$32,018
2004	$7,210	$197	$2,371	$72	$1,991	$261	$8,293	$2,635	$14,848	$18,404	$19,474	$37,878
2005	$8,336	$197	$2,609	$85	$2,364	$310	$9,694	$3,128	$17,214	$21,231	$22,706	$43,937
2006	$8,725	$197	$2,855	$99	$2,749	$360	$11,142	$3,638	$18,846	$23,379	$25,232	$48,611
2007	$9,126	$197	$3,110	$113	$3,147	$412	$12,640	$4,165	$20,533	$25,599	$27,844	$53,443
2008	$9,541	$197	$3,241	$121	$3,559	$466	$14,189	$4,710	$21,405	$27,756	$29,673	$57,429
2009	$9,786	$160	$3,248	$128	$3,984	$522	$15,717	$5,273	$22,048	$29,562	$31,306	$60,868
2010	$9,835	$85	$3,089	$136	$4,425	$580	$17,185	$5,856	$22,380	$30,911	$32,660	$63,571
2011	$9,664	$0	$2,717	$145	$4,880	$639	$18,552	$6,458	$22,310	$31,717	$33,648	$65,364
2012	$9,243	$0	$2,085	$153	$5,350	$701	$19,183	$7,081	$21,742	$31,366	$34,174	$65,539
2013	$8,544	$0	$1,143	$162	$5,837	$765	$19,601	$7,725	$20,577	$30,214	$34,139	$64,354

INDUSTRIAL
CUM. NET SAVINGS, MWa

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	1.9	0.3	0.9	0.0	0.0	0.0	0.9	0.0	2.7	4.0	2.7	6.7
1995	5.2	0.5	2.0	0.0	0.0	0.0	1.8	0.0	8.0	9.6	8.0	17.6
1996	8.8	0.8	3.4	0.0	0.0	0.0	5.4	0.0	17.0	18.4	17.0	35.3
1997	14.3	1.0	5.1	0.0	0.0	0.0	10.1	0.0	28.5	30.5	28.5	59.0
1998	22.6	1.3	7.0	0.0	0.0	0.0	15.9	0.0	42.6	46.7	42.6	89.4
1999	25.4	1.3	7.6	0.1	1.2	0.1	19.3	1.1	48.1	53.8	50.4	104.2
2000	28.3	1.3	8.2	0.1	2.4	0.3	22.7	2.2	53.5	60.8	58.2	119.0
2001	31.1	1.3	8.8	0.2	3.7	0.4	26.1	3.4	59.0	67.8	66.0	133.8
2002	33.9	1.3	9.4	0.2	4.9	0.5	29.5	4.5	64.5	74.8	73.8	148.6
2003	36.8	1.3	10.0	0.3	6.1	0.6	32.9	5.6	69.9	81.8	81.6	163.4
2004	39.6	1.3	10.6	0.3	7.3	0.8	36.3	6.7	75.4	88.8	89.4	178.3
2005	42.4	1.3	11.2	0.4	8.5	0.9	39.8	7.8	80.9	95.8	97.2	193.1
2006	43.4	1.3	11.7	0.4	9.7	1.0	43.2	8.9	84.5	101.0	103.2	204.2
2007	44.3	1.3	12.3	0.5	11.0	1.1	46.6	10.1	88.2	106.1	109.2	215.3
2008	45.2	1.3	12.6	0.5	12.2	1.3	50.0	11.2	90.0	110.9	113.3	224.3
2009	46.2	1.3	12.9	0.6	13.4	1.4	53.4	12.3	91.8	115.8	117.5	233.3
2010	47.1	1.3	13.2	0.6	14.6	1.5	56.8	13.4	93.6	120.6	121.7	242.3
2011	48.1	1.3	13.5	0.7	15.8	1.6	60.2	14.5	95.5	125.4	125.8	251.2
2012	49.0	1.3	13.8	0.7	17.1	1.8	62.5	15.6	97.3	129.1	130.0	259.1
2013	50.0	1.3	14.1	0.8	18.3	1.9	64.8	16.8	99.1	132.8	134.1	266.9
Total	50.0	1.3	14.1	0.8	18.3	1.9	64.8	16.8	99.1	132.8	134.1	266.9

INDUSTRIAL
CUM. CAPACITY, MW

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	2.1	0.3	1.0	0.0	0.0	0.0	0.9	0.0	2.8	4.2	2.8	7.1
1995	5.7	0.6	2.2	0.0	0.0	0.0	1.8	0.0	8.4	10.2	8.4	18.6
1996	9.5	0.8	3.7	0.0	0.0	0.0	5.4	0.0	17.7	19.5	17.7	37.2
1997	15.6	1.1	5.5	0.0	0.0	0.0	10.1	0.0	29.7	32.3	29.7	62.0
1998	24.6	1.4	7.6	0.0	0.0	0.0	15.9	0.0	44.4	49.4	44.4	93.8
1999	27.6	1.4	8.2	0.1	1.3	0.1	19.3	1.1	50.1	56.8	52.5	109.3
2000	30.7	1.4	8.9	0.1	2.6	0.3	22.7	2.2	55.8	64.1	60.7	124.7
2001	33.8	1.4	9.5	0.2	4.0	0.4	26.1	3.4	61.5	71.4	68.8	140.2
2002	36.9	1.4	10.2	0.2	5.3	0.5	29.5	4.5	67.2	78.7	76.9	155.7
2003	39.9	1.4	10.8	0.3	6.6	0.7	32.9	5.6	72.9	86.1	85.1	171.1
2004	43.0	1.4	11.5	0.3	7.9	0.8	36.3	6.7	78.6	93.4	93.2	186.6
2005	46.1	1.4	12.1	0.4	9.3	1.0	39.8	7.8	84.2	100.7	101.3	202.1
2006	47.1	1.4	12.8	0.5	10.6	1.1	43.2	8.9	88.0	106.0	107.6	213.6
2007	48.1	1.4	13.4	0.5	11.9	1.2	46.6	10.1	91.8	111.3	113.8	225.1
2008	49.2	1.4	13.7	0.6	13.2	1.4	50.0	11.2	93.7	116.2	118.2	234.4
2009	50.2	1.4	14.1	0.6	14.6	1.5	53.4	12.3	95.6	121.2	122.5	243.7
2010	51.2	1.4	14.4	0.7	15.9	1.6	56.8	13.4	97.5	126.1	126.8	253.0
2011	52.3	1.4	14.7	0.7	17.2	1.8	60.2	14.5	99.4	131.1	131.2	262.3
2012	53.3	1.4	15.0	0.8	18.5	1.9	62.5	15.6	101.3	134.9	135.5	270.4
2013	54.3	1.4	15.4	0.9	19.9	2.0	64.8	16.8	103.2	138.7	139.9	278.6
Total	54.3	1.4	15.4	0.9	19.9	2.0	64.8	16.8	103.2	138.7	139.9	278.6

Appendix H - Program Summaries: Medium Case Forecast

IRRIGATION PROGRAM
SUMMARY REPORT
ALL COSTS IN REAL $, INCLUDES LINE LOSSES

	CUMULATIVE				INCREMENTAL									
YEAR	NET ENERGY MWa	CAPACITY MW	NET ENERGY Savings MWh	GROSS MWa	GROSS ENERGY MWh	OTHER INVESTMT k$	UTILITY FINANCE k$	UTILITY EXPENSE k$	NPV CUSTOMER O & M k$	REAL ESC REVENUE, k$	TOTAL MEASURE COST k$	DEFERRED OVERHEAD k$	PENETRA-TION RATE	NUMBER OF PARTICIPANTS
1994	0.4	0.4	3,694	0.4	3,694	$0	$599	$56	($289)	$66	$599	$140	0.6%	1
1995	0.8	0.9	7,389	0.8	3,694	$0	$589	$66	($289)	$128	$589	$140	1.2%	1
1996	1.3	1.3	11,083	1.3	3,694	$0	$578	$56	($289)	$188	$578	$140	1.8%	1
1997	1.6	1.7	14,448	1.6	3,365	$0	$279	$66	$0	$212	$279	$140	2.3%	1
1998	2.0	2.1	17,814	2.0	3,365	$0	$279	$56	$0	$236	$279	$140	2.9%	1
1999	3.2	3.3	27,773	3.2	9,959	$832	$878	$58	$0	$324	$1,710	$658	4.5%	3
2000	4.3	4.4	37,733	4.3	9,959	$832	$878	$58	$0	$410	$1,710	$658	6.0%	3
2001	5.4	5.6	47,692	5.4	9,959	$832	$878	$58	$0	$493	$1,710	$658	7.6%	3
2002	6.6	6.8	57,652	6.6	9,959	$832	$878	$58	$0	$573	$1,710	$658	9.2%	3
2003	7.7	8.0	67,611	7.7	9,959	$832	$878	$58	$0	$651	$1,710	$658	10.8%	3
2004	8.9	9.1	77,570	8.9	9,959	$832	$878	$58	$0	$726	$1,710	$658	12.4%	3
2005	10.0	10.3	87,530	10.0	9,959	$832	$878	$58	$0	$798	$1,710	$658	14.0%	3
2006	11.1	11.5	97,489	11.1	9,959	$832	$878	$58	$0	$868	$1,710	$658	15.6%	3
2007	12.3	12.6	107,449	12.3	9,959	$832	$878	$58	$0	$936	$1,710	$658	17.2%	3
2008	13.4	13.8	117,408	13.4	9,959	$832	$878	$58	$599	$1,002	$1,710	$658	18.8%	3
2009	14.5	15.0	127,368	14.5	9,959	$832	$878	$58	$589	$1,025	$1,710	$658	20.4%	3
2010	15.7	16.2	137,327	15.7	9,959	$832	$878	$58	$578	$1,010	$1,710	$658	22.0%	3
2011	16.8	17.3	147,287	16.8	9,959	$832	$878	$58	$279	$960	$1,710	$658	23.6%	3
2012	18.0	18.5	157,246	18.0	9,959	$832	$878	$58	$279	$896	$1,710	$658	25.2%	3
2013	19.1	19.7	167,206	19.1	9,959	$832	$878	$58	$1,710	$821	$1,710	$658	26.8%	3
TOTAL	19.1	19.7	167,206	19.1	167,206	$12,475	$15,493	$1,172	$3,168		$27,968	$10,571	27%	56

DISCOUNT RATE	5.2%
TOTAL RESOURCE COS	21.2
UTILITY COST	8.6
UTAH %	47%
ESC TERM	15.0

ESC LOAN RATE	7.0%
AVE. ANNUAL ESC REVENUE, k$	$4,513
MEASURE COST, $/1ST YR KWH=	0.185
ADMINISTRATIVE ADDER, DEFERRED	39%
ADMINISTRATIVE ADDER, EXPENSE	3%

PROGRAM SAVINGS, % OF SALES=	13.6%
SUPPLEMENTAL SAVED ADDED	
SUPPLEMENTAL COST ADDED	
OTHER FINANCE	

IRRIGATION PROGRAM
PROGRAM PENETRATION

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah
1994	0.2%	6.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1995	0.2%	6.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1996	0.2%	6.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1997	0.0%	6.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1998	0.0%	6.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1999	1.5%	1.5%	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	1.5%
2000	1.5%	1.5%	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	1.5%
2001	1.5%	1.5%	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	1.5%
2002	1.5%	1.5%	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	1.5%
2003	1.5%	1.5%	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	1.5%
2004	1.5%	1.5%	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	1.5%
2005	1.5%	1.5%	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	1.5%
2006	1.5%	1.5%	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	1.5%
2007	1.5%	1.5%	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	1.5%
2008	1.5%	1.5%	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	1.5%
2009	1.5%	1.5%	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	1.5%
2010	1.5%	1.5%	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	1.5%
2011	1.5%	1.5%	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	1.5%
2012	1.5%	1.5%	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	1.5%
2013	1.5%	1.5%	1.5%	0.0%	1.5%	0.0%	0.0%	0.0%	1.5%
Total	23.1%	52.7%	22.5%	0.0%	22.5%	0.0%	0.0%	0.0%	22.5%

Appendix H - Program Summaries: Medium Case Forecast

IRRIGATION PROGRAM
INCREMENTAL GROSS SAVINGS, MWh

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	329	3,365	0	0	0	0	0	0	0	3,694	0	3,694
1995	329	3,365	0	0	0	0	0	0	0	3,694	0	3,694
1996	329	3,365	0	0	0	0	0	0	0	3,694	0	3,694
1997	0	3,365	0	0	0	0	0	0	0	3,365	0	3,365
1998	0	3,365	0	0	0	0	0	0	0	3,365	0	3,365
1999	2,489	936	1,287	0	4,048	0	0	0	1,199	4,713	5,247	9,959
2000	2,489	936	1,287	0	4,048	0	0	0	1,199	4,713	5,247	9,959
2001	2,489	936	1,287	0	4,048	0	0	0	1,199	4,713	5,247	9,959
2002	2,489	936	1,287	0	4,048	0	0	0	1,199	4,713	5,247	9,959
2003	2,489	936	1,287	0	4,048	0	0	0	1,199	4,713	5,247	9,959
2004	2,489	936	1,287	0	4,048	0	0	0	1,199	4,713	5,247	9,959
2005	2,489	936	1,287	0	4,048	0	0	0	1,199	4,713	5,247	9,959
2006	2,489	936	1,287	0	4,048	0	0	0	1,199	4,713	5,247	9,959
2007	2,489	936	1,287	0	4,048	0	0	0	1,199	4,713	5,247	9,959
2008	2,489	936	1,287	0	4,048	0	0	0	1,199	4,713	5,247	9,959
2009	2,489	936	1,287	0	4,048	0	0	0	1,199	4,713	5,247	9,959
2010	2,489	936	1,287	0	4,048	0	0	0	1,199	4,713	5,247	9,959
2011	2,489	936	1,287	0	4,048	0	0	0	1,199	4,713	5,247	9,959
2012	2,489	936	1,287	0	4,048	0	0	0	1,199	4,713	5,247	9,959
2013	2,489	936	1,287	0	4,048	0	0	0	1,199	4,713	5,247	9,959
Total	38,320	30,873	19,311	0	60,713	0	0	0	17,989	88,504	78,702	167,206

IRRIGATION PROGRAM
MEASURE COST, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$320	$279	$0	$0	$0	$0	$0	$0	$0	$599	$0	$599
1995	$309	$279	$0	$0	$0	$0	$0	$0	$0	$589	$0	$589
1996	$299	$279	$0	$0	$0	$0	$0	$0	$0	$578	$0	$578
1997	$0	$279	$0	$0	$0	$0	$0	$0	$0	$279	$0	$279
1998	$0	$279	$0	$0	$0	$0	$0	$0	$0	$279	$0	$279
1999	$422	$154	$215	$0	$707	$0	$0	$0	$211	$791	$918	$1,710
2000	$422	$154	$215	$0	$707	$0	$0	$0	$211	$791	$918	$1,710
2001	$422	$154	$215	$0	$707	$0	$0	$0	$211	$791	$918	$1,710
2002	$422	$154	$215	$0	$707	$0	$0	$0	$211	$791	$918	$1,710
2003	$422	$154	$215	$0	$707	$0	$0	$0	$211	$791	$918	$1,710
2004	$422	$154	$215	$0	$707	$0	$0	$0	$211	$791	$918	$1,710
2005	$422	$154	$215	$0	$707	$0	$0	$0	$211	$791	$918	$1,710
2006	$422	$154	$215	$0	$707	$0	$0	$0	$211	$791	$918	$1,710
2007	$422	$154	$215	$0	$707	$0	$0	$0	$211	$791	$918	$1,710
2008	$422	$154	$215	$0	$707	$0	$0	$0	$211	$791	$918	$1,710
2009	$422	$154	$215	$0	$707	$0	$0	$0	$211	$791	$918	$1,710
2010	$422	$154	$215	$0	$707	$0	$0	$0	$211	$791	$918	$1,710
2011	$422	$154	$215	$0	$707	$0	$0	$0	$211	$791	$918	$1,710
2012	$422	$154	$215	$0	$707	$0	$0	$0	$211	$791	$918	$1,710
2013	$422	$154	$215	$0	$707	$0	$0	$0	$211	$791	$918	$1,710
Total	$7,262	$3,713	$3,219	$0	$10,607	$0	$0	$0	$3,167	$14,193	$13,775	$27,968

IRRIGATION PROGRAM
DEFERRED COST, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$320	$419	$0	$0	$0	$0	$0	$0	$0	$739	$0	$739
1995	$309	$419	$0	$0	$0	$0	$0	$0	$0	$728	$0	$728
1996	$299	$419	$0	$0	$0	$0	$0	$0	$0	$718	$0	$718
1997	$0	$419	$0	$0	$0	$0	$0	$0	$0	$419	$0	$419
1998	$0	$419	$0	$0	$0	$0	$0	$0	$0	$419	$0	$419
1999	$163	$33	$83	$0	$272	$0	$0	$0	$81	$279	$354	$632
2000	$163	$33	$83	$0	$272	$0	$0	$0	$81	$279	$354	$632
2001	$163	$33	$83	$0	$272	$0	$0	$0	$81	$279	$354	$632
2002	$163	$33	$83	$0	$272	$0	$0	$0	$81	$279	$354	$632
2003	$163	$33	$83	$0	$272	$0	$0	$0	$81	$279	$354	$632
2004	$163	$33	$83	$0	$272	$0	$0	$0	$81	$279	$354	$632
2005	$163	$33	$83	$0	$272	$0	$0	$0	$81	$279	$354	$632
2006	$163	$33	$83	$0	$272	$0	$0	$0	$81	$279	$354	$632
2007	$163	$33	$83	$0	$272	$0	$0	$0	$81	$279	$354	$632
2008	$163	$33	$83	$0	$272	$0	$0	$0	$81	$279	$354	$632
2009	$163	$33	$83	$0	$272	$0	$0	$0	$81	$279	$354	$632
2010	$163	$33	$83	$0	$272	$0	$0	$0	$81	$279	$354	$632
2011	$163	$33	$83	$0	$272	$0	$0	$0	$81	$279	$354	$632
2012	$163	$33	$83	$0	$272	$0	$0	$0	$81	$279	$354	$632
2013	$163	$33	$83	$0	$272	$0	$0	$0	$81	$279	$354	$632
Total	$3,367	$2,594	$1,239	$0	$4,084	$0	$0	$0	$1,219	$7,201	$5,303	$12,504

IRRIGATION PROGRAM
EXPENSE, K$
NOMINAL $'s

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$0	$56	$0	$0	$0	$0	$0	$0	$0	$56	$0	$56
1995	$0	$66	$0	$0	$0	$0	$0	$0	$0	$66	$0	$66
1996	$0	$56	$0	$0	$0	$0	$0	$0	$0	$56	$0	$56
1997	$0	$66	$0	$0	$0	$0	$0	$0	$0	$66	$0	$66
1998	$0	$56	$0	$0	$0	$0	$0	$0	$0	$56	$0	$56
1999	$17	$37	$9	$0	$28	$0	$0	$0	$8	$63	$37	$100
2000	$18	$38	$9	$0	$29	$0	$0	$0	$9	$65	$38	$103
2001	$18	$40	$9	$0	$30	$0	$0	$0	$9	$67	$39	$106
2002	$19	$41	$10	$0	$31	$0	$0	$0	$9	$69	$41	$110
2003	$19	$42	$10	$0	$32	$0	$0	$0	$10	$72	$42	$114
2004	$20	$44	$10	$0	$34	$0	$0	$0	$10	$74	$44	$118
2005	$21	$45	$11	$0	$35	$0	$0	$0	$10	$77	$45	$122
2006	$21	$47	$11	$0	$36	$0	$0	$0	$11	$79	$47	$126
2007	$22	$48	$11	$0	$37	$0	$0	$0	$11	$82	$48	$130
2008	$23	$50	$12	$0	$38	$0	$0	$0	$11	$85	$50	$135
2009	$24	$52	$12	$0	$40	$0	$0	$0	$12	$88	$52	$139
2010	$25	$54	$12	$0	$41	$0	$0	$0	$12	$90	$53	$144
2011	$25	$55	$13	$0	$42	$0	$0	$0	$13	$94	$55	$149
2012	$26	$57	$13	$0	$44	$0	$0	$0	$13	$97	$57	$154
2013	$27	$59	$14	$0	$45	$0	$0	$0	$14	$100	$59	$159
Total	$325	$1,010	$165	$0	$544	$0	$0	$0	$163	$1,500	$707	$2,207

IRRIGATION PROGRAM
INCREMENTAL ESC REVENUE, K$

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	$39	$34	$0	$0	$0	$0	$0	$0	$0	$72	$0	$72
1995	$77	$68	$0	$0	$0	$0	$0	$0	$0	$145	$0	$145
1996	$116	$104	$0	$0	$0	$0	$0	$0	$0	$220	$0	$220
1997	$116	$141	$0	$0	$0	$0	$0	$0	$0	$257	$0	$257
1998	$116	$180	$0	$0	$0	$0	$0	$0	$0	$296	$0	$296
1999	$176	$202	$31	$0	$101	$0	$0	$0	$30	$408	$131	$539
2000	$238	$225	$62	$0	$205	$0	$0	$0	$61	$525	$266	$790
2001	$302	$248	$95	$0	$312	$0	$0	$0	$93	$645	$406	$1,051
2002	$369	$272	$129	$0	$424	$0	$0	$0	$126	$770	$550	$1,320
2003	$437	$298	$163	$0	$539	$0	$0	$0	$161	$898	$699	$1,598
2004	$508	$324	$200	$0	$658	$0	$0	$0	$196	$1,031	$854	$1,885
2005	$582	$350	$237	$0	$781	$0	$0	$0	$233	$1,169	$1,014	$2,183
2006	$658	$378	$276	$0	$908	$0	$0	$0	$271	$1,311	$1,179	$2,490
2007	$736	$407	$315	$0	$1,039	$0	$0	$0	$310	$1,458	$1,350	$2,808
2008	$817	$437	$357	$0	$1,175	$0	$0	$0	$351	$1,611	$1,526	$3,137
2009	$863	$434	$399	$0	$1,316	$0	$0	$0	$393	$1,696	$1,709	$3,405
2010	$872	$397	$444	$0	$1,461	$0	$0	$0	$436	$1,713	$1,898	$3,611
2011	$847	$326	$489	$0	$1,612	$0	$0	$0	$481	$1,661	$2,093	$3,754
2012	$824	$218	$536	$0	$1,767	$0	$0	$0	$528	$1,578	$2,295	$3,873
2013	$804	$73	$585	$0	$1,928	$0	$0	$0	$576	$1,463	$2,503	$3,966

IRRIGATION PROGRAM
CUM. NET SAVINGS, MWa

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.4
1995	0.1	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.8
1996	0.1	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	0.0	1.3
1997	0.1	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.6	0.0	1.6
1998	0.1	1.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	2.0
1999	0.4	2.0	0.1	0.0	0.5	0.0	0.0	0.0	0.1	2.6	0.6	3.2
2000	0.7	2.1	0.3	0.0	0.9	0.0	0.0	0.0	0.3	3.1	1.2	4.3
2001	1.0	2.2	0.4	0.0	1.4	0.0	0.0	0.0	0.4	3.6	1.8	5.4
2002	1.2	2.3	0.6	0.0	1.8	0.0	0.0	0.0	0.5	4.2	2.4	6.6
2003	1.5	2.5	0.7	0.0	2.3	0.0	0.0	0.0	0.7	4.7	3.0	7.7
2004	1.8	2.6	0.9	0.0	2.8	0.0	0.0	0.0	0.8	5.3	3.6	8.9
2005	2.1	2.7	1.0	0.0	3.2	0.0	0.0	0.0	1.0	5.8	4.2	10.0
2006	2.4	2.8	1.2	0.0	3.7	0.0	0.0	0.0	1.1	6.3	4.8	11.1
2007	2.7	2.9	1.3	0.0	4.2	0.0	0.0	0.0	1.2	6.9	5.4	12.3
2008	3.0	3.0	1.5	0.0	4.6	0.0	0.0	0.0	1.4	7.4	6.0	13.4
2009	3.2	3.1	1.6	0.0	5.1	0.0	0.0	0.0	1.5	8.0	6.6	14.5
2010	3.5	3.2	1.8	0.0	5.5	0.0	0.0	0.0	1.6	8.5	7.2	15.7
2011	3.8	3.3	1.9	0.0	6.0	0.0	0.0	0.0	1.8	9.0	7.8	16.8
2012	4.1	3.4	2.1	0.0	6.5	0.0	0.0	0.0	1.9	9.6	8.4	18.0
2013	4.4	3.5	2.2	0.0	6.9	0.0	0.0	0.0	2.1	10.1	9.0	19.1
Total	4.4	3.5	2.2	0.0	6.9	0.0	0.0	0.0	2.1	10.1	9.0	19.1

IRRIGATION PROGRAM
CUM. CAPACITY, MW

YEAR	Oregon	California	Washington	Idaho - PPL	Idaho - UPL	Montana	Wyoming - PPL	Wyoming - UPL	Utah	Pacific Division	Utah Division	Total Company
1994	0.1	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.0	0.7
1995	0.1	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.4	0.0	1.4
1996	0.2	1.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1	0.0	2.1
1997	0.2	2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7	0.0	2.7
1998	0.2	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.4	0.0	3.4
1999	0.7	3.4	0.2	0.0	0.8	0.0	0.0	0.0	0.2	4.3	1.0	5.3
2000	1.1	3.6	0.5	0.0	1.5	0.0	0.0	0.0	0.5	5.2	2.0	7.2
2001	1.6	3.7	0.7	0.0	2.3	0.0	0.0	0.0	0.7	6.1	3.0	9.1
2002	2.1	3.9	1.0	0.0	3.1	0.0	0.0	0.0	0.9	7.0	4.0	11.0
2003	2.6	4.1	1.2	0.0	3.9	0.0	0.0	0.0	1.1	7.9	5.0	12.9
2004	3.0	4.3	1.5	0.0	4.6	0.0	0.0	0.0	1.4	8.8	6.0	14.8
2005	3.5	4.4	1.7	0.0	5.4	0.0	0.0	0.0	1.6	9.7	7.0	16.7
2006	4.0	4.6	2.0	0.0	6.2	0.0	0.0	0.0	1.8	10.6	8.0	18.5
2007	4.4	4.8	2.2	0.0	6.9	0.0	0.0	0.0	2.1	11.5	9.0	20.4
2008	4.9	5.0	2.4	0.0	7.7	0.0	0.0	0.0	2.3	12.4	10.0	22.3
2009	5.4	5.2	2.7	0.0	8.5	0.0	0.0	0.0	2.5	13.3	11.0	24.2
2010	5.9	5.3	2.9	0.0	9.2	0.0	0.0	0.0	2.7	14.1	12.0	26.1
2011	6.3	5.5	3.2	0.0	10.0	0.0	0.0	0.0	3.0	15.0	13.0	28.0
2012	6.8	5.7	3.4	0.0	10.8	0.0	0.0	0.0	3.2	15.9	14.0	29.9
2013	7.3	5.9	3.7	0.0	11.6	0.0	0.0	0.0	3.4	16.8	15.0	31.8
Total	7.3	5.9	3.7	0.0	11.6	0.0	0.0	0.0	3.4	16.8	15.0	31.8

APPENDIX
I

APPENDIX I - Demand Side Resource Two Year Acquisition Plan

The following tables provide detailed unit and savings targets by program area by state for 1994 and 1995. Residential and commercial subtotals are included for each table. The tables each have six columns. The first column is the program name, the second is the definition of units, such as homes, square feet, etc., the third is the number of units, the fourth is the MWH savings target, the fifth is the aMW and is calculated by taking MWH savings divided by 8760 hours per year and rounded to the nearest one-tenth, and the final column is the company budget. The budget is total deferred expenditures including company funded loans and program operation expense. The budget is not utility cost since it includes the loan dispersements to program participants for Energy Service Contracts and is not net of the ESC payments.

Demand Side Resource Two Year Acquisition Plan

1994					
Total Company					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	3,142	15,201	1.7	$8.66
Existing Residential	Homes	16,075	31,180	3.6	$10.44
Low Income	Homes	1,215	2,003	0.2	$1.78
Appliances	Appliances	10,163	2,499	0.3	$.57
Residential Total			50,883	5.8	$21.45
New Commercial	Sq. Ft.	4,731,845	22,932	2.6	$7.35
Existing Commercial	Sq. Ft.	933,417	18,702	2.1	$4.04
Commercial Total			41,634	4.8	$11.39
Industrial	n/a		56,344	6.4	$9.59
Total			148,861	17.0	$42.43

1995					
Total Company					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	3,604	17,513	2.0	$7.83
Existing Residential	Homes	2,829	15,556	1.8	$5.89
Low Income	Homes	1,215	2,023	0.2	$1.84
Appliances	Appliances	10,317	2,505	0.3	$.59
Residential Total			37,597	4.3	$16.15
New Commercial	Sq. Ft.	5,364,326	25,261	2.9	$7.55
Existing Commercial	Sq. Ft.	2,240,201	36,933	4.2	$7.61
Commercial Total			62,194	7.1	$15.16
Industrial	n/a		101,731	11.6	$15.95
Total			201,522	23.0	$47.27

Demand Side Resource Two Year Acquisition Plan

1994					
California					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	139	618	0.1	$.38
Existing Residential	Homes	225	1,355	0.2	$.99
Low Income	Homes	100	150	0.0	$.13
Appliances	Appliances	248	55	0.0	$.01
Residential Total			2,178	0.2	$1.51
New Commercial	Sq. Ft.	63,625	320	0.0	$.10
Existing Commercial	Sq. Ft.		0	0.0	$.00
Commercial Total			320	0.0	$.10
Industrial	n/a		2,990	0.3	$.75
Total			5,488	0.6	$2.36

1995					
California					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	200	871	0.1	$.42
Existing Residential	Homes	110	555	0.1	$.32
Low Income	Homes	100	150	0.0	$.13
Appliances	Appliances	247	54	0.0	$.01
Residential Total			1,630	0.2	$.87
New Commercial	Sq. Ft.	86,814	445	0.1	$.13
Existing Commercial	Sq. Ft.		0	0.0	$.00
Commercial Total			445	0.1	$.13
Industrial	n/a		2,990	0.3	$.76
Total			5,065	0.6	$1.77

Demand Side Resource Two Year Acquisition Plan

1994					
Idaho					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	156	1,116	0.1	$.44
Existing Residential	Homes	25	109	0.0	$.03
Low Income	Homes	25	24	0.0	$.03
Appliances	Appliances	246	69	0.0	$.01
Residential Total			1,318	0.2	$.51
New Commercial	Sq. Ft.	73,315	501	0.1	$.16
Existing Commercial	Sq. Ft.		0	0.0	$.00
Commercial Total			501	0.1	$.16
Industrial	n/a		2,634	0.3	$.67
Total			4,453	0.5	$1.35

1995					
Idaho					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	209	1,515	0.2	$.45
Existing Residential	Homes	60	259	0.0	$.07
Low Income	Homes	25	44	0.0	$.04
Appliances	Appliances	244	68	0.0	$.01
Residential Total			1,886	0.2	$.57
New Commercial	Sq. Ft.	106,368	724	0.1	$.21
Existing Commercial	Sq. Ft.		0	0.0	$.00
Commercial Total			724	0.1	$.21
Industrial	n/a		7,884	0.9	$1.23
Total			10,494	1.2	$2.01

Demand Side Resource Two Year Acquisition Plan

1994					
Montana					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	66	415	0.0	$.17
Existing Residential	Homes	25	109	0.0	$.03
Low Income	Homes	15	29	0.0	$.03
Appliances	Appliances	168	41	0.0	$.01
Residential Total			594	0.1	$.24
New Commercial	Sq. Ft.	33,503	144	0.0	$.05
Existing Commercial	Sq. Ft.		0	0.0	$.00
Commercial Total			144	0.0	$.05
Industrial	n/a		0	0.0	$.00
Total			738	0.1	$.29

1995					
Montana					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	67	351	0.0	$.14
Existing Residential	Homes	60	259	0.0	$.07
Low Income	Homes	15	29	0.0	$.04
Appliances	Appliances	168	41	0.0	$.01
Residential Total			680	0.1	$.26
New Commercial	Sq. Ft.	40,290	175	0.0	$.05
Existing Commercial	Sq. Ft.		0	0.0	$.00
Commercial Total			175	0.0	$.05
Industrial	n/a		0	0.0	$.00
Total			855	0.1	$.31

Demand Side Resource Two Year Acquisition Plan

1994					
Oregon					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	2,264	10,070	1.1	$5.94
Existing Residential	Homes	2,150	8,349	1.0	$2.65
Low Income	Homes	550	825	0.1	$.68
Appliances	Appliances	6,109	2,127	0.2	$.51
Residential Total			21,371	2.4	$9.77
New Commercial	Sq. Ft.	1,621,316	7,524	0.9	$2.34
Existing Commercial	Sq. Ft.	933,417	13,402	1.5	$2.69
Commercial Total			20,926	2.4	$5.04
Industrial	n/a		12,755	1.5	$2.07
Total			55,052	6.3	$16.88

1995					
Oregon					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	2,601	11,776	1.3	$5.38
Existing Residential	Homes	2,120	8,298	0.9	$2.84
Low Income	Homes	550	825	0.1	$.73
Appliances	Appliances	6,155	2,139	0.2	$.53
Residential Total			23,038	2.6	$9.48
New Commercial	Sq. Ft.	1,739,542	8,021	0.9	$2.34
Existing Commercial	Sq. Ft.	2,240,201	28,103	3.2	$5.52
Commercial Total			36,124	4.1	$7.87
Industrial	n/a		18,962	2.2	$2.95
Total			78,124	8.9	$20.30

Demand Side Resource Two Year Acquisition Plan

1994					
Washington					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	488	2,843	0.3	$1.65
Existing Residential	Homes	650	8,393	1.0	$3.61
Low Income	Homes	375	750	0.1	$.67
Appliances	Appliances	1,110	207	0.0	$.03
Residential Total			12,193	1.4	$5.96
New Commercial	Sq. Ft.	186,131	1,057	0.1	$.35
Existing Commercial	Sq. Ft.		0	0.0	$.00
Commercial Total			1,057	0.1	$.35
Industrial	n/a		8,051	0.9	$1.34
Total			21,301	2.4	$7.65

1995					
Washington					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	474	2,740	0.3	$1.31
Existing Residential	Homes	479	6,185	0.7	$2.58
Low Income	Homes	375	750	0.1	$.67
Appliances	Appliances	1,115	203	0.0	$.03
Residential Total			9,878	1.1	$4.59
New Commercial	Sq. Ft.	270,206	1,072	0.1	$.38
Existing Commercial	Sq. Ft.		0	0.0	$.00
Commercial Total			1,072	0.1	$.38
Industrial	n/a		12,154	1.4	$1.99
Total			23,104	2.6	$6.96

Demand Side Resource Two Year Acquisition Plan

1994					
Utah					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes		0	0.0	$.00
Existing Residential	Homes	13,000	12,864	1.5	$3.12
Low Income	Homes	150	225	0.0	$.25
Appliances	Appliances	2,134	0	0.0	$.00
Residential Total			13,089	1.5	$3.36
New Commercial	Sq. Ft.	2,597,885	12,906	1.5	$4.18
Existing Commercial	Sq. Ft.		5,300	0.6	$1.35
Commercial Total			18,206	2.1	$5.52
Industrial	n/a		29,213	3.3	$4.66
Total			60,508	6.9	$13.55

1995					
Utah					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes		0	0.0	$.00
Existing Residential	Homes		0	0.0	$.00
Low Income	Homes	150	225	0.0	$.25
Appliances	Appliances	2,138	0	0.0	$.00
Residential Total			225	0.0	$.25
New Commercial	Sq. Ft.	2,927,116	14,229	1.6	$4.24
Existing Commercial	Sq. Ft.		8,830	1.0	$2.09
Commercial Total			23,059	2.6	$6.33
Industrial	n/a		57,639	6.6	$8.73
Total			80,923	9.2	$15.30

Demand Side Resource Two Year Acquisition Plan

1994					
Wyoming					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	29	139	0.0	$.09
Existing Residential	Homes		0	0.0	$.00
Low Income	Homes		0	0.0	$.00
Appliances	Appliances	148	0	0.0	$.00
Residential Total			139	0.0	$.09
New Commercial	Sq. Ft.	156,070	480	0.1	$.17
Existing Commercial	Sq. Ft.		0	0.0	$.00
Commercial Total			480	0.1	$.17
Industrial	n/a		701	0.1	$.10
Total			1,320	0.2	$.36

1995					
Wyoming					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	53	260	0.0	$.14
Existing Residential	Homes		0	0.0	$.00
Low Income	Homes		0	0.0	$.00
Appliances	Appliances	250	0	0.0	$.00
Residential Total			260	0.0	$.14
New Commercial	Sq. Ft.	193,990	595	0.1	$.19
Existing Commercial	Sq. Ft.		0	0.0	$.00
Commercial Total			595	0.1	$.19
Industrial	n/a		2,102	0.2	$.29
Total			2,957	0.3	$.61

Demand Side Resource Two Year Acquisition Plan

1994					
Pacific Division					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	3,113	14,193	1.7	$8.24
Existing Residential	Homes	3,075	18,316	2.1	$7.32
Low Income	Homes	1,065	1,759	0.2	$1.51
Appliances	Appliances	7,881	2,499	0.3	$.57
Residential Total			36,767	4.2	$17.64
New Commercial	Sq. Ft.	1,977,890	9,546	1.1	$3.01
Existing Commercial	Sq. Ft.	933,417	13,402	1.5	$2.69
Commercial Total			22,948	2.6	$5.70
Industrial	n/a		23,796	3.0	$4.16
Total			83,511	9.5	$27.50

1995					
Pacific Division					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	3,551	16,043	2.0	$7.36
Existing Residential	Homes	2,829	15,556	1.8	$5.89
Low Income	Homes	1,065	1,763	0.2	$1.57
Appliances	Appliances	7,929	2,505	0.3	$.59
Residential Total			35,867	4.1	$15.40
New Commercial	Sq. Ft.	2,243,220	10,437	1.2	$3.11
Existing Commercial	Sq. Ft.	2,240,201	28,103	3.2	$5.52
Commercial Total			38,540	4.4	$8.64
Industrial	n/a		34,106	4.8	$5.71
Total			99,384	11.3	$29.74

Demand Side Resource Two Year Acquisition Plan

1994					
Utah Division					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	29	1,008	0.0	$.42
Existing Residential	Homes	13,000	12,864	1.5	$3.12
Low Income	Homes	150	244	0.0	$.27
Appliances	Appliances	2,282	0	0.0	$.00
Residential Total			14,116	1.6	$3.81
New Commercial	Sq. Ft.	2,753,955	13,386	1.5	$4.34
Existing Commercial	Sq. Ft.	0	5,300	0.6	$1.35
Commercial Total			18,686	2.1	$5.69
Industrial	n/a		32,548	3.4	$5.43
Total			65,350	7.5	$14.94

1995					
Utah Division					
PROGRAM	**UNITS**	**# UNITS**	**MWH SAVINGS**	**aMW**	**BUDGET Def/O&M (Million $)**
New Residential	Homes	53	1,470	0.0	$.48
Existing Residential	Homes	0	0	0.0	$.00
Low Income	Homes	150	260	0.0	$.28
Appliances	Appliances	2,388	0	0.0	$.00
Residential Total			1,730	0.2	$.75
New Commercial	Sq. Ft.	3,121,106	14,824	1.7	$4.44
Existing Commercial	Sq. Ft.	0	8,830	1.0	$2.09
Commercial Total			23,654	2.7	$6.52
Industrial	n/a		67,625	6.8	$10.24
Total			93,009	10.6	$17.52

APPENDIX J

APPENDIX J

Methodology for Financial Analysis of DSR Investments

Page j-1 contains the financial and modeling assumptions, the program megawatt hour savings by year and state, and the program costs by category.

Page j-2 contains the after-tax cash flow analysis. The follwing is a column by column explanation of the DSR financial model calculations with after-tax cash flows. What does this go to?

COLUMN	EXPLANATION
2	Lost retail revenues which are calculated by multiplying megawatt hour savings by the projected retail price by jurisdiction.
3	Shows the projected ESC revenues. This would include the total ESC payment received which would include both the interest portion that would be treated as income and the principle portion which would not.
4	Provides current O&M expenses (note in this case all O&M expenses are deferred and are shown in column 11).
5	Bad debt losses are assumed to be 0.5 percent of the ESC payments.
6	System cost savings are equal to incremental power cost savings, avoided line losses, plus 15 percent.
7	Operating (Cost) or benefit is the sum of columns 2 through 6.
8	Income taxes are the taxes actually paid (current) rather than the taxes that are booked.
9	Grants and rebates would be included, but in this example there are none.
10	ESC loans are the funds advanced to the customer to cover incremental measure cost.
11	O&M cost which are deferred
12	Total investment is the sum of columns 10 and 11.
13	The unleveraged cash flow is used to calculate the IRR. In this example the IRR is 14 percent. Come again? What example!!!

The box at the bottom of the table shows the 1994 Net Present Value @ 8% which for this program example is approximately $25 million, with an Internal Rate of Return of 14.02 %, and a discounted payback period of 11.72 years.

Pages j-3 and j-4 show the calculation of revenue requirements. Column 14, Revenue Requirement Increase (decrease) is the important result which shows that this program decreases revenue requirement by about $40 million (39,598). Page j-4 shows the calculation of rate base.

Pages j-5, j-6, and j-7 contain backup calculations. Page j-5 shows megawatt-hour savings by state and the tax calculations. Page j-6 shows the system cost assumptions and the ESC payment calculations. Page j-7 shows the retail price forecasts assumptions by state and year in cents per kwh.

Page j-8 contains a calculation of the real levelized cost of the program per kWh including the impact of lost revenues. In this case the real levelized cost is 34.99 mills (6.15 in column 6 plus 28.84 in column 9). Comparing this with the target of 43.63 mills (column 7) which represents our incremental power cost grossed up for line losses plus the 15 percent adder, shows that the program comes in below the company's target and therefore meets the internal cost effectiveness criteria .

Example: Financial Analysis tables using the Major Accounts program follows:

PACIFICORP ELECTRIC OPERATIONS

MAJOR ACCOUNTS WITH DEF. LOST REVENUE, 2% PRICE INCR., INCR. PWR. COST

CALCULATION OF REVENUE REQUIREMENTS

(THOUSANDS OF DOLLARS)

JANUARY 26, 1994

O&M deferred

YEAR (1)	O&M EXPENSE (2)	BOOK AMORT (3)	INTEREST EXPENSE (4)	PREFERRED RETURN (5)	COMMON RETURN (6)	INCOME TAXES (7)	ANNUAL COST (8)	BAD DEBT LOSSES (9)	RETAIL REVENUE (10)	SYSTEM COST SAVINGS (11)	ESc REVENUE (12)	DEFERRED NET OPP REVENUES (13)	REV RQMT INCREASE (DECREASE) (14)	CUM. PV REV RQMT BENEFIT (15)	MWH SAVINGS (16)
1994	0	148	57	7	85	56	354	1	289	(316)	(199)	18	147	(136)	8,750
1995	0	761	278	36	420	276	1,771	5	1,466	(1,687)	(1,008)	147	694	(731)	43,800
1996	0	2,156	766	99	1,155	761	4,936	14	4,203	(5,007)	(2,843)	(11)	1,293	(1,757)	122,650
1997	0	4,355	1,494	193	2,253	1,483	9,778	29	8,607	(11,876)	(5,703)	(11)	823	(2,362)	245,300
1998	0	7,231	2,375	307	3,583	2,358	15,853	47	14,477	(20,253)	(9,384)	(11)	729	(2,858)	403,000
1999	0	8,976	2,697	348	4,069	2,679	18,768	57	18,045	(25,614)	(11,430)	(11)	(185)	(2,742)	490,600
2000	0	9,244	2,385	308	3,598	2,369	17,904	57	18,475	(26,630)	(11,430)	(11)	(1,634)	(1,788)	490,600
2001	0	9,520	2,064	266	3,114	2,050	17,014	57	18,917	(27,645)	(11,430)	(11)	(3,098)	(115)	490,600
2002	0	9,805	1,733	224	2,615	1,721	16,098	57	19,369	(28,717)	(11,430)	(11)	(4,635)	2,204	490,600
2003	0	10,098	1,392	180	2,101	1,383	15,154	57	19,832	(29,902)	(11,430)	(11)	(6,300)	5,122	490,600
2004	0	10,201	1,045	135	1,577	1,038	13,995	56	20,306	(31,087)	(11,231)	(11)	(7,971)	8,541	490,600
2005	0	9,697	704	91	1,063	700	12,255	52	20,792	(32,328)	(10,422)	(11)	(9,662)	12,378	490,600
2006	0	8,152	399	52	602	396	9,601	43	21,289	(33,626)	(8,587)	(11)	(11,291)	16,529	490,600
2007	0	5,535	165	21	249	164	6,134	29	21,799	(34,980)	(5,727)	(11)	(12,756)	20,872	490,600
2008	0	2,019	36	5	54	36	2,150	10	22,322	(36,447)	(2,046)	(11)	(14,021)	25,292	490,600
2009	0	33	1	0	2	1	39	0	22,449	(37,237)	0	(11)	(14,761)	29,601	481,850
2010	0	27	1	0	2	1	30	0	21,316	(35,916)	0	(11)	(14,581)	33,542	446,800
2011	0	20	1	0	1	1	22	0	17,975	(30,805)	0	0	(12,807)	36,747	367,950
2012	0	13	0	0	0	0	14	0	12,271	(21,383)	0	0	(9,097)	38,855	245,300
2013	0	7	0	0	0	0	7	0	4,487	(7,958)	0	0	(3,464)	39,598	87,600
2014	0	0	0	0	0	0	0	0	0	0	0	0	0	39,598	0
2015	0	0	0	0	0	0	0	0	0	0	0	0	0	39,598	0
2016	0	0	0	0	0	0	0	0	0	0	0	0	0	39,598	0
2017	0	0	0	0	0	0	0	0	0	0	0	0	0	39,598	0
2018	0	0	0	0	0	0	0	0	0	0	0	0	0	39,598	0
2019	0	0	0	0	0	0	0	0	0	0	0	0	0	39,598	0
2020	0	0	0	0	0	0	0	0	0	0	0	0	0	39,598	0
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	39,598	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	39,598	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	39,598	0
TOTAL	0	98,000	17,592	2,271	26,542	17,473	161,879	571	308,686	(479,415)	(114,300)	0	(122,578)		7,359,000
1994 NET PRESENT VALUE @ 8%							87,475	298	132,157	(199,939)	(59,651)	62	(39,598)		

Discounted Revenue Requirement Breakeven 8.05 YEARS

PACIFICORP ELECTRIC OPERATIONS
MAJOR ACCOUNTS WITH DEF. LOST REVENUE, 2% PRICE INCR., INCR. PWR. COST
CALCULATION OF RATE BASE
(THOUSANDS OF DOLLARS)
JANUARY 26, 1994

YEAR (1)	BEGINNING RATE BASE (2)	GRANTS/ REBATES (3)	AMORT OF GRANTS/ REBATES (4)	ESC LOANS (5)	AMORT OF LOANS (6)	DEFERRED OPPOR REV (7)	AMORT OF OPPOR REV (8)	DEFERRED EXPENSES (9)	AMORT OF DEF. EXP. (10)	DEFERRED TAXES (11)	ENDING RATE BASE (12)	AVERAGE RATE BASE (13)
1994	0	0	0	3,400	(148)	(18)	0	100	0	(31)	3,303	1,651
1995	3,303	0	0	10,400	(755)	(147)	0	100	(7)	20	12,914	8,108
1996	12,914	0	0	20,900	(2,142)	0	11	100	(13)	(37)	31,733	22,323
1997	31,733	0	0	27,900	(4,335)	0	11	100	(20)	(34)	55,354	43,543
1998	55,354	0	0	34,900	(7,204)	0	11	100	(27)	(32)	83,103	69,228
1999	83,103	0	0	0	(8,943)	0	11	0	(33)	8	74,146	78,624
2000	74,146	0	0	0	(9,211)	0	11	0	(33)	8	64,921	69,534
2001	64,921	0	0	0	(9,487)	0	11	0	(33)	8	55,421	60,171
2002	55,421	0	0	0	(9,772)	0	11	0	(33)	8	45,635	50,528
2003	45,635	0	0	0	(10,065)	0	11	0	(33)	8	35,556	40,596
2004	35,556	0	0	0	(10,168)	0	11	0	(33)	8	25,375	30,465
2005	25,375	0	0	0	(9,664)	0	11	0	(33)	8	15,697	20,536
2006	15,697	0	0	0	(8,119)	0	11	0	(33)	8	7,564	11,631
2007	7,564	0	0	0	(5,502)	0	11	0	(33)	8	2,048	4,806
2008	2,048	0	0	0	(1,986)	0	11	0	(33)	8	48	1,048
2009	48	0	0	0	0	0	11	0	(33)	8	35	42
2010	35	0	0	0	0	0	11	0	(27)	6	25	30
2011	25	0	0	0	0	0	0	0	(20)	8	12	19
2012	12	0	0	0	0	0	0	0	(13)	5	4	8
2013	4	0	0	0	0	0	0	0	(7)	3	0	2
2014	0	0	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL		0	0	97,500	(97,500)	(166)	166	500	(500)	0		

PACIFICORP ELECTRIC OPERATIONS
MAJOR ACCOUNTS WITH DEF. LOST REVENUE, 2% PRICE INCR., INCR. PWR. COST
MEGAWATT-HOUR SAVINGS BY STATE, TAX CALCULATIONS
JANUARY 26, 1994

											DETAIL OF TAX DEPRECIATION / AMORTIZATION				
YEAR (1)	OREGON (2)	WASH (3)	IDAHO (4)	MONTANA (5)	WYOMING (6)	CALIF (7)	UTAH (8)	IDAHO (9)	WYOMING (10)	TOTAL (11)	GRANTS/ REBATES (11)	ESC LOANS (12)	DEFERRED EXPENSES (13)	DEFERRED OPPOR REV (14)	TAX DEDUCTION (15)
1994	2,625	875	0	0	0	0	5,250	0	0	8,750	0	148	100	0	248
1995	13,140	4,380	0	0	0	0	26,280	0	0	43,800	0	755	100	0	855
1996	36,795	12,265	0	0	0	0	73,590	0	0	122,650	0	2,142	100	0	2,242
1997	73,590	24,530	0	0	0	0	147,180	0	0	245,300	0	4,335	100	0	4,435
1998	120,900	40,300	0	0	0	0	241,800	0	0	403,000	0	7,204	100	0	7,304
1999	147,180	49,060	0	0	0	0	294,360	0	0	490,600	0	8,943	0	0	8,943
2000	147,180	49,060	0	0	0	0	294,360	0	0	490,600	0	9,211	0	0	9,211
2001	147,180	49,060	0	0	0	0	294,360	0	0	490,600	0	9,487	0	0	9,487
2002	147,180	49,060	0	0	0	0	294,360	0	0	490,600	0	9,772	0	0	9,772
2003	147,180	49,060	0	0	0	0	294,360	0	0	490,600	0	10,065	0	0	10,065
2004	147,180	49,060	0	0	0	0	294,360	0	0	490,600	0	10,168	0	0	10,168
2005	147,180	49,060	0	0	0	0	294,360	0	0	490,600	0	9,664	0	0	9,664
2006	147,180	49,060	0	0	0	0	294,360	0	0	490,600	0	8,119	0	0	8,119
2007	147,180	49,060	0	0	0	0	294,360	0	0	490,600	0	5,502	0	0	5,502
2008	147,180	49,060	0	0	0	0	294,360	0	0	490,600	0	1,986	0	0	1,986
2009	144,555	48,185	0	0	0	0	289,110	0	0	481,850	0	0	0	0	0
2010	134,040	44,680	0	0	0	0	268,080	0	0	446,800	0	0	0	0	0
2011	110,385	36,795	0	0	0	0	220,770	0	0	367,950	0	0	0	0	0
2012	73,590	24,530	0	0	0	0	147,180	0	0	245,300	0	0	0	0	0
2013	26,280	8,760	0	0	0	0	52,560	0	0	87,600	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	2,207,700	735,900	0	0	0	0	4,415,400	0	0	7,359,000	0	97,500	500	0	98,000

PACIFICORP ELECTRIC OPERATIONS
MAJOR ACCOUNTS WITH DEF. LOST REVENUE, 2% PRICE INCR., INCR. PWR. COST
SYSTEM COST AND ESC PAYMENT CALCULATIONS
JANUARY 26, 1994

							---- DSR MEASURES @ 3.00% INTEREST ----						
							EQUAL PAYMENTS		GRADUATED ANNUAL PAYMENTS				
	T&D COSTS	POWER COST	TOTAL CAPACITY	ENERGY	SYSTEM COST W/ LOSSES		TOTAL	PRINCIPAL	TOTAL	INTEREST	PRINCIPAL	DSR MEASURES	
YEAR	$/KW	$/KW	¢/KWH	¢/KWH	¢/KWH	YEAR	PAYMENTS	PAYMENTS	PAYMENTS	PAYMENTS	PAYMENTS	AMORT	PAYMENTS
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1994	0.00	49.20	0.80	2.20	3.61	1	11.723%	8.723%	9.432%	3.000%	6.432%	4.36%	5.86%
1995	0.00	49.20	0.80	2.40	3.85	2	11.723%	8.985%	9.903%	2.807%	7.096%	8.85%	11.72%
1996	0.00	49.20	0.80	2.60	4.08	3	11.723%	9.254%	10.398%	2.594%	7.804%	9.12%	11.72%
1997	0.00	88.32	1.44	2.59	4.84	4	11.723%	9.532%	10.918%	2.360%	8.558%	9.39%	11.72%
1998	0.00	90.48	1.48	2.71	5.03	5	11.723%	9.818%	11.464%	2.103%	9.361%	9.67%	11.72%
1999	0.00	92.64	1.51	2.83	5.22	6	11.723%	10.112%	12.038%	1.822%	10.215%	9.97%	11.72%
2000	0.00	95.04	1.55	2.96	5.43	7	11.723%	10.416%	12.639%	1.516%	11.123%	10.26%	11.72%
2001	0.00	97.32	1.59	3.10	5.64	8	11.723%	10.728%	13.271%	1.182%	12.089%	10.57%	11.72%
2002	0.00	99.84	1.63	3.25	5.85	9	11.723%	11.050%	13.935%	0.820%	13.115%	10.89%	11.72%
2003	0.00	102.36	1.67	3.40	6.10	10	11.723%	11.382%	14.632%	0.426%	14.206%	11.22%	11.72%
2004	0.00	105.00	1.71	3.56	6.34	11	0.000%	0.000%	0.000%	0.000%	0.000%	5.69%	5.86%
2005	0.00	107.76	1.76	3.73	6.59	12	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2006	0.00	110.52	1.80	3.90	6.85	13	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2007	0.00	113.52	1.85	4.09	7.13	14	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2008	0.00	116.52	1.90	4.28	7.43	15	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2009	0.00	119.64	1.95	4.48	7.73	16	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2010	0.00	122.76	2.00	4.69	8.04	17	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2011	0.00	126.12	2.06	4.91	8.37	18	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2012	0.00	129.60	2.11	5.15	8.72	19	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2013	0.00	133.08	2.17	5.39	9.09	20	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2014	0.00	136.80	2.23	5.65	9.46	21	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2015	0.00	140.64	2.29	5.91	9.86	22	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2016	0.00	144.48	2.36	6.20	10.27	23	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2017	0.00	148.56	2.42	6.49	10.71	24	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2018	0.00	152.76	2.49	6.80	11.17	25	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2019	0.00	157.20	2.56	7.12	11.64	26	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2020	0.00	161.64	2.64	7.46	12.13	27	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2021	0.00	166.32	2.71	7.82	12.65	28	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2022	0.00	171.12	2.79	8.19	13.19	29	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
2023	0.00	176.04	2.87	8.58	13.77	30	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
						31	0.000%	0.000%	0.000%	0.000%	0.000%	0.00%	0.00%
							117.231%	100.000%	118.631%	18.631%	100.000%	100.00%	117.23%

PACIFICORP ELECTRIC OPERATIONS
MAJOR ACCOUNTS WITH DEF. LOST REVENUE, 2% PRICE INCR., INCR. PWR. COST
RETAIL PRICES - CENTS PER KWH
JANUARY 26, 1994

YEAR (1)	OREGON (2)	WASH (3)	IDAHO (4)	MONTANA (5)	WYOMING (6)	CALIF (7)	UTAH (8)	IDAHO (9)	WYOMING (10)	AVERAGE (11)
1994	3.86	3.63	4.29	3.36	3.08	5.35	2.96	4.66	4.39	3.30
1995	3.86	3.63	4.29	3.36	3.08	5.35	3.04	4.66	4.39	3.35
1996	3.94	3.70	4.38	3.43	3.14	5.46	3.13	4.75	4.48	3.43
1997	4.02	3.78	4.46	3.50	3.20	5.57	3.21	4.85	4.57	3.51
1998	4.10	3.85	4.55	3.57	3.27	5.68	3.30	4.95	4.66	3.59
1999	4.18	3.93	4.64	3.64	3.33	5.79	3.39	5.04	4.75	3.68
2000	4.26	4.01	4.74	3.71	3.40	5.91	3.48	5.15	4.85	3.77
2001	4.35	4.09	4.83	3.78	3.47	6.02	3.57	5.25	4.94	3.86
2002	4.43	4.17	4.93	3.86	3.54	6.15	3.67	5.35	5.04	3.95
2003	4.52	4.25	5.03	3.94	3.61	6.27	3.77	5.46	5.14	4.04
2004	4.61	4.34	5.13	4.02	3.68	6.39	3.87	5.57	5.25	4.14
2005	4.71	4.43	5.23	4.10	3.75	6.52	3.97	5.68	5.35	4.24
2006	4.80	4.51	5.33	4.18	3.83	6.65	4.08	5.79	5.46	4.34
2007	4.90	4.60	5.44	4.26	3.91	6.78	4.19	5.91	5.57	4.44
2008	4.99	4.70	5.55	4.35	3.98	6.92	4.30	6.03	5.68	4.55
2009	5.09	4.79	5.66	4.43	4.06	7.06	4.42	6.15	5.79	4.66
2010	5.20	4.89	5.77	4.52	4.15	7.20	4.54	6.27	5.91	4.77
2011	5.30	4.98	5.89	4.61	4.23	7.34	4.66	6.40	6.03	4.89
2012	5.41	5.08	6.01	4.70	4.31	7.49	4.79	6.53	6.15	5.00
2013	5.51	5.18	6.13	4.80	4.40	7.64	4.92	6.66	6.27	5.12
2014	5.62	5.29	6.25	4.89	4.49	7.79	5.05	6.79	6.40	0.00
2015	5.74	5.39	6.37	4.99	4.58	7.95	5.19	6.92	6.52	0.00
2016	5.85	5.50	6.50	5.09	4.67	8.11	5.33	7.06	6.65	0.00
2017	5.97	5.61	6.63	5.19	4.76	8.27	5.47	7.20	6.79	0.00
2018	6.09	5.72	6.76	5.30	4.86	8.44	5.62	7.35	6.92	0.00
2019	6.21	5.84	6.90	5.40	4.95	8.60	5.77	7.50	7.06	0.00
2020	6.33	5.96	7.04	5.51	5.05	8.78	5.93	7.65	7.20	0.00
2021	6.46	6.07	7.18	5.62	5.15	8.95	6.09	7.80	7.35	0.00
2022	6.59	6.20	7.32	5.74	5.26	9.13	6.25	7.95	7.49	0.00
2023	6.72	6.32	7.47	5.85	5.36	9.31	6.42	8.11	7.64	0.00

PACIFICORP ELECTRIC OPERATIONS

MAJOR ACCOUNTS WITH DEF. LOST REVENUE, 2% PRICE INCR., INCR. PWR. COST
1994 REAL LEVELIZED COST OF 19.75 MILLS PER KWH (26.79 NOMINAL LEVELIZED)
(THOUSANDS OF DOLLARS)
JANUARY 26, 1994

YEAR (1)	TOTAL RESOURCE COST (2)	CUSTOMER COST (3)	GROSS UTILITY COST (4)	ESC REVENUE (5)	NET UTILITY COST (6)	POWER SYSTEM SAVINGS (7)	AVERAGE BILL IMPACT (8)	LOST RETAIL REVENUE (9)	RATE PAYER IMPACT (10)	MWH SAVINGS (11)
1994	372	0	372	(198)	174	(316)	(142)	289	147	8,750
1995	1,919	0	1,919	(1,003)	916	(1,687)	(772)	1,466	694	43,800
1996	4,925	0	4,925	(2,829)	2,096	(5,007)	(2,911)	4,203	1,293	122,650
1997	9,767	0	9,767	(5,675)	4,092	(11,876)	(7,784)	8,607	823	245,300
1998	15,842	0	15,842	(9,337)	6,505	(20,253)	(13,748)	14,477	729	403,000
1999	18,757	0	18,757	(11,373)	7,384	(25,614)	(18,230)	18,045	(185)	490,600
2000	17,893	0	17,893	(11,373)	6,520	(26,630)	(20,109)	18,475	(1,634)	490,600
2001	17,003	0	17,003	(11,373)	5,631	(27,645)	(22,015)	18,917	(3,098)	490,600
2002	16,087	0	16,087	(11,373)	4,714	(28,717)	(24,003)	19,369	(4,635)	490,600
2003	15,143	0	15,143	(11,373)	3,770	(29,902)	(26,132)	19,832	(6,300)	490,600
2004	13,984	0	13,984	(11,175)	2,810	(31,087)	(28,277)	20,306	(7,971)	490,600
2005	12,244	0	12,244	(10,370)	1,874	(32,328)	(30,454)	20,792	(9,662)	490,600
2006	9,590	0	9,590	(8,544)	1,046	(33,626)	(32,580)	21,289	(11,291)	490,600
2007	6,123	0	6,123	(5,698)	425	(34,980)	(34,555)	21,799	(12,756)	490,600
2008	2,139	0	2,139	(2,035)	104	(36,447)	(36,343)	22,322	(14,021)	490,600
2009	27	0	27	0	27	(37,237)	(37,210)	22,449	(14,761)	481,850
2010	19	0	19	0	19	(35,916)	(35,897)	21,316	(14,581)	446,800
2011	22	0	22	0	22	(30,805)	(30,782)	17,975	(12,807)	367,950
2012	14	0	14	0	14	(21,383)	(21,368)	12,271	(9,097)	245,300
2013	7	0	7	0	7	(7,958)	(7,952)	4,487	(3,464)	87,600
2014	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0
TOTAL	161,879	0	161,879	(113,728)	48,151	(479,415)	(431,264)	308,686	(122,578)	7,359,000
1994 NET PRESENT VALUE @ 8%										
	87,537	0	87,537	(59,353)	28,184	(199,939)	(171,755)	132,157	(39,598)	3,267,167
NOMINAL (1) AND REAL (2) LEVELIZED COST IN MILLS/KWH										
(1)	26.79	0.00	26.79	(18.17)	8.63	(61.20)	(52.57)	40.45	(12.12)	
(2)	19.10	0.00	19.10	(12.95)	6.15	(43.63)	(37.48)	28.84	(8.64)	

POSITIONING FOR COMPETITION AND UNCERTAINTY

RAMPP

Resource and Market Planning Program

RAMPP - 3

MODELING APPENDIX

APRIL, 1994

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APRIL, 1994

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Section 5 Other Tables/Graphs (Not appearing in main report)

IPM Outputs

a) Percentage Winter Capacity Additions (%)
b) Winter Capacity Produced in 2003 (MW)
c) Annual Energy Produced in 2003 (MWa)
d) Winter Capacity Produced in 2013 (MW)
e) Annual Energy Produced in 2013 (MWa)

(Note: Tables 5-1 thru 5-15 include the above five reports.)

Financial Results

Miscellaneous

Section 6 Detailed Model Output (Selected Representative Outputs)

a) Financial Model Output for 1994-2013 (including end effects to 2043)
b) Total Projected Emissions
c) Incremental Winter Capacity (MW) of Resource Additions
d) Cumulative Annual Energy (MWa)
e) Annual Capacity Factors (%)

(Note: all the case model output includes each of the above five reports.)

Base Study Plan

Case #2, Low Load, Med Gas, md.ac.ar	#6- 1 thru 5
Case #7, Med Low Load, Med Gas, md.ac.ar	#6- 6 thru 10
Case #16, Med Load, Low Gas, md.ac.ar	#6- 11 thru 15
Case #17, Med Load, Low Gas, md.ac.sr	#6- 16 thru 20
Case #19, Med Load, Low Gas, md.nc.sr	#6- 21 thru 25
Case #28, Med Load, Med Gas, unc	#6- 26 thru 30
Case #29, Med Load, Med Gas, ld.ac.ar	#6- 31 thru 35
Case #33, Med Load, Med Gas, md.ac.ar	#6- 36 thru 40
Case #34, Med Load, Med Gas, md.ac.sr	#6- 41 thru 45
Case #35, Med Load, Med Gas, md.nc.ar	#6- 46 thru 50
Case #36, Med Load, Med Gas, md.nc.sr	#6- 51 thru 55
Case #37, Med Load, Med Gas, ad.ac.ar	#6- 56 thru 60
Case #41, Med Load, Med Gas, hd.ac.ar	#6- 61 thru 65
Case #50, Med Load, High Gas, md.ac.ar	#6- 66 thru 70
Case #69, Med-High Load, Med Gas, md.ac.ar	#6- 71 thru 75
Case #90, High Load, Med Gas, md.ac.ar	#6- 76 thru 80

Sensitivities

Case #211, Potential SCE contract on Med Load, Med Gas, md.nc.sr	#6- 81 thru 85
Case #213, Potential Hermiston on Med Load, Med Gas, md.ac.ar	
Following cases are Wind Renewables	#6- 86 thru 90
Case #261, Lower cap cost Med Load, Med Gas, md.nc.ar	#6- 91 thru 95
Case #262, 0% inf on geo O&M Med Load, Med Gas, md.nc.ar	#6- 96 thru 100
Case #263, 0% inf on wind O&M on Med Load, Med Gas, md.nc.ar	#6-101 thru 105
Case #264, 2.5% inf on O&M on Med Load, Med Gas, md.nc.ar	#6-106 thru 110
Case #265, Reserves to 1.2 Med Load, Med Gas, md.nc.ar	#6-111 thru 115
Case #266, Reserves to win on Med Load, Med Gas, md.nc.ar	#6-116 thru 120
Case #267, 35% more wind energy on Med Load, Med Gas, md.nc.ar	#6-121 thru 125

Environmental Cost Adders

Case #301, LO CO2, LO NOX on Med Load, Med Gas, md.ac.ar	#6-126 thru 130
Case #307, LO CO2, LO NOX on MedLoad, Med Gas, hd.ac.ar	#6-131 thru 135
Case #313, LO CO2, LO NOX on Med Load, High Gas, md.ac.ar	#6-136 thru 140
Case #316, LO CO2, LO NOX on Med High Load, Med Gas, hd.ac.ar	#6-141 thru 145
Case #324, Dispatch case w/o adders on LO CO2, LO NOX on Med Load, Med Gas, md.ac.ar	#6-146 thru 150

Section 7 Portfolio: Cost Components
(Back-up to Table #4-7 in Main Report)

Section 1

Modeling Recommendations for RAMPP-3

from

RAMPP-2 Acknowledgments

from

Utility Commissions:

OPUC
WUTC
UPSC

RAMPP-1 and RAMPP-2 Modeling Process

The modeling approach used in RAMPP-1 was a trial plan approach where utility planners selected the quantity and timing of new resource additions and evaluated the performance of these resources using both power cost and financial models. The resource plan that minimized costs under a wide range of scenarios was selected as the company's preferred plan.

The company used the Resource Integration Model (RIM) for resource selection in RAMPP-2. RIM is a capacity expansion model, written internally, which selected a separate resource expansion path for each of the 26 futures and sensitivities examined. RIM selected resources whenever existing resources fell below a 15% peak reserve margin and a 150-300 MWa energy reserve margin. The resulting sets of new resources were then evaluated by the power cost and financial models in an interactive fashion.

The resource selection logic started with a comparison of the existing stack of resources with the projected loads for the year to determine the required quantity of resources. If resources were required, they were selected from the resource portfolio so as to minimize system costs. The resource portfolio ranked or scored the resources so that the lowest cost resource was chosen first. If more than one resource was required, RIM selected additional resources until the reserve requirements were met. The model also checked to ensure that resources selected together minimized total system costs.

The RIM continued this process until a 20-year illustrative plan was developed. The next step was analysis of the trial plan in the power cost model to examine in detail the effect of the resource plan on fuel and operating costs and on the non-firm market power costs under various hydro conditions.

The resource schedule was then analyzed by the financial model to determine the financial and rate effects. Illustrative plans were produced for twenty six cases: four load forecasts, four scenarios, and eighteen environmental, load growth and other sensitivities.

The primary differences between the modeling approaches used in RAMPP-1 and RAMPP-2 and the use of the IPM model in RAMPP-3 are:

- IPM is a single optimization model that performs all of the resource evaluation.
- IPM has the ability to examine a much broader range of futures, scenarios and sensitivities.
- IPM incorporates transmission constraints directly into the modeling process.
- IPM incorporates operating costs of new resources through the planning horizon in its selection criteria.

The modeling processes used in RAMPP-1 and RAMPP-2 did not provide the optimal least-cost set of resources for each illustrative plan. Also, transmission constraints were handled outside the model. Analysts reviewed model results for potential transmission constraints and made adjustments to the resource schedule when transmission problems appeared.

Modeling Recommendations Implemented in RAMPP-3

The Public Utility Commissions in three of the seven states in which PacifiCorp serves retail electric loads prepared formal written comments on RAMPP-2.

OPUC comments were contained in Order No. 93-206, issued February 12, 1993. UPSC comments were contained in Docket No. 90-2035-01, issued June 1, 1993. WUTC comments came in the form of a letter to PacifiCorp dated June 28, 1993.

All of the commissions stated that Pacificorp's RAMPP-2 process met the substantive and procedural requirements of each Commission's Orders on least-cost planning.

Each commission also provided comments and recommendations for PacifiCorp to incorporate into RAMPP-3. Several of these comments related to the resource planning model used by PacifiCorp in RAMPP-2 because it did not use a linear programming algorithm to select future resources. The OPUC and other members of the RAMPP-2 Resource Advisory Group (RAG) expressed concerns that the resources selected, and therefore the RAMPP-2 plan did result in a true "least-cost" plan.

RAG members also stated that Pacificorp's existing model did not recognize the flexibility of conservation in meeting load uncertainty. Other specific recommendations from OPUC and our RAMPP-3 responses were:

Recommendation #12: Pacific should include replacement capital costs and transmission costs in supply-side cost estimates.
Response: Replacement capital costs are considered explicitly in the IPM structure. The IPM objective function minimizes the present value of annual capital costs over a 50-year time horizon. This formulation minimizes the "end effects" problems normally associated with generation planning models that use a 20-year time horizon. End-effects occur in planning models when near the end of a study, low capital cost, high operating cost plants are chosen because they represent the "least-cost" solution during the remaining 4-6 years of the 20-year study. By extending the planning horizon to 50 years, end-effects problems are minimized. Resources retired during model runs are replaced with new resources chosen from the resource portfolio.

Transmission costs associated with supply-side resources are included in the generating plant cost estimates. The plant construction costs include the transmission costs necessary to connect the resource to the system grid. Please see the discussion "Transmission System" in Chapter 4 of the main report for additional detail.

Recommendation #13: Pacific should include costs of natural gas transmission and storage capacity, electric transmission, and backup fuel facilities in the projected costs of new combustion turbine facilities.
Response: All of the above costs associated with the construction of new combustion turbine facilities are included in the resource portfolio cost estimates. Please see the discussions "Gas-Fired Resources" and "Cogeneration" in Chapter 4, and Action Plan Item #3, Chapter 12 of the main report for additional detail.

Recommendation #14: Pacific should insure that estimates of gas fuel costs are reasonably consistent with other forecasts, and examine other commodity and capacity and demand related costs components separately.
Response: PacifiCorp undertook an extensive review of gas prices and forecasts for RAMPP-3, and considered the commodity, capacity and demand related components separately. Please see the discussion labeled "Gas Price Projections" in Chapter 3 of the main report for additional detail.

Recommendation #15: Pacific should develop and incorporate estimates of external costs consistent with any Commission guidelines adopted in UM-424 in the next least-cost plan. Within six months of an order in this proceeding, Pacific should submit a study that examines the effect of recognizing external costs in system dispatch decisions.
Response: PacifiCorp tested twenty-one cases with various levels of external costs added to resources contained in the portfolio. Please see Chapter 7 of the main report for additional detail on the incorporation of external costs in the RAMPP-3 planning process.

Recommendation #17: Pacific should formulate or acquire a planning model that considers expected operation of existing and potential resources in ranking and choosing new resources.
Response: The IPM model acquired by PacifiCorp for RAMPP-3 specifically incudes expected operation of existing and potential units. The objective function of the IPM model minimizes the present value of future capital and operating costs over the 50-year time horizon. Please see the discussion "IPM Model Structure" in the following Section 2 for additional detail.

Recommendation #22: The Commission should not acknowledge actions by Pacific to maintain a two to three year energy surplus.
Response: For RAMPP-3, the company eliminated the energy surplus requirement because the IPM model recognizes transmission constraints. The model logic dispatches resources to meet load in each of the eight segments of the load duration curve, for each of the four seasons. There are no energy reserve margin constraints in IPM. The company does include a 15% peak reserve margin in IPM, consistent with its requirements under the Pacific Northwest Coordination Agreement and the Inter Company Pool reserve sharing agreements. Please see the discussion "Reserve Requirements" in Chapter 4 of the main report for additional detail.

The WUTC comments on the modeling approach taken in RAMPP-2 were similar to those of the OPUC. They stressed the importance of having a baseline run in RAMPP-3 to "facilitate comparative analyses by interested persons" of other scenarios and assumptions.

The UPSC comments on modeling were similar in scope and much more extensive. Their recommendations were that PacifiCorp should use a generation expansion model which:

Recommendation #3: Has the ability to optimize the selection of least-cost resources based on a total resource cost criterion.
Response: The IPM model chosen by PacifiCorp does optimize the selection of least-cost resources over a 50-year time horizon. Please see the discussion in "IPM Model: Description/Overview" in the following Section 2 for additional detail.

Recommendation #4: Considers the dispatch of the new system before it chooses a particular resource as least cost.
Response: The model meets this requirement. This recommendation is almost identical to OPUC Recommendation #17. Please refer to that response.

Recommendation #6: Accounts for transmission constraints between geographic areas and considers the potential for off-system sales when it analyzes a particular resource.
Response: One of the primary reasons PacifiCorp chose the IPM over other models was its ability to incorporate the company's transmission constraints in the resource selection and operation logic. Please see the discussion "Transmission System" in Chapter 4 of the main report for additional detail.

Off-system sales opportunities are an integral part of the IPM resource selection and operation logic. Please see the discussion of non-firm market sensitivities in Chapters 5 and 6 of the main report and the discussion "Sales" in the following Section 3 for additional detail.

The UPSC Order also contained several other recommendations that are closely related to the design and operation of PacifiCorp's new resource planning model. These are as follows:

Recommendation #7: The Commission finds that RAMPP-3 should carefully consider the decision to plan under the critical water assumption and the assumption regarding off-system sales market. Model runs should be made using an average water assumption and different assumptions regarding the availability and cost of off-system purchases and sales.
Response: The company used average water as its primary planning criteria for RAMPP-3 and the IPM model has the ability to analyze off-system sales and purchases under a variety of scenarios. Please see the discussion "Critical Versus Average Water Planning" in Chapter 5 and discussions on non-firm market sensitivities in both Chapters 5 and 6 of the main report for additional detail. Also refer to the discussion on "Sales" and "Purchases" in the following Section 3.

Recommendation #8: The Commission finds that the Company should review its assumptions regarding retrofit and refurbishing costs and the two year energy surplus with the RAG committee before including such assumptions in the RAMPP-3 report.
Response: After discussion with the RAG committee, the Company eliminated the two year energy surplus from the model and reviewed its assumptions regarding plant refurbishment costs. Please see the discussions "Reserve Requirements" and "Plant Refurbishment" in Chapter 4 of the main report for additional detail.

Recommendation #18: The Commission finds that, if practical, future IRP's should list DSR by program according to cost effectiveness levels and the model should select the programs when they become cost effective to implement.
Response: The company incorporated this request by analyzing 4 DSR strategies under seven futures, plus an unconstrained run where the IPM chose DSR irrespective of program implementation constraints. Please see the discussions "Demand Side Resource Alternatives" in Chapter 4 and "DSR Strategies" in Chapter 6 of the main report for additional detail.

Recommendation #24: The Commission finds that RAMPP-3 should include model runs which analyze the implication of regulations that would require dispatching of the system on a full cost basis including environmental adders.
Response: In RAMPP-3, the Company performed extensive analysis on the effects of environmental cost adders and constraints on the resource planning process. Chapter 7 of the main report is devoted to the environmental analysis performed by the Company and also includes an analysis of environmental dispatch under alternative levels of adders.

Recommendation #25: The Commission finds that the Company should pursue increasing the quantification of emission levels under different strategies to assess the costs of further emission reductions.
Response: The company complied with this request. Please see Chapter 7 of the main report for additional detail.

Recommendation #28: The Commission finds that future IRP's should calculate avoided costs using different load decrements and will investigate and explain how different load factor assumptions affect new resource choice.
Response: The avoided cost decrement issue is addressed in Chapter 9 of the main report.

PacifiCorp agreed to most of the OPUC, WUTC and UPSC suggestions regarding modeling for RAMPP-3. The Company selected a linear programming optimization model that addresses these concerns for use in RAMPP-3. The description of the model in the following Section 2 will highlight the features of the model that reflect the Commission's recommendations.

However, some of the suggestions are extremely difficult, if not impossible to implement within the framework of an optimization model. The rationale for not implementing these suggestions is discussed next.

Modeling Recommendations Not Implemented in RAMPP-3

The UPSC Order contained in Docket No. 90-2035-01 contained a variety of suggestions to PacifiCorp regarding what capabilities should be included in the resource planning model used to develop RAMPP-3. Most of them were either contained in the IPM model as it was delivered or was added later. However, three of the UPSC's suggestions could not be implemented in the IPM model. The UPSC recommendations and the reasons they were not incorporated into IPM are as follows:

Recommendation #5: Make risk, uncertainty and resource diversity an integral part of the new model's resource selection and dispatch logic.
Response: A literal interpretation of this UPSC request would require a probabilistic dispatch algorithm within the existing IPM optimization model. Such a model would strain the capability of the fastest super computer given the large size and complexity of Pacificorp's service territory and resource mix. The current version of the IPM model specified for PacifiCorp requires up to 18 hours for a solution, without probabilistic or Monte Carlo logic. However, the Company believes it has adequately addressed the critically important issues of risk, uncertainty and resource diversity without making them an integral part of the model's dispatch logic.

There are two ways to incorporate risk, uncertainty and resource diversity into the Integrated Resource Planning process:

- Develop a probabilistic dispatch algorithm for an optimization model or
- Utilize techniques such as Multi-Attribute Trade Off (MATO) analysis.

MATO tests the various resource strategies against the widest possible range of scenarios and futures in the IRP process. PacifiCorp used MATO in RAMPP-3. In the choice of scenarios and sensitivities, the company analyzed most of the probable outcomes for the two variables which are subject to considerable uncertainty both gas prices and load growth. For RAMPP-3, the company used five different rates of load growth and three rates of increases in gas prices, for the 16 different resource strategies (4 DSR, 2 coal and 2 renewables) analyzed in this process. Over 150 model runs were made in RAMPP-3. By comparing the model results under these diverse scenarios, the Company has framed most of the likely outcomes for load growth and gas prices under the various resource strategies and sensitivities.

The Company included over fifty potential resources, addressing concerns of resource diversity. These resources include wind, geothermal, solar, coal, demand side management and others, in the list of potential resources for IPM runs. The sensitivities examined in RAMPP-3 include the following:

- Economics of the SCE peaking contract
- Economics of the Hermiston cogenerating plant
- Seven sensitivities regarding reductions in various aspects of wind and geothermal resource costs
- Three extra load level sensitivities

The company believes it has complied with the spirit of the UPSC's request on the issues of risk, uncertainty and resource diversity.

Recommendation #33: Price elasticity should be incorporated by a feedback mechanism from the load forecast to the new IRP model.
Response: This request would also entail a substantial increase in the size and complexity of the IPM model and require a link with the Company's load forecasting models. While easier than the UPSC's prior request, the problem would still be complex and model solution times would be increased considerably. The proposed feedback mechanism would not add much to the analysis because of the nature of the utility pricing structure and the process of load forecasting and resource planning.

Optimization models, because of their size and computational requirements, are for the most part stand alone models. They do not interface well with other modeling techniques. Given the slow rate of increase in electric rates, incorporation of a feedback loop within IPM would not add much insight into the resource planning process.

Recommendation #31: The new model should incorporate potential resource acquisitions from other utilities.
Response: It would be very difficult to meaningfully quantify a "generic" potential power or resource purchase because the Company would have to specify the purchase price, quantity and terms. These conditions of a power purchase are complex and subject to negotiation.

Section 2

Modeling Implementation

Optimization Models : Background /History

Electric utilities were among a number of industries (others being petroleum, transportation, and large scale manufacturing), which pioneered the application of linear programming techniques. These applications began shortly after George Dantzig's 1946 paper on the Simplex solution algorithm (which greatly increased the speed of determining the existence of an optimal solution) and the development of modern, high speed computers.

During the period from the 1950's through the 1970's, the rapid load growth and structural stability of the electric utility industry made determination of optimal generation expansion paths an ideal candidate for linear programming models. Researchers at the Electricite' de France developed the basic structure of a generation expansion model using linear programming techniques. Their research in the 1950's was the basis for later developments in the US and United Kingdom.

Interest in linear programming models increased with the increasing computational capacity of computers in the 1960's and 1970's. During this period, economists and engineers published a wide body of literature in professional journals on this subject. By the late 1970's, linear programming models were in use at a large number of utilities, and with the EPRI/NARUC Electric Utility Rate Design Study of the late 1970's, interest developed in the application of linear programming models for use in marginal cost based rate design studies.

Simulation models were (and still are) used by Pacific Northwest utilities to develop the hydro regulation studies, which determine the hourly, daily, monthly and seasonal operating strategies of the dams on the Pacific Northwest hydro system. These models, also developed in the late 1950's and early 1960's, determine the response of the more than 150 dams and reservoir to changes in stream flows and runoff, to the often conflicting uses (navigation, flood control, irrigation, electric generation, fish migration, fish and wildlife habitat, recreation, water quality and supply).

Two examples of simulation models are:

Hydro Simulation (HYDROSIM), a BPA model that simulates the operation of the Northwest hydro system under a variety of load and stream flow conditions; and,

Systems Analysis Model (SAM), a model jointly developed by Pacific Northwest utilities beginning in 1981, which uses probabilistic simulation to model the operational and planning activities of the entire Pacific Northwest system on an hourly or monthly basis for up to 20 years.

Outside of the Pacific Northwest, thermal-based utilities use simulation models for forecasting future generation system operating costs. The primary expenses analyzed by such models are fuel, operations and maintenance and generation start-up costs. Such costs often comprise 40-60% of the cost of providing electricity at these utilities.

Major applications of simulation models are: preparation of fuel budgets; long term purchase and sales analysis; demand-side resource analysis; and, analysis of generating unit operations. An example of an hourly simulation model is PROMOD, a widely used production simulation model written by Energy Management Associates.

Simulation models generally are not used for the resource selection portion of utility least-cost planning because they simulate the operation of a given set of existing and potential resources. Optimal resource selection logic is not included in simulation models because of computational constraints. Simulation models are often used in tandem with optimization models in the least-cost planning process for the more in-depth analysis of system operations provided by simulation models. However, use of simulation models by themselves will not produce the least-cost mix of resources for a utility.

IPM Model: Description/Overview

The Integrated Planning Model (IPM) is an optimization model that uses a linear programming formulation to select investment options and to dispatch generating and load management resources to meet overall electricity demand and energy requirements. Investment options are selected by the model given the cost and performance characteristics of available options, forecasts of customer demands for electricity, and reliability criteria. System dispatch, determining the most efficient use of existing and new resources available to utilities and their customers, is optimized given the resource mix, unit operating characteristics, and fuel and other costs. Unit and system operating constraints provide system-specific realism to the model's simulations.

IPM is a dynamic model; that is, it has the capability to use forecasts of future conditions, requirements, and option characteristics to make decisions for the present. Decisions are made on the basis of minimizing the net present value of capital plus operating costs over the full planning horizon.

Several factors are taken into account in determining the cost-minimizing planning strategy. Investment choices are made from among a wide variety of resource options as listed in the resource portfolio. A unique feature of the IPM model is its ability to represent and account for the different characteristics of alternative types of resource options. Resource options include:

- Demand-side resources (conservation and load management programs),
- Non-utility sources of power (bulk power purchases from independent power producers and cogenerated power),
- Increased utilization of existing resources (life extension and increased utilities outside the region),
- Mature and advanced utility generating technologies (integrated gasification combined cycle units).

Utility generating options are characterized in terms of their capital costs, operating and maintenance costs, fuel costs, fuel quality, heat rates, reliability, and lead times. In the case of demand-side options, characteristics include capital and program administration costs, market penetration rates, and load shape impacts. The amount and scheduling of available power and its costs characterize possible bulk power purchase options, either for economy or for firm power purchases.

Decisions about fuel conversion, retrofits, re-powering, life extension, and economic retirements are based upon trade-off between capital costs and fuel savings over the planning horizon, as well as how these options compare with other available alternatives.

IPM Model Structure

General Description and Logic

The Objective Function is the basic equation that is optimized in IPM. It is a linear equation that consists of the present value of the sum of all the costs over the time horizon to be evaluated. The variable costs are for both the generation and transmission of electricity, the capital costs are for the construction of new plants, fixed operating and maintenance costs, and costs associated with demand-side management and conservation resources.

All costs are stated in present value dollars. Plant fuel and variable operating and maintenance costs are escalated based on projected increases, then discounted back to 1994, using Pacificorp's 8.8% present value factor.

Capital costs for new generating capacity are expressed as the annual present value carrying costs over the expected life of the unit. Costs are included for the period over which plant is considered. The annual fixed charges include provisions for debt, equity, taxes, insurance and other such annual expenses that are related to the level of plant investment.

Capital costs for existing units are not considered because they do not effect the choice of new generating capacity. Operating costs of existing capacity are included. The objective function described above is minimized subject to the following constraints:

The total operation of all generating plants in operation plus power purchases must be no less than the load plus sales in each period. Referred to as a load or demand constraints, they ensure that the model produces adequate generation in all segments of the load duration curve under analysis.

The net generation of each plant must not exceed the rated capacity of the plant. Similar constraints are in place for purchase power contracts. These capacity constraints specify the maximum output and any seasonal restrictions on each plant.

There are a variety of constraints limiting the availability of hydro resources.

Reserve margin constraints that specify the percentage of resources required in excess of the peak demand for each year under study. The Company uses a 15% reserve margin for RAMPP-3. If existing capacity plus any new capacity is less than the peak load plus the 15% reserve margin, new capacity is added to satisfy this constraint.

Minimum operating level constraints are also required for units that are either 'must run' units or can be cycled on nights and weekends.

Transmission constraints limit the amount of energy that can be transferred among the six regions to the lesser of the capacity of the lines or the contractual rights held by PacifiCorp.

Emission constraints can be added for CO_2, NO_x and TSP emissions.

In addition to the above mentioned constraints, there are a variety of other constraints related to special requirements of demand side resources such as market penetration, ramp rates, etc. Also required is a series of constraints which establish the resources in the existing system.

Cost-Benefit Accounting

IPM puts the costs and benefits of demand and supply-side resource options on a 'level playing field,' ensuring that all costs and benefits are treated on the same basis and that model decisions are not arbitrarily biased.

There are four aspects of IPM's formulation that enforce the level playing field concept.

First, IPM is dynamic. In discounting all costs to a base year and including them in a single, multi-year objective function, IPM properly captures the complexity of multi-year expense inter-relationships. The dynamic feature also ensures that changing patterns of unit dispatch over time are taken into account.

Second, IPM properly accounts for end effects. The model is typically run for 3 or 4 years at a time with the last year used to minimize end-effects.

Third, IPM includes all the years of the study horizon in the objective function, rather than including costs only for the actual years run. In this way IPM calculates total discounted costs over the entire study horizon. Including all the intervening years in the objective function permits the model to capture more accurately the escalation of the cost components over time. It also accurately weighs the out years, further minimizing end effects.

Because of the large size and complexity of the PacifiCorp system, IPM could not solve for each year in the study horizon (1994-2043). The Company chose the following years to include in its analysis: each year from 1994 through 2001, 2003, 2006, 2009, 2013, 2022, and 2036. After the year 2001, the run years represent a number of years, as shown below:

Run Year	Year Represented
1994	1994
1995	1995
1996	1996
1997	1997
1998	1998
1999	1999
2000	2000
2001	2001
2003	2002-2004
2006	2005-2007
2009	2008-2010
2013	2011-2015
2022	2016-2028
2036	2029-2043

As stated earlier, costs are discounted back to the base year, 1994. In calculating variable generation costs for a given run year, the model takes the discounted sum of the variable cost component (fuel and O&M) over the years represented by the run year and discounts them back to a base year. For example, the 2003 coefficient of MWh generated by a utility plant is:

$$TVC_{2002}/(1+d)^{8} + TVC_{2003}/(1+d)^{9} + TVC_{2004}/(1+d)^{10}$$

where TVC is the total variable cost (in $1000/mwh)

TVC is calculated based on the fuel and O&M for each year, not for the run year representing the actual year. This methodology permits IPM to accurately model changing patterns of fuel prices. Similar calculations are performed for all other cost components.

Finally, the model's treatment of demand-side options is designed to place these options on equal footing with conventional utility options. One of the more intricate aspects of the formulation is the notion of a levelized impact. An investment in a conventional unit or even a non-utility option has a fixed maximum capacity and an expected maximum capacity factor that does not vary over time. On the other hand, an investment in a demand-side option has an associated stream of savings that are driven by market penetration curves. These streams can be thought of as cost savings. It would not be accurate to choose a sample year and calculate the savings based solely on that year. Rather, to put the reduction in load on the same basis as the costs that are avoided, levelizing the impacts is appropriate. The levelization methodology is used only to provide a meaningful mapping of actual year to run years, and to properly weigh the impacts within the years represented by the run year.

For example, if the demand side program has energy saving streams for the first five years

Year	GWh Saved
1	13.00
2	63.05
3	110.97
4	172.00
5	230.48

The levelization method computes an annuity of these GWh savings, that is, it is the discounted sum of these impacts divided by the sum of the discount factors. With a 3% discount rate the levelized savings is 114.69 GWh. Note that the impacts are not discounted however: a GWh saved in 1990 is still a GWh in 2000.

Energy Costs in IPM

Energy costs associated with alternative scenarios for each future are developed within IPM. Four seasonal load duration curves are used by IPM to estimate the load requirements of the PacifiCorp system. Each seasonal load duration curve is further divided into eight segments, yielding 32 discrete periods to which IPM will dispatch resources for each year of the analysis period. The Company's generating units and purchases are operated in economic order, subject to the following forced outage and maintenance constraints.

Forced outages refer to the unplanned loss of a generating unit due to mechanical failures. Linear programming models cannot directly incorporate such probabilistic events, so IPM limits the amount of capacity that a unit can produce in each load segment in each year. For example, if the forced outage rate for a 100 MW combustion turbine is 5%, IPM limits the capacity of the plant to 95%, or 95 MW.

Maintenance requirements are handled in a similar fashion, only the season in which the maintenance is planned to occur is specified. If the same combustion turbine requires 3 weeks of maintenance during the February, March, and April periods, the unit's capacity would be reduced by 3/12 or 25%. The effective capacity of the plant would be reduced to 75 MW for this period. Combining the forced outage and maintenance effects for the turbine would constrain the plants operating level to 70 MW in the Spring season.

Fixed Costs in IPM

IPM includes the capital costs associated with new generating capacity, and the fixed operations and maintenance expense of existing and new units. The capital costs are included for each new resource included in IPM, including interest during construction. The annual cost per MW of potential capacity is calculated as in-service year installed cost times Pacificorp's capital recovery factor. This includes the real (adjusted for the effects of inflation) cost of debt, equity, taxes, insurance and other fixed costs related to capital investment. Table 4-9 in the main report shows the capital recovery factors by resource. They range from a low of 5.48% to a high of 9.84% in real 1994 dollars. This variation is due to different service lives and taxes on the various resources. Fixed O&M expenses are added on a $/MW basis for all existing and potential units.

In IPM's objective function, the annual costs for units are summed over the years in which they are included in the analysis. The economic costs recognized by the model reflects only those costs in the time frame of the analysis period, 1994- 2043. Because the study period has been extended to 2043, 'end effects' problems normally associated with such models have been mitigated.

Objective Function

The objective function is the equation or problem that is minimized by IPM. The current structure is to minimize the present value of all future resource fixed and variable costs. Again, these costs do not reflect the capital costs of existing PacifiCorp generating plants because they represent sunk costs. The objective function in its simplified form can be expressed as follows:

Minimize NGFC + EGFC + NGVC + EGVC

Where:

NGFC = New generating plant annualized capital and fixed O&M costs in $/MW for each year in which it is included in the model.

EGFC = Existing generating plant fixed O&M costs in $/MW for each year in which it is included in the model.

NGVC = New generating plant fuel and variable O&M expenses in $/mwh

EGVC = Existing generating plant fuel and variable O&M expenses in $/mwh

Costs in the objective function are present value costs. The costs in each of the years have been escalated by the appropriate index to account for changes in real prices, then discounted back to the base year, 1994, at 8.8%. The capital costs are the present value avoidable costs per MW of capacity in each year of the study.

IPM minimizes the Objective function subject to the constraints listed earlier in this section. The current structure of IPM on the PacifiCorp system results in about 7,500 constraints, which is at the upper end of the capability of the computers used to solve the model. Run times for certain scenarios exceeded 30 hours. Solution times of this magnitude represent a serious additional constraint when the RAMPP-3 requirements indicated that in excess of 150 separate runs of the model would be necessary to properly analyze the issues.

Initial IPM Testing (July 1992 to September 1992)

IPM, LPS-867, and IPM Case Manager were initially delivered in July 1992 followed by training at ICF Resources in Fairfax, Virginia in August. Groundbreaking testing followed for the next few months. The major IPM testing issues, at this time were: Data from both other Power Planning models and also from RAMPP-2 were adapted to IPM format for initial testing. Adaptation was done in two areas: One, using the DOS based Case Manager, with its user friendly screens and fields and Two, directly editing IPM's text based input files on the UNIX workstations. Understanding of the IPM data formats and their meanings, and its use of the LP solution methodology was occurring with hands on experience.

Various levels of aggregation of the data were tested. PacifiCorp's hourly load shape was adapted into regional/seasonal load duration curves. Research was done into the optimal number of seasons and their best definitions. Seasons consist of a group of months. Initial research was done into the optimal segmentation of these curves by number and width.

Initial research was also done into determining the most appropriate area and transmission definitions for RAMPP-3 purposes, i.e., enough detail to represent transmission constraints without excessively slowing down runtime or expanding the LP matrix beyond its limitations. Aggregations from two areas up to seven areas were tested arriving at six areas as the best fit to all the criteria.

Difficulties with firm sales, matrix limitations and the case manager were investigated: IPM's original firm sales input was a load duration curve representation of the aggregation of all firm sales in a region. Modeling the large number of firm sales that PacifiCorp deals with and the large number of contract starts and stops in various years became a major undertaking involving multiple Excel spreadsheets. Since load duration curve segment definitions were being experimented with at this time, the firm sales process became a serious problem. PacifiCorp later negotiated with ICF to develop a new sales/purchase format that allows individual detailed representation.

The LPS-867 was originally a DOS based LP, intended for smaller or less detailed representations than PacifiCorp's seven state system by 50 year study. The original 10,000 row limit constraint required high levels of data aggregation. This severely handicapped the level of meaningful detail represented and drastically reduced the number of years which could be simulated.

Despite its user-friendliness, the Case Manager was eventually abandoned for two reasons: One, it was a fairly new product, with some unrecoverable errors still to be debugged, mostly involving maintenance schedules and pumped storage definitions and Two, it only handled a subset of all of the IPM input data. Critical portions of data (transmission, DSM, and firm sales) had to be directly edited into the IPM input text files

PMDAM Testing (October 1992 to March 1993)

PMDAM was initially delivered in October. No formal training was provided, since the model did not, as yet, have a commercial vendor. However, phone and on-site assistance was provided by Mr. Ed Cazalet, the model's creator.

Groundbreaking testing followed for the next few months. The major PMDAM testing issues at this time were preliminary modeling of PacifiCorp system, binary report design and one-utility PacifiCorp representation. The same process that had occurred with IPM was undertaken with PMDAM. An understanding of the model, with its different solution methodology, and the richness of its data and their formats occurred with hands-on experience.

Unlike other models, PMDAM did not come with standard output reports. Instead, all of the input, intermediate, and output data for a study were made available for user-created custom reports, using pre-supplied data-access functions. Data-access became a useful feature, once PacifiCorp personnel understood how to use these functions and designed and created necessary reports.

PMDAM was originally intended as a Western US. regional model, solving the problem of interactions between utilities. For RAMPP-3 purposes, the model had to be customized to solve a single-utility problem, with most of the existing utility-based logic adapted into an area-based logic. Wholesale transactions with external entities required the creation of a "rest of the world" geographic area identity. The major model difficulties encountered were documentation, support and inability to predictably converge on a solution.

One of the deficiencies of not having an established vendor was the lack of standard user oriented documentation, such as a manual, or a modeling write-up and examples. The only documentation available was source code documentation and a listing of the data available for custom reports. All problems and difficulties, or questions of clarification, required the assistance of a support person and the only one available was Mr. Cazalet. He had other obligations as well and needed to divide his time and efforts between clients.

Ultimately, the final obstacle was the model's inability to converge to a solution on a run. This may have been due to the changes required to modify the model into the one-utility representation, or was inherent in the LaGrangian solution technique, or a combination of both.

The moment came in the RAMPP-3 schedule for a final decision on a model. PMDAM's inability to converge to a solution and its lack of documentation led PacifiCorp to revisit IPM.

Fine-Tuning of IPM for Production (April 1993 to October 1993)

PMDAM's difficulties, coupled with ICF's delivery of a larger LP and Power Planning's purchase of faster workstations, led to a resumption of IPM testing. While more-detailed testing occurred, ICF began work on agreed to major code fixes to the model, including a new sales/purchase format, and a binary-data dump which would allow users to create custom reports.

Specific modeling questions were now being addressed. The final load duration curve definitions (load areas, seasons) and segment definitions (number of, width of) were determined. Specific non-standard resource modeling issues were addressed, such as the non-dispatch ability of wind, T&D efficiencies, etc.

A series of highly-detailed bench marking tests were started, comparing items such as resource dispatch and link flows to other models. The in-house power production model, MultiSym was used as this benchmark.

At this time, new code was delivered with the following new features: new sales/purchase flexibilities, system-wide energy not served (ENS) costing, transmission capacities enhanced, segmental hourly mapping and the new binary output code.

Individual contracts could now be defined with individual parameters such as capacity, cost, start and end years, capacity factor minimums and maximums, restrictions to certain segments and seasons. Also, non-firm markets, which play an important part of the overall cost of the system, could now be defined for the first time.

Originally, IPM used the highest cost resource in each region as the cost of ENS in that region since regional load/resource balance was usually enforced. However, PacifiCorp needed a system-wide balance to be enforced, so a single system-wide cost of ENS was needed. A new input file allowed the user to define this system-wide desired cost of ENS.

The transmission enhancements allowed capacities to vary by season and segment.

Load diversity was captured by the preservation of hours when moving from one area to another. This load mapping became necessary to more accurately model pumped storage and peaking return issues.

As with any computer program, new code went through a series of iterations of user testing and debugging. One example was the delivery of a second version of the new sales/purchase feature after extensive testing of the initial delivery found several bugs.

As the bench marking became more detailed, more refined modeling questions were addressed, such as: hydro condition, topology fine-tuning, modeling of nonfirm markets, modeling of new transmission costs, modeling of return limits of the BPA Peaking contract, modeling of real O&M escalation for renewable resources, modeling of typical SCCT dispatch and representation of quantity of new resources available.

The IPM format is consistent with the format of an EPRI model for the development of DSR cost estimates. However, PacifiCorp was unable to use the EPRI model and had to develop a method to input DSR data independently. Success occurred only after several rounds of attempts and revisions. The lack of an EPRI model caused a great amount of iterating between our in house DSM and IPM model to get consistent results between the two. This led to a finer understanding of how the IPM model computes peak conservation penetrations by program. The mechanism to start a program in a specific year was a turning point. This allowed cases to match the unconstrained runs as necessary.

Since RAMPP-3 would be doing a multi-attribute trade-off analysis of over a hundred individual runs, considerable time and effort was needed to examine the many aspects of computer runtime and how to reduce it without sacrificing meaningful detail. These included: number of end years and effect of end years, usage of initial solutions and the optimal pattern of runs, which initial solutions should be used for which runs to minimize run times, number of run years and mapping of non-run years (forward mapping, backward mapping, or middle mapping) to run years.

A wide variety of reports were created: internal analytical reports for bench marking , other regular run checks, reports which would feed into presentation quality touch-up on the Macintosh and files which were used as input to the Financial Model.

The following somewhat "mechanical" issues were addressed to allow production runs, data retrieval and production graphs and tables.

Duplicating input files for over 150 cases would have required more computer disk space than was practical or feasible, and would also have led to redundancy and confusion. Establishing a library control system linking one set of final data to the appropriate input variations and the various production directories eliminated the needless redundancies and confusion. This library control system also preserved a record of editing changes, eliminating the potential nightmare of mistakenly replacing older, correct data with newer, incorrect changes.

Maintaining order over the more than 150 cases required a well-thought-out and easy-to-use directory hierarchy.

IPM is three separate programs (matrix generator, LP, and matrix reporter) which are run in sequence overnight. Intelligent automation is needed to select the correct input files and start a run.

The RAMPP-3 production studies were to be run on four UNIX workstations networked together and shared with other analysts running other studies on other models. An intelligent "job allocation" program was needed to allocate the workstations among the various studies and users. In addition, because IPM jobs solved much more quickly using a solution from another run, the run queues needed to match up the submitted job with the "previous" job whose solution it will be using, if that "previous" job hadn't already finished.

Post-run analysis, multi-attribute trade-off analysis, and presentation-quality reporting took place on desktop Macintosh computers, using spreadsheet and graphical tools. Seamless networking and simultaneous access to study files from both workstations and desktop computers were developed.

Generation of standard analytical and presentation-quality reports for the over 150 studies, as well as the numerous comparative reports and analysis of combinations of studies, required automation on the Macintosh using macros and prepared linked templates.

Production runs and analysis commenced in October of 1993.

Section 3

Financial Model Description

Model Inputs

The following is a write-up discussing model processing and the revenue requirement calculation in detail.

The information flowing into the financial model is from the IPM optimization model, DSR input files, load forecasting files, and five year plan inputs.

IPM model data transfers include power costs (purchase power, fuel costs, O&M), new resource construction, system load energy (mwh).

MWh Energy Sales before conservation and numbers of customers are provided by Load Forecasting.

DSR data files are from Demand Side Policy & Strategy. Information transferred includes utility loan investment with terms and interest rates, deferred costs, DSR utility expense, conservation MWh before losses by class, DSR penetration rate, and DSR customer costs.

Input file data is from the five-year financial plan (1993 to 1997) and includes beginning plant and reserve by function (fossil, hydro, transmission, distribution, general, mining), beginning deferred taxes, and beginning working capital; book life by function; tax depreciation percentages by asset type; existing plant deferred taxes, forecasted for 20 years; 1994 to 1997 construction; AFUDC; CWIP; regular sales for resale; other revenues; change in working capital; amortization; property tax rate; business tax rate; federal tax rate.

Integrated Resource Planning input file data includes construction schedule, lead times and raw capitalization.

Model Processing

The following are processes that the model computes from the input file information:

Weighted cost of capital - existing & forecasted
Cumulative plant and reserve balances

Discount rates	Deferred taxes
Tax depreciation	Book depreciation
Plant retirements	Betterment addition forecasts
Rate base closings	AFUDC

DSR (ESC) loan balance, loan payment, principal payment
DSR deferred amortization
DSR cumulative plant balance and reserve
DSR deferred tax

Existing Plant Revenue Requirements

Listed below are the major elements included in the financial model.

Plant in Service is beginning plant, reduced by annual retirements.
Retirements are calculated by functional group based on percentages applied to prior year plant in service balance. Model does not include CWIP. Balance is cumulative.
Accumulated Depreciation is beginning accumulated depreciation increased by annual depreciation and amortization reduced by annual retirements calculated in plant in service. Balance is cumulative.
Deferred tax balance is beginning deferred taxes plus the annual change to deferred taxes. Deferred taxes are calculated based on the current year book depreciation less the current year tax depreciation times the income tax rate of 36.91% (company composite that includes state taxes). With no new plant additions, deferred taxes increase until 1998 when the book depreciation exceeds the tax depreciation.
Working Capital represents the current assets less the current liabilities in the beginning balance. Working capital is unchanged in the model.
Rate Base Total is calculated as plant in service, less accumulated depreciation & deferred taxes, plus working capital.
Rate Base Lagged is the prior year ending rate base. Current year plant additions receive recovery in the following year. The model assumes perfect regulation (costs are fully recovered through customer prices).
Rate of Return is the current authorized weighted average allowed return on rate base 10.5%.
Rate Gross Up for income Tax is 3.44% to cover the income taxes on the common and preferred return. This is calculated as the common and preferred return, divided by one minus the income tax rate, less the common and preferred returns.
Return on Rate Base is lagged rate base times the rate of return.
Gross up for Income Taxes is lagged rate base times rate grossed up for income taxes.
Book Depreciation - Reflects the decline in asset value over its economic life and is calculated as current year existing plant in service times the book depreciation rates calculated on a functional basis. Added to this is book amortization (leasehold improvements, computer equipment, intangibles) from the five-year plan inputs.
Return on Rate Base Existing is calculated by adding the return on rate base plus gross up for income taxes and book depreciation.

Plant Additions Revenue Requirements

Plant in service (Existing Betterments) is calculated as the prior year existing plant with betterments, times the betterment rates calculated on a functional basis. This balance is cumulative. Plant retirements are calculated after one year on existing betterments using retirement percentages by functional group.
Betterments grow at roughly 5% of gross plant investment, including existing betterments. Investment includes additions to distribution facilities as a result of load growth.
Accumulated Depreciation (Existing Betterments) is increased by annual depreciation and reduced by annual retirements on existing betterments. This balance is cumulative.
Plant in Service (New Resources) adds the annual new resources to the prior year balance (balance is cumulative). Plant retirements are calculated annually using an estimated 2% per year of plant investment.
Accumulated Depreciation (New Resources) is increased by annual depreciation and reduced by annual retirements on new resources. Balance is cumulative.
Deferred Tax Balance accumulates the deferred taxes for existing betterments and new resources (excluding purchase power). Deferred taxes are calculated as above under existing revenue requirement.
Working Capital - Represents the increase in working capital over the beginning balance. Through 1997, working capital is from five- year plan. After 1997, model forecasts working capital based on revenue growth.
Rate Base Total is calculated by adding the plant in service for existing betterments and the new resources, less the accumulated depreciation for existing betterments and new resources, less deferred taxes, plus working capital.
Rate Base Lagged is the prior year additions to rate base.
Rate of Return is the calculated forecasted cost of capital of 10.43%. The weighting is based on forecasted capital structure and cost of capital as follows:

LTD	8.99%	Weighted 49%,
Preferred	8.93%	Weighted 6%
Common	12.2%	Weighted 45%

Rate Gross Up for Income Tax is 3.53% to cover the income taxes on the common and preferred return. Calculated as in above (see existing revenue requirement).
Return on Rate Base is rate base lagged times the forecasted rate of return.
Gross up for Income Taxes is rate base lagged times rate grossed up for income taxes.
Book Depreciation is current year plant in service (existing betterments) times the book depreciation rates calculated on a functional basis, plus current year cumulative new resource investment times book depreciation rates.
Return on Rate Base Additions is calculated by adding the return on rate base plus gross up for income taxes and book depreciation.

DSR Revenue Requirements

Gross Utility Loans accumulate the investment in DSR loans. Principal loan reductions are reflected as Accumulated Amortization of Loans. Fully-paid loans are removed from gross utility loans and accumulated amortization on loans. Model assumes all loans are paid in full, but payments are offset by any bad debt expense.

Accumulated Amortization on Loans accumulates the principal loan repayments and is reduced by fully-paid loans.

Gross Utility Deferred is cumulative DSR deferred program investments. Investment is removed after deferred costs are fully amortized.

Accumulated Amortization Deferred accumulates the amortization of the DSR deferred programs. DSR deferred investments are removed after fully amortizing.

Deferred Tax Balance accumulates the deferred taxes for utility deferred programs. For tax purposes, the utility deferred investment are fully depreciated over one year. Book depreciation is based on 20-year life for residential, 15-year life for commercial, and 15-year life for industrial. No deferred taxes are calculated on utility loans.

Rate Base Total is calculated by adding the gross utility loans, plus the gross utility deferred, less the accumulated amortization on loans, less the accumulated depreciation on DSR deferred, less deferred taxes.

Rate Base Lagged is the prior year DSR rate base.

Rate of Return is the forecasted cost of capital 10.43% (See Additions Revenue Requirement).

Rate Gross Up for income Tax is 3.53% to cover the income taxes on the common and preferred return. (See Additions Revenue Requirement).

Return on Rate Base is DSR rate base lagged times the forecasted rate of return.

Gross up for Income Taxes is DSR rate base lagged times rate grossed up for income taxes.

Book Amortization is current year utility deferred times the book depreciation rates calculated on a customer class basis, plus the annual principal repayment on the DSR utility loans.

Return on Rate Base DSR is calculated by adding the return on DSR rate base, plus gross up for income taxes and book amortization.

Summary Revenue Requirements

Total Return on Rate Base adds the return on rate base for existing, new resources, all betterment additions, and DSR.
Fuel is an input from the IPM model and includes fuel costs of thermal generating resources. New resource fuel costs are included.
Purchase power is an input from IPM and includes firm and nonfirm purchase power to cover energy and capacity requirements. (BPA peaking contract is included as part of O&M costs).
O&M is an input from IPM for power supply O&M and includes the operations and maintenance expenses other than fuel, wheeling cost, and purchase power. Non-power supply O&M is from the five-year plan, and escalates annually at inflation after the plan period (this includes transmission, distribution, sales, customer service, and A&G costs). New resource O&M costs are included.
Wheeling is input from five-year plan data. After 1997, wheeling escalates at inflation.
DSR Bad Debt Expense calculates potential losses from the nonpayment of loans at .5% as ESC revenues.
DSR Expense is a transfer from the DSR files (Demand Side Policy & Strategy). This reflects the utility operating costs incurred that are charged to expense.
Taxes Other Than Income Taxes reflects property taxes and general business (franchise) taxes. Property taxes are calculated as current year plant investment, excluding DSR, times .83%, based on a weighted average from the five-year plan. General business taxes are calculated at 1.25% of operating revenues (based on a weighted average from the five year plan).
Total Operating Expenses are the sum of fuel, purchase power, O&M, wheeling, DSR bad debt expense, DSR expense, and taxes other than income taxes. Depreciation is not included but is treated as part of the return on rate base.
Total Revenue Requirement is the total return on rate base, plus total operating expenses. This number is before revenue credits.
Sales for Resale are a transfer from the IPM model and reflect nonfirm or secondary sales.
Special Sales for Resale reflect the existing firm sales for resale and are provided by Integrated Resource Planning.
Energy Service Revenues (ESC) are revenues from customers who receive energy service loans for acquiring DSR resources. This reflects the customers' total annual loan payment.
Other Revenues are from the five-year plan and reflect utility revenues from non-mwh sources (i.e. rents of facilities, pole contact rentals, regulatory adjustments). Other revenues escalate at inflation after 1997.
Operating Revenues represent the total revenue requirement, less revenue credits (sales for resale, energy service charge revenues, other revenues).

Model Results Output Explanation

Loads:

System Load (MWa): The optimization (IPM, integrated planning model) model forecasts energy requirement before DSR resources are determined. This is the load the company is required to meet through generating resources or purchase power, measured at the busbar. System load includes the retail energy requirements, plus regular sales for resale energy requirements (requirement or on-system sales). This excludes the firm wholesale sales energy requirements.
Conservation (MWa): Level of DSR resources selected by IPM from DSR strategies of low, medium, accelerated, & high (Data is from Demand Side Policy & Strategy).
System Load After Conservation (MWa): Represents the system load net of conservation.
Energy Sales After Conservation (MWa): The retail energy sales to residential, commercial, and industrial customers, plus the regular sales for resale, measured at the customer meter. The forecasted energy sales load growth before conservation was provided by the load forecasting department (low, medium low, medium, medium high, high). The regular sales for resale were provided by Integrated Resource Planning.

Total Customers (000): Represents the forecast of company customers under the energy sales load forecasts used in the optimization model.
Net Electric Plant ($M): Adds the optimization model resource additions (completed and CWIP) to total gross electric plant, less accumulated depreciation reserve, in deriving net electric plant. (Net electric plant includes conservation assets, betterment additions, new resource additions from optimization model, less retirements, less accumulated depreciation.)
Net Conservation Assets ($M): The portion of net electric plant that is due to investments in conservation resources after cumulative amortization. This includes ESC (energy service charge) loan programs and non-ESC (deferred) programs.

Utility Cost:

Operating Revenues ($M): (Nominal) Model assumes perfect regulation, where all plant additions are added to rate base in the year completed, starting after 1997 when CWIP is zero. The rate base is lagged one year for computing the return on rate base. Depreciation, O&M expenses, taxes other than income taxes, and income taxes are added to return on rate base, providing gross operating revenues. Gross operating revenues are reduced by the revenue credit (sales for resale excluding regular, DSR energy service charge, and other revenues).
Cost in Mills/Kwh: Operating revenues divided by energy sales after conservation.
Average Customer Bill (Annual $): Operating revenues per customers.

Total Cost:
DSR Customer Cost ($M): Customer investment and benefits from DSR Resources. (Data is from Demand Side Policy & Strategy).
Levelized DSR Customer Cost ($M): Customer cost levelized over 20 years using the company's after-tax discount rate of 8.8%.
Energy Service Charge ($M): Revenue from customers who receive energy service loans for acquiring DSR resources. This reflects the customers total annual loan payments.
Total Resource Cost ($M): (Nominal) Operating revenues plus energy service charges and levelized DSR customer costs.
Cost in Mills/Kwh: Total resource cost divided by energy sales before conservation.

Footnotes/Mathematical Computations

Nominal Dollars are stated in current year values, which includes the impact of inflation.
Real Dollars are nominal values divided by one plus the inflation rate (3.4%) after 1994 to the Year minus Base Year power. Computation removes annual inflation impacts.
NPV is the fifty year net present value of a stream of values discounted at the company's 8.8% after tax discount rate.
Annual Growth Rate calculates the compound annual growth rate over 50 years.
Real Levelized Utility Cost (mills/kwh) is the levelized utility cost using the real discount rate (one plus discount rate divided by one plus the inflation rate), divided by the levelized energy sales after conservation, times one plus the inflation rate. This computes the utility costs on a $/mwh basis without the impact of inflation and allows the company to rank resources when comparing resource additions in different years.
Real Levelized Total Cost (mills/kwh) is the levelized total resource cost using the real discount rate (one plus discount rate divided by one plus the inflation rate), divided by the levelized energy sales before conservation times one plus the inflation rate. This computes the total resource costs on a per mwh basis without the impact of inflation.

New Resource Analysis
February 8, 1994

Section 4

IPM Model Input Files

Detailed Descriptions

The following paragraphs describe the variables and formats required by IPM model, and examples for each of them. The descriptions of items in all the files follow the order used in the input files.

A. Supply Side Resources (plant.dat)
B. Demand Side Resources (demand.dat, impact.dat, dsmpct.dat)
C. Renewables (renewbl.dat)
D. Sales (sales.dat, sale.dat)
E. Purchases (purchase.dat)
F. Load Duration Curve (*ldc.dat, hourly load data file)
G. Emission Control (co2.dat, so2.dat)
H. Miscellaneous (concole.dat, repdata.dat, unserv.dat, CONFIG.LPS, bincons.dat)

A. Supply-Side Resources (plant.dat)

The existing and potential supply side resources of the company are identified in plant.dat file, which has 24 parts. Some of the parts have more than one copy due to the selections of Future, DSR, Coal & Renewable strategies of the runs, as well as Environmental Adders and Sensitivity studies.

1. Title

This is the first entry in this file, which is the name of a run.

```
C****************************************
Load = m  Gas = mg  DSR = unc  Coal = ac  Renewables = ar
```

In this case, it is a run for Medium load growth, Medium gas price, Unconstrained DSR and Any-Coal & Any-Renewable strategy.

2. Planning Horizon

Planning horizon indicates the current year, first year of the study and the number of years in the study. A 50 year instead of 20 year planning horizon is used for the purpose of including end effects.

```
C*** CURRENT YEAR (IYRC)
1994
C*** FIRST YEAR OF STUDY (LPF)
1994
C*** NUMBER OF YEARS IN THE STUDY (NY)
0050
```

3. Definition of Regions

In this section, the file specifies the number of regions, reserve margins, losses from generators to customer meters, and file names for hourly load data and cuts of segments on the load duration curve (see Paragraph F), as well as the joint reserve margin of all the regions.

```
C*** NUMBER OF REGIONS
0006
C*** REGION          R.M.    % LOSS   LOAD FILE      LDC FILE
-----------------------------------------------------------------
B    BRIDGER         -1.0      0.0    owc95b.dat     owcldc.dat
O    OWC             -1.0      0.0    owc95b.dat     owcldc.dat
U    UTAH            -1.0      0.0    uta95b.dat     utaldc.dat
W    WYOMING         -1.0      0.0    wyo95b.dat     wyoldc.dat
D    DSW             -1.0      0.0    uta95b.dat     utaldc.dat
C    CAL             -1.0      0.0    owc95b.dat     owcldc.dat
C*** JOINT RESERVE MARGIN
CI4-2x-F6.1-
0001   15.0
```

BRIDGER generates mainly for OWC region and CAL gets power mainly from OWC, which are why these two regions use the same load pattern files as OWC. DSW region's sales are mainly to UTAH, so it uses UTAH's load pattern files.

Company does not enforced reserve margins in each region. However, a joint reserve margin of 15% is enforced for Company's entire service region. This margin is fixed for the entire planning horizon.

The loss between generators and customer meters are included in the load forecast.

4. Load and Run Years

Energy (GWh) and peaks (MW) of annual load by region are listed for the entire planning horizon.

There are copies for five Load futures and three Load Level sensitivities.

```
C*** YEARS TO BE RUN, YEARLY GENERATION (GWH) AND PEAK (MW) medium forecast
C*****************************************************************************************************
YEAR RUN    BRI           OWC          UTA          WYO          DSW          CAL
-------------------------------------------------------------------------------------------------------
 1994 YES 0.005 0.001 20984 4940 18100 2550  7816 1007 0.005 0.001 0.005 0.001
 1995 YES 0.005 0.001 21436 4025 18723 2640  7882 1016 0.005 0.001 0.005 0.001
...... ......
 2001 YES 0.005 0.001 24221 4548 22385 3162  8780 1132 0.005 0.001 0.005 0.001
 2002 NO  0.005 0.001 24749 4648 22978 3245  9016 1162 0.005 0.001 0.005 0.001
...... ......
 2012 NO  0.005 0.001 30552 5703 27527 3879 11225 1439 0.005 0.001 0.005 0.001
 2013 YES 0.005 0.001 30865 5797 27861 3948 11337 1461 0.005 0.001 0.005 0.001
 2014 NO  0.005 0.001 30865 5797 27861 3948 11337 1461 0.005 0.001 0.005 0.001
...... ......
 2036 YES 0.005 0.001 30865 5797 27861 3948 11337 1461 0.005 0.001 0.005 0.001
...... ......
 2043 NO  0.005 0.001 30865 5797 27861 3948 11337 1461 0.005 0.001 0.005 0.001
```

BRIDGER, DSW and CAL regions do not have loads. BRIDGER region is used because there is no direct transmission between WYO and OWC. DSW and CAL are wholesale markets. Since IPM does not allow zero-valued loads, 0.005 and 0.001 are used as dummy energy and peaks respectively. Because of the machine time constraints, not every year in the 50-year planning horizon is run.

A flag is used to indicate if there is inter-region transmission.

```
C*** TRANSMISSION FLAG (0=NO TRANSMISSION; 1=TRANSMISSION)
0001
```

To closely follow the load changes, the non-run years are mapped to specific run years with the pattern that the number of non-run years before and after a run year is the same.

```
C*** YEAR MAP
ACTUAL  REPRESENTED BY
 YEAR     YEAR
------------------------
 1994     1994
 1995     1995
 ......  ......
 2001     2001
 2002     2003
 ......  ......
 2012     2013
 2013     2013
 2014     2013
 ......  ......
 2036     2036
 ......  ......
 2043     2036
```

5. Number of Plants

The number of plants, existing and potential, is specified.

```
C*** NUMBER OF AGGREGATE PLANTS
0078
```

6. Definition of Seasons

The number and names of seasons are defined here.

```
C*** NUMBER OF SEASONS (NPER)
004
C*** SEASONS NAMES
-------- -------- -------- --------
WIN    SPR    SUM    FAL
```

7. Number of Segments in Each Season

For all the seasons, the numbers of load segments are identified, followed by the definition of Base-Load, Mid-Load and Peak-Load sections in terms of segments in each season.

```
NUMBER OF LOAD SEGMENTS BY SEASON
 8 8 8 8
C*** SEGMENT DEFINITIONS SEASON 1
C*** BASE (TOP, BOTTOM)
 7 8
C*** MID (TOP, BOTTOM)
 6 6
C*** PEAK (TOP, BOTTOM)
 1 5
C*** SEGMENT DEFINITIONS SEASON 2
```

8. Existing Pumped Storage

This section contains the number of existing pumped storage units, and for each unit, the efficiency of pumping (%), efficiency of generation (%), pump capacity (MW) and reservoir capacity (GWh), as well as the years when these are applicable.

```
C****** NUMBER OF EXISTING PUMP STORAGE PLANTS (IPST)
 0004   EFF 1   EFF 2   PMP. CAP.  RESERVOIR  YEAR   YEAR
-------------------------------------------------------------
  006   100.0   100.0   1100.0       55.0     1994   2043
  007   100.0   100.0     18.0        1.7     1994   1994
  007   100.0   100.0     16.0        1.5     1995   1995
...... ......
  007   100.0   100.0      4.5        0.4     2000   2043
...... ......
  067    78.0   100.0    100.0       41.7     1994   2043
```

The first column lists the plant numbers as defined in part 11 later.

The next indicates the segments when the pumping and generation may occur in terms of segments. The first two columns are for the pumping range, and the last two the generation range.

```
C***RANGE OF SEGS IN WHICH PUMPING OCCURS
WIN
0006 008 001 005
SPR
0006 008 001 005
SUM
0006 008 001 005
FAL
0006 008 001 005
```

9. Number of Fuels Types

The number of fuels used by all the plants is specified here.

```
C******** NUMBER OF FUEL TYPES
0032
```

10. Escalation Rates

These include the numbers of escalation rates for capital and O&M cost, nominal discount rate, inflation rate by year, fuel price escalation rate, variable O&M escalation rate, fixed O&M escalation rate, and capital escalation rate.

```
C*** NUMBER OF CAPITAL TYPES
0001
C*** NUMBER OF O&M ESCALATION TYPES
0001
C*** DISCOUNT RATE - NOMINAL (%)
 5.2
C*** TABLE OF INFLATION RATES
YEAR RATE
---- ----
1994  0.0
1995  0.0
...... ......
2013  0.0
...... ......
2043  0.0
C*** FUEL ESCALATION DATA TABLE FLAG (1=YES OR 0=NO)
0000
C*** VARIABLE O&M ESCALATION DATA TABLE FLAG (1=YES OR 0=NO)
0000
C*** FIXED O&M ESCALATION DATA TABLE FLAG (1=YES OR 0=NO)
0000
C*** CAPITAL ESCALATION DATA TABLE FLAG (1=YES OR 0=NO)
0000
```

IPM model does not use inflation rate by year, therefore, all the numbers in that table are 0's. Changes in fuel prices are incorporated in the fuel price section (part 17). There are no annual capital, variable and fixed O & M escalation rates used.

11. Plant Data

This is a table of general information on all the supply-side resources, existing and potential. For each resource, the file lists its code and name, if it is a retrofit and its original plant code when it is a retrofit, fraction of capacity lost due to retrofit (%), utility type (coal, hydro, purchase, etc., which is defined in file repdata.dat described later in Paragraph H.2), region it is (or will be) in, plant type (CC CT, cogeneration, renewable, etc., which is also defined in file repdata.dat), physical life and book life (number of years), efficiency (%, for potential resources, % of capacity contributes to reserve margin), forced outage rate (%), incremental heat rate (BTU/kWh), variable O & M cost (mills/kWh), fixed O & M cost ($/kW/year), capital cost ($/kW), and whether it is an existing or potential resource.

There is one copy for the runs in Base Plan, six copies for Environmental Adders cases, and one copy for Reduced Wind Cost sensitivity run.

--- Oct 18 --- ----- PLANT TABLE - PLANT.011.PLANT.TABLE ---------------- - 78 Plants Modeled

#	Name	Long Name	RETRFIT	PLNY	UT	R	TY	OM	CP	LF	BJ	EFF	FOR	HEAT	VOM	FOM	CAP	E/P
1	APS	APS Sec CTs		0.0	1	D	4	1	1	50	50	1.00	10.20	7600	14.49	0.0	0	E
......	......																	
16	DJN	Dave Johnston 1,2,3		0.0	1	W	1	1	1	50	50	1.00	7.09	10222	0.00	22.4	0	E
......	......																	
24	HYD	Hydro Pacific		0.0	3	O	6	1	1	75	75	1.00	0.00	0	0.00	9.4	0	E
......	......																	
61	UCT	Utah Simple Cycle CT		0.0	1	U	4	1	1	50	30	1.00	1.50	10545	7.00	21.8	578	P
62	UCV	Utah CC CT Convert	UCT UCT	-66.7	1	U	5	1	1	50	35	1.00	3.30	5250	1.00	10.0	1347	P
......	......																	
78	WW2	Wyo Wind w/o Tax C		0.0	3	W	10	1	1	50	20	0.33	0.00	10000	4.20	9.5	1362	P

12. Fuels

This section contains how many types of fuels each resource uses and what they are. The fuels are numbered in file repdata.dat, which is described later (see Paragraph H.2). There are three copies for each of the Gas Price futures.

---Sept 16 --- Plant.012.Fuel.mg ----- Medium Gas Price ---------

#	NAME	#FUELS	FUELS ALLOWED (11I3) (INCLUDING FLAME STABLIZATION FUEL)
1	APS	1	23
......	......		
16	DJN	1	7
......	......		
24	HYD	1	1
......	......		
62	UCV	1	23
......	......		
78	WW2	1	32

13. Fuels to Stabilize Flames

There are no different fuels used for this purpose.

```
- Sept 2 ---  PLANT.013.FLAME.STABLE -------------------------
C*** FLAME STABILIZATION
-- --  -
 1 APS    0
...... ......
78 WW2        0
```

14. Maintenance Schedule

This table lists capacity availabilities (%) after maintenance for all the resources by season and for the entire planning horizon.

```
---- Oct 6 ------ MAINTENANCE SECTION ---
APS.
1994-2043     100.0   100.0   100.0   100.0
...... ......
HYD.
1994-2043      97.0    93.0    80.0    98.0
...... ......
DJN.
1994-1994     100.0    91.1   100.0    93.5
1995-1995     100.0    80.6   100.0   100.0
1996-1996     100.0    91.1   100.0    95.7
1997-1997     100.0    82.8   100.0   100.0
1998-1998     100.0    86.6   100.0    95.7
1999-1999     100.0    76.3   100.0   100.0
...... ......
2043-2043     100.0    80.6   100.0   100.0
...... ......
UCV.
1994-2043     100.0    85.0   100.0   100.0
...... ......
WW2.
1994-2043     100.0   100.0   100.0   100.0
```

15. Capacity Factor

Capacity factors constrain the energy output from the resources. For each resource, the capacity factors (%) are presented by season for the entire planning horizon.

```
- Oct 12 -- CAPACITY FACTOR SECTION --
APS. 0
1994-2043   100.0   100.0   100.0   100.0
...... .....
DJN. 0
1994-2043   100.0   100.0   100.0   100.0
...... ......
HYD. 0
1994-2043    69.0    60.0    40.0    52.0
...... ......
OC1. 0
1994-2043   100.0   100.0   100.0   100.0
...... ......
WW2. 0
1994-2043    59.2    32.4    18.4    30.9
```

The number "0" after each resource code indicates that the constraint is of a less-or-equal-to type, that is, the resource must operate at the capacity factor no greater than the specified numbers.

16. Capital Charge Rate

For all the potential resources, this section lists the capital charge rates by year for the entire planning horizon.

---- Sept 29 ---- Capital Charge Rates for Potential Units ------------------

	CPU.	OC1.	OC2.	OCC.	OCT.	OCV.	OGT.	OPS.	OW1.
1994	8.95	8.95	8.95	8.95	9.16	8.95	8.95	8.12	9.84
1995	8.95	8.95	8.95	8.95	9.16	8.95	8.95	8.12	9.84
....									
2043	8.95	8.95	8.95	8.95	9.16	8.95	8.95	8.12	9.84

---- Sept 29 ---- Capital Charge Rates for Potential Units ------------------

	OW2.	UC1.	UC2.	UCC.	UCT.	UCV.	UCY.	UFB.	UGC.
....									

17. Fuel Price and Emission

This section contains CO2, NOx and other particles' emission rates (lbs/MMBTU), as well as the prices (cents/MMBTU) of all the fuels by year for the entire planning horizon. There is a fixed amount of SO2 allowance as discussed in the portfolio chapter of the main report, so that its emission is not modeled and the entries here are 0's. There are three copies for the Renewable O & M sensitivies, and one for all the other runs. The reports on emissions are not generated by IPM model, therefore, the emission rates listed here may not be the latest.

-----November 12 -------- FUEL PRICE AND EMISSION DATA ---------

—	PURCH	CARBN	CENTR	CHOL4	COLST	CRAIG	DJOHN	GADSB	HAYDN
SO2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NOX	0.000	0.450	0.450	0.450	0.450	0.450	0.480	0.200	0.450
TSP	0.000	0.040	0.010	0.050	0.030	0.030	0.040	0.003	0.030
CO2	0.0	198.0	213.0	215.0	215.0	215.0	218.0	133.0	215.0
ASH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1994	0.0	73.0	133.0	169.0	80.4	108.7	63.4	196.6	93.3
1995	0.0	72.5	127.8	169.1	81.0	108.8	62.1	196.9	93.8
....									
2043	0.0	71.5	126.5	165.9	82.2	108.3	60.6	225.1	94.5

-----November 12 -------- FUEL PRICE AND EMISSION DATA ---------

—	HUNTN	HUNTR	JBRDG	NAUGH	WYODK	COALU	COALW	GLCCW	GLSCW
....									

18. Turn Down

These are the constraints on resource capacities when turning down, if there is any. It is not used here.

---- TURN.DOWN SECTION ----

00

19. Area Protection

Area protection section indicates the number of resources which must run in a specific segment on the load duration curve with certain fraction of the capacities and at the specified heat rates. This allows minimum generation levels to be represented.

```
---- AREA PROTECTION SECTION ----
        51
-------------------------------
...... ......
DJN.
     0.444   8     12138.0
     0.444   8     12138.0
     0.444   8     12138.0
     0.444   8     12138.0
...... ......
HYD.
     0.107   8         0.0
     0.072   8         0.0
     0.077   8         0.0
     0.075   8         0.0
...... ......
WW2.
     0.591   8     10000.0
     0.323   8     10000.0
     0.183   8     10000.0
     0.308   8     10000.0
```

20. Capacities of Existing Resources

Incremental capacities (MW) of the existing resources are listed by year for the entire planning horizon. The first non-zero number in a column indicates when the resource is available. The negative (positive) numbers are the reductions (additions) to the existing capacities.

```
----- Oct 12 --- Capacity Bounds for Existing Units -------------
         APS    APT    ASE    BHC    BLU    BPA    BPS    CAR    CEN
---------------------------------------------------------------------
 1994    200      0      0     84     22    700     17    178    638
 1995      0      0      0      0      0      0     -2      0      0
...... ......
 2043      0      0      0      0      0      0      0      0      0
-------- Capacity Bounds for Existing Units --------------------
         CHL    CLS    CRG    CRM    CSH    DES    DJN    GDS    GRT
---------------------------------------------------------------------
...... ......
```

21. Capacities of Potential Resources

There are four parts determining how new resources can be added in terms of capacities (MW). Each of the four Coal & Renewable combinations has its own copy of these parts.

Lower-Bounds

These are the minimum incremental capacities of each resource to be added in each year. In Strategic-Renewable cases, the renewable resources are forced in. Thus, their lower capacity bounds have non-zero values.

---- LOWER CAPACITY BOUNDS FOR POTENTIAL UNITS --- AC AR Oct 18

	CPU.	OC1.	OC2.	OCC.	OCT.	OCV.	OGT.	OPS.	OW1.
1994	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0
....									
2043	0	0	0	0	0	0	0	0	0

---- LOWER CAPACITY BOUNDS FOR POTENTIAL UNITS ---

	OW2.	UC1.	UC2.	UCC.	UCT.	UCV.	UCY.	UFB.	UGC.
....									

Upper-Bounds

These are the maximum incremental capacities of each resource to be added in each year.

---UPPER CAPACITY BOUNDS FOR POTENTIAL UNITS ---

	CPU.	OC1.	OC2.	OCC.	OCT.	OCV.	OGT.	OPS.	OW1.
1994	2000	0	0	0	0	0	0	0	0
1995	2000	0	0	0	0	0	0	0	0
1996	2000	0	0	0	0	0	0	0	0
1997	2000	160	470	0	0	0	0	0	150
1998	2000	160	470	450	370	450	100	200	150
....									
2043	2000	160	470	450	370	450	100	200	0

---UPPER CAPACITY BOUNDS FOR POTENTIAL UNITS ---

	OW2.	UC1.	UC2.	UCC.	UCT.	UCV.	UCY.	UFB.	UGC.
....									

Cumulative Lower-Bounds

These are the minimum capacities of each resource to be added up to each year.

---- LOWER CUMULATIVE CAPACITY BOUNDS FOR POTENTIAL UNITS ---

	CPU.	OC1.	OC2.	OCC.	OCT.	OCV.	OGT.	OPS.	OW1.
1994	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0
....									
2043	0	0	0	0	0	0	0	0	0

---- LOWER CUMULATIVE CAPACITY BOUNDS FOR POTENTIAL UNITS ---

	OW2.	UC1.	UC2.	UCC.	UCT.	UCV.	UCY.	UFB.	UGC.
....									

When the model is to choose the capacities, all the entries here are zeros.

Cumulative Upper-Bounds
These are the maximum capacities of each resource to be added up to each year.

---UPPER CUMULATIVE CAPACITY BOUNDS FOR POTENTIAL UNITS ---

	CPU.	OC1.	OC2.	OCC.	OCT.	OCV.	OGT.	OPS.	OW1.
1994	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0
1996	0	320	1320	0	0	0	0	0	0
....									
2043	0	0	0	0	0	0	0	0	0

---UPPER CUMULATIVE CAPACITY BOUNDS FOR POTENTIAL UNITS ---

	OW2.	UC1.	UC2.	UCC.	UCT.	UCV.	UCY.	UFB.	UGC.
....									

If the entries in an entire column are 0's, the model will decide the upper cumulative bounds. If in a column there is any non-zero number, the 0's before that non-zero number imply that the upper cumulative capacity should not be greater than zero which is the same as saying that the resource is not available, and the 0's after that non-zero number imply that there is no change to the cumulative upper bounds which is the same as saying that the cumulative upper bounds stay the same as determined by the previous non-zero value.

22. Reserve Margin Capacities
These are the capacities (MW) of existing resources which will contribute towards the joint reserve margin.

-------- RESERVE MARGIN CAPACITIES FOR EXISTING UNITS ---

	APS	APT	ASE	BHC	BLU	BPA	BPS	CAR	CEN
1994	0	0	0	0	22	1100	17	178	638
1995	0	0	0	0	0	0	-2	0	0
....									
2043	0	0	0	0	0	0	0	0	0

--- RESERVE MARGIN CAPACITIES FOR EXISTING UNITS ---

	CHL	CLS	CRG	CRM	CSH	DES	DJN	GDS	GRT
....									

The reserve contributions of potential resources are determined in part 11.

23. Transmission
The first part of this section contains the number of transmission lines, their efficiencies (fraction), forced outage rates (%), transmission costs (mills/kWh) in seasons and segments.

C*** Firm TRANSMISSION, only -- Sept 2
C NUMBER OF LINKES
21

C-EFF	F.O.R	-COST-	-SEA-	-SEG-
1.00	0.0	0.5		
......	......			
1.00	0.0	0.5		
1.00	0.0	0.5		
......	......			
......	......			
1.00	0.0	0.5	1	1
1.00	0.0	0.5	2	2
......	......			
1.00	0.0	0.5		

Then the above table is followed by the capacity (MW) of each transmission line, and from and to regions in different time periods when the capacity is applicable.

CAPS	FROM	TO	YEARS	NO
1500	B	O	1994-2043	1
......	......			
815	B	U	1994-2043	5
275	U	B	1994-2043	6
792	O	C	1994-2043	15
633	O	C	1994-2043	16
......	......			
0	W	D	1994-2043	21

The next are the joint constraints on transmission lines.

NUMBER OF JOINT CONSTRAINTS
0002
C FORM OF CONSTRAINTS

TRBO	1	
......	......	
TRBU	1	
TRUB		1
......	......	
TRUO		1
TRUD		
......	......	
TROC		
TROC		
......	......	
TRWD		
RHS	1500	275

The number "1500" on the last row means that the joint capacity of the two transmission lines, TRBO and TRBU as indicated by a "1" in the corresponding column, can not exceeds 1500MW. The same meaning holds true for the column with "275" in the last row. The orders of transmission lines are the same in all above tables.

24. Flag for Demand Side Programs

The last line in file plant.dat is a flag used to specify if there are demand side programs to be modeled. At present, this flag does not work.

```
C*** DEMAND SIDE FLAG (0=NO DEMAND SIDE OPTIONS; 1=YES)
0001
```

B. Demand-Side Resources (demand.dat, impact.dat, dsmpct.dat)

Three files are used to model demand side programs:

1. demand.dat

This file contains the number of demand side programs. For each program, there are number of years it operates, its capital charge rate, the factor used to scale the cost and impact, which region it operates, and whether it operates in the case under study. There are 19 copies of this file for all the DSR options under all the Load futures, and one for a DSR sensitivity run.

```
C-006-MUST RUN -- MD CASE, MEDIUM GROWTH -- INDUSTRIAL/10 --10/C
YES
C*** NUMBER OF AGGREGATE DEMAND SIDE OPTIONS
26
C-----------------------------------------------------------
#  NAME LONG NAME                 YRS   RATE%  DSFAC REG RUN
--------------------------------------------------------------------
 1  EF2  COMMERCIAL FINANSWER      60    0.000  1.0    2   1
 2  EF3  COMMERCIAL FINANSWER      60    0.000  1.0    3   1
...... ......
26  XT4  XTRA COMML MEASURES       60    5.479  1.0    4   0
```

The regions are indicated by numbers which correspond to the order defined in plant.dat file, Paragraph A.3.

The market penetrations (MWh, or number of units) of all the demand side programs are specified in the following for 50 years (the maximum number of years the programs can run during the planning horizon).

```
Market Pentration Info. for DSO's
 DSO      EF2     EF3     EF4     122     123     124     IN2     IN3
---------------------------------------------------------------------------
YR 1     6993   12274     287    2107    1029      80    2665    2391
YR 2    14757   24923     651    4851    3250     247    6807    7044
...... ......
YR20   297981  280293   37128  181447  189413   44386   59609  117502
YR21   297981  280293   37128  181447  189413   44386   59609  117502
...... ......
YR50   297981  280293   37128  181447  189413   44386   59609  117502
...... ......
```

Since RAMPP-3 is to study the change of load level and resource selection in 20 years, the penetration effects of demand side programs are only modeled for 20 years, and after the 20th year, the numbers do not change.

2. impact.dat

At the beginning of this file, whether the first year of the study is a leap year and which day in a week the study year starts are identified. There are five copies of this file, one for each of the Load futures.

```
C*005* DEMAND SIDE OPTIONS IMPACTS FILE *8/16/93*******
C--UNCONSTRAINED RUN--INDUSTRIAL/10--------------------------------
LEAP   DAY1  (LEAP:1=LEAP YR,0=NOT; DAY1:1=MON,2=TUE,..,7=SUN)
-   -
0   7
```

Then, for each demand side program, this file specifies the fraction of the program capacity in (load) peak reduction, loss between generator and customer meters (%), equipment cost per unit ($thousand), cost of rebate per unit ($thousand), and the hourly load impact (kW/MWh or kW/unit) by week day, weekend day and peak day in each season.

```
------------ LOAD IMPACT DATA FOR DEMAND SIDE OPTIONS  (KW'S)-------
                    RM       LOSS       EQUIP     VARYP    REBATE
PROGRAM= EF2
RM FACTOR           1.0         0.0     553.05       0.0        0.0
C--
---WINTER WEEKDAY
  -0.036368  -0.041333  -0.043656  -0.056042  -0.039490  -0.087909
  -0.270518  -0.222402  -0.400315  -0.409894  -0.381590  -0.343063
  -0.289498  -0.255819  -0.218287  -0.212733  -0.209958  -0.185270
  -0.093957  -0.045801  -0.037912  -0.056539  -0.052432  -0.055650
---WINTER WEEKEND
...... ......
---WINTER PEAKDAY
...... ......
---SPRING WEEKDAY
...... ......
```

3. dsmpct.dat

This file defines the minimum and maximum fractions of each demand side program to be run, if there is any, in specified years. There is one copy each for Unconstrained DSR, LD DSR, a DSR sensitivity run, and all other DSR options.

```
DSM Minimum specifications
--I---Ixxxx--8.3f--
EF2
  1994   1.
  1999   1.
...... ......
*
```

```
DSM Maximum specifications
--|---|xxxx--8.3f--
  1998   0.
CR4
...... ......
*
```

C. Renewables (renewbl.dat)

File renewbl.dat contains, for each renewable resource, hourly load pattern (kW) corresponds to 1MW of renewable load resources in 24 hours by season.

```
************** Renewables ****************
---------- IMPACT DATA in kW's ------------
PROGRAM= WFC      --- Wind in Washington (Foote Cree
---winter
       560.0  573.3  573.3  566.7  586.7  600.0
       640.0  573.3  600.0  606.7  626.7  640.0
       606.7  613.3  606.7  600.0  586.7  573.3
       566.7  560.0  560.0  573.3  613.3  600.0
---spring
...... ......
---summer
...... ......
---fall
...... ......
```

D. Sales (sales.dat, sale.dat)

There are two input files for sales contracts: sales.dat and sale.dat. The second one, sale.dat, was added to the model because the original file, sales.dat, can not handle individual contracts. In sales.dat, all the contracts in a region need to be combined as one and then spread over the load segments. Since the model still requires file sales.dat, all the entries in this file are 0's.

```
REGION B
---- ----
1994 2043
LS  US  INCREASE
--  --  -------
01  08      0.   (Winter)
++++
01  08      0.   (Spring)
++++
01  08      0.   (Summer)
++++
01  08      0.   (Fall)
-------------------------------------------------
REGION O
...... ......
```

There are nine sections in sale.dat file.

1. Number of Contracts

The number of sales contracts, firm and non-firm, is identified.

```
Sales
C** number of sales
38
```

2. General Information of Non-Firm Contracts

The general information includes: code, name, type of contract (firm and non-firm), existing or potential, region, earliest and latest available years, length of the contract (number of years), latest termination year, capacity (MW), contribution to reserve margin (fraction), fixed cost ($/kW/year) and cost multiplier. There is one copy for No Non-Firm Sales sensitivity run, and one for all others.

```
C**
Description of options
-------------------
```

Code (A3)	Name (A20)	F/N	E/P	Reg	Start First Year	Start Last Year	Len	Last Year Avail	Disp Cap (MW)	Res. Marg. Fract.	Fixed Cost $/kw/yr	Cost mult.
CAH	Cal. Sec., HLH	N	E	C	1994	1994	1	2015	1000.0	0.0	0	0.85
......	......											
NSL	NW Sec., LLH	N	E	O	1994	1994	1	2015	300.0	0.0	0	0.60

The region codes are defined in file plant.dat (Paragraph A.3). The model uses Cost Multiplier to calculate if it is economical to dispatch a contract at its price compared with the incremenal prices generated by the model for each segment, The termination of a potential contract is either the Last Year Available, or the year when the contract starts plus the length of the contract, whichever is earlier.

3. General Information of Firm Contracts

For easy modification, the information about firm contracts is separated from the one about non-firm contracts. There is no requirement on the order of non-firm and firm contracts.

S01	Canadian Entitlement	F	E	O	1994	1994	0	1995	18.0	0.0	0.0	0.00
S02	Canadian Entitlement	F	E	O	1996	1996	0	2043	9.0	0.0	0.0	0.00
S03	Colockum	F	E	O	1994	1994	0	2008	63.0	0.0	0.0	0.00
......	......											
S32	Tri-State Seasonal E	F	E	W	1994	1994	0	2007	50.0	0.0	0.0	0.00

For existing contracts, the length of contract is ignored, instead, its last year available is used to terminate it. Some contracts have more than one entry

(Canadian Entitlement, for example) because their capacities change over their contractual periods. Colockum is a purchase contract, but since the model can not handle negative purchase (energy return of the purchase contract), the energy return part is modeled as a sales contract.

4. Availability of Non-Firm Contracts

This section has the availabilities of non-firm contracts. For each contract, they are determined by percentage of capacity available in peak and non-peak segments by season, and in all the years when it is available.

```
C**
SALES AVAILABILITY (% by year and seaso
------------------------------------------
C** sales option
CAH
C**
Years 1994-2015
                         Season
                  ------------------------
Time of Day  Winter  Spring Summe   Fall
-----------------------------------------------
Off-peak        0.0     0.0     0.0     0.0
Mid-peak        0.0     0.0     0.0     0.0
On-peak       100.0   100.0   100.0   100.0
...... ......
C** sales option
NSL
C**
Years 1994-2015
...... ......
```

Then followed by availabilities of firm contracts.

5. Availability of Firm Contracts

```
C** Canadian Entitlement
S01
C**
Years 1994-1995
                         Season
                  ------------------------
Time of Day  Winter  Spring Summe   Fall
-----------------------------------------------
Off-peak      100.0   100.0   100.0   100.0
Mid-peak       43.5    43.5    43.5    43.5
On-peak         0.0     0.0     0.0     0.0
...... ......
C** Tri-State Seasonal Exchange
S32
...... ......
```

The definitions of Off-peak, Mid-peak and On-peak are in plant.dat (see Paragraph A.7).

6. Prices of Non-Firm Contracts

This section lists the prices (mills/kWh) of non-firm sales contract in peak and non-peak segments by season, and in all the years when it is available. The model selects contracts using this information. There are copies for nine NOx-CO2 and Gas Price future combinations, one for Critical Water sensitivity run, and one for each of the Gas Price futures.

C**
sale

C** sale Option
CAH
C**
Years 1994-1996

Time of Day	Winter	Spring	Summer	Fall
	Season			
Off-peak	29.2	19.6	28.0	26.7
Mid-peak	29.2	19.6	28.0	26.7
On-peak	29.2	19.6	28.0	26.7

....
C**
Years 2015-2015
....

7. Prices of Firm Contracts

For firm contracts, prices are not relevant in dispatch selections. They are used to determine the financial impact of a case under study. However, due to the complex nature of the Company's pricing system, IPM model can not effectively deal with the price information for firm sales contracts. And such information is taken up separately in the financial modeling. Thus, all the entries in this section are 0's.

C** Canadian Entitlement
S01
C**
Years 1994-1995

Time of Day	Winter	Spring	Summer	Fall
	Season			
Off-peak	0.0	0.0	0.0	0.0
Mid-peak	0.0	0.0	0.0	0.0
On-peak	0.0	0.0	0.0	0.0

....

8. Capacity Factors of Non-Firm Contracts

These specify the energy sales from the non-firm sales contracts. The capacity factors (%) are listed by year.

```
C
C - CAPACITY FACTORS
---------------
C**
CAH         CF
C**  -- --- ----
Years       1994-2015         100.0
...... ......
C**
NSL         CF
C**  ---- --- ---
Years       1994-2015          77.8
```

9. Capacity Factors of Firm Contracts

The same information as above, but for firm sales contracts, is in this section.

```
C** Canadian Entitlement
S01 E       CF
C**  ---- --- ---
 Years 1994-1995      100.0
...... ......
C** Tri-State Seasonal Exchar
S32 E       CF
C**  -- --- ----
 Years 1994-2007      100.0
```

The letter "E" after each contract code means that the capacity factor constraint is of equal-to type, that is, the energy from a contract should satify exactly the capacity factor specified. If there is no indication after the code, the less-or-equal-to type of constraint is implied.

E. Purchases (purchase.dat)

This file is also an addition to the model as sale.dat file. All the firm purchase contracts were originally listed in plant.dat file as one type of resources (see Paragraph A.11). However, because of the nature of non-firm contracts, off-peak firm contracts, and interruptable purchase contracts, more information needs to be entered in order for the model to decide when to purchase what and how much. This file has the same sections and format as sale.dat, except it contains the information on purchase contracts. Due to the time constraints, only some of the firm purchase contracts who are mainly for purchased energy during off-peak segments along the load duration curve are move to this file.

1. Number of Contracts

This is the total number of non-firm and firm purchase contracts (existing or potential) in purchase.dat file.

```
Purchase Options
C** number of purchases
09
```

2. General Information of Non-Firm Contracts

The general information includes the code and name of each contract, non-firm or firm type, existing or potential, region, earliest and latest contract starting years, length of the contract (number of years), termination year of the contract, capacity (MW), contribution to reserve margin (fraction), fixed cost ($/kW/year) and cost multiplier. There is one copy for No Non-Firm Purchases sensitivity run, and one for all others.

C**
Description of options

Code (A3)	Name (A20)	F/N	E/P	Reg	Start ----- First Year	--- Last Year	Len	Last Year Avail	Disp Cap (MW)	Res. Marg. Fract.	Fixed Cost $/kw/yr	Cost mult.
DPH	DSW Sec., HLH	N	E	D	1994	1994	1	2043	250.0	0.0	0	1.00
......	......											
WPL	Wyo Sec., LLH	N	E	W	1994	1994	1	2043	250.0	0.0	0	1.00

The region codes are defined in file plant.dat (Paragraph A.3).

3. General Information of Firm Contracts

This is the same information as in above section, but for firm purchase contracts.

ASU	APS Supplemental	F	E	D	1994	1994	1	2043	250.0	0.0	0.0	1.00
......	......											
INT	Interruptible Rep	F	E	U	1994	1994	1	2043	316.0	0.0	0.0	10000.0

4. Availability of Non-Firm Contracts

Availabilities determine how much capacity, as percentage of the maximum capacity, can be purchased in given load segments by season.

C**
PURCHASES AVAIL (% by year and season)

C** purchase option
DPH
C**
Years 1994-2043

Time of Day	Season Winter	Spring	Summer	Fall
Off-peak	0.0	0.0	0.0	0.0
Mid-peak	0.0	0.0	0.0	0.0
On-peak	100.0	100.0	100.0	100.0

....
C** purchase option
....

5. Availability of Firm Contracts

Avaliabilities (% of maximum capacities) for firm purchase contracts:

C** purchase option
DPH
C**
Years 1994-2043

Time of Day	Winter	Spring	Summer	Fall
Off-peak	100.0	100.0	100.0	100.0
Mid-peak	100.0	100.0	100.0	100.0
On-peak	0.0	0.0	0.0	0.0

....
C** purchase option
INT
C**
Years 1994-2043

Time of Day	Winter	Spring	Summer	Fall
Off-peak	99.0	97.7	97.7	98.9
Mid-peak	100.0	97.6	97.6	98.6
On-peak	100.0	97.6	97.6	98.6

The definitions of Off-peak, Mid-peak and On-peak are in plant.dat (see Paragraph A.7)

6. Prices of Non-Firm Contracts

These are the purchase prices for non-firm contract (mills/kWh). There are copies for nine NOx-CO2 and Gas Price future combinations, one for Critical Water sensitivity run, and one for each of the Gas Price futures.

C**
purchase

C** purchase Option
DPH
C**
Years 1994-1996

Time of Day	Winter	Spring	Summer	Fall
Off-peak	26.2	26.9	32.6	29.4
Mid-peak	26.2	26.9	32.6	29.4
On-peak	26.2	26.9	32.6	29.4

....
C**
Years 2043-2043
....

C** purchase Option
WPL
C**
Years 1994-1996

Time of Day	Winter	Spring	Summer	Fall
	Season			
Off-peak	13.4	16.9	17.6	13.4
Mid-peak	13.4	16.9	17.6	13.4
On-peak	13.4	16.9	17.6	13.4

....
C**
Years 2043-2043

Time of Day	Winter	Spring	Summer	Fall
	Season			
Off-peak	76.4	96.8	100.9	76.4
Mid-peak	76.4	96.8	100.9	76.4
On-peak	76.4	96.8	100.9	76.4

7. Prices of Firm Contracts

Purchase prices for firm contract (mills/kWh):

C** purchase Option
ASU
C**
Years 1994-2043

Time of Day	Winter	Spring	Summer	Fall
	Season			
Off-peak	22.0	22.0	22.0	22.0
Mid-peak	22.0	22.0	22.0	22.0
On-peak	0.0	0.0	0.0	0.0

....
C** purchase Option
INT
C**
Years 1994-2043

Time of Day	Winter	Spring	Summer	Fall
	Season			
Off-peak	0.00214	0.00214	0.00214	0.00214
Mid-peak	0.00214	0.00214	0.00214	0.00214
On-peak	0.00214	0.00214	0.00214	0.00214

8. Capacity Factors of Non-Firm Contracts

Capacity factors of non-firm purchase contracts:

```
C**
Capacity Factors
---------------
C**
DPH        CF
Years        1994-2043        100.0
...... ......
C**
WPL        CF
C**  --- ---  -----
Years        1994-2043        100.0
```

9. Capacity Factors of Firm Contracts

Capacity factors of firm purchase contracts:

```
C**
ASU        CF
C**  ---- ----  -----
Years   1994-2043        100.0
...... ......
C**
INT        CF
C**  ---- ----  -----
Years   1994-2043          1.0
```

The energy from these contracts can not exceeds the specified capacity factors.

F. Load Duration Curve (hourly load data files, *ldc.dat)

There are two groups of files determining the shape of the hourly load: hourly load data in MW by day and month for a typical year, and percentage of hours in each load segment on the load duration curve by season and region (Load duration curve is the curve of hourly load data in a season sorted from highest to lowest. And load segments are the cuts on the load duration curve). Each group has three files for OWC, UTA and WYO load regions respectively as named in Paragraph A.3.

1. Hourly Load Data

This file contains the hourly load data (MW) for one load region. There are three such files.

```
 1   1   1931  1696  1716  1640  1701  2007  2349  2559  2799  2895  2838  2769
 1   1   2722  2615  2539  2529  2616  2781  2823  2784  2731  2591  2352  2154
 1   2   2226  2042  1958  2027  2259  2470  3019  3682  3787  3491  3348  3147
 1   2   3079  2991  2892  2867  2986  3263  3307  3187  3059  2859  2650  2424
...... ......
 1  31   2228  2046  1981  2052  2263  2475  3025  3687  3791  3505  3360  3157
 1  31   3077  3001  2900  2872  2996  3274  3321  3195  3066  2866  2655  2422
 2   1   2283  2174  2149  2201  2316  2562  3236  3888  3970  3542  3393  3239
 2   1   3113  2982  2872  2846  2915  3162  3344  3286  3121  2885  2626  2446
...... ......
12   1   2024  1928  1904  1923  2029  2388  2818  3255  3314  3262  3144  2993
12   1   2904  2842  2790  2789  2924  3128  3104  3002  2905  2771  2592  2347
...... ......
12  31   2204  2110  2062  2080  2134  2275  2514  2769  3010  3116  3056  2964
12  31   2882  2809  2754  2738  2869  3042  3030  2970  2890  2768  2567  2349
```

The first and second columns are for month and day in the month. Then for each day, there are two lines of numbers: one for the first 12 hours and another for the second 12 hours.

2. Cuts of Load Segments

Each load region has its own load duration curves for all the seasons. In this file, the number of segments in each season is specified, as well as the percentage of hours in each segments in that season.

```
C     THE PERCENTAGE OF HOURS IN EACH SEGMENT
C Segment 5, 57% of the hours, is obligatory.
C There are total of 8 segments for all the seasons and regions.
C Segments 1 thru 5 are on-peak, segment 6 is mid-peak and segments 7 and 8 are off-peak
0004    NUMBER OF SEASONS
*********       WIN
WIN
 8   NCUTS
CUT AT  TOP OF_BOTTOM OF
----- ----- ------
.021    1
.093    2
.227    3
.405    4
.570    5
.718    6
.968    7
# MONS   MONTHS IN SEASON
---   -- -- -- -- -- -- -- -- -- -- -- --
 03   001 002 012
*********       SPR
SPR
...... ......
```

The numbers in the first column are cumulative percentage of hours in a segment. If a season has eight segments, the eighth segment will have 100% of cumulative percentage of hours. The same season in all the regions is required to have the same number of segments.

After the definitions of segments, the months in each season are identified.

There are three such files, one for each region.

G. Emission Control

There are two files specifying the levels of CO2 and SO2 are allowed to emit: co2.dat and so2.dat. They are not used.

co2.dat

```
C*** CO2 CONSTRAINTS: STD IN 000' TONS
NUMBER OF CONSTRAINT=00
```

so2.dat

```
C*** SO2 CONSTRAINTS:  STD IN LBS/MBTU IF TYPE2, STD IN 000' TONS TYPE 1
NUMBER OF CONSTRAINT=00
```

H. Miscellaneous

1. console.dat

This file controls what reports are available from the model and which reports are to be generated.

The number of regions in a study and their order are listed first.

```
6    NUMBER OF REGIONAL REPORTS
1    BRI
2    OWC
3    UTA
4    WYO
5    DSW
6    CAL
RUN  TABLE GENERATED
--------------------------------
1    GENERATION BY SEASON AND PLANT
0    TOTAL ANNUAL COSTS BY UNIT IN CONSTANT
1    DEMAND-SIDE PROGRAMS SELECTED AND PENETRATION
...... ......
0    WRITE SPREADSHEET FILE 2
```

Currently, this file is not used. All the reports are generated by a separate program from the binary-data dump files.

2. repdata.dat

Fuels numbers, utility types and plant types used in plant.dat are defined in repdata.dat file.

Fuels

The first part of the file numbers all the fuels used by the supply side resources, and identified by the types of fuels. The description of each type follows.

```
** Sept 16 **   FUEL MAP, CONVERSION UNITS AND FACTORS,NAMES
FU  FU. NAME    TY
-- ------- -- --------- -----
  1 PURCH       6
  2 CARBN       1
...... ......
 32 WIND        2
FU  FU. NAME    UNITS             FACTOR
-- ------------ ---------- -----
  6             NUMBER OF FUEL TYPES
  1 Coal        MILL.  TONS       21.213
  2 Gas         BILLION CUFT       1.000
  3 Hydro       TRILLN. BTUS       1.000
  4 Nuclear     TRILLN. BTUS       1.000
  5 Gas for Coal BILLION CUFT      1.000
  6 None        TRILLN. BTUS       1.000  <--TYPE 'NONE' MUST BE LAST
```

Plant Types and Utility Types

In this section, the numbers of plant types and utility types are identified first. Then for each type of plant, there is utility type it belongs to and its plant number. The utility type names are listed also.

```
 11 -- NUMBER OF PLANT TYPES        #  TYPE
  5 -- NUMBER OF UTILITY TYPES
  1 Coal                     1    1  FOSSIL - U
  2 Nuclear                  2    2  NUCLEAR- U
  1 Oil/Gas                  3    3  OTHER  - U
  1 Combustion Turbines      4    4  NONUTILITY
  1 Combined Cycle           5    5  PUMP STORA
  3 Hydro                    6
  4 Cogen                    7
  3 Purchase                 8
  3 Potential                9
  3 Renewable               10
  5 Storage                 11
C****
```

3. unserv.dat

The cost of unserved energy is in this file.

```
unserved energy
mills/kwh    year-year
-------      ------
999.         1994-2043
```

4. CONFIG.LPS

This file controls how the IPM model should run: whether the problem is of minimizing or maxmizing type, how many iterations before it records the intermediate run results, and what the initial and final solution files are.

```
PROBLEM FILE: matrix.mps
SOLUTION FILE=sln$$$.###
MIN-MAX=min
IT WRITE=125
Scan keyboard for Alt-I=No
ADVANCED BASIS FILE: bss1.###
OPT BASIS SAVE=bss2.###
```

5. bincons.dat

This file indicates all the variables to be output to the binary-data file for each run, which will be used to generate reports.

```
3 Aggregate flag (1=Annual,2=Seasonal,3=Segment)

C*  **                                K  Y  r  Sea  Seg
Y   Class: System (only 1 instance)   -  -  -  -    -
Y   Unserved energy                   N  Y  Y  Y
Y   Capacity                          N  Y
Y   New Builds                        N  Y
Y   Generation                        N  Y  Y  Y
Y   Purchases (Gwh)                   N  Y  Y  Y
Y   Sales (Gwh)                       N  Y  Y  Y
Y   Purchases (mw)                    N  Y
...... ......
```

Section 5

Other Tables / Graphs

(Not appearing in Main Report)

Table 5-1.a

Summary of Low and Medium Low Load Growths and Medium Gas Percentage of Winter Capacity Additions (%)

Additions in 10 years (1994 - 2003)

Load	Low					Medium Low				
DSM	Uncons-trained	medium				Uncons-trained	medium			
Coal		any		no			any		no	
Renewable		any	strat	any	strat		any	strat	any	strat
Case #	1	2	3	4	5	6	7	8	9	10
MW Additions										
DSR	100.0	100.0	50.5	100.0	50.5	96.9	70.2	49.0	70.2	49.0
Renewable	0.0	0.0	49.5	0.0	49.5	0.0	0.0	45.4	0.0	45.4
Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peaking Resources	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	29.8	5.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions										
DSR	100.0	100.0	63.4	100.0	63.4	95.3	59.4	59.8	87.8	63.1
Renewable	0.0	0.0	36.6	0.0	36.6	0.0	0.0	32.7	0.0	34.5
Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	0.0	0.0	0.0	0.0	4.7	40.6	6.3	0.0	0.0
Peaking Resources	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	12.2	2.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Additions in 20 years (1994 - 2013)

Load	Low					Medium Low				
DSM	Uncons-trained	medium				Uncons-trained	medium			
Coal		any		no			any		no	
Renewable		any	strat	any	strat		any	strat	any	strat
Case #	1	2	3	4	5	6	7	8	9	10
MW Additions										
DSR	100.0	100.0	62.0	100.0	62.0	57.7	60.9	49.7	60.9	49.7
Renewable	0.0	0.0	38.0	0.0	38.0	0.0	0.0	27.5	0.0	27.5
Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	0.0	0.0	0.0	0.0	26.9	24.2	8.9	0.0	0.0
Peaking Resources	0.0	0.0	0.0	0.0	0.0	15.3	15.0	13.9	39.1	22.7
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions										
DSR	100.0	100.0	73.8	100.0	73.8	53.2	57.7	58.1	85.5	67.4
Renewable	0.0	0.0	26.2	0.0	26.2	0.0	0.0	18.9	0.0	22.1
Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	0.0	0.0	0.0	0.0	41.0	36.6	16.6	0.0	0.0
Peaking Resources	0.0	0.0	0.0	0.0	0.0	5.8	5.6	6.4	14.5	10.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

T5-01.percent.resource-l-ml

Table 5-1.b

Summary of Low and Medium Low Load Growths and Medium Gas Winter Capacity (MW) Produced in 2003 (10th year) by New Resources added between 1994 - 2003

Load	Low					Medium Low				
DSM		medium					medium			
Coal	Uncons-trained	any		no		Uncons-trained	any		no	
Renewable		any	strat	any	strat		any	strat	any	strat
Case #	1	2	3	4	5	6	7	8	9	10
DSR	7.2	318.9	318.9	318.9	318.9	372.6	336.7	336.7	336.7	336.7
OWC Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	0.0	110.0	0.0	110.0
OWC Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	0.0	58.0	0.0	58.0
O OWC Geothermal	0.0	0.0	13.0	0.0	13.0	0.0	0.0	13.0	0.0	13.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C OWC Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	7.2	318.9	499.9	318.9	499.9	372.6	336.7	517.7	336.7	517.7
DSR	4.5	179.2	179.2	179.2	179.2	302.2	189.3	189.3	189.3	189.3
Utah Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	0.0	110.0	0.0	110.0
Utah Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	0.0	58.0	0.0	58.0
Utah Geothermal	0.0	0.0	12.0	0.0	12.0	0.0	0.0	12.0	0.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	0.0	0.0	0.0	24.6	242.8	37.6	0.0	0.0
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.4	242.8	64.9
	4.5	179.2	359.2	179.2	359.2	326.8	432.1	434.3	432.1	434.2
DSR	1.3	42.5	42.5	42.5	42.5	82.4	44.9	44.9	44.9	44.9
W Wyo Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	0.0	110.0	0.0	110.0
Y Wyo Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	0.0	58.0	0.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	1.3	42.5	210.5	42.5	210.5	82.4	44.9	212.9	44.9	212.9
DSR	13.0	540.6	540.6	540.6	540.6	757.2	570.9	570.9	570.9	570.9
T Renewable	0.0	0.0	529.0	0.0	529.0	0.0	0.0	529.0	0.0	529.0
O Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	0.0	0.0	0.0	0.0	0.0	24.6	242.8	37.6	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.4	242.8	64.9
Total	13.0	540.6	1069.6	540.6	1069.6	781.8	813.7	1164.9	813.7	1164.8

Summary of Low and Medium Low Load Growths and Medium Gas
Annual Energy (MWa) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Load	Low					Medium Low				
DSM	Uncons-trained	medium				Uncons-trained	medium			
Coal		any		no			any		no	
Renewable		any	strat	any	strat		any	strat	any	strat
Case #	1	2	3	4	5	6	7	8	9	10
DSR	3.8	139.3	139.3	139.3	139.3	176.0	146.3	146.3	146.3	146.3
OWC Wind with Tax C	0.0	0.0	26.2	0.0	26.2	0.0	0.0	26.3	0.0	26.3
OWC Wind without Tax C	0.0	0.0	13.8	0.0	13.8	0.0	0.0	13.9	0.0	13.9
O OWC Geothermal	0.0	0.0	9.9	0.0	9.9	0.0	0.0	10.2	0.0	10.2
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C OWC Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	3.8	139.3	189.2	139.3	189.2	176.0	146.3	196.7	146.3	196.7
DSR	3.2	128.7	128.7	128.7	128.7	206.1	137.7	137.7	137.7	137.7
Utah Wind with Tax C	0.0	0.0	38.6	0.0	38.6	0.0	0.0	38.6	0.0	38.6
Utah Wind without Tax C	0.0	0.0	20.3	0.0	20.3	0.0	0.0	20.4	0.0	20.4
Utah Geothermal	0.0	0.0	9.1	0.0	9.1	0.0	0.0	9.4	0.0	9.4
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	0.0	0.0	0.0	22.6	222.5	34.4	0.0	0.0
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.2	45.1	12.4
	3.2	128.7	196.7	128.7	196.7	228.7	360.2	246.7	182.8	218.5
DSR	0.7	38.8	38.8	38.8	38.8	77.2	41.2	41.2	41.2	41.2
W Wyo Wind with Tax C	0.0	0.0	38.6	0.0	38.6	0.0	0.0	38.6	0.0	38.6
Y Wyo Wind without Tax C	0.0	0.0	20.3	0.0	20.3	0.0	0.0	20.4	0.0	20.4
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.7	38.8	97.7	38.8	97.7	77.2	41.2	100.2	41.2	100.2
DSR	7.7	306.8	306.8	306.8	306.8	459.3	325.2	325.2	325.2	325.2
T Renewable	0.0	0.0	176.8	0.0	176.8	0.0	0.0	177.8	0.0	177.8
O Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	0.0	0.0	0.0	0.0	0.0	22.6	222.5	34.4	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.2	45.1	12.4
Total	7.7	306.8	483.6	306.8	483.6	481.9	547.7	543.6	370.3	515.4

T5-01.aMW.10yr-l-ml

Table 5-1.d

Summary of Low and Medium Low Load Growths and Medium Gas Winter Capacity (MW) Produced in 2013 (20th year) by New Resources added between 1994 - 2013

Load	Low					Medium Low				
DSM		medium					medium			
Coal	Uncons-trained	any		no		Uncons-trained	any		no	
Renewable		any	strat	any	strat		any	strat	any	strat
Case #	1	2	3	4	5	6	7	8	9	10
DSR	9.0	449.7	449.7	449.7	449.7	513.2	509.0	509.0	509.0	509.0
OWC Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	0.0	110.0	0.0	110.0
OWC Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	0.0	58.0	0.0	58.0
O OWC Geothermal	0.0	0.0	13.0	0.0	13.0	0.0	0.0	13.0	0.0	13.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C OWC Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	114.7	0.0
	9.0	449.7	630.7	449.7	630.7	513.2	509.0	690.0	623.7	690.0
DSR	6.1	331.2	331.2	331.2	331.2	304.0	356.9	356.9	356.9	356.9
Utah Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	0.0	110.0	0.0	110.0
Utah Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	0.0	58.0	0.0	58.0
Utah Geothermal	0.0	0.0	12.0	0.0	12.0	0.0	0.0	12.0	0.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	0.0	0.0	0.0	423.7	379.3	170.3	0.0	0.0
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Pumped Storage	0.0	0.0	0.0	0.0	0.0	241.5	235.4	266.5	500.0	436.8
	6.1	331.2	511.2	331.2	511.2	969.2	971.6	973.7	856.9	973.7
DSR	1.8	83.1	83.1	83.1	83.1	91.0	89.8	89.8	89.8	89.8
W Wyo Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	0.0	110.0	0.0	110.0
Y Wyo Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	0.0	58.0	0.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	1.8	83.1	251.1	83.1	251.1	91.0	89.8	257.8	89.8	257.8
DSR	16.9	864.0	864.0	864.0	864.0	908.2	955.7	955.7	955.7	955.7
T Renewable	0.0	0.0	529.0	0.0	529.0	0.0	0.0	529.0	0.0	529.0
O Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	0.0	0.0	0.0	0.0	0.0	423.7	379.3	170.3	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	241.5	235.4	266.5	614.7	436.8
Total	16.9	864.0	1393.0	864.0	1393.0	1573.4	1570.4	1921.5	1570.4	1921.5

Table 5-1.e

Summary of Low and Medium Low Load Growths and Medium Gas
Annual Energy (MWa) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load	Low					Medium Low				
DSM	Uncons-trained	medium				Uncons-trained	medium			
Coal		any		no			any		no	
Renewable		any	strat	any	strat		any	strat	any	strat
Case #	1	2	3	4	5	6	7	8	9	10
DSR	4.7	198.5	198.5	198.5	198.5	213.3	219.1	219.1	219.1	219.1
OWC Wind with Tax C	0.0	0.0	26.2	0.0	26.2	0.0	0.0	26.3	0.0	26.3
OWC Wind without Tax C	0.0	0.0	13.8	0.0	13.8	0.0	0.0	13.9	0.0	13.9
O OWC Geothermal	0.0	0.0	9.9	0.0	9.9	0.0	0.0	10.7	0.0	11.2
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C OWC Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	4.7	198.5	248.4	198.5	248.4	213.3	219.1	270.0	219.1	270.5
DSR	4.3	225.0	225.0	225.0	225.0	207.8	247.6	247.6	247.6	247.6
Utah Wind with Tax C	0.0	0.0	38.6	0.0	38.6	0.0	0.0	38.6	0.0	38.6
Utah Wind without Tax C	0.0	0.0	20.3	0.0	20.3	0.0	0.0	20.4	0.0	20.4
Utah Geothermal	0.0	0.0	9.1	0.0	9.1	0.0	0.0	9.7	0.0	9.9
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	0.0	0.0	0.0	388.3	347.6	156.1	0.0	0.0
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Pumped Storage	0.0	0.0	0.0	0.0	0.0	54.7	53.3	60.4	93.0	85.0
	4.3	225.0	293.0	225.0	293.0	650.8	648.5	532.8	340.6	401.5
DSR	0.9	74.4	74.4	74.4	74.4	82.1	80.9	80.9	80.9	80.9
W Wyo Wind with Tax C	0.0	0.0	38.6	0.0	38.6	0.0	0.0	38.6	0.0	38.6
Y Wyo Wind without Tax C	0.0	0.0	20.3	0.0	20.3	0.0	0.0	20.4	0.0	20.4
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.9	74.4	133.3	74.4	133.3	82.1	80.9	139.9	80.9	139.9
DSR	9.9	497.9	497.9	497.9	497.9	503.2	547.6	547.6	547.6	547.6
T Renewable	0.0	0.0	176.8	0.0	176.8	0.0	0.0	178.6	0.0	179.3
O Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	0.0	0.0	0.0	0.0	0.0	388.3	347.6	156.1	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	54.7	53.3	60.4	93.0	85.0
Total	9.9	497.9	674.7	497.9	674.7	946.2	948.5	942.7	640.6	811.9

T5-01.aMW.20yr-l-ml

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Table 5-2.a

Summary of Medium Load Growth and Low Gas
Percentage of Winter Capacity Additions (%)

Additions in 10 years (1994 - 2003)

DSM		low				medium				accelerated				high			
Coal	Uncons-	any		no		any		no		any		no		any		no	
Renewable	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
MW Additions																	
DSR	43.3	13.5	11.6	13.5	11.6	29.7	25.3	29.7	25.3	32.9	28.0	32.9	28.0	38.9	33.1	38.9	33.1
Renewable	0.0	0.0	21.6	0.0	21.6	0.0	22.0	0.0	22.0	0.0	22.1	0.0	22.1	0.0	22.3	0.0	22.3
Cogeneration	22.6	30.3	23.7	69.5	50.5	23.3	17.7	59.8	43.2	22.5	16.6	56.9	40.6	19.3	13.7	54.2	38.2
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	18.1	28.5	19.1	0.0	0.0	27.5	17.8	0.0	0.0	25.5	16.5	0.0	0.0	24.9	16.8	0.0	0.0
Peaking Resources	16.0	27.6	23.9	17.0	16.3	19.5	17.1	10.5	9.4	19.1	16.7	10.3	9.2	16.9	14.1	6.9	6.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																	
DSR	40.5	13.0	12.8	12.2	12.1	26.1	25.8	25.0	24.5	30.3	30.0	29.0	28.5	34.5	33.8	32.6	32.1
Renewable	0.0	0.0	13.1	0.0	12.3	0.0	13.2	0.0	12.6	0.0	13.2	0.0	12.5	0.0	13.5	0.0	12.7
Cogeneration	29.1	39.3	35.4	83.2	70.4	29.6	26.1	72.2	59.9	28.5	24.3	68.3	56.0	25.0	20.4	65.5	53.1
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	25.8	40.8	31.5	0.0	0.0	38.7	29.1	0.0	0.0	35.7	26.9	0.0	0.0	35.6	27.6	0.0	0.0
Peaking Resources	4.6	6.9	7.2	4.6	5.1	5.5	5.7	2.9	3.0	5.4	5.5	2.8	3.0	4.9	4.7	1.9	2.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Additions in 20 years (1994 - 2013)

DSM		low				medium				accelerated				high			
Coal	Uncons-	any		no		any		no		any		no		any		no	
Renewable	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
MW Additions																	
DSR	29.6	13.7	12.5	13.7	12.5	28.4	26.0	28.4	26.0	29.4	26.9	29.4	26.9	34.9	31.9	34.9	31.9
Renewable	0.0	0.0	12.6	0.0	12.6	0.0	12.8	0.0	12.8	0.0	12.8	0.0	12.8	0.0	12.9	0.0	12.9
Cogeneration	12.0	16.5	13.8	50.2	39.9	12.7	10.3	40.9	32.5	12.2	9.6	40.2	31.7	10.4	7.9	37.6	29.2
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	31.9	38.3	31.3	0.0	0.0	32.4	26.6	0.0	0.0	31.9	26.4	0.0	0.0	30.1	24.6	0.0	0.0
Peaking Resources	26.5	31.6	29.8	36.1	35.0	26.5	24.3	30.7	28.7	26.6	24.3	30.5	28.6	24.6	22.7	27.6	26.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																	
DSR	27.5	13.5	13.6	14.4	14.7	27.2	27.0	28.5	28.7	28.4	28.2	29.8	30.0	32.8	32.6	33.9	34.1
Renewable	0.0	0.0	7.7	0.0	8.3	0.0	7.9	0.0	8.4	0.0	7.9	0.0	8.4	0.0	8.1	0.0	8.5
Cogeneration	18.3	24.0	22.1	78.0	69.4	18.8	16.6	64.6	56.2	18.2	15.6	63.5	54.9	15.8	13.1	59.7	50.9
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	49.9	57.4	51.5	0.0	0.0	49.7	44.3	0.0	0.0	49.1	44.0	0.0	0.0	47.1	41.9	0.0	0.0
Peaking Resources	4.3	5.1	5.2	7.6	7.6	4.3	4.2	6.9	6.8	4.3	4.2	6.7	6.7	4.3	4.3	6.4	6.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

T5-02.percent.resource-m.lg

Table 5-2.b

Summary of Medium Load Growth and Low Gas
Winter Capacity (MW) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

DSM		low				medium				accelerated				high			
Coal	Uncons-	any		no		any		no		any		no		any		no	
Renewable	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
DSR	432.6	149.3	149.3	149.3	149.3	359.2	359.2	359.2	359.2	381.8	381.8	381.8	381.8	468.6	468.6	468.6	468.6
OWC Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
OWC Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O OWC Geothermal	0.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C OWC Cogeneration 2	453.2	636.4	581.5	1037.0	960.5	477.9	425.1	986.0	924.5	459.7	396.1	946.8	880.1	390.2	324.3	917.3	856.4
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	885.8	785.7	911.8	1186.3	1290.8	837.1	965.3	1345.2	1464.7	841.5	958.9	1328.6	1442.9	858.8	973.9	1385.9	1506.0
DSR	346.8	118.5	118.5	118.5	118.5	200.8	200.8	200.8	200.8	238.9	238.9	238.9	238.9	261.4	261.4	261.4	261.4
Utah Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
Utah Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
Utah Geothermal	0.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	420.0	277.1	0.0	0.0	238.8	113.4	0.0	0.0	213.1	90.6	0.0	0.0	178.1	49.2
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	363.1	597.7	468.3	0.0	0.0	563.9	427.9	0.0	0.0	519.6	395.4	0.0	0.0	504.4	399.4	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	118.8	86.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Pumped Storage	320.4	461.1	500.0	357.1	398.7	398.8	409.6	215.7	224.8	390.2	400.0	209.8	220.9	341.3	334.3	140.5	152.3
	1030.3	1296.1	1353.3	895.6	974.3	1163.5	1218.3	655.3	719.0	1148.7	1214.3	661.8	730.4	1107.1	1175.1	580.0	642.9
DSR	89.9	15.8	15.8	15.8	15.8	48.2	48.2	48.2	48.2	49.6	49.6	49.6	49.6	56.4	56.4	56.4	56.4
W Wyo Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
Y Wyo Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	89.9	15.8	183.8	15.8	183.8	48.2	216.2	48.2	216.2	49.6	217.6	49.6	217.6	56.4	224.4	56.4	224.4
DSR	869.3	283.6	283.6	283.6	283.6	608.2	608.2	608.2	608.2	670.3	670.3	670.3	670.3	786.4	786.4	786.4	786.4
T Renewable	0.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0
O Cogeneration	453.2	636.4	581.5	1457.0	1237.6	477.9	425.1	1224.8	1037.9	459.7	396.1	1159.9	970.7	390.2	324.3	1095.4	905.6
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	363.1	597.7	468.3	0.0	0.0	563.9	427.9	0.0	0.0	519.6	395.4	0.0	0.0	504.4	399.4	0.0	0.0
L Simple Cycle CT	0.0	118.8	86.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	320.4	461.1	500.0	357.1	398.7	398.8	409.6	215.7	224.8	390.2	400.0	209.8	220.9	341.3	334.3	140.5	152.3
Total	2006.0	2097.6	2448.9	2097.7	2448.9	2048.8	2399.8	2048.7	2399.9	2039.8	2390.8	2040.0	2390.9	2022.3	2373.4	2022.3	2373.3

Summary of Medium Load Growth and Low Gas
Annual Energy (MWa) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

DSM	Uncons-	low				medium				accelerated				high			
Coal	trained	any		no		any		no		any		no		any		no	
Renewable		any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
DSR	195.5	79.1	79.1	79.1	79.1	155.4	155.4	155.4	155.4	176.0	176.0	176.0	176.0	200.9	200.9	200.9	200.9
OWC Wind with Tax C	0.0	0.0	26.3	0.0	26.2	0.0	26.2	0.0	26.2	0.0	26.2	0.0	26.2	0.0	26.2	0.0	26.2
OWC Wind without Tax C	0.0	0.0	13.9	0.0	13.8	0.0	13.8	0.0	13.8	0.0	13.8	0.0	13.8	0.0	13.8	0.0	13.8
O OWC Geothermal	0.0	0.0	10.2	0.0	10.1	0.0	10.4	0.0	10.2	0.0	10.4	0.0	10.2	0.0	10.9	0.0	10.2
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C OWC Cogeneration 2	375.0	526.5	481.0	842.9	787.0	395.3	351.7	808.0	757.5	380.3	327.8	775.7	721.1	324.5	270.2	751.6	701.7
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	570.5	605.6	610.5	922.0	916.2	550.7	557.5	963.4	963.1	556.3	554.2	951.7	947.3	525.4	522.0	952.5	952.8
DSR	243.5	81.3	81.3	81.3	81.3	148.9	148.9	148.9	148.9	183.2	183.2	183.2	183.2	197.7	197.7	197.7	197.7
Utah Wind with Tax C	0.0	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6
Utah Wind without Tax C	0.0	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4
Utah Geothermal	0.0	0.0	9.5	0.0	9.5	0.0	9.5	0.0	9.9	0.0	9.5	0.0	9.9	0.0	9.8	0.0	9.9
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	347.6	227.9	0.0	0.0	197.8	93.2	0.0	0.0	176.4	74.5	0.0	0.0	147.5	40.5
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	332.8	547.8	429.1	0.0	0.0	516.8	392.2	0.0	0.0	476.1	362.4	0.0	0.0	462.2	366.0	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	6.6	4.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Pumped Storage	59.5	85.6	92.8	66.3	74.0	74.0	76.1	40.0	42.5	72.4	74.3	38.9	42.0	63.4	62.1	26.1	28.3
	635.8	721.3	676.5	495.2	451.7	739.7	685.7	386.7	353.5	731.7	688.4	398.5	368.6	723.3	694.6	371.3	335.4
DSR	83.5	14.2	14.2	14.2	14.2	43.5	43.5	43.5	43.5	44.8	44.8	44.8	44.8	49.7	49.7	49.7	49.7
W Wyo Wind with Tax C	0.0	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6
Y Wyo Wind without Tax C	0.0	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	83.5	14.2	73.2	14.2	73.2	43.5	102.5	43.5	102.5	44.8	103.8	44.8	103.8	49.7	108.7	49.7	108.7
DSR	522.5	174.6	174.6	174.6	174.6	347.8	347.8	347.8	347.8	404.0	404.0	404.0	404.0	448.3	448.3	448.3	448.3
T Renewable	0.0	0.0	177.9	0.0	177.6	0.0	177.9	0.0	178.1	0.0	177.9	0.0	178.1	0.0	178.7	0.0	178.1
O Cogeneration	375.0	526.5	481.0	1190.5	1014.9	395.3	351.7	1005.8	850.7	380.3	327.8	952.1	795.6	324.5	270.2	899.1	742.2
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	332.8	547.8	429.1	0.0	0.0	516.8	392.2	0.0	0.0	476.1	362.4	0.0	0.0	462.2	366.0	0.0	0.0
L Simple Cycle CT	0.0	6.6	4.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	59.5	85.6	92.8	66.3	74.0	74.0	76.1	40.0	42.5	72.4	74.3	38.9	42.0	63.4	62.1	26.1	28.3
Total	1289.8	1341.1	1360.2	1431.4	1441.1	1333.9	1345.7	1393.6	1419.1	1332.8	1346.4	1395.0	1419.7	1298.4	1325.3	1373.5	1396.9

Table 5-2.d

Summary of Medium Load Growth and Low Gas
Winter Capacity (MW) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

DSM	Uncons-	low				medium			
Coal		any		no		any		no	
Renewable	trained	any	strat	any	strat	any	strat	any	strat
Case #	11	12	13	14	15	16	17	18	19
DSR	629.9	254.7	254.7	254.7	254.7	577.1	577.1	577.1	577.1
OWC Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
OWC Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O OWC Geothermal	0.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0
W OWC Cogeneration 1	0.0	0.0	0.0	195.7	82.0	0.0	0.0	0.0	0.0
C OWC Cogeneration 2	453.2	636.4	581.5	1320.0	1320.0	477.9	425.1	1305.5	1227.1
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	495.9	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
	1579.0	1391.1	1517.2	2270.4	2337.7	1555.0	1683.2	2382.6	2485.2
DSR	379.4	230.7	230.7	230.7	230.7	390.0	390.0	390.0	390.0
Utah Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
Utah Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
Utah Geothermal	0.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	420.0	277.1	0.0	0.0	238.8	113.4
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	1200.7	1474.0	1314.7	0.0	0.0	1222.4	1097.3	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	216.3	252.8	391.0	469.8	0.0	0.0	156.0	182.0
Utah Pumped Storage	500.0	499.9	500.0	500.1	500.1	500.0	499.9	500.0	500.0
	2080.1	2420.9	2478.2	1541.8	1657.7	2112.4	2167.2	1284.8	1365.4
DSR	102.7	41.0	41.0	41.0	41.0	104.1	104.1	104.1	104.1
W Wyo Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
Y Wyo Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	102.7	41.0	209.0	41.0	209.0	104.1	272.1	104.1	272.1
DSR	1112.0	526.4	526.4	526.4	526.4	1071.2	1071.2	1071.2	1071.2
T Renewable	0.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0
O Cogeneration	453.2	636.4	581.5	1935.7	1679.1	477.9	425.1	1544.3	1340.5
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	1200.7	1474.0	1314.7	0.0	0.0	1222.4	1097.3	0.0	0.0
L Simple Cycle CT	0.0	216.3	252.8	391.0	469.8	0.0	0.0	156.0	182.0
Pumped Storage	995.9	999.9	1000.0	1000.1	1000.1	1000.0	999.9	1000.0	1000.0
Total	3761.8	3853.0	4204.4	3853.2	4204.4	3771.5	4122.5	3771.5	4122.7

DSM	accelerated				high			
Coal	any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat
Case #	20	21	22	23	24	25	26	27
DSR	587.2	587.2	587.2	587.2	724.2	724.2	724.2	724.2
OWC Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
OWC Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O OWC Geothermal	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C OWC Cogeneration 2	459.7	396.1	1300.3	1215.8	390.2	324.3	1225.6	1145.5
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	500.0	500.0	500.0	500.0	419.4	425.9	500.0	500.0
	1546.9	1664.3	2387.5	2484.0	1533.8	1655.4	2449.8	2550.7
DSR	414.2	414.2	414.2	414.2	463.5	463.5	463.5	463.5
Utah Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
Utah Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
Utah Geothermal	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	213.1	90.6	0.0	0.0	178.1	49.2
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	1201.0	1086.6	0.0	0.0	1124.2	1005.7	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	147.4	176.4	0.0	0.0	30.2	61.2
Utah Pumped Storage	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
	2115.2	2180.8	1274.7	1361.2	2087.7	2149.2	1171.8	1253.9
DSR	104.2	104.2	104.2	104.2	115.2	115.2	115.2	115.2
W Wyo Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
Y Wyo Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	104.2	272.2	104.2	272.2	115.2	283.2	115.2	283.2
DSR	1105.6	1105.6	1105.6	1105.6	1302.9	1302.9	1302.9	1302.9
T Renewable	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0
O Cogeneration	459.7	396.1	1513.4	1306.4	390.2	324.3	1403.7	1194.7
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	1201.0	1086.6	0.0	0.0	1124.2	1005.7	0.0	0.0
L Simple Cycle CT	0.0	0.0	147.4	176.4	0.0	0.0	30.2	61.2
Pumped Storage	1000.0	1000.0	1000.0	1000.0	919.4	925.9	1000.0	1000.0
Total	3766.3	4117.3	3766.4	4117.4	3736.7	4087.8	3736.8	4087.8

Summary of Medium Load Growth and Low Gas
Annual Energy (MWa) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

DSM	Uncons-	low				medium				accelerated				high			
Coal		any		no		any		no		any		no		any		no	
Renewable	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
DSR	248.5	124.3	124.3	124.3	124.3	244.4	244.4	244.4	244.4	252.9	252.9	252.9	252.9	294.3	294.3	294.3	294.3
OWC Wind with Tax C	0.0	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3
OWC Wind without Tax C	0.0	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9
O OWC Geothermal	0.0	0.0	11.4	0.0	10.9	0.0	11.4	0.0	10.9	0.0	11.4	0.0	10.9	0.0	11.4	0.0	10.9
W OWC Cogeneration 1	0.0	0.0	0.0	182.2	76.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C OWC Cogeneration 2	403.0	565.8	517.0	1155.6	1173.9	424.9	378.0	1169.0	1095.2	408.7	352.3	1165.4	1086.0	346.9	288.3	1103.0	1027.7
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	1.3	9.3	9.6	55.8	54.8	1.4	1.5	54.1	50.8	1.4	1.4	52.3	50.5	0.7	0.7	50.2	50.5
	652.8	699.4	702.5	1517.9	1480.5	670.7	675.5	1467.5	1441.5	663.0	658.2	1470.6	1440.5	641.9	634.9	1447.5	1423.6
DSR	268.8	156.2	156.2	156.2	156.2	277.2	277.2	277.2	277.2	293.7	293.7	293.7	293.7	324.5	324.5	324.5	324.5
Utah Wind with Tax C	0.0	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6
Utah Wind without Tax C	0.0	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4
Utah Geothermal	0.0	0.0	9.6	0.0	10.2	0.0	9.6	0.0	10.2	0.0	9.6	0.0	10.2	0.0	9.6	0.0	10.1
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	387.0	254.8	0.0	0.0	219.6	104.3	0.0	0.0	196.3	83.3	0.0	0.0	163.8	45.2
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	1100.3	1350.8	1204.7	0.0	0.0	1120.3	1005.6	0.0	0.0	1100.6	995.8	0.0	0.0	1030.2	921.6	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	12.0	14.1	21.7	26.1	0.0	0.0	8.7	10.1	0.0	0.0	8.2	9.8	0.0	0.0	1.7	3.4
Utah Pumped Storage	93.7	99.2	97.3	91.4	84.6	94.8	94.3	84.7	83.5	94.3	94.2	84.1	83.4	93.2	93.0	84.0	83.6
	1462.8	1618.2	1540.9	656.3	590.9	1492.3	1445.7	590.2	544.3	1488.6	1452.3	582.3	539.4	1447.9	1407.7	574.0	525.8
DSR	90.1	37.6	37.6	37.6	37.6	91.2	91.2	91.2	91.2	91.5	91.5	91.5	91.5	99.5	99.5	99.5	99.5
W Wyo Wind with Tax C	0.0	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6
Y Wyo Wind without Tax C	0.0	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	90.1	37.6	96.6	37.6	96.6	91.2	150.2	91.2	150.2	91.5	150.5	91.5	150.5	99.5	158.5	99.5	158.5
DSR	607.4	318.1	318.1	318.1	318.1	612.8	612.8	612.8	612.8	638.1	638.1	638.1	638.1	718.3	718.3	718.3	718.3
T Renewable	0.0	0.0	179.2	0.0	179.3	0.0	179.2	0.0	179.3	0.0	179.2	0.0	179.3	0.0	179.2	0.0	179.2
O Cogeneration	403.0	565.8	517.0	1724.8	1505.1	424.9	378.0	1388.6	1199.5	408.7	352.3	1361.7	1169.3	346.9	288.3	1266.8	1072.9
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	1100.3	1350.8	1204.7	0.0	0.0	1120.3	1005.6	0.0	0.0	1100.6	995.8	0.0	0.0	1030.2	921.6	0.0	0.0
L Simple Cycle CT	0.0	12.0	14.1	21.7	26.1	0.0	0.0	8.7	10.1	0.0	0.0	8.2	9.8	0.0	0.0	1.7	3.4
Pumped Storage	95.0	108.5	106.9	147.2	139.4	96.2	95.8	138.8	134.3	95.7	95.6	136.4	133.9	93.9	93.7	134.2	134.1
Total	2205.7	2355.2	2340.0	2211.8	2168.0	2254.2	2271.4	2148.9	2136.0	2243.1	2261.0	2144.4	2130.4	2189.3	2201.1	2121.0	2107.9

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Summary of Medium Load Growth and Medium Gas
Percentage of Winter Capacity Additions (%)

Additions in 10 years (1994 - 2003)

DSM		low				medium				accelerated				high			
Coal	Uncons-	any		no		any		no		any		no		any		no	
Renewable	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44
MW Additions																	
DSR	41.8	13.5	11.6	13.5	11.6	29.7	25.3	29.7	25.3	32.9	28.0	32.9	28.0	38.9	33.1	38.9	33.1
Renewable	0.0	0.0	21.6	0.0	21.6	0.0	22.0	0.0	22.0	0.0	22.1	0.0	22.1	0.0	22.3	0.0	22.3
Cogeneration	9.6	19.2	14.2	63.1	45.5	14.7	11.5	51.6	36.0	11.1	7.5	48.7	33.7	8.9	5.6	45.9	31.0
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	38.2	43.5	33.4	0.0	0.0	39.2	29.2	0.0	0.0	39.7	30.1	0.0	0.0	39.2	29.4	0.0	0.0
Peaking Resources	10.5	23.8	19.2	23.3	21.3	16.4	12.0	18.7	16.6	16.3	12.2	18.4	16.2	13.1	9.5	15.2	13.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																	
DSR	35.1	12.0	11.7	12.9	12.7	24.6	23.7	26.5	26.1	28.6	27.6	30.7	30.2	32.2	31.2	34.7	34.2
Renewable	0.0	0.0	11.8	0.0	12.9	0.0	12.1	0.0	13.3	0.0	12.2	0.0	13.3	0.0	12.4	0.0	13.6
Cogeneration	12.2	23.7	19.9	79.9	66.8	18.4	16.1	67.6	54.3	14.2	10.6	63.5	50.4	11.7	8.5	60.4	47.1
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	49.3	57.5	50.1	0.0	0.0	52.1	43.7	0.0	0.0	52.4	45.0	0.0	0.0	52.2	44.5	0.0	0.0
Peaking Resources	3.3	6.9	6.5	7.3	7.7	4.8	4.4	5.9	6.2	4.9	4.5	5.8	6.1	3.8	3.6	4.8	5.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Additions in 20 years (1994 - 2013)

DSM		low				medium				accelerated				high			
Coal	Uncons-	any		no		any		no		any		no		any		no	
Renewable	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44
MW Additions																	
DSR	30.0	13.7	12.5	13.7	12.5	28.4	26.0	28.4	26.0	29.4	26.9	29.4	26.9	34.9	31.9	34.9	31.9
Renewable	0.0	0.0	12.6	0.0	12.6	0.0	12.8	0.0	12.8	0.0	12.8	0.0	12.8	0.0	12.9	0.0	12.9
Cogeneration	5.1	10.4	8.2	41.8	31.3	8.0	6.7	31.3	23.0	6.0	4.4	30.5	22.4	4.8	3.3	27.6	20.9
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	41.2	50.0	42.8	0.0	0.0	38.1	30.9	0.0	0.0	38.8	32.0	0.0	0.0	37.6	30.9	0.0	0.0
Peaking Resources	23.7	26.0	23.9	44.6	43.6	25.5	23.6	40.3	38.2	25.8	23.9	40.2	37.9	22.7	21.0	37.5	34.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																	
DSR	25.6	12.4	12.3	16.3	17.0	26.4	26.4	33.5	34.1	27.7	27.7	35.0	35.5	31.5	31.5	40.2	39.8
Renewable	0.0	0.0	6.9	0.0	9.6	0.0	7.7	0.0	10.0	0.0	7.8	0.0	10.0	0.0	7.9	0.0	9.9
Cogeneration	7.7	14.2	12.2	74.2	63.6	11.8	10.8	58.3	47.8	9.1	7.3	57.0	46.6	7.3	5.5	52.5	42.9
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	61.3	68.6	63.8	0.0	0.0	56.7	50.3	0.0	0.0	58.2	52.5	0.0	0.0	56.4	50.7	0.0	0.0
Peaking Resources	5.4	4.8	4.7	9.5	9.8	5.1	4.8	8.2	8.1	5.0	4.7	8.1	7.9	4.8	4.6	7.4	7.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 5-3.b

Summary of Medium Load Growth and Medium Gas Winter Capacity (MW) Produced in 2003 (10th year) by New Resources added between 1994 - 2003

DSM	Uncons-trained	low				medium				accelerated				high			
Coal		any		no		any		no		any		no		any		no	
Renewable		any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44
DSR	432.6	149.3	149.3	149.3	149.3	359.2	359.2	359.2	359.2	381.8	381.8	381.8	381.8	468.6	468.6	468.6	468.6
OWC Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
OWC Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O OWC Geothermal	0.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0
W OWC Cogeneration 1	192.1	197.3	168.5	320.0	320.0	160.0	160.0	320.1	319.9	183.4	162.9	319.9	319.9	179.2	133.9	320.0	320.0
C OWC Cogeneration 2	0.0	204.7	178.3	752.4	680.3	142.0	115.6	624.8	523.3	43.7	17.3	591.0	485.3	0.3	0.0	569.5	390.6
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	11.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	624.7	551.3	677.1	1221.7	1342.0	661.2	815.8	1304.1	1383.4	608.9	743.0	1292.7	1368.0	648.1	783.5	1358.1	1360.2
DSR	318.1	118.5	118.5	118.5	118.5	200.8	200.8	200.8	200.8	238.9	238.9	238.9	238.9	261.4	261.4	261.4	261.4
Utah Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
Utah Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
Utah Geothermal	0.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	1.1	0.0	0.0	0.0	39.0	21.0	0.0	0.0	39.0	0.0	0.0	0.0	39.0	24.1
T Utah Cogeneration 2	0.0	0.0	0.0	250.8	114.0	0.0	0.0	73.8	0.0	0.0	0.0	44.4	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	767.3	912.1	818.7	0.0	0.0	802.5	699.7	0.0	0.0	809.1	718.8	0.0	0.0	792.4	698.4	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	10.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Pumped Storage	210.4	500.0	470.8	489.8	500.0	336.2	287.4	383.0	398.5	333.3	292.5	375.2	386.2	264.0	225.6	307.4	323.3
	1295.8	1530.6	1588.0	860.2	923.0	1339.5	1367.9	696.6	800.3	1381.3	1430.2	697.5	805.1	1317.8	1365.4	607.8	788.8
DSR	89.9	15.8	15.8	15.8	15.8	48.2	48.2	48.2	48.2	49.6	49.6	49.6	49.6	56.4	56.4	56.4	56.4
W Wyo Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
Y Wyo Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	89.9	15.8	183.8	15.8	183.8	48.2	216.2	48.2	216.2	49.6	217.6	49.6	217.6	56.4	224.4	56.4	224.4
DSR	840.6	283.6	283.6	283.6	283.6	608.2	608.2	608.2	608.2	670.3	670.3	670.3	670.3	786.4	786.4	786.4	786.4
T Renewable	0.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0
O Cogeneration	192.1	402.0	346.8	1324.3	1114.3	302.0	275.6	1057.7	864.2	227.1	180.2	994.3	805.2	179.5	133.9	928.5	734.7
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	767.3	912.1	818.7	0.0	0.0	802.5	699.7	0.0	0.0	809.1	718.8	0.0	0.0	792.4	698.4	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	10.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	210.4	500.0	470.8	489.8	511.4	336.2	287.4	383.0	398.5	333.3	292.5	375.2	386.2	264.0	225.6	307.4	323.3
Total	2010.4	2097.7	2448.9	2097.7	2448.8	2048.9	2399.9	2048.9	2399.9	2039.8	2390.8	2039.8	2390.7	2022.3	2373.3	2022.3	2373.4

Table 5-3.c

Summary of Medium Load Growth and Medium Gas
Annual Energy (MWa) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

DSM	Uncons-	low				medium				accelerated				high			
Coal	trained	any		no		any		no		any		no		any		no	
Renewable		any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44
DSR	195.5	79.1	79.1	79.1	79.1	| 155.4	155.4	155.4	155.4	176.0	176.0	176.0	176.0	200.9	200.9	200.9	200.9
OWC Wind with Tax C	0.0	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3
OWC Wind without Tax C	0.0	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9
O OWC Geothermal	0.0	0.0	9.9	0.0	10.1	0.0	10.2	0.0	10.1	0.0	10.2	0.0	10.1	0.0	10.2	0.0	10.1
W OWC Cogeneration 1	173.5	175.4	149.7	277.5	277.5	142.2	140.1	279.7	277.5	163.1	141.0	279.7	277.5	162.7	121.6	279.7	277.5
C OWC Cogeneration 2	0.0	169.3	147.5	598.7	550.1	117.5	95.6	512.0	428.8	37.1	14.7	484.2	397.7	0.3	0.0	466.6	320.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	369.0	423.8	426.4	955.3	958.7	415.1	441.5	947.1	912.0	376.2	382.1	939.9	901.5	363.9	372.9	947.2	848.7
DSR	221.7	81.3	81.3	81.3	81.3	148.9	148.9	148.9	148.9	183.2	183.2	183.2	183.2	197.7	197.7	197.7	197.7
Utah Wind with Tax C	0.0	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6
Utah Wind without Tax C	0.0	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4
Utah Geothermal	0.0	0.0	9.1	0.0	9.4	0.0	9.3	0.0	9.7	0.0	9.3	0.0	9.7	0.0	9.3	0.0	9.7
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	1.0	0.0	0.0	0.0	34.2	18.4	0.0	0.0	34.2	0.0	0.0	0.0	33.9	21.0
T Utah Cogeneration 2	0.0	0.0	0.0	207.5	93.8	0.0	0.0	61.0	0.0	0.0	0.0	36.7	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	703.2	835.9	750.2	0.0	0.0	735.4	641.2	0.0	0.0	741.4	658.7	0.0	0.0	726.1	640.0	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Pumped Storage	47.7	99.8	98.0	99.0	104.0	68.3	64.0	77.1	83.3	69.1	66.2	76.3	81.7	53.2	51.1	62.6	67.7
	972.6	1017.0	997.6	388.8	348.1	952.6	922.4	321.2	319.3	993.7	976.4	330.4	333.6	977.0	957.1	294.2	355.1
DSR	83.5	14.2	14.2	14.2	14.2	43.5	43.5	43.5	43.5	44.8	44.8	44.8	44.8	49.7	49.7	49.7	49.7
W Wyo Wind with Tax C	0.0	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6
Y Wyo Wind without Tax C	0.0	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	83.5	14.2	73.2	14.2	73.2	43.5	102.5	43.5	102.5	44.8	103.8	44.8	103.8	49.7	108.7	49.7	108.7
DSR	500.7	174.6	174.6	174.6	174.6	347.8	347.8	347.8	347.8	404.0	404.0	404.0	404.0	448.3	448.3	448.3	448.3
T Renewable	0.0	0.0	177.2	0.0	177.7	0.0	177.7	0.0	178.0	0.0	177.7	0.0	178.0	0.0	177.7	0.0	178.0
O Cogeneration	173.5	344.7	297.2	1084.7	921.4	259.7	235.7	886.9	724.7	200.2	155.7	834.8	675.2	163.0	121.6	780.2	618.5
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	703.2	835.9	750.2	0.0	0.0	735.4	641.2	0.0	0.0	741.4	658.7	0.0	0.0	726.1	640.0	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	47.7	99.8	98.0	99.0	105.7	68.3	64.0	77.1	83.3	69.1	66.2	76.3	81.7	53.2	51.1	62.6	67.7
Total	1425.1	1455.0	1497.2	1358.3	1380.0	1411.2	1466.4	1311.8	1333.8	1414.7	1462.3	1315.1	1338.9	1390.6	1438.7	1291.1	1312.5

Table 5-3.d

Summary of Medium Load Growth and Medium Gas
Winter Capacity (MW) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

DSM	Uncons-	low				medium				accelerated				high			
Coal	trained	any		no		any		no		any		no		any		no	
Renewable		any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44
DSR	705.1	254.7	254.7	254.7	254.7	577.1	577.1	577.1	577.1	587.2	587.2	587.2	587.2	724.2	724.2	724.2	724.2
OWC Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
OWC Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O OWC Geothermal	0.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0
W OWC Cogeneration 1	192.1	197.3	168.5	320.0	320.0	160.0	160.0	320.1	319.9	183.4	162.9	319.9	319.9	179.2	133.9	320.0	320.0
C OWC Cogeneration 2	0.0	204.7	178.3	1000.1	844.5	142.0	115.6	747.3	589.5	43.7	17.3	744.7	565.1	0.3	0.0	672.6	494.8
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	391.6	500.0	500.0	500.0	500.0	461.4	472.5	500.0	500.0	470.4	483.7	500.0	500.0	348.2	359.7	500.0	500.0
	1288.8	1156.7	1282.8	2074.8	2100.2	1340.5	1506.2	2144.5	2167.5	1284.7	1432.1	2151.8	2153.2	1251.9	1398.8	2216.8	2220.0
DSR	320.3	230.7	230.7	230.7	230.7	390.0	390.0	390.0	390.0	414.2	414.2	414.2	414.2	463.5	463.5	463.5	463.5
Utah Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
Utah Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
Utah Geothermal	0.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0
T Utah Cogeneration 2	0.0	0.0	0.0	250.8	114.0	0.0	0.0	73.8	0.0	0.0	0.0	44.4	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	1546.7	1924.8	1798.7	0.0	0.0	1436.9	1274.2	0.0	0.0	1463.1	1318.8	0.0	0.0	1406.2	1262.3	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	3.2	716.8	831.4	0.0	0.0	520.3	574.0	0.0	0.0	512.6	558.6	0.0	0.0	402.2	402.1
Utah Pumped Storage	499.9	500.0	500.0	500.0	500.0	500.1	500.0	500.0	500.0	500.0	499.9	500.0	500.0	500.1	499.9	500.0	500.0
	2366.9	2655.5	2712.6	1737.3	1895.1	2327.0	2344.2	1523.1	1683.0	2377.3	2412.9	1510.2	1691.8	2369.8	2405.7	1404.7	1584.6
DSR	102.7	41.0	41.0	41.0	41.0	104.1	104.1	104.1	104.1	104.2	104.2	104.2	104.2	115.2	115.2	115.2	115.2
W Wyo Wind with Tax C	0.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
Y Wyo Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	102.7	41.0	209.0	41.0	209.0	104.1	272.1	104.1	272.1	104.2	272.2	104.2	272.2	115.2	283.2	115.2	283.2
DSR	1128.1	526.4	526.4	526.4	526.4	1071.2	1071.2	1071.2	1071.2	1105.6	1105.6	1105.6	1105.6	1302.9	1302.9	1302.9	1302.9
T Renewable	0.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0
O Cogeneration	192.1	402.0	346.8	1609.9	1317.5	302.0	275.6	1180.2	948.4	227.1	180.2	1148.0	924.0	179.5	133.9	1031.6	853.8
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	1546.7	1924.8	1798.7	0.0	0.0	1436.9	1274.2	0.0	0.0	1463.1	1318.8	0.0	0.0	1406.2	1262.3	0.0	0.0
L Simple Cycle CT	0.0	0.0	3.5	716.8	831.4	0.0	0.0	520.3	574.0	0.0	0.0	512.6	558.6	0.0	0.0	402.2	402.1
Pumped Storage	891.5	1000.0	1000.0	1000.0	1000.0	961.5	972.5	1000.0	1000.0	970.4	983.6	1000.0	1000.0	848.3	859.6	1000.0	1000.0
Total	3758.4	3853.2	4204.4	3853.1	4204.3	3771.6	4122.5	3771.7	4122.6	3766.2	4117.2	3766.2	4117.2	3736.9	4087.7	3736.7	4087.8

Summary of Medium Load Growth and Medium Gas
Annual Energy (MWa) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

DSM	Uncons-	low				medium				accelerated				high			
Coal		any		no		any		no		any		no		any		no	
Renewable	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44
DSR	278.3	124.3	124.3	124.3	124.3	244.4	244.4	244.4	244.4	252.9	252.9	252.9	252.9	294.3	294.3	294.3	294.3
OWC Wind with Tax C	0.0	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3
OWC Wind without Tax C	0.0	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9
O OWC Geothermal	0.0	0.0	11.4	0.0	10.9	0.0	11.4	0.0	10.9	0.0	11.7	0.0	10.9	0.0	11.7	0.0	10.9
W OWC Cogeneration 1	178.8	183.7	156.8	297.9	297.9	148.9	148.9	297.9	297.9	170.7	151.7	297.9	297.9	166.8	124.6	297.9	297.9
C OWC Cogeneration 2	0.0	182.0	158.5	885.8	752.5	126.2	102.8	666.1	524.1	38.9	15.4	664.2	502.5	0.3	0.0	604.2	439.9
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	1.6	3.9	4.1	55.6	48.2	1.6	1.4	35.0	31.8	1.9	1.8	33.1	30.7	1.5	1.5	22.5	31.0
	458.7	493.9	495.3	1363.6	1274.0	521.1	549.1	1243.4	1149.3	464.4	473.7	1248.1	1135.1	462.9	472.3	1218.9	1114.2
DSR	224.2	156.2	156.2	156.2	156.2	277.2	277.2	277.2	277.2	293.7	293.7	293.7	293.7	324.5	324.5	324.5	324.5
Utah Wind with Tax C	0.0	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6
Utah Wind without Tax C	0.0	0.0	20.3	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4
Utah Geothermal	0.0	0.0	9.4	0.0	10.1	0.0	9.6	0.0	10.1	0.0	9.5	0.0	10.1	0.0	9.6	0.0	10.1
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	36.3	36.3	0.0	0.0	36.3	36.2	0.0	0.0	36.3	36.2	0.0	0.0	36.3	36.2
T Utah Cogeneration 2	0.0	0.0	0.0	227.6	104.5	0.0	0.0	67.8	0.0	0.0	0.0	41.2	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	1417.4	1763.8	1648.2	0.0	0.0	1316.9	1167.8	0.0	0.0	1340.8	1208.5	0.0	0.0	1288.5	1156.8	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.2	39.9	46.2	0.0	0.0	28.9	31.9	0.0	0.0	28.5	31.1	0.0	0.0	22.4	22.4
Utah Pumped Storage	122.8	118.4	118.2	90.5	89.4	117.3	109.3	86.1	81.2	113.3	105.5	85.5	80.3	108.3	102.4	87.1	78.5
	1764.4	2038.4	1991.1	550.5	501.7	1711.4	1622.9	496.3	495.6	1747.8	1676.1	485.2	510.4	1721.3	1652.2	470.3	530.7
DSR	90.1	37.6	37.6	37.6	37.6	91.2	91.2	91.2	91.2	91.5	91.5	91.5	91.5	99.5	99.5	99.5	99.5
W Wyo Wind with Tax C	0.0	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6
Y Wyo Wind without Tax C	0.0	0.0	20.3	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	90.1	37.6	96.5	37.6	96.6	91.2	150.2	91.2	150.2	91.5	150.4	91.5	150.5	99.5	158.4	99.5	158.5
DSR	592.6	318.1	318.1	318.1	318.1	612.8	612.8	612.8	612.8	638.1	638.1	638.1	638.1	718.3	718.3	718.3	718.3
T Renewable	0.0	0.0	178.8	0.0	179.2	0.0	179.2	0.0	179.2	0.0	179.2	0.0	179.2	0.0	179.3	0.0	179.2
O Cogeneration	178.8	365.7	315.3	1447.6	1191.2	275.1	251.7	1068.1	858.2	209.6	167.1	1039.6	836.6	167.1	124.6	938.4	774.0
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	1417.4	1763.8	1648.2	0.0	0.0	1316.9	1167.8	0.0	0.0	1340.8	1208.5	0.0	0.0	1288.5	1156.8	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.2	39.9	46.2	0.0	0.0	28.9	31.9	0.0	0.0	28.5	31.1	0.0	0.0	22.4	22.4
Pumped Storage	124.4	122.3	122.3	146.1	137.6	118.9	110.7	121.1	113.0	115.2	107.3	118.6	111.0	109.8	103.9	109.6	109.5
Total	2313.2	2569.9	2582.9	1951.7	1872.3	2323.7	2322.2	1830.9	1795.1	2303.7	2300.2	1824.8	1796.0	2283.7	2282.9	1788.7	1803.4

TS-03.aMW.20yr-m.mg

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Summary of Medium Load Growth and High Gas
Percentage of Winter Capacity Additions (%)

Additions in 10 years (1994 - 2003)

DSM		low				medium				accelerated				high			
Coal	Uncons-	any		no		any		no		any		no		any		no	
Renewable	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61
MW Additions																	
DSR	42.9	13.5	11.6	9.7	11.6	29.7	25.3	21.9	25.3	32.9	28.0	24.3	28.0	38.9	33.1	28.7	33.1
Renewable	0.0	0.0	21.6	41.0	21.6	0.0	22.0	38.4	22.0	0.0	22.1	38.1	22.1	0.0	22.3	38.4	22.3
Cogeneration	4.8	17.4	12.2	13.3	20.3	7.8	11.5	12.9	18.2	7.8	6.7	11.6	14.1	7.9	5.6	11.7	13.5
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	43.6	47.2	36.2	0.0	0.0	45.1	31.3	0.0	0.0	45.5	31.7	0.0	0.0	44.1	31.2	0.0	0.0
Peaking Resources	8.7	21.9	18.4	36.0	46.5	17.4	9.8	26.8	34.5	13.8	11.5	25.9	35.7	9.1	7.8	21.2	31.1
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																	
DSR	35.4	11.8	11.6	16.8	18.8	24.6	23.2	30.7	33.7	27.6	27.4	35.3	40.5	30.9	30.7	38.0	44.0
Renewable	0.0	0.0	11.7	37.2	19.3	0.0	11.9	31.4	17.3	0.0	12.0	30.8	17.9	0.0	12.2	29.8	17.5
Cogeneration	6.0	20.4	16.3	34.4	48.6	10.3	15.3	28.9	38.6	9.9	9.3	25.3	31.3	10.0	7.8	24.3	29.1
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	55.8	61.1	53.7	0.0	0.0	59.9	46.0	0.0	0.0	58.1	47.0	0.0	0.0	56.3	46.5	0.0	0.0
Peaking Resources	2.8	6.7	6.7	11.6	13.3	5.2	3.6	9.0	10.4	4.4	4.2	8.6	10.3	2.9	2.9	7.9	9.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Additions in 20 years (1994 - 2013)

DSM		low				medium				accelerated				high			
Coal	Uncons-	any		no		any		no		any		no		any		no	
Renewable	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61
MW Additions																	
DSR	30.0	13.7	12.5	8.6	9.0	28.4	26.0	19.6	20.6	29.4	26.9	20.2	20.5	34.9	31.9	25.0	25.1
Renewable	0.0	0.0	12.6	52.5	48.8	0.0	12.8	44.1	39.9	0.0	12.8	44.3	43.5	0.0	12.9	40.6	40.6
Cogeneration	2.5	9.5	7.1	6.4	8.6	4.2	6.7	6.6	8.4	4.2	3.9	5.9	6.2	4.3	3.2	6.1	6.2
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	43.3	50.1	43.0	0.0	0.0	42.3	33.9	0.0	0.0	41.6	34.7	0.0	0.0	38.9	32.5	0.0	0.0
Peaking Resources	24.1	26.8	24.8	32.5	33.7	25.1	20.6	29.7	31.2	24.8	21.7	29.6	29.8	21.9	19.4	28.3	28.1
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																	
DSR	25.8	12.5	12.5	17.8	17.7	26.2	25.1	34.1	34.3	27.3	26.7	35.6	35.6	31.1	30.5	40.4	40.2
Renewable	0.0	0.0	7.0	54.5	49.4	0.0	7.3	40.8	36.8	0.0	7.5	41.4	40.6	0.0	7.6	37.0	37.3
Cogeneration	3.9	13.0	10.7	20.1	25.4	6.4	10.3	18.6	22.5	6.4	6.2	16.6	17.5	6.5	5.2	16.8	16.7
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	65.0	69.6	64.9	0.0	0.0	62.5	52.5	0.0	0.0	61.4	54.7	0.0	0.0	57.8	51.8	0.0	0.0
Peaking Resources	5.3	4.9	4.9	7.6	7.5	5.0	4.7	6.5	6.5	4.8	4.9	6.3	6.3	4.6	4.8	5.8	5.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

T5-04.percent.resource-m.hg

Table 5-4.b

Summary of Medium Load Growth and High Gas
Winter Capacity (MW) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

DSM		low				medium				accelerated				high			
Coal	Uncons-	any		no		any		no		any		no		any		no	
Renewable	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61
DSR	452.5	149.3	149.3	149.3	149.3	359.2	359.2	359.2	359.2	381.8	381.8	381.8	381.8	468.6	468.6	468.6	468.6
OWC Wind with Tax C	0.0	0.0	110.0	300.0	110.0	0.0	110.0	166.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0
OWC Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O OWC Geothermal	0.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0
W OWC Cogeneration 1	95.5	160.0	160.0	320.0	320.0	160.0	160.0	320.0	320.0	160.0	160.0	320.0	319.9	160.0	132.7	320.0	319.9
C OWC Cogeneration 2	0.0	204.7	139.1	29.2	139.3	0.0	115.6	0.0	76.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	548.0	514.0	629.4	798.5	789.6	519.2	815.8	845.2	936.8	541.8	722.8	851.8	882.7	628.6	782.3	938.6	969.5
DSR	317.9	118.5	118.5	118.5	118.5	200.8	200.8	200.8	200.8	238.9	238.9	238.9	238.9	261.4	261.4	261.4	261.4
Utah Wind with Tax C	0.0	0.0	110.0	450.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	450.0	110.0
Utah Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
Utah Geothermal	0.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0.0	0.0	0.0	17.3	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	875.9	990.0	885.3	0.0	0.0	924.0	751.1	0.0	0.0	927.3	757.7	0.0	0.0	892.5	741.0	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	554.0	638.0	0.0	0.0	272.7	356.7	0.0	0.0	263.9	395.4	0.0	0.0	110.7	292.5
Utah Pumped Storage	175.5	459.4	451.8	500.0	500.0	356.6	236.0	470.4	470.4	282.2	273.9	451.1	458.8	183.3	184.3	470.6	445.4
	1369.3	1567.9	1635.6	1661.5	1475.5	1481.4	1367.9	1432.9	1246.9	1448.4	1450.5	1403.9	1290.4	1337.2	1366.7	1292.7	1179.3
DSR	89.9	15.8	15.8	15.8	15.8	48.2	48.2	48.2	48.2	49.6	49.6	49.6	49.6	56.4	56.4	56.4	56.4
W Wyo Wind with Tax C	0.0	0.0	110.0	450.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	450.0	110.0
Y Wyo Wind without Tax C	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	89.9	15.8	183.8	465.8	183.8	48.2	216.2	498.2	216.2	49.6	217.6	499.6	217.6	56.4	224.4	506.4	224.4
DSR	860.3	283.6	283.6	283.6	283.6	608.2	608.2	608.2	608.2	670.3	670.3	670.3	670.3	786.4	786.4	786.4	786.4
T Renewable	0.0	0.0	529.0	1200.0	529.0	0.0	529.0	1066.0	529.0	0.0	529.0	1050.0	529.0	0.0	529.0	1050.0	529.0
O Cogeneration	95.5	364.7	299.1	388.2	498.3	160.0	275.6	359.0	435.6	160.0	160.0	320.0	337.2	160.0	132.7	320.0	319.9
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	875.9	990.0	885.3	0.0	0.0	924.0	751.1	0.0	0.0	927.3	757.7	0.0	0.0	892.5	741.0	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	554.0	638.0	0.0	0.0	272.7	356.7	0.0	0.0	263.9	395.4	0.0	0.0	110.7	292.5
Pumped Storage	175.5	459.4	451.8	500.0	500.0	356.6	236.0	470.4	470.4	282.2	273.9	451.1	458.8	183.3	184.3	470.6	445.4
Total	2007.2	2097.7	2448.8	2925.8	2448.9	2048.8	2399.9	2776.3	2399.9	2039.8	2390.9	2755.3	2390.7	2022.2	2373.4	2737.7	2373.2

T5-04.MW.10yr-m.hg

Summary of Medium Load Growth and High Gas
Annual Energy (MWa) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

DSM		low				medium				accelerated				high			
Coal	Uncons-	any		no		any		no		any		no		any		no	
Renewable	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61
DSR	203.4	79.1	79.1	79.1	79.1	155.4	155.4	155.4	155.4	176.0	176.0	176.0	176.0	200.9	200.9	200.9	200.9
OWC Wind with Tax C	0.0	0.0	26.3	71.7	26.3	0.0	26.3	39.6	26.3	0.0	26.3	35.8	26.3	0.0	26.3	35.8	26.3
OWC Wind without Tax C	0.0	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9
O OWC Geothermal	0.0	0.0	9.9	0.0	10.8	0.0	10.2	0.0	10.6	0.0	10.2	0.0	10.6	0.0	10.2	0.0	10.6
W OWC Cogeneration 1	86.9	139.5	135.0	297.0	296.8	145.5	135.0	291.9	296.8	145.3	137.8	289.1	296.8	145.3	114.3	287.3	296.8
C OWC Cogeneration 2	0.0	163.6	111.2	25.5	119.0	0.0	94.4	0.0	65.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	290.3	382.2	375.4	473.3	545.9	300.9	435.2	486.9	568.4	321.3	364.2	500.9	523.6	346.2	365.6	524.0	548.5
DSR	221.7	81.3	81.3	81.3	81.3	148.9	148.9	148.9	148.9	183.2	183.2	183.2	183.2	197.7	197.7	197.7	197.7
Utah Wind with Tax C	0.0	0.0	38.6	158.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	158.0	38.6
Utah Wind without Tax C	0.0	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4
Utah Geothermal	0.0	0.0	9.1	0.0	10.0	0.0	9.3	0.0	9.7	0.0	9.3	0.0	9.8	0.0	9.3	0.0	9.7
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	35.9	35.9	0.0	0.0	35.3	35.7	0.0	0.0	0.0	15.9	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	802.7	907.2	811.3	0.0	0.0	846.8	688.3	0.0	0.0	849.8	694.3	0.0	0.0	817.9	679.0	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	30.8	35.5	0.0	0.0	15.2	19.8	0.0	0.0	14.7	22.0	0.0	0.0	6.2	16.3
Utah Pumped Storage	39.7	99.9	101.8	89.8	87.7	73.8	53.5	87.3	87.1	63.9	62.1	83.7	80.9	41.5	41.8	87.4	79.2
	1064.1	1088.4	1062.5	395.8	309.4	1069.5	959.0	444.7	360.2	1096.9	1007.9	439.6	370.8	1057.1	986.8	449.3	361.9
DSR	83.5	14.2	14.2	14.2	14.2	43.5	43.5	43.5	43.5	44.8	44.8	44.8	44.8	49.7	49.7	49.7	49.7
W Wyo Wind with Tax C	0.0	0.0	38.6	158.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	158.0	38.6
Y Wyo Wind without Tax C	0.0	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	83.5	14.2	73.2	172.2	73.2	43.5	102.5	201.5	102.5	44.8	103.8	202.8	103.8	49.7	108.7	207.7	108.7
DSR	508.6	174.6	174.6	174.6	174.6	347.8	347.8	347.8	347.8	404.0	404.0	404.0	404.0	448.3	448.3	448.3	448.3
T Renewable	0.0	0.0	177.2	387.7	179.0	0.0	177.7	355.6	178.5	0.0	177.7	351.8	178.6	0.0	177.7	351.8	178.5
O Cogeneration	86.9	303.1	246.2	358.4	451.7	145.5	229.4	327.2	397.9	145.3	137.8	289.1	312.7	145.3	114.3	287.3	296.8
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	802.7	907.2	811.3	0.0	0.0	846.8	688.3	0.0	0.0	849.8	694.3	0.0	0.0	817.9	679.0	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	30.8	35.5	0.0	0.0	15.2	19.8	0.0	0.0	14.7	22.0	0.0	0.0	6.2	16.3
Pumped Storage	39.7	99.9	101.8	89.8	87.7	73.8	53.5	87.3	87.1	63.9	62.1	83.7	80.9	41.5	41.8	87.4	79.2
Total	1437.9	1484.8	1511.1	1041.3	928.5	1413.9	1496.7	1133.1	1031.1	1463.0	1475.9	1143.3	998.2	1453.0	1461.1	1181.0	1019.1

T5-04.aMW.10yr-m.hg

Table 5-4.d

Summary of Medium Load Growth and High Gas
Winter Capacity (MW) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

DSM	Uncons-	low				medium				accelerated				high			
Coal		any		no		any		no		any		no		any		no	
Renewable	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61
DSR	705.1	254.7	254.7	254.7	254.7	577.1	577.1	577.1	577.1	587.2	587.2	587.2	587.2	724.2	724.2	724.2	724.2
OWC Wind with Tax C	0.0	0.0	110.0	300.0	110.0	0.0	110.0	166.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0
OWC Wind without Tax C	0.0	0.0	58.0	1050.0	966.0	0.0	58.0	844.2	658.0	0.0	58.0	815.9	848.4	0.0	58.0	629.3	668.8
O OWC Geothermal	0.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0
W OWC Cogeneration 1	95.5	160.0	160.0	320.0	320.0	160.0	160.0	320.0	320.0	160.0	160.0	320.0	319.9	160.0	132.7	320.0	319.9
C OWC Cogeneration 2	0.0	204.7	139.1	29.2	139.3	0.0	115.6	0.0	76.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	31.7	42.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	407.4	500.0	500.0	500.0	500.0	445.4	347.9	500.0	500.0	435.4	395.0	500.0	500.0	319.7	292.7	500.0	500.0
	1208.0	1151.1	1276.9	2453.9	2303.0	1182.5	1381.6	2407.3	2254.7	1182.6	1323.2	2373.1	2378.5	1203.9	1330.6	2323.5	2335.9
DSR	320.1	230.7	230.7	230.7	230.7	390.0	390.0	390.0	390.0	414.2	414.2	414.2	414.2	463.5	463.5	463.5	463.5
Utah Wind with Tax C	0.0	0.0	110.0	450.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	450.0	110.0
Utah Wind without Tax C	0.0	0.0	58.0	902.9	1108.0	0.0	58.0	501.5	945.4	0.0	58.0	558.4	1010.0	0.0	58.0	442.8	962.9
Utah Geothermal	0.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.3	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	1627.6	1930.4	1807.6	0.0	0.0	1595.0	1398.9	0.0	0.0	1565.3	1427.8	0.0	0.0	1454.1	1330.5	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	988.2	960.6	0.0	0.0	626.3	623.1	0.0	0.0	617.9	609.1	0.0	0.0	475.8	462.6
Utah Pumped Storage	500.0	499.9	500.0	500.0	500.0	500.0	500.1	500.0	500.0	500.0	499.9	500.0	499.9	499.9	500.0	500.0	500.0
	2447.7	2661.0	2718.3	3110.8	2960.3	2485.0	2469.0	2506.8	2619.5	2479.5	2521.9	2540.5	2672.5	2417.5	2474.0	2332.1	2511.0
DSR	102.7	41.0	41.0	41.0	41.0	104.1	104.1	104.1	104.1	104.2	104.2	104.2	104.2	115.2	115.2	115.2	115.2
W Wyo Wind with Tax C	0.0	0.0	110.0	450.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	450.0	110.0
Y Wyo Wind without Tax C	0.0	0.0	58.0	54.4	411.3	0.0	58.0	0.0	121.4	0.0	58.0	0.0	132.5	0.0	58.0	0.0	124.5
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	102.7	41.0	209.0	545.4	562.3	104.1	272.1	554.1	335.5	104.2	272.2	554.2	346.7	115.2	283.2	565.2	349.7
DSR	1127.9	526.4	526.4	526.4	526.4	1071.2	1071.2	1071.2	1071.2	1105.6	1105.6	1105.6	1105.6	1302.9	1302.9	1302.9	1302.9
T Renewable	0.0	0.0	529.0	3207.3	2840.3	0.0	529.0	2411.7	2079.8	0.0	529.0	2424.3	2345.9	0.0	529.0	2122.1	2111.2
O Cogeneration	95.5	364.7	299.1	388.2	498.3	160.0	275.6	359.0	435.6	160.0	160.0	320.0	337.2	160.0	132.7	320.0	319.9
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	1627.6	1930.4	1807.6	0.0	0.0	1595.0	1398.9	0.0	0.0	1565.3	1427.8	0.0	0.0	1454.1	1330.5	0.0	0.0
L Simple Cycle CT	0.0	31.7	42.1	988.2	960.6	0.0	0.0	626.3	623.1	0.0	0.0	617.9	609.1	0.0	0.0	475.8	462.6
Pumped Storage	907.4	999.9	1000.0	1000.0	1000.0	945.4	848.0	1000.0	1000.0	935.4	894.9	1000.0	999.9	819.6	792.7	1000.0	1000.0
Total	3758.4	3853.1	4204.2	6110.1	5825.6	3771.6	4122.7	5468.2	5209.7	3766.3	4117.3	5467.8	5397.7	3736.6	4087.8	5220.8	5196.6

T5-04.MW.20yr-m.hg

Summary of Medium Load Growth and High Gas
Annual Energy (MWa) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

DSM	Uncons-	low				medium				accelerated				high			
Coal		any		no		any		no		any		no		any		no	
Renewable	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	45	46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61
DSR	278.3	124.3	124.3	124.3	124.3	244.4	244.4	244.4	244.4	252.9	252.9	252.9	252.9	294.3	294.3	294.3	294.3
OWC Wind with Tax C	0.0	0.0	26.3	71.7	26.3	0.0	26.3	39.6	26.3	0.0	26.3	35.8	26.3	0.0	26.3	35.8	26.3
OWC Wind without Tax C	0.0	0.0	13.9	250.8	230.7	0.0	13.9	201.6	157.2	0.0	13.9	194.9	202.7	0.0	13.9	150.3	159.8
O OWC Geothermal	0.0	0.0	11.7	0.0	11.2	0.0	11.4	0.0	11.4	0.0	11.7	0.0	11.4	0.0	11.7	0.0	11.4
W OWC Cogeneration 1	88.9	148.9	148.9	297.9	297.9	148.9	148.9	297.9	297.9	148.9	148.9	297.9	297.9	148.9	123.5	297.9	297.9
C OWC Cogeneration 2	0.0	182.0	123.7	25.9	123.8	0.0	102.8	0.0	68.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	2.4	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	2.1	4.0	4.1	3.5	4.1	2.4	1.4	2.0	2.0	2.2	1.9	2.0	2.0	1.6	1.5	1.5	1.6
	369.3	461.6	456.1	774.1	818.3	395.7	549.1	785.5	807.3	404.0	455.6	783.5	793.2	444.8	471.2	779.8	791.3
DSR	224.2	156.2	156.2	156.2	156.2	277.2	277.2	277.2	277.2	293.7	293.7	293.7	293.7	324.5	324.5	324.5	324.5
Utah Wind with Tax C	0.0	0.0	38.6	158.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	158.0	38.6
Utah Wind without Tax C	0.0	0.0	20.3	317.0	389.0	0.0	20.3	176.1	331.9	0.0	20.3	196.0	354.6	0.0	20.3	155.4	338.0
Utah Geothermal	0.0	0.0	9.4	0.0	10.0	0.0	9.5	0.0	10.0	0.0	9.5	0.0	10.0	0.0	9.5	0.0	10.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	35.5	35.5	0.0	0.0	35.4	35.4	0.0	0.0	0.0	15.7	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	1491.5	1769.0	1656.5	0.0	0.0	1461.7	1282.0	0.0	0.0	1434.4	1308.4	0.0	0.0	1332.5	1219.3	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	54.9	53.4	0.0	0.0	34.8	34.6	0.0	0.0	34.4	33.9	0.0	0.0	26.5	25.7
Utah Pumped Storage	119.4	118.2	118.7	77.8	77.3	113.5	113.0	79.7	79.0	110.8	115.7	77.4	77.1	105.5	111.6	75.6	75.5
	1835.1	2043.4	1999.7	799.4	760.0	1852.4	1740.6	761.2	806.7	1838.9	1786.2	759.5	823.6	1762.5	1723.8	740.0	812.3
DSR	90.1	37.6	37.6	37.6	37.6	91.2	91.2	91.2	91.2	91.5	91.5	91.5	91.5	99.5	99.5	99.5	99.5
W Wyo Wind with Tax C	0.0	0.0	38.6	158.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	158.0	38.6
Y Wyo Wind without Tax C	0.0	0.0	20.3	19.1	144.4	0.0	20.3	0.0	42.6	0.0	20.3	0.0	46.5	0.0	20.3	0.0	43.7
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	90.1	37.6	96.5	214.7	220.6	91.2	150.1	249.2	172.4	91.5	150.4	249.5	176.6	99.5	158.4	257.5	181.8
DSR	592.6	318.1	318.1	318.1	318.1	612.8	612.8	612.8	612.8	638.1	638.1	638.1	638.1	718.3	718.3	718.3	718.3
T Renewable	0.0	0.0	179.1	974.6	888.8	0.0	178.9	733.3	656.6	0.0	179.2	742.7	728.7	0.0	179.2	657.5	666.4
O Cogeneration	88.9	330.9	272.6	359.3	457.2	148.9	251.7	333.3	401.4	148.9	148.9	297.9	313.6	148.9	123.5	297.9	297.9
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	1491.5	1769.0	1656.5	0.0	0.0	1461.7	1282.0	0.0	0.0	1434.4	1308.4	0.0	0.0	1332.5	1219.3	0.0	0.0
L Simple Cycle CT	0.0	2.4	3.2	54.9	53.4	0.0	0.0	34.8	34.6	0.0	0.0	34.4	33.9	0.0	0.0	26.5	25.7
Pumped Storage	121.5	122.2	122.8	81.3	81.4	115.9	114.4	81.7	81.0	113.0	117.6	79.4	79.1	107.1	113.1	77.1	77.1
Total	2294.5	2542.6	2552.3	1788.2	1798.9	2339.3	2439.8	1795.9	1786.4	2334.4	2392.2	1792.5	1793.4	2306.8	2353.4	1777.3	1785.4

TS-04.aMW 20yr-m.hg

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Summary of Medium High Load Growth
Percentage of Winter Capacity Additions (%)

Additions in 10 years (1994 - 2003)

Gas	Low		Medium																	High	
DSM	medium			low				medium				accelerated				high				medium	
Coal	any	no	Uncons-	any		no		any		no		any		no		any		no		any	no
Renewable	strat	strat	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
Case #	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82
MW Additions																					
DSR	18.1	18.1	30.0	8.9	8.1	8.4	8.1	20.1	18.1	18.9	18.1	23.7	21.4	23.7	21.4	26.1	23.6	26.1	23.6	18.1	18.1
Renewable	14.4	14.4	0.0	0.0	14.2	8.4	14.2	0.0	14.4	8.5	14.4	0.0	14.5	0.0	14.5	0.0	14.5	0.0	14.5	14.4	14.4
Cogeneration	42.4	51.7	24.9	34.5	29.2	57.7	53.4	29.1	24.4	52.4	48.3	28.3	23.9	57.0	46.2	27.4	22.9	55.8	45.4	21.8	36.6
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	6.3	0.0	29.8	29.4	24.8	0.0	0.0	29.9	24.4	0.0	0.0	29.6	23.5	0.0	0.0	29.4	23.4	0.0	0.0	27.2	0.0
Peaking Resources	18.7	15.7	15.3	27.2	23.7	25.5	24.3	21.0	18.6	20.1	19.2	18.4	16.7	19.4	18.0	17.1	15.5	18.1	16.5	18.4	30.9
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																					
DSR	17.6	17.2	26.1	8.6	8.4	8.9	8.9	17.2	16.9	17.9	17.8	20.0	19.7	21.1	20.9	21.6	21.4	22.8	22.5	16.8	20.8
Renewable	8.2	8.0	0.0	0.0	7.9	5.0	8.3	0.0	7.9	5.0	8.3	0.0	7.9	0.0	8.4	0.0	7.9	0.0	8.3	7.8	9.7
Cogeneration	59.5	70.4	29.8	43.9	39.9	79.8	76.6	36.6	33.3	71.8	68.4	34.9	32.2	73.6	65.6	33.8	31.0	72.1	64.2	29.2	62.5
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	9.8	0.0	39.6	41.2	37.6	0.0	0.0	41.0	36.6	0.0	0.0	40.2	35.0	0.0	0.0	39.9	34.8	0.0	0.0	40.4	0.0
Peaking Resources	4.8	4.3	4.5	6.3	6.2	6.3	6.3	5.3	5.3	5.4	5.5	5.0	5.2	5.3	5.2	4.7	4.9	5.1	5.0	5.8	7.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Additions in 20 years (1994 - 2013)

Gas	Low		Medium																	High	
DSM	medium			low				medium				accelerated				high				medium	
Coal	any	no	Uncons-	any		no		any		no		any		no		any		no		any	no
Renewable	strat	strat	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
Case #	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82
MW Additions																					
DSR	18.2	18.2	20.7	8.7	8.3	8.5	8.3	19.3	18.2	18.7	18.2	20.8	19.7	20.8	19.7	23.4	22.2	23.4	22.2	18.2	13.4
Renewable	7.9	7.9	0.0	0.0	7.8	4.5	7.8	0.0	7.9	4.6	7.9	0.0	7.9	0.0	7.9	0.0	7.9	0.0	7.9	7.9	43.8
Cogeneration	23.1	31.2	14.2	18.0	16.0	31.5	30.8	15.1	13.3	31.9	31.2	14.7	13.0	33.0	31.3	14.2	12.5	33.1	31.4	11.9	14.7
Combined Cycle CT	0.0	8.2	0.0	0.0	0.0	13.7	12.2	0.0	0.0	8.7	7.3	0.0	0.0	10.1	7.2	0.0	0.0	8.9	6.2	0.0	0.0
Coal	27.3	0.0	44.4	45.6	41.5	0.0	0.0	43.7	39.4	0.0	0.0	43.8	39.5	0.0	0.0	43.3	39.0	0.0	0.0	42.3	0.0
Peaking Resources	23.4	34.4	20.6	27.7	26.5	41.8	41.0	21.9	21.2	36.2	35.3	20.7	19.9	36.1	34.0	19.2	18.4	34.5	32.4	19.7	28.1
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																					
DSR	16.9	19.5	16.4	8.2	8.1	10.0	10.0	16.2	16.3	19.9	19.9	16.8	16.8	20.7	20.5	18.7	18.7	22.9	22.7	15.9	20.6
Renewable	4.4	5.0	0.0	0.0	4.2	3.0	5.1	0.0	4.2	3.0	5.1	0.0	4.2	0.0	5.1	0.0	4.2	0.0	5.1	4.1	37.8
Cogeneration	33.4	54.8	19.2	24.3	22.9	55.0	55.1	20.4	19.0	55.2	55.2	19.8	18.5	55.7	55.1	19.1	17.7	55.7	54.9	16.6	36.3
Combined Cycle CT	0.0	14.5	0.0	0.0	0.0	24.2	22.0	0.0	0.0	15.1	13.1	0.0	0.0	17.1	12.7	0.0	0.0	15.1	10.9	0.0	0.0
Coal	41.0	0.0	60.9	63.3	60.5	0.0	0.0	59.8	56.9	0.0	0.0	59.9	57.0	0.0	0.0	58.9	56.1	0.0	0.0	59.7	0.0
Peaking Resources	4.3	6.2	3.5	4.2	4.3	7.8	7.8	3.6	3.7	6.8	6.8	3.5	3.5	6.5	6.5	3.3	3.4	6.2	6.4	3.7	5.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

T5-05.percent.resource-mh

Summary of Medium High Load Growth
Winter Capacity (MW) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Gas	Low		Medium																	High	
DSM	medium		Uncons-	low				medium				accelerated				high				medium	
Coal	any	no		any		no		any		no		any		no		any		no		any	no
Renewable	strat	strat	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
Case #	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82
DSR	393.4	393.4	515.1	156.9	156.9	156.9	156.9	393.4	393.4	393.4	393.4	470.2	470.2	470.2	470.2	519.8	519.8	519.8	519.8	393.4	393.4
OWC Wind with Tax C	110.0	110.0	0.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	110	110.0
OWC Wind without Tax C	58.0	58.0	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58	58.0
O OWC Geothermal	13.0	13.0	0.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	13	13.0
W OWC Cogeneration 1	160.0	160.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.1	320.0	320.0	320.0	320.0	320	320.0
C OWC Cogeneration 2	1146.4	1278.5	491.2	842.3	768.5	1280.5	1207.5	644.7	574.5	1065.5	990.6	614.1	551.9	1100.6	944.4	579.2	514.8	1056.7	910.6	480.8	771.5
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
OWC Pumped Storage	13.6	0.0	0.0	116.2	146.9	102.0	97.5	48.2	73.0	34.9	48.5	61.2	80.9	45.1	3.9	37.2	54.7	30.1	0.0	176.4	0.0
	1894.4	2012.9	1326.3	1435.4	1573.3	1859.4	1962.9	1406.3	1541.9	1813.8	1933.5	1465.5	1604.0	1935.9	1919.6	1456.2	1590.3	1926.6	1931.4	1551.6	1665.9
DSR	217.8	217.8	363.1	127.0	127.0	127.0	127.0	217.8	217.8	217.8	217.8	252.7	252.7	252.7	252.7	277.2	277.2	277.2	277.2	217.8	217.8
Utah Wind with Tax C	110.0	110.0	0.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	110	110.0
Utah Wind without Tax C	58.0	58.0	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58	58.0
Utah Geothermal	12.0	12.0	0.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	12	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
U Utah Cogeneration 1	39.0	39.0	0.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	0.0	0.0	0.0	39.0	0.0	0	39.0
T Utah Cogeneration 2	210.0	420.1	0.0	0.0	0.0	420.0	419.9	0.0	0.0	420.0	420.0	0.0	0.0	420.0	420.0	0.0	0.0	420.0	420.1	0	210.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah Coal	231.7	0.0	972.4	990.0	922.6	0.0	0.0	990.0	894.8	0.0	0.0	976.6	859.4	0.0	0.0	967.2	852.2	0.0	0.0	990	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah Simple Cycle CT	172.5	93.6	0.0	300.9	233.6	308.8	307.5	148.1	110.8	172.6	155.0	46.4	28.2	93.4	152.1	26.0	10.0	63.7	101.1	0	632.6
Utah Pumped Storage	500.0	482.1	500.0	499.9	500.0	500.0	500.0	500.0	500.0	499.9	500.0	499.9	500.0	500.0	500.0	500.0	499.9	500.0	500.0	500	500.0
	1551.0	1432.6	1835.5	1917.8	1963.2	1544.8	1573.4	1855.9	1903.4	1499.3	1511.8	1775.6	1820.3	1305.1	1504.8	1770.4	1819.3	1299.9	1478.4	1887.8	1779.4
DSR	53.7	53.7	102.5	17.0	17.0	17.0	17.0	53.7	53.7	53.7	53.7	57.5	57.5	57.5	57.5	61.0	61.0	61.0	61.0	53.7	53.7
W Wyo Wind with Tax C	110.0	110.0	0.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	110	110.0
Y Wyo Wind without Tax C	58.0	58.0	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
	221.7	221.7	102.5	17.0	185.0	167.0	185.0	53.7	221.7	203.7	221.7	57.5	225.5	57.5	225.5	61.0	229.0	61.0	229.0	227.6	221.7
DSR	664.9	664.9	980.7	300.9	300.9	300.9	300.9	664.9	664.9	664.9	664.9	780.4	780.4	780.4	780.4	858.0	858.0	858.0	858.0	664.9	664.9
T Renewable	529.0	529.0	0.0	0.0	529.0	300.0	529.0	0.0	529.0	300.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	529	529.0
O Cogeneration	1555.4	1897.6	811.2	1162.3	1088.5	2059.5	1986.4	964.7	894.5	1844.5	1769.6	934.1	871.9	1879.6	1684.5	899.2	834.8	1835.7	1650.7	800.8	1340.5
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
A Coal	231.7	0.0	972.4	990.0	922.6	0.0	0.0	990.0	894.8	0.0	0.0	976.6	859.4	0.0	0.0	967.2	852.2	0.0	0.0	995.9	0.0
L Simple Cycle CT	172.5	93.6	0.0	300.9	233.6	308.8	307.5	148.1	110.8	172.6	155.0	46.4	28.2	93.4	152.1	26.0	10.0	63.7	101.1	0	632.6
Pumped Storage	513.6	482.1	500.0	616.1	646.9	602.0	597.5	548.2	573.0	534.8	548.5	561.1	580.9	545.1	503.9	537.2	554.6	530.1	500.0	676.4	500.0
Total	3667.1	3667.2	3264.3	3370.2	3721.5	3571.2	3721.3	3315.9	3667.0	3516.8	3667.0	3298.6	3649.8	3298.5	3649.9	3287.6	3638.6	3287.5	3638.8	3667	3667.0

TS-05.MW.10yr-mh

Summary of Medium High Load Growth
Annual Energy (MWa) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

	Gas	Low		Medium																	High	
	DSM	medium			low				medium				accelerated				high				medium	
	Coal	any	no	Uncons-	any		no		any		no		any		no		any		no		any	no
	Renewable	strat	strat	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
	Case #	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82
	DSR	168.7	168.7	232.3	84.3	84.3	84.3	84.3	168.7	168.7	168.7	168.7	198.8	198.8	198.8	198.8	216.1	216.1	216.1	216.1	168.7	168.7
	OWC Wind with Tax C	26.2	26.2	0.0	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	26.3	26.3
	OWC Wind without Tax C	13.8	13.8	0.0	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	13.9	13.9
O	OWC Geothermal	10.2	10.1	0.0	0.0	9.9	0.0	9.9	0.0	9.9	0.0	10.1	0.0	9.9	0.0	10.1	0.0	9.9	0.0	10.1	9.9	10.1
W	OWC Cogeneration 1	139.9	138.4	273.5	277.8	277.8	277.5	277.5	277.5	277.8	277.5	277.5	277.7	277.8	279.3	277.5	277.6	277.8	278.8	277.5	281.1	294.6
C	OWC Cogeneration 2	939.3	1039.6	395.5	689.0	618.3	1033.5	973.5	532.0	468.2	865.6	802.9	499.0	447.5	888.3	771.3	473.0	417.5	854.2	743.4	377.9	638.2
	OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
	OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
	OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
	OWC Pumped Storage	2.1	0.0	0.0	17.7	22.8	15.5	14.8	8.9	13.0	5.3	7.4	11.4	14.2	7.1	0.6	6.9	9.7	4.7	0.0	23	0.0
		1300.2	1396.8	901.3	1068.8	1053.3	1410.8	1400.2	987.1	977.8	1317.1	1306.8	986.9	988.4	1373.5	1298.5	973.6	971.2	1353.8	1287.3	900.8	1151.8
	DSR	163.0	163.0	259.7	89.2	89.2	89.2	89.2	163.0	163.0	163.0	163.0	195.0	195.0	195.0	195.0	210.2	210.2	210.2	210.2	163	163.0
	Utah Wind with Tax C	38.6	38.6	0.0	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	38.6	38.6
	Utah Wind without Tax C	20.4	20.4	0.0	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	20.4	20.4
	Utah Geothermal	9.9	9.7	0.0	0.0	9.1	0.0	9.3	0.0	9.1	0.0	9.3	0.0	9.1	0.0	9.3	0.0	9.1	0.0	9.3	9.1	9.7
	Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
U	Utah Cogeneration 1	35.0	35.0	0.0	0.0	0.0	34.2	34.2	0.0	0.0	34.2	34.2	0.0	0.0	34.2	0.0	0.0	0.0	34.7	0.0	0	35.7
T	Utah Cogeneration 2	173.8	345.9	0.0	0.0	0.0	347.5	347.3	0.0	0.0	346.4	346.0	0.0	0.0	347.5	345.8	0.0	0.0	347.5	345.3	0	175.8
A	Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
H	Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
	Utah Coal	212.4	0.0	891.1	907.2	845.4	0.0	0.0	907.2	820.0	0.0	0.0	895.0	787.5	0.0	0.0	886.3	781.0	0.0	0.0	907.2	0.0
	Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
	Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
	Utah Simple Cycle CT	9.6	5.2	0.0	16.7	13.0	17.2	17.1	8.2	6.2	9.6	8.6	2.6	1.6	5.2	8.5	1.4	0.6	3.5	5.6	0	35.2
	Utah Pumped Storage	92.8	91.0	101.3	104.7	103.6	101.1	101.9	99.4	100.5	99.5	101.3	98.0	100.9	99.4	100.6	96.8	100.0	98.3	100.2	109	92.8
		755.5	708.8	1252.1	1117.8	1119.3	641.9	658.0	1177.8	1157.8	705.4	721.4	1190.6	1153.1	681.3	718.2	1194.7	1159.9	694.2	729.6	1247.3	571.2
	DSR	48.2	48.2	95.1	15.3	15.3	15.3	15.3	48.2	48.2	48.2	48.2	50.8	50.8	50.8	50.8	53.3	53.3	53.3	53.3	48.2	48.2
W	Wyo Wind with Tax C	38.6	38.6	0.0	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	38.6	38.6
Y	Wyo Wind without Tax C	20.4	20.4	0.0	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	20.4	20.4
O	Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
M	Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
I	Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.4	0.0
N	Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
G	Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
	Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
		107.2	107.2	95.1	15.3	74.3	68.0	74.3	48.2	107.2	100.9	107.2	50.8	109.8	50.8	109.8	53.3	112.3	53.3	112.3	112.6	107.2
	DSR	379.9	379.9	587.1	188.8	188.8	188.8	188.8	379.9	379.9	379.9	379.9	444.6	444.6	444.6	444.6	479.6	479.6	479.6	479.6	379.9	379.9
T	Renewable	178.1	177.8	0.0	0.0	177.2	105.4	177.4	0.0	177.2	105.4	177.6	0.0	177.2	0.0	177.6	0.0	177.2	0.0	177.6	177.2	178.0
O	Cogeneration	1288.0	1558.9	669.0	966.8	896.1	1692.7	1632.5	809.5	746.0	1523.7	1460.6	776.7	725.3	1549.3	1394.6	750.6	695.3	1515.2	1366.2	659	1144.3
T	Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
A	Coal	212.4	0.0	891.1	907.2	845.4	0.0	0.0	907.2	820.0	0.0	0.0	895.0	787.5	0.0	0.0	886.3	781.0	0.0	0.0	912.6	0.0
L	Simple Cycle CT	9.6	5.2	0.0	16.7	13.0	17.2	17.1	8.2	6.2	9.6	8.6	2.6	1.6	5.2	8.5	1.4	0.6	3.5	5.6	0	35.2
	Pumped Storage	94.9	91.0	101.3	122.4	126.4	116.6	116.7	108.3	113.5	104.8	108.7	109.4	115.1	106.5	101.2	103.7	109.7	103.0	100.2	132	92.8
	Total	2162.9	2212.8	2248.5	2201.9	2246.9	2120.7	2132.5	2213.1	2242.8	2123.4	2135.4	2228.3	2251.3	2105.6	2126.5	2221.6	2243.4	2101.3	2129.2	2260.7	1830.2

TS-05.aMW.10yr-mh

Table 5-5.d

Summary of Medium High Load Growth
Winter Capacity (MW) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Gas	Low		Medium																	High	
DSM	medium			low				medium				accelerated				high				medium	
Coal	any	no	Uncons-	any		no		any		no		any		no		any		no		any	no
Renewable	strat	strat	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
Case #	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82
DSR	680.0	680.0	816.8	270.8	270.8	270.8	270.8	680.0	680.0	680.0	680.0	762.7	762.7	762.7	762.7	852.9	852.9	852.9	852.9	680	680.0
OWC Wind with Tax C	110.0	110.0	0.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	110	110.0
OWC Wind without Tax C	58.0	58.0	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58	1163.4
O OWC Geothermal	13.0	13.0	0.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	13	13.0
W OWC Cogeneration 1	160.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.1	320.0	320.0	320.0	320.0	320	320.0
C OWC Cogeneration 2	1146.4	1320.0	582.6	842.3	768.5	1320.0	1320.0	644.7	574.5	1320.0	1320.0	614.1	551.9	1319.9	1320.1	579.2	514.8	1320.0	1320.0	480.8	771.5
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	237.6	183.4	0.0	0.0	71.9	17.0	0.0	0.0	29.4	0.0	0.0	0.0	8.1	0.0	0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
OWC Simple Cycle CT	0.0	0.0	184.1	402.1	420.6	0.0	0.0	232.1	247.1	0.0	0.0	200.2	207.3	0.0	0.0	153.1	162.4	0.0	0.0	325.9	0.0
OWC Pumped Storage	500.0	500.0	500.0	499.9	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500	500.0
	2667.4	3001.0	2403.5	2335.1	2460.9	2648.4	2775.2	2376.8	2502.6	2891.9	3018.0	2397.0	2522.9	2932.0	3083.9	2405.2	2531.1	3001.0	3173.9	2487.7	3557.9
DSR	429.5	429.5	380.9	249.7	249.7	249.7	249.7	429.5	429.5	429.5	429.5	434.7	434.7	434.7	434.7	499.3	499.3	499.3	499.3	429.5	429.5
Utah Wind with Tax C	110.0	110.0	0.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	110	110.0
Utah Wind without Tax C	58.0	58.0	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58	1372.2
Utah Geothermal	12.0	12.0	0.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	12	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
U Utah Cogeneration 1	39.0	39.0	0.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0	39.0
T Utah Cogeneration 2	210.0	420.1	0.0	0.0	0.0	420.0	419.9	0.0	0.0	420.0	420.0	0.0	0.0	420.0	420.0	0.0	0.0	420.0	420.1	0	210.0
A Utah Combined Cycle CT	0.0	553.3	0.0	0.0	0.0	678.1	651.3	0.0	0.0	497.7	477.0	0.0	0.0	612.4	480.6	0.0	0.0	557.2	412.6	0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah Coal	1838.8	0.0	2822.8	2941.0	2833.9	0.0	0.0	2787.5	2649.1	0.0	0.0	2787.6	2653.1	0.0	0.0	2740.2	2607.7	0.0	0.0	2835.2	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah Simple Cycle CT	573.7	1315.5	126.8	389.9	384.7	1791.8	1793.8	161.4	177.1	1378.1	1374.8	117.3	129.1	1298.4	1281.6	60.0	69.7	1188.2	1163.1	0	1570.8
Utah Pumped Storage	500.0	500.1	500.0	499.9	500.0	500.0	500.0	500.0	500.0	499.9	500.0	499.9	500.0	500.0	500.0	500.0	499.9	500.0	500.0	500	500.0
	3771.0	3437.5	3830.5	4080.5	4148.3	3828.6	3833.7	3878.4	3935.7	3414.2	3420.3	3839.5	3896.9	3304.5	3335.9	3799.5	3856.6	3203.7	3214.1	3944.7	4243.5
DSR	117.5	117.5	119.8	45.4	45.4	45.4	45.4	117.5	117.5	117.5	117.5	122.3	122.3	122.3	122.3	129.6	129.6	129.6	129.6	117.5	117.5
W Wyo Wind with Tax C	110.0	110.0	0.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	110	110.0
Y Wyo Wind without Tax C	58.0	58.0	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58	1108.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
I Wyo Coal	0.0	0.0	0.0	10.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
	285.5	285.5	119.8	55.6	213.4	195.4	213.4	117.5	285.5	267.5	285.5	122.3	290.3	122.3	290.3	129.6	297.6	129.6	297.6	291.4	1335.5
DSR	1227.0	1227.0	1317.5	565.9	565.9	565.9	565.9	1227.0	1227.0	1227.0	1227.0	1319.7	1319.7	1319.7	1319.7	1481.8	1481.8	1481.8	1481.8	1227	1227.0
T Renewable	529.0	529.0	0.0	0.0	529.0	300.0	529.0	0.0	529.0	300.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	529	3998.6
O Cogeneration	1555.4	2099.1	902.6	1162.3	1088.5	2099.0	2098.9	964.7	894.5	2099.0	2099.0	934.1	871.9	2098.9	2099.2	899.2	834.8	2099.0	2099.1	800.8	1340.5
T Combined Cycle CT	0.0	553.3	0.0	0.0	0.0	915.7	834.7	0.0	0.0	569.6	494.0	0.0	0.0	641.8	480.6	0.0	0.0	565.3	412.6	0	0.0
A Coal	1838.8	0.0	2822.8	2951.2	2833.9	0.0	0.0	2787.5	2649.1	0.0	0.0	2787.6	2653.1	0.0	0.0	2740.2	2607.7	0.0	0.0	2841.1	0.0
L Simple Cycle CT	573.7	1315.5	310.9	792.0	805.3	1791.8	1793.8	393.5	424.2	1378.1	1374.8	317.5	336.4	1298.4	1281.6	213.1	232.1	1188.2	1163.1	325.9	1570.8
Pumped Storage	1000.0	1000.1	1000.0	999.8	1000.0	1000.0	1000.0	1000.0	1000.0	999.9	1000.0	999.9	1000.0	1000.0	1000.0	1000.0	999.9	1000.0	1000.0	1000	1000.0
Total	6723.9	6724.0	6353.8	6471.2	6822.6	6672.4	6822.3	6372.7	6723.8	6573.6	6723.8	6358.8	6710.1	6358.8	6710.1	6334.3	6685.3	6334.3	6685.6	6723.8	9136.9

Summary of Medium High Load Growth
Annual Energy (MWa) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Gas	Low		Medium																	High	
DSM	medium			low				medium				accelerated				high				medium	
Coal	any	no	Uncons-	any		no		any		no		any		no		any		no		any	no
Renewable	strat	strat	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
Case #	62	63	64	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82
DSR	280.8	280.8	318.9	134.1	134.1	134.1	134.1	280.8	280.8	280.8	280.8	300.2	300.2	300.2	300.2	332.1	332.1	332.1	332.1	280.8	280.8
OWC Wind with Tax C	26.3	26.3	0.0	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	26.3	26.3
OWC Wind without Tax C	13.9	13.9	0.0	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	13.9	277.9
O OWC Geothermal	11.2	10.9	0.0	0.0	11.4	0.0	10.9	0.0	11.4	0.0	10.9	0.0	11.4	0.0	10.9	0.0	11.4	0.0	10.9	11.7	11.2
W OWC Cogeneration 1	148.9	297.9	297.9	297.9	297.9	297.2	297.2	297.9	297.9	297.2	297.2	297.9	297.9	297.2	297.4	297.9	297.9	297.3	297.9	297.9	297.9
C OWC Cogeneration 2	1015.5	1225.5	518.1	742.6	683.3	1219.5	1219.5	573.2	510.8	1217.6	1214.8	546.0	490.7	1222.8	1214.2	515.0	457.7	1221.5	1214.6	427.5	704.1
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	221.1	170.7	0.0	0.0	66.9	15.8	0.0	0.0	27.3	0.0	0.0	0.0	7.6	0.0	0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
OWC Simple Cycle CT	0.0	0.0	13.8	30.4	32.0	0.0	0.0	17.3	18.6	0.0	0.0	15.0	15.7	0.0	0.0	11.5	12.3	0.0	0.0	40	0.0
OWC Pumped Storage	45.6	56.7	3.3	3.4	7.1	64.7	64.2	3.6	3.6	63.3	62.3	3.5	3.5	53.6	61.5	3.3	3.3	53.3	66.6	2.8	18.9
	1542.2	1912.0	1152.0	1208.4	1206.0	1936.6	1936.8	1172.8	1163.3	1925.8	1922.0	1162.6	1159.6	1901.1	1924.4	1159.8	1154.9	1911.8	1962.3	1100.9	1617.1
DSR	311.4	311.4	273.0	173.3	173.3	173.3	173.3	311.4	311.4	311.4	311.4	312.5	312.5	312.5	312.5	352.9	352.9	352.9	352.9	311.4	311.4
Utah Wind with Tax C	38.6	38.6	0.0	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	38.6	38.6
Utah Wind without Tax C	20.4	20.4	0.0	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4	20.3	481.7
Utah Geothermal	9.6	10.2	0.0	0.0	9.3	0.0	10.3	0.0	9.3	0.0	10.3	0.0	9.3	0.0	10.3	0.0	9.3	0.0	10.3	9.2	9.7
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
U Utah Cogeneration 1	34.3	36.3	0.0	0.0	0.0	36.0	36.0	0.0	0.0	36.0	36.0	0.0	0.0	36.0	36.0	0.0	0.0	36.0	36.2	0	35.5
T Utah Cogeneration 2	173.0	386.2	0.0	0.0	0.0	377.1	377.1	0.0	0.0	377.1	377.1	0.0	0.0	377.1	377.1	0.0	0.0	377.1	378.1	0	185.8
A Utah Combined Cycle CT	0.0	514.8	0.0	0.0	0.0	626.3	601.6	0.0	0.0	460.1	440.7	0.0	0.0	566.2	444.1	0.0	0.0	516.5	381.4	0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah Coal	1685.1	0.0	2586.9	2695.1	2597.0	0.0	0.0	2554.4	2427.7	0.0	0.0	2554.5	2431.2	0.0	0.0	2511.1	2389.7	0.0	0.0	2598.2	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah Simple Cycle CT	31.9	73.1	7.1	21.7	21.4	99.6	99.7	9.0	9.8	76.6	76.4	6.5	7.2	72.2	71.2	3.3	3.9	66.1	64.7	0	87.3
Utah Pumped Storage	101.0	88.7	124.1	124.1	124.1	109.9	108.1	124.1	124.1	98.6	96.9	124.1	124.1	99.7	96.2	124.1	124.1	95.2	94.4	119.6	75.4
	2405.3	1479.7	2991.1	3014.2	2984.0	1474.9	1465.1	2998.9	2941.2	1412.5	1407.8	2997.6	2943.2	1463.7	1406.4	2991.4	2938.8	1443.8	1377.0	3097.3	1225.4
DSR	101.5	101.5	103.6	41.8	41.8	41.8	41.8	101.5	101.5	101.5	101.5	104.9	104.9	104.9	104.9	110.2	110.2	110.2	110.2	101.5	101.5
W Wyo Wind with Tax C	38.6	38.6	0.0	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	38.6	38.6
Y Wyo Wind without Tax C	20.4	20.4	0.0	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4	20.3	389.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
I Wyo Coal	0.0	0.0	0.0	9.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.4	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
	160.5	160.5	103.6	51.2	100.7	94.5	100.8	101.5	160.4	154.2	160.5	104.9	163.8	104.9	163.9	110.2	169.1	110.2	169.2	165.8	529.1
DSR	693.7	693.7	695.5	349.2	349.2	349.2	349.2	693.7	693.7	693.7	693.7	717.6	717.6	717.6	717.6	795.2	795.2	795.2	795.2	693.7	693.7
T Renewable	179.0	179.3	0.0	0.0	178.7	105.4	179.4	0.0	178.7	105.4	179.4	0.0	178.7	0.0	179.4	0.0	178.7	0.0	179.4	178.9	1273.0
O Cogeneration	1371.7	1945.9	816.0	1040.5	981.2	1929.8	1929.8	871.1	808.7	1927.9	1925.1	843.9	788.6	1933.1	1924.7	812.9	755.6	1931.9	1926.8	725.4	1223.3
T Combined Cycle CT	0.0	514.8	0.0	0.0	0.0	847.4	772.3	0.0	0.0	527.0	456.5	0.0	0.0	593.5	444.1	0.0	0.0	524.1	381.4	0	0.0
A Coal	1685.1	0.0	2586.9	2704.5	2597.0	0.0	0.0	2554.4	2427.7	0.0	0.0	2554.5	2431.2	0.0	0.0	2511.1	2389.7	0.0	0.0	2603.6	0.0
L Simple Cycle CT	31.9	73.1	20.9	52.1	53.4	99.6	99.7	26.3	28.4	76.6	76.4	21.5	22.9	72.2	71.2	14.8	16.2	66.1	64.7	40	87.3
Pumped Storage	146.6	145.4	127.4	127.5	131.2	174.6	172.3	127.7	127.7	161.9	159.2	127.6	127.6	153.3	157.7	127.4	127.4	148.5	161.0	122.4	94.3
Total	4108.0	3552.2	4246.7	4273.8	4290.7	3506.0	3502.7	4273.2	4264.9	3492.5	3490.3	4265.1	4266.6	3469.7	3494.7	4261.4	4262.8	3465.8	3508.5	4364	3371.6

T5-05.aMW.20yr-mh

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Summary of High Load Growth
Percentage of Winter Capacity Additions (%)

Additions in 10 years (1994 - 2003)

	Low		Medium																	High	
DSM	medium			low				medium				accelerated				high				medium	
Coal	any	no	Uncons-	any		no		any		no		any		no		any		no		any	no
Renewable	strat	strat	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
Case #	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100	101	102	103
MW Additions																					
DSR	13.9	13.9	24.3	6.6	6.1	6.3	6.1	15.0	13.9	14.3	13.9	18.4	17.1	17.6	17.1	19.8	18.4	19.0	18.4	13.9	13.2
Renewable	10.3	10.3	0.0	0.0	10.2	6.0	10.2	0.0	10.3	6.0	10.3	0.0	10.4	6.1	10.4	0.0	10.4	6.1	10.4	10.3	17.6
Cogeneration	36.8	40.9	34.0	33.9	31.6	41.7	40.5	34.3	32.0	42.2	40.9	34.5	31.8	42.4	41.1	34.6	31.5	42.5	41.2	29.6	38.8
Combined Cycle CT	0.0	9.2	0.0	0.0	0.0	12.4	10.8	0.0	0.0	8.5	7.8	0.0	0.0	7.8	6.3	0.0	0.0	7.2	5.7	0.0	1.8
Coal	13.3	0.0	21.8	27.7	22.5	0.0	0.0	25.3	20.5	0.0	0.0	24.6	20.2	0.0	0.0	24.3	20.1	0.0	0.0	25.8	0.0
Peaking Resources	25.6	25.6	19.9	31.8	29.6	33.7	32.5	25.4	23.2	28.9	27.0	22.5	20.5	26.1	25.1	21.4	19.6	25.2	24.2	20.4	28.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																					
DSR	13.9	14.0	22.1	6.8	6.7	7.2	7.2	13.5	13.3	14.5	14.3	15.8	15.6	17.0	16.9	16.7	16.5	18.0	17.9	12.8	14.9
Renewable	6.1	6.1	0.0	0.0	5.9	3.8	6.3	0.0	5.8	3.7	6.2	0.0	5.7	3.7	6.2	0.0	5.7	3.7	6.2	5.6	11.6
Cogeneration	54.0	60.4	42.4	46.1	45.8	63.3	63.0	44.7	44.1	63.2	62.0	44.1	43.0	62.4	62.0	44.0	42.5	62.4	62.0	38.1	64.4
Combined Cycle CT	0.0	14.7	0.0	0.0	0.0	20.0	17.7	0.0	0.0	13.3	12.4	0.0	0.0	12.1	10.0	0.0	0.0	11.1	9.1	0.0	3.1
Coal	21.3	0.0	30.6	41.2	35.5	0.0	0.0	36.4	31.3	0.0	0.0	35.0	30.5	0.0	0.0	34.4	30.3	0.0	0.0	38.0	0.0
Peaking Resources	4.8	4.7	4.9	6.0	6.1	5.7	5.8	5.4	5.5	5.2	5.1	5.1	5.2	4.9	4.8	4.9	5.0	4.8	4.8	5.5	5.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Additions in 20 years (1994 - 2013)

	Low		Medium																	High	
DSM	medium			low				medium				accelerated				high				medium	
Coal	any	no	Uncons-	any		no		any		no		any		no		any		no		any	no
Renewable	strat	strat	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
Case #	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100	101	102	103
MW Additions																					
DSR	14.3	14.3	16.8	6.5	6.3	6.4	6.3	14.8	14.3	14.5	14.3	16.6	16.0	16.2	16.0	18.1	17.4	17.7	17.4	14.2	10.5
Renewable	5.5	5.5	0.0	0.0	5.5	3.2	5.5	0.0	5.5	3.2	5.5	0.0	5.6	3.2	5.6	0.0	5.6	3.2	5.6	6.8	42.1
Cogeneration	19.8	22.0	17.9	17.6	17.0	22.1	21.8	17.9	17.2	22.4	22.0	17.9	17.2	22.4	22.1	17.9	17.3	22.5	22.1	17.0	16.2
Combined Cycle CT	2.9	26.0	1.5	3.9	3.3	30.2	29.0	2.0	1.4	26.0	24.7	1.7	1.1	25.7	24.5	1.4	0.8	24.7	23.6	0.0	2.8
Coal	31.8	0.0	42.8	44.6	41.7	0.0	0.0	42.5	39.5	0.0	0.0	42.8	39.7	0.0	0.0	42.3	39.2	0.0	0.0	42.6	0.0
Peaking Resources	25.7	32.2	21.0	27.3	26.3	38.2	37.5	22.8	22.1	33.9	33.4	21.0	20.4	32.4	31.9	20.3	19.7	31.9	31.3	19.3	28.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																					
DSR	13.0	14.1	13.2	6.1	6.1	7.0	7.0	12.5	12.5	14.4	14.4	13.0	13.0	15.0	15.0	14.1	14.1	16.3	16.3	12.0	15.0
Renewable	3.0	3.3	0.0	0.0	2.9	2.0	3.3	0.0	2.9	2.0	3.4	0.0	2.9	2.0	3.4	0.0	2.9	2.0	3.4	3.3	33.9
Cogeneration	28.7	35.0	23.6	23.3	23.2	35.3	35.2	23.5	23.5	35.7	35.8	23.5	23.5	35.8	35.8	23.6	23.6	36.0	36.0	22.9	37.8
Combined Cycle CT	4.3	42.2	2.0	5.5	4.8	48.9	47.6	2.7	2.0	41.9	40.5	2.3	1.6	41.4	40.1	1.9	1.2	39.9	38.6	0.0	6.5
Coal	46.9	0.0	58.2	61.3	59.2	0.0	0.0	58.0	55.9	0.0	0.0	58.2	56.1	0.0	0.0	57.4	55.3	0.0	0.0	59.0	0.0
Peaking Resources	4.1	5.4	3.1	3.9	3.9	6.8	6.7	3.2	3.2	6.0	6.0	3.0	3.0	5.8	5.8	3.0	2.9	5.7	5.7	2.8	6.9
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

T5-06.percent.resource-h

Table 5-6.b

Summary of High Load Growth
Winter Capacity (MW) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Gas	Low		Medium																	High	
DSM	medium			low				medium				accelerated				high				medium	
Coal	any	no	Uncons-	any		no		any		no		any		no		any		no		any	no
Renewable	strat	strat	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
Case #	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100	101	102	103
DSR	422.8	422.8	613.7	163.3	163.3	163.3	163.3	422.8	422.8	422.8	422.8	538.3	538.3	538.3	538.3	580.1	580.1	580.1	580.1	422.8	422.8
OWC Wind with Tax C	110.0	110.0	0.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	110	110.0
OWC Wind without Tax C	58.0	58.0	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58	58.0
O OWC Geothermal	13.0	13.0	0.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	13	13.0
W OWC Cogeneration 1	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320	320.0
C OWC Cogeneration 2	1320.0	1320.0	1279.3	1320.0	1320.0	1320.0	1320.0	1320.0	1320.0	1320.0	1320.0	1320.0	1300.2	1320.0	1320.0	1320.0	1284.6	1320.1	1320.0	1196.5	1320.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
OWC Pumped Storage	14.5	0.0	231.7	290.6	281.6	18.4	30.7	208.5	293.9	0.0	9.5	232.2	248.7	0.0	1.0	220.5	230.8	0.0	0.0	327.1	77.2
	2258.3	2243.8	2444.7	2094.2	2265.9	1821.7	2015.0	2271.3	2537.7	2062.8	2253.3	2410.5	2588.2	2178.3	2360.3	2440.6	2596.5	2220.2	2401.1	2447.4	2321.0
DSR	233.0	233.0	416.9	135.9	135.9	135.9	135.9	233.0	233.0	233.0	233.0	269.9	269.9	269.9	269.9	291.1	291.1	291.1	291.1	233	233.0
Utah Wind with Tax C	110.0	110.0	0.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0	110	110.0
Utah Wind without Tax C	58.0	58.0	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58	479.0
Utah Geothermal	12.0	12.0	0.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	12	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
U Utah Cogeneration 1	39.0	39.0	0.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0	39.0
T Utah Cogeneration 2	210.0	420.0	0.0	0.0	0.0	420.0	420.0	0.0	0.0	420.0	420.0	0.0	0.0	420.0	420.0	0.0	0.0	420.0	420.0	0	420.0
A Utah Combined Cycle CT	0.0	473.2	0.0	0.0	0.0	624.7	557.6	0.0	0.0	423.9	398.5	0.0	0.0	387.5	323.2	0.0	0.0	358.3	292.5	0	96.4
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah Coal	684.3	0.0	990.0	990.0	990.0	0.0	0.0	990.0	990.0	0.0	0.0	990.0	990.0	0.0	0.0	990.0	990.0	0.0	0.0	990	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah Simple Cycle CT	796.3	811.9	204.2	745.4	751.7	1176.9	1152.6	506.9	397.9	940.2	877.1	338.8	299.8	793.6	778.0	292.4	266.5	747.9	734.9	220.2	972.5
Utah Pumped Storage	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	499.9	500.0
	2642.6	2657.1	2111.1	2371.3	2557.6	3046.5	2985.1	2229.9	2300.9	2706.1	2647.6	2098.7	2239.7	2560.0	2510.1	2073.5	2227.6	2506.3	2457.5	2123.1	2861.9
DSR	58.4	58.4	113.3	18.3	18.3	18.3	18.3	58.4	58.4	58.4	58.4	64.6	64.6	64.6	64.6	67.2	67.2	67.2	67.2	58.4	58.4
W Wyo Wind with Tax C	110.0	110.0	0.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0	110	110.0
Y Wyo Wind without Tax C	58.0	58.0	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
I Wyo Coal	0.0	0.0	37.4	351.5	176.7	0.0	0.0	216.6	62.3	0.0	0.0	178.1	42.4	0.0	0.0	161.4	34.5	0.0	0.0	330.3	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
	226.4	226.4	150.7	369.8	363.0	168.3	186.3	275.0	288.7	208.4	226.4	242.7	275.0	214.6	232.6	228.6	269.7	217.2	235.2	556.7	226.4
DSR	714.2	714.2	1143.9	317.5	317.5	317.5	317.5	714.2	714.2	714.2	714.2	872.8	872.8	872.8	872.8	938.4	938.4	938.4	938.4	714.2	714.2
T Renewable	529.0	529.0	0.0	0.0	529.0	300.0	529.0	0.0	529.0	300.0	529.0	0.0	529.0	300.0	529.0	0.0	529.0	300.0	529.0	529	950.0
O Cogeneration	1889.0	2099.0	1599.3	1640.0	1640.0	2099.0	2099.0	1640.0	1640.0	2099.0	2099.0	1640.0	1620.2	2099.0	2099.0	1640.0	1604.6	2099.1	2099.0	1516.5	2099.0
T Combined Cycle CT	0.0	473.2	0.0	0.3	0.0	624.7	557.6	0.0	0.0	423.9	398.5	0.0	0.0	387.5	323.2	0.0	0.0	358.3	292.5	0	96.4
A Coal	684.3	0.0	1027.4	1341.5	1166.7	0.0	0.0	1206.6	1052.3	0.0	0.0	1168.1	1032.4	0.0	0.0	1151.4	1024.5	0.0	0.0	1320.3	0.0
L Simple Cycle CT	796.3	811.9	204.2	745.4	751.7	1176.9	1152.6	506.9	397.9	940.2	877.1	338.8	299.8	793.6	778.0	292.4	266.5	747.9	734.9	220.2	972.5
Pumped Storage	514.5	500.0	731.7	790.6	781.6	518.4	530.7	708.5	793.9	500.0	509.5	732.2	748.7	500.0	501.0	720.5	730.8	500.0	500.0	827	577.2
Total	5127.3	5127.3	4706.5	4835.3	5186.5	5036.5	5186.4	4776.2	5127.3	4977.3	5127.3	4751.9	5102.9	4952.9	5103.0	4742.7	5093.8	4943.7	5093.8	5127.2	5409.3

T5-06.MW.10yr-h

Summary of High Load Growth
Annual Energy (MWa) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Gas	Low		Medium																	High	
DSM	medium		Uncons-	low				medium				accelerated				high				medium	
Coal	any	no		any		no		any		no		any		no		any		no		any	no
Renewable	strat	strat	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
Case #	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100	101	102	103
DSR	180.2	180.2	270.4	88.5	88.5	88.5	88.5	180.2	180.2	180.2	180.2	217.2	217.2	217.2	217.2	231.9	231.9	231.9	231.9	180.2	180.2
OWC Wind with Tax C	26.3	26.3	0.0	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	26.3	26.3
OWC Wind without Tax C	13.9	13.9	0.0	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	13.9	13.9
O OWC Geothermal	10.3	10.3	0.0	0.0	10.1	0.0	10.2	0.0	9.9	0.0	10.1	0.0	9.9	0.0	10.1	0.0	9.9	0.0	10.1	9.9	10.1
W OWC Cogeneration 1	283.5	283.5	283.1	286.9	286.2	290.0	289.8	283.5	286.2	292.7	286.6	283.0	280.9	289.2	285.4	282.3	278.7	289.7	285.9	275.9	292.9
C OWC Cogeneration 2	1092.0	1092.0	1023.8	1087.5	1092.0	1092.0	1092.0	1074.7	1071.4	1092.0	1092.0	1068.6	1052.5	1092.0	1092.0	1066.0	1038.8	1092.0	1092.0	937.9	1092.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
OWC Pumped Storage	2.6	0.0	36.4	40.2	43.3	2.9	4.8	35.3	43.3	0.0	1.4	37.3	39.2	0.0	0.1	33.4	36.4	0.0	0.0	53.4	11.2
	1608.8	1606.2	1613.7	1503.4	1560.3	1473.4	1525.5	1573.7	1631.2	1564.9	1610.5	1606.1	1639.9	1598.4	1645.0	1613.6	1635.9	1613.6	1660.1	1497.5	1627.1
DSR	176.6	176.6	305.2	97.2	97.2	97.2	97.2	176.6	176.6	176.6	176.6	208.8	208.8	208.8	208.8	221.7	221.7	221.7	221.7	176.6	176.6
Utah Wind with Tax C	38.6	38.6	0.0	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6	38.6	38.6
Utah Wind without Tax C	20.4	20.4	0.0	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	20.4	168.2
Utah Geothermal	9.9	9.9	0.0	0.0	9.4	0.0	9.8	0.0	9.3	0.0	9.6	0.0	9.3	0.0	9.6	0.0	9.1	0.0	9.6	9.1	9.7
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
U Utah Cogeneration 1	35.4	35.7	0.0	0.0	0.0	35.7	35.7	0.0	0.0	35.7	35.4	0.0	0.0	35.4	35.4	0.0	0.0	35.7	35.4	0	35.7
T Utah Cogeneration 2	176.1	354.1	0.0	0.0	0.0	361.1	359.2	0.0	0.0	360.0	357.7	0.0	0.0	359.1	358.0	0.0	0.0	360.0	358.6	0	353.3
A Utah Combined Cycle CT	0.0	430.7	0.0	0.0	0.0	560.8	500.2	0.0	0.0	375.8	352.7	0.0	0.0	343.0	286.1	0.0	0.0	317.2	258.9	0	85.4
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah Coal	627.1	0.0	907.2	907.2	907.2	0.0	0.0	907.2	907.2	0.0	0.0	907.2	907.2	0.0	0.0	907.2	907.2	0.0	0.0	907.2	0.0
Utah IGCT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah Simple Cycle CT	44.3	45.1	11.3	41.4	41.8	65.4	64.1	28.2	22.1	52.3	48.8	18.8	16.7	44.1	43.3	16.3	14.8	41.6	40.9	12.2	54.1
Utah Pumped Storage	92.8	92.8	103.2	96.0	98.4	92.8	94.2	100.0	103.9	93.4	94.2	101.3	105.4	93.9	94.6	101.4	105.3	93.7	94.9	111.1	92.8
	1221.2	1203.9	1326.9	1141.8	1213.0	1265.7	1219.4	1212.0	1278.1	1146.5	1134.0	1236.1	1306.4	1137.0	1094.8	1246.6	1317.1	1122.6	1079.0	1275.2	1014.4
DSR	52.0	52.0	104.9	16.5	16.5	16.5	16.5	52.0	52.0	52.0	52.0	56.4	56.4	56.4	56.4	58.2	58.2	58.2	58.2	52	52.0
W Wyo Wind with Tax C	38.6	38.6	0.0	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6	38.6	38.6
Y Wyo Wind without Tax C	20.4	20.4	0.0	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	20.4	20.4
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
I Wyo Coal	0.0	0.0	34.3	322.1	161.9	0.0	0.0	198.5	57.1	0.0	0.0	163.2	38.9	0.0	0.0	147.9	31.6	0.0	0.0	302.7	0.0
N Wyo IGCT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
	111.0	111.0	139.2	338.6	237.4	69.2	75.5	250.5	168.1	104.7	111.0	219.6	154.3	109.1	115.4	206.1	148.8	110.9	117.2	413.7	111.0
DSR	408.8	408.8	680.5	202.2	202.2	202.2	202.2	408.8	408.8	408.8	408.8	482.4	482.4	482.4	482.4	511.8	511.8	511.8	511.8	408.8	408.8
T Renewable	178.4	178.4	0.0	0.0	177.7	105.4	178.2	0.0	177.4	105.4	177.9	0.0	177.4	105.4	177.9	0.0	177.2	105.4	177.9	177.2	325.8
O Cogeneration	1587.0	1765.3	1306.9	1374.4	1378.2	1778.8	1776.7	1358.2	1357.6	1780.4	1771.7	1351.6	1333.4	1775.7	1770.8	1348.3	1317.5	1777.4	1771.9	1213.8	1773.9
T Combined Cycle CT	0.0	430.7	0.0	0.3	0.0	560.8	500.2	0.0	0.0	375.8	352.7	0.0	0.0	343.0	286.1	0.0	0.0	317.2	258.9	0	85.4
A Coal	627.1	0.0	941.5	1229.3	1069.1	0.0	0.0	1105.7	964.3	0.0	0.0	1070.4	946.1	0.0	0.0	1055.1	938.8	0.0	0.0	1209.9	0.0
L Simple Cycle CT	44.3	45.1	11.3	41.4	41.8	65.4	64.1	28.2	22.1	52.3	48.8	18.8	16.7	44.1	43.3	16.3	14.8	41.6	40.9	12.2	54.1
Pumped Storage	95.4	92.8	139.6	136.2	141.7	95.7	99.0	135.3	147.2	93.4	95.6	138.6	144.6	93.9	94.7	134.8	141.7	93.7	94.9	164.5	104.5
Total	2941.0	2921.1	3079.8	2983.8	3010.7	2808.3	2828.4	3036.2	3077.4	2816.1	2855.5	3061.8	3100.6	2844.5	2855.2	3066.3	3101.8	2847.1	2856.3	3186.4	2752.5

T5-06.aMW.10yr-h

Table 5-6.d

Summary of High Load Growth
Winter Capacity (MW) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Gas	Low		Medium																	High	
DSM	medium		Uncons-	low				medium				accelerated				high				medium	
Coal	any	no		any		no		any		no		any		no		any		no		any	no
Renewable	strat	strat	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
Case #	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100	101	102	103
DSR	765.4	765.4	935.7	285.0	285.0	285.0	285.0	765.4	765.4	765.4	765.4	907.4	907.4	907.4	907.4	977.4	977.4	977.4	977.4	765.4	765.4
OWC Wind with Tax C	110.0	110.0	0.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	110	110.0
OWC Wind without Tax C	58.0	58.0	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	187.1	1558.0
O OWC Geothermal	13.0	13.0	0.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	13	13.0
W OWC Cogeneration 1	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320	320.0
C OWC Cogeneration 2	1320.0	1320.0	1320.0	1320.0	1320.0	1320.0	1320.0	1320.0	1320.0	1320.0	1320.0	1320.0	1319.9	1320.0	1320.0	1320.0	1320.0	1320.1	1320.0	1320.1	1320.0
OWC Combined Cycle CT	273.1	866.4	133.2	366.7	320.2	1042.2	997.0	180.6	132.9	887.8	821.5	154.0	103.4	856.0	798.1	128.5	76.9	804.9	752.3	0	208.8
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
OWC Simple Cycle CT	406.0	0.0	462.9	791.1	783.0	542.0	527.8	550.7	543.6	114.7	127.9	471.6	467.4	0.0	3.6	429.9	426.7	0.0	0.0	0	0.0
OWC Pumped Storage	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.1	500.0	500.0	500.0	500.1	500.0	500.0	500.0	500.1	642.6	415.9
	3765.5	3952.8	3671.8	3582.8	3709.2	4009.2	4130.8	3636.7	3762.9	3907.9	4035.9	3673.0	3799.1	3903.4	4030.2	3675.8	3802.0	3922.4	4050.8	500	500.0
																				3858.2	5211.1
DSR	466.2	466.2	462.9	269.0	269.0	269.0	269.0	466.2	466.2	466.2	466.2	471.0	471.0	471.0	471.0	530.0	530.0	530.0	530.0	466.2	466.2
Utah Wind with Tax C	110.0	110.0	0.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0	110	110.0
Utah Wind without Tax C	58.0	58.0	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58	1979.0
Utah Geothermal	12.0	12.0	0.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	12	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
U Utah Cogeneration 1	39.0	39.0	0.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0	39.0
T Utah Cogeneration 2	210.0	420.0	0.0	0.0	0.0	420.0	420.0	0.0	0.0	420.0	420.0	0.0	0.0	420.0	420.0	0.0	0.0	420.0	420.0	0	420.0
A Utah Combined Cycle CT	0.0	1549.9	0.0	0.0	0.0	1595.8	1577.9	0.0	0.0	1404.0	1382.2	0.0	0.0	1397.5	1385.5	0.0	0.0	1362.3	1347.9	0	157.1
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah Coal	3029.7	0.0	3672.2	3763.1	3681.3	0.0	0.0	3621.5	3599.1	0.0	0.0	3669.7	3618.5	0.0	0.0	3631.5	3574.7	0.0	0.0	3775.7	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah Simple Cycle CT	1043.3	2068.0	463.1	745.4	751.7	2069.9	2068.3	545.0	558.9	2062.1	2060.9	449.9	470.7	2036.4	2028.5	425.7	444.0	1976.7	1970.9	220.2	2256.4
Utah Pumped Storage	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	499.9	500.0
	5468.2	5223.1	5098.2	5277.5	5382.0	5043.7	5054.2	5132.7	5304.2	5041.3	5048.3	5090.6	5240.2	5013.9	5024.0	5087.2	5228.7	4978.0	4987.8	5142	5939.7
DSR	131.8	131.8	134.8	49.8	49.8	49.8	49.8	131.8	131.8	131.8	131.8	140.8	140.8	140.8	140.8	146.1	146.1	146.1	146.1	131.8	131.8
W Wyo Wind with Tax C	110.0	110.0	0.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0	110	110.0
Y Wyo Wind without Tax C	58.0	58.0	0.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58	1558.0
O Wyo Combined Cycle CT	0.0	57.9	0.0	0.0	0.0	233.0	222.8	0.0	0.0	152.4	149.6	0.0	0.0	151.6	146.8	0.0	0.0	144.0	137.8	0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
I Wyo Coal	0.0	0.0	247.0	385.7	338.2	0.0	0.0	281.2	166.6	0.0	0.0	254.2	161.5	0.0	0.0	230.2	145.7	0.0	0.0	330.3	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	11.4	21.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
	299.8	357.7	381.8	435.5	556.0	444.2	462.0	413.0	466.4	434.2	449.4	395.0	470.3	442.4	455.6	376.3	459.8	440.1	451.9	630.1	1799.8
DSR	1363.4	1363.4	1533.4	603.8	603.8	603.8	603.8	1363.4	1363.4	1363.4	1363.4	1519.2	1519.2	1519.2	1519.2	1653.5	1653.5	1653.5	1653.5	1363.4	1363.4
T Renewable	529.0	529.0	0.0	0.0	529.0	300.0	529.0	0.0	529.0	300.0	529.0	0.0	529.0	300.0	529.0	0.0	529.0	300.0	529.0	658.1	5450.0
O Cogeneration	1889.0	2099.0	1640.0	1640.0	1640.0	2099.0	2099.0	1640.0	1640.0	2099.0	2099.0	1640.0	1639.9	2099.0	2099.0	1640.0	1640.0	2099.1	2099.0	1640.1	2099.0
T Combined Cycle CT	273.1	2474.2	133.2	366.7	320.2	2871.0	2797.7	180.6	132.9	2444.2	2353.3	154.0	103.4	2405.1	2330.4	128.5	76.9	2311.2	2238.0	0	365.9
A Coal	3029.7	0.0	3919.2	4148.8	4019.5	0.0	0.0	3902.7	3765.7	0.0	0.0	3923.9	3780.0	0.0	0.0	3861.7	3720.4	0.0	0.0	4106	0.0
L Simple Cycle CT	1449.3	2068.0	926.0	1536.5	1534.7	2623.3	2617.5	1095.7	1102.5	2176.8	2188.8	921.5	938.1	2036.4	2032.1	855.6	870.7	1976.7	1970.9	862.8	2672.3
Pumped Storage	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.1	1000.0	1000.0	1000.0	1000.1	1000.0	1000.0	1000.0	1000.1	999.9	1000.0
Total	9533.5	9533.6	9151.8	9295.8	9647.2	9497.1	9647.0	9182.4	9533.5	9383.4	9533.6	9158.6	9509.6	9359.7	9509.8	9139.3	9490.5	9340.5	9490.5	9630.3	12950.6

Table 5-6.e

Summary of High Load Growth
Annual Energy (MWa) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Gas	Low		Medium																	High	
DSM	medium			low				medium				accelerated				high				medium	
Coal	any	no	Uncons-	any		no		any		no		any		no		any		no		any	no
Renewable	strat	strat	trained	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
Case #	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100	101	102	103
DSR	311.9	311.9	358.0	142.4	142.4	142.4	142.4	311.9	311.9	311.9	311.9	341.0	341.0	341.0	341.0	367.3	367.3	367.3	367.3	311.9	311.9
OWC Wind with Tax C	26.3	26.3	0.0	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	26.3	26.3
OWC Wind without Tax C	13.9	13.9	0.0	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	44.7	372.2
O OWC Geothermal	11.2	10.9	0.0	0.0	10.8	0.0	10.9	0.0	11.2	0.0	10.9	0.0	11.2	0.0	10.9	0.0	11.2	0.0	10.9	11	11.0
W OWC Cogeneration 1	297.9	297.5	297.9	297.9	297.9	297.0	297.0	297.9	297.9	297.0	297.0	297.9	297.9	297.0	297.0	297.9	297.9	297.0	297.0	297.9	297.9
C OWC Cogeneration 2	1193.1	1199.2	1155.6	1146.1	1146.1	1192.3	1189.9	1153.0	1152.0	1200.2	1200.0	1154.6	1155.0	1203.9	1200.9	1155.8	1158.7	1206.7	1207.3	1160.9	1227.5
OWC Combined Cycle CT	254.1	806.1	123.9	341.3	297.9	965.2	922.9	168.0	123.6	826.1	764.3	143.3	96.2	796.5	742.6	119.6	71.5	748.9	700.0	0	194.2
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
OWC Simple Cycle CT	29.5	0.0	33.6	61.9	61.4	38.8	37.8	40.0	39.6	8.2	9.2	34.2	33.9	0.0	0.3	31.2	31.0	0.0	0.0	54.6	30.1
OWC Pumped Storage	42.8	82.4	5.1	12.3	13.0	91.6	91.0	5.4	5.4	85.4	82.5	5.2	6.3	82.5	80.8	5.0	7.9	77.6	77.0	4.4	42.0
	2180.7	2748.2	1974.1	2001.9	2009.7	2727.3	2732.1	1976.2	1981.8	2728.8	2716.0	1976.2	1981.7	2720.9	2713.7	1976.8	1985.7	2697.5	2699.7	1911.7	2513.1
DSR	344.2	344.2	339.8	190.8	190.8	190.8	190.8	344.2	344.2	344.2	344.2	342.0	342.0	342.0	342.0	378.0	378.0	378.0	378.0	344.2	344.2
Utah Wind with Tax C	38.6	38.6	0.0	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6	38.6	38.6
Utah Wind without Tax C	20.3	20.4	0.0	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4	20.3	694.7
Utah Geothermal	9.4	10.3	0.0	0.0	9.1	0.0	10.3	0.0	9.1	0.0	10.3	0.0	9.3	0.0	10.3	0.0	9.3	0.0	10.3	9.1	10.2
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
U Utah Cogeneration 1	32.6	36.2	0.0	0.0	0.0	35.7	35.7	0.0	0.0	35.7	35.7	0.0	0.0	35.7	35.7	0.0	0.0	35.7	35.7	0	35.5
T Utah Cogeneration 2	173.0	377.1	0.0	0.0	0.0	377.1	377.1	0.0	0.0	377.1	377.1	0.0	0.0	377.1	376.4	0.0	0.0	377.1	377.1	0	374.4
A Utah Combined Cycle CT	0.0	1439.2	0.0	0.0	0.0	1457.4	1440.8	0.0	0.0	1279.3	1259.3	0.0	0.0	1273.4	1261.7	0.0	0.0	1242.2	1228.3	0	136.5
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah Coal	2776.4	0.0	3365.2	3448.5	3373.5	0.0	0.0	3318.7	3298.2	0.0	0.0	3362.9	3316.0	0.0	0.0	3327.8	3275.8	0.0	0.0	3460	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Utah Simple Cycle CT	58.0	115.0	25.7	41.4	41.8	115.1	115.0	30.3	31.1	114.6	114.6	25.0	26.2	113.2	112.8	23.7	24.7	109.9	109.6	12.2	172.3
Utah Pumped Storage	113.3	96.3	124.1	124.1	124.1	119.8	117.8	124.1	124.1	115.4	115.1	124.1	118.0	115.7	113.9	124.1	116.9	117.1	115.1	109.5	107.1
	3565.8	2477.3	3854.8	3804.8	3798.2	2348.6	2346.5	3817.3	3865.6	2319.0	2315.3	3854.0	3870.4	2309.8	2311.8	3853.6	3863.6	2312.7	2313.1	3993.9	1913.5
DSR	112.6	112.6	115.3	46.0	46.0	46.0	46.0	112.6	112.6	112.6	112.6	118.9	118.9	118.9	118.9	122.7	122.7	122.7	122.7	112.6	112.6
W Wyo Wind with Tax C	38.6	38.6	0.0	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6	38.6	38.6
Y Wyo Wind without Tax C	20.4	20.4	0.0	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4	20.3	546.9
O Wyo Combined Cycle CT	0.0	53.5	0.0	0.0	0.0	213.5	204.2	0.0	0.0	140.1	137.6	0.0	0.0	139.4	135.0	0.0	0.0	132.4	126.7	0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
I Wyo Coal	0.0	0.0	226.3	353.5	310.0	0.0	0.0	257.7	152.7	0.0	0.0	233.0	148.1	0.0	0.0	211.0	133.5	0.0	0.0	302.7	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	1.2	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0.0
	171.6	225.1	341.6	399.5	414.9	313.4	311.4	370.3	324.2	305.4	309.2	351.9	325.9	311.0	312.9	333.7	315.1	307.8	308.4	474.2	698.1
DSR	768.7	768.7	813.1	379.2	379.2	379.2	379.2	768.7	768.7	768.7	768.7	801.9	801.9	801.9	801.9	868.0	868.0	868.0	868.0	768.7	768.7
T Renewable	178.7	179.4	0.0	0.0	177.9	105.4	179.4	0.0	178.3	105.4	179.4	0.0	178.5	105.4	179.4	0.0	178.5	105.4	179.4	208.9	1738.5
O Cogeneration	1696.6	1910.0	1453.5	1444.0	1444.0	1902.1	1899.7	1450.9	1449.9	1910.0	1909.8	1452.5	1452.9	1913.7	1910.0	1453.7	1456.6	1916.5	1917.1	1458.8	1935.3
T Combined Cycle CT	254.1	2298.8	123.9	341.3	297.9	2636.1	2567.9	168.0	123.6	2245.5	2161.2	143.3	96.2	2209.3	2139.3	119.6	71.5	2123.5	2055.0	0	330.7
A Coal	2776.4	0.0	3591.5	3802.0	3683.5	0.0	0.0	3576.4	3450.9	0.0	0.0	3595.9	3464.1	0.0	0.0	3538.8	3409.3	0.0	0.0	3762.7	0.0
L Simple Cycle CT	87.5	115.0	59.3	103.3	103.2	155.1	155.0	70.3	70.7	122.8	123.8	59.2	60.1	113.2	113.1	54.9	55.7	109.9	109.6	66.8	202.4
Pumped Storage	156.1	178.7	129.2	136.4	137.1	211.4	208.8	129.5	129.5	200.8	197.6	129.3	124.3	198.2	194.7	129.1	124.8	194.7	192.1	113.9	149.1
Total	5918.1	5450.6	6170.5	6206.2	6222.8	5389.3	5390.0	6163.8	6171.6	5353.2	5340.5	6182.1	6178.0	5341.7	5338.4	6164.1	6164.4	5318.0	5321.2	6379.8	5124.7

T5 06 aMW 20yr-h

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Summary by Load Level for Any-Coal & Any-Renewable Strategy (AC.AR)
Percentage of Winter Capacity Additions (%)

Additions in 10 years (1994 - 2003)

Load Level	L	ML	M												MH				H			
Gas Price	MG	MG	LG				MG				HG				MG				MG			
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD
Case #	2	7	12	16	20	24	29	33	37	41	46	50	54	58	65	69	73	77	86	90	94	98
MW Additions																						
DSR	100.0	70.2	13.5	29.7	32.9	38.9	13.5	29.7	32.9	38.9	13.5	29.7	32.9	38.9	8.9	20.1	23.7	26.1	6.6	15.0	18.4	19.8
Renewable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cogeneration	0.0	0.0	30.3	23.3	22.5	19.3	19.2	14.7	11.1	8.9	17.4	7.8	7.8	7.9	34.5	29.1	28.3	27.4	33.9	34.3	34.5	34.6
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	29.8	28.5	27.5	25.5	24.9	43.5	39.2	39.7	39.2	47.2	45.1	45.5	44.1	29.4	29.9	29.6	29.4	27.7	25.3	24.6	24.3
Peaking Resources	0.0	0.0	27.6	19.5	19.1	16.9	23.8	16.4	16.3	13.1	21.9	17.4	13.8	9.1	27.2	21.0	18.4	17.1	31.8	25.4	22.5	21.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																						
DSR	100.0	59.4	13.0	26.1	30.3	34.5	12.0	24.6	28.6	32.2	11.8	24.6	27.6	30.9	8.6	17.2	20.0	21.6	6.8	13.5	15.8	16.7
Renewable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cogeneration	0.0	0.0	39.3	29.6	28.5	25.0	23.7	18.4	14.2	11.7	20.4	10.3	9.9	10.0	43.9	36.6	34.9	33.8	46.1	44.7	44.1	44.0
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	40.6	40.8	38.7	35.7	35.6	57.5	52.1	52.4	52.2	61.1	59.9	58.1	56.3	41.2	41.0	40.2	39.9	41.2	36.4	35.0	34.4
Peaking Resources	0.0	0.0	6.9	5.5	5.4	4.9	6.9	4.8	4.9	3.8	6.7	5.2	4.4	2.9	6.3	5.3	5.0	4.7	6.0	5.4	5.1	4.9
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Additions in 20 years (1994 - 2013)

Load Level	L	ML	M												MH				H			
Gas Price	MG	MG	LG				MG				HG				MG				MG			
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD
Case #	2	7	12	16	20	24	29	33	37	41	46	50	54	58	65	69	73	77	86	90	94	98
MW Additions																						
DSR	100.0	60.9	13.7	28.4	29.4	34.9	13.7	28.4	29.4	34.9	13.7	28.4	29.4	34.9	8.7	19.3	20.8	23.4	6.5	14.8	16.6	18.1
Renewable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cogeneration	0.0	0.0	16.5	12.7	12.2	10.4	10.4	8.0	6.0	4.8	9.5	4.2	4.2	4.3	18.0	15.1	14.7	14.2	17.6	17.9	17.9	17.9
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.9	2.0	1.7	1.4
Coal	0.0	24.2	38.3	32.4	31.9	30.1	50.0	38.1	38.8	37.6	50.1	42.3	41.6	38.9	45.6	43.7	43.8	43.3	44.6	42.5	42.8	42.3
Peaking Resources	0.0	15.0	31.6	26.5	26.6	24.6	26.0	25.5	25.8	22.7	26.8	25.1	24.8	21.9	27.7	21.9	20.7	19.2	27.3	22.8	21.0	20.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																						
DSR	100.0	57.7	13.5	27.2	28.4	32.8	12.4	26.4	27.7	31.5	12.5	26.2	27.3	31.1	8.2	16.2	16.8	18.7	6.1	12.5	13.0	14.1
Renewable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cogeneration	0.0	0.0	24.0	18.8	18.2	15.8	14.2	11.8	9.1	7.3	13.0	6.4	6.4	6.5	24.3	20.4	19.8	19.1	23.3	23.5	23.5	23.6
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5	2.7	2.3	1.9
Coal	0.0	36.6	57.4	49.7	49.1	47.1	68.6	56.7	58.2	56.4	69.6	62.5	61.4	57.8	63.3	59.8	59.9	58.9	61.3	58.0	58.2	57.4
Peaking Resources	0.0	5.6	5.1	4.3	4.3	4.3	4.8	5.1	5.0	4.8	4.9	5.0	4.8	4.6	4.2	3.6	3.5	3.3	3.9	3.2	3.0	3.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

T5-07.ac.ar.percentage

Table 5-7.b

Summary by Load Level for Any-Coal & Any-Renewable Strategy (AC.AR)
Winter Capacity (MW) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Load Level	L	ML	M												MH				H			
Gas Price	MG	MG	LG				MG				HG				MG				MG			
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD
Case #	2	7	12	16	20	24	29	33	37	41	46	50	54	58	65	69	73	77	86	90	94	98
DSR	318.9	336.7	149.3	359.2	381.8	468.6	149.3	359.2	381.8	468.6	149.3	359.2	381.8	468.6	156.9	393.4	470.2	519.8	163.3	422.8	538.3	580.1
OWC Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O OWC Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	197.3	160.0	183.4	179.2	160.0	160.0	160.0	160.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
C OWC Cogeneration 2	0.0	0.0	636.4	477.9	459.7	390.2	204.7	142.0	43.7	0.3	204.7	0.0	0.0	0.0	842.3	644.7	614.1	579.2	1320.0	1320.0	1320.0	1320.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	116.2	48.2	61.2	37.2	290.6	208.5	232.2	220.5
	318.9	336.7	785.7	837.1	841.5	858.8	551.3	661.2	608.9	648.1	514.0	519.2	541.8	628.6	1435.4	1406.[illegible]	1465.5	1456.2	2094.2	2271.3	2410.5	2440.6
DSR	179.2	189.3	118.5	200.8	238.9	261.4	118.5	200.8	238.9	261.4	118.5	200.8	238.9	261.4	127.0	217.8	252.7	277.2	135.9	233.0	269.9	291.1
Utah Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	242.8	597.7	563.9	519.6	504.4	912.1	802.5	809.1	792.4	990.0	924.0	927.3	892.5	990.0	990.0	976.6	967.2	990.0	990.0	990.0	990.0
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	118.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	300.9	148.1	46.4	26.0	745.4	506.9	338.8	292.4
Utah Pumped Storage	0.0	0.0	461.1	398.8	390.2	341.3	500.0	336.2	333.3	264.0	459.4	356.6	282.2	183.3	499.9	500.0	499.9	500.0	500.0	500.0	500.0	500.0
	179.2	432.1	1296.1	1163.5	1148.7	1107.1	1530.6	1339.5	1381.3	1317.8	1567.9	1481.4	1448.4	1337.2	1917.8	1855.9	1775.6	1770.4	2371.3	2229.9	2098.7	2073.5
DSR	42.5	44.9	15.8	48.2	49.6	56.4	15.8	48.2	49.6	56.4	15.8	48.2	49.6	56.4	17.0	53.7	57.5	61.0	18.3	58.4	64.6	67.2
W Wyo Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Y Wyo Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	351.5	216.6	178.1	161.4
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	42.5	44.9	15.8	48.2	49.6	56.4	15.8	48.2	49.6	56.4	15.8	48.2	49.6	56.4	17.0	53.7	57.5	61.0	369.8	275.0	242.7	228.6
DSR	540.6	570.9	283.6	608.2	670.3	786.4	283.6	608.2	670.3	786.4	283.6	608.2	670.3	786.4	300.9	664.9	780.4	858.0	317.5	714.2	872.8	938.4
T Renewable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O Cogeneration	0.0	0.0	636.4	477.9	459.7	390.2	402.0	302.0	227.1	179.5	364.7	160.0	160.0	160.0	1162.3	964.7	934.1	899.2	1640.0	1640.0	1640.0	1640.0
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0
A Coal	0.0	242.8	597.7	563.9	519.6	504.4	912.1	802.5	809.1	792.4	990.0	924.0	927.3	892.5	990.0	990.0	976.6	967.2	1341.5	1206.6	1168.1	1151.4
L Simple Cycle CT	0.0	0.0	118.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	300.9	148.1	46.4	26.0	745.4	506.9	338.8	292.4
Pumped Storage	0.0	0.0	461.1	398.8	390.2	341.3	500.0	336.2	333.3	264.0	459.4	356.6	282.2	183.3	616.1	548.2	561.1	537.2	790.6	708.5	732.2	720.5
Total	540.6	813.7	2097.6	2048.8	2039.8	2022.3	2097.7	2048.9	2039.8	2022.3	2097.7	2048.8	2039.8	2022.2	3370.2	3315.9	3298.6	3287.6	4835.3	4776.2	4751.9	4742.7

Summary by Load Level for Any-Coal & Any-Renewable Strategy (AC.AR)
Annual Energy (MWa) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Load Level	L	ML	M												MH				H			
Gas Price	MG	MG	LG				MG				HG				MG				MG			
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD
Case #	2	7	12	16	20	24	29	33	37	41	46	50	54	58	65	69	73	77	86	90	94	98
DSR	139.3	146.3	79.1	155.4	176.0	200.9	79.1	155.4	176.0	200.9	79.1	155.4	176.0	200.9	84.3	168.7	198.8	216.1	88.5	180.2	217.2	231.9
OWC Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O OWC Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	175.4	142.2	163.1	162.7	139.5	145.5	145.3	145.3	277.8	277.5	277.7	277.6	286.9	283.5	283.0	282.3
C OWC Cogeneration 2	0.0	0.0	526.5	395.3	380.3	324.5	169.3	117.5	37.1	0.3	163.6	0.0	0.0	0.0	689.0	532.0	499.0	473.0	1087.5	1074.7	1068.6	1066.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.7	8.9	11.4	6.9	40.2	35.3	37.3	33.4
	139.3	146.3	605.6	550.7	556.3	525.4	423.8	415.1	376.2	363.9	382.2	300.9	321.3	346.2	1068.8	987.1	986.9	973.6	1503.4	1573.7	1606.1	1613.6
DSR	128.7	137.7	81.3	148.9	183.2	197.7	81.3	148.9	183.2	197.7	81.3	148.9	183.2	197.7	89.2	163.0	195.0	210.2	97.2	176.6	208.8	221.7
Utah Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	222.5	547.8	516.8	476.1	462.2	835.9	735.4	741.4	726.1	907.2	846.8	849.8	817.9	907.2	907.2	895.0	886.3	907.2	907.2	907.2	907.2
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	6.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.7	8.2	2.6	1.4	41.4	28.2	18.8	16.3
Utah Pumped Storage	0.0	0.0	85.6	74.0	72.4	63.4	99.8	68.3	69.1	53.2	99.9	73.8	63.9	41.5	104.7	99.4	98.0	96.8	96.0	100.0	101.3	101.4
	128.7	360.2	721.3	739.7	731.7	723.3	1017.0	952.6	993.7	977.0	1088.4	1069.5	1096.9	1057.1	1117.8	1177.8	1190.6	1194.7	1141.8	1212.0	1236.1	1246.6
DSR	38.8	41.2	14.2	43.5	44.8	49.7	14.2	43.5	44.8	49.7	14.2	43.5	44.8	49.7	15.3	48.2	50.8	53.3	16.5	52.0	56.4	58.2
W Wyo Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Y Wyo Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	322.1	198.5	163.2	147.9
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	38.8	41.2	14.2	43.5	44.8	49.7	14.2	43.5	44.8	49.7	14.2	43.5	44.8	49.7	15.3	48.2	50.8	53.3	338.6	250.5	219.6	206.1
DSR	306.8	325.2	174.6	347.8	404.0	448.3	174.6	347.8	404.0	448.3	174.6	347.8	404.0	448.3	188.8	379.9	444.6	479.6	202.2	408.8	482.4	511.8
T Renewable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O Cogeneration	0.0	0.0	526.5	395.3	380.3	324.5	344.7	259.7	200.2	163.0	303.1	145.5	145.3	145.3	966.8	809.5	776.7	750.6	1374.4	1358.2	1351.6	1348.3
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0
A Coal	0.0	222.5	547.8	516.8	476.1	462.2	835.9	735.4	741.4	726.1	907.2	846.8	849.8	817.9	907.2	907.2	895.0	886.3	1229.3	1105.7	1070.4	1055.1
L Simple Cycle CT	0.0	0.0	6.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.7	8.2	2.6	1.4	41.4	28.2	18.8	16.3
Pumped Storage	0.0	0.0	85.6	74.0	72.4	63.4	99.8	68.3	69.1	53.2	99.9	73.8	63.9	41.5	122.4	108.3	109.4	103.7	136.2	135.3	138.6	134.8
Total	306.8	547.7	1341.1	1333.9	1332.8	1298.4	1455.0	1411.2	1414.7	1390.6	1484.8	1413.9	1463.0	1453.0	2201.9	2213.1	2228.3	2221.6	2983.8	3036.2	3061.8	3066.3

T5-07.ac.ar.aMW-10yrs

Summary by Load Level for Any-Coal & Any-Renewable Strategy (AC.AR)
Winter Capacity (MW) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

	Load Level	L	ML	M												MH				H			
	Gas Price	MG	MG	LG				MG				HG				MG				MG			
	DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD
	Case #	2	7	12	16	20	24	29	33	37	41	46	50	54	58	65	69	73	77	86	90	94	98
	DSR	449.7	509.0	254.7	577.1	587.2	724.2	254.7	577.1	587.2	724.2	254.7	577.1	587.2	724.2	270.8	680.0	762.7	852.9	285.0	765.4	907.4	977.4
	OWC Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	OWC Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O	OWC Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W	OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	197.3	160.0	183.4	179.2	160.0	160.0	160.0	160.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
C	OWC Cogeneration 2	0.0	0.0	636.4	477.9	459.7	390.2	204.7	142.0	43.7	0.3	204.7	0.0	0.0	0.0	842.3	644.7	614.1	579.2	1320.0	1320.0	1320.0	1320.0
	OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	366.7	180.6	154.0	128.5
	OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.7	0.0	0.0	0.0	402.1	232.1	200.2	153.1	791.1	550.7	471.6	429.9
	OWC Pumped Storage	0.0	0.0	500.0	500.0	500.0	419.4	500.0	461.4	470.4	348.2	500.0	445.4	435.4	319.7	499.9	500.0	500.0	500.0	500.0	500.0	500.0	500.0
		449.7	509.0	1391.1	1555.0	1546.9	1533.8	1156.7	1340.5	1284.7	1251.9	1151.1	1182.5	1182.6	1203.9	2335.1	2376.8	2397.0	2405.2	3582.8	3636.7	3673.0	3675.8
	DSR	331.2	356.9	230.7	390.0	414.2	463.5	230.7	390.0	414.2	463.5	230.7	390.0	414.2	463.5	249.7	429.5	434.7	499.3	269.0	466.2	471.0	530.0
	Utah Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U	Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T	Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A	Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H	Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah Coal	0.0	379.3	1474.0	1222.4	1201.0	1124.2	1924.8	1436.9	1463.1	1406.2	1930.4	1595.0	1565.3	1454.1	2941.0	2787.5	2787.6	2740.2	3763.1	3621.5	3669.7	3631.5
	Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah Simple Cycle CT	0.0	0.0	216.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	389.9	161.4	117.3	60.0	745.4	545.0	449.9	425.7
	Utah Pumped Storage	0.0	235.4	499.9	500.0	500.0	500.0	500.0	500.1	500.0	500.1	499.9	500.0	500.0	499.9	499.9	500.0	499.9	500.0	500.0	500.0	500.0	500.0
		331.2	971.6	2420.9	2112.4	2115.2	2087.7	2655.5	2327.0	2377.3	2369.8	2661.0	2485.0	2479.5	2417.5	4080.5	3878.4	3839.5	3799.5	5277.5	5132.7	5090.6	5087.2
	DSR	83.1	89.8	41.0	104.1	104.2	115.2	41.0	104.1	104.2	115.2	41.0	104.1	104.2	115.2	45.4	117.5	122.3	129.6	49.8	131.8	140.8	146.1
W	Wyo Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Y	Wyo Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O	Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M	Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I	Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.2	0.0	0.0	0.0	385.7	281.2	254.2	230.2
N	Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G	Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		83.1	89.8	41.0	104.1	104.2	115.2	41.0	104.1	104.2	115.2	41.0	104.1	104.2	115.2	55.6	117.5	122.3	129.6	435.5	413.0	395.0	376.3
	DSR	864.0	955.7	526.4	1071.2	1105.6	1302.9	526.4	1071.2	1105.6	1302.9	526.4	1071.2	1105.6	1302.9	565.9	1227.0	1319.7	1481.8	603.8	1363.4	1519.2	1653.5
T	Renewable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O	Cogeneration	0.0	0.0	636.4	477.9	459.7	390.2	402.0	302.0	227.1	179.5	364.7	160.0	160.0	160.0	1162.3	964.7	934.1	899.2	1640.0	1640.0	1640.0	1640.0
T	Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	366.7	180.6	154.0	128.5
A	Coal	0.0	379.3	1474.0	1222.4	1201.0	1124.2	1924.8	1436.9	1463.1	1406.2	1930.4	1595.0	1565.3	1454.1	2951.2	2787.5	2787.6	2740.2	4148.8	3902.7	3923.9	3861.7
L	Simple Cycle CT	0.0	0.0	216.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.7	0.0	0.0	0.0	792.0	393.5	317.5	213.1	1536.5	1095.7	921.5	855.6
	Pumped Storage	0.0	235.4	999.9	1000.0	1000.0	919.4	1000.0	961.5	970.4	848.3	999.9	945.4	935.4	819.6	999.8	1000.0	999.9	1000.0	1000.0	1000.0	1000.0	1000.0
	Total	864.0	1570.4	3853.0	3771.5	3766.3	3736.7	3853.2	3771.6	3766.2	3736.9	3853.1	3771.6	3766.3	3736.6	6471.2	6372.7	6358.8	6334.3	9295.8	9182.4	9158.6	9139.3

T5-07.ac.ar.MW add 20yrs

Summary by Load Level for Any-Coal & Any-Renewable Strategy (AC.AR)
Annual Energy (MWa) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load Level	L	ML	M												MH				H			
Gas Price	MG	MG	LG				MG				HG				MG				MG			
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD
Case #	2	7	12	16	20	24	29	33	37	41	46	50	54	58	65	69	73	77	86	90	94	98
DSR	198.5	219.1	124.3	244.4	252.9	294.3	124.3	244.4	252.9	294.3	124.3	244.4	252.9	294.3	134.1	280.8	300.2	332.1	142.4	311.9	341.0	367.3
OWC Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O OWC Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	183.7	148.9	170.7	166.8	148.9	148.9	148.9	148.9	297.9	297.9	297.9	297.9	297.9	297.9	297.9	297.9
C OWC Cogeneration 2	0.0	0.0	565.8	424.9	408.7	346.9	182.0	126.2	38.9	0.3	182.0	0.0	0.0	0.0	742.6	573.2	546.0	515.0	1146.1	1153.0	1154.6	1155.8
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	341.3	168.0	143.3	119.6
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	30.4	17.3	15.0	11.5	61.9	40.0	34.2	31.2
OWC Pumped Storage	0.0	0.0	9.3	1.4	1.4	0.7	3.9	1.6	1.9	1.5	4.0	2.4	2.2	1.6	3.4	3.6	3.5	3.3	12.3	5.4	5.2	5.0
	198.5	219.1	699.4	670.7	663.0	641.9	493.9	521.1	464.4	462.9	461.6	395.7	404.0	444.8	1208.4	1172.8	1162.6	1159.8	2001.9	1976.2	1976.2	1976.8
DSR	225.0	247.6	156.2	277.2	293.7	324.5	156.2	277.2	293.7	324.5	156.2	277.2	293.7	324.5	173.3	311.4	312.5	352.9	190.8	344.2	342.0	378.0
Utah Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	347.6	1350.8	1120.3	1100.6	1030.2	1763.8	1316.9	1340.8	1288.5	1769.0	1461.7	1434.4	1332.5	2695.1	2554.4	2554.5	2511.1	3448.5	3318.7	3362.9	3327.8
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.7	9.0	6.5	3.3	41.4	30.3	25.0	23.7
Utah Pumped Storage	0.0	53.3	99.2	94.8	94.3	93.2	118.4	117.3	113.3	108.3	118.2	113.5	110.8	105.5	124.1	124.1	124.1	124.1	124.1	124.1	124.1	124.1
	225.0	648.5	1618.2	1492.3	1488.6	1447.9	2038.4	1711.4	1747.8	1721.3	2043.4	1852.4	1838.9	1762.5	3014.2	2998.9	2997.6	2991.4	3804.8	3817.3	3854.0	3853.6
DSR	74.4	80.9	37.6	91.2	91.5	99.5	37.6	91.2	91.5	99.5	37.6	91.2	91.5	99.5	41.8	101.5	104.9	110.2	46.0	112.6	118.9	122.7
W Wyo Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Y Wyo Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.4	0.0	0.0	0.0	353.5	257.7	233.0	211.0
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	74.4	80.9	37.6	91.2	91.5	99.5	37.6	91.2	91.5	99.5	37.6	91.2	91.5	99.5	51.2	101.5	104.9	110.2	399.5	370.3	351.9	333.7
DSR	497.9	547.6	318.1	612.8	638.1	718.3	318.1	612.8	638.1	718.3	318.1	612.8	638.1	718.3	349.2	693.7	717.6	795.2	379.2	768.7	801.9	868.0
T Renewable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O Cogeneration	0.0	0.0	565.8	424.9	408.7	346.9	365.7	275.1	209.6	167.1	330.9	148.9	148.9	148.9	1040.5	871.1	843.9	812.9	1444.0	1450.9	1452.5	1453.7
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	341.3	168.0	143.3	119.6
A Coal	0.0	347.6	1350.8	1120.3	1100.6	1030.2	1763.8	1316.9	1340.8	1288.5	1769.0	1461.7	1434.4	1332.5	2704.5	2554.4	2554.5	2511.1	3802.0	3576.4	3595.9	3538.8
L Simple Cycle CT	0.0	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	0.0	52.1	26.3	21.5	14.8	103.3	70.3	59.2	54.9
Pumped Storage	0.0	53.3	108.5	96.2	95.7	93.9	122.3	118.9	115.2	109.8	122.2	115.9	113.0	107.1	127.5	127.7	127.6	127.4	136.4	129.5	129.3	129.1
Total	497.9	948.5	2355.2	2254.2	2243.1	2189.3	2569.9	2323.7	2303.7	2283.7	2542.6	2339.3	2334.4	2306.8	4273.8	4273.2	4265.1	4261.4	6206.2	6163.8	6182.1	6164.1

T5-07.ac.ar.aMW-20yrs

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Summary by Load Level for Any-Coal & Strategic-Renewable Strategy (AC.SR)
Percentage of Winter Capacity Additions (%)

Additions in 10 years (1994 - 2003)

Load Level	L	ML	M												MH						H					
Gas Price	MG	MG	LG				MG				HG				LG	MG				HG	LG	MG				HG
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	MD	LD	MD	AD	HD	MD	MD	LD	MD	AD	HD	MD
Case #	3	8	13	17	21	25	30	34	38	42	47	51	55	59	62	66	70	74	78	81	83	87	91	95	99	102
MW Additions																										
DSR	50.5	49.0	11.6	25.3	28.0	33.1	11.6	25.3	28.0	33.1	11.6	25.3	28.0	33.1	18.1	8.1	18.1	21.4	23.6	18.1	13.9	6.1	13.9	17.1	18.4	13.9
Renewable	49.5	45.4	21.6	22.0	22.1	22.3	21.6	22.0	22.1	22.3	21.6	22.0	22.1	22.3	14.4	14.2	14.4	14.5	14.5	14.4	10.3	10.2	10.3	10.4	10.4	10.3
Cogeneration	0.0	0.0	23.7	17.7	16.6	13.7	14.2	11.5	7.5	5.6	12.2	11.5	6.7	5.6	42.4	29.2	24.4	23.9	22.9	21.8	36.8	31.6	32.0	31.8	31.5	29.6
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	3.2	19.1	17.8	16.5	16.8	33.4	29.2	30.1	29.4	36.2	31.3	31.7	31.2	6.3	24.8	24.4	23.5	23.4	27.2	13.3	22.5	20.5	20.2	20.1	25.8
Peaking Resources	0.0	2.4	23.9	17.1	16.7	14.1	19.2	12.0	12.2	9.5	18.4	9.8	11.5	7.8	18.7	23.7	18.6	16.7	15.5	18.4	25.6	29.6	23.2	20.5	19.6	20.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																										
DSR	63.4	59.8	12.8	25.8	30.0	33.8	11.7	23.7	27.6	31.2	11.6	23.2	27.4	30.7	17.6	8.4	16.9	19.7	21.4	16.8	13.9	6.7	13.3	15.6	16.5	12.8
Renewable	36.6	32.7	13.1	13.2	13.2	13.5	11.8	12.1	12.2	12.4	11.7	11.9	12.0	12.2	8.2	7.9	7.9	7.9	7.9	7.8	6.1	5.9	5.8	5.7	5.7	5.6
Cogeneration	0.0	0.0	35.4	26.1	24.3	20.4	19.9	16.1	10.6	8.5	16.3	15.3	9.3	7.8	59.5	39.9	33.3	32.2	31.0	29.2	54.0	45.8	44.1	43.0	42.5	38.1
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	6.3	31.5	29.1	26.9	27.6	50.1	43.7	45.0	44.5	53.7	46.0	47.0	46.5	9.8	37.6	36.6	35.0	34.8	40.4	21.3	35.5	31.3	30.5	30.3	38.0
Peaking Resources	0.0	1.1	7.2	5.7	5.5	4.7	6.5	4.4	4.5	3.6	6.7	3.6	4.2	2.9	4.8	6.2	5.3	5.2	4.9	5.8	4.8	6.1	5.5	5.2	5.0	5.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Additions in 20 years (1994 - 2013)

Load Level	L	ML	M												MH						H					
Gas Price	MG	MG	LG				MG				HG				LG	MG				HG	LG	MG				HG
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	MD	LD	MD	AD	HD	MD	MD	LD	MD	AD	HD	MD
Case #	3	8	13	17	21	25	30	34	38	42	47	51	55	59	62	66	70	74	78	81	83	87	91	95	99	102
MW Additions																										
DSR	62.0	49.7	12.5	26.0	26.9	31.9	12.5	26.0	26.9	31.9	12.5	26.0	26.9	31.9	18.2	8.3	18.2	19.7	22.2	18.2	14.3	6.3	14.3	16.0	17.4	14.2
Renewable	38.0	27.5	12.6	12.8	12.8	12.9	12.6	12.8	12.8	12.9	12.6	12.8	12.8	12.9	7.9	7.8	7.9	7.9	7.9	7.9	5.5	5.5	5.5	5.6	5.6	6.8
Cogeneration	0.0	0.0	13.8	10.3	9.6	7.9	8.2	6.7	4.4	3.3	7.1	6.7	3.9	3.2	23.1	16.0	13.3	13.0	12.5	11.9	19.8	17.0	17.2	17.2	17.3	17.0
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.9	3.3	1.4	1.1	0.8	0.0
Coal	0.0	8.9	31.3	26.6	26.4	24.6	42.8	30.9	32.0	30.9	43.0	33.9	34.7	32.5	27.3	41.5	39.4	39.5	39.0	42.3	31.8	41.7	39.5	39.7	39.2	42.6
Peaking Resources	0.0	13.9	29.8	24.3	24.3	22.7	23.9	23.6	23.9	21.0	24.8	20.6	21.7	19.4	23.4	26.5	21.2	19.9	18.4	19.7	25.7	26.3	22.1	20.4	19.7	19.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																										
DSR	73.8	58.1	13.6	27.0	28.2	32.6	12.3	26.4	27.7	31.5	12.5	25.1	26.7	30.5	16.9	8.1	16.3	16.8	18.7	15.9	13.0	6.1	12.5	13.0	14.1	12.0
Renewable	26.2	18.9	7.7	7.9	7.9	8.1	6.9	7.7	7.8	7.9	7.0	7.3	7.5	7.6	4.4	4.2	4.2	4.2	4.2	4.1	3.0	2.9	2.9	2.9	2.9	3.3
Cogeneration	0.0	0.0	22.1	16.6	15.6	13.1	12.2	10.8	7.3	5.5	10.7	10.3	6.2	5.2	33.4	22.9	19.0	18.5	17.7	16.6	28.7	23.2	23.5	23.5	23.6	22.9
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.3	4.8	2.0	1.6	1.2	0.0
Coal	0.0	16.6	51.5	44.3	44.0	41.9	63.8	50.3	52.5	50.7	64.9	52.5	54.7	51.8	41.0	60.5	56.9	57.0	56.1	59.7	46.9	59.2	55.9	56.1	55.3	59.0
Peaking Resources	0.0	6.4	5.2	4.2	4.2	4.3	4.7	4.8	4.7	4.6	4.9	4.7	4.9	4.8	4.3	4.3	3.7	3.5	3.4	3.7	4.1	3.9	3.2	3.0	2.9	2.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

T5-08.ac.sr.percentage

Table 5-8.b

Summary by Load Level for Any-Coal & Strategic-Renewable Strategy (AC.SR)
Winter Capacity (MW) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Load Level	L	ML	M												MH						H					
Gas Price	MG	MG	LG				MG				HG				LG	MG				HG	LG	MG				HG
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	MD	LD	MD	AD	HD	MD	MD	LD	MD	AD	HD	MD
Case #	3	8	13	17	21	25	30	34	38	42	47	51	55	59	62	66	70	74	78	81	83	87	91	95	99	102
DSR	318.9	336.7	149.3	359.2	381.8	468.6	149.3	359.2	381.8	468.6	149.3	359.2	381.8	468.6	393.4	156.9	393.4	470.2	519.8	393.4	422.8	163.3	422.8	538.3	580.1	422.8
OWC Wind with Tax C	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
OWC Wind without Tax C	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0
O OWC Geothermal	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	168.5	160.0	162.9	133.9	160.0	160.0	160.0	132.7	160.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
C OWC Cogeneration 2	0.0	0.0	581.5	425.1	396.1	324.3	178.3	115.6	17.3	0.0	139.1	115.6	0.0	0.0	1146.4	768.5	574.5	551.9	514.8	480.8	1320.0	1320.0	1320.0	1300.2	1284.6	1196.5
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.6	146.9	73.0	80.9	54.7	176.4	14.5	281.6	293.9	248.7	230.8	327.1
	499.9	517.7	911.8	965.3	958.9	973.9	677.1	815.8	743.0	783.5	629.4	815.8	722.8	782.3	1894.4	1573.3	1541.9	1604.0	1590.3	1551.6	2258.3	2265.9	2537.7	2588.2	2596.5	2447.4
DSR	179.2	189.3	118.5	200.8	238.9	261.4	118.5	200.8	238.9	261.4	118.5	200.8	238.9	261.4	217.8	127.0	217.8	252.7	277.2	217.8	233.0	135.9	233.0	269.9	291.1	233.0
Utah Wind with Tax C	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
Utah Wind without Tax C	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0
Utah Geothermal	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	39.0	0.0	0.0	0.0	0.0	0.0	39.0	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	210.0	0.0	0.0	0.0	0.0	0.0	210.0	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	37.6	468.3	427.9	395.4	399.4	818.7	699.7	718.8	698.4	885.3	751.1	757.7	741.0	231.7	922.6	894.8	859.4	852.2	990.0	684.3	990.0	990.0	990.0	990.0	990.0
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	86.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	172.5	233.6	110.8	28.2	10.0	0.0	796.3	751.7	397.9	299.8	266.5	220.2
Utah Pumped Storage	0.0	27.4	500.0	409.6	400.0	334.3	470.8	287.4	292.5	225.6	451.8	236.0	273.9	184.3	500.0	500.0	500.0	500.0	499.9	500.0	500.0	500.0	500.0	500.0	500.0	499.9
	359.2	434.3	1353.3	1218.3	1214.3	1175.1	1588.0	1367.9	1430.2	1365.4	1635.6	1367.9	1450.5	1366.7	1551.0	1963.2	1903.4	1820.3	1819.3	1887.8	2642.6	2557.6	2300.9	2239.7	2227.6	2123.1
DSR	42.5	44.9	15.8	48.2	49.6	56.4	15.8	48.2	49.6	56.4	15.8	48.2	49.6	56.4	53.7	17.0	53.7	57.5	61.0	53.7	58.4	18.3	58.4	64.6	67.2	58.4
W Wyo Wind with Tax C	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
Y Wyo Wind without Tax C	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	0.0	176.7	62.3	42.4	34.5	330.3
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	210.5	212.9	183.8	216.2	217.6	224.4	183.8	216.2	217.6	224.4	183.8	216.2	217.6	224.4	221.7	185.0	221.7	225.5	229.0	227.6	226.4	363.0	288.7	275.0	269.7	556.7
DSR	540.6	570.9	283.6	608.2	670.3	786.4	283.6	608.2	670.3	786.4	283.6	608.2	670.3	786.4	664.9	300.9	664.9	780.4	858.0	664.9	714.2	317.5	714.2	872.8	938.4	714.2
T Renewable	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0
O Cogeneration	0.0	0.0	581.5	425.1	396.1	324.3	346.8	275.6	180.2	133.9	299.1	275.6	160.0	132.7	1555.4	1088.5	894.5	871.9	834.8	800.8	1889.0	1640.0	1640.0	1620.2	1604.6	1516.5
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	0.0	37.6	468.3	427.9	395.4	399.4	818.7	699.7	718.8	698.4	885.3	751.1	757.7	741.0	231.7	922.6	894.8	859.4	852.2	995.9	684.3	1166.7	1052.3	1032.4	1024.5	1320.3
L Simple Cycle CT	0.0	0.0	86.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	172.5	233.6	110.8	28.2	10.0	0.0	796.3	751.7	397.9	299.8	266.5	220.2
Pumped Storage	0.0	27.4	500.0	409.6	400.0	334.3	470.8	287.4	292.5	225.6	451.8	236.0	273.9	184.3	513.6	646.9	573.0	580.9	554.6	676.4	514.5	781.6	793.9	748.7	730.8	827.0
Total	1069.6	1164.9	2448.9	2399.8	2390.8	2373.4	2448.9	2399.9	2390.8	2373.3	2448.8	2399.9	2390.9	2373.4	3667.1	3721.5	3667.0	3649.8	3638.6	3667.0	5127.3	5186.5	5127.3	5102.9	5093.8	5127.2

Summary by Load Level for Any-Coal & Strategic-Renewable Strategy (AC.SR)
Annual Energy (MWa) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Load Level	L	ML	M												MH						H					
Gas Price	MG	MG	LG				MG				HG				LG	MG				HG	LG	MG				HG
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	MD	LD	MD	AD	HD	MD	MD	LD	MD	AD	HD	MD
Case #	3	8	13	17	21	25	30	34	38	42	47	51	55	59	62	66	70	74	78	81	83	87	91	95	99	102
DSR	139.3	146.3	79.1	155.4	176.0	200.9	79.1	155.4	176.0	200.9	79.1	155.4	176.0	200.9	168.7	84.3	168.7	198.8	216.1	168.7	180.2	88.5	180.2	217.2	231.9	180.2
OWC Wind with Tax C	26.2	26.3	26.3	26.2	26.2	26.2	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.2	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3
OWC Wind without Tax C	13.8	13.9	13.9	13.8	13.8	13.8	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.8	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9
O OWC Geothermal	9.9	10.2	10.2	10.4	10.4	10.9	9.9	10.2	10.2	10.2	9.9	10.2	10.2	10.2	10.2	9.9	9.9	9.9	9.9	9.9	10.3	10.1	9.9	9.9	9.9	9.9
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	149.7	140.1	141.0	121.6	135.0	135.0	137.8	114.3	139.9	277.8	277.8	277.8	277.8	281.1	283.5	286.2	286.2	280.9	278.7	275.9
C OWC Cogeneration 2	0.0	0.0	481.0	351.7	327.8	270.2	147.5	95.6	14.7	0.0	111.2	94.4	0.0	0.0	939.3	618.3	468.2	447.5	417.5	377.9	1092.0	1092.0	1071.4	1052.5	1038.8	937.9
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1	22.8	13.0	14.2	9.7	23.0	2.6	43.3	43.3	39.2	36.4	53.4
	189.2	196.7	610.5	557.5	554.2	522.0	426.4	441.5	382.1	372.9	375.4	435.2	364.2	365.6	1300.2	1053.3	977.8	988.4	971.2	900.8	1608.8	1560.3	1631.2	1639.9	1635.9	1497.5
DSR	128.7	137.7	81.3	148.9	183.2	197.7	81.3	148.9	183.2	197.7	81.3	148.9	183.2	197.7	163.0	89.2	163.0	195.0	210.2	163.0	176.6	97.2	176.6	208.8	221.7	176.6
Utah Wind with Tax C	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6
Utah Wind without Tax C	20.3	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4
Utah Geothermal	9.1	9.4	9.5	9.5	9.5	9.8	9.1	9.3	9.3	9.3	9.1	9.3	9.3	9.3	9.9	9.1	9.1	9.1	9.1	9.1	9.9	9.4	9.3	9.3	9.1	9.1
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.0	0.0	0.0	0.0	0.0	0.0	35.4	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	173.8	0.0	0.0	0.0	0.0	0.0	176.1	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	34.4	429.1	392.2	362.4	366.0	750.2	641.2	658.7	640.0	811.3	688.3	694.3	679.0	212.4	845.4	820.0	787.5	781.0	907.2	627.1	907.2	907.2	907.2	907.2	907.2
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	4.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.6	13.0	6.2	1.6	0.6	0.0	44.3	41.8	22.1	16.7	14.8	12.2
Utah Pumped Storage	0.0	6.2	92.8	76.1	74.3	62.1	98.0	64.0	66.2	51.1	101.8	53.5	62.1	41.8	92.8	103.6	100.5	100.9	100.0	109.0	92.8	98.4	103.9	105.4	105.3	111.1
	196.7	246.7	676.5	685.7	688.4	694.6	997.6	922.4	976.4	957.1	1062.5	959.0	1007.9	986.8	755.5	1119.3	1157.8	1153.1	1159.9	1247.3	1221.2	1213.0	1278.1	1306.4	1317.1	1275.2
DSR	38.8	41.2	14.2	43.5	44.8	49.7	14.2	43.5	44.8	49.7	14.2	43.5	44.8	49.7	48.2	15.3	48.2	50.8	53.3	48.2	52.0	16.5	52.0	56.4	58.2	52.0
W Wyo Wind with Tax C	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6
Y Wyo Wind without Tax C	20.3	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.4	0.0	161.9	57.1	38.9	31.6	302.7
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	.0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	97.7	100.2	73.2	102.5	103.8	108.7	73.2	102.5	103.8	108.7	73.2	102.5	103.8	108.7	107.2	74.3	107.2	109.8	112.3	112.6	111.0	237.4	168.1	154.3	148.8	413.7
DSR	306.8	325.2	174.6	347.8	404.0	448.3	174.6	347.8	404.0	448.3	174.6	347.8	404.0	448.3	379.9	188.8	379.9	444.6	479.6	379.9	408.8	202.2	408.8	482.4	511.8	408.8
T Renewable	176.8	177.8	177.9	177.9	177.9	178.7	177.2	177.7	177.7	177.7	177.2	177.7	177.7	177.7	178.1	177.2	177.2	177.2	177.2	177.2	178.4	177.7	177.4	177.4	177.2	177.2
O Cogeneration	0.0	0.0	481.0	351.7	327.8	270.2	297.2	235.7	155.7	121.6	246.2	229.4	137.8	114.3	1288.0	896.1	746.0	725.3	695.3	659.0	1587.0	1378.2	1357.6	1333.4	1317.5	1213.8
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	0.0	34.4	429.1	392.2	362.4	366.0	750.2	641.2	658.7	640.0	811.3	688.3	694.3	679.0	212.4	845.4	820.0	787.5	781.0	912.6	627.1	1069.1	964.3	946.1	938.8	1209.9
L Simple Cycle CT	0.0	0.0	4.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.6	13.0	6.2	1.6	0.6	0.0	44.3	41.8	22.1	16.7	14.8	12.2
Pumped Storage	0.0	6.2	92.8	76.1	74.3	62.1	98.0	64.0	66.2	51.1	101.8	53.5	62.1	41.8	94.9	126.4	113.5	115.1	109.7	132.0	95.4	141.7	147.2	144.6	141.7	164.5
Total	483.6	543.6	1360.2	1345.7	1346.4	1325.3	1497.2	1466.4	1462.3	1438.7	1511.1	1496.7	1475.9	1461.1	2162.9	2246.9	2242.8	2251.3	2243.4	2260.7	2941.0	3010.7	3077.4	3100.6	3101.8	3186.4

T5 08.ac.sr.aMW-10yrs

Table 5-8.d

Summary by Load Level for Any-Coal & Strategic-Renewable Strategy (AC.SR)
Winter Capacity (MW) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load Level	L	ML	M												MH						H					
Gas Price	MG	MG	LG				MG				HG				LG	MG				HG	LG	MG				HG
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	MD	LD	MD	AD	HD	MD	MD	LD	MD	AD	HD	MD
Case #	3	8	13	17	21	25	30	34	38	42	47	51	55	59	62	66	70	74	78	81	83	87	91	95	99	102
DSR	449.7	509.0	254.7	577.1	587.2	724.2	254.7	577.1	587.2	724.2	254.7	577.1	587.2	724.2	680.0	270.8	680.0	762.7	852.9	680.0	765.4	285.0	765.4	907.4	977.4	765.4
OWC Wind with Tax C	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
OWC Wind without Tax C	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	187.1
O OWC Geothermal	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	168.5	160.0	162.9	133.9	160.0	160.0	160.0	132.7	160.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
C OWC Cogeneration 2	0.0	0.0	581.5	425.1	396.1	324.3	178.3	115.6	17.3	0.0	139.1	115.6	0.0	0.0	1146.4	768.5	574.5	551.9	514.8	480.8	1320.0	1320.0	1320.0	1319.9	1320.0	1320.1
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	273.1	320.2	132.9	103.4	76.9	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	42.1	0.0	0.0	0.0	0.0	420.6	247.1	207.3	162.4	325.9	406.0	783.0	543.6	467.4	426.7	642.6
OWC Pumped Storage	0.0	0.0	500.0	500.0	500.0	425.9	500.0	472.5	483.7	359.7	500.0	347.9	395.0	292.7	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
	630.7	690.0	1517.2	1683.2	1664.3	1655.4	1282.8	1506.2	1432.1	1398.8	1276.9	1381.6	1323.2	1330.6	2667.4	2460.9	2502.6	2522.9	2531.1	2487.7	3765.5	3709.2	3762.9	3799.1	3802.0	3858.2
DSR	331.2	356.9	230.7	390.0	414.2	463.5	230.7	390.0	414.2	463.5	230.7	390.0	414.2	463.5	429.5	249.7	429.5	434.7	499.3	429.5	466.2	269.0	466.2	471.0	530.0	466.2
Utah Wind with Tax C	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
Utah Wind without Tax C	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0
Utah Geothermal	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	39.0	0.0	0.0	0.0	0.0	0.0	39.0	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	210.0	0.0	0.0	0.0	0.0	0.0	210.0	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	170.3	1314.7	1097.3	1086.6	1005.7	1798.7	1274.2	1318.8	1262.3	1807.6	1398.9	1427.8	1330.5	1838.8	2833.9	2649.1	2653.1	2607.7	2835.2	3029.7	3681.3	3599.1	3618.5	3574.7	3775.7
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	252.8	0.0	0.0	0.0	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	573.7	384.7	177.1	129.1	69.7	0.0	1043.3	751.7	558.9	470.7	444.0	220.2
Utah Pumped Storage	0.0	266.5	500.0	499.9	500.0	500.0	500.0	500.0	499.9	499.9	500.0	500.1	499.9	500.0	500.0	500.0	500.0	500.0	499.9	500.0	500.0	500.0	500.0	500.0	500.0	499.9
	511.2	973.7	2478.2	2167.2	2180.8	2149.2	2712.6	2344.2	2412.9	2405.7	2718.3	2469.0	2521.9	2474.0	3771.0	4148.3	3935.7	3896.9	3856.6	3944.7	5468.2	5382.0	5304.2	5240.2	5228.7	5142.0
DSR	83.1	89.8	41.0	104.1	104.2	115.2	41.0	104.1	104.2	115.2	41.0	104.1	104.2	115.2	117.5	45.4	117.5	122.3	129.6	117.5	131.8	49.8	131.8	140.8	146.1	131.8
W Wyo Wind with Tax C	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
Y Wyo Wind without Tax C	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	0.0	338.2	166.6	161.5	145.7	330.3
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	251.1	257.8	209.0	272.1	272.2	283.2	209.0	272.1	272.2	283.2	209.0	272.1	272.2	283.2	285.5	213.4	285.5	290.3	297.6	291.4	299.8	556.0	466.4	470.3	459.8	630.1
DSR	864.0	955.7	526.4	1071.2	1105.6	1302.9	526.4	1071.2	1105.6	1302.9	526.4	1071.2	1105.6	1302.9	1227.0	565.9	1227.0	1319.7	1481.8	1227.0	1363.4	603.8	1363.4	1519.2	1653.5	1363.4
T Renewable	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	658.1
O Cogeneration	0.0	0.0	581.5	425.1	396.1	324.3	346.8	275.6	180.2	133.9	299.1	275.6	160.0	132.7	1555.4	1088.5	894.5	871.9	834.8	800.8	1889.0	1640.0	1640.0	1639.9	1640.0	1640.1
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	273.1	320.2	132.9	103.4	76.9	0.0
A Coal	0.0	170.3	1314.7	1097.3	1086.6	1005.7	1798.7	1274.2	1318.8	1262.3	1807.6	1398.9	1427.8	1330.5	1838.8	2833.9	2649.1	2653.1	2607.7	2841.1	3029.7	4019.5	3765.7	3780.0	3720.4	4106.0
L Simple Cycle CT	0.0	0.0	252.8	0.0	0.0	0.0	3.5	0.0	0.0	0.0	42.1	0.0	0.0	0.0	573.7	805.3	424.2	336.4	232.1	325.9	1449.3	1534.7	1102.5	938.1	870.7	862.8
Pumped Storage	0.0	266.5	1000.0	999.9	1000.0	925.9	1000.0	972.5	983.6	859.6	1000.0	848.0	894.9	792.7	1000.0	1000.0	1000.0	1000.0	999.9	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	999.9
Total	1393.0	1921.5	4204.4	4122.5	4117.3	4087.8	4204.4	4122.5	4117.2	4087.7	4204.2	4122.7	4117.3	4087.8	6723.9	6822.6	6723.8	6710.1	6685.3	6723.8	9533.5	9647.2	9533.5	9509.6	9490.5	9630.3

Table 5-8.e

Summary by Load Level for Any-Coal & Strategic-Renewable Strategy (AC.SR)
Annual Energy (MWa) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load Level	L	ML	M												MH						H					
Gas Price	MG	MG	LG				MG				HG				LG	MG				HG	LG	MG				HG
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	MD	LD	MD	AD	HD	MD	MD	LD	MD	AD	HD	MD
Case #	3	8	13	17	21	25	30	34	38	42	47	51	55	59	62	66	70	74	78	81	83	87	91	95	99	102
DSR	198.5	219.1	124.3	244.4	252.9	294.3	124.3	244.4	252.9	294.3	124.3	244.4	252.9	294.3	280.8	134.1	280.8	300.2	332.1	280.8	311.9	142.4	311.9	341.0	367.3	311.9
OWC Wind with Tax C	26.2	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3
OWC Wind without Tax C	13.8	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	44.7
O OWC Geothermal	9.9	10.7	11.4	11.4	11.4	11.4	11.4	11.4	11.7	11.7	11.7	11.4	11.7	11.7	11.2	11.4	11.4	11.4	11.4	11.7	11.2	10.8	11.2	11.2	11.2	11.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	156.8	148.9	151.7	124.6	148.9	148.9	148.9	123.5	148.9	297.9	297.9	297.9	297.9	297.9	297.9	297.9	297.9	297.9	297.9	297.9
C OWC Cogeneration 2	0.0	0.0	517.0	378.0	352.3	288.3	158.5	102.8	15.4	0.0	123.7	102.8	0.0	0.0	1015.5	683.3	510.8	490.7	457.7	427.5	1193.1	1146.1	1152.0	1155.0	1158.7	1160.9
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	254.1	297.9	123.6	96.2	71.5	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2	0.0	0.0	0.0	0.0	32.0	18.6	15.7	12.3	40.0	29.5	61.4	39.6	33.9	31.0	54.6
OWC Pumped Storage	0.0	0.0	9.6	1.5	1.4	0.7	4.1	1.4	1.8	1.5	4.1	1.4	1.9	1.5	45.6	7.1	3.6	3.5	3.3	2.8	42.8	13.0	5.4	6.3	7.9	4.4
	248.4	270.0	702.5	675.5	658.2	634.9	495.3	549.1	473.7	472.3	456.1	549.1	455.6	471.2	1542.2	1206.0	1163.3	1159.6	1154.9	1100.9	2180.7	2009.7	1981.8	1981.7	1985.7	1911.7
DSR	225.0	247.6	156.2	277.2	293.7	324.5	156.2	277.2	293.7	324.5	156.2	277.2	293.7	324.5	311.4	173.3	311.4	312.5	352.9	311.4	344.2	190.8	344.2	342.0	378.0	344.2
Utah Wind with Tax C	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6
Utah Wind without Tax C	20.3	20.4	20.4	20.4	20.4	20.4	20.3	20.4	20.3	20.3	20.3	20.3	20.3	20.3	20.4	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Utah Geothermal	9.1	9.7	9.6	9.6	9.6	9.6	9.4	9.6	9.5	9.6	9.4	9.5	9.5	9.5	9.6	9.3	9.3	9.3	9.3	9.2	9.4	9.1	9.1	9.3	9.3	9.1
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.3	0.0	0.0	0.0	0.0	0.0	32.6	0.0	0.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	173.0	0.0	0.0	0.0	0.0	0.0	173.0	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	156.1	1204.7	1005.6	995.8	921.6	1648.2	1167.8	1208.5	1156.8	1656.5	1282.0	1308.4	1219.3	1685.1	2597.0	2427.7	2431.2	2389.7	2598.2	2776.4	3373.5	3298.2	3316.0	3275.8	3460.0
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	14.1	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.9	21.4	9.8	7.2	3.9	0.0	58.0	41.8	31.1	26.2	24.7	12.2
Utah Pumped Storage	0.0	60.4	97.3	94.3	94.2	93.0	118.2	109.3	105.5	102.4	118.7	113.0	115.7	111.6	101.0	124.1	124.1	124.1	124.1	119.6	113.3	124.1	124.1	118.0	116.9	109.5
	293.0	532.8	1540.9	1445.7	1452.3	1407.7	1991.1	1622.9	1676.1	1652.2	1999.7	1740.6	1786.2	1723.8	2405.3	2984.0	2941.2	2943.2	2938.8	3097.3	3565.8	3798.2	3865.6	3870.4	3863.6	3993.9
DSR	74.4	80.9	37.6	91.2	91.5	99.5	37.6	91.2	91.5	99.5	37.6	91.2	91.5	99.5	101.5	41.8	101.5	104.9	110.2	101.5	112.6	46.0	112.6	118.9	122.7	112.6
W Wyo Wind with Tax C	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6
Y Wyo Wind without Tax C	20.3	20.4	20.4	20.4	20.4	20.4	20.3	20.4	20.3	20.3	20.3	20.3	20.3	20.3	20.4	20.3	20.3	20.3	20.3	20.3	20.4	20.3	20.3	20.3	20.3	20.3
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.4	0.0	310.0	152.7	148.1	133.5	302.7
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	133.3	139.9	96.6	150.2	150.5	158.5	96.5	150.2	150.4	158.4	96.5	150.1	150.4	158.4	160.5	100.7	160.4	163.8	169.1	165.8	171.6	414.9	324.2	325.9	315.1	474.2
DSR	497.9	547.6	318.1	612.8	638.1	718.3	318.1	612.8	638.1	718.3	318.1	612.8	638.1	718.3	693.7	349.2	693.7	717.6	795.2	693.7	768.7	379.2	768.7	801.9	868.0	768.7
T Renewable	176.8	178.6	179.2	179.2	179.2	179.2	178.8	179.2	179.2	179.3	179.1	178.9	179.2	179.2	179.0	178.7	178.7	178.7	178.7	178.9	178.7	177.9	178.3	178.5	178.5	208.9
O Cogeneration	0.0	0.0	517.0	378.0	352.3	288.3	315.3	251.7	167.1	124.6	272.6	251.7	148.9	123.5	1371.7	981.2	808.7	788.6	755.6	725.4	1696.6	1444.0	1449.9	1452.9	1456.6	1458.8
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	254.1	297.9	123.6	96.2	71.5	0.0
A Coal	0.0	156.1	1204.7	1005.6	995.8	921.6	1648.2	1167.8	1208.5	1156.8	1656.5	1282.0	1308.4	1219.3	1685.1	2597.0	2427.7	2431.2	2389.7	2603.6	2776.4	3683.5	3450.9	3464.1	3409.3	3762.7
L Simple Cycle CT	0.0	0.0	14.1	0.0	0.0	0.0	0.2	0.0	0.0	0.0	3.2	0.0	0.0	0.0	31.9	53.4	28.4	22.9	16.2	40.0	87.5	103.2	70.7	60.1	55.7	66.8
Pumped Storage	0.0	60.4	106.9	95.8	95.6	93.7	122.3	110.7	107.3	103.9	122.8	114.4	117.6	113.1	146.6	131.2	127.7	127.6	127.4	122.4	156.1	137.1	129.5	124.3	124.8	113.9
Total	674.7	942.7	2340.0	2271.4	2261.0	2201.1	2582.9	2322.2	2300.2	2282.9	2552.3	2439.8	2392.2	2353.4	4108.0	4290.7	4264.9	4266.6	4262.8	4364.0	5918.1	6222.8	6171.6	6178.0	6164.4	6379.8

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Summary by Load Level for No-Coal & Any-Renewable Strategy (NC.AR)
Percentage of Winter Capacity Additions (%)

Additions in 10 years (1994 - 2003)

Load Level	L	ML	M												MH				H			
Gas Price	MG	MG	LG				MG				HG				MG				MG			
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD
Case #	4	9	14	18	22	26	31	35	39	43	48	52	56	60	67	71	75	79	88	92	96	100
MW Additions																						
DSR	100.0	70.2	13.5	29.7	32.9	38.9	13.5	29.7	32.9	38.9	9.7	21.9	24.3	28.7	8.4	18.9	23.7	26.1	6.3	14.3	17.6	19.0
Renewable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.0	38.4	38.1	38.4	8.4	8.5	0.0	0.0	6.0	6.0	6.1	6.1
Cogeneration	0.0	0.0	69.5	59.8	56.9	54.2	63.1	51.6	48.7	45.9	13.3	12.9	11.6	11.7	57.7	52.4	57.0	55.8	41.7	42.2	42.4	42.5
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.4	8.5	7.8	7.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peaking Resources	0.0	29.8	17.0	10.5	10.3	6.9	23.3	18.7	18.4	15.2	36.0	26.8	25.9	21.2	25.5	20.1	19.4	18.1	33.7	28.9	26.1	25.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																						
DSR	100.0	87.8	12.2	25.0	29.0	32.6	12.9	26.5	30.7	34.7	16.8	30.7	35.3	38.0	8.9	17.9	21.1	22.8	7.2	14.5	17.0	18.0
Renewable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	37.2	31.4	30.8	29.8	5.0	5.0	0.0	0.0	3.8	3.7	3.7	3.7
Cogeneration	0.0	0.0	83.2	72.2	68.3	65.5	79.9	67.6	63.5	60.4	34.4	28.9	25.3	24.3	79.8	71.8	73.6	72.1	63.3	63.2	62.4	62.4
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	13.3	12.1	11.1
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peaking Resources	0.0	12.2	4.6	2.9	2.8	1.9	7.3	5.9	5.8	4.8	11.6	9.0	8.6	7.9	6.3	5.4	5.3	5.1	5.7	5.2	4.9	4.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Additions in 20 years (1994 - 2013)

Load Level	L	ML	M												MH				H			
Gas Price	MG	MG	LG				MG				HG				MG				MG			
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD
Case #	4	9	14	18	22	26	31	35	39	43	48	52	56	60	67	71	75	79	88	92	96	100
MW Additions																						
DSR	100.0	60.9	13.7	28.4	29.4	34.9	13.7	28.4	29.4	34.9	8.6	19.6	20.2	25.0	8.5	18.7	20.8	23.4	6.4	14.5	16.2	17.7
Renewable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.5	44.1	44.3	40.6	4.5	4.6	0.0	0.0	3.2	3.2	3.2	3.2
Cogeneration	0.0	0.0	50.2	40.9	40.2	37.6	41.8	31.3	30.5	27.6	6.4	6.6	5.9	6.1	31.5	31.9	33.0	33.1	22.1	22.4	22.4	22.5
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.7	8.7	10.1	8.9	30.2	26.0	25.7	24.7
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peaking Resources	0.0	39.1	36.1	30.7	30.5	27.6	44.6	40.3	40.2	37.5	32.5	29.7	29.6	28.3	41.8	36.2	36.1	34.5	38.2	33.9	32.4	31.9
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																						
DSR	100.0	85.5	14.4	28.5	29.8	33.9	16.3	33.5	35.0	40.2	17.8	34.1	35.6	40.4	10.0	19.9	20.7	22.9	7.0	14.4	15.0	16.3
Renewable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.5	40.8	41.4	37.0	3.0	3.0	0.0	0.0	2.0	2.0	2.0	2.0
Cogeneration	0.0	0.0	78.0	64.6	63.5	59.7	74.2	58.3	57.0	52.5	20.1	18.6	16.6	16.8	55.0	55.2	55.7	55.7	35.3	35.7	35.8	36.0
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	24.2	15.1	17.1	15.1	48.9	41.9	41.4	39.9
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peaking Resources	0.0	14.5	7.6	6.9	6.7	6.4	9.5	8.2	8.1	7.4	7.6	6.5	6.3	5.8	7.8	6.8	6.5	6.2	6.8	6.0	5.8	5.7
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 5-9.b

Summary by Load Level for No-Coal & Any-Renewable Strategy (NC.AR)
Winter Capacity (MW) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Load Level	L	ML	M												MH				H			
Gas Price	MG	MG	LG				MG				HG				MG				MG			
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD
Case #	4	9	14	18	22	26	31	35	39	43	48	52	56	60	67	71	75	79	88	92	96	100
DSR	318.9	336.7	149.3	359.2	381.8	468.6	149.3	359.2	381.8	468.6	149.3	359.2	381.8	468.6	156.9	393.4	470.2	519.8	163.3	422.8	538.3	580.1
OWC Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	300.0	166.0	150.0	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O OWC Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	320.0	320.1	319.9	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
C OWC Cogeneration 2	0.0	0.0	1037.0	986.0	946.8	917.3	752.4	624.8	591.0	569.5	29.2	0.0	0.0	0.0	1280.5	1065.5	1100.6	1056.7	1320.0	1320.0	1320.0	1320.1
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	102.0	34.9	45.1	30.1	18.4	0.0	0.0	0.0
	318.9	336.7	1186.3	1345.2	1328.6	1385.9	1221.7	1304.1	1292.7	1358.1	798.5	845.2	851.8	938.6	1859.4	'1813.8	1935.9	1926.6	1821.7	2062.8	2178.3	2220.2
DSR	179.2	189.3	118.5	200.8	238.9	261.4	118.5	200.8	238.9	261.4	118.5	200.8	238.9	261.4	127.0	217.8	252.7	277.2	135.9	233.0	269.9	291.1
Utah Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	450.0	450.0	450.0	450.0	150.0	150.0	0.0	0.0	150.0	150.0	150.0	150.0
Utah Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	1.1	39.0	39.0	39.0	39.0	39.0	0.0	0.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
T Utah Cogeneration 2	0.0	0.0	420.0	238.8	213.1	178.1	250.8	73.8	44.4	0.0	0.0	0.0	0.0	0.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	624.7	423.9	387.5	358.3
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	554.0	272.7	263.9	110.7	308.8	172.6	93.4	63.7	1176.9	940.2	793.6	747.9
Utah Pumped Storage	0.0	242.8	357.1	215.7	209.8	140.5	489.8	383.0	375.2	307.4	500.0	470.4	451.1	470.6	500.0	499.9	500.0	500.0	500.0	500.0	500.0	500.0
	179.2	432.1	895.6	655.3	661.8	580.0	860.2	696.6	697.5	607.8	1661.5	1432.9	1403.9	1292.7	1544.8	1499.3	1305.1	1299.9	3046.5	2706.1	2560.0	2506.3
DSR	42.5	44.9	15.8	48.2	49.6	56.4	15.8	48.2	49.6	56.4	15.8	48.2	49.6	56.4	17.0	53.7	57.5	61.0	18.3	58.4	64.6	67.2
W Wyo Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	450.0	450.0	450.0	450.0	150.0	150.0	0.0	0.0	150.0	150.0	150.0	150.0
Y Wyo Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	42.5	44.9	15.8	48.2	49.6	56.4	15.8	48.2	49.6	56.4	465.8	498.2	499.6	506.4	167.0	203.7	57.5	61.0	168.3	208.4	214.6	217.2
DSR	540.6	570.9	283.6	608.2	670.3	786.4	283.6	608.2	670.3	786.4	283.6	608.2	670.3	786.4	300.9	664.9	780.4	858.0	317.5	714.2	872.8	938.4
T Renewable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1200.0	1066.0	1050.0	1050.0	300.0	300.0	0.0	0.0	300.0	300.0	300.0	300.0
O Cogeneration	0.0	0.0	1457.0	1224.8	1159.9	1095.4	1324.3	1057.7	994.3	928.5	388.2	359.0	320.0	320.0	2059.5	1844.5	1879.6	1835.7	2099.0	2099.0	2099.0	2099.1
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	624.7	423.9	387.5	358.3
A Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	554.0	272.7	263.9	110.7	308.8	172.6	93.4	63.7	1176.9	940.2	793.6	747.9
Pumped Storage	0.0	242.8	357.1	215.7	209.8	140.5	489.8	383.0	375.2	307.4	500.0	470.4	451.1	470.6	602.0	534.8	545.1	530.1	518.4	500.0	500.0	500.0
Total	540.6	813.7	2097.7	2048.7	2040.0	2022.3	2097.7	2048.9	2039.8	2022.3	2925.8	2776.3	2755.3	2737.7	3571.2	3516.8	3298.5	3287.5	5036.5	4977.3	4952.9	4943.7

Summary by Load Level for No-Coal & Any-Renewable Strategy (NC.AR)
Annual Energy (MWa) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Load Level	L	ML	M												MH				H			
Gas Price	MG	MG	LG				MG				HG				MG				MG			
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD
Case #	4	9	14	18	22	26	31	35	39	43	48	52	56	60	67	71	75	79	88	92	96	100
DSR	139.3	146.3	79.1	155.4	176.0	200.9	79.1	155.4	176.0	200.9	79.1	155.4	176.0	200.9	84.3	168.7	198.8	216.1	88.5	180.2	217.2	231.9
OWC Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	71.7	39.6	35.8	35.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O OWC Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	277.5	279.7	279.7	279.7	297.0	291.9	289.1	287.3	277.5	277.5	279.3	278.8	290.0	292.7	289.2	289.7
C OWC Cogeneration 2	0.0	0.0	842.9	808.0	775.7	751.6	598.7	512.0	484.2	466.6	25.5	0.0	0.0	0.0	1033.5	865.6	888.3	854.2	1092.0	1092.0	1092.0	1092.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.5	5.3	7.1	4.7	2.9	0.0	0.0	0.0
	139.3	146.3	922.0	963.4	951.7	952.5	955.3	947.1	939.9	947.2	473.3	486.9	500.9	524.0	1410.8	1317.1	1373.5	1353.8	1473.4	1564.9	1598.4	1613.6
DSR	128.7	137.7	81.3	148.9	183.2	197.7	81.3	148.9	183.2	197.7	81.3	148.9	183.2	197.7	89.2	163.0	195.0	210.2	97.2	176.6	208.8	221.7
Utah Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	158.0	158.0	158.0	158.0	52.7	52.7	0.0	0.0	52.7	52.7	52.7	52.7
Utah Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	1.0	34.2	34.2	33.9	35.9	35.3	0.0	0.0	34.2	34.2	34.2	34.7	35.7	35.7	35.4	35.7
T Utah Cogeneration 2	0.0	0.0	347.6	197.8	176.4	147.5	207.5	61.0	36.7	0.0	0.0	0.0	0.0	0.0	347.5	346.4	347.5	347.5	361.1	360.0	359.1	360.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	560.8	375.8	343.0	317.2
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.8	15.2	14.7	6.2	17.2	9.6	5.2	3.5	65.4	52.3	44.1	41.6
Utah Pumped Storage	0.0	45.1	66.3	40.0	38.9	26.1	99.0	77.1	76.3	62.6	89.8	87.3	83.7	87.4	101.1	99.5	99.4	98.3	92.8	93.4	93.9	93.7
	128.7	182.8	495.2	386.7	398.5	371.3	388.8	321.2	330.4	294.2	395.8	444.7	439.6	449.3	641.9	705.4	681.3	694.2	1265.7	1146.5	1137.0	1122.6
DSR	38.8	41.2	14.2	43.5	44.8	49.7	14.2	43.5	44.8	49.7	14.2	43.5	44.8	49.7	15.3	48.2	50.8	53.3	16.5	52.0	56.4	58.2
W Wyo Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	158.0	158.0	158.0	158.0	52.7	52.7	0.0	0.0	52.7	52.7	52.7	52.7
Y Wyo Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	38.8	41.2	14.2	43.5	44.8	49.7	14.2	43.5	44.8	49.7	172.2	201.5	202.8	207.7	68.0	100.9	50.8	53.3	69.2	104.7	109.1	110.9
DSR	306.8	325.2	174.6	347.8	404.0	448.3	174.6	347.8	404.0	448.3	174.6	347.8	404.0	448.3	188.8	379.9	444.6	479.6	202.2	408.8	482.4	511.8
T Renewable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	387.7	355.6	351.8	351.8	105.4	105.4	0.0	0.0	105.4	105.4	105.4	105.4
O Cogeneration	0.0	0.0	1190.5	1005.8	952.1	899.1	1084.7	886.9	834.8	780.2	358.4	327.2	289.1	287.3	1692.7	1523.7	1549.3	1515.2	1778.8	1780.4	1775.7	1777.4
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	560.8	375.8	343.0	317.2
A Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.8	15.2	14.7	6.2	17.2	9.6	5.2	3.5	65.4	52.3	44.1	41.6
Pumped Storage	0.0	45.1	66.3	40.0	38.9	26.1	99.0	77.1	76.3	62.6	89.8	87.3	83.7	87.4	116.6	104.8	106.5	103.0	95.7	93.4	93.9	93.7
Total	306.8	370.3	1431.4	1393.6	1395.0	1373.5	1358.3	1311.8	1315.1	1291.1	1041.3	1133.1	1143.3	1181.0	2120.7	2123.4	2105.6	2101.3	2808.3	2816.1	2844.5	2847.1

T5-09.nc.ar.aMW-10yrs

Table 5-9.d

Summary by Load Level for No-Coal & Any-Renewable Strategy (NC.AR)
Winter Capacity (MW) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load Level	L	ML	M												MH				H			
Gas Price	MG	MG	LG				MG				HG				MG				MG			
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD
Case #	4	9	14	18	22	26	31	35	39	43	48	52	56	60	67	71	75	79	88	92	96	100
DSR	449.7	509.0	254.7	577.1	587.2	724.2	254.7	577.1	587.2	724.2	254.7	577.1	587.2	724.2	270.8	680.0	762.7	852.9	285.0	765.4	907.4	977.4
OWC Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	300.0	166.0	150.0	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1050.0	844.2	815.9	629.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O OWC Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W OWC Cogeneration 1	0.0	0.0	195.7	0.0	0.0	0.0	320.0	320.1	319.9	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
C OWC Cogeneration 2	0.0	0.0	1320.0	1305.5	1300.3	1225.6	1000.1	747.3	744.7	672.6	29.2	0.0	0.0	0.0	1320.0	1320.0	1319.9	1320.0	1320.0	1320.0	1320.0	1320.1
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	237.6	71.9	29.4	8.1	1042.2	887.8	856.0	804.9
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	542.0	114.7	0.0	0.0
OWC Pumped Storage	0.0	114.7	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
	449.7	623.7	2270.4	2382.6	2387.5	2449.8	2074.8	2144.5	2151.8	2216.8	2453.9	2407.3	2373.1	2323.5	2648.4	2891.9	2932.0	3001.0	4009.2	3907.9	3903.4	3922.4
DSR	331.2	356.9	230.7	390.0	414.2	463.5	230.7	390.0	414.2	463.5	230.7	390.0	414.2	463.5	249.7	429.5	434.7	499.3	269.0	466.2	471.0	530.0
Utah Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	450.0	450.0	450.0	450.0	150.0	150.0	0.0	0.0	150.0	150.0	150.0	150.0
Utah Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	902.9	501.5	558.4	442.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	39.0	39.0	39.0	39.0	39.0	39.0	0.0	0.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
T Utah Cogeneration 2	0.0	0.0	420.0	238.8	213.1	178.1	250.8	73.8	44.4	0.0	0.0	0.0	0.0	0.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0	420.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	678.1	497.7	612.4	557.2	1595.8	1404.0	1397.5	1362.3
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	391.0	156.0	147.4	30.2	716.8	520.3	512.6	402.2	988.2	626.3	617.9	475.8	1791.8	1378.1	1298.4	1188.2	2069.9	2062.1	2036.4	1976.7
Utah Pumped Storage	0.0	500.0	500.1	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	499.9	500.0	500.0	500.0	500.0	500.0	500.0
	331.2	856.9	1541.8	1284.8	1274.7	1171.8	1737.3	1523.1	1510.2	1404.7	3110.8	2506.8	2540.5	2332.1	3828.6	3414.2	3304.5	3203.7	5043.7	5041.3	5013.9	4978.0
DSR	83.1	89.8	41.0	104.1	104.2	115.2	41.0	104.1	104.2	115.2	41.0	104.1	104.2	115.2	45.4	117.5	122.3	129.6	49.8	131.8	140.8	146.1
W Wyo Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	450.0	450.0	450.0	450.0	150.0	150.0	0.0	0.0	150.0	150.0	150.0	150.0
Y Wyo Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	233.0	152.4	151.6	144.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.4	0.0	0.0	0.0
	83.1	89.8	41.0	104.1	104.2	115.2	41.0	104.1	104.2	115.2	545.4	554.1	554.2	565.2	195.4	267.5	122.3	129.6	444.2	434.2	442.4	440.1
DSR	864.0	955.7	526.4	1071.2	1105.6	1302.9	526.4	1071.2	1105.6	1302.9	526.4	1071.2	1105.6	1302.9	565.9	1227.0	1319.7	1481.8	603.8	1363.4	1519.2	1653.5
T Renewable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3207.3	2411.7	2424.3	2122.1	300.0	300.0	0.0	0.0	300.0	300.0	300.0	300.0
O Cogeneration	0.0	0.0	1935.7	1544.3	1513.4	1403.7	1609.9	1180.2	1148.0	1031.6	388.2	359.0	320.0	320.0	2099.0	2099.0	2098.9	2099.0	2099.0	2099.0	2099.0	2099.1
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	915.7	569.6	641.8	565.3	2871.0	2444.2	2405.1	2311.2
A Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
L Simple Cycle CT	0.0	0.0	391.0	156.0	147.4	30.2	716.8	520.3	512.6	402.2	988.2	626.3	617.9	475.8	1791.8	1378.1	1298.4	1188.2	2623.3	2176.8	2036.4	1976.7
Pumped Storage	0.0	614.7	1000.1	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	999.9	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0
Total	864.0	1570.4	3853.2	3771.5	3766.4	3736.8	3853.1	3771.7	3766.2	3736.7	6110.1	5468.2	5467.8	5220.8	6672.4	6573.6	6358.8	6334.3	9497.1	9383.4	9359.7	9340.5

TS-09.nc.ar MW add 20yrs

Summary by Load Level for No-Coal & Any-Renewable Strategy (NC.AR)
Annual Energy (MWa) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load Level	L	ML	M												MH				H			
Gas Price	MG	MG	LG				MG				HG				MG				MG			
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD
Case #	4	9	14	18	22	26	31	35	39	43	48	52	56	60	67	71	75	79	88	92	96	100
DSR	198.5	219.1	124.3	244.4	252.9	294.3	124.3	244.4	252.9	294.3	124.3	244.4	252.9	294.3	134.1	280.8	300.2	332.1	142.4	311.9	341.0	367.3
OWC Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	71.7	39.6	35.8	35.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	250.8	201.6	194.9	150.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O OWC Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
W OWC Cogeneration 1	0.0	0.0	182.2	0.0	0.0	0.0	297.9	297.9	297.9	297.9	297.9	297.9	297.9	297.9	297.2	297.2	297.2	297.3	297.0	297.0	297.0	297.0
C OWC Cogeneration 2	0.0	0.0	1155.6	1169.0	1165.4	1103.0	885.8	666.1	664.2	604.2	25.9	0.0	0.0	0.0	1219.5	1217.6	1222.8	1221.5	1192.3	1200.2	1203.9	1206.7
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	221.1	66.9	27.3	7.6	965.2	826.1	796.5	748.9
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.8	8.2	0.0	0.0
OWC Pumped Storage	0.0	0.0	55.8	54.1	52.3	50.2	55.6	35.0	33.1	22.5	3.5	2.0	2.0	1.5	64.7	63.3	53.6	53.3	91.6	85.4	82.5	77.6
	198.5	219.1	1517.9	1467.5	1470.6	1447.5	1363.6	1243.4	1248.1	1218.9	774.1	785.5	783.5	779.8	1936.6	1925.8	1901.1	1911.8	2727.3	2728.8	2720.9	2697.5
DSR	225.0	247.6	156.2	277.2	293.7	324.5	156.2	277.2	293.7	324.5	156.2	277.2	293.7	324.5	173.3	311.4	312.5	352.9	190.8	344.2	342.0	378.0
Utah Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	158.0	158.0	158.0	158.0	52.7	52.7	0.0	0.0	52.7	52.7	52.7	52.7
Utah Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	317.0	176.1	196.0	155.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	36.3	36.3	36.3	36.3	35.5	35.4	0.0	0.0	36.0	36.0	36.0	36.0	35.7	35.7	35.7	35.7
T Utah Cogeneration 2	0.0	0.0	387.0	219.6	196.3	163.8	227.6	67.8	41.2	0.0	0.0	0.0	0.0	0.0	377.1	377.1	377.1	377.1	377.1	377.1	377.1	377.1
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	626.3	460.1	566.2	516.5	1457.4	1279.3	1273.4	1242.2
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	21.7	8.7	8.2	1.7	39.9	28.9	28.5	22.4	54.9	34.8	34.4	26.5	99.6	76.6	72.2	66.1	115.1	114.6	113.2	109.9
Utah Pumped Storage	0.0	93.0	91.4	84.7	84.1	84.0	90.5	86.1	85.5	87.1	77.8	79.7	77.4	75.6	109.9	98.6	99.7	95.2	119.8	115.4	115.7	117.1
	225.0	340.6	656.3	590.2	582.3	574.0	550.5	496.3	485.2	470.3	799.4	761.2	759.5	740.0	1474.9	1412.5	1463.7	1443.8	2348.6	2319.0	2309.8	2312.7
DSR	74.4	80.9	37.6	91.2	91.5	99.5	37.6	91.2	91.5	99.5	37.6	91.2	91.5	99.5	41.8	101.5	104.9	110.2	46.0	112.6	118.9	122.7
W Wyo Wind with Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	158.0	158.0	158.0	158.0	52.7	52.7	0.0	0.0	52.7	52.7	52.7	52.7
Y Wyo Wind without Tax C	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	213.5	140.1	139.4	132.4
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0
	74.4	80.9	37.6	91.2	91.5	99.5	37.6	91.2	91.5	99.5	214.7	249.2	249.5	257.5	94.5	154.2	104.9	110.2	313.4	305.4	311.0	307.8
DSR	497.9	547.6	318.1	612.8	638.1	718.3	318.1	612.8	638.1	718.3	318.1	612.8	638.1	718.3	349.2	693.7	717.6	795.2	379.2	768.7	801.9	868.0
T Renewable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	974.6	733.3	742.7	657.5	105.4	105.4	0.0	0.0	105.4	105.4	105.4	105.4
O Cogeneration	0.0	0.0	1724.8	1388.6	1361.7	1266.8	1447.6	1068.1	1039.6	938.4	359.3	333.3	297.9	297.9	1929.8	1927.9	1933.1	1931.9	1902.1	1910.0	1913.7	1916.5
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	847.4	527.0	593.5	524.1	2636.1	2245.5	2209.3	2123.5
A Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
L Simple Cycle CT	0.0	0.0	21.7	8.7	8.2	1.7	39.9	28.9	28.5	22.4	54.9	34.8	34.4	26.5	99.6	76.6	72.2	66.1	155.1	122.8	113.2	109.9
Pumped Storage	0.0	93.0	147.2	138.8	136.4	134.2	146.1	121.1	118.6	109.6	81.3	81.7	79.4	77.1	174.6	161.9	153.3	148.5	211.4	200.8	198.2	194.7
Total	497.9	640.6	2211.8	2148.9	2144.4	2121.0	1951.7	1830.9	1824.8	1788.7	1788.2	1795.9	1792.5	1777.3	3506.0	3492.5	3469.7	3465.8	5389.3	5353.2	5341.7	5318.0

T5-09.nc.ar.aMW-20yrs

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Summary by Load Level for No-Coal & Strategic-Renewable Strategy (NC.SR)
Percentage of Winter Capacity Additions (%)

Additions in 10 years (1994 - 2003)

Load Level	L	ML	M												MH						H					
Gas Price	MG	MG	LG				MG				HG				LG	MG				HG	LG	MG				HG
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	MD	LD	MD	AD	HD	MD	MD	LD	MD	AD	HD	MD
Case #	5	10	15	19	23	27	32	36	40	44	49	53	57	61	63	68	72	76	80	82	84	89	93	97	101	103
MW Additions																										
DSR	50.5	49.0	11.6	25.3	28.0	33.1	11.6	25.3	28.0	33.1	11.6	25.3	28.0	33.1	18.1	8.1	18.1	21.4	23.6	18.1	13.9	6.1	13.9	17.1	18.4	13.2
Renewable	49.5	45.4	21.6	22.0	22.1	22.3	21.6	22.0	22.1	22.3	21.6	22.0	22.1	22.3	14.4	14.2	14.4	14.5	14.5	14.4	10.3	10.2	10.3	10.4	10.4	17.6
Cogen	0.0	0.0	50.5	43.2	40.6	38.2	45.5	36.0	33.7	31.0	20.3	18.2	14.1	13.5	51.7	53.4	48.3	46.2	45.4	36.6	40.9	40.5	40.9	41.1	41.2	38.8
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.2	10.8	7.8	6.3	5.7	1.8
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peaking Resources	0.0	5.6	16.3	9.4	9.2	6.4	21.3	16.6	16.2	13.6	46.5	34.5	35.7	31.1	15.7	24.3	19.2	18.0	16.5	30.9	25.6	32.5	27.0	25.1	24.2	28.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																										
DSR	63.4	63.1	12.1	24.5	28.5	32.1	12.7	26.1	30.2	34.2	18.8	33.7	40.5	44.0	17.2	8.9	17.8	20.9	22.5	20.8	14.0	7.2	14.3	16.9	17.9	14.9
Renewable	36.6	34.5	12.3	12.6	12.5	12.7	12.9	13.3	13.3	13.6	19.3	17.3	17.9	17.5	8.0	8.3	8.3	8.4	8.3	9.7	6.1	6.3	6.2	6.2	6.2	11.8
Cogen	0.0	0.0	70.4	59.9	56.0	53.1	66.8	54.3	50.4	47.1	48.6	38.6	31.3	29.1	70.4	76.6	68.4	65.6	64.2	62.5	60.4	63.0	62.0	62.0	62.0	64.4
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.7	17.7	12.4	10.0	9.1	3.1
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peaking Resources	0.0	2.4	5.1	3.0	3.0	2.0	7.7	6.2	6.1	5.2	13.3	10.4	10.3	9.4	4.3	6.3	5.5	5.2	5.0	7.0	4.7	5.8	5.1	4.8	4.8	5.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Additions in 20 years (1994 - 2013)

Load Level	L	ML	M												MH						H					
Gas Price	MG	MG	LG				MG				HG				LG	MG				HG	LG	MG				HG
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	MD	LD	MD	AD	HD	MD	MD	LD	MD	AD	HD	MD
Case #	5	10	15	19	23	27	32	36	40	44	49	53	57	61	63	68	72	76	80	82	84	89	93	97	101	103
MW Additions																										
DSR	62.0	49.7	12.5	26.0	26.9	31.9	12.5	26.0	26.9	31.9	9.0	20.6	20.5	25.1	18.2	8.3	18.2	19.7	22.2	13.4	14.3	6.3	14.3	16.0	17.4	10.5
Renewable	38.0	27.5	12.6	12.8	12.8	12.9	12.6	12.8	12.8	12.9	48.8	39.9	43.5	40.6	7.9	7.8	7.9	7.9	7.9	43.8	5.5	5.5	5.5	5.6	5.6	42.1
Cogen	0.0	0.0	39.9	32.5	31.7	29.2	31.3	23.0	22.4	20.9	8.6	8.4	6.2	6.2	31.2	30.8	31.2	31.3	31.4	14.7	22.0	21.8	22.0	22.1	22.1	16.2
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.2	12.2	7.3	7.2	6.2	0.0	26.0	29.0	24.7	24.5	23.6	2.8
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peaking Resources	0.0	22.7	35.0	28.7	28.6	26.0	43.6	38.2	37.9	34.3	33.7	31.2	29.8	28.1	34.4	41.0	35.3	34.0	32.4	28.1	32.2	37.5	33.4	31.9	31.3	28.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																										
DSR	73.8	67.4	14.7	28.7	30.0	34.1	17.0	34.1	35.5	39.8	17.7	34.3	35.6	40.2	19.5	10.0	19.9	20.5	22.7	20.6	14.1	7.0	14.4	15.0	16.3	15.0
Renewable	26.2	22.1	8.3	8.4	8.4	8.5	9.6	10.0	10.0	9.9	49.4	36.8	40.6	37.3	5.0	5.1	5.1	5.1	5.1	37.8	3.3	3.3	3.4	3.4	3.4	33.9
Cogen	0.0	0.0	69.4	56.2	54.9	50.9	63.6	47.8	46.6	42.9	25.4	22.5	17.5	16.7	54.8	55.1	55.2	55.1	54.9	36.3	35.0	35.2	35.8	35.8	36.0	37.8
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.5	22.0	13.1	12.7	10.9	0.0	42.2	47.6	40.5	40.1	38.6	6.5
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peaking Resources	0.0	10.5	7.6	6.8	6.7	6.5	9.8	8.1	7.9	7.3	7.5	6.5	6.3	5.8	6.2	7.8	6.8	6.5	6.4	5.4	5.4	6.7	6.0	5.8	5.7	6.9
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 5-10.b

Summary by Load Level for No-Coal & Strategic-Renewable Strategy (NC.SR)
Winter Capacity (MW) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Load Level	L	ML	M												MH						H					
Gas Price	MG	MG	LG				MG				HG				LG	MG				HG	LG	MG				HG
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	MD	LD	MD	AD	HD	MD	MD	LD	MD	AD	HD	MD
Case #	5	10	15	19	23	27	32	36	40	44	49	53	57	61	63	68	72	76	80	82	84	89	93	97	101	103
DSR	318.9	336.7	149.3	359.2	381.8	468.6	149.3	359.2	381.8	468.6	149.3	359.2	381.8	468.6	393.4	156.9	393.4	470.2	519.8	393.4	422.8	163.3	422.8	538.3	580.1	422.8
OWC Wind with Tax C	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
OWC Wind without Tax C	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0
O OWC Geothermal	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	320.0	319.9	319.9	320.0	320.0	320.0	319.9	319.9	160.0	320.0	320.0	320.1	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
C OWC Cogeneration 2	0.0	0.0	960.5	924.5	880.1	856.4	680.3	523.3	485.3	390.6	139.3	76.6	0.0	0.0	1278.5	1207.5	990.6	944.4	910.6	771.5	1320.0	1320.0	1320.0	1320.0	1320.0	1320.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	11.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	97.5	48.5	3.9	0.0	0.0	0.0	30.7	9.5	1.0	0.0	77.2
	499.9	517.7	1290.8	1464.7	1442.9	1506.0	1342.0	1383.4	1368.0	1360.2	789.6	936.8	882.7	969.5	2012.9	1962.9	1933.5	1919.6	1931.4	1665.9	2243.8	2015.0	2253.3	2360.3	2401.1	2321.0
DSR	179.2	189.3	118.5	200.8	238.9	261.4	118.5	200.8	238.9	261.4	118.5	200.8	238.9	261.4	217.8	127.0	217.8	252.7	277.2	217.8	233.0	135.9	233.0	269.9	291.1	233.0
Utah Wind with Tax C	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
Utah Wind without Tax C	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	479.0
Utah Geothermal	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.0	0.0	24.1	39.0	39.0	17.3	0.0	39.0	39.0	39.0	0.0	0.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
T Utah Cogeneration 2	0.0	0.0	277.1	113.4	90.6	49.2	114.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	420.1	419.9	420.0	420.0	420.1	210.0	420.0	420.0	420.0	420.0	420.0	420.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	473.2	557.6	398.5	323.2	292.5	96.4
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	10.5	0.0	0.0	0.0	638.0	356.7	395.4	292.5	93.6	307.5	155.0	152.1	101.1	632.6	811.9	1152.6	877.1	778.0	734.9	972.5
Utah Pumped Storage	0.0	64.9	398.7	224.8	220.9	152.3	500.0	398.5	386.2	323.3	500.0	470.4	458.8	445.4	482.1	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
	359.2	434.2	974.3	719.0	730.4	642.9	923.0	800.3	805.1	788.8	1475.5	1246.9	1290.4	1179.3	1432.6	1573.4	1511.8	1504.8	1478.4	1779.4	2657.1	2985.1	2647.6	2510.1	2457.5	2861.9
DSR	42.5	44.9	15.8	48.2	49.6	56.4	15.8	48.2	49.6	56.4	15.8	48.2	49.6	56.4	53.7	17.0	53.7	57.5	61.0	53.7	58.4	18.3	58.4	64.6	67.2	58.4
W Wyo Wind with Tax C	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
Y Wyo Wind without Tax C	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	210.5	212.9	183.8	216.2	217.6	224.4	183.8	216.2	217.6	224.4	183.8	216.2	217.6	224.4	221.7	185.0	221.7	225.5	229.0	221.7	226.4	186.3	226.4	232.6	235.2	226.4
DSR	540.6	570.9	283.6	608.2	670.3	786.4	283.6	608.2	670.3	786.4	283.6	608.2	670.3	786.4	664.9	300.9	664.9	780.4	858.0	664.9	714.2	317.5	714.2	872.8	938.4	714.2
T Renewable	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	950.0
O Cogeneration	0.0	0.0	1237.6	1037.9	970.7	905.6	1114.3	864.2	805.2	734.7	498.3	435.6	337.2	319.9	1897.6	1986.4	1769.6	1684.5	1650.7	1340.5	2099.0	2099.0	2099.0	2099.0	2099.0	2099.0
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	473.2	557.6	398.5	323.2	292.5	96.4
A Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	10.5	0.0	0.0	0.0	638.0	356.7	395.4	292.5	93.6	307.5	155.0	152.1	101.1	632.6	811.9	1152.6	877.1	778.0	734.9	972.5
Pumped Storage	0.0	64.9	398.7	224.8	220.9	152.3	511.4	398.5	386.2	323.3	500.0	470.4	458.8	445.4	482.1	597.5	548.5	503.9	500.0	500.0	500.0	530.7	509.5	501.0	500.0	577.2
Total	1069.6	1164.8	2448.9	2399.9	2390.9	2373.3	2448.8	2399.9	2390.7	2373.4	2448.9	2399.9	2390.7	2373.2	3667.2	3721.3	3667.0	3649.9	3638.8	3667.0	5127.3	5186.4	5127.3	5103.0	5093.8	5409.3

Summary by Load Level for No-Coal & Strategic-Renewable Strategy (NC.SR)
Annual Energy (MWa) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

	Load Level	L	ML	M												MH						H					
	Gas Price	MG	MG	LG				MG				HG				LG	MG				HG	LG	MG				HG
	DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	MD	LD	MD	AD	HD	MD	MD	LD	MD	AD	HD	MD
	Case #	5	10	15	19	23	27	32	36	40	44	49	53	57	61	63	68	72	76	80	82	84	89	93	97	101	103
	DSR	139.3	146.3	79.1	155.4	176.0	200.9	79.1	155.4	176.0	200.9	79.1	155.4	176.0	200.9	168.7	84.3	168.7	198.8	216.1	168.7	180.2	88.5	180.2	217.2	231.9	180.2
	OWC Wind with Tax C	26.2	26.3	26.2	26.2	26.2	26.2	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.2	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3
	OWC Wind without Tax C	13.8	13.9	13.8	13.8	13.8	13.8	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.8	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9
O	OWC Geothermal	9.9	10.2	10.1	10.2	10.2	10.2	10.1	10.1	10.1	10.1	10.8	10.6	10.6	10.6	10.1	9.9	10.1	10.1	10.1	10.1	10.3	10.2	10.1	10.1	10.1	10.1
W	OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	277.5	277.5	277.5	277.5	296.8	296.8	296.8	296.8	138.4	277.5	277.5	277.5	277.5	294.6	283.5	289.8	286.6	285.4	285.9	292.9
C	OWC Cogeneration 2	0.0	0.0	787.0	757.5	721.1	701.7	550.1	428.8	397.7	320.0	119.0	65.4	0.0	0.0	1039.6	973.5	802.9	771.3	743.4	638.2	1092.0	1092.0	1092.0	1092.0	1092.0	1092.0
	OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.8	7.4	0.6	0.0	0.0	0.0	4.8	1.4	0.1	0.0	11.7
		189.2	196.7	916.2	963.1	947.3	952.8	958.7	912.0	901.5	848.7	545.9	568.4	523.6	548.5	1396.8	1400.2	1306.8	1298.5	1287.3	1151.8	1606.2	1525.5	1610.5	1645.0	1660.1	1627.1
	DSR	128.7	137.7	81.3	148.9	183.2	197.7	81.3	148.9	183.2	197.7	81.3	148.9	183.2	197.7	163.0	89.2	163.0	195.0	210.2	163.0	176.6	97.2	176.6	208.8	221.7	176.6
	Utah Wind with Tax C	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6
	Utah Wind without Tax C	20.3	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	168.2
	Utah Geothermal	9.1	9.4	9.5	9.9	9.9	9.9	9.4	9.7	9.7	9.7	10.0	9.7	9.8	9.7	9.7	9.3	9.3	9.3	9.3	9.7	9.9	9.8	9.6	9.6	9.6	9.7
	Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U	Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.4	0.0	21.0	35.9	35.7	15.9	0.0	35.0	34.2	34.2	0.0	0.0	35.7	35.7	35.7	35.4	35.4	35.4	35.7
T	Utah Cogeneration 2	0.0	0.0	227.9	93.2	74.5	40.5	93.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	345.9	347.3	346.0	345.8	345.3	175.8	354.1	359.2	357.7	358.0	358.6	353.3
A	Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	430.7	500.2	352.7	286.1	258.9	85.4
H	Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	35.5	19.8	22.0	16.3	5.2	17.1	8.6	8.5	5.6	35.2	45.1	64.1	48.8	43.3	40.9	54.1
	Utah Pumped Storage	0.0	12.4	74.0	42.5	42.0	28.3	104.0	83.3	81.7	67.7	87.7	87.1	80.9	79.2	91.0	101.9	101.3	100.6	100.2	92.8	92.8	94.2	94.2	94.6	94.9	92.8
		196.7	218.5	451.7	353.5	368.6	335.4	348.1	319.3	333.6	355.1	309.4	360.2	370.8	361.9	708.8	658.0	721.4	718.2	729.6	571.2	1203.9	1219.4	1134.0	1094.8	1079.0	1014.4
	DSR	38.8	41.2	14.2	43.5	44.8	49.7	14.2	43.5	44.8	49.7	14.2	43.5	44.8	49.7	48.2	15.3	48.2	50.8	53.3	48.2	52.0	16.5	52.0	56.4	58.2	52.0
W	Wyo Wind with Tax C	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6
Y	Wyo Wind without Tax C	20.3	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4
O	Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M	Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I	Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N	Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G	Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		97.7	100.2	73.2	102.5	103.8	108.7	73.2	102.5	103.8	108.7	73.2	102.5	103.8	108.7	107.2	74.3	107.2	109.8	112.3	107.2	111.0	75.5	111.0	115.4	117.2	111.0
	DSR	306.8	325.2	174.6	347.8	404.0	448.3	174.6	347.8	404.0	448.3	174.6	347.8	404.0	448.3	379.9	188.8	379.9	444.6	479.6	379.9	408.8	202.2	408.8	482.4	511.8	408.8
T	Renewable	176.8	177.8	177.6	178.1	178.1	178.1	177.7	178.0	178.0	178.0	179.0	178.5	178.6	178.5	177.8	177.4	177.6	177.6	177.6	178.0	178.4	178.2	177.9	177.9	177.9	325.8
O	Cogeneration	0.0	0.0	1014.9	850.7	795.6	742.2	921.4	724.7	675.2	618.5	451.7	397.9	312.7	296.8	1558.9	1632.5	1460.6	1394.6	1366.2	1144.3	1765.3	1776.7	1771.7	1770.8	1771.9	1773.9
T	Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	430.7	500.2	352.7	286.1	258.9	85.4
A	Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
L	Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.0	35.5	19.8	22.0	16.3	5.2	17.1	8.6	8.5	5.6	35.2	45.1	64.1	48.8	43.3	40.9	54.1
	Pumped Storage	0.0	12.4	74.0	42.5	42.0	28.3	105.7	83.3	81.7	67.7	87.7	87.1	80.9	79.2	91.0	116.7	108.7	101.2	100.2	92.8	92.8	99.0	95.6	94.7	94.9	104.5
	Total	483.6	515.4	1441.1	1419.1	1419.7	1396.9	1380.0	1333.8	1338.9	1312.5	928.5	1031.1	998.2	1019.1	2212.8	2132.5	2135.4	2126.5	2129.2	1830.2	2921.1	2820.4	2855.5	2855.2	2856.3	2752.5

T5-10.nc.sr.aMW-10yrs

Teble 5-10.d

Summary by Load Level for No-Coal & Strategic-Renewable Strategy (NC.SR)
Winter Capacity (MW) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load Level	L	ML	M											
Gas Price	MG	MG	LG				MG				HG			
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD
Case #	5	10	15	19	23	27	32	36	40	44	49	53	57	61
DSR	449.7	509.0	254.7	577.1	587.2	724.2	254.7	577.1	587.2	724.2	254.7	577.1	587.2	724.2
OWC Wind with Tax C	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
OWC Wind without Tax C	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	966.0	658.0	848.4	668.8
O OWC Geothermal	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
W OWC Cogeneration 1	0.0	0.0	82.0	0.0	0.0	0.0	320.0	319.9	319.9	320.0	320.0	320.0	319.9	319.9
C OWC Cogeneration 2	0.0	0.0	1320.0	1227.1	1215.8	1145.5	844.5	589.5	565.1	494.8	139.3	76.6	0.0	0.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
	630.7	690.0	2337.7	2485.2	2484.0	2550.7	2100.2	2167.5	2153.2	2220.0	2303.0	2254.7	2378.5	2335.9
DSR	331.2	356.9	230.7	390.0	414.2	463.5	230.7	390.0	414.2	463.5	230.7	390.0	414.2	463.5
Utah Wind with Tax C	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
Utah Wind without Tax C	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	1108.0	945.4	1010.0	962.9
Utah Geothermal	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	39.0	39.0	39.0	39.0	39.0	39.0	17.3	0.0
T Utah Cogeneration 2	0.0	0.0	277.1	113.4	90.6	49.2	114.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	469.8	182.0	176.4	61.2	831.4	574.0	558.6	402.1	960.6	623.1	609.1	462.6
Utah Pumped Storage	0.0	436.8	500.1	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	499.9	500.0
	511.2	973.7	1657.7	1365.4	1361.2	1253.9	1895.1	1683.0	1691.8	1584.6	2960.3	2619.5	2672.5	2511.0
DSR	83.1	89.8	41.0	104.1	104.2	115.2	41.0	104.1	104.2	115.2	41.0	104.1	104.2	115.2
W Wyo Wind with Tax C	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
Y Wyo Wind without Tax C	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	411.3	121.4	132.5	124.5
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	251.1	257.8	209.0	272.1	272.2	283.2	209.0	272.1	272.2	283.2	562.3	335.5	346.7	349.7
DSR	864.0	955.7	526.4	1071.2	1105.6	1302.9	526.4	1071.2	1105.6	1302.9	526.4	1071.2	1105.6	1302.9
T Renewable	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	529.0	2840.3	2079.8	2345.9	2111.2
O Cogeneration	0.0	0.0	1679.1	1340.5	1306.4	1194.7	1317.5	948.4	924.0	853.8	498.3	435.6	337.2	319.9
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
L Simple Cycle CT	0.0	0.0	469.8	182.0	176.4	61.2	831.4	574.0	558.6	402.1	960.6	623.1	609.1	462.6
Pumped Storage	0.0	436.8	1000.1	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	999.9	1000.0
Total	1393.0	1921.5	4204.4	4122.7	4117.4	4087.8	4204.3	4122.6	4117.2	4087.8	5825.6	5209.7	5397.7	5196.6

Load Level	MH						H					
Gas Price	LG	MG				HG	LG	MG				HG
DSM	MD	LD	MD	AD	HD	MD	MD	LD	MD	AD	HD	MD
Case #	63	68	72	76	80	82	84	89	93	97	101	103
DSR	680.0	270.8	680.0	762.7	852.9	680.0	765.4	285.0	765.4	907.4	977.4	765.4
OWC Wind with Tax C	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
OWC Wind without Tax C	58.0	58.0	58.0	58.0	58.0	1163.4	58.0	58.0	58.0	58.0	58.0	1558.0
O OWC Geothermal	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
W OWC Cogeneration 1	320.0	320.0	320.0	320.1	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
C OWC Cogeneration 2	1320.0	1320.0	1320.0	1320.1	1320.0	771.5	1320.0	1320.0	1320.0	1320.0	1320.0	1320.0
OWC Combined Cycle CT	0.0	183.4	17.0	0.0	0.0	0.0	866.4	997.0	821.5	798.1	752.3	208.8
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	527.8	127.9	3.6	0.0	415.9
OWC Pumped Storage	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.1	500.1	500.1	500.0
	3001.0	2775.2	3018.0	3083.9	317[illegible].9	3557.9	3952.8	4130.8	4035.9	4030.2	4050.8	5211.1
DSR	429.5	249.7	429.5	434.7	499.3	429.5	466.2	269.0	466.2	471.0	530.0	466.2
Utah Wind with Tax C	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
Utah Wind without Tax C	58.0	58.0	58.0	58.0	58.0	1372.2	58.0	58.0	58.0	58.0	58.0	1979.0
Utah Geothermal	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
T Utah Cogeneration 2	420.1	419.9	420.0	420.0	420.1	210.0	420.0	420.0	420.0	420.0	420.0	420.0
A Utah Combined Cycle CT	553.3	651.3	477.0	480.6	412.6	0.0	1549.9	1577.9	1382.2	1385.5	1347.9	157.1
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	1315.5	1793.8	1374.8	1281.6	1163.1	1570.8	2068.0	2068.3	2060.9	2028.5	1970.9	2256.4
Utah Pumped Storage	500.1	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
	3437.5	3833.7	3420.3	3335.9	3214.1	4243.5	5223.1	5054.2	5048.3	5024.0	4987.8	5939.7
DSR	117.5	45.4	117.5	122.3	129.6	117.5	131.8	49.8	131.8	140.8	146.1	131.8
W Wyo Wind with Tax C	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0	110.0
Y Wyo Wind without Tax C	58.0	58.0	58.0	58.0	58.0	1108.0	58.0	58.0	58.0	58.0	58.0	1558.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	57.9	222.8	149.6	146.8	137.8	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.4	0.0	0.0	0.0	0.0
	285.5	213.4	285.5	290.3	297.6	1335.5	357.7	462.0	449.4	455.6	451.9	1799.8
DSR	1227.0	565.9	1227.0	1319.7	1481.8	1227.0	1363.4	603.8	1363.4	1519.2	1653.5	1363.4
T Renewable	529.0	529.0	529.0	529.0	529.0	3998.6	529.0	529.0	529.0	529.0	529.0	5450.0
O Cogeneration	2099.1	2098.9	2099.0	2099.2	2099.1	1340.5	2099.0	2099.0	2099.0	2099.0	2099.0	2099.0
T Combined Cycle CT	553.3	834.7	494.0	480.6	412.6	0.0	2474.2	2797.7	2353.3	2330.4	2238.0	365.9
A Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
L Simple Cycle CT	1315.5	1793.8	1374.8	1281.6	1163.1	1570.8	2068.0	2617.5	2188.8	2032.1	1970.9	2672.3
Pumped Storage	1000.1	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.1	1000.1	1000.1	1000.0
Total	6724.0	6822.3	6723.8	6710.1	6685.6	9136.9	9533.6	9647.0	9533.6	9509.8	9490.5	12950.6

Summary by Load Level for No-Coal & Strategic-Renewable Strategy (NC.SR)
Annual Energy (MWa) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load Level	L	ML	M												MH						H					
Gas Price	MG	MG	LG				MG				HG				LG	MG				HG	LG	MG				HG
DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	MD	LD	MD	AD	HD	MD	MD	LD	MD	AD	HD	MD
Case #	5	10	15	19	23	27	32	36	40	44	49	53	57	61	63	68	72	76	80	82	84	89	93	97	101	103
DSR	198.5	219.1	124.3	244.4	252.9	294.3	124.3	244.4	252.9	294.3	124.3	244.4	252.9	294.3	280.8	134.1	280.8	300.2	332.1	280.8	311.9	142.4	311.9	341.0	367.3	311.9
OWC Wind with Tax C	26.2	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3	26.3
OWC Wind without Tax C	13.8	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	230.7	157.2	202.7	159.8	13.9	13.9	13.9	13.9	13.9	277.9	13.9	13.9	13.9	13.9	13.9	372.2
O OWC Geothermal	9.9	11.2	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	11.2	11.4	11.4	11.4	10.9	10.9	10.9	10.9	10.9	11.2	10.9	10.9	10.9	10.9	10.9	11.0
W OWC Cogeneration 1	0.0	0.0	76.4	0.0	0.0	0.0	297.9	297.9	297.9	297.9	297.9	297.9	297.9	297.9	297.9	297.2	297.2	297.4	297.9	297.9	297.5	297.0	297.0	297.0	297.0	297.9
C OWC Cogeneration 2	0.0	0.0	1173.9	1095.2	1086.0	1027.7	752.5	524.1	502.5	439.9	123.8	68.1	0.0	0.0	1225.5	1219.5	1214.8	1214.2	1214.6	704.1	1199.2	1189.9	1200.0	1200.9	1207.3	1227.5
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	170.7	15.8	0.0	0.0	0.0	806.1	922.9	764.3	742.6	700.0	194.2
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	37.8	9.2	0.3	0.0	30.1
OWC Pumped Storage	0.0	0.0	54.8	50.8	50.5	50.5	48.2	31.8	30.7	31.0	4.1	2.0	2.0	1.6	56.7	64.2	62.3	61.5	66.6	18.9	82.4	91.0	82.5	80.8	77.0	42.0
	248.4	270.5	1480.5	1441.5	1440.5	1423.6	1274.0	1149.3	1135.1	1114.2	818.3	807.3	793.2	791.3	1912.0	1936.8	1922.0	1924.4	1962.3	1617.1	2748.2	2732.1	2716.0	2713.7	2699.7	2513.1
DSR	225.0	247.6	156.2	277.2	293.7	324.5	156.2	277.2	293.7	324.5	156.2	277.2	293.7	324.5	311.4	173.3	311.4	312.5	352.9	311.4	344.2	190.8	344.2	342.0	378.0	344.2
Utah Wind with Tax C	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6
Utah Wind without Tax C	20.3	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	389.0	331.9	354.6	338.0	20.4	20.4	20.4	20.4	20.4	481.7	20.4	20.4	20.4	20.4	20.4	694.7
Utah Geothermal	9.1	9.9	10.2	10.2	10.2	10.1	10.1	10.1	10.1	10.1	10.0	10.0	10.0	10.0	10.2	10.3	10.3	10.3	10.3	9.7	10.3	10.3	10.3	10.3	10.3	10.2
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	36.3	36.2	36.2	36.2	35.5	35.4	15.7	0.0	36.3	36.0	36.0	36.0	36.2	35.5	36.2	35.7	35.7	35.7	35.7	35.5
T Utah Cogeneration 2	0.0	0.0	254.8	104.3	83.3	45.2	104.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	386.2	377.1	377.1	377.1	378.1	185.8	377.1	377.1	377.1	376.4	377.1	374.4
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	514.8	601.6	440.7	444.1	381.4	0.0	1439.2	1440.8	1259.3	1261.7	1228.3	136.5
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	26.1	10.1	9.8	3.4	46.2	31.9	31.1	22.4	53.4	34.6	33.9	25.7	73.1	99.7	76.4	71.2	64.7	87.3	115.0	115.0	114.6	112.8	109.6	172.3
Utah Pumped Storage	0.0	85.0	84.6	83.5	83.4	83.6	89.4	81.2	80.3	78.5	77.3	79.0	77.1	75.5	88.7	108.1	96.9	96.2	94.4	75.4	96.3	117.8	115.1	113.9	115.1	107.1
	293.0	401.5	590.9	544.3	539.4	525.8	501.7	495.6	510.4	530.7	760.0	806.7	823.6	812.3	1479.7	1465.1	1407.8	1406.4	1377.0	1225.4	2477.3	2346.5	2315.3	2311.8	2313.1	1913.5
DSR	74.4	80.9	37.6	91.2	91.5	99.5	37.6	91.2	91.5	99.5	37.6	91.2	91.5	99.5	101.5	41.8	101.5	104.9	110.2	101.5	112.6	46.0	112.6	118.9	122.7	112.6
W Wyo Wind with Tax C	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6	38.6
Y Wyo Wind without Tax C	20.3	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	144.4	42.6	46.5	43.7	20.4	20.4	20.4	20.4	20.4	389.0	20.4	20.4	20.4	20.4	20.4	546.9
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	53.5	204.2	137.6	135.0	126.7	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	0.0	0.0
	133.3	139.9	96.6	150.2	150.5	158.5	96.6	150.2	150.5	158.5	220.6	172.4	176.6	181.8	160.5	100.8	160.5	163.9	169.2	529.1	225.1	311.4	309.2	312.9	308.4	698.1
DSR	497.9	547.6	318.1	612.8	638.1	718.3	318.1	612.8	638.1	718.3	318.1	612.8	638.1	718.3	693.7	349.2	693.7	717.6	795.2	693.7	768.7	379.2	768.7	801.9	868.0	768.7
T Renewable	176.8	179.3	179.3	179.3	179.3	179.2	179.2	179.2	179.2	179.2	888.8	656.6	728.7	666.4	179.3	179.4	179.4	179.4	179.4	1273.0	179.4	179.4	179.4	179.4	179.4	1738.5
O Cogeneration	0.0	0.0	1505.1	1199.5	1169.3	1072.9	1191.2	858.2	836.6	774.0	457.2	401.4	313.6	297.9	1945.9	1929.8	1925.1	1924.7	1926.8	1223.3	1910.0	1899.7	1909.8	1910.0	1917.1	1935.3
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	514.8	772.3	456.5	444.1	381.4	0.0	2298.8	2567.9	2161.2	2139.3	2055.0	330.7
A Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
L Simple Cycle CT	0.0	0.0	26.1	10.1	9.8	3.4	46.2	31.9	31.1	22.4	53.4	34.6	33.9	25.7	73.1	99.7	76.4	71.2	64.7	87.3	115.0	155.0	123.8	113.1	109.6	202.4
Pumped Storage	0.0	85.0	139.4	134.3	133.9	134.1	137.6	113.0	111.0	109.5	81.4	81.0	79.1	77.1	145.4	172.3	159.2	157.7	161.0	94.3	178.7	208.8	197.6	194.7	192.1	149.1
Total	674.7	811.9	2168.0	2136.0	2130.4	2107.9	1872.3	1795.1	1796.0	1803.4	1798.9	1786.4	1793.4	1785.4	3552.2	3502.7	3490.3	3494.7	3508.5	3371.6	5450.6	5390.0	5340.5	5338.4	5321.2	5124.7

T5-10.nc.sr.aMW-20yrs

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Summary by Load Level for Low DSR Strategy (LD)
Percentage of Winter Capacity Additions (%)

Additions in 10 years (1994 - 2003)

Load Level	M												MH				H			
Gas Price	LG				MG				HG				MG				MG			
Coal	any		no		any		no		any		no		any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	12	13	14	15	29	30	31	32	46	47	48	49	65	66	67	68	86	87	88	89
MW Additions																				
DSR	13.5	11.6	13.5	11.6	13.5	11.6	13.5	11.6	13.5	11.6	9.7	11.6	8.9	8.1	8.4	8.1	6.6	6.1	6.3	6.1
Renewable	0.0	21.6	0.0	21.6	0.0	21.6	0.0	21.6	0.0	21.6	41.0	21.6	0.0	14.2	8.4	14.2	0.0	10.2	6.0	10.2
Cogeneration	30.3	23.7	69.5	50.5	19.2	14.2	63.1	45.5	17.4	12.2	13.3	20.3	34.5	29.2	57.7	53.4	33.9	31.6	41.7	40.5
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.4	10.8
Coal	28.5	19.1	0.0	0.0	43.5	33.4	0.0	0.0	47.2	36.2	0.0	0.0	29.4	24.8	0.0	0.0	27.7	22.5	0.0	0.0
Peaking Resources	27.6	23.9	17.0	16.3	23.8	19.2	23.3	21.3	21.9	18.4	36.0	46.5	27.2	23.7	25.5	24.3	31.8	29.6	33.7	32.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																				
DSR	13.0	12.8	12.2	12.1	12.0	11.7	12.9	12.7	11.8	11.6	16.8	18.8	8.6	8.4	8.9	8.9	6.8	6.7	7.2	7.2
Renewable	0.0	13.1	0.0	12.3	0.0	11.8	0.0	12.9	0.0	11.7	37.2	19.3	0.0	7.9	5.0	8.3	0.0	5.9	3.8	6.3
Cogeneration	39.3	35.4	83.2	70.4	23.7	19.9	79.9	66.8	20.4	16.3	34.4	48.6	43.9	39.9	79.8	76.6	46.1	45.8	63.3	63.0
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	17.7
Coal	40.8	31.5	0.0	0.0	57.5	50.1	0.0	0.0	61.1	53.7	0.0	0.0	41.2	37.6	0.0	0.0	41.2	35.5	0.0	0.0
Peaking Resources	6.9	7.2	4.6	5.1	6.9	6.5	7.3	7.7	6.7	6.7	11.6	13.3	6.3	6.2	6.3	6.3	6.0	6.1	5.7	5.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Additions in 20 years (1994 - 2013)

Load Level	M												MH				H			
Gas Price	LG				MG				HG				MG				MG			
Coal	any		no		any		no		any		no		any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	12	13	14	15	29	30	31	32	46	47	48	49	65	66	67	68	86	87	88	89
MW Additions																				
DSR	13.7	12.5	13.7	12.5	13.7	12.5	13.7	12.5	13.7	12.5	8.6	9.0	8.7	8.3	8.5	8.3	6.5	6.3	6.4	6.3
Renewable	0.0	12.6	0.0	12.6	0.0	12.6	0.0	12.6	0.0	12.6	52.5	48.8	0.0	7.8	4.5	7.8	0.0	5.5	3.2	5.5
Cogeneration	16.5	13.8	50.2	39.9	10.4	8.2	41.8	31.3	9.5	7.1	6.4	8.6	18.0	16.0	31.5	30.8	17.6	17.0	22.1	21.8
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.7	12.2	3.9	3.3	30.2	29.0
Coal	38.3	31.3	0.0	0.0	50.0	42.8	0.0	0.0	50.1	43.0	0.0	0.0	45.6	41.5	0.0	0.0	44.6	41.7	0.0	0.0
Peaking Resources	31.6	29.8	36.1	35.0	26.0	23.9	44.6	43.6	26.8	24.8	32.5	33.7	27.7	26.5	41.8	41.0	27.3	26.3	38.2	37.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																				
DSR	13.5	13.6	14.4	14.7	12.4	12.3	16.3	17.0	12.5	12.5	17.8	17.7	8.2	8.1	10.0	10.0	6.3	6.1	7.0	7.0
Renewable	0.0	7.7	0.0	8.3	0.0	6.9	0.0	9.6	0.0	7.0	54.5	49.4	0.0	4.2	3.0	5.1	0.0	2.9	2.0	3.3
Cogeneration	24.0	22.1	78.0	69.4	14.2	12.2	74.2	63.6	13.0	10.7	20.1	25.4	24.3	22.9	55.0	55.1	24.7	23.2	35.3	35.2
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	24.2	22.0	5.8	4.8	48.9	47.6
Coal	57.4	51.5	0.0	0.0	68.6	63.8	0.0	0.0	69.6	64.9	0.0	0.0	63.3	60.5	0.0	0.0	59.0	59.2	0.0	0.0
Peaking Resources	5.1	5.2	7.6	7.6	4.8	4.7	9.5	9.8	4.9	4.9	7.6	7.5	4.2	4.3	7.8	7.8	4.1	3.9	6.8	6.7
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

T5-11.ld.percentage

Table 5-11.b

Summary by Load Level for Low DSR Strategy (LD)
Winter Capacity (MW) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Load Level	M												MH				H			
Gas Price	LG				MG				HG				MG				MG			
Coal	any		no		any		no		any		no		any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	12	13	14	15	29	30	31	32	46	47	48	49	65	66	67	68	86	87	88	89
DSR	149.3	149.3	149.3	149.3	149.3	149.3	149.3	149.3	149.3	149.3	149.3	149.3	156.9	156.9	156.9	156.9	163.3	163.3	163.3	163.3
OWC Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	300.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
OWC Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O OWC Geothermal	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	197.3	168.5	320.0	320.0	160.0	160.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
C OWC Cogeneration 2	636.4	581.5	1037.0	960.5	204.7	178.3	752.4	680.3	204.7	139.1	29.2	139.3	842.3	768.5	1280.5	1207.5	1320.0	1320.0	1320.0	1320.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.4	0.0	0.0	0.0	0.0	116.2	146.9	102.0	97.5	290.6	281.6	18.4	30.7
	785.7	911.8	1186.3	1290.8	551.3	677.1	1221.7	1342.0	514.0	629.4	798.5	789.6	1435.4	1573.3	1859.4	1962.9	2094.2	2265.9	1821.7	2015.0
DSR	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	127.0	127.0	127.0	127.0	135.9	135.9	135.9	135.9
Utah Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0
Utah Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
Utah Geothermal	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0
T Utah Cogeneration 2	0.0	0.0	420.0	277.1	0.0	0.0	250.8	114.0	0.0	0.0	0.0	0.0	0.0	0.0	420.0	419.9	0.0	0.0	420.0	420.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	624.7	557.6
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	597.7	468.3	0.0	0.0	912.1	818.7	0.0	0.0	990.0	885.3	0.0	0.0	990.0	922.6	0.0	0.0	990.0	990.0	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	118.8	86.5	0.0	0.0	0.0	0.0	0.0	10.5	0.0	0.0	554.0	638.0	300.9	233.6	308.8	307.5	745.4	751.7	1176.9	1152.6
Utah Pumped Storage	461.1	500.0	357.1	398.7	500.0	470.8	489.8	500.0	459.4	451.8	500.0	500.0	499.9	500.0	500.0	500.0	500.0	500.0	500.0	500.0
	1296.1	1353.3	895.6	974.3	1530.6	1588.0	860.2	923.0	1567.9	1635.6	1661.5	1475.5	1917.8	1963.2	1544.8	1573.4	2371.3	2557.6	3046.5	2985.1
DSR	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	15.8	17.0	17.0	17.0	17.0	18.3	18.3	18.3	18.3
W Wyo Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0
Y Wyo Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	351.5	176.7	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	15.8	183.8	15.8	183.8	15.8	183.8	15.8	183.8	15.8	183.8	465.8	183.8	17.0	185.0	167.0	185.0	369.8	363.0	168.3	186.3
DSR	283.6	283.6	283.6	283.6	283.6	283.6	283.6	283.6	283.6	283.6	283.6	283.6	300.9	300.9	300.9	300.9	317.5	317.5	317.5	317.5
T Renewable	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	1200.0	529.0	0.0	529.0	300.0	529.0	0.0	529.0	300.0	529.0
O Cogeneration	636.4	581.5	1457.0	1237.6	402.0	346.8	1324.3	1114.3	364.7	299.1	388.2	498.3	1162.3	1088.5	2059.5	1986.4	1640.0	1640.0	2099.0	2099.0
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	624.7	557.6
A Coal	597.7	468.3	0.0	0.0	912.1	818.7	0.0	0.0	990.0	885.3	0.0	0.0	990.0	922.6	0.0	0.0	1341.5	1166.7	0.0	0.0
L Simple Cycle CT	118.8	86.5	0.0	0.0	0.0	0.0	0.0	10.5	0.0	0.0	554.0	638.0	300.9	233.6	308.8	307.5	745.4	751.7	1176.9	1152.6
Pumped Storage	461.1	500.0	357.1	398.7	500.0	470.8	489.8	511.4	459.4	451.8	500.0	500.0	616.1	646.9	602.0	597.5	790.6	781.6	518.4	530.7
Total	2097.6	2448.9	2097.7	2448.9	2097.7	2448.9	2097.7	2448.8	2097.7	2448.8	2925.8	2448.9	3370.2	3721.5	3571.2	3721.3	4835.3	5186.5	5036.5	5186.4

Table 5-11.c

Summary by Load Level for Low DSR Strategy (LD)
Annual Energy (MWa) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

	Load Level	M												MH				H			
	Gas Price	LG				MG				HG				MG				MG			
	Coal	any		no		any		no		any		no		any		no		any		no	
	Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
	Case #	12	13	14	15	29	30	31	32	46	47	48	49	65	66	67	68	86	87	88	89
	DSR	79.1	79.1	79.1	79.1	79.1	79.1	79.1	79.1	79.1	79.1	79.1	79.1	84.3	84.3	84.3	84.3	88.5	88.5	88.5	88.5
	OWC Wind with Tax C	0.0	26.3	0.0	26.2	0.0	26.3	0.0	26.3	0.0	26.3	71.7	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3
	OWC Wind without Tax C	0.0	13.9	0.0	13.8	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9
O	OWC Geothermal	0.0	10.2	0.0	10.1	0.0	9.9	0.0	10.1	0.0	9.9	0.0	10.8	0.0	9.9	0.0	9.9	0.0	10.1	0.0	10.2
W	OWC Cogeneration 1	0.0	0.0	0.0	0.0	175.4	149.7	277.5	277.5	139.5	135.0	297.0	296.8	277.8	277.8	277.5	277.5	286.9	286.2	290.0	289.8
C	OWC Cogeneration 2	526.5	481.0	842.9	787.0	169.3	147.5	598.7	550.1	163.6	111.2	25.5	119.0	689.0	618.3	1033.5	973.5	1087.5	1092.0	1092.0	1092.0
	OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0
	OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.0	0.0	0.0	0.0	17.7	22.8	15.5	14.8	40.2	43.3	2.9	4.8
		605.6	610.5	922.0	916.2	423.8	426.4	955.3	958.7	382.2	375.4	473.3	545.9	1068.8	1053.3	1410.8	1400.2	1503.4	1560.3	1473.4	1525.5
	DSR	81.3	81.3	81.3	81.3	81.3	81.3	81.3	81.3	81.3	81.3	81.3	81.3	89.2	89.2	89.2	89.2	97.2	97.2	97.2	97.2
	Utah Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6
	Utah Wind without Tax C	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4
	Utah Geothermal	0.0	9.5	0.0	9.5	0.0	9.1	0.0	9.4	0.0	9.1	0.0	10.0	0.0	9.1	0.0	9.3	0.0	9.4	0.0	9.8
	Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U	Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	35.9	35.9	0.0	0.0	34.2	34.2	0.0	0.0	35.7	35.7
T	Utah Cogeneration 2	0.0	0.0	347.6	227.9	0.0	0.0	207.5	93.8	0.0	0.0	0.0	0.0	0.0	0.0	347.5	347.3	0.0	0.0	361.1	359.2
A	Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	560.8	500.2
H	Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah Coal	547.8	429.1	0.0	0.0	835.9	750.2	0.0	0.0	907.2	811.3	0.0	0.0	907.2	845.4	0.0	0.0	907.2	907.2	0.0	0.0
	Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah Simple Cycle CT	6.6	4.8	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	30.8	35.5	16.7	13.0	17.2	17.1	41.4	41.8	65.4	64.1
	Utah Pumped Storage	85.6	92.8	66.3	74.0	99.8	98.0	99.0	104.0	99.9	101.8	89.8	87.7	104.7	103.6	101.1	101.9	96.0	98.4	92.8	94.2
		721.3	676.5	495.2	451.7	1017.0	997.6	388.8	348.1	1088.4	1062.5	395.8	309.4	1117.8	1119.3	641.9	658.0	1141.8	1213.0	1265.7	1219.4
	DSR	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	15.3	15.3	15.3	15.3	16.5	16.5	16.5	16.5
W	Wyo Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6
Y	Wyo Wind without Tax C	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4
O	Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M	Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I	Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	322.1	161.9	0.0	0.0
N	Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G	Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		14.2	73.2	14.2	73.2	14.2	73.2	14.2	73.2	14.2	73.2	172.2	73.2	15.3	74.3	68.0	74.3	338.6	237.4	69.2	75.5
	DSR	174.6	174.6	174.6	174.6	174.6	174.6	174.6	174.6	174.6	174.6	174.6	174.6	188.8	188.8	188.8	188.8	202.2	202.2	202.2	202.2
T	Renewable	0.0	177.9	0.0	177.6	0.0	177.2	0.0	177.7	0.0	177.2	387.7	179.0	0.0	177.2	105.4	177.4	0.0	177.7	105.4	178.2
O	Cogeneration	526.5	481.0	1190.5	1014.9	344.7	297.2	1084.7	921.4	303.1	246.2	358.4	451.7	966.8	896.1	1692.7	1632.5	1374.4	1378.2	1778.8	1776.7
T	Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	560.8	500.2
A	Coal	547.8	429.1	0.0	0.0	835.9	750.2	0.0	0.0	907.2	811.3	0.0	0.0	907.2	845.4	0.0	0.0	1229.3	1069.1	0.0	0.0
L	Simple Cycle CT	6.6	4.8	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	30.8	35.5	16.7	13.0	17.2	17.1	41.4	41.8	65.4	64.1
	Pumped Storage	85.6	92.8	66.3	74.0	99.8	98.0	99.0	105.7	99.9	101.8	89.8	87.7	122.4	126.4	116.6	116.7	136.2	141.7	95.7	99.0
	Total	1341.1	1360.2	1431.4	1441.1	1455.0	1497.2	1358.3	1380.0	1484.8	1511.1	1041.3	928.5	2201.9	2246.9	2120.7	2132.5	2983.8	3010.7	2808.3	2820.4

T5-11.ld aMW-10yrs

Table 5-11.d

Summary by Load Level for Low DSR Strategy (LD)
Winter Capacity (MW) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load Level	M												MH				H			
Gas Price	LG				MG				HG				MG				MG			
Coal	any		no		any		no		any		no		any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	12	13	14	15	29	30	31	32	46	47	48	49	65	66	67	68	86	87	88	89
DSR	254.7	254.7	254.7	254.7	254.7	254.7	254.7	254.7	254.7	254.7	254.7	254.7	270.8	270.8	270.8	270.8	285.0	285.0	285.0	285.0
OWC Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	300.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
OWC Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	1050.0	966.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O OWC Geothermal	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0
W OWC Cogeneration 1	0.0	0.0	195.7	82.0	197.3	168.5	320.0	320.0	160.0	160.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
C OWC Cogeneration 2	636.4	581.5	1320.0	1320.0	204.7	178.3	1000.1	844.5	204.7	139.1	29.2	139.3	842.3	768.5	1320.0	1320.0	1320.0	1320.0	1320.0	1320.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	237.6	183.4	366.7	320.2	1042.2	997.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	31.7	42.1	0.0	0.0	402.1	420.6	0.0	0.0	791.1	783.0	542.0	527.8
OWC Pumped Storage	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	499.9	500.0	500.0	500.0	500.0	500.0	500.0	500.0
	1391.1	1517.2	2270.4	2337.7	1156.7	1282.8	2074.8	2100.2	1151.1	1276.9	2453.9	2303.0	2335.1	2460.9	2648.4	2775.2	3582.8	3709.2	4009.2	4130.8
DSR	230.7	230.7	230.7	230.7	230.7	230.7	230.7	230.7	230.7	230.7	230.7	230.7	249.7	249.7	249.7	249.7	269.0	269.0	269.0	269.0
Utah Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0
Utah Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	902.9	1108.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
Utah Geothermal	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0
T Utah Cogeneration 2	0.0	0.0	420.0	277.1	0.0	0.0	250.8	114.0	0.0	0.0	0.0	0.0	0.0	0.0	420.0	419.9	0.0	0.0	420.0	420.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	678.1	651.3	0.0	0.0	1595.8	1577.9
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	1474.0	1314.7	0.0	0.0	1924.8	1798.7	0.0	0.0	1930.4	1807.6	0.0	0.0	2941.0	2833.9	0.0	0.0	3763.1	3681.3	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	216.3	252.8	391.0	469.8	0.0	3.2	716.8	831.4	0.0	0.0	988.2	960.6	389.9	384.7	1791.8	1793.8	745.4	751.7	2069.9	2068.3
Utah Pumped Storage	499.9	500.0	500.1	500.1	500.0	500.0	500.0	500.0	499.9	500.0	500.0	500.0	499.9	500.0	500.0	500.0	500.0	500.0	500.0	500.0
	2420.9	2478.2	1541.8	1657.7	2655.5	2712.6	1737.3	1895.1	2661.0	2718.3	3110.8	2960.3	4080.5	4148.3	3828.6	3833.7	5277.5	5382.0	5043.7	5054.2
DSR	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	45.4	45.4	45.4	45.4	49.8	49.8	49.8	49.8
W Wyo Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	150.0	110.0
Y Wyo Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	54.4	411.3	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	233.0	222.8
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.2	0.0	0.0	0.0	385.7	338.2	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.4	21.4
	41.0	209.0	41.0	209.0	41.0	209.0	41.0	209.0	41.0	209.0	545.4	562.3	55.6	213.4	195.4	213.4	435.5	556.0	444.2	462.0
DSR	526.4	526.4	526.4	526.4	526.4	526.4	526.4	526.4	526.4	526.4	526.4	526.4	565.9	565.9	565.9	565.9	603.8	603.8	603.8	603.8
T Renewable	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	3207.3	2840.3	0.0	529.0	300.0	529.0	0.0	529.0	300.0	529.0
O Cogeneration	636.4	581.5	1935.7	1679.1	402.0	346.8	1609.9	1317.5	364.7	299.1	388.2	498.3	1162.3	1088.5	2099.0	2098.9	1640.0	1640.0	2099.0	2099.0
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	915.7	834.7	366.7	320.2	2871.0	2797.7
A Coal	1474.0	1314.7	0.0	0.0	1924.8	1798.7	0.0	0.0	1930.4	1807.6	0.0	0.0	2951.2	2833.9	0.0	0.0	4148.8	4019.5	0.0	0.0
L Simple Cycle CT	216.3	252.8	391.0	469.8	0.0	3.5	716.8	831.4	31.7	42.1	988.2	960.6	792.0	805.3	1791.8	1793.8	1536.5	1534.7	2623.3	2617.5
Pumped Storage	999.9	1000.0	1000.1	1000.1	1000.0	1000.0	1000.0	1000.0	999.9	1000.0	1000.0	1000.0	999.8	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0
Total	3853.0	4204.4	3853.2	4204.4	3853.2	4204.4	3853.1	4204.3	3853.1	4204.2	6110.1	5825.6	6471.2	6822.6	6672.4	6822.3	9295.8	9647.2	9497.1	9647.0

T5-11.ld.MW add-20yrs

Summary by Load Level for Low DSR Strategy (LD)
Annual Energy (MWa) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load Level	M												MH				H			
Gas Price	LG				MG				HG				MG				MG			
Coal	any		no		any		no		any		no		any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	12	13	14	15	29	30	31	32	46	47	48	49	65	66	67	68	86	87	88	89
DSR	124.3	124.3	124.3	124.3	124.3	124.3	124.3	124.3	124.3	124.3	124.3	124.3	134.1	134.1	134.1	134.1	142.4	142.4	142.4	142.4
OWC Wind with Tax C	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	71.7	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3
OWC Wind without Tax C	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	250.8	230.7	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9
O OWC Geothermal	0.0	11.4	0.0	10.9	0.0	11.4	0.0	10.9	0.0	11.7	0.0	11.2	0.0	11.4	0.0	10.9	0.0	10.8	0.0	10.9
W OWC Cogeneration 1	0.0	0.0	182.2	76.4	183.7	156.8	297.9	297.9	148.9	148.9	297.9	297.9	297.9	297.9	297.2	297.2	297.9	297.9	297.0	297.0
C OWC Cogeneration 2	565.8	517.0	1155.6	1173.9	182.0	158.5	885.8	752.5	182.0	123.7	25.9	123.8	742.6	683.3	1219.5	1219.5	1146.1	1146.1	1192.3	1189.9
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	221.1	170.7	341.3	297.9	965.2	922.9
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	3.2	0.0	0.0	30.4	32.0	0.0	0.0	61.9	61.4	38.8	37.8
OWC Pumped Storage	9.3	9.6	55.8	54.8	3.9	4.1	55.6	48.2	4.0	4.1	3.5	4.1	3.4	7.1	64.7	64.2	12.3	13.0	91.6	91.0
	699.4	702.5	1517.9	1480.5	493.9	495.3	1363.6	1274.0	461.6	456.1	774.1	818.3	1208.4	1206.0	1936.6	1936.8	2001.9	2009.7	2727.3	2732.1
DSR	156.2	156.2	156.2	156.2	156.2	156.2	156.2	156.2	156.2	156.2	156.2	156.2	173.3	173.3	173.3	173.3	190.8	190.8	190.8	190.8
Utah Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6
Utah Wind without Tax C	0.0	20.4	0.0	20.4	0.0	20.3	0.0	20.4	0.0	20.3	317.0	389.0	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4
Utah Geothermal	0.0	9.6	0.0	10.2	0.0	9.4	0.0	10.1	0.0	9.4	0.0	10.0	0.0	9.3	0.0	10.3	0.0	9.1	0.0	10.3
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	36.3	36.3	0.0	0.0	35.5	35.5	0.0	0.0	36.0	36.0	0.0	0.0	35.7	35.7
T Utah Cogeneration 2	0.0	0.0	387.0	254.8	0.0	0.0	227.6	104.5	0.0	0.0	0.0	0.0	0.0	0.0	377.1	377.1	0.0	0.0	377.1	377.1
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	626.3	601.6	0.0	0.0	1457.4	1440.8
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	1350.8	1204.7	0.0	0.0	1763.8	1648.2	0.0	0.0	1769.0	1656.5	0.0	0.0	2695.1	2597.0	0.0	0.0	3448.5	3373.5	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	12.0	14.1	21.7	26.1	0.0	0.2	39.9	46.2	0.0	0.0	54.9	53.4	21.7	21.4	99.6	99.7	41.4	41.8	115.1	115.0
Utah Pumped Storage	99.2	97.3	91.4	84.6	118.4	118.2	90.5	89.4	118.2	118.7	77.8	77.3	124.1	124.1	109.9	108.1	124.1	124.1	119.8	117.8
	1618.2	1540.9	656.3	590.9	2038.4	1991.1	550.5	501.7	2043.4	1999.7	799.4	760.0	3014.2	2984.0	1474.9	1465.1	3804.8	3798.2	2348.6	2346.5
DSR	37.6	37.6	37.6	37.6	37.6	37.6	37.6	37.6	37.6	37.6	37.6	37.6	41.8	41.8	41.8	41.8	37.6	46.0	46.0	46.0
W Wyo Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	52.7	38.6	0.0	38.6	52.7	38.6
Y Wyo Wind without Tax C	0.0	20.4	0.0	20.4	0.0	20.3	0.0	20.4	0.0	20.3	19.1	144.4	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	213.5	204.2
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.4	0.0	0.0	0.0	0.0	310.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	2.2
	37.6	96.6	37.6	96.6	37.6	96.5	37.6	96.6	37.6	96.5	214.7	220.6	51.2	100.7	94.5	100.8	37.6	414.9	313.4	311.4
DSR	318.1	318.1	318.1	318.1	318.1	318.1	318.1	318.1	318.1	318.1	318.1	318.1	349.2	349.2	349.2	349.2	370.8	379.2	379.2	379.2
T Renewable	0.0	179.2	0.0	179.3	0.0	178.8	0.0	179.2	0.0	179.1	974.6	888.8	0.0	178.7	105.4	179.4	0.0	177.9	105.4	179.4
O Cogeneration	565.8	517.0	1724.8	1505.1	365.7	315.3	1447.6	1191.2	330.9	272.6	359.3	457.2	1040.5	981.2	1929.8	1929.8	1444.0	1444.0	1902.1	1899.7
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	847.4	772.3	341.3	297.9	2636.1	2567.9
A Coal	1350.8	1204.7	0.0	0.0	1763.8	1648.2	0.0	0.0	1769.0	1656.5	0.0	0.0	2704.5	2597.0	0.0	0.0	3448.5	3683.5	0.0	0.0
L Simple Cycle CT	12.0	14.1	21.7	26.1	0.0	0.2	39.9	46.2	2.4	3.2	54.9	53.4	52.1	53.4	99.6	99.7	103.3	103.2	155.1	155.0
Pumped Storage	108.5	106.9	147.2	139.4	122.3	122.3	146.1	137.6	122.2	122.8	81.3	81.4	127.5	131.2	174.6	172.3	136.4	137.1	211.4	208.8
Total	2355.2	2340.0	2211.8	2168.0	2569.9	2582.9	1951.7	1872.3	2542.6	2552.3	1788.2	1798.9	4273.8	4290.7	3506.0	3502.7	5844.3	6222.8	5389.3	5390.0

T5-11.ld.aMW-20yrs

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Summary by Load Level for Medium DSR and Any-Coal Strategy (MD.AC)
Percentage of Winter Capacity Additions (%)

Additions in 10 years (1994 - 2003)

Load Level	L		ML		M						MH				H			
Gas Price	MG		MG		LG		MG		HG		LG	MG		HG	LG	MG		HG
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	strat	any	strat	strat	strat	any	strat	strat
Case #	2	3	7	8	16	17	33	34	50	51	62	69	70	81	83	90	91	102
MW Additions																		
DSR	100.0	50.5	70.2	49.0	29.7	25.3	29.7	25.3	29.7	25.3	18.1	20.1	18.1	18.1	13.9	15.0	13.9	13.9
Renewable	0.0	49.5	0.0	45.4	0.0	22.0	0.0	22.0	0.0	22.0	14.4	0.0	14.4	14.4	10.3	0.0	10.3	10.3
Cogeneration	0.0	0.0	0.0	0.0	23.3	17.7	14.7	11.5	7.8	11.5	42.4	29.1	24.4	21.8	36.8	34.3	32.0	29.6
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	0.0	29.8	3.2	27.5	17.8	39.2	29.2	45.1	31.3	6.3	29.9	24.4	27.2	13.3	25.3	20.5	25.8
Peaking Resources	0.0	0.0	0.0	2.4	19.5	17.1	16.4	12.0	17.4	9.8	18.7	21.0	18.6	18.4	25.6	25.4	23.2	20.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																		
DSR	100.0	63.4	59.4	59.8	26.1	25.8	24.6	23.7	24.6	23.2	17.6	17.2	16.9	16.8	13.9	13.5	13.3	12.8
Renewable	0.0	36.6	0.0	32.7	0.0	13.2	0.0	12.1	0.0	11.9	8.2	0.0	7.9	7.8	6.1	0.0	5.8	5.6
Cogeneration	0.0	0.0	0.0	0.0	29.6	26.1	18.4	16.1	10.3	15.3	59.5	36.6	33.3	29.2	54.0	44.7	44.1	38.1
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.0	0.0	40.6	6.3	38.7	29.1	52.1	43.7	59.9	46.0	9.8	41.0	36.6	40.4	21.3	36.4	31.3	38.0
Peaking Resources	0.0	0.0	0.0	1.1	5.5	5.7	4.8	4.4	5.2	3.6	4.8	5.3	5.3	5.8	4.8	5.4	5.5	5.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Additions in 20 years (1994 - 2013)

Load Level	L		ML		M						MH				H			
Gas Price	MG		MG		LG		MG		HG		LG	MG		HG	LG	MG		HG
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	strat	any	strat	strat	strat	any	strat	strat
Case #	2	3	7	8	16	17	33	34	50	51	62	69	70	81	83	90	91	102
MW Additions																		
DSR	100.0	62.0	60.9	49.7	28.4	26.0	28.4	26.0	28.4	26.0	18.2	19.3	18.2	18.2	14.3	14.8	14.3	14.2
Renewable	0.0	38.0	0.0	27.5	0.0	12.8	0.0	12.8	0.0	12.8	7.9	0.0	7.9	7.9	5.5	0.0	5.5	6.8
Cogeneration	0.0	0.0	0.0	0.0	12.7	10.3	8.0	6.7	4.2	6.7	23.1	15.1	13.3	11.9	19.8	17.9	17.2	17.0
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.9	2.0	1.4	0.0
Coal	0.0	0.0	24.2	8.9	32.4	26.6	38.1	30.9	42.3	33.9	27.3	43.7	39.4	42.3	31.8	42.5	39.5	42.6
Peaking Resources	0.0	0.0	15.0	13.9	26.5	24.3	25.5	23.6	25.1	20.6	23.4	21.9	21.2	19.7	25.7	22.8	22.1	19.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																		
DSR	100.0	73.8	57.7	58.1	27.2	27.0	26.4	26.4	26.2	25.1	16.9	16.2	16.3	15.9	13.0	12.5	12.5	12.0
Renewable	0.0	26.2	0.0	18.9	0.0	7.9	0.0	7.7	0.0	7.3	4.4	0.0	4.2	4.1	3.0	0.0	2.9	3.3
Cogeneration	0.0	0.0	0.0	0.0	18.8	16.6	11.8	10.8	6.4	10.3	33.4	20.4	19.0	16.6	28.7	23.5	23.5	22.9
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.3	2.7	2.0	0.0
Coal	0.0	0.0	36.6	16.6	49.7	44.3	56.7	50.3	62.5	52.5	41.0	59.8	56.9	59.7	46.9	58.0	55.9	59.0
Peaking Resources	0.0	0.0	5.6	6.4	4.3	4.2	5.1	4.8	5.0	4.7	4.3	3.6	3.7	3.7	4.1	3.2	3.2	2.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 5-12.b

Summary by Load Level for Medium DSR and Any-Coal Strategy (MD.AC)
Winter Capacity (MW) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Load Level	L		ML		M						MH				H			
Gas Price	MG		MG		LG		MG		HG		LG	MG		HG	LG	MG		HG
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	strat	any	strat	strat	strat	any	strat	strat
Case #	2	3	7	8	16	17	33	34	50	51	62	69	70	81	83	90	91	102
DSR	318.9	318.9	336.7	336.7	359.2	359.2	359.2	359.2	359.2	359.2	393.4	393.4	393.4	393.4	422.8	422.8	422.8	422.8
OWC Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	110.0	0.0	110.0	110.0	110.0	0.0	110.0	110.0
OWC Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58.0	0.0	58.0	58.0	58.0	0.0	58.0	58.0
O OWC Geothermal	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	13.0	0.0	13.0	13.0	13.0	0.0	13.0	13.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	160.0	160.0	160.0	160.0	160.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
C OWC Cogeneration 2	0.0	0.0	0.0	0.0	477.9	425.1	142.0	115.6	0.0	115.6	1146.4	644.7	574.5	480.8	1320.0	1320.0	1320.0	1196.5
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.6	48.2	73.0	76.4	14.5	208.5	293.9	327.1
	318.9	499.9	336.7	517.7	837.1	965.3	661.2	815.8	519.2	815.8	1894.4	1406.3	1541.9	1551.6	2258.3	2271.3	2537.7	2447.4
DSR	179.2	179.2	189.3	189.3	200.8	200.8	200.8	200.8	200.8	200.8	217.8	217.8	217.8	217.8	233.0	233.0	233.0	233.0
Utah Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	110.0	0.0	110.0	110.0	110.0	0.0	110.0	110.0
Utah Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58.0	0.0	58.0	58.0	58.0	0.0	58.0	58.0
Utah Geothermal	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	12.0	0.0	12.0	12.0	12.0	0.0	12.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	39.0	0.0	0.0	0.0	39.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	210.0	0.0	0.0	0.0	210.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	242.8	37.6	563.9	427.9	802.5	699.7	924.0	751.1	231.7	990.0	894.8	990.0	684.3	990.0	990.0	990.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	172.5	148.1	110.8	0.0	796.3	506.9	397.9	220.2
Utah Pumped Storage	0.0	0.0	0.0	27.4	398.8	409.6	336.2	287.4	356.6	236.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	499.9
	179.2	359.2	432.1	434.3	1163.5	1218.3	1339.5	1367.9	1481.4	1367.9	1551.0	1855.9	1903.4	1887.8	2642.6	2229.9	2300.9	2123.1
DSR	42.5	42.5	44.9	44.9	48.2	48.2	48.2	48.2	48.2	48.2	53.7	53.7	53.7	53.7	58.4	58.4	58.4	58.4
W Wyo Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	110.0	0.0	110.0	110.0	110.0	0.0	110.0	110.0
Y Wyo Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58.0	0.0	58.0	58.0	58.0	0.0	58.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	0.0	216.6	62.3	330.3
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	42.5	210.5	44.9	212.9	48.2	216.2	48.2	216.2	48.2	216.2	221.7	53.7	221.7	227.6	226.4	275.0	288.7	556.7
DSR	540.6	540.6	570.9	570.9	608.2	608.2	608.2	608.2	608.2	608.2	664.9	664.9	664.9	664.9	714.2	714.2	714.2	714.2
T Renewable	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	529.0	0.0	529.0	529.0	529.0	0.0	529.0	529.0
O Cogeneration	0.0	0.0	0.0	0.0	477.9	425.1	302.0	275.6	160.0	275.6	1555.4	964.7	894.5	800.8	1889.0	1640.0	1640.0	1516.5
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	0.0	0.0	242.8	37.6	563.9	427.9	802.5	699.7	924.0	751.1	231.7	990.0	894.8	995.9	684.3	1206.6	1052.3	1320.3
L Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	172.5	148.1	110.8	0.0	796.3	506.9	397.9	220.2
Pumped Storage	0.0	0.0	0.0	27.4	398.8	409.6	336.2	287.4	356.6	236.0	513.6	548.2	573.0	676.4	514.5	708.5	793.9	827.0
Total	540.6	1069.6	813.7	1164.9	2048.8	2399.8	2048.9	2399.9	2048.8	2399.9	3667.1	3315.9	3667.0	3667.0	5127.3	4776.2	5127.3	5127.2

Summary by Load Level for Medium DSR and Any-Coal Strategy (MD.AC)
Annual Energy (MWa) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Load Level	L		ML		M						MH				H			
Gas Price	MG		MG		LG		MG		HG		LG	MG		HG	LG	MG		HG
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	strat	any	strat	strat	strat	any	strat	strat
Case #	2	3	7	8	16	17	33	34	50	51	62	69	70	81	83	90	91	102
DSR	139.3	139.3	146.3	146.3	155.4	155.4	155.4	155.4	155.4	155.4	168.7	168.7	168.7	168.7	180.2	180.2	180.2	180.2
OWC Wind with Tax C	0.0	26.2	0.0	26.3	0.0	26.2	0.0	26.3	0.0	26.3	26.2	0.0	26.3	26.3	26.3	0.0	26.3	26.3
OWC Wind without Tax C	0.0	13.8	0.0	13.9	0.0	13.8	0.0	13.9	0.0	13.9	13.8	0.0	13.9	13.9	13.9	0.0	13.9	13.9
O OWC Geothermal	0.0	9.9	0.0	10.2	0.0	10.4	0.0	10.2	0.0	10.2	10.2	0.0	9.9	9.9	10.3	0.0	9.9	9.9
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	142.2	140.1	145.5	135.0	139.9	277.5	277.8	281.1	283.5	283.5	286.2	275.9
C OWC Cogeneration 2	0.0	0.0	0.0	0.0	395.3	351.7	117.5	95.6	0.0	94.4	939.3	532.0	468.2	377.9	1092.0	1074.7	1071.4	937.9
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1	8.9	13.0	23.0	2.6	35.3	43.3	53.4
	139.3	189.2	146.3	196.7	550.7	557.5	415.1	441.5	300.9	435.2	1300.2	987.1	977.8	900.8	1608.8	1573.7	1631.2	1497.5
DSR	128.7	128.7	137.7	137.7	148.9	148.9	148.9	148.9	148.9	148.9	163.0	163.0	163.0	163.0	176.6	176.6	176.6	176.6
Utah Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	38.6	0.0	38.6	38.6	38.6	0.0	38.6	38.6
Utah Wind without Tax C	0.0	20.3	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	20.4	0.0	20.4	20.4	20.4	0.0	20.4	20.4
Utah Geothermal	0.0	9.1	0.0	9.4	0.0	9.5	0.0	9.3	0.0	9.3	9.9	0.0	9.1	9.1	9.9	0.0	9.3	9.1
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.0	0.0	0.0	0.0	35.4	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	173.8	0.0	0.0	0.0	176.1	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	222.5	34.4	516.8	392.2	735.4	641.2	846.8	688.3	212.4	907.2	820.0	907.2	627.1	907.2	907.2	907.2
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.6	8.2	6.2	0.0	44.3	28.2	22.1	12.2
Utah Pumped Storage	0.0	0.0	0.0	6.2	74.0	76.1	68.3	64.0	73.8	53.5	92.8	99.4	100.5	109.0	92.8	100.0	103.9	111.1
	128.7	196.7	360.2	246.7	739.7	685.7	952.6	922.4	1069.5	959.0	755.5	1177.8	1157.8	1247.3	1221.2	1212.0	1278.1	1275.2
DSR	38.8	38.8	41.2	41.2	43.5	43.5	43.5	43.5	43.5	43.5	48.2	48.2	48.2	48.2	52.0	52.0	52.0	52.0
W Wyo Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	38.6	0.0	38.6	38.6	38.6	0.0	38.6	38.6
Y Wyo Wind without Tax C	0.0	20.3	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	20.4	0.0	20.4	20.4	20.4	0.0	20.4	20.4
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.4	0.0	198.5	57.1	302.7
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	38.8	97.7	41.2	100.2	43.5	102.5	43.5	102.5	43.5	102.5	107.2	48.2	107.2	112.6	111.0	250.5	168.1	413.7
DSR	306.8	306.8	325.2	325.2	347.8	347.8	347.8	347.8	347.8	347.8	379.9	379.9	379.9	379.9	408.8	408.8	408.8	408.8
T Renewable	0.0	176.8	0.0	177.8	0.0	177.9	0.0	177.7	0.0	177.7	178.1	0.0	177.2	177.2	178.4	0.0	177.4	177.2
O Cogeneration	0.0	0.0	0.0	0.0	395.3	351.7	259.7	235.7	145.5	229.4	1288.0	809.5	746.0	659.0	1587.0	1358.2	1357.6	1213.8
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
A Coal	0.0	0.0	222.5	34.4	516.8	392.2	735.4	641.2	846.8	688.3	212.4	907.2	820.0	912.6	627.1	1105.7	964.3	1209.9
L Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.6	8.2	6.2	0.0	44.3	28.2	22.1	12.2
Pumped Storage	0.0	0.0	0.0	6.2	74.0	76.1	68.3	64.0	73.8	53.5	94.9	108.3	113.5	132.0	95.4	135.3	147.2	164.5
Total	306.8	483.6	547.7	543.6	1333.9	1345.7	1411.2	1466.4	1413.9	1496.7	2162.9	2213.1	2242.8	2260.7	2941.0	3036.2	3077.4	3186.4

T6-12.md.ac.aMW-10yrs

Table 5-12.d

Summary by Load Level for Medium DSR and Any-Coal Strategy (MD.AC)
Winter Capacity (MW) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load Level	L		ML		M						MH				H			
Gas Price	MG		MG		LG		MG		HG		LG	MG		HG	LG	MG		HG
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	strat	any	strat	strat	strat	any	strat	strat
Case #	2	3	7	8	16	17	33	34	50	51	62	69	70	81	83	90	91	102
DSR	449.7	449.7	509.0	509.0	577.1	577.1	577.1	577.1	577.1	577.1	680.0	680.0	680.0	680.0	765.4	765.4	765.4	765.4
OWC Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	110.0	0.0	110.0	110.0	110.0	0.0	110.0	110.0
OWC Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58.0	0.0	58.0	58.0	58.0	0.0	58.0	187.1
O OWC Geothermal	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	13.0	0.0	13.0	13.0	13.0	0.0	13.0	13.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	160.0	160.0	160.0	160.0	160.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
C OWC Cogeneration 2	0.0	0.0	0.0	0.0	477.9	425.1	142.0	115.6	0.0	115.6	1146.4	644.7	574.5	480.8	1320.0	1320.0	1320.0	1320.1
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	273.1	180.6	132.9	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	232.1	247.1	325.9	406.0	550.7	543.6	642.6
OWC Pumped Storage	0.0	0.0	0.0	0.0	500.0	500.0	461.4	472.5	445.4	347.9	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0
	449.7	630.7	509.0	690.0	1555.0	1683.2	1340.5	1506.2	1182.5	1381.6	2667.4	2376.8	2502.6	2487.7	3765.5	3636.7	3762.9	3858.2
DSR	331.2	331.2	356.9	356.9	390.0	390.0	390.0	390.0	390.0	390.0	429.5	429.5	429.5	429.5	466.2	466.2	466.2	466.2
Utah Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	110.0	0.0	110.0	110.0	110.0	0.0	110.0	110.0
Utah Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58.0	0.0	58.0	58.0	58.0	0.0	58.0	58.0
Utah Geothermal	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	12.0	0.0	12.0	12.0	12.0	0.0	12.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	39.0	0.0	0.0	0.0	39.0	0.0	0.0	0.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	210.0	0.0	0.0	0.0	210.0	0.0	0.0	0.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	379.3	170.3	1222.4	1097.3	1436.9	1274.2	1595.0	1398.9	1838.8	2787.5	2649.1	2835.2	3029.7	3621.5	3599.1	3775.7
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	573.7	161.4	177.1	0.0	1043.3	545.0	558.9	220.2
Utah Pumped Storage	0.0	0.0	235.4	266.5	500.0	499.9	500.1	500.0	500.0	500.1	500.0	500.0	500.0	500.0	500.0	500.0	500.0	499.9
	331.2	511.2	971.6	973.7	2112.4	2167.2	2327.0	2344.2	2485.0	2469.0	3771.0	3878.4	3935.7	3944.7	5468.2	5132.7	5304.2	5142.0
DSR	83.1	83.1	89.8	89.8	104.1	104.1	104.1	104.1	104.1	104.1	117.5	117.5	117.5	117.5	131.8	131.8	131.8	131.8
W Wyo Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	110.0	0.0	110.0	110.0	110.0	0.0	110.0	110.0
Y Wyo Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58.0	0.0	58.0	58.0	58.0	0.0	58.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	0.0	281.2	166.6	330.3
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	83.1	251.1	89.8	257.8	104.1	272.1	104.1	272.1	104.1	272.1	285.5	117.5	285.5	291.4	299.8	413.0	466.4	630.1
DSR	864.0	864.0	955.7	955.7	1071.2	1071.2	1071.2	1071.2	1071.2	1071.2	1227.0	1227.0	1227.0	1227.0	1363.4	1363.4	1363.4	1363.4
T Renewable	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	529.0	0.0	529.0	529.0	529.0	0.0	529.0	658.1
O Cogeneration	0.0	0.0	0.0	0.0	477.9	425.1	302.0	275.6	160.0	275.6	1555.4	964.7	894.5	800.8	1889.0	1640.0	1640.0	1640.1
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	273.1	180.6	132.9	0.0
A Coal	0.0	0.0	379.3	170.3	1222.4	1097.3	1436.9	1274.2	1595.0	1398.9	1838.8	2787.5	2649.1	2841.1	3029.7	3902.7	3765.7	4106.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	573.7	393.5	424.2	325.9	1449.3	1095.7	1102.5	862.8
Pumped Storage	0.0	0.0	235.4	266.5	1000.0	999.9	961.5	972.5	945.4	848.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	999.9
Total	864.0	1393.0	1570.4	1921.5	3771.5	4122.5	3771.6	4122.5	3771.6	4122.7	6723.9	6372.7	6723.8	6723.8	9533.5	9182.4	9533.5	9630.3

Summary by Load Level for Medium DSR and Any-Coal Strategy (MD.AC)
Annual Energy (MWa) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

	Load Level	L		ML		M						MH				H			
	Gas Price	MG		MG		LG		MG		HG		LG	MG		HG	LG	MG		HG
	Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	strat	any	strat	strat	strat	any	strat	strat
	Case #	2	3	7	8	16	17	33	34	50	51	62	69	70	81	83	90	91	102
	DSR	198.5	198.5	219.1	219.1	244.4	244.4	244.4	244.4	244.4	244.4	280.8	280.8	280.8	280.8	311.9	311.9	311.9	311.9
	OWC Wind with Tax C	0.0	26.2	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	26.3	0.0	26.3	26.3	26.3	0.0	26.3	26.3
	OWC Wind without Tax C	0.0	13.8	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	13.9	0.0	13.9	13.9	13.9	0.0	13.9	44.7
O	OWC Geothermal	0.0	9.9	0.0	10.7	0.0	11.4	0.0	11.4	0.0	11.4	11.2	0.0	11.4	11.7	11.2	0.0	11.2	11.0
W	OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	148.9	148.9	148.9	148.9	148.9	297.9	297.9	297.9	297.9	297.9	297.9	297.9
C	OWC Cogeneration 2	0.0	0.0	0.0	0.0	424.9	378.0	126.2	102.8	0.0	102.8	1015.5	573.2	510.8	427.5	1193.1	1153.0	1152.0	1160.9
	OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	254.1	168.0	123.6	0.0
	OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.3	18.6	40.0	29.5	40.0	39.6	54.6
	OWC Pumped Storage	0.0	0.0	0.0	0.0	1.4	1.5	1.6	1.4	2.4	1.4	45.6	3.6	3.6	2.8	42.8	5.4	5.4	4.4
		198.5	248.4	219.1	270.0	670.7	675.5	521.1	549.1	395.7	549.1	1542.2	1172.8	1163.3	1100.9	2180.7	1976.2	1981.8	1911.7
	DSR	225.0	225.0	247.6	247.6	277.2	277.2	277.2	277.2	277.2	277.2	311.4	311.4	311.4	311.4	344.2	344.2	344.2	344.2
	Utah Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	38.6	0.0	38.6	38.6	38.6	0.0	38.6	38.6
	Utah Wind without Tax C	0.0	20.3	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.3	20.4	0.0	20.3	20.3	20.3	0.0	20.3	20.3
	Utah Geothermal	0.0	9.1	0.0	9.7	0.0	9.6	0.0	9.6	0.0	9.5	9.6	0.0	9.3	9.2	9.4	0.0	9.1	9.1
	Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U	Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.3	0.0	0.0	0.0	32.6	0.0	0.0	0.0
T	Utah Cogeneration 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	173.0	0.0	0.0	0.0	173.0	0.0	0.0	0.0
A	Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H	Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah Coal	0.0	0.0	347.6	156.1	1120.3	1005.6	1316.9	1167.8	1461.7	1282.0	1685.1	2554.4	2427.7	2598.2	2776.4	3318.7	3298.2	3460.0
	Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.9	9.0	9.8	0.0	58.0	30.3	31.1	12.2
	Utah Pumped Storage	0.0	0.0	53.3	60.4	94.8	94.3	117.3	109.3	113.5	113.0	101.0	124.1	124.1	119.6	113.3	124.1	124.1	109.5
		225.0	293.0	648.5	532.8	1492.3	1445.7	1711.4	1622.9	1852.4	1740.6	2405.3	2998.9	2941.2	3097.3	3565.8	3817.3	3865.6	3993.9
	DSR	74.4	74.4	80.9	80.9	91.2	91.2	91.2	91.2	91.2	91.2	101.5	101.5	101.5	101.5	112.6	112.6	112.6	112.6
W	Wyo Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	38.6	0.0	38.6	38.6	38.6	0.0	38.6	38.6
Y	Wyo Wind without Tax C	0.0	20.3	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.3	20.4	0.0	20.3	20.3	20.4	0.0	20.3	20.3
O	Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M	Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I	Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.4	0.0	257.7	152.7	302.7
N	Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G	Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		74.4	133.3	80.9	139.9	91.2	150.2	91.2	150.2	91.2	150.1	160.5	101.5	160.4	165.8	171.6	370.3	324.2	474.2
	DSR	497.9	497.9	547.6	547.6	612.8	612.8	612.8	612.8	612.8	612.8	693.7	693.7	693.7	693.7	768.7	768.7	768.7	768.7
T	Renewable	0.0	176.8	0.0	178.6	0.0	179.2	0.0	179.2	0.0	178.9	179.0	0.0	178.7	178.9	178.7	0.0	178.3	208.9
O	Cogeneration	0.0	0.0	0.0	0.0	424.9	378.0	275.1	251.7	148.9	251.7	1371.7	871.1	808.7	725.4	1696.6	1450.9	1449.9	1458.8
T	Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	254.1	168.0	123.6	0.0
A	Coal	0.0	0.0	347.6	156.1	1120.3	1005.6	1316.9	1167.8	1461.7	1282.0	1685.1	2554.4	2427.7	2603.6	2776.4	3576.4	3450.9	3762.7
L	Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.9	26.3	28.4	40.0	87.5	70.3	70.7	66.8
	Pumped Storage	0.0	0.0	53.3	60.4	96.2	95.8	118.9	110.7	115.9	114.4	146.6	127.7	127.7	122.4	156.1	129.5	129.5	113.9
	Total	497.9	674.7	948.5	942.7	2254.2	2271.4	2323.7	2322.2	2339.3	2439.8	4108.0	4273.2	4264.9	4364.0	5918.1	6163.8	6171.6	6379.8

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Summary by Load Level for Medium DSR and No-Coal Strategy (MD.NC)
Percentage of Winter Capacity Additions (%)

Additions in 10 years (1994 - 2003)

Load Level	L		ML		M						MH				H			
Gas Price	MG		MG		LG		MG		HG		LG	MG		HG	LG	MG		HG
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	strat	any	strat	strat	strat	any	strat	strat
Case #	4	5	9	10	18	19	35	36	52	53	63	71	72	82	84	92	93	103
MW Additions																		
DSR	100.0	50.5	70.2	49.0	29.7	25.3	29.7	25.3	21.9	25.3	18.1	18.9	18.1	18.1	13.9	14.3	13.9	13.2
Renewable	0.0	49.5	0.0	45.4	0.0	22.0	0.0	22.0	38.4	22.0	14.4	8.5	14.4	14.4	10.3	6.0	10.3	17.6
Cogeneration	0.0	0.0	0.0	0.0	59.8	43.2	51.6	36.0	12.9	18.2	51.7	52.4	48.3	36.6	40.9	42.2	40.9	38.8
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.2	8.5	7.8	1.8
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peaking Resources	0.0	0.0	29.8	5.6	10.5	9.4	18.7	16.6	26.8	34.5	15.7	20.1	19.2	30.9	25.6	28.9	27.0	28.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																		
DSR	100.0	63.4	87.8	63.1	25.0	24.5	26.5	26.1	30.7	33.7	17.2	17.9	17.8	20.8	14.0	14.5	14.3	14.9
Renewable	0.0	36.6	0.0	34.5	0.0	12.6	0.0	13.3	31.4	17.3	8.0	5.0	8.3	9.7	6.1	3.7	6.2	11.8
Cogeneration	0.0	0.0	0.0	0.0	72.2	59.9	67.6	54.3	28.9	38.6	70.4	71.8	68.4	62.5	60.4	63.2	62.0	64.4
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.7	13.3	12.4	3.1
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peaking Resources	0.0	0.0	12.2	2.4	2.9	3.0	5.9	6.2	9.0	10.4	4.3	5.4	5.5	7.0	4.7	5.2	5.1	5.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Additions in 20 years (1994 - 2013)

Load Level	L		ML		M						MH				H			
Gas Price	MG		MG		LG		MG		HG		LG	MG		HG	LG	MG		HG
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	strat	any	strat	strat	strat	any	strat	strat
Case #	4	5	9	10	18	19	35	36	52	53	63	71	72	82	84	92	93	103
MW Additions																		
DSR	100.0	62.0	60.9	49.7	28.4	26.0	28.4	26.0	19.6	20.6	18.2	18.7	18.2	13.4	14.3	14.5	14.3	10.5
Renewable	0.0	38.0	0.0	27.5	0.0	12.8	0.0	12.8	44.1	39.9	7.9	4.6	7.9	43.8	5.5	3.2	5.5	42.1
Cogeneration	0.0	0.0	0.0	0.0	40.9	32.5	31.3	23.0	6.6	8.4	31.2	31.9	31.2	14.7	22.0	22.4	22.0	16.2
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.2	8.7	7.3	0.0	26.0	26.0	24.7	2.8
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peaking Resources	0.0	0.0	39.1	22.7	30.7	28.7	40.3	38.2	29.7	31.2	34.4	36.2	35.3	28.1	32.2	33.9	33.4	28.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																		
DSR	100.0	73.8	85.5	67.4	28.5	28.7	33.5	34.1	34.1	34.3	19.5	19.9	19.9	20.6	14.1	14.4	14.4	15.0
Renewable	0.0	26.2	0.0	22.1	0.0	8.4	0.0	10.0	40.8	36.8	5.0	3.0	5.1	37.8	3.3	2.0	3.4	33.9
Cogeneration	0.0	0.0	0.0	0.0	64.6	56.2	58.3	47.8	18.6	22.5	54.8	55.2	55.2	36.3	35.0	35.7	35.8	37.8
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.5	15.1	13.1	0.0	42.2	41.9	40.5	6.5
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Peaking Resources	0.0	0.0	14.5	10.5	6.9	6.8	8.2	8.1	6.5	6.5	6.2	6.8	6.8	5.4	5.4	6.0	6.0	6.9
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 5-13.b

Summary by Load Level for Medium DSR and No-Coal Strategy (MD.NC)
Winter Capacity (MW) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Load Level	L		ML		M						MH				H			
Gas Price	MG		MG		LG		MG		HG		LG	MG		HG	LG	MG		HG
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	strat	any	strat	strat	strat	any	strat	strat
Case #	4	5	9	10	18	19	35	36	52	53	63	71	72	82	84	92	93	103
DSR	318.9	318.9	336.7	336.7	359.2	359.2	359.2	359.2	359.2	359.2	393.4	393.4	393.4	393.4	422.8	422.8	422.8	422.8
OWC Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	166.0	110.0	110.0	0.0	110.0	110.0	110.0	0.0	110.0	110.0
OWC Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58.0	0.0	58.0	58.0	58.0	0.0	58.0	58.0
O OWC Geothermal	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	13.0	0.0	13.0	13.0	13.0	0.0	13.0	13.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	320.1	319.9	320.0	320.0	160.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
C OWC Cogeneration 2	0.0	0.0	0.0	0.0	986.0	924.5	624.8	523.3	0.0	76.6	1278.5	1065.5	990.6	771.5	1320.0	1320.0	1320.0	1320.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.9	48.5	0.0	0.0	0.0	9.5	77.2
	318.9	499.9	336.7	517.7	1345.2	1464.7	1304.1	1383.4	845.2	936.8	2012.9	1813.8	1933.5	1665.9	2243.8	2062.8	2253.3	2321.0
DSR	179.2	179.2	189.3	189.3	200.8	200.8	200.8	200.8	200.8	200.8	217.8	217.8	217.8	217.8	233.0	233.0	233.0	233.0
Utah Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	450.0	110.0	110.0	150.0	110.0	110.0	110.0	150.0	110.0	110.0
Utah Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58.0	0.0	58.0	58.0	58.0	0.0	58.0	479.0
Utah Geothermal	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	12.0	0.0	12.0	12.0	12.0	0.0	12.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	39.0	21.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	238.8	113.4	73.8	0.0	0.0	0.0	420.1	420.0	420.0	210.0	420.0	420.0	420.0	420.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	473.2	423.9	398.5	96.4
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	272.7	356.7	93.6	172.6	155.0	632.6	811.9	940.2	877.1	972.5
Utah Pumped Storage	0.0	0.0	242.8	64.9	215.7	224.8	383.0	398.5	470.4	470.4	482.1	499.9	500.0	500.0	500.0	500.0	500.0	500.0
	179.2	359.2	432.1	434.2	655.3	719.0	696.6	800.3	1432.9	1246.9	1432.6	1499.3	1511.8	1779.4	2657.1	2706.1	2647.6	2861.9
DSR	42.5	42.5	44.9	44.9	48.2	48.2	48.2	48.2	48.2	48.2	53.7	53.7	53.7	53.7	58.4	58.4	58.4	58.4
W Wyo Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	450.0	110.0	110.0	150.0	110.0	110.0	110.0	150.0	110.0	110.0
Y Wyo Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	58.0	0.0	58.0	58.0	58.0	0.0	58.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	42.5	210.5	44.9	212.9	48.2	216.2	48.2	216.2	498.2	216.2	221.7	203.7	221.7	221.7	226.4	208.4	226.4	226.4
DSR	540.6	540.6	570.9	570.9	608.2	608.2	608.2	608.2	608.2	608.2	664.9	664.9	664.9	664.9	714.2	714.2	714.2	714.2
T Renewable	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	1066.0	529.0	529.0	300.0	529.0	529.0	529.0	300.0	529.0	950.0
O Cogeneration	0.0	0.0	0.0	0.0	1224.8	1037.9	1057.7	864.2	359.0	435.6	1897.6	1844.5	1769.6	1340.5	2099.0	2099.0	2099.0	2099.0
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	473.2	423.9	398.5	96.4
A Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	272.7	356.7	93.6	172.6	155.0	632.6	811.9	940.2	877.1	972.5
Pumped Storage	0.0	0.0	242.8	64.9	215.7	224.8	383.0	398.5	470.4	470.4	482.1	534.8	548.5	500.0	500.0	500.0	509.5	577.2
Total	540.6	1069.6	813.7	1164.8	2048.7	2399.9	2048.9	2399.9	2776.3	2399.9	3667.2	3516.8	3667.0	3667.0	5127.3	4977.3	5127.3	5409.3

Summary by Load Level for Medium DSR and No-Coal Strategy (MD.NC)
Annual Energy (MWa) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Load Level	L		ML		M						MH				H			
Gas Price	MG		MG		LG		MG		HG		LG	MG		HG	LG	MG		HG
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	strat	any	strat	strat	strat	any	strat	strat
Case #	4	5	9	10	18	19	35	36	52	53	63	71	72	82	84	92	93	103
DSR	139.3	139.3	146.3	146.3	155.4	155.4	155.4	155.4	155.4	155.4	168.7	168.7	168.7	168.7	180.2	180.2	180.2	180.2
OWC Wind with Tax C	0.0	26.2	0.0	26.3	0.0	26.2	0.0	26.3	39.6	26.3	26.2	0.0	26.3	26.3	26.3	0.0	26.3	26.3
OWC Wind without Tax C	0.0	13.8	0.0	13.9	0.0	13.8	0.0	13.9	0.0	13.9	13.8	0.0	13.9	13.9	13.9	0.0	13.9	13.9
O OWC Geothermal	0.0	9.9	0.0	10.2	0.0	10.2	0.0	10.1	0.0	10.6	10.1	0.0	10.1	10.1	10.3	0.0	10.1	10.1
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	279.7	277.5	291.9	296.8	138.4	277.5	277.5	294.6	283.5	292.7	286.6	292.9
C OWC Cogeneration 2	0.0	0.0	0.0	0.0	808.0	757.5	512.0	428.8	0.0	65.4	1039.6	865.6	802.9	638.2	1092.0	1092.0	1092.0	1092.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3	7.4	0.0	0.0	0.0	1.4	11.7
	139.3	**189.2**	**146.3**	**196.7**	**963.4**	**963.1**	**947.1**	**912.0**	**486.9**	**568.4**	**1396.8**	**1317.1**	**1306.8**	**1151.8**	**1606.2**	**1564.9**	**1610.5**	**1627.1**
DSR	128.7	128.7	137.7	137.7	148.9	148.9	148.9	148.9	148.9	148.9	163.0	163.0	163.0	163.0	176.6	176.6	176.6	176.6
Utah Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	158.0	38.6	38.6	52.7	38.6	38.6	38.6	52.7	38.6	38.6
Utah Wind without Tax C	0.0	20.3	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	20.4	0.0	20.4	20.4	20.4	0.0	20.4	168.2
Utah Geothermal	0.0	9.1	0.0	9.4	0.0	9.9	0.0	9.7	0.0	9.7	9.7	0.0	9.3	9.7	9.9	0.0	9.6	9.7
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	34.2	18.4	35.3	35.7	35.0	34.2	34.2	35.7	35.7	35.7	35.4	35.7
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	197.8	93.2	61.0	0.0	0.0	0.0	345.9	346.4	346.0	175.8	354.1	360.0	357.7	353.3
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	430.7	375.8	352.7	85.4
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.2	19.8	5.2	9.6	8.6	35.2	45.1	52.3	48.8	54.1
Utah Pumped Storage	0.0	0.0	45.1	12.4	40.0	42.5	77.1	83.3	87.3	87.1	91.0	99.5	101.3	92.8	92.8	93.4	94.2	92.8
	128.7	**196.7**	**182.8**	**218.5**	**386.7**	**353.5**	**321.2**	**319.3**	**444.7**	**360.2**	**708.8**	**705.4**	**721.4**	**571.2**	**1203.9**	**1146.5**	**1134.0**	**1014.4**
DSR	38.8	38.8	41.2	41.2	43.5	43.5	43.5	43.5	43.5	43.5	48.2	48.2	48.2	48.2	52.0	52.0	52.0	52.0
W Wyo Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	158.0	38.6	38.6	52.7	38.6	38.6	38.6	52.7	38.6	38.6
Y Wyo Wind without Tax C	0.0	20.3	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	20.4	0.0	20.4	20.4	20.4	0.0	20.4	20.4
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	38.8	**97.7**	**41.2**	**100.2**	**43.5**	**102.5**	**43.5**	**102.5**	**201.5**	**102.5**	**107.2**	**100.9**	**107.2**	**107.2**	**111.0**	**104.7**	**111.0**	**111.0**
DSR	306.8	306.8	325.2	325.2	347.8	347.8	347.8	347.8	347.8	347.8	379.9	379.9	379.9	379.9	408.8	408.8	408.8	408.8
T Renewable	0.0	176.8	0.0	177.8	0.0	178.1	0.0	178.0	355.6	178.5	177.8	105.4	177.6	178.0	178.4	105.4	177.9	325.8
O Cogeneration	0.0	0.0	0.0	0.0	1005.8	850.7	886.9	724.7	327.2	397.9	1558.9	1523.7	1460.6	1144.3	1765.3	1780.4	1771.7	1773.9
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	430.7	375.8	352.7	85.4
A Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.2	19.8	5.2	9.6	8.6	35.2	45.1	52.3	48.8	54.1
Pumped Storage	0.0	0.0	45.1	12.4	40.0	42.5	77.1	83.3	87.3	87.1	91.0	104.8	108.7	92.8	92.8	93.4	95.6	104.5
Total	**306.8**	**483.6**	**370.3**	**515.4**	**1393.6**	**1419.1**	**1311.6**	**1333.8**	**1133.1**	**1031.1**	**2212.8**	**2123.4**	**2135.4**	**1830.2**	**2921.1**	**2816.1**	**2855.5**	**2752.5**

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T5-13.md.nc.aMW-10yrs

Summary by Load Level for Medium DSR and No-Coal Strategy (MD.NC)
Winter Capacity (MW) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load Level	L		ML		M						MH				H			
Gas Price	MG		MG		LG		MG		HG		LG	MG		HG	LG	MG		HG
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	strat	any	strat	strat	strat	any	strat	strat
Case #	4	5	9	10	18	19	35	36	52	53	63	71	72	82	84	92	93	103
DSR	449.7	449.7	509.0	509.0	577.1	577.1	577.1	577.1	577.1	577.1	680.0	680.0	680.0	680.0	765.4	765.4	765.4	765.4
OWC Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	166.0	110.0	110.0	0.0	110.0	110.0	110.0	0.0	110.0	110.0
OWC Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	844.2	658.0	58.0	0.0	58.0	1163.4	58.0	0.0	58.0	1558.0
O OWC Geothermal	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	13.0	0.0	13.0	13.0	13.0	0.0	13.0	13.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	320.1	319.9	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
C OWC Cogeneration 2	0.0	0.0	0.0	0.0	1305.5	1227.1	747.3	589.5	0.0	76.6	1320.0	1320.0	1320.0	771.5	1320.0	1320.0	1320.0	1320.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	71.9	17.0	0.0	866.4	887.8	821.5	208.8
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	114.7	127.9	415.9
OWC Pumped Storage	0.0	0.0	114.7	0.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.1	500.0
	449.7	**630.7**	**623.7**	**690.0**	**2382.6**	**2485.2**	**2144.5**	**2167.5**	**2407.3**	**2254.7**	**3001.0**	**2891.9**	**3018.0**	**3557.9**	**3952.8**	**3907.9**	**4035.9**	**5211.1**
DSR	331.2	331.2	356.9	356.9	390.0	390.0	390.0	390.0	390.0	390.0	429.5	429.5	429.5	429.5	466.2	466.2	466.2	466.2
Utah Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	450.0	110.0	110.0	150.0	110.0	110.0	110.0	150.0	110.0	110.0
Utah Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	501.5	945.4	58.0	0.0	58.0	1372.2	58.0	0.0	58.0	1979.0
Utah Geothermal	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	12.0	0.0	12.0	12.0	12.0	0.0	12.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0	39.0
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	238.8	113.4	73.8	0.0	0.0	0.0	420.1	420.0	420.0	210.0	420.0	420.0	420.0	420.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	553.3	497.7	477.0	0.0	1549.9	1404.0	1382.2	157.1
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	156.0	182.0	520.3	574.0	626.3	623.1	1315.5	1378.1	1374.8	1570.8	2068.0	2062.1	2060.9	2256.4
Utah Pumped Storage	0.0	0.0	500.0	436.8	500.0	500.0	500.0	500.0	500.0	500.0	500.1	499.9	500.0	500.0	500.0	500.0	500.0	500.0
	331.2	**511.2**	**856.9**	**973.7**	**1284.8**	**1365.4**	**1523.1**	**1683.0**	**2506.8**	**2619.5**	**3437.5**	**3414.2**	**3420.3**	**4243.5**	**5223.1**	**5041.3**	**5048.3**	**5939.7**
DSR	83.1	83.1	89.8	89.8	104.1	104.1	104.1	104.1	104.1	104.1	117.5	117.5	117.5	117.5	131.8	131.8	131.8	131.8
W Wyo Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	450.0	110.0	110.0	150.0	110.0	110.0	110.0	150.0	110.0	110.0
Y Wyo Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	121.4	58.0	0.0	58.0	1108.0	58.0	0.0	58.0	1558.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	57.9	152.4	149.6	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	83.1	**251.1**	**89.8**	**257.8**	**104.1**	**272.1**	**104.1**	**272.1**	**554.1**	**335.5**	**285.5**	**267.5**	**285.5**	**1335.5**	**357.7**	**434.2**	**449.4**	**1799.8**
DSR	864.0	864.0	955.7	955.7	1071.2	1071.2	1071.2	1071.2	1071.2	1071.2	1227.0	1227.0	1227.0	1227.0	1363.4	1363.4	1363.4	1363.4
T Renewable	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	2411.7	2079.8	529.0	300.0	529.0	3998.6	529.0	300.0	529.0	5450.0
O Cogeneration	0.0	0.0	0.0	0.0	1544.3	1340.5	1180.2	948.4	359.0	435.6	2099.1	2099.0	2099.0	1340.5	2099.0	2099.0	2099.0	2099.0
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	553.3	569.6	494.0	0.0	2474.2	2444.2	2353.3	365.9
A Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	156.0	182.0	520.3	574.0	626.3	623.1	1315.5	1378.1	1374.8	1570.8	2068.0	2176.8	2188.8	2672.3
Pumped Storage	0.0	0.0	614.7	436.8	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.1	999.9	1000.0	1000.0	1000.0	1000.0	1000.1	1000.0
Total	**864.0**	**1393.0**	**1570.4**	**1921.5**	**3771.5**	**4122.7**	**3771.7**	**4122.6**	**5468.2**	**5209.7**	**6724.0**	**6573.6**	**6723.8**	**9136.9**	**9533.6**	**9383.4**	**9533.6**	**12950.6**

T5-13 md nc MW add 20yrs

Table 5-13.e

Summary by Load Level for Medium DSR and No-Coal Strategy (MD.NC)
Annual Energy (MWa) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load Level	L		ML		M						MH				H			
Gas Price	MG		MG		LG		MG		HG		LG	MG		HG	LG	MG		HG
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	strat	any	strat	strat	strat	any	strat	strat
Case #	4	5	9	10	18	19	35	36	52	53	63	71	72	82	84	92	93	103
DSR	198.5	198.5	219.1	219.1	244.4	244.4	244.4	244.4	244.4	244.4	280.8	280.8	280.8	280.8	311.9	311.9	311.9	311.9
OWC Wind with Tax C	0.0	26.2	0.0	26.3	0.0	26.3	0.0	26.3	39.6	26.3	26.3	0.0	26.3	26.3	26.3	0.0	26.3	26.3
OWC Wind without Tax C	0.0	13.8	0.0	13.9	0.0	13.9	0.0	13.9	201.6	157.2	13.9	0.0	13.9	277.9	13.9	0.0	13.9	372.2
O OWC Geothermal	0.0	9.9	0.0	11.2	0.0	10.9	0.0	10.9	0.0	11.4	10.9	0.0	10.9	11.2	10.9	0.0	10.9	11.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	297.9	297.9	297.9	297.9	297.9	297.2	297.2	297.9	297.5	297.0	297.0	297.9
C OWC Cogeneration 2	0.0	0.0	0.0	0.0	1169.0	1095.2	666.1	524.1	0.0	68.1	1225.5	1217.6	1214.8	704.1	1199.2	1200.2	1200.0	1227.5
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	66.9	15.8	0.0	806.1	826.1	764.3	194.2
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.2	9.2	30.1
OWC Pumped Storage	0.0	0.0	0.0	0.0	54.1	50.8	35.0	31.8	2.0	2.0	56.7	63.3	62.3	18.9	82.4	85.4	82.5	42.0
	198.5	248.4	219.1	270.5	1467.5	1441.5	1243.4	1149.3	785.5	807.3	1912.0	1925.8	1922.0	1617.1	2748.2	2728.8	2716.0	2513.1
DSR	225.0	225.0	247.6	247.6	277.2	277.2	277.2	277.2	277.2	277.2	311.4	311.4	311.4	311.4	344.2	344.2	344.2	344.2
Utah Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	158.0	38.6	38.6	52.7	38.6	38.6	38.6	52.7	38.6	38.6
Utah Wind without Tax C	0.0	20.3	0.0	20.4	0.0	20.4	0.0	20.4	176.1	331.9	20.4	0.0	20.4	481.7	20.4	0.0	20.4	694.7
Utah Geothermal	0.0	9.1	0.0	9.9	0.0	10.2	0.0	10.1	0.0	10.0	10.2	0.0	10.3	9.7	10.3	0.0	10.3	10.2
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	36.3	36.2	35.4	35.4	36.3	36.0	36.0	35.5	36.2	35.7	35.7	35.5
T Utah Cogeneration 2	0.0	0.0	0.0	0.0	219.6	104.3	67.8	0.0	0.0	0.0	386.2	377.1	377.1	185.8	377.1	377.1	377.1	374.4
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	514.8	460.1	440.7	0.0	1439.2	1279.3	1259.3	136.5
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	8.7	10.1	28.9	31.9	34.8	34.6	73.1	76.6	76.4	87.3	115.0	114.6	114.6	172.3
Utah Pumped Storage	0.0	0.0	93.0	85.0	84.7	83.5	86.1	81.2	79.7	79.0	88.7	98.6	96.9	75.4	96.3	115.4	115.1	107.1
	225.0	293.0	340.6	401.5	590.2	544.3	496.3	495.6	761.2	806.7	1479.7	1412.5	1407.8	1225.4	2477.3	2319.0	2315.3	1913.5
DSR	74.4	74.4	80.9	80.9	91.2	91.2	91.2	91.2	91.2	91.2	101.5	101.5	101.5	101.5	112.6	112.6	112.6	112.6
W Wyo Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	158.0	38.6	38.6	52.7	38.6	38.6	38.6	52.7	38.6	38.6
Y Wyo Wind without Tax C	0.0	20.3	0.0	20.4	0.0	20.4	0.0	20.4	0.0	42.6	20.4	0.0	20.4	389.0	20.4	0.0	20.4	546.9
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	53.5	140.1	137.6	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	74.4	133.3	80.9	139.9	91.2	150.2	91.2	150.2	249.2	172.4	160.5	154.2	160.5	529.1	225.1	305.4	309.2	698.1
DSR	497.9	497.9	547.6	547.6	612.8	612.8	612.8	612.8	612.8	612.8	693.7	693.7	693.7	693.7	768.7	768.7	768.7	768.7
T Renewable	0.0	176.8	0.0	179.3	0.0	179.3	0.0	179.2	733.3	656.6	179.3	105.4	179.4	1273.0	179.4	105.4	179.4	1738.5
O Cogeneration	0.0	0.0	0.0	0.0	1388.6	1199.5	1068.1	858.2	333.3	401.4	1945.9	1927.9	1925.1	1223.3	1910.0	1910.0	1909.8	1935.3
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	514.8	527.0	456.5	0.0	2298.8	2245.5	2161.2	330.7
A Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	8.7	10.1	28.9	31.9	34.8	34.6	73.1	76.6	76.4	87.3	115.0	122.8	123.8	202.4
Pumped Storage	0.0	0.0	93.0	85.0	138.8	134.3	121.1	113.0	81.7	81.0	145.4	161.9	159.2	94.3	178.7	200.8	197.6	149.1
Total	497.9	674.7	640.6	811.9	2148.9	2136.0	1830.9	1795.1	1795.9	1786.4	3552.2	3492.5	3490.3	3371.6	5450.6	5353.2	5340.5	5124.7

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Summary by Load Level for Accelerated DSR Strategy (AD)
Percentage of Winter Capacity Additions (%)

Additions in 10 years (1994 - 2003)

Load Level	M												MH				H			
Gas Price	LG				MG				HG				MG				MG			
Coal	any		no		any		no		any		no		any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	20	21	22	23	37	38	39	40	54	55	56	57	73	74	75	76	94	95	96	97
MW Additions																				
DSR	32.9	28.0	32.9	28.0	32.9	28.0	32.9	28.0	32.9	28.0	24.3	28.0	23.7	21.4	23.7	21.4	18.4	17.1	17.6	17.1
Renewable	0.0	22.1	0.0	22.1	0.0	22.1	0.0	22.1	0.0	22.1	38.1	22.1	0.0	14.5	0.0	14.5	0.0	10.4	6.1	10.4
Cogeneration	22.5	16.6	56.9	40.6	11.1	7.5	48.7	33.7	7.8	6.7	11.6	14.1	28.3	23.9	57.0	46.2	34.5	31.8	42.4	41.1
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.8	6.3
Coal	25.5	16.5	0.0	0.0	39.7	30.1	0.0	0.0	45.5	31.7	0.0	0.0	29.6	23.5	0.0	0.0	24.6	20.2	0.0	0.0
Peaking Resources	19.1	16.7	10.3	9.2	16.3	12.2	18.4	16.2	13.8	11.5	25.9	35.7	18.4	16.7	19.4	18.0	22.5	20.5	26.1	25.1
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																				
DSR	30.3	30.0	29.0	28.5	28.6	27.6	30.7	30.2	27.6	27.4	35.3	40.5	20.0	19.7	21.1	20.9	15.8	15.6	17.0	16.9
Renewable	0.0	13.2	0.0	12.5	0.0	12.2	0.0	13.3	0.0	12.0	30.8	17.9	0.0	7.9	0.0	8.4	0.0	5.7	3.7	6.2
Cogeneration	28.5	24.3	68.3	56.0	14.2	10.6	63.5	50.4	9.9	9.3	25.3	31.3	34.9	32.2	73.6	65.6	44.1	43.0	62.4	62.0
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.1	10.0
Coal	35.7	26.9	0.0	0.0	52.4	45.0	0.0	0.0	58.1	47.0	0.0	0.0	40.2	35.0	0.0	0.0	35.0	30.5	0.0	0.0
Peaking Resources	5.4	5.5	2.8	3.0	4.9	4.5	5.8	6.1	4.4	4.2	8.6	10.3	5.0	5.2	5.3	5.2	5.1	5.2	4.9	4.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Additions in 20 years (1994 - 2013)

Load Level	M												MH				H			
Gas Price	LG				MG				HG				MG				MG			
Coal	any		no		any		no		any		no		any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	20	21	22	23	37	38	39	40	54	55	56	57	73	74	75	76	94	95	96	97
MW Additions																				
DSR	29.4	26.9	29.4	26.9	29.4	26.9	29.4	26.9	29.4	26.9	20.2	20.5	20.8	19.7	20.8	19.7	16.6	16.0	16.2	16.0
Renewable	0.0	12.8	0.0	12.8	0.0	12.8	0.0	12.8	0.0	12.8	44.3	43.5	0.0	7.9	0.0	7.9	0.0	5.6	3.2	5.6
Cogeneration	12.2	9.6	40.2	31.7	6.0	4.4	30.5	22.4	4.2	3.9	5.9	6.2	14.7	13.0	33.0	31.3	17.9	17.2	22.4	22.1
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.1	7.2	1.7	1.1	25.7	24.5
Coal	31.9	26.4	0.0	0.0	38.8	32.0	0.0	0.0	41.6	34.7	0.0	0.0	43.8	39.5	0.0	0.0	42.8	39.7	0.0	0.0
Peaking Resources	26.6	24.3	30.5	28.6	25.8	23.9	40.2	37.9	24.8	21.7	29.6	29.8	20.7	19.9	36.1	34.0	21.0	20.4	32.4	31.9
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																				
DSR	28.4	28.2	29.8	30.0	27.7	27.7	35.0	35.5	27.3	26.7	35.6	35.6	16.8	16.8	20.7	20.5	13.1	13.0	15.0	15.0
Renewable	0.0	7.9	0.0	8.4	0.0	7.8	0.0	10.0	0.0	7.5	41.4	40.6	0.0	4.2	0.0	5.1	0.0	2.9	2.0	3.4
Cogeneration	18.2	15.6	63.5	54.9	9.1	7.3	57.0	46.6	6.4	6.2	16.6	17.5	19.8	18.5	55.7	55.1	24.5	23.5	35.8	35.8
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.1	12.7	2.4	1.6	41.4	40.1
Coal	49.1	44.0	0.0	0.0	58.2	52.5	0.0	0.0	61.4	54.7	0.0	0.0	59.9	57.0	0.0	0.0	56.8	56.1	0.0	0.0
Peaking Resources	4.3	4.2	6.7	6.7	5.0	4.7	8.1	7.9	4.8	4.9	6.3	6.3	3.5	3.5	6.5	6.5	3.2	3.0	5.8	5.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

T5 14.ad percentage

Table 5-14.b

Summary by Load Level for Accelerated DSR Strategy (AD)
Winter Capacity (MW) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Load Level	M												MH				H			
Gas Price	LG				MG				HG				MG				MG			
Coal	any		no		any		no		any		no		any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	20	21	22	23	37	38	3[illegible]	40	54	55	56	57	73	74	75	76	94	95	96	97
DSR	381.8	381.8	381.8	381.8	381.8	381.8	381.8	381.8	381.8	381.8	381.8	381.8	470.2	470.2	470.2	470.2	538.3	538.3	538.3	538.3
OWC Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
OWC Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O OWC Geothermal	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	183.4	162.9	319.9	319.9	160.0	160.0	320.0	319.9	320.0	320.0	320.0	320.1	320.0	320.0	320.0	320.0
C OWC Cogeneration 2	459.7	396.1	946.8	880.1	43.7	17.3	591.0	485.3	0.0	0.0	0.0	0.0	614.1	551.9	1100.6	944.4	1320.0	1300.2	1320.0	1320.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	61.2	80.9	45.1	3.9	232.2	248.7	0.0	1.0
	841.5	958.9	1328.6	1442.9	608.9	743.0	1292.7	1368.0	541.8	722.8	851.8	882.7	1465.5	1604.0	1935.9	1919.6	2410.5	2588.2	2178.3	2360.3
DSR	238.9	238.9	238.9	238.9	238.9	238.9	238.9	238.9	238.9	238.9	238.9	238.9	252.7	252.7	252.7	252.7	269.9	269.9	269.9	269.9
Utah Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	150.0	110.0
Utah Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
Utah Geothermal	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	39.0	0.0	0.0	0.0	0.0	17.3	0.0	0.0	39.0	0.0	0.0	0.0	39.0	39.0
T Utah Cogeneration 2	0.0	0.0	213.1	90.6	0.0	0.0	44.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	420.0	420.0	0.0	0.0	420.0	420.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	387.5	323.2
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	519.6	395.4	0.0	0.0	809.1	718.8	0.0	0.0	927.3	757.7	0.0	0.0	976.6	859.4	0.0	0.0	990.0	990.0	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	263.9	395.4	46.4	28.2	93.4	152.1	338.8	299.8	793.6	778.0
Utah Pumped Storage	390.2	400.0	209.8	220.9	333.3	292.5	375.2	386.2	282.2	273.9	451.1	458.8	499.9	500.0	500.0	500.0	500.0	500.0	500.0	500.0
	1148.7	1214.3	661.8	730.4	1381.3	1430.2	697.5	805.1	1448.4	1450.5	1403.9	1290.4	1775.6	1820.3	1305.1	1504.8	2098.7	2239.7	2560.0	2510.1
DSR	49.6	49.6	49.6	49.6	49.6	49.6	49.6	49.6	49.6	49.6	49.6	49.6	57.5	57.5	57.5	57.5	64.6	64.6	64.6	64.6
W Wyo Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	150.0	110.0
Y Wyo Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	178.1	42.4	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	49.6	217.6	49.6	217.6	49.6	217.6	49.6	217.6	49.6	217.6	499.6	217.6	57.5	225.5	57.5	225.5	242.7	275.0	214.6	232.6
DSR	670.3	670.3	670.3	670.3	670.3	670.3	670.3	670.3	670.3	670.3	670.3	670.3	780.4	780.4	780.4	780.4	872.8	872.8	872.8	872.8
T Renewable	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	1050.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	300.0	529.0
O Cogeneration	459.7	396.1	1159.9	970.7	227.1	180.2	994.3	805.2	160.0	160.0	320.0	337.2	934.1	871.9	1879.6	1684.5	1640.0	1620.2	2099.0	2099.0
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	387.5	323.2
A Coal	519.6	395.4	0.0	0.0	809.1	718.8	0.0	0.0	927.3	757.7	0.0	0.0	976.6	859.4	0.0	0.0	1168.1	1032.4	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	263.9	395.4	46.4	28.2	93.4	152.1	338.8	299.8	793.6	778.0
Pumped Storage	390.2	400.0	209.8	220.9	333.3	292.5	375.2	386.2	282.2	273.9	451.1	458.8	561.1	580.9	545.1	503.9	732.2	748.7	500.0	501.0
Total	2039.8	2390.8	2040.0	2390.9	2039.8	2390.8	2039.8	2390.7	2039.8	2390.9	2755.3	2390.7	3298.6	3649.8	3298.5	3649.9	4751.9	5102.9	4952.9	5103.0

Summary by Load Level for Accelerated DSR Strategy (AD)
Annual Energy (MWa) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Load Level	M												MH				H			
Gas Price	LG				MG				HG				MG				MG			
Coal	any		no		any		no		any		no		any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	20	21	22	23	37	38	39	40	54	55	56	57	73	74	75	76	94	95	96	97
DSR	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0	176.0	198.8	198.8	198.8	198.8	217.2	217.2	217.2	217.2
OWC Wind with Tax C	0.0	26.2	0.0	26.2	0.0	26.3	0.0	26.3	0.0	26.3	35.8	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3
OWC Wind without Tax C	0.0	13.8	0.0	13.8	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9
O OWC Geothermal	0.0	10.4	0.0	10.2	0.0	10.2	0.0	10.1	0.0	10.2	0.0	10.6	0.0	9.9	0.0	10.1	0.0	9.9	0.0	10.1
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	163.1	141.0	279.7	277.5	145.3	137.8	289.1	296.8	277.7	277.8	279.3	277.5	283.0	280.9	289.2	285.4
C OWC Cogeneration 2	380.3	327.8	775.7	721.1	37.1	14.7	484.2	397.7	0.0	0.0	0.0	0.0	499.0	447.5	888.3	771.3	1068.6	1052.5	1092.0	1092.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.4	14.2	7.1	0.6	37.3	39.2	0.0	0.1
	556.3	554.2	951.7	947.3	376.2	382.1	939.9	901.5	321.3	364.2	500.9	523.6	986.9	988.4	1373.5	1298.5	1606.1	1639.9	1598.4	1645.0
DSR	183.2	183.2	183.2	183.2	183.2	183.2	183.2	183.2	183.2	183.2	183.2	183.2	195.0	195.0	195.0	195.0	208.8	208.8	208.8	208.8
Utah Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	52.7	38.6
Utah Wind without Tax C	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4
Utah Geothermal	0.0	9.5	0.0	9.9	0.0	9.3	0.0	9.7	0.0	9.3	0.0	9.8	0.0	9.1	0.0	9.3	0.0	9.3	0.0	9.6
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	34.2	0.0	0.0	0.0	0.0	15.9	0.0	0.0	34.2	0.0	0.0	0.0	35.4	35.4
T Utah Cogeneration 2	0.0	0.0	176.4	74.5	0.0	0.0	36.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	347.5	345.8	0.0	0.0	359.1	358.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	343.0	286.1
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	476.1	362.4	0.0	0.0	741.4	658.7	0.0	0.0	849.8	694.3	0.0	0.0	895.0	787.5	0.0	0.0	907.2	907.2	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.7	22.0	2.6	1.6	5.2	8.5	18.8	16.7	44.1	43.3
Utah Pumped Storage	72.4	74.3	38.9	42.0	69.1	66.2	76.3	81.7	63.9	62.1	83.7	80.9	98.0	100.9	99.4	100.6	101.3	105.4	93.9	94.6
	731.7	688.4	398.5	368.6	993.7	976.4	330.4	333.6	1096.9	1007.9	439.6	370.8	1190.6	1153.1	681.3	718.2	1236.1	1306.4	1137.0	1094.8
DSR	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	44.8	50.8	50.8	50.8	50.8	56.4	56.4	56.4	56.4
W Wyo Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	52.7	38.6
Y Wyo Wind without Tax C	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	163.2	38.9	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	44.8	103.8	44.8	103.8	44.8	103.8	44.8	103.8	44.8	103.8	202.8	103.8	50.8	109.8	50.8	109.8	219.6	154.3	109.1	115.4
DSR	404.0	404.0	404.0	404.0	404.0	404.0	404.0	404.0	404.0	404.0	404.0	404.0	444.6	444.6	444.6	444.6	482.4	482.4	482.4	482.4
T Renewable	0.0	177.9	0.0	178.1	0.0	177.7	0.0	178.0	0.0	177.7	351.8	178.6	0.0	177.2	0.0	177.6	0.0	177.4	105.4	177.9
O Cogeneration	380.3	327.8	952.1	795.6	200.2	155.7	834.8	675.2	145.3	137.8	289.1	312.7	776.7	725.3	1549.3	1394.6	1351.6	1333.4	1775.7	1770.8
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	343.0	286.1
A Coal	476.1	362.4	0.0	0.0	741.4	658.7	0.0	0.0	849.8	694.3	0.0	0.0	895.0	787.5	0.0	0.0	1070.4	946.1	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.7	22.0	2.6	1.6	5.2	8.5	18.8	16.7	44.1	43.3
Pumped Storage	72.4	74.3	38.9	42.0	69.1	66.2	76.3	81.7	63.9	62.1	83.7	80.9	109.4	115.1	106.5	101.2	138.6	144.6	93.9	94.7
Total	1332.8	1346.4	1395.0	1419.7	1414.7	1462.3	1315.1	1338.9	1463.0	1475.9	1143.3	998.2	2228.3	2251.3	2105.6	2126.5	3061.8	3100.6	2844.5	2855.2

T5-14.ad.aMW-10yrs

Table 5-14.d

Summary by Load Level for Accelerated DSR Strategy (AD)
Winter Capacity (MW) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load Level	M												MH				H			
Gas Price	LG				MG				HG				MG				MG			
Coal	any		no		any		no		any		no		any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	20	21	22	23	37	38	39	40	54	55	56	57	73	74	75	76	94	95	96	97
DSR	587.2	587.2	587.2	587.2	587.2	587.2	587.2	587.2	587.2	587.2	587.2	587.2	762.7	762.7	762.7	762.7	907.4	907.4	907.4	907.4
OWC Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
OWC Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	815.9	848.4	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O OWC Geothermal	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	183.4	162.9	319.9	319.9	160.0	160.0	320.0	319.9	320.0	320.0	320.0	320.1	320.0	320.0	320.0	320.0
C OWC Cogeneration 2	459.7	396.1	1300.3	1215.8	43.7	17.3	744.7	565.1	0.0	0.0	0.0	0.0	614.1	551.9	1319.9	1320.1	1320.0	1319.9	1320.0	1320.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.4	0.0	154.0	103.4	856.0	798.1
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.2	207.3	0.0	0.0	471.6	467.4	0.0	3.6
OWC Pumped Storage	500.0	500.0	500.0	500.0	470.4	483.7	500.0	500.0	435.4	395.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.0	500.1
	1546.9	1664.3	2387.5	2484.0	1284.7	1432.1	2151.8	2153.2	1182.6	1323.2	2373.1	2378.5	2397.0	2522.9	2932.0	3083.9	3673.0	3799.1	3903.4	4030.2
DSR	414.2	414.2	414.2	414.2	414.2	414.2	414.2	414.2	414.2	414.2	414.2	414.2	434.7	434.7	434.7	434.7	471.0	471.0	471.0	471.0
Utah Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	150.0	110.0
Utah Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	558.4	1010.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
Utah Geothermal	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	39.0	39.0	0.0	0.0	0.0	17.3	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0
T Utah Cogeneration 2	0.0	0.0	213.1	90.6	0.0	0.0	44.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	420.0	420.0	0.0	0.0	420.0	420.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	612.4	480.6	0.0	0.0	1397.5	1385.5
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	1201.0	1086.6	0.0	0.0	1463.1	1318.8	0.0	0.0	1565.3	1427.8	0.0	0.0	2787.6	2653.1	0.0	0.0	3669.7	3618.5	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	147.4	176.4	0.0	0.0	512.6	558.6	0.0	0.0	617.9	609.1	117.3	129.1	1298.4	1281.6	449.9	470.7	2036.4	2028.5
Utah Pumped Storage	500.0	500.0	500.0	500.0	500.0	499.9	500.0	500.0	500.0	499.9	500.0	499.9	499.9	500.0	500.0	500.0	500.0	500.0	500.0	500.0
	2115.2	2180.8	1274.7	1361.2	2377.3	2412.9	1510.2	1691.8	2479.5	2521.9	2540.5	2672.5	3839.5	3896.9	3304.5	3335.9	5090.6	5240.2	5013.9	5024.0
DSR	104.2	104.2	104.2	104.2	104.2	104.2	104.2	104.2	104.2	104.2	104.2	104.2	122.3	122.3	122.3	122.3	140.8	140.8	140.8	140.8
W Wyo Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	150.0	110.0
Y Wyo Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	132.5	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	151.6	146.8
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	254.2	161.5	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	104.2	272.2	104.2	272.2	104.2	272.2	104.2	272.2	104.2	272.2	554.2	346.7	122.3	290.3	122.3	290.3	395.0	470.3	442.4	455.6
DSR	1105.6	1105.6	1105.6	1105.6	1105.6	1105.6	1105.6	1105.6	1105.6	1105.6	1105.6	1105.6	1319.7	1319.7	1319.7	1319.7	1519.2	1519.2	1519.2	1519.2
T Renewable	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	2424.3	2345.9	0.0	529.0	0.0	529.0	0.0	529.0	300.0	529.0
O Cogeneration	459.7	396.1	1513.4	1306.4	227.1	180.2	1148.0	924.0	160.0	160.0	320.0	337.2	934.1	871.9	2098.9	2099.2	1640.0	1639.9	2099.0	2099.0
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	641.8	480.6	154.0	103.4	2405.1	2330.4
A Coal	1201.0	1086.6	0.0	0.0	1463.1	1318.8	0.0	0.0	1565.3	1427.8	0.0	0.0	2787.6	2653.1	0.0	0.0	3923.9	3780.0	0.0	0.0
L Simple Cycle CT	0.0	0.0	147.4	176.4	0.0	0.0	512.6	558.6	0.0	0.0	617.9	609.1	317.5	336.4	1298.4	1281.6	921.5	938.1	2036.4	2032.1
Pumped Storage	1000.0	1000.0	1000.0	1000.0	970.4	983.6	1000.0	1000.0	935.4	894.9	1000.0	999.9	999.9	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.1
Total	3766.3	4117.3	3766.4	4117.4	3766.2	4117.2	3766.2	4117.2	3766.3	4117.3	5467.8	5397.7	6358.8	6710.1	6358.8	6710.1	9158.6	9509.6	9359.7	9509.8

Summary by Load Level for Accelerated DSR Strategy (AD)
Annual Energy (MWa) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load Level	M												MH				H			
Gas Price	LG				MG				HG				MG				MG			
Coal	any		no		any		no		any		no		any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	20	21	22	23	37	38	39	40	54	55	56	57	73	74	75	76	94	95	96	97
DSR	252.9	252.9	252.9	252.9	252.9	252.9	252.9	252.9	252.9	252.9	252.9	252.9	300.2	300.2	300.2	300.2	341.0	341.0	341.0	341.0
OWC Wind with Tax C	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	35.8	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3
OWC Wind without Tax C	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	194.9	202.7	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9
O OWC Geothermal	0.0	11.4	0.0	10.9	0.0	11.7	0.0	10.9	0.0	11.7	0.0	11.4	0.0	11.4	0.0	10.9	0.0	11.2	0.0	10.9
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	170.7	151.7	297.9	297.9	148.9	148.9	297.9	297.9	297.9	297.9	297.2	297.4	297.9	297.9	297.0	297.0
C OWC Cogeneration 2	408.7	352.3	1165.4	1086.0	38.9	15.4	664.2	502.5	0.0	0.0	0.0	0.0	546.0	490.7	1222.8	1214.2	1154.6	1155.0	1203.9	1200.9
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.3	0.0	143.3	96.2	796.5	742.6
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.0	15.7	[illegible]	0.0	34.2	33.9	0.0	0.3
OWC Pumped Storage	1.4	1.4	52.3	50.5	1.9	1.8	33.1	30.7	2.2	1.9	2.0	2.0	3.5	3.5	53.6	61.5	5.2	6.3	82.5	80.8
	663.0	658.2	1470.6	1440.5	464.4	473.7	1248.1	1135.1	404.0	455.6	783.5	793.2	1162.6	1159.6	1901.1	1924.4	1976.2	1981.7	2720.9	2713.7
DSR	293.7	293.7	293.7	293.7	293.7	293.7	293.7	293.7	293.7	293.7	293.7	293.7	312.5	312.5	312.5	312.5	342.0	342.0	342.0	342.0
Utah Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	52.7	38.6
Utah Wind without Tax C	0.0	20.4	0.0	20.4	0.0	20.3	0.0	20.4	0.0	20.3	196.0	354.6	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4
Utah Geothermal	0.0	9.6	0.0	10.2	0.0	9.5	0.0	10.1	0.0	9.5	0.0	10.0	0.0	9.3	0.0	10.3	0.0	9.3	0.0	10.3
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	36.3	36.2	0.0	0.0	0.0	15.7	0.0	0.0	36.0	36.0	0.0	0.0	35.7	35.7
T Utah Cogeneration 2	0.0	0.0	196.3	83.3	0.0	0.0	41.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	377.1	377.1	0.0	0.0	377.1	376.4
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	566.2	444.1	0.0	0.0	1273.4	1261.7
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	1100.6	995.8	0.0	0.0	1340.8	1208.5	0.0	0.0	1434.4	1308.4	0.0	0.0	2554.5	2431.2	0.0	0.0	3362.9	3316.0	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	8.2	9.8	0.0	0.0	28.5	31.1	0.0	0.0	34.4	33.9	6.5	7.2	72.2	71.2	25.0	26.2	113.2	112.8
Utah Pumped Storage	94.3	94.2	84.1	83.4	113.3	105.5	85.5	80.3	110.8	115.7	77.4	77.1	124.1	124.1	99.7	96.2	124.1	118.0	115.7	113.9
	1488.6	1452.3	582.3	539.4	1747.8	1676.1	485.2	510.4	1838.9	1786.2	759.5	823.6	2997.6	2943.2	1463.7	1406.4	3854.0	3870.4	2309.8	2311.8
DSR	91.5	91.5	91.5	91.5	91.5	91.5	91.5	91.5	91.5	91.5	91.5	91.5	104.9	104.9	104.9	104.9	91.5	118.9	118.9	118.9
W Wyo Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	52.7	38.6
Y Wyo Wind without Tax C	0.0	20.4	0.0	20.4	0.0	20.3	0.0	20.4	0.0	20.3	0.0	46.5	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	139.4	135.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	148.1	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	91.5	150.5	91.5	150.5	91.5	150.4	91.5	150.5	91.5	150.4	249.5	176.6	104.9	163.8	104.9	163.9	91.5	325.9	311.0	312.9
DSR	638.1	638.1	638.1	638.1	638.1	638.1	638.1	638.1	638.1	638.1	638.1	638.1	717.6	717.6	717.6	717.6	774.5	801.9	801.9	801.9
T Renewable	0.0	179.2	0.0	179.3	0.0	179.2	0.0	179.2	0.0	179.2	742.7	728.7	0.0	178.7	0.0	179.4	0.0	178.5	105.4	179.4
O Cogeneration	408.7	352.3	1361.7	1169.3	209.6	167.1	1039.6	836.6	148.9	148.9	297.9	313.6	843.9	788.6	1933.1	1924.7	1452.5	1452.9	1913.7	1910.0
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	593.5	444.1	143.3	96.2	2209.3	2139.3
A Coal	1100.6	995.8	0.0	0.0	1340.8	1208.5	0.0	0.0	1434.4	1308.4	0.0	0.0	2554.5	2431.2	0.0	0.0	3362.9	3464.1	0.0	0.0
L Simple Cycle CT	0.0	0.0	8.2	9.8	0.0	0.0	28.5	31.1	0.0	0.0	34.4	33.9	21.5	22.9	72.2	71.2	59.2	60.1	113.2	113.1
Pumped Storage	95.7	95.6	136.4	133.9	115.2	107.3	118.6	111.0	113.0	117.6	79.4	79.1	127.6	127.6	153.3	157.7	129.3	124.3	198.2	194.7
Total	2243.1	2261.0	2144.4	2130.4	2303.7	2300.2	1824.8	1796.0	2334.4	2392.2	1792.5	1793.4	4265.1	4266.6	3469.7	3494.7	5921.7	6178.0	5341.7	5338.4

T5-14.ad.aMW-20yrs

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Summary by Load Level for High DSR Strategy (HD)
Percentage of Winter Capacity Additions (%)

Additions in 10 years (1994 - 2003)

Load Level	M												MH				H			
Gas Price	LG				MG				HG				MG				MG			
Coal	any		no		any		no		any		no		any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	24	25	26	27	41	42	43	44	58	59	60	61	77	78	79	80	98	99	100	101
MW Additions																				
DSR	38.9	33.1	38.9	33.1	38.9	33.1	38.9	33.1	38.9	33.1	28.7	33.1	26.1	23.6	26.1	23.6	19.8	18.4	19.0	18.4
Renewable	0.0	22.3	0.0	22.3	0.0	22.3	0.0	22.3	0.0	22.3	38.4	22.3	0.0	14.5	0.0	14.5	0.0	10.4	6.1	10.4
Cogeneration	19.3	13.7	54.2	38.2	8.9	5.6	45.9	31.0	7.9	5.6	11.7	13.5	27.4	22.9	55.8	45.4	34.6	31.5	42.5	41.2
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.2	5.7
Coal	24.9	16.8	0.0	0.0	39.2	29.4	0.0	0.0	44.1	31.2	0.0	0.0	29.4	23.4	0.0	0.0	24.3	20.1	0.0	0.0
Peaking Resources	16.9	14.1	6.9	6.4	13.1	9.5	15.2	13.6	9.1	7.8	21.2	31.1	17.1	15.5	18.1	16.5	21.4	19.6	25.2	24.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																				
DSR	34.5	33.8	32.6	32.1	32.2	31.2	34.7	34.2	30.9	30.7	38.0	44.0	21.6	21.4	22.8	22.5	16.7	16.5	18.0	17.9
Renewable	0.0	13.5	0.0	12.7	0.0	12.4	0.0	13.6	0.0	12.2	29.8	17.5	0.0	7.9	0.0	8.3	0.0	5.7	3.7	6.2
Cogeneration	25.0	20.4	65.5	53.1	11.7	8.5	60.4	47.1	10.0	7.8	24.3	29.1	33.8	31.0	72.1	64.2	44.0	42.5	62.4	62.0
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.1	9.1
Coal	35.6	27.6	0.0	0.0	52.2	44.5	0.0	0.0	56.3	46.5	0.0	0.0	39.9	34.8	0.0	0.0	34.4	30.3	0.0	0.0
Peaking Resources	4.9	4.7	1.9	2.0	3.8	3.6	4.8	5.2	2.9	2.9	7.9	9.4	4.7	4.9	5.1	5.0	4.9	5.0	4.8	4.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Additions in 20 years (1994 - 2013)

Load Level	M												MH				H			
Gas Price	LG				MG				HG				MG				MG			
Coal	any		no		any		no		any		no		any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	24	25	26	27	41	42	43	44	58	59	60	61	77	78	79	80	98	99	100	101
MW Additions																				
DSR	34.9	31.9	34.9	31.9	34.9	31.9	34.9	31.9	34.9	31.9	25.0	25.1	23.4	22.2	23.4	22.2	18.1	17.4	17.7	17.4
Renewable	0.0	12.9	0.0	12.9	0.0	12.9	0.0	12.9	0.0	12.9	40.6	40.6	0.0	7.9	0.0	7.9	0.0	5.6	3.2	5.6
Cogeneration	10.4	7.9	37.6	29.2	4.8	3.3	27.6	20.9	4.3	3.2	6.1	6.2	14.2	12.5	33.1	31.4	17.9	17.3	22.5	22.1
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.9	6.2	1.4	0.8	24.7	23.6
Coal	30.1	24.6	0.0	0.0	37.6	30.9	0.0	0.0	38.9	32.5	0.0	0.0	43.3	39.0	0.0	0.0	42.3	39.2	0.0	0.0
Peaking Resources	24.6	22.7	27.6	26.0	22.7	21.0	37.5	34.3	21.9	19.4	28.3	28.1	19.2	18.4	34.5	32.4	20.3	19.7	31.9	31.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MWa Additions																				
DSR	32.8	32.6	33.9	34.1	31.5	31.5	40.2	39.8	31.1	30.5	40.4	40.2	18.7	18.7	22.9	22.7	14.1	14.1	16.3	16.3
Renewable	0.0	8.1	0.0	8.5	0.0	7.9	0.0	9.9	0.0	7.6	37.0	37.3	0.0	4.2	0.0	5.1	0.0	2.9	2.0	3.4
Cogeneration	15.8	13.1	59.7	50.9	7.3	5.5	52.5	42.9	6.5	5.2	16.8	16.7	19.1	17.7	55.7	54.9	23.6	23.6	36.0	36.0
Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.1	10.9	1.9	1.2	39.9	38.6
Coal	47.1	41.9	0.0	0.0	56.4	50.7	0.0	0.0	57.8	51.8	0.0	0.0	58.9	56.1	0.0	0.0	57.4	55.3	0.0	0.0
Peaking Resources	4.3	4.3	6.4	6.5	4.8	4.6	7.4	7.3	4.6	4.8	5.8	5.8	3.3	3.4	6.2	6.4	3.0	2.9	5.7	5.7
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

T5-15.hd percentage

Table 5-15.b

Summary by Load Level for High DSR Strategy (HD)
Winter Capacity (MW) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

	Load Level	M												MH				H			
	Gas Price	LG				MG				HG				MG				MG			
	Coal	any		no		any		no		any		no		any		no		any		no	
	Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
	Case #	24	25	26	27	41	42	43	44	58	59	60	61	77	78	79	80	98	99	100	101
	DSR	468.6	468.6	468.6	468.6	468.6	468.6	468.6	468.6	468.6	468.6	468.6	468.6	519.8	519.8	519.8	519.8	580.1	580.1	580.1	580.1
	OWC Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
	OWC Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O	OWC Geothermal	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0
W	OWC Cogeneration 1	0.0	0.0	0.0	0.0	179.2	133.9	320.0	320.0	160.0	132.7	320.0	319.9	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
C	OWC Cogeneration 2	390.2	324.3	917.3	856.4	0.3	0.0	569.5	390.6	0.0	0.0	0.0	0.0	579.2	514.8	1056.7	910.6	1320.0	1284.6	1320.1	1320.0
	OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	37.2	54.7	30.1	0.0	220.5	230.8	0.0	0.0
		858.8	973.9	1385.9	1506.0	648.1	783.5	1358.1	1360.2	628.6	782.3	938.6	969.5	1456.2	1590.3	1926.6	1931.4	2440.6	2596.5	2220.2	2401.1
	DSR	261.4	261.4	261.4	261.4	261.4	261.4	261.4	261.4	261.4	261.4	261.4	261.4	277.2	277.2	277.2	277.2	291.1	291.1	291.1	291.1
	Utah Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	150.0	110.0
	Utah Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
	Utah Geothermal	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0
	Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U	Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	39.0	24.1	0.0	0.0	0.0	0.0	0.0	0.0	39.0	0.0	0.0	0.0	39.0	39.0
T	Utah Cogeneration 2	0.0	0.0	178.1	49.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	420.0	420.1	0.0	0.0	420.0	420.0
A	Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	358.3	292.5
H	Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah Coal	504.4	399.4	0.0	0.0	792.4	698.4	0.0	0.0	892.5	741.0	0.0	0.0	967.2	852.2	0.0	0.0	0.0	0.0	0.0	0.0
	Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	990.0	990.0	0.0	0.0
	Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	110.7	292.5	26.0	10.0	63.7	101.1	292.4	266.5	747.9	734.9
	Utah Pumped Storage	341.3	334.3	140.5	152.3	264.0	225.6	307.4	323.3	183.3	184.3	470.6	445.4	500.0	499.9	500.0	500.0	500.0	500.0	500.0	500.0
		1107.1	1175.1	580.0	642.9	1317.8	1365.4	607.8	788.8	1337.2	1366.7	1292.7	1179.3	1770.4	1819.3	1299.9	1478.4	2073.5	2227.6	2506.3	2457.5
	DSR	56.4	56.4	56.4	56.4	56.4	56.4	56.4	56.4	56.4	56.4	56.4	56.4	61.0	61.0	61.0	61.0	67.2	67.2	67.2	67.2
W	Wyo Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	150.0	110.0
Y	Wyo Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O	Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M	Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I	Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
N	Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	161.4	34.5	0.0	0.0
G	Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		56.4	224.4	56.4	224.4	56.4	224.4	56.4	224.4	56.4	224.4	506.4	224.4	61.0	229.0	61.0	229.0	228.6	269.7	217.2	235.2
	DSR	786.4	786.4	786.4	786.4	786.4	786.4	786.4	786.4	786.4	786.4	786.4	786.4	858.0	858.0	858.0	858.0	938.4	938.4	938.4	938.4
T	Renewable	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	1050.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	300.0	529.0
O	Cogeneration	390.2	324.3	1095.4	905.6	179.5	133.9	928.5	734.7	160.0	132.7	320.0	319.9	899.2	834.8	1835.7	1650.7	1640.0	1604.6	2099.1	2099.0
T	Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	358.3	292.5
A	Coal	504.4	399.4	0.0	0.0	792.4	698.4	0.0	0.0	892.5	741.0	0.0	0.0	967.2	852.2	0.0	0.0	1151.4	1024.5	0.0	0.0
L	Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	110.7	292.5	26.0	10.0	63.7	101.1	292.4	266.5	747.9	734.9
	Pumped Storage	341.3	334.3	140.5	152.3	264.0	225.6	307.4	323.3	183.3	184.3	470.6	445.4	537.2	554.6	530.1	500.0	720.5	730.8	500.0	500.0
	Total	2022.3	2373.4	2022.3	2373.3	2022.3	2373.3	2022.3	2373.4	2022.2	2373.4	2737.7	2373.2	3287.6	3638.6	3287.5	3638.8	4742.7	5093.8	4943.7	5093.8

Summary by Load Level for High DSR Strategy (HD)
Annual Energy (MWa) Produced in 2003 (10th year)
by New Resources added between 1994 - 2003

Load Level	M												MH				H			
Gas Price	LG				MG				HG				MG				MG			
Coal	any		no		any		no		any		no		any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	24	25	26	27	41	42	43	44	58	59	60	61	77	78	79	80	98	99	100	101
DSR	200.9	200.9	200.9	200.9	200.9	200.9	200.9	200.9	200.9	200.9	200.9	200.9	216.1	216.1	216.1	216.1	231.9	231.9	231.9	231.9
OWC Wind with Tax C	0.0	26.2	0.0	26.2	0.0	26.3	0.0	26.3	0.0	26.3	35.8	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3
OWC Wind without Tax C	0.0	13.8	0.0	13.8	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9
O OWC Geothermal	0.0	10.9	0.0	10.2	0.0	10.2	0.0	10.1	0.0	10.2	0.0	10.6	0.0	9.9	0.0	10.1	0.0	9.9	0.0	10.1
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	162.7	121.6	279.7	277.5	145.3	114.3	287.3	296.8	277.6	277.8	278.8	277.5	282.3	278.7	289.7	285.9
C OWC Cogeneration 2	324.5	270.2	751.6	701.7	0.3	0.0	466.6	320.0	0.0	0.0	0.0	0.0	473.0	417.5	854.2	743.4	1066.0	1038.8	1092.0	1092.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.9	9.7	4.7	0.0	33.4	36.4	0.0	0.0
	525.4	522.0	952.5	952.8	363.9	372.9	947.2	848.7	346.2	365.6	524.0	548.5	973.6	971.2	1353.8	1287.3	1613.6	1635.9	1613.6	1660.1
DSR	197.7	197.7	197.7	197.7	197.7	197.7	197.7	197.7	197.7	197.7	197.7	197.7	210.2	210.2	210.2	210.2	221.7	221.7	221.7	221.7
Utah Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	52.7	38.6
Utah Wind without Tax C	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4
Utah Geothermal	0.0	9.8	0.0	9.9	0.0	9.3	0.0	9.7	0.0	9.3	0.0	9.7	0.0	9.1	0.0	9.3	0.0	9.1	0.0	9.6
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	33.9	21.0	0.0	0.0	0.0	0.0	0.0	0.0	34.7	0.0	0.0	0.0	35.7	35.4
T Utah Cogeneration 2	0.0	0.0	147.5	40.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	347.5	345.3	0.0	0.0	360.0	358.6
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	317.2	258.9
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	462.2	366.0	0.0	0.0	726.1	640.0	0.0	0.0	817.9	679.0	0.0	0.0	886.3	781.0	0.0	0.0	907.2	907.2	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.2	16.3	1.4	0.6	3.5	5.6	16.3	14.8	41.6	40.9
Utah Pumped Storage	63.4	62.1	26.1	28.3	53.2	51.1	62.6	67.7	41.5	41.8	87.4	79.2	96.8	100.0	98.3	100.2	101.4	105.3	93.7	94.9
	723.3	694.6	371.3	335.4	977.0	957.1	294.2	355.1	1057.1	986.8	449.3	361.9	1194.7	1159.9	694.2	729.6	1246.6	1317.1	1122.6	1079.0
DSR	49.7	49.7	49.7	49.7	49.7	49.7	49.7	49.7	49.7	49.7	49.7	49.7	53.3	53.3	53.3	53.3	58.2	58.2	58.2	58.2
W Wyo Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	52.7	38.6
Y Wyo Wind without Tax C	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4	0.0	20.4
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	147.9	31.6	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	49.7	108.7	49.7	108.7	49.7	108.7	49.7	108.7	49.7	108.7	207.7	108.7	53.3	112.3	53.3	112.3	206.1	148.8	110.9	117.2
DSR	448.3	448.3	448.3	448.3	448.3	448.3	448.3	448.3	448.3	448.3	448.3	448.3	479.6	479.6	479.6	479.6	511.8	511.8	511.8	511.8
T Renewable	0.0	178.7	0.0	178.1	0.0	177.7	0.0	178.0	0.0	177.7	351.8	178.5	0.0	177.2	0.0	177.6	0.0	177.2	105.4	177.9
O Cogeneration	324.5	270.2	899.1	742.2	163.0	121.6	780.2	618.5	145.3	114.3	287.3	296.8	750.6	695.3	1515.2	1366.2	1348.3	1317.5	1777.4	1771.9
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	317.2	258.9
A Coal	462.2	366.0	0.0	0.0	726.1	640.0	0.0	0.0	817.9	679.0	0.0	0.0	886.3	781.0	0.0	0.0	1055.1	938.8	0.0	0.0
L Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.2	16.3	1.4	0.6	3.5	5.6	16.3	14.8	41.6	40.9
Pumped Storage	63.4	62.1	26.1	28.3	53.2	51.1	62.6	67.7	41.5	41.8	87.4	79.2	103.7	109.7	103.0	100.2	134.8	141.7	93.7	94.9
Total	1298.4	1325.3	1373.5	1396.9	1390.6	1438.7	1291.1	1312.5	1453.0	1461.1	1181.0	1019.1	2221.6	2243.4	2101.3	2129.2	3066.3	3101.8	2847.1	2856.3

T5-15.hd.aMW-10yrs

Summary by Load Level for High DSR Strategy (HD)
Winter Capacity (MW) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load Level	M												MH				H			
Gas Price	LG				MG				HG				MG				MG			
Coal	any		no		any		no		any		no		any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	24	25	26	27	41	42	43	44	58	59	60	61	77	78	79	80	98	99	100	101
DSR	724.2	724.2	724.2	724.2	724.2	724.2	724.2	724.2	724.2	724.2	724.2	724.2	852.9	852.9	852.9	852.9	977.4	977.4	977.4	977.4
OWC Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	150.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0
OWC Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	629.3	668.8	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O OWC Geothermal	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0	0.0	13.0
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	179.2	133.9	320.0	320.0	160.0	132.7	320.0	319.9	320.0	320.0	320.0	320.0	320.0	320.0	320.0	320.0
C OWC Cogeneration 2	390.2	324.3	1225.6	1145.5	0.3	0.0	672.6	494.8	0.0	0.0	0.0	0.0	579.2	514.8	1320.0	1320.0	1320.0	1320.0	1320.1	1320.0
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1	0.0	128.5	76.9	804.9	752.3
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	153.1	162.4	[illegible]	0.0	429.9	426.7	0.0	0.0
OWC Pumped Storage	419.4	425.9	500.0	500.0	348.2	359.7	500.0	500.0	319.7	292.7	500.0	500.0	500.0	500.0	[illegible]	500.0	500.0	500.0	500.0	500.1
	1533.8	1655.4	2449.8	2550.7	1251.9	1398.8	2216.8	2220.0	1203.9	1330.6	2323.5	2335.9	2405.2	2531.1	3001.0	3173.9	3675.8	3802.0	3922.4	4050.8
DSR	463.5	463.5	463.5	463.5	463.5	463.5	463.5	463.5	463.5	463.5	463.5	463.5	499.3	499.3	499.3	499.3	530.0	530.0	530.0	530.0
Utah Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	150.0	110.0
Utah Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	442.8	962.9	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
Utah Geothermal	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0	0.0	12.0
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	39.0	39.0	0.0	0.0	0.0	0.0	0.0	0.0	39.0	39.0	0.0	0.0	39.0	39.0
T Utah Cogeneration 2	0.0	0.0	178.1	49.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	420.0	420.1	0.0	0.0	420.0	420.0
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	557.2	412.6	0.0	0.0	1362.3	1347.9
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	1124.2	1005.7	0.0	0.0	1406.2	1262.3	0.0	0.0	1454.1	1330.5	0.0	0.0	2740.2	2607.7	0.0	0.0	3631.5	3574.7	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	30.2	61.2	0.0	0.0	402.2	402.1	0.0	0.0	475.8	462.6	60.0	69.7	1188.2	1163.1	425.7	444.0	1976.7	1970.9
Utah Pumped Storage	500.0	500.0	500.0	500.0	500.1	499.9	500.0	500.0	499.9	500.0	500.0	500.0	500.0	499.9	500.0	500.0	500.0	500.0	500.0	500.0
	2087.7	2149.2	1171.8	1253.9	2369.8	2405.7	1404.7	1584.6	2417.5	2474.0	2332.1	2511.0	3799.5	3856.6	3203.7	3214.1	5087.2	5228.7	4978.0	4987.8
DSR	115.2	115.2	115.2	115.2	115.2	115.2	115.2	115.2	115.2	115.2	115.2	115.2	129.6	129.6	129.6	129.6	146.1	146.1	146.1	146.1
W Wyo Wind with Tax C	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	450.0	110.0	0.0	110.0	0.0	110.0	0.0	110.0	150.0	110.0
Y Wyo Wind without Tax C	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0	0.0	124.5	0.0	58.0	0.0	58.0	0.0	58.0	0.0	58.0
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	144.0	137.8
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	230.2	145.7	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	115.2	283.2	115.2	283.2	115.2	283.2	115.2	283.2	115.2	283.2	565.2	349.7	129.6	297.6	129.6	297.6	376.3	459.8	440.1	451.9
DSR	1302.9	1302.9	1302.9	1302.9	1302.9	1302.9	1302.9	1302.9	1302.9	1302.9	1302.9	1302.9	1481.8	1481.8	1481.8	1481.8	1653.5	1653.5	1653.5	1653.5
T Renewable	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	0.0	529.0	2122.1	2111.2	0.0	529.0	0.0	529.0	0.0	529.0	300.0	529.0
O Cogeneration	390.2	324.3	1403.7	1194.7	179.5	133.9	1031.6	853.8	160.0	132.7	320.0	319.9	899.2	834.8	2099.0	2099.1	1640.0	1640.0	2099.1	2099.0
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	565.3	412.6	128.5	76.9	2311.2	2238.0
A Coal	1124.2	1005.7	0.0	0.0	1406.2	1262.3	0.0	0.0	1454.1	1330.5	0.0	0.0	2740.2	2607.7	0.0	0.0	3861.7	3720.4	0.0	0.0
L Simple Cycle CT	0.0	0.0	30.2	61.2	0.0	0.0	402.2	402.1	0.0	0.0	475.8	462.6	213.1	232.1	1188.2	1163.1	855.6	870.7	1976.7	1970.9
Pumped Storage	919.4	925.9	1000.0	1000.0	848.3	859.6	1000.0	1000.0	819.6	792.7	1000.0	1000.0	1000.0	999.9	1000.0	1000.0	1000.0	1000.0	1000.0	1000.1
Total	3736.7	4087.8	3736.8	4087.8	3736.9	4087.7	3736.7	4087.8	3736.6	4087.8	5220.8	5196.6	6334.3	6685.3	6334.3	6685.6	9139.3	9490.5	9340.5	9490.5

Summary by Load Level for High DSR Strategy (HD)
Annual Energy (MWa) Produced in 2013 (20th year)
by New Resources added between 1994 - 2013

Load Level	M												MH				H			
Gas Price	LG				MG				HG				MG				MG			
Coal	any		no		any		no		any		no		any		no		any		no	
Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #	24	25	26	27	41	42	43	44	58	59	60	61	77	78	79	80	98	99	100	101
DSR	294.3	294.3	294.3	294.3	294.3	294.3	294.3	294.3	294.3	294.3	294.3	294.3	332.1	332.1	332.1	332.1	367.3	367.3	367.3	367.3
OWC Wind with Tax C	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3	35.8	26.3	0.0	26.3	0.0	26.3	0.0	26.3	0.0	26.3
OWC Wind without Tax C	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9	150.3	159.8	0.0	13.9	0.0	13.9	0.0	13.9	0.0	13.9
O OWC Geothermal	0.0	11.4	0.0	10.9	0.0	11.7	0.0	10.9	0.0	11.7	0.0	11.4	0.0	11.4	0.0	10.9	0.0	11.2	0.0	10.9
W OWC Cogeneration 1	0.0	0.0	0.0	0.0	166.8	124.6	297.9	297.9	148.9	123.5	297.9	297.9	297.9	297.9	297.3	297.9	297.9	297.9	297.0	297.0
C OWC Cogeneration 2	346.9	288.3	1103.0	1027.7	0.3	0.0	604.2	439.9	0.0	0.0	0.0	0.0	515.0	457.7	1221.5	1214.6	1155.8	1158.7	1206.7	1207.3
OWC Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.6	0.0	119.6	71.5	748.9	700.0
OWC CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OWC Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	12.3	0.0	0.0	31.2	31.0	0.0	0.0
OWC Pumped Storage	0.7	0.7	50.2	50.5	1.5	1.5	22.5	31.0	1.6	1.5	1.5	1.6	3.3	3.3	53.3	66.6	5.0	7.9	77.6	77.0
	641.9	634.9	1447.5	1423.6	462.9	472.3	1218.9	1114.2	444.8	471.2	779.8	791.3	1159.8	1154.9	1911.8	1962.3	1976.8	1985.7	2697.5	2699.7
DSR	324.5	324.5	324.5	324.5	324.5	324.5	324.5	324.5	324.5	324.5	324.5	324.5	352.9	352.9	352.9	352.9	378.0	378.0	378.0	378.0
Utah Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	52.7	38.6
Utah Wind without Tax C	0.0	20.4	0.0	20.4	0.0	20.3	0.0	20.4	0.0	20.3	155.4	338.0	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4
Utah Geothermal	0.0	9.6	0.0	10.1	0.0	9.6	0.0	10.1	0.0	9.5	0.0	10.0	0.0	9.3	0.0	10.3	0.0	9.3	0.0	10.3
Utah Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
U Utah Cogeneration 1	0.0	0.0	0.0	0.0	0.0	0.0	36.3	36.2	0.0	0.0	0.0	0.0	0.0	0.0	36.0	36.2	0.0	0.0	35.7	35.7
T Utah Cogeneration 2	0.0	0.0	163.8	45.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	377.1	378.1	0.0	0.0	377.1	377.1
A Utah Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	516.5	381.4	0.0	0.0	1242.2	1228.3
H Utah CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Coal	1030.2	921.6	0.0	0.0	1288.5	1156.8	0.0	0.0	1332.5	1219.3	0.0	0.0	2511.1	2389.7	0.0	0.0	3327.8	3275.8	0.0	0.0
Utah IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah Simple Cycle CT	0.0	0.0	1.7	3.4	0.0	0.0	22.4	22.4	0.0	0.0	26.5	25.7	3.3	3.9	66.1	64.7	23.7	24.7	109.9	109.6
Utah Pumped Storage	93.2	93.0	84.0	83.6	108.3	102.4	87.1	78.5	105.5	111.6	75.6	75.5	124.1	124.1	95.2	94.4	124.1	116.9	117.1	115.1
	1447.9	1407.7	574.0	525.8	1721.3	1652.2	470.3	530.7	1762.5	1723.8	740.0	812.3	2991.4	2938.8	1443.8	1377.0	3853.6	3863.6	2312.7	2313.1
DSR	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	110.2	110.2	110.2	110.2	122.7	122.7	122.7	122.7
W Wyo Wind with Tax C	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	158.0	38.6	0.0	38.6	0.0	38.6	0.0	38.6	52.7	38.6
Y Wyo Wind without Tax C	0.0	20.4	0.0	20.4	0.0	20.3	0.0	20.4	0.0	20.3	0.0	43.7	0.0	20.3	0.0	20.4	0.0	20.3	0.0	20.4
O Wyo Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	132.4	126.7
M Wyo CC CT Convert	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
I Wyo Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	211.0	133.5	0.0	0.0
N Wyo IG CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
G Wyo FB Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyo Simple Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	99.5	158.5	99.5	158.5	99.5	158.4	99.5	158.5	99.5	158.4	257.5	181.8	110.2	169.1	110.2	169.2	333.7	315.1	307.8	308.4
DSR	718.3	718.3	718.3	718.3	718.3	718.3	718.3	718.3	718.3	718.3	718.3	718.3	795.2	795.2	795.2	795.2	868.0	868.0	868.0	868.0
T Renewable	0.0	179.2	0.0	179.2	0.0	179.3	0.0	179.2	0.0	179.2	657.5	666.4	0.0	178.7	0.0	179.4	0.0	178.5	105.4	179.4
O Cogeneration	346.9	288.3	1266.8	1072.9	167.1	124.6	938.4	774.0	148.9	123.5	297.9	297.9	812.9	755.6	1931.9	1926.8	1453.7	1456.6	1916.5	1917.1
T Combined Cycle CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	524.1	381.4	119.6	71.5	2123.5	2055.0
A Coal	1030.2	921.6	0.0	0.0	1288.5	1156.8	0.0	0.0	1332.5	1219.3	0.0	0.0	2511.1	2389.7	0.0	0.0	3538.8	3409.3	0.0	0.0
L Simple Cycle CT	0.0	0.0	1.7	3.4	0.0	0.0	22.4	22.4	0.0	0.0	26.5	25.7	14.8	16.2	66.1	64.7	54.9	55.7	109.9	109.6
Pumped Storage	93.9	93.7	134.2	134.1	109.8	103.9	109.6	109.5	107.1	113.1	77.1	77.1	127.4	127.4	148.5	161.0	129.1	124.8	194.7	192.1
Total	2189.3	2201.1	2121.0	2107.9	2283.7	2282.9	1788.7	1803.4	2306.8	2353.4	1777.3	1785.4	4261.4	4262.8	3465.8	3508.5	6164.1	6164.4	5318.0	5321.2

TS-15.hd.aMW-20yrs

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Renewable Additions in MW

Table 5-16

Future		DSR	2003				2013			
Load	Gas Price	Strategy	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR
Low	Medium	Unconstrained			0				0	
Low	Medium	Medium	0	529	0	529	0	529	0	529
Medium Low	Medium	Unconstrained			0				0	
Medium Low	Medium	Medium	0	529	0	529	0	529	0	529
Medium	Low	Unconstrained			0				0	
Medium	Low	Low	0	529	0	529	0	529	0	529
Medium	Low	Medium	0	529	0	529	0	529	0	529
Medium	Low	Accelerated	0	529	0	529	0	529	0	529
Medium	Low	High	0	529	0	529	0	529	0	529
Medium	Medium	Unconstrained			0				0	
Medium	Medium	Low	0	529	0	529	0	529	0	529
Medium	Medium	Medium	0	529	0	529	0	529	0	529
Medium	Medium	Accelerated	0	529	0	529	0	529	0	529
Medium	Medium	High	0	529	0	529	0	529	0	529
Medium	High	Unconstrained			0				0	
Medium	High	Low	1,200	529	0	529	3,207	2,840	0	529
Medium	High	Medium	1,066	529	0	529	2,412	2,080	0	529
Medium	High	Accelerated	1,050	529	0	529	2,424	2,346	0	529
Medium	High	High	1,050	529	0	529	2,122	2,111	0	529
Medium H	Low	Medium		529		529		529		529
Medium H	Medium	Unconstrained			0				0	
Medium H	Medium	Low	300	529	0	529	300	529	0	529
Medium H	Medium	Medium	300	529	0	529	300	529	0	529
Medium H	Medium	Accelerated	0	529	0	529	0	529	0	529
Medium H	Medium	High	0	529	0	529	0	529	0	529
Medium H	High	Medium		529		529		3,999		529
High	Low	Medium		529		529		529		529
High	Medium	Unconstrained			0				0	
High	Medium	Low	300	529	0	529	300	529	0	529
High	Medium	Medium	300	529	0	529	300	529	0	529
High	Medium	Accelerated	300	529	0	529	300	529	0	529
High	Medium	High	300	529	0	529	300	529	0	529
High	High	Medium		950		529		5,450		658

Cogeneration Additions in MW

Table 5-17

Future		DSR	2003				2013			
Load	Gas Price	Strategy	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR
Low	Medium	Unconstrained			0				0	
Low	Medium	Medium	0	0	0	0	0	0	0	0
Medium Low	Medium	Unconstrained			0				0	
Medium Low	Medium	Medium	0	0	0	0	0	0	0	0
Medium	Low	Unconstrained			453				453	
Medium	Low	Low	1,457	1,238	636	582	1,936	1,679	636	582
Medium	Low	Medium	1,225	1,038	478	425	1,544	1,341	478	425
Medium	Low	Accelerated	1,160	971	460	396	1,513	1,306	460	396
Medium	Low	High	1,095	906	390	324	1,404	1,195	390	324
Medium	Medium	Unconstrained			192				192	
Medium	Medium	Low	1,324	1,114	402	347	1,610	1,318	402	347
Medium	Medium	Medium	1,058	864	302	276	1,180	948	302	276
Medium	Medium	Accelerated	994	805	227	180	1,148	924	227	180
Medium	Medium	High	929	735	180	134	1,032	854	134	134
Medium	High	Unconstrained			96				96	
Medium	High	Low	388	498	365	299	388	498	365	299
Medium	High	Medium	359	436	160	276	359	436	160	276
Medium	High	Accelerated	320	337	160	160	320	337	160	160
Medium	High	High	320	320	160	133	320	320	160	133
Medium H	Low	Medium		1,898		1,555		2,099		1,555
Medium H	Medium	Unconstrained			811				903	
Medium H	Medium	Low	2,060	1,986	1,162	1,089	2,099	2,099	1,162	1,089
Medium H	Medium	Medium	1,845	1,770	965	895	2,099	2,099	965	895
Medium H	Medium	Accelerated	1,880	1,685	934	872	2,099	2,099	934	872
Medium H	Medium	High	1,836	1,651	899	835	2,099	2,099	899	835
Medium H	High	Medium		1,341		801		1,341		801
High	Low	Medium		2,099		1,889		2,099		1,889
High	Medium	Unconstrained			1,599				1,640	
High	Medium	Low	2,099	2,099	1,640	1,640	2,099	2,099	1,640	1,640
High	Medium	Medium	2,099	2,099	1,640	1,640	2,099	2,099	1,640	1,640
High	Medium	Accelerated	2,099	2,099	1,640	1,620	2,099	2,099	1,640	1,640
High	Medium	High	2,099	2,099	1,640	1,605	2,099	2,099	1,640	1,640
High	High	Medium		2,099		1,517		2,099		1,640

T5-17.cogeneration

Combined Cycle Additions in MW

Table 5-18

Future		DSR	2003				2013			
Load	Gas Price	Strategy	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR
Low	Medium	Unconstrained			0				0	
Low	Medium	Medium	0	0	0	0	0	0	0	0
Medium Low	Medium	Unconstrained			0				0	
Medium Low	Medium	Medium	0	0	0	0	0	0	0	0
Medium	Low	Unconstrained			0				0	
Medium	Low	Low	0	0	0	0	0	0	0	0
Medium	Low	Medium	0	0	0	0	0	0	0	0
Medium	Low	Accelerated	0	0	0	0	0	0	0	0
Medium	Low	High	0	0	0	0	0	0	0	0
Medium	Medium	Unconstrained			0				0	
Medium	Medium	Low	0	0	0	0	0	0	0	0
Medium	Medium	Medium	0	0	0	0	0	0	0	0
Medium	Medium	Accelerated	0	0	0	0	0	0	0	0
Medium	Medium	High	0	0	0	0	0	0	0	0
Medium	High	Unconstrained			0				0	
Medium	High	Low	0	0	0	0	0	0	0	0
Medium	High	Medium	0	0	0	0	0	0	0	0
Medium	High	Accelerated	0	0	0	0	0	0	0	0
Medium	High	High	0	0	0	0	0	0	0	0
Medium H	Low	Medium		0		0		553		0
Medium H	Medium	Unconstrained			0				0	
Medium H	Medium	Low	0	0	0	0	916	835	0	0
Medium H	Medium	Medium	0	0	0	0	570	494	0	0
Medium H	Medium	Accelerated	0	0	0	0	642	481	0	0
Medium H	Medium	High	0	0	0	0	565	413	0	0
Medium H	High	Medium		0		0		0		0
High	Low	Medium		473		0		2,474		273
High	Medium	Unconstrained			0				133	
High	Medium	Low	625	558	0	0	2,871	2,798	367	320
High	Medium	Medium	424	399	0	0	2,444	2,353	181	133
High	Medium	Accelerated	388	323	0	0	2,405	2,330	154	103
High	Medium	High	358	293	0	0	2,311	2,238	129	77
High	High	Medium		96		0		366		0

T5-18.combined-Cycle

Coal Additions in MW

Table 5-19

Future		DSR	2003				2013			
Load	Gas Price	Strategy	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR
Low	Medium	Unconstrained			0				0	
Low	Medium	Medium	0	0	0	0	0	0	0	0
Medium Low	Medium	Unconstrained			25				424	
Medium Low	Medium	Medium	0	0	243	38	0	0	379	170
Medium	Low	Unconstrained			363				1,201	
Medium	Low	Low	0	0	598	468	0	0	1,474	1,315
Medium	Low	Medium	0	0	564	428	0	0	1,222	1,097
Medium	Low	Accelerated	0	0	520	395	0	0	1,201	1,087
Medium	Low	High	0	0	504	399	0	0	1,124	1,006
Medium	Medium	Unconstrained			767				1,547	
Medium	Medium	Low	0	0	912	819	0	0	1,925	1,799
Medium	Medium	Medium	0	0	803	700	0	0	1,437	1,274
Medium	Medium	Accelerated	0	0	809	719	0	0	1,463	1,319
Medium	Medium	High	0	0	792	698	0	0	0	1,262
Medium	High	Unconstrained			876				0	
Medium	High	Low	0	0	990	885	0	0	1,930	1,808
Medium	High	Medium	0	0	924	751	0	0	1,595	1,399
Medium	High	Accelerated	0	0	927	758	0	0	1,565	1,428
Medium	High	High	0	0	893	741	0	0	1,454	1,331
Medium H	Low	Medium		0		232		0		1,839
Medium H	Medium	Unconstrained			972				2,823	
Medium H	Medium	Low	0	0	990	923	0	0	2,951	2,834
Medium H	Medium	Medium	0	0	990	895	0	0	2,788	2,649
Medium H	Medium	Accelerated	0	0	977	859	0	0	2,788	2,653
Medium H	Medium	High	0	0	967	852	0	0	2,740	2,608
Medium H	High	Medium		0		996		0		2,841
High	Low	Medium		0		684		0		3,030
High	Medium	Unconstrained			1,027				3,919	
High	Medium	Low	0	0	1,342	1,167	0	0	4,149	4,020
High	Medium	Medium	0	0	1,207	1,052	0	0	3,903	3,766
High	Medium	Accelerated	0	0	1,168	1,032	0	0	3,924	3,780
High	Medium	High	0	0	1,151	1,025	0	0	3,862	3,720
High	High	Medium		0		1,320		0		4,106

T5-19.coal

Pumped Storage Additions in MW

Table 5-20

Future		DSR	2003				2013			
Load	Gas Price	Strategy	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR
Low	Medium	Unconstrained			0				0	
Low	Medium	Medium	0	0	0	0	0	0	0	0
Medium Low	Medium	Unconstrained			0				242	
Medium Low	Medium	Medium	243	65	0	27	615	437	235	267
Medium	Low	Unconstrained			320				996	
Medium	Low	Low	357	399	461	500	1,000	1,000	1,000	1,000
Medium	Low	Medium	216	225	399	410	1,000	1,000	1,000	1,000
Medium	Low	Accelerated	210	221	390	400	1,000	1,000	1,000	1,000
Medium	Low	High	141	152	341	334	1,000	1,000	919	926
Medium	Medium	Unconstrained			210				892	
Medium	Medium	Low	490	511	500	471	1,000	1,000	1,000	1,000
Medium	Medium	Medium	383	399	336	287	1,000	1,000	962	973
Medium	Medium	Accelerated	375	386	333	293	1,000	1,000	970	984
Medium	Medium	High	307	323	264	226	1,000	1,000	1,000	860
Medium	High	Unconstrained			176				1,000	
Medium	High	Low	500	500	459	452	1,000	1,000	1,000	1,000
Medium	High	Medium	470	470	357	236	1,000	1,000	945	848
Medium	High	Accelerated	451	459	282	274	1,000	1,000	935	895
Medium	High	High	471	445	183	184	1,000	1,000	820	793
Medium H	Low	Medium		482		514		1,000		1,000
Medium H	Medium	Unconstrained			500				1,000	
Medium H	Medium	Low	602	598	616	647	1,000	1,000	1,000	1,000
Medium H	Medium	Medium	535	549	548	573	1,000	1,000	1,000	1,000
Medium H	Medium	Accelerated	545	504	561	581	1,000	1,000	1,000	1,000
Medium H	Medium	High	530	500	537	555	1,000	1,000	1,000	1,000
Medium H	High	Medium		500		676		1,000		1,000
High	Low	Medium		500		515		1,000		1,000
High	Medium	Unconstrained			732				1,000	
High	Medium	Low	518	531	791	782	1,000	1,000	1,000	1,000
High	Medium	Medium	500	510	709	794	1,000	1,000	1,000	1,000
High	Medium	Accelerated	500	501	732	749	1,000	1,000	1,000	1,000
High	Medium	High	500	500	721	731	1,000	1,000	1,000	1,000
High	High	Medium		577		827		1,000		1,000

Simple Cycle Additions in MW

Table 5-21

Future		DSR	2003				2013			
Load	Gas Price	Strategy	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR
Low	Medium	Unconstrained			0				0	
Low	Medium	Medium	0	0	0	0	0	0	0	0
Medium Low	Medium	Unconstrained			0				0	
Medium Low	Medium	Medium	0	0	0	0	0	0	0	0
Medium	Low	Unconstrained			0				0	
Medium	Low	Low	0	0	119	87	391	470	216	253
Medium	Low	Medium	0	0	0	0	156	182	0	0
Medium	Low	Accelerated	0	0	0	0	147	176	0	0
Medium	Low	High	0	0	0	0	30	61	0	0
Medium	Medium	Unconstrained			0				0	
Medium	Medium	Low	0	11	0	0	717	831	0	4
Medium	Medium	Medium	0	0	0	0	520	574	0	0
Medium	Medium	Accelerated	0	0	0	0	513	559	0	0
Medium	Medium	High	0	0	0	0	402	402	961	0
Medium	High	Unconstrained			0				961	
Medium	High	Low	554	638	0	0	961	961	32	42
Medium	High	Medium	273	357	0	0	626	623	0	0
Medium	High	Accelerated	264	395	0	0	618	609	0	0
Medium	High	High	111	293	0	0	476	463	0	0
Medium H	Low	Medium		94		173		1,316		574
Medium H	Medium	Unconstrained			0				311	
Medium H	Medium	Low	309	308	301	234	1,792	1,794	792	805
Medium H	Medium	Medium	173	155	148	111	1,378	1,375	394	424
Medium H	Medium	Accelerated	93	152	46	28	1,298	1,282	318	336
Medium H	Medium	High	64	101	26	10	1,188	1,163	213	232
Medium H	High	Medium		633		0		1,571		326
High	Low	Medium		812		796		2,068		1,449
High	Medium	Unconstrained			204				926	
High	Medium	Low	1,177	1,153	745	752	2,623	2,618	1,537	1,535
High	Medium	Medium	940	877	507	398	2,177	2,189	1,096	1,103
High	Medium	Accelerated	794	778	339	300	2,036	2,032	922	938
High	Medium	High	748	735	292	267	1,977	1,971	856	871
High	High	Medium		973		220		2,672		863

T5-21.simple-cycle

Peaking Resources Additions in MW

Pumped Storage and Simple Cycles

Table 5-22

Future		DSR	2003				2013			
Load	Gas Price	Strategy	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR
Low	Medium	Unconstrained			0				0	
Low	Medium	Medium	0	0	0	0	0	0	0	0
Medium Low	Medium	Unconstrained			0				242	
Medium Low	Medium	Medium	243	65	0	27	615	437	235	267
Medium	Low	Unconstrained			320				996	
Medium	Low	Low	357	399	580	587	1,391	1,470	1,216	1,253
Medium	Low	Medium	216	225	399	410	1,156	1,182	1,000	1,000
Medium	Low	Accelerated	210	221	390	400	1,147	1,176	1,000	1,000
Medium	Low	High	141	152	341	334	1,030	1,061	919	926
Medium	Medium	Unconstrained			210				892	
Medium	Medium	Low	490	522	500	471	1,717	1,831	1,000	1,004
Medium	Medium	Medium	383	399	336	287	1,520	1,574	962	973
Medium	Medium	Accelerated	375	386	333	293	1,513	1,559	970	984
Medium	Medium	High	307	323	264	226	1,402	1,402	848	860
Medium	High	Unconstrained			176				907	
Medium	High	Low	1,054	1,138	459	452	1,988	1,961	1,032	1,042
Medium	High	Medium	743	827	357	236	1,626	1,623	945	848
Medium	High	Accelerated	715	854	282	274	1,618	1,609	935	895
Medium	High	High	581	738	183	184	1,476	1,463	820	793
Medium H	Low	Medium		576		686		2,316		1,574
Medium H	Medium	Unconstrained			500				1,311	
Medium H	Medium	Low	911	905	917	881	2,792	2,794	1,792	1,805
Medium H	Medium	Medium	707	704	696	684	2,378	2,375	1,394	1,424
Medium H	Medium	Accelerated	639	656	608	609	2,298	2,282	1,317	1,336
Medium H	Medium	High	594	601	563	565	2,188	2,163	1,213	1,232
Medium H	High	Medium		1,133		676		2,571		1,326
High	Low	Medium		1,312		1,311		3,068		2,449
High	Medium	Unconstrained			936				1,926	
High	Medium	Low	1,695	1,683	1,536	1,533	3,623	3,618	2,537	2,535
High	Medium	Medium	1,440	1,387	1,215	1,192	3,177	3,189	2,096	2,103
High	Medium	Accelerated	1,294	1,279	1,071	1,049	3,036	3,032	1,922	1,938
High	Medium	High	1,248	1,235	1,013	997	2,977	2,971	1,856	1,871
High	High	Medium		1,550		1,047		3,672		1,863

Non-firm Sales in MWa

Table 5-23

Future		DSR	2003				2013			
Load	Gas Price	Strategy	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR
Low	Medium	Unconstrained			525				724	
Low	Medium	Medium	690	744	690	744	1,036	1,064	1,036	1,064
Medium Low	Medium	Unconstrained			449				618	
Medium Low	Medium	Medium	426	462	463	469	446	556	617	618
Medium	Low	Unconstrained			475				371	
Medium	Low	Low	376	327	521	516	234	256	492	488
Medium	Low	Medium	430	372	477	518	254	263	398	531
Medium	Low	Accelerated	433	358	493	501	252	263	405	453
Medium	Low	High	443	372	497	498	243	257	423	452
Medium	Medium	Unconstrained			477				433	
Medium	Medium	Low	485	491	508	511	379	330	517	521
Medium	Medium	Medium	461	475	488	507	313	294	456	467
Medium	Medium	Accelerated	464	478	486	499	312	297	429	424
Medium	Medium	High	455	470	472	490	296	305	418	413
Medium	High	Unconstrained			464				395	
Medium	High	Low	487	489	478	484	489	465	476	467
Medium	High	Medium	469	481	474	477	464	452	427	430
Medium	High	Accelerated	471	483	473	476	464	452	420	420
Medium	High	High	463	476	462	462	455	441	383	383
Medium H	Low	Medium		485		475		321		491
Medium H	Medium	Unconstrained			523				456	
Medium H	Medium	Low	487	484	521	526	300	298	487	482
Medium H	Medium	Medium	482	485	518	524	304	303	469	466
Medium H	Medium	Accelerated	478	480	522	525	291	308	460	463
Medium H	Medium	High	476	482	520	523	294	321	460	463
Medium H	High	Medium		389		534		179		462
High	Low	Medium		434		434		342		430
High	Medium	Unconstrained			508				502	
High	Medium	Low	400	405	453	472	335	336	511	519
High	Medium	Medium	411	430	485	499	312	304	503	493
High	Medium	Accelerated	428	428	494	506	308	307	502	492
High	Medium	High	430	429	497	507	303	303	497	493
High	High	Medium		406		549		142		531

T5-23.nf energy sales

Non-firm Purchases in MWa

Table 5-24

Future		DSR	2003				2013			
Load	Gas Price	Strategy	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR
Low	Medium	Unconstrained			45				31	
Low	Medium	Medium	32	13	32	13	0	0	0	0
Medium Low	Medium	Unconstrained			105				152	
Medium Low	Medium	Medium	193	109	85	94	212	180	152	157
Medium	Low	Unconstrained			63				152	
Medium	Low	Low	234	251	68	68	228	232	153	151
Medium	Low	Medium	213	224	88	54	230	237	151	152
Medium	Low	Accelerated	209	229	63	69	230	233	151	151
Medium	Low	High	188	225	62	72	232	233	152	154
Medium	Medium	Unconstrained			68				154	
Medium	Medium	Low	115	107	104	87	245	261	153	153
Medium	Medium	Medium	108	111	97	71	266	269	152	152
Medium	Medium	Accelerated	107	109	90	74	267	269	154	154
Medium	Medium	High	108	114	92	81	272	269	154	154
Medium	High	Unconstrained			181				187	
Medium	High	Low	105	104	178	182	243	249	167	175
Medium	High	Medium	90	86	177	179	257	265	186	179
Medium	High	Accelerated	89	85	176	176	257	268	186	179
Medium	High	High	89	83	187	187	269	277	190	190
Medium H	Low	Medium		108		128		292		152
Medium H	Medium	Unconstrained			87				152	
Medium H	Medium	Low	130	118	133	107	266	264	153	150
Medium H	Medium	Medium	114	110	110	98	265	263	151	152
Medium H	Medium	Accelerated	125	109	106	93	266	261	151	152
Medium H	Medium	High	123	108	103	92	269	264	152	153
Medium H	High	Medium		224		85		234		153
High	Low	Medium		192		183		260		162
High	Medium	Unconstrained			131				153	
High	Medium	Low	213	211	157	159	230	227	135	140
High	Medium	Medium	216	202	144	133	235	236	154	153
High	Medium	Accelerated	206	199	137	126	240	238	153	153
High	Medium	High	205	199	130	125	254	248	153	153
High	High	Medium		214		106		266		157

Reserve Margin by Strategy (%)

Table 5-25

Future / Strategy	1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
Load = l Gas = mg DSR = unc Coal = ac Renewables = ar	19.2	23.2	23.6	23.6	25.6	25.2	25.0	24.2	17.3	20.1	16.0	19.3
Load = l Gas = mg DSR = md Coal = nc Renewables = ar	19.6	24.1	25.1	25.9	29.0	29.6	30.6	30.9	25.1	30.5	28.0	33.6
Load = l Gas = mg DSR = md Coal = nc Renewables = sr	19.6	24.1	25.1	26.2	29.8	30.9	32.2	33.1	27.4	32.9	30.4	36.1
Load = l Gas = mg DSR = md Coal = ac Renewables = ar	19.6	24.1	25.1	25.9	29.0	29.6	30.6	30.9	25.1	30.5	28.0	33.6
Load = l Gas = mg DSR = md Coal = ac Renewables = sr	19.6	24.1	25.1	26.2	29.8	30.9	32.2	33.1	27.4	32.9	30.4	36.1
Load = ml Gas = mg DSR = unc Coal = ac Renewables = ar	15.9	18.6	17.9	16.6	17.8	16.7	16.0	15.0	14.9	15.4	14.9	14.9
Load = ml Gas = mg DSR = md Coal = nc Renewables = ar	16.1	19.2	18.9	18.1	19.7	19.3	19.4	18.9	15.0	16.8	15.0	15.0
Load = ml Gas = mg DSR = md Coal = nc Renewables = sr	16.1	19.2	18.9	18.4	20.4	20.5	20.9	21.0	15.0	16.8	15.0	15.0
Load = ml Gas = mg DSR = md Coal = ac Renewables = ar	16.1	19.2	18.9	18.1	19.7	19.3	19.4	18.9	15.0	16.8	15.0	15.0
Load = ml Gas = mg DSR = md Coal = ac Renewables = sr	16.1	19.2	18.9	18.4	20.4	20.5	20.9	21.0	15.0	16.8	15.0	15.0
Load = m Gas = mg DSR = unc Coal = ac Renewables = ar	15.0	16.5	15.0	15.0	15.0	15.0	15.0	15.0	14.9	14.9	14.9	15.0
Load = m Gas = mg DSR = ld Coal = nc Renewables = ar	13.5	15.2	13.3	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Load = m Gas = mg DSR = ld Coal = nc Renewables = sr	13.5	15.2	13.3	15.0	15.1	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Load = m Gas = mg DSR = ld Coal = ac Renewables = ar	13.5	15.2	13.3	15.0	15.0	15.0	15.0	15.4	15.0	15.0	15.0	15.0
Load = m Gas = mg DSR = ld Coal = ac Renewables = sr	13.5	15.2	13.3	15.0	15.1	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Load = m Gas = mg DSR = md Coal = nc Renewables = ar	13.7	15.4	13.7	15.0	15.2	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Load = m Gas = mg DSR = md Coal = nc Renewables = sr	13.7	15.4	13.7	15.0	15.6	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Load = m Gas = mg DSR = md Coal = ac Renewables = ar	13.7	15.4	13.7	15.0	15.2	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Load = m Gas = mg DSR = md Coal = ac Renewables = sr	13.7	15.4	13.7	15.0	15.6	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Load = m Gas = mg DSR = ad Coal = nc Renewables = ar	13.8	15.9	14.8	15.0	15.3	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Load = m Gas = mg DSR = ad Coal = nc Renewables = sr	13.8	15.9	14.8	15.0	15.6	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Load = m Gas = mg DSR = ad Coal = ac Renewables = ar	13.8	15.9	14.8	15.0	15.3	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Load = m Gas = mg DSR = ad Coal = ac Renewables = sr	13.8	15.9	14.8	15.0	15.6	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Load = m Gas = mg DSR = hd Coal = nc Renewables = ar	14.0	16.1	15.1	15.0	15.4	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Load = m Gas = mg DSR = hd Coal = nc Renewables = sr	14.0	16.1	15.1	15.0	15.8	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Load = m Gas = mg DSR = hd Coal = ac Renewables = ar	14.0	16.1	15.1	15.0	15.4	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Load = m Gas = mg DSR = hd Coal = ac Renewables = sr	14.0	16.1	15.1	15.0	15.8	15.0	15.0	15.0	15.0	15.0	15.0	15.0

Energy Comparison (MWa)

Table 5-26

Load = l Gas = mg DSR = md Coal = nc Renewables = sr

	1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
Native Load	5,045	5,044	5,077	5,024	5,013	5,022	5,086	5,096	5,183	5,269	5,345	5,373
Pumped Storage	312	311	310	310	309	307	306	306	306	305	305	305
Firm Sales	1,483	1,480	1,438	1,455	1,455	1,477	1,456	1,434	1,410	1,220	1,043	841
Non-Firm Sales	536	591	569	599	647	654	674	726	744	863	896	1,064
DSR	-20	-43	-72	-109	-152	-183	-215	-248	-307	-384	-449	-498
Total Requirements	7,356	7,383	7,322	7,279	7,272	7,277	7,307	7,314	7,336	7,273	7,140	7,085
Existing Generation	6,664	6,731	6,831	6,797	6,786	6,759	6,790	6,760	6,802	6,752	6,642	6,589
Firm Purchases	623	608	440	422	407	397	387	381	360	357	335	333
Non-Firm Purchases	70	44	52	47	32	32	14	9	13	0	0	0
New Resources	0	0	0	27	61	103	130	176	176	176	176	176
Total Resources	7,357	7,383	7,323	7,293	7,286	7,291	7,321	7,326	7,351	7,285	7,153	7,098

Load = ml Gas = mg DSR = md Coal = nc Renewables = sr

	1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
Native Load	5,224	5,286	5,382	5,404	5,461	5,522	5,630	5,678	5,855	6,088	6,335	6,620
Pumped Storage	312	311	310	308	309	307	306	306	322	320	397	413
Firm Sales	1,483	1,480	1,438	1,455	1,455	1,477	1,456	1,434	1,410	1,220	1,043	841
Non-Firm Sales	469	496	455	435	461	446	445	473	462	552	516	556
DSR	-20	-43	-72	-109	-152	-186	-223	-259	-325	-414	-487	-548
Total Requirements	7,468	7,530	7,513	7,493	7,534	7,566	7,614	7,632	7,724	7,767	7,804	7,882
Existing Generation	6,730	6,818	6,955	6,934	6,961	6,963	6,991	6,999	7,075	7,124	6,990	7,034
Firm Purchases	641	628	451	434	410	402	393	388	364	361	376	420
Non-Firm Purchases	96	84	107	113	115	110	115	81	109	106	200	180
New Resources	0	0	0	27	61	103	130	177	190	189	251	264
Total Resources	7,467	7,530	7,513	7,508	7,547	7,578	7,629	7,645	7,738	7,780	7,817	7,898

Load = m Gas = mg DSR = md Coal = nc Renewables = sr

	1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
Native Load	5,353	5,484	5,661	5,759	5,890	6,024	6,207	6,322	6,634	6,987	7,411	7,998
Pumped Storage	312	311	309	310	309	307	306	306	413	405	426	449
Firm Sales	1,483	1,480	1,438	1,455	1,455	1,477	1,456	1,434	1,410	1,220	1,043	841
Non-Firm Sales	420	431	334	374	380	343	327	366	475	523	460	294
DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
Total Requirements	7,547	7,663	7,670	7,789	7,882	7,962	8,066	8,156	8,584	8,684	8,802	8,969
Existing Generation	6,776	6,887	7,035	6,971	7,025	7,026	7,082	7,078	7,138	7,182	7,021	7,090
Firm Purchases	645	644	452	434	411	403	393	388	364	379	423	442
Non-Firm Purchases	128	133	183	141	171	173	144	122	111	128	236	269
New Resources	0	0	0	255	289	371	461	582	985	1,009	1,136	1,182
Total Resources	7,549	7,664	7,670	7,801	7,896	7,973	8,080	8,170	8,598	8,698	8,816	8,983

ljh T5-26.energy comparison

Energy Output of DSR Additions (MWa)

Table 5-27

Future / DSR Strategy	1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
Load = l Gas = mg DSR = unc	4	5	5	6	7	7	7	7	8	9	9	10
Load = l Gas = mg DSR = md	20	43	72	109	152	183	215	248	307	384	449	498
Load = ml Gas = mg DSR = unc	7	10	14	18	30	34	39	44	459	474	489	503
Load = ml Gas = mg DSR = md	20	43	72	109	152	186	223	259	325	414	487	548
Load = m Gas = lg DSR = unc	63	70	98	149	157	165	173	182	523	550	578	607
Load = m Gas = lg DSR = ld	16	35	54	72	87	106	121	137	175	228	277	318
Load = m Gas = lg DSR = md	21	43	73	109	152	189	231	272	348	451	538	613
Load = m Gas = lg DSR = ad	34	79	152	191	236	270	305	341	404	490	570	638
Load = m Gas = lg DSR = hd	36	84	161	204	254	292	334	375	448	547	639	718
Load = m Gas = mg DSR = unc	62	68	120	239	259	269	275	281	501	521	542	593
Load = m Gas = mg DSR = ld	16	35	54	72	87	106	121	137	175	228	277	318
Load = m Gas = mg DSR = md	21	43	73	109	152	189	231	272	348	451	538	613
Load = m Gas = mg DSR = ad	34	79	152	191	236	270	305	341	404	490	570	638
Load = m Gas = mg DSR = hd	36	84	161	204	254	292	334	375	448	547	639	718
Load = m Gas = hg DSR = unc	62	68	120	239	269	307	313	320	509	529	572	593
Load = m Gas = hg DSR = ld	16	35	54	72	87	106	121	137	175	228	277	318
Load = m Gas = hg DSR = md	21	43	73	109	152	189	231	272	348	451	538	613
Load = m Gas = hg DSR = ad	34	79	152	191	236	270	305	341	404	490	570	638
Load = m Gas = hg DSR = hd	36	84	161	204	254	292	334	375	448	547	639	718
Load = mh Gas = mg DSR = unc	154	192	463	469	477	485	494	504	587	618	648	696
Load = mh Gas = mg DSR = ld	16	35	57	77	94	113	130	147	189	249	302	349
Load = mh Gas = mg DSR = md	21	43	73	109	152	197	244	292	380	502	604	694
Load = mh Gas = mg DSR = ad	36	84	161	204	253	292	332	373	445	543	636	718
Load = mh Gas = mg DSR = hd	37	87	165	210	262	305	351	397	480	593	700	795
Load = h Gas = mg DSR = unc	389	555	582	593	603	615	628	642	681	724	767	813
Load = h Gas = mg DSR = ld	16	35	60	82	100	120	138	157	202	268	327	379
Load = h Gas = mg DSR = md	21	43	73	109	153	203	256	309	409	548	664	769
Load = h Gas = mg DSR = ad	38	88	167	213	265	309	355	400	482	596	704	802
Load = h Gas = mg DSR = hd	38	89	170	217	270	319	369	420	512	639	759	868

Summary of Low and Medium Low Load Growths and Medium Gas

Financial Results for 2013 (including end effects to 2043)

DSM		medium							
Load		Low				Medium Low			
Coal		any		no		any		no	
Renewable		any	strat	any	strat	any	strat	any	strat
Case #		2	3	4	5	7	8	9	10
System Load (MWa)		5,672	5,672	5,672	5,672	6,920	6,920	6,920	6,920
Conservation (MWa)		498	498	498	498	548	548	548	548
After Conservation									
System Load (MWa)		5,174	5,174	5,174	5,174	6,372	6,372	6,372	6,372
Energy Sales (MWa)		4,636	4,636	4,636	4,636	5,783	5,783	5,783	5,783
Total Customers (000's)		1,274	1,274	1,274	1,274	1,485	1,485	1,485	1,485
Net Electric Plant ($M)		14,587	14,801	14,587	14,801	16,199	16,014	15,689	15,747
Net Conservation Assets ($M)		636	636	636	636	751	751	751	751
Utility Cost									
Operating Revenues ($M)	Nominal	3,778	3,862	3,778	3,862	4,528	4,575	4,598	4,593
	Real	2,002	2,046	2,002	2,046	2,399	2,424	2,436	2,433
Cost in mills/kWh	Nominal	93.0	95.1	93.0	95.1	89.4	90.3	90.8	90.7
	Real	49.3	50.4	49.3	50.4	47.4	47.9	48.1	48.0
Average Customer Bill ($)	Nominal	2,966	3,032	2,966	3,032	3,049	3,081	3,096	3,093
	Real	1,572	1,606	1,572	1,606	1,615	1,632	1,640	1,638
Total Resource Cost									
DSR Customer Cost ($M)		64	64	64	64	71	71	71	71
Levelized (20-year at 8.8%)		123	123	123	123	125	125	125	125
Energy Service Charge ($M)		105	105	105	105	122	122	122	122
Total Resource Cost ($M)	Nominal	4,006	4,089	4,006	4,089	4,775	4,822	4,844	4,840
	Real	2,122	2,167	2,122	2,167	2,530	2,555	2,567	2,564
Cost in mills/kWh	Nominal	89.8	91.7	89.8	91.7	86.7	87.6	88.0	87.9
	Real	47.6	48.6	47.6	48.6	45.9	46.4	46.6	46.6
50-Year Nominal NPV ($M)									
Utility Cost		38,040	38,791	38,040	38,791	41,419	41,939	41,582	41,984
Total Resource Cost		39,310	40,061	39,310	40,061	42,760	43,280	42,923	43,325
50-year Real Levelized Cost in Mills/kWh									
Utility Cost		50.1	51.1	50.1	51.1	47.0	47.6	47.2	47.7
Total Resource Cost		48.6	49.6	48.6	49.6	45.8	46.4	46.0	46.4

T5-28.financial sum.l-ml

Summary of Medium Load Growth and Low Gas
Financial Results for 2013 (including end effects to 2043)

	DSM	low				medium				accelerated				high			
	Coal	any		no		any		no		any		no		any		no	
	Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
	Case #	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
System Load (MWa)		8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297
Conservation (MWa)		318	318	318	318	613	613	613	613	638	638	638	638	718	718	718	718
After Conservation																	
System Load (MWa)		7,979	7,979	7,979	7,979	7,684	7,684	7,684	7,684	7,659	7,659	7,659	7,659	7,578	7,578	7,578	7,578
Energy Sales (MWa)		7,233	7,233	7,233	7,233	6,963	6,963	6,963	6,963	6,940	6,940	6,940	6,940	6,868	6,868	6,868	6,868
Total Customers (000's)		1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725
Net Electric Plant ($M)		20,432	20,334	18,102	18,129	19,935	19,912	17,947	18,056	19,897	19,894	17,935	18,043	19,730	19,686	17,919	18,024
Net Conservation Assets ($M)		481	481	481	481	876	876	876	876	851	851	851	851	979	979	979	979
Utility Cost																	
Operating Revenues ($M)	Nominal	5,618	5,664	5,537	5,598	5,503	5,551	5,410	5,471	5,496	5,543	5,402	5,463	5,453	5,512	5,368	5,429
	Real	2,976	3,001	2,934	2,966	2,916	2,941	2,866	2,898	2,912	2,937	2,862	2,894	2,889	2,920	2,844	2,876
Cost in mills/kWh	Nominal	88.7	89.4	87.4	88.4	90.2	91.0	88.7	89.7	90.4	91.2	88.9	89.9	90.6	91.6	89.2	90.2
	Real	47.0	47.4	46.3	46.8	47.8	48.2	47.0	47.5	47.9	48.3	47.1	47.6	48.0	48.5	47.3	47.8
Average Customer Bill ($)	Nominal	3,257	3,284	3,211	3,246	3,191	3,219	3,137	3,172	3,187	3,214	3,132	3,167	3,162	3,196	3,112	3,148
	Real	1,726	1,740	1,701	1,719	1,690	1,705	1,662	1,680	1,688	1,703	1,659	1,678	1,675	1,693	1,649	1,668
Total Resource Cost																	
DSR Customer Cost ($M)		56	56	56	56	85	85	85	85	79	79	79	79	106	106	106	106
Levelized (20-year at 8.8%)		84	84	84	84	150	150	150	150	138	138	138	138	164	164	164	164
Energy Service Charge ($M)		75	75	75	75	141	141	141	141	132	132	132	132	146	146	146	146
Total Resource Cost ($M)	Nominal	5,777	5,823	5,696	5,756	5,794	5,842	5,701	5,762	5,766	5,813	5,672	5,733	5,762	5,822	5,677	5,738
	Real	3,061	3,085	3,018	3,050	3,070	3,095	3,020	3,053	3,055	3,080	3,005	3,037	3,053	3,084	3,008	3,040
Cost in mills/kWh	Nominal	87.6	88.3	86.4	87.3	87.9	88.6	86.5	87.4	87.5	88.2	86.1	87.0	87.4	88.3	86.1	87.1
	Real	46.4	46.8	45.8	46.3	46.6	47.0	45.8	46.3	46.3	46.7	45.6	46.1	46.3	46.8	45.6	46.1
50-Year Nominal NPV ($M)																	
Utility Cost		47,167	47,664	47,188	47,692	46,379	46,878	46,406	46,901	46,334	46,837	46,361	46,857	46,096	46,598	46,112	46,612
Total Resource Cost		48,071	48,568	48,092	48,596	47,945	48,444	47,971	48,467	47,791	48,295	47,818	48,315	47,818	48,320	47,834	48,333
50-year Real Levelized Cost in Mills/kWh																	
Utility Cost		45.7	46.2	45.7	46.2	46.2	46.7	46.2	46.7	46.4	46.9	46.5	47.0	46.5	47.0	46.6	47.1
Total Resource Cost		45.3	45.7	45.3	45.8	45.1	45.6	45.2	45.6	45.0	45.5	45.0	45.5	45.0	45.5	45.0	45.5

Summary of Medium Load Growth and Medium Gas

Financial Results for 2013 (including end effects to 2043)

	DSM	low				medium				accelerated				high			
	Coal	any		no		any		no		any		no		any		no	
	Renewable	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
	Case #	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44
System Load (MWa)		8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297
Conservation (MWa)		318	318	318	318	613	613	613	613	638	638	638	638	718	718	718	718
After Conservation																	
System Load (MWa)		7,979	7,979	7,979	7,979	7,684	7,684	7,684	7,684	7,659	7,659	7,659	7,659	7,578	7,578	7,578	7,578
Energy Sales (MWa)		7,233	7,233	7,233	7,233	6,963	6,963	6,963	6,963	6,940	6,940	6,940	6,940	6,868	6,868	6,868	6,868
Total Customers (000's)		1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725
Net Electric Plant ($M)		21,210	21,152	18,006	18,089	20,223	20,100	17,947	18,071	20,269	20,165	17,935	18,063	20,129	20,031	17,918	18,049
Net Conservation Assets ($M)		481	481	481	481	876	876	876	876	851	851	851	851	979	979	979	979
Utility Cost																	
Operating Revenues ($M)	Nominal	5,556	5,615	5,623	5,694	5,456	5,506	5,499	5,560	5,454	5,513	5,490	5,549	5,409	5,464	5,456	5,501
	Real	2,943	2,975	2,979	3,017	2,891	2,917	2,913	2,946	2,890	2,921	2,909	2,940	2,866	2,895	2,891	2,915
Cost in mills/kWh	Nominal	87.7	88.6	88.7	89.9	89.5	90.3	90.2	91.2	89.7	90.7	90.3	91.3	89.9	90.8	90.7	91.4
	Real	46.5	47.0	47.0	47.6	47.4	47.8	47.8	48.3	47.5	48.0	47.8	48.4	47.6	48.1	48.1	48.5
Average Customer Bill ($)	Nominal	3,221	3,256	3,260	3,301	3,164	3,192	3,188	3,224	3,162	3,196	3,183	3,217	3,136	3,168	3,164	3,190
	Real	1,707	1,725	1,727	1,749	1,676	1,691	1,689	1,708	1,675	1,693	1,687	1,705	1,662	1,678	1,676	1,690
Total Resource Cost																	
DSR Customer Cost ($M)		56	56	56	56	85	85	85	85	79	79	79	79	106	106	106	106
Levelized (20-year at 8.8%)		84	84	84	84	150	150	150	150	138	138	138	138	164	164	164	164
Energy Service Charge ($M)		75	75	75	75	141	141	141	141	132	132	132	132	146	146	146	146
Total Resource Cost ($M)	Nominal	5,714	5,774	5,782	5,853	5,747	5,797	5,790	5,851	5,724	5,782	5,760	5,819	5,718	5,773	5,766	5,811
	Real	3,027	3,059	3,063	3,101	3,045	3,071	3,068	3,100	3,032	3,064	3,052	3,083	3,030	3,059	3,055	3,078
Cost in mills/kWh	Nominal	86.7	87.6	87.7	88.8	87.2	88.0	87.9	88.8	86.8	87.7	87.4	88.3	86.8	87.6	87.5	88.2
	Real	45.9	46.4	46.5	47.0	46.2	46.6	46.5	47.0	46.0	46.5	46.3	46.8	46.0	46.4	46.3	46.7
50-Year Nominal NPV ($M)																	
Utility Cost		47,195	47,681	47,742	48,224	46,337	46,802	46,894	47,338	46,327	46,809	46,834	47,270	46,067	46,549	46,563	46,970
Total Resource Cost		48,099	48,586	48,647	49,128	47,903	48,368	48,460	48,903	47,784	48,266	48,291	48,727	47,789	48,271	48,285	48,691
50-year Real Levelized Cost in Mills/kWh																	
Utility Cost		45.7	46.2	46.3	46.7	46.1	46.6	46.7	47.1	46.4	46.9	46.9	47.4	46.5	47.0	47.0	47.4
Total Resource Cost		45.3	45.7	45.8	46.3	45.1	45.5	45.6	46.0	45.0	45.4	45.5	45.9	45.0	45.4	45.5	45.8

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Summary of Medium Load Growth and High Gas

Financial Results for 2013 (including end effects to 2043)

DSM		low				medium				accelerated				high			
Coal		any		no		any		no		any		no		any		no	
Renewable		any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat
Case #		46	47	48	49	50	51	52	53	54	55	56	57	58	59	60	61
System Load (MWa)		8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297
Conservation (MWa)		318	318	318	318	613	613	613	613	638	638	638	638	718	718	718	718
After Conservation																	
System Load (MWa)		7,979	7,979	7,979	7,979	7,684	7,684	7,684	7,684	7,659	7,659	7,659	7,659	7,578	7,578	7,578	7,578
Energy Sales (MWa)		7,233	7,233	7,233	7,233	6,963	6,963	6,963	6,963	6,940	6,940	6,940	6,940	6,868	6,868	6,868	6,868
Total Customers (000's)		1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725
Net Electric Plant ($M)		21,132	21,101	21,925	22,472	20,466	20,292	20,800	21,176	20,375	20,344	20,868	21,603	20,110	20,104	20,330	21,220
Net Conservation Assets ($M)		481	481	481	481	876	876	876	876	851	851	851	851	979	979	979	979
Utility Cost																	
Operating Revenues ($M)	Nominal	5,489	5,551	6,097	6,141	5,407	5,399	5,772	5,815	5,389	5,431	5,760	5,857	5,343	5,390	5,661	5,761
	Real	2,908	2,941	3,230	3,254	2,865	2,861	3,058	3,081	2,855	2,877	3,052	3,103	2,831	2,856	2,999	3,052
Cost in mills/kWh	Nominal	86.6	87.6	96.2	96.9	88.6	88.5	94.6	95.3	88.6	89.3	94.8	96.3	88.8	89.6	94.1	95.8
	Real	45.9	46.4	51.0	51.4	47.0	46.9	50.1	50.5	47.0	47.3	50.2	51.0	47.1	47.5	49.9	50.7
Average Customer Bill ($)	Nominal	3,183	3,219	3,535	3,561	3,135	3,131	3,347	3,371	3,124	3,149	3,340	3,396	3,098	3,125	3,282	3,340
	Real	1,686	1,705	1,873	1,886	1,661	1,659	1,773	1,786	1,655	1,668	1,769	1,799	1,641	1,656	1,739	1,770
Total Resource Cost																	
DSR Customer Cost ($M)		56	56	56	56	85	85	85	85	79	79	79	79	106	106	106	106
Levelized (20-year at 8.8%)		84	84	84	84	150	150	150	150	138	138	138	138	164	164	164	164
Energy Service Charge ($M)		75	75	75	75	141	141	141	141	132	132	132	132	146	146	146	146
Total Resource Cost ($M)	Nominal	5,648	5,710	6,255	6,300	5,698	5,690	6,063	6,106	5,658	5,700	6,030	6,126	5,652	5,699	5,970	6,070
	Real	2,992	3,025	3,314	3,338	3,019	3,015	3,212	3,235	2,998	3,020	3,195	3,246	2,995	3,020	3,163	3,216
Cost in mills/kWh	Nominal	85.7	86.6	94.9	95.6	86.5	86.3	92.0	92.6	85.8	86.5	91.5	92.9	85.8	86.5	90.6	92.1
	Real	45.4	45.9	50.3	50.6	45.8	45.7	48.7	49.1	45.5	45.8	48.5	49.2	45.4	45.8	48.0	48.8
50-Year Nominal NPV ($M)																	
Utility Cost		47,153	47,652	50,053	49,925	46,403	46,607	48,541	48,474	46,305	46,687	48,469	48,534	45,945	46,381	48,015	48,106
Total Resource Cost		48,057	48,557	50,957	50,829	47,969	48,173	50,107	50,039	47,762	48,144	49,926	49,992	47,667	48,103	49,737	49,827
50-year Real Levelized Cost in Mills/kWh																	
Utility Cost		45.7	46.2	48.5	48.4	46.2	46.4	48.3	48.3	46.4	46.8	48.6	48.6	46.4	46.8	48.5	48.6
Total Resource Cost		45.2	45.7	48.0	47.9	45.2	45.4	47.2	47.1	45.0	45.3	47.0	47.1	44.9	45.3	46.8	46.9

Table 5-32

Summary of Medium High Load Growth

Financial Results for 2013 (including end effects to 2043)

	Gas	low		medium																high	
	DSM	medium		low				medium				accelerated				high				medium	
	Coal	any	no	any		no		any		no		any		no		any		no		any	no
	Renewable	strat	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
	Case #	62	63	65	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82
System Load (MWa)		9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923	9,923
Conservation (MWa)		694	694	349	349	349	349	694	694	694	694	718	718	718	718	795	795	795	795	694	694
After Conservation																					
System Load (MWa)		9,229	9,229	9,573	9,573	9,573	9,573	9,229	9,229	9,229	9,229	9,205	9,205	9,205	9,205	9,127	9,127	9,127	9,127	9,229	9,229
Energy Sales (MWa)		8,360	8,360	8,674	8,674	8,674	8,674	8,360	8,360	8,360	8,360	8,340	8,340	8,340	8,340	8,269	8,269	8,269	8,269	8,360	8,360
Total Customers (000's)		2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018	2,018
Net Electric Plant ($M)		23,876	20,494	25,420	25,347	20,355	20,463	25,140	25,047	20,353	20,462	25,090	25,031	20,306	20,442	25,039	24,978	20,322	20,458	25,349	26,712
Net Conservation Assets ($M)		1,026	1,026	497	497	497	497	1,026	1,026	1,026	1,026	990	990	990	990	1,141	1,141	1,141	1,141	1,026	1,026
Utility Cost																					
Operating Revenues ($M)	Nominal	6,420	6,444	6,591	6,656	6,760	6,792	6,432	6,502	6,563	6,596	6,419	6,486	6,542	6,573	6,381	6,451	6,500	6,530	6,493	7,329
	Real	3,401	3,414	3,492	3,526	3,581	3,599	3,408	3,445	3,477	3,495	3,401	3,436	3,466	3,482	3,381	3,418	3,443	3,460	3,440	3,883
Cost in mills/kWh	Nominal	87.7	88.0	86.7	87.6	89.0	89.4	87.8	88.8	89.6	90.1	87.9	88.8	89.6	90.0	88.1	89.1	89.7	90.2	88.7	100.1
	Real	46.5	46.6	46.0	46.4	47.1	47.4	46.5	47.0	47.5	47.7	46.6	47.0	47.4	47.7	46.7	47.2	47.5	47.8	47.0	53.0
Average Customer Bill ($)	Nominal	3,182	3,194	3,267	3,298	3,350	3,366	3,188	3,222	3,252	3,269	3,181	3,214	3,242	3,258	3,163	3,197	3,221	3,236	3,218	3,632
	Real	1,686	1,692	1,731	1,747	1,775	1,783	1,689	1,707	1,723	1,732	1,685	1,703	1,718	1,726	1,675	1,694	1,706	1,715	1,705	1,924
Total Resource Cost																					
DSR Customer Cost ($M)		99	99	64	64	64	64	99	99	99	99	89	89	89	89	121	121	121	121	99	99
Levelized (20-year at 8.8%)		170	170	90	90	90	90	170	170	170	170	146	146	146	146	182	182	182	182	170	170
Energy Service Charge ($M)		164	164	79	79	79	79	164	164	164	164	151	151	151	151	168	168	168	168	164	164
Total Resource Cost ($M)	Nominal	6,754	6,778	6,760	6,824	6,928	6,961	6,766	6,835	6,896	6,930	6,716	6,783	6,839	6,870	6,731	6,801	6,849	6,880	6,827	7,662
	Real	3,578	3,591	3,581	3,615	3,671	3,688	3,585	3,621	3,654	3,671	3,558	3,594	3,624	3,640	3,566	3,603	3,629	3,645	3,617	4,060
Cost in mills/kWh	Nominal	85.7	86.0	85.8	86.6	87.9	88.3	85.9	86.8	87.5	88.0	85.2	86.1	86.8	87.2	85.4	86.3	86.9	87.3	86.6	97.3
	Real	45.4	45.6	45.5	45.9	46.6	46.8	45.5	46.0	46.4	46.6	45.2	45.6	46.0	46.2	45.3	45.7	46.1	46.3	45.9	51.5
50-Year Nominal NPV ($M)																					
Utility Cost		52,410	52,682	53,278	53,767	54,588	54,811	52,290	52,785	53,449	53,664	52,137	52,627	53,125	53,504	51,930	52,423	52,886	53,257	53,043	56,461
Total Resource Cost		54,176	54,448	54,241	54,730	55,552	55,774	54,056	54,551	55,215	55,430	53,711	54,202	54,699	55,078	53,859	54,352	54,815	55,186	54,809	58,227
50-year Real Levelized Cost in Mills/kWh																					
Utility Cost		45.8	46.0	45.3	45.7	46.4	46.6	45.7	46.1	46.7	46.9	45.8	46.2	46.7	47.0	45.9	46.3	46.7	47.1	46.3	49.3
Total Resource Cost		44.8	45.0	44.8	45.2	45.9	46.1	44.7	45.1	45.6	45.8	44.4	44.8	45.2	45.5	44.5	44.9	45.3	45.6	45.3	48.1

T5-32 financial sum mh

Table 5-33

Summary of High Load Growth

Financial Results for 2013 (including end effects to 2043)

Gas		low		medium																high	
DSM		medium		low				medium				accelerated				high				medium	
Coal		any	no	any		no		any		no		any		no		any		no		any	no
Renewable		strat	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	any	strat	strat	strat
Case #		83	84	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100	101	102	103
System Load (MWa)		11,680	11,680	11,680	11,680	11,680	11,680	11,680	11,680	11,680	11,680	11,680	11,680	11,680	11,680	11,680	11,680	11,680	11,680	11,680	11,680
Conservation (MWa)		769	769	379	379	379	379	769	769	769	769	802	802	802	802	868	868	868	868	769	769
After Conservation																					
System Load (MWa)		10,911	10,911	11,300	11,300	11,300	11,300	10,911	10,911	10,911	10,911	10,878	10,878	10,878	10,878	10,812	10,812	10,812	10,812	10,911	10,911
Energy Sales (MWa)		9,878	9,878	10,232	10,232	10,232	10,232	9,878	9,878	9,878	9,878	9,850	9,850	9,850	9,850	9,787	9,787	9,787	9,787	9,878	9,878
Total Customers (000's)		2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263
Net Electric Plant ($M)		28,276	23,017	29,914	29,932	22,874	22,986	29,617	29,545	22,886	22,988	29,597	29,496	22,794	22,907	29,653	29,552	22,952	23,066	30,401	30,334
Net Conservation Assets ($M)		1,164	1,164	526	526	526	526	1,164	1,164	1,164	1,164	1,122	1,122	1,122	1,122	1,404	1,404	1,404	1,404	1,164	1,164
Utility Cost																					
Operating Revenues ($M)	Nominal	7,457	7,465	7,674	7,716	7,957	7,986	7,462	7,510	7,729	7,763	7,421	7,475	7,691	7,722	7,405	7,459	7,674	7,703	7,541	8,881
	Real	3,951	3,955	4,066	4,088	4,215	4,231	3,953	3,979	4,095	4,113	3,931	3,960	4,075	4,091	3,923	3,952	4,066	4,081	3,995	4,705
Cost in mills/kWh	Nominal	86.2	86.3	85.6	86.1	88.8	89.1	86.2	86.8	89.3	89.7	86.0	86.6	89.1	89.5	86.4	87.0	89.5	89.9	87.2	102.6
	Real	45.7	45.7	45.4	45.6	47.0	47.2	45.7	46.0	47.3	47.5	45.6	45.9	47.2	47.4	45.8	46.1	47.4	47.6	46.2	54.4
Average Customer Bill ($)	Nominal	3,295	3,298	3,391	3,409	3,515	3,528	3,297	3,318	3,415	3,430	3,279	3,303	3,398	3,412	3,272	3,296	3,391	3,404	3,332	3,924
	Real	1,746	1,747	1,796	1,806	1,862	1,869	1,747	1,758	1,809	1,817	1,737	1,750	1,800	1,807	1,733	1,746	1,796	1,803	1,765	2,079
Total Resource Cost																					
DSR Customer Cost ($M)		109	109	72	72	72	72	109	109	109	109	100	100	100	100	146	146	146	146	109	109
Levelized (20-year at 8.8%)		179	179	97	97	97	97	179	179	179	179	161	161	161	161	222	222	222	222	179	179
Energy Service Charge ($M)		186	186	84	84	84	84	186	186	186	186	170	170	170	170	214	214	214	214	186	186
Total Resource Cost ($M)	Nominal	7,822	7,830	7,855	7,897	8,137	8,166	7,827	7,875	8,093	8,128	7,752	7,806	8,022	8,053	7,841	7,895	8,110	8,139	7,906	9,246
	Real	4,144	4,148	4,161	4,184	4,311	4,327	4,147	4,172	4,288	4,306	4,107	4,135	4,250	4,266	4,154	4,183	4,297	4,312	4,189	4,898
Cost in mills/kWh	Nominal	84.4	84.5	84.8	85.2	87.8	88.1	84.5	85.0	87.3	87.7	83.6	84.2	86.6	86.9	84.6	85.2	87.5	87.8	85.3	99.8
	Real	44.7	44.8	44.9	45.1	46.5	46.7	44.7	45.0	46.3	46.5	44.3	44.6	45.9	46.0	44.8	45.1	46.4	46.5	45.2	52.9
50-Year Nominal NPV ($M)																					
Utility Cost		58,639	59,049	59,980	60,428	61,809	62,024	58,788	59,243	60,508	60,733	58,519	58,982	60,250	60,469	58,255	58,722	59,984	60,201	59,903	65,092
Total Resource Cost		60,535	60,945	61,013	61,461	62,841	63,056	60,684	61,139	62,404	62,629	60,269	60,731	62,000	62,218	60,687	61,154	62,416	62,633	61,799	66,988
50-year Real Levelized Cost in Mills/kWh																					
Utility Cost		45.0	45.4	44.9	45.2	46.3	46.4	45.2	45.5	46.5	46.6	45.2	45.6	46.6	46.7	45.2	45.6	46.6	46.7	46.0	50.0
Total Resource Cost		44.1	44.4	44.5	44.8	45.8	46.0	44.2	44.6	45.5	45.6	43.9	44.3	45.2	45.3	44.2	44.6	45.5	45.6	45.0	48.8

Summary by Load Level and for Any-Coal & Any-Renewable Strategy (AC.AR)

Financial Results for 2013 (including end effects to 2043)

	Load	L	ML	M												MH				H			
	Gas	MG	MG	LG				MG				HG				MG				MG			
	DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD
	Case #	2	7	12	16	20	24	29	33	37	41	46	50	54	58	65	69	73	77	86	90	94	98
System Load (MWa)		5,672	6,920	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	9,923	9,923	9,923	9,923	11,680	11,680	11,680	11,680
Conservation (MWa)		498	548	318	613	638	718	318	613	638	718	318	613	638	718	349	694	718	795	379	769	802	868
After Conservation																							
System Load (MWa)		5,174	6,372	7,979	7,684	7,659	7,578	7,979	7,684	7,659	7,578	7,979	7,684	7,659	7,578	9,573	9,229	9,205	9,127	11,300	10,911	10,878	10,812
Energy Sales (MWa)		4,636	5,783	7,233	6,963	6,940	6,868	7,233	6,963	6,940	6,868	7,233	6,963	6,940	6,868	8,674	8,360	8,340	8,269	10,232	9,878	9,850	9,787
Total Customers (000's)		1,274	1,485	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	2,018	2,018	2,018	2,018	2,263	2,263	2,263	2,263
Net Electric Plant ($M)		14,587	16,199	20,432	19,935	19,897	19,730	21,210	20,223	20,269	20,129	21,132	20,466	20,375	20,110	25,420	24,140	25,090	25,039	29,914	29,617	29,597	29,653
Net Conservation Assets ($M)		636	751	481	876	851	979	481	876	851	979	481	876	851	979	497	1,026	990	1,141	526	1,164	1,122	1,404
<u>Utility Cost</u>																							
Operating Revenues ($M)	Nominal	3,778	4,528	5,618	5,503	5,496	5,453	5,556	5,456	5,454	5,409	5,489	5,407	5,389	5,343	6,591	6,432	6,419	6,381	7,674	7,462	7,421	7,405
	Real	2,002	2,399	2,976	2,916	2,912	2,889	2,943	2,891	2,890	2,866	2,908	2,865	2,855	2,831	3,492	3,408	3,401	3,381	4,066	3,953	3,931	3,923
Cost in mills/kWh	Nominal	93.0	89.4	88.7	90.2	90.4	90.6	87.7	89.5	89.7	89.9	86.6	88.6	88.6	88.8	86.7	87.8	87.9	88.1	85.6	86.2	86.0	86.4
	Real	49.3	47.4	47.0	47.8	47.9	48.0	46.5	47.4	47.5	47.6	45.9	47.0	47.0	47.1	46.0	46.5	46.6	46.7	45.4	45.7	45.6	45.8
Average Customer Bill ($	Nominal	2,966	3,049	3,257	3,191	3,187	3,162	3,221	3,164	3,162	3,136	3,183	3,135	3,124	3,098	3,267	3,188	3,181	3,163	3,391	3,297	3,279	3,272
	Real	1,572	1,615	1,726	1,690	1,688	1,675	1,707	1,676	1,675	1,662	1,686	1,661	1,655	1,641	1,731	1,689	1,685	1,675	1,796	1,747	1,737	1,733
<u>Total Cost</u>																							
DSR Customer Cost ($M)		64	71	56	85	79	106	56	85	79	106	56	85	79	106	64	99	89	121	72	109	100	146
Levelized (50-year at 8.8%)		123	125	84	150	138	164	84	150	138	164	84	150	138	164	90	170	146	182	97	179	161	222
Energy Service Charge ($M)		105	122	75	141	132	146	75	141	132	146	75	141	132	146	79	164	151	168	84	186	170	214
Total Resource Cost ($M)	Nominal	4,006	4,775	5,777	5,794	5,766	5,762	5,714	5,747	5,724	5,718	5,648	5,698	5,658	5,652	6,760	6,766	6,716	6,731	7,855	7,827	7,752	7,841
	Real	2,122	2,530	3,061	3,070	3,055	3,053	3,027	3,045	3,032	3,030	2,992	3,019	2,998	2,995	3,581	3,585	3,558	3,566	4,161	4,147	4,107	4,154
Cost in mills/kWh	Nominal	89.8	86.7	87.6	87.9	87.5	87.4	86.7	87.2	86.8	86.8	85.7	86.5	85.8	85.8	85.8	85.9	85.2	85.4	84.8	84.5	83.6	84.6
	Real	47.6	45.9	46.4	46.6	46.3	46.3	45.9	46.2	46.0	46.0	45.4	45.8	45.5	45.4	45.5	45.5	45.2	45.3	44.9	44.7	44.3	44.8
50-Year Nominal NPV ($M)																							
Operating Revenues		38,040	41,419	47,167	46,379	46,334	46,096	47,195	46,337	46,327	46,067	47,153	46,403	46,305	45,945	53,278	52,290	52,137	51,930	59,980	58,788	58,519	58,255
Total Resource Cost		39,310	42,760	48,071	47,945	47,791	47,818	48,099	47,903	47,784	47,789	48,057	47,969	47,762	47,667	54,241	54,056	53,711	53,859	61,013	60,684	60,269	60,687
5-year Real Levelized Cost in Mills/kWh																							
Utility Cost		50.1	47.0	45.7	46.2	46.4	46.5	45.7	46.1	46.4	46.5	45.7	46.2	46.4	46.4	45.3	45.7	45.8	45.9	44.9	45.2	45.2	45.2
Total Cost		48.6	45.8	45.3	45.1	45.0	45.0	45.3	45.1	45.0	45.0	45.2	45.2	45.0	44.9	44.8	44.7	44.4	44.5	44.5	44.2	43.9	44.2

T5-34.financial sum-AC.AR

Table 5-35

Summary by Load Level and for Any-Coal & Strategic-Renewable Strategy (AC.SR)
Financial Results for 2013 (including end effects to 2043)

	Load	L	ML	M											
	Gas	MG	MG	LG				MG				HG			
	DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD
	Case #	3	8	13	17	21	25	30	34	38	42	47	51	55	59
System Load (MWa)		5,672	6,920	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297
Conservation (MWa)		498	548	318	613	638	718	318	613	638	718	318	613	638	718
After Conservation															
System Load (MWa)		5,174	6,372	7,979	7,684	7,659	7,578	7,979	7,684	7,659	7,578	7,979	7,684	7,659	7,578
Energy Sales (MWa)		4,636	5,783	7,233	6,963	6,940	6,868	7,233	6,963	6,940	6,868	7,233	6,963	6,940	6,868
Total Customers (000's)		1,274	1,485	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725
Net Electric Plant ($M)		14,801	16,014	20,334	19,912	19,894	19,686	21,152	20,100	20,165	20,031	21,101	20,292	20,344	20,104
Net Conservation Assets ($M)		636	751	481	876	851	979	481	876	851	979	481	876	851	979
Utility Cost															
Operating Revenues ($M)	Nominal	3,862	4,575	5,664	5,551	5,543	5,512	5,615	5,506	5,513	5,464	5,551	5,399	5,431	5,390
	Real	2,046	2,424	3,001	2,941	2,937	2,920	2,975	2,917	2,921	2,895	2,941	2,861	2,877	2,856
Cost in mills/kWh	Nominal	95.1	90.3	89.4	91.0	91.2	91.6	88.6	90.3	90.7	90.8	87.6	88.5	89.3	89.6
	Real	50.4	47.9	47.4	48.2	48.3	48.5	47.0	47.8	48.0	48.1	46.4	46.9	47.3	47.5
Average Customer Bill ($)	Nominal	3,032	3,081	3,284	3,219	3,214	3,196	3,256	3,192	3,196	3,168	3,219	3,131	3,149	3,125
	Real	1,606	1,632	1,740	1,705	1,703	1,693	1,725	1,691	1,693	1,678	1,705	1,659	1,668	1,656
Total Resource Cost															
DSR Customer Cost ($M)		64	71	56	85	79	106	56	85	79	106	56	85	79	106
Levelized (20-year at 8.8%)		123	125	84	150	138	164	84	150	138	164	84	150	138	164
Energy Service Charge ($M)		105	122	75	141	132	146	75	141	132	146	75	141	132	146
Total Resource Cost ($M)	Nominal	4,089	4,822	5,823	5,842	5,813	5,822	5,774	5,797	5,782	5,773	5,710	5,690	5,700	5,699
	Real	2,167	2,555	3,085	3,095	3,080	3,084	3,059	3,071	3,064	3,059	3,025	3,015	3,020	3,020
Cost in mills/kWh	Nominal	91.7	87.6	88.3	88.6	88.2	88.3	87.6	88.0	87.7	87.6	86.6	86.3	86.5	86.5
	Real	48.6	46.4	46.8	47.0	46.7	46.8	46.4	46.6	46.5	46.4	45.9	45.7	45.8	45.8
50-Year Nominal NPV ($M)															
Utility Cost		38,791	41,939	47,664	46,878	46,837	46,598	47,681	46,802	46,809	46,549	47,652	46,607	46,687	46,381
Total Resource Cost		40,061	43,280	48,568	48,444	48,295	48,320	48,586	48,368	48,266	48,271	48,557	48,173	48,144	48,103
50-year Real Levelized Cost in Mills/kWh															
Utility Cost		51.1	47.6	46.2	46.7	46.9	47.0	46.2	46.6	46.9	47.0	46.2	46.4	46.8	46.8
Total Resource Cost		49.6	46.4	45.7	45.6	45.5	45.5	45.7	45.5	45.4	45.4	45.7	45.4	45.3	45.3

	Load	MH						H					
	Gas	LG	MG				HG	LG	MG				HG
	DSM	MD	LD	MD	AD	HD	MD	MD	LD	MD	AD	HD	MD
	Case #	62	66	70	74	78	81	83	87	91	95	99	102
System Load (MWa)		9,923	9,923	9,923	9,923	9,923	9,923	11,680	11,680	11,680	11,680	11,680	11,680
Conservation (MWa)		694	349	694	718	795	694	769	379	769	802	868	769
After Conservation													
System Load (MWa)		9,229	9,573	9,229	9,205	9,127	9,229	10,911	11,300	10,911	10,878	10,812	10,911
Energy Sales (MWa)		8,360	8,674	8,360	8,340	8,269	8,360	9,878	10,232	9,878	9,850	9,787	9,878
Total Customers (000's)		2,018	2,018	2,018	2,018	2,018	2,018	2,263	2,263	2,263	2,263	2,263	2,263
Net Electric Plant ($M)		23,876	25,347	25,047	25,031	24,978	25,349	28,276	29,932	29,545	29,496	29,552	30,401
Net Conservation Assets ($M)		1,026	497	1,026	990	1,141	1,026	1,164	526	1,164	1,122	1,404	1,164
Utility Cost													
Operating Revenues ($M)	Nominal	6,420	6,656	6,502	6,486	6,451	6,493	7,457	7,716	7,510	7,475	7,459	7,541
	Real	3,401	3,526	3,445	3,436	3,418	3,440	3,951	4,088	3,979	3,960	3,952	3,995
Cost in mills/kWh	Nominal	87.7	87.6	88.8	88.8	89.1	88.7	86.2	86.1	86.8	86.6	87.0	87.2
	Real	46.5	46.4	47.0	47.0	47.2	47.0	45.7	45.6	46.0	45.9	46.1	46.2
Average Customer Bill ($)	Nominal	3,182	3,298	3,222	3,214	3,197	3,218	3,295	3,409	3,318	3,303	3,296	3,332
	Real	1,686	1,747	1,707	1,703	1,694	1,705	1,746	1,806	1,758	1,750	1,746	1,765
Total Resource Cost													
DSR Customer Cost ($M)		99	64	99	89	121	99	109	72	109	100	146	109
Levelized (20-year at 8.8%)		170	90	170	146	182	170	179	97	179	161	222	179
Energy Service Charge ($M)		164	79	164	151	168	164	186	84	186	170	214	186
Total Resource Cost ($M)	Nominal	6,754	6,824	6,835	6,783	6,801	6,827	7,822	7,897	7,875	7,806	7,895	7,906
	Real	3,578	3,615	3,621	3,594	3,603	3,617	4,144	4,184	4,172	4,135	4,183	4,189
Cost in mills/kWh	Nominal	85.7	86.6	86.8	86.1	86.3	86.6	84.4	85.2	85.0	84.2	85.2	85.3
	Real	45.4	45.9	46.0	45.6	45.7	45.9	44.7	45.1	45.0	44.6	45.1	45.2
50-Year Nominal NPV ($M)													
Utility Cost		52,410	53,767	52,785	52,627	52,423	53,043	58,639	60,428	59,243	58,982	58,722	59,903
Total Resource Cost		54,176	54,730	54,551	54,202	54,352	54,809	60,535	61,461	61,139	60,731	61,154	61,799
50-year Real Levelized Cost in Mills/kWh													
Utility Cost		45.8	45.7	46.1	46.2	46.3	46.3	45.0	45.2	45.5	45.6	45.6	46.0
Total Resource Cost		44.8	45.2	45.1	44.8	44.9	45.3	44.1	44.8	44.6	44.3	44.6	45.0

Summary by Load Level and for No-Coal & Any-Renewable Strategy (NC.AR)

Financial Results for 2013 (includeing end effects to 2043)

	Load	L	ML	M												MH				H			
	Gas	MG	MG	LG				MG				HG				MG				MG			
	DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD
	Case #	4	9	14	18	22	26	31	35	39	43	48	52	56	60	67	71	75	79	88	92	96	100
System Load (MWa)		5,672	6,920	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	9,923	9,923	9,923	9,923	11,680	11,680	11,680	11,680
Conservation (MWa)		498	548	318	613	638	718	318	613	638	718	318	613	638	718	349	694	718	795	379	769	802	868
After Conservation																							
System Load (MWa)		5,174	6,372	7,979	7,684	7,659	7,578	7,979	7,684	7,659	7,578	7,979	7,684	7,659	7,578	9,573	9,229	9,205	9,127	11,300	10,911	10,878	10,812
Energy Sales (MWa)		4,636	5,783	7,233	6,963	6,940	6,868	7,233	6,963	6,940	6,868	7,233	6,963	6,940	6,868	8,674	8,360	8,340	8,269	10,232	9,878	9,850	9,787
Total Customers (000's)		1,274	1,485	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	2,018	2,018	2,018	2,018	2,263	2,263	2,263	2,263
Net Electric Plant ($M)		14,587	15,689	18,102	17,947	17,935	17,919	18,006	17,947	17,935	17,918	21,925	20,800	20,868	20,330	20,355	20,353	20,306	20,322	22,874	22,886	22,794	22,952
Net Conservation Assets ($M)		636	751	481	876	851	979	481	876	851	979	481	876	851	979	497	1,026	990	1,141	526	1,164	1,122	1,404
Utility Cost																							
Operating Revenues ($M)	Nominal	3,778	4,598	5,537	5,410	5,402	5,368	5,623	5,499	5,490	5,456	6,097	5,772	5,760	5,661	6,760	6,563	6,542	6,500	7,957	7,729	7,691	7,674
	Real	2,002	2,436	2,934	2,866	2,862	2,844	2,979	2,913	2,909	2,891	3,230	3,058	3,052	2,999	3,581	3,477	3,466	3,443	4,215	4,095	4,075	4,066
Cost in mills/kWh	Nominal	93.0	90.8	87.4	88.7	88.9	89.2	88.7	90.2	90.3	90.7	96.2	94.6	94.8	94.1	89.0	89.6	89.6	89.7	88.8	89.3	89.1	89.5
	Real	49.3	48.1	46.3	47.0	47.1	47.3	47.0	47.8	47.8	48.1	51.0	50.1	50.2	49.9	47.1	47.5	47.4	47.5	47.0	47.3	47.2	47.4
Average Customer Bill ($)	Nominal	2,966	3,096	3,211	3,137	3,132	3,112	3,260	3,188	3,183	3,164	3,535	3,347	3,340	3,282	3,360	3,252	3,242	3,221	3,515	3,415	3,398	3,391
	Real	1,572	1,640	1,701	1,662	1,659	1,649	1,727	1,689	1,687	1,676	1,873	1,773	1,769	1,739	1,775	1,723	1,718	1,706	1,862	1,809	1,800	1,796
Total Cost																							
DSR Customer Cost ($M)		64	71	56	85	79	106	56	85	79	106	56	85	79	106	64	99	89	121	72	109	100	146
Levelized (50-year at 8.8%)		123	125	84	150	138	164	84	150	138	164	84	150	138	164	90	170	146	182	97	179	161	222
Energy Service Charge ($M)		105	122	75	141	132	146	75	141	132	146	75	141	132	146	79	164	151	168	84	186	170	214
Total Resource Cost ($M)	Nominal	4,006	4,844	5,696	5,701	5,672	5,677	5,782	5,790	5,760	5,766	6,255	6,063	6,030	5,970	6,928	6,896	6,839	6,849	8,137	8,093	8,022	8,110
	Real	2,122	2,567	3,018	3,020	3,005	3,008	3,063	3,068	3,052	3,055	3,314	3,212	3,195	3,163	3,671	3,654	3,624	3,629	4,311	4,288	4,250	4,297
Cost in mills/kWh	Nominal	89.8	88.0	86.4	86.5	86.1	86.1	87.7	87.9	87.4	87.5	94.9	92.0	91.5	90.6	87.9	87.5	86.8	86.9	87.8	87.3	86.6	87.5
	Real	47.6	46.6	45.8	45.8	45.6	45.6	46.5	46.5	46.3	46.3	50.3	48.7	48.5	48.0	46.6	46.4	46.0	46.1	46.5	46.3	45.9	46.4
50-Year Nominal NPV ($M)																							
Operating Revenues		38,040	41,582	47,188	46,406	46,361	46,112	47,742	46,894	46,834	46,563	50,053	48,541	48,469	48,015	54,588	53,449	53,125	52,886	61,809	60,508	60,250	59,984
Total Resource Cost		39,310	42,923	48,092	47,971	47,818	47,834	48,647	48,460	48,291	48,285	50,957	50,107	49,926	49,737	55,552	55,215	54,699	54,815	62,841	62,404	62,000	62,416
50-year Real Levelized Cost in Mills/kWh																							
Utility Cost		50.1	47.2	45.7	46.2	46.5	46.6	46.3	46.7	46.9	47.0	48.5	48.3	48.6	48.5	46.4	46.7	46.7	46.7	46.3	46.5	46.6	46.6
Total Cost		48.6	46.0	45.3	45.2	45.0	45.0	45.8	45.6	45.5	45.5	48.0	47.2	47.0	46.8	45.9	45.6	45.2	45.3	45.8	45.5	45.2	45.5

T5-36 financial sum-NC.AR

Table 5-37

Summary by Load Level and for No-Coal & Strategic-Renewable Strategy (NC.SR)

Financial Results for 2013 (including end effects to 2043)

	Load	L	ML	M												MH						H					
	Gas	MG	MG	LG				MG				HG				LG	MG				HG	LG	MG				HG
	DSM	MD	MD	LD	MD	AD	HD	LD	MD	AD	HD	LD	MD	AD	HD	MD	LD	MD	AD	HD	MD	MD	LD	MD	AD	HD	MD
	Case #	5	10	15	19	23	27	32	36	40	44	49	53	57	61	63	68	72	76	80	82	84	89	93	97	101	103
System Load (MWa)		5,672	6,920	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	9,923	9,923	9,923	9,923	9,923	9,923	11,680	11,680	11,680	11,680	11,680	11,680
Conservation (MWa)		498	548	318	613	638	718	318	613	638	718	318	613	638	718	694	349	694	718	795	694	769	379	769	802	868	769
After Conservation																											
System Load (MWa)		5,174	6,372	7,979	7,684	7,659	7,578	7,979	7,684	7,659	7,578	7,979	7,684	7,659	7,578	9,229	9,573	9,229	9,205	9,127	9,229	10,911	11,300	10,911	10,878	10,812	10,911
Energy Sales (MWa)		4,636	5,783	7,233	6,963	6,940	6,868	7,233	6,963	6,940	6,868	7,233	6,963	6,940	6,868	8,360	8,674	8,360	8,340	8,269	8,360	9,878	10,232	9,878	9,850	9,787	9,878
Total Customers (000's)		1,274	1,485	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	2,018	2,018	2,018	2,018	2,018	2,018	2,263	2,263	2,263	2,263	2,263	2,263
Net Electric Plant ($M)		14,801	15,747	18,129	18,056	18,043	18,024	18,089	18,071	18,063	18,049	22,472	21,176	21,603	21,220	20,494	20,463	20,462	20,442	20,458	26,712	23,017	22,986	22,988	22,907	23,066	30,334
Net Conservation Assets ($M)		636	751	481	876	851	979	481	876	851	979	481	876	851	979	1,026	497	1,026	990	1,141	1,026	1,164	526	1,164	1,122	1,404	1,164
<u>Utility Cost</u>																											
Operating Revenues ($M)	Nominal	3,862	4,593	5,598	5,471	5,463	5,429	5,694	5,560	5,549	5,501	6,141	5,815	5,857	5,761	6,444	6,792	6,596	6,573	6,530	7,329	7,465	7,986	7,763	7,722	7,703	8,881
	Real	2,046	2,433	2,966	2,898	2,894	2,876	3,017	2,946	2,940	2,915	3,254	3,081	3,103	3,052	3,414	3,599	3,495	3,482	3,460	3,883	3,955	4,231	4,113	4,091	4,081	4,705
Cost in mills/kWh	Nominal	95.1	90.7	88.4	89.7	89.9	90.2	89.9	91.2	91.3	91.4	96.9	95.3	96.3	95.8	88.0	89.4	90.1	90.0	90.2	100.1	86.3	89.1	89.7	89.5	89.9	102.6
	Real	50.4	48.0	46.8	47.5	47.6	47.8	47.6	48.3	48.4	48.5	51.4	50.5	51.0	50.7	46.6	47.4	47.7	47.7	47.8	53.0	45.7	47.2	47.5	47.4	47.6	54.4
Average Customer Bill ($)	Nominal	3,032	3,093	3,246	3,172	3,167	3,148	3,301	3,224	3,217	3,190	3,561	3,371	3,396	3,340	3,194	3,366	3,269	3,258	3,236	3,632	3,298	3,528	3,430	3,412	3,404	3,924
	Real	1,606	1,638	1,719	1,680	1,678	1,668	1,749	1,708	1,705	1,690	1,886	1,786	1,799	1,770	1,692	1,783	1,732	1,726	1,715	1,924	1,747	1,869	1,817	1,807	1,803	2,079
<u>Total Resource Cost</u>																											
DSR Customer Cost ($M)		64	71	56	85	79	106	56	85	79	106	56	85	79	106	99	64	99	89	121	99	109	72	109	100	146	109
Levelized (20-year at 8.8%)		123	125	84	150	138	164	84	150	138	164	84	150	138	164	170	90	170	146	182	170	179	97	179	161	222	179
Energy Service Charge ($M)		105	122	75	141	132	146	75	141	132	146	75	141	132	146	164	79	164	151	168	164	186	84	186	170	214	186
Total Resource Cost ($M)	Nominal	4,089	4,840	5,756	5,762	5,733	5,738	5,853	5,851	5,819	5,811	6,300	6,106	6,126	6,070	6,778	6,961	6,930	6,870	6,880	7,662	7,830	8,166	8,128	8,053	8,139	9,246
	Real	2,167	2,564	3,050	3,053	3,037	3,040	3,101	3,100	3,083	3,078	3,338	3,235	3,246	3,216	3,591	3,688	3,671	3,640	3,645	4,060	4,148	4,327	4,306	4,266	4,312	4,898
Cost in mills/kWh	Nominal	91.7	87.9	87.3	87.4	87.0	87.1	88.8	88.8	88.3	88.2	95.6	92.6	92.9	92.1	86.0	88.3	88.0	87.2	87.3	97.3	84.5	88.1	87.7	86.9	87.8	99.8
	Real	48.6	46.6	46.3	46.3	46.1	46.1	47.0	47.0	46.8	46.7	50.6	49.1	49.2	48.8	45.6	46.8	46.6	46.2	46.3	51.5	44.8	46.7	46.5	46.0	46.5	52.9
50-Year Nominal NPV ($M)																											
Utility Cost		38,791	41,984	47,692	46,901	46,857	46,612	48,224	47,338	47,270	46,970	49,925	48,474	48,534	48,106	52,682	54,811	53,664	53,504	53,257	56,461	59,049	62,024	60,733	60,469	60,201	65,092
Total Resource Cost		40,061	43,325	48,596	48,467	48,315	48,333	49,128	48,903	48,727	48,691	50,829	50,039	49,992	49,827	54,448	55,774	55,430	55,078	55,186	58,227	60,945	63,056	62,629	62,218	62,633	66,988
50-year Real Levelized Cost in Mills/kWh																											
Utility Cost		51.1	47.7	46.2	46.7	47.0	47.1	46.7	47.1	47.4	47.4	48.4	48.3	48.6	48.6	46.0	46.6	46.9	47.0	47.1	49.3	45.4	46.4	46.6	46.7	46.7	50.0
Total Resource Cost		49.6	46.4	45.8	45.6	45.5	45.5	46.3	46.0	45.9	45.8	47.9	47.1	47.1	46.9	45.0	46.1	45.8	45.5	45.6	48.1	44.4	46.0	45.6	45.3	45.6	48.8

Table 5-38

Summary of Environmental Cost Adders Sensitivities

Financial Results for 2013 (including end effects to 2043)

Run against			#33 M.MG.MD.AC.AR							#41 M.MG.HD.AC.AR							#50 M.HG.MD.AC.AR				#69 MH.MG.MD.AC.AR					
NOx & TSP			Low			High				Low			High				Low				Low			High		
CO2			L	M	H	L	M	H		L	M	H	L	M	H		L	M	H		L	M	H	L	M	H
Case #		33	301	302	303	304	305	306	41	307	308	309	310	311	312	50	313	314	315	69	316	317	318	319	320	321
System Load (MWa)		8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	9,923	9,923	9,923	9,923	9,923	9,923	9,923
Conservation (MWa)		613	613	613	613	613	613	613	718	718	718	718	718	718	718	613	613	613	613	694	694	694	694	694	694	694
After Conservation																										
System Load (MWa)		7,684	7,684	7,684	7,684	7,684	7,684	7,684	7,578	7,578	7,578	7,578	7,578	7,578	7,578	7,684	7,684	7,684	7,684	9,229	9,229	9,229	9,229	9,229	9,229	9,229
Energy Sales (MWa)		6,963	6,963	6,963	6,963	6,963	6,963	6,963	6,868	6,868	6,868	6,868	6,868	6,868	6,868	6,963	6,963	6,963	6,963	8,360	8,360	8,360	8,360	8,360	8,360	8,360
Total Customers (000's)		1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	2,018	2,018	2,018	2,018	2,018	2,018	2,018
Net Electric Plant ($M)		20,223	20,104	19,106	20,222	21,426	20,109	21,713	20,129	19,785	18,996	20,038	21,070	19,822	21,542	20,466	20,463	20,166	24,540	25,140	24,821	24,482	26,019	25,590	25,515	27,545
Net Conservation Assets ($M)		876	876	876	876	876	876	876	979	979	979	979	979	979	979	876	876	876	876	1,026	1,026	1,026	1,026	1,026	1,026	1,026
Utility Cost																										
Operating Revenues ($M)	Nominal	5,456	5,480	5,437	6,473	5,532	5,657	6,808	5,409	5,466	5,379	6,366	5,510	5,578	6,753	5,407	5,489	5,472	6,474	6,432	6,450	6,514	7,572	6,590	6,808	7,838
	Real	2,891	2,903	2,881	3,429	2,931	2,997	3,607	2,866	2,896	2,850	3,373	2,919	2,955	3,578	2,865	2,908	2,899	3,430	3,408	3,417	3,451	4,012	3,492	3,607	4,153
Cost in mills/kWh	Nominal	89.5	89.9	89.1	106.1	90.7	92.7	111.6	89.9	90.9	89.4	105.8	91.6	92.7	112.3	88.6	90.0	89.7	106.1	87.8	88.1	89.0	103.4	90.0	93.0	107.0
	Real	47.4	47.6	47.2	56.2	48.1	49.1	59.1	47.6	48.1	47.4	56.1	48.5	49.1	59.5	47.0	47.7	47.5	56.2	46.5	46.7	47.1	54.8	47.7	49.3	56.7
Average Customer Bill ($)	Nominal	3,164	3,178	3,153	3,753	3,207	3,280	3,947	3,136	3,169	3,119	3,691	3,195	3,234	3,916	3,135	3,183	3,173	3,753	3,188	3,197	3,228	3,752	3,266	3,374	3,884
	Real	1,676	1,683	1,670	1,988	1,699	1,738	2,091	1,662	1,679	1,652	1,955	1,693	1,713	2,074	1,661	1,686	1,681	1,989	1,689	1,694	1,710	1,988	1,730	1,788	2,058
Total Resource Cost																										
DSR Customer Cost ($M)		85	85	85	85	85	85	85	106	106	106	106	106	106	106	85	85	85	85	99	99	99	99	99	99	99
Levelized (20-year at 8.8%)		150	150	150	150	150	150	150	164	164	164	164	164	164	164	150	150	150	150	170	170	170	170	170	170	170
Energy Service Charge ($M)		141	141	141	141	141	141	141	146	146	146	146	146	146	146	141	141	141	141	164	164	164	164	164	164	164
Total Resource Cost ($M)	Nominal	5,747	5,771	5,728	6,764	5,823	5,948	7,099	5,718	5,775	5,688	6,675	5,819	5,887	7,063	5,698	5,780	5,763	6,765	6,766	6,784	6,847	7,906	6,924	7,142	8,172
	Real	3,045	3,058	3,035	3,584	3,085	3,151	3,761	3,030	3,059	3,013	3,536	3,083	3,119	3,742	3,019	3,062	3,053	3,584	3,585	3,594	3,628	4,188	3,668	3,784	4,329
Cost in mills/kWh	Nominal	87.2	87.6	86.9	102.6	88.3	90.2	107.7	86.8	87.6	86.3	101.3	88.3	89.3	107.2	86.5	87.7	87.4	102.6	85.9	86.1	86.9	100.3	87.9	90.6	103.7
	Real	46.2	46.4	46.0	54.4	46.8	47.8	57.1	46.0	46.4	45.7	53.7	46.8	47.3	56.8	45.8	46.5	46.3	54.4	45.5	45.6	46.0	53.2	46.6	48.0	55.0
50-Year Nominal NPV ($M)																										
Utility Cost		46,337	46,980	49,155	54,757	47,901	50,884	56,529	46,067	46,668	48,805	54,156	47,526	50,446	56,310	46,403	47,064	48,710	54,401	52,290	53,168	55,297	61,341	54,454	57,305	62,697
Total Resource Cost		47,903	48,545	50,721	56,322	49,467	52,449	58,095	47,789	48,390	50,527	55,878	49,248	52,168	58,032	47,969	48,630	50,276	55,967	54,056	54,934	57,063	63,107	56,220	59,071	64,463
50-year Real Levelized Cost in Mills/kWh																										
Utility Cost		46.1	46.8	48.9	54.5	47.7	50.7	56.3	46.5	47.1	49.3	54.7	48.0	50.9	56.8	46.2	46.9	48.5	54.2	45.7	46.4	48.3	53.6	47.5	50.0	54.7
Total Resource Cost		45.1	45.7	47.8	53.0	46.6	49.4	54.7	45.0	45.6	47.6	52.6	46.4	49.1	54.6	45.2	45.8	47.3	52.7	44.7	45.4	47.2	52.2	46.5	48.8	53.3
Trade between Cost and Emissions "Tax" (NPV $M)																										
Insurance Cost		0	643	2818	8420	1564	4547	10192	0	601	2739	8089	1459	4380	10243	0	661	2307	7998	0	878	3007	9051	2164	5015	10407
Adder "Tax" Cost		0	1139	5192	13284	2563	7899	16486	0	1112	5080	12827	2482	7669	16384	0	1069	4078	11290	0	1517	5707	14622	3492	8992	17631

Table 5-39

Summary of Load Level Sensitivities

(Using Medium Gas Price, Medium DSR, No-Coal and Strategic-Renewables)

Financial Results for 2013 (including end effects to 2043)

Load Level		Medium Low	Reduced Load	Medium	Economic Development	Medium High	High	Electri-fication
Case #		10	201	36	202	72	93	203
System Load (MWa)		6,920	7,494	8,297	8,886	9,923	11,680	12,883
Conservation (MWa)		548	613	613	613	694	769	769
After Conservation								
System Load (MWa)		6,372	6,881	7,684	8,273	9,229	10,911	12,114
Energy Sales (MWa)		5,783	6,256	6,963	7,500	8,360	9,878	10,944
Total Customers (000's)		1,485	1,725	1,725	1,890	2,018	2,263	2,263
Net Electric Plant ($M)		15,747	17,136	18,071	19,127	20,462	22,988	26,217
Net Conservation Assets ($M)		751	876	876	876	1,026	1,164	1,164
Utility Cost								
Operating Revenues ($M)	Nominal	4,593	5,058	5,560	5,961	6,596	7,763	8,608
	Real	2,433	2,680	2,946	3,158	3,495	4,113	4,560
Cost in mills/kWh	Nominal	90.7	92.3	91.2	90.7	90.1	89.7	89.8
	Real	48.0	48.9	48.3	48.1	47.7	47.5	47.6
Average Customer Bill ($)	Nominal	3,093	2,933	3,224	3,155	3,269	3,430	3,803
	Real	1,638	1,554	1,708	1,671	1,732	1,817	2,015
Total Resource Cost								
DSR Customer Cost ($M)		71	85	85	85	99	109	109
Levelized (20-year at 8.8%)		125	150	150	150	170	179	179
Energy Service Charge ($M)		122	141	141	141	164	186	186
Total Resource Cost ($M)	Nominal	4,840	5,349	5,851	6,252	6,930	8,128	8,972
	Real	2,564	2,834	3,100	3,312	3,671	4,306	4,754
Cost in mills/kWh	Nominal	87.9	89.6	88.8	88.5	88.0	87.7	88.0
	Real	46.6	47.5	47.0	46.9	46.6	46.5	46.6
50-Year Nominal NPV ($M)								
Utility Cost		41,984	43,872	47,338	49,720	53,664	60,733	62,582
Total Resource Cost		43,325	45,438	48,903	51,286	55,430	62,629	64,478
50-year Real Levelized Cost in Mills/kWh								
Utility Cost		47.7	48.5	47.1	47.1	46.9	46.6	43.5
Total Resource Cost		46.4	47.2	46.0	46.1	45.8	45.6	42.7

Summary of Portfolio/Transmission Sensitivities

Financial Results for 2013 (including end effects to 2043)

Run against		#35		#33		#36 M.MG.MD.NC.SR					#33 M.MG.MD.AC.AR		
									IGCC avail when No Coal		Transmission		
Sensitivity		m.mg md.nc.ar	Hermiston as Potential Unit	m.mg md.ac.ar	Hermiston as Potential Unit	m.mg md.nc.sr	SCE as Potential Unit	CCCT to IGCC		Low IGCC Cost	From Bridger to OWC +300MW	From Utah to OWC +600MW	Real Discount Rate at 3%
Case #		35	212	33	213	36	211	222	223	224	231	232	241
System Load (MWa)		8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297
Conservation (MWa)		613	613	613	613	613	613	613	613	613	613	613	613
After Conservation													
System Load (MWa)		7,684	7,684	7,684	7,684	7,684	7,684	7,684	7,684	7,684	7,684	7,684	7,684
Energy Sales (MWa)		6,963	6,963	6,963	6,963	6,963	6,963	6,963	6,963	6,963	6,963	6,963	6,963
Total Customers (000's)		1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725
Net Electric Plant ($M)		17,947	17,912	20,223	20,507	18,071	18,027	18,621	19,977	19,375	20,523	20,876	20,386
Net Conservation Assets ($M)		876	876	876	876	876	876	876	876	876	876	876	876
Utility Cost													
Operating Revenues ($M)	Nominal	5,499	5,368	5,456	5,192	5,560	5,552	5,311	5,554	5,417	5,416	5,360	5,414
	Real	2,913	2,844	2,891	2,750	2,946	2,941	2,814	2,943	2,870	2,869	2,840	2,869
Cost in mills/kWh	Nominal	90.2	88.0	89.5	85.1	91.2	91.0	87.1	91.1	88.8	88.8	87.9	88.8
	Real	47.8	46.6	47.4	45.1	48.3	48.2	46.1	48.2	47.1	47.0	46.6	47.0
Average Customer Bill ($)	Nominal	3,188	3,112	3,164	3,010	3,224	3,219	3,079	3,220	3,141	3,140	3,108	3,139
	Real	1,689	1,649	1,676	1,595	1,708	1,705	1,631	1,706	1,664	1,664	1,647	1,663
Total Resource Cost													
DSR Customer Cost ($M)		85	85	85	85	85	85	85	85	85	85	85	85
Levelized (20-year at 8.8%)		150	150	150	150	150	150	150	150	150	150	150	150
Energy Service Charge ($M)		141	141	141	141	141	141	141	141	141	141	141	141
Total Resource Cost ($M)	Nominal	5,790	5,659	5,747	5,483	5,851	5,843	5,602	5,845	5,708	5,707	5,651	5,705
	Real	3,068	2,998	3,045	2,905	3,100	3,096	2,968	3,097	3,024	3,024	2,994	3,023
Cost in mills/kWh	Nominal	87.9	85.9	87.2	83.2	88.8	88.7	85.0	88.7	86.6	86.6	85.7	86.6
	Real	46.5	45.5	46.2	44.1	47.0	47.0	45.0	47.0	45.9	45.9	45.4	45.9
50-Year Nominal NPV ($M)													
Utility Cost		46,894	45,758	46,337	45,332	47,338	47,354	46,040	47,096	46,561	46,205	46,115	46,319
Total Resource Cost		48,460	47,323	47,903	46,898	48,903	48,920	47,606	48,662	48,127	47,771	47,680	47,885
50-year Real Levelized Cost in Mills/kWh													
Utility Cost		46.7	45.6	46.1	45.1	47.1	47.1	45.8	46.9	46.4	46.0	45.9	46.1
Total Resource Cost		45.6	44.6	45.1	44.2	46.0	46.1	44.8	45.8	45.3	45.0	44.9	45.1

T5-40.financial sum-misc

Table 5-41

Summary of Wholesales Market Sensitivities

Financial Results for 2013 (including end effects to 2043)

Run against			#36 M.MG.MD.NC.SR				
Sensitivity		m.mg md.nc.sr	Critical Water Condition	Change Non-Firm Sales Price Lower	Change Non-Firm Sales Price Higher	No Non-Firm Sales	No Non-Firm Sales or Purchases
Case #		36	251	252	253	254	255
System Load (MWa)		8,297	8,297	8,297	8,297	8,297	8,297
Conservation (MWa)		613	613	613	613	613	613
After Conservation							
System Load (MWa)		7,684	7,684	7,684	7,684	7,684	7,684
Energy Sales (MWa)		6,963	6,963	6,963	6,963	6,963	6,963
Total Customers (000's)		1,725	1,725	1,725	1,725	1,725	1,725
Net Electric Plant ($M)		18,071	20,245	20,238	20,364	20,757	20,464
Net Conservation Assets ($M)		876	876	876	876	876	876
<u>Utility Cost</u>							
Operating Revenues ($M)	Nominal	5,560	5,555	5,546	5,305	5,566	5,559
	Real	2,946	2,943	2,938	2,810	2,949	2,945
Cost in mills/kWh	Nominal	91.2	91.1	90.9	87.0	91.3	91.1
	Real	48.3	48.2	48.2	46.1	48.3	48.3
Average Customer Bill ($)	Nominal	3,224	3,221	3,216	3,076	3,227	3,223
	Real	1,708	1,706	1,704	1,629	1,710	1,708
<u>Total Resource Cost</u>							
DSR Customer Cost ($M)		85	85	85	85	85	85
Levelized (20-year at 8.8%)		150	150	150	150	150	150
Energy Service Charge ($M)		141	141	141	141	141	141
Total Resource Cost ($M)	Nominal	5,851	5,846	5,837	5,596	5,857	5,850
	Real	3,100	3,097	3,092	2,965	3,103	3,100
Cost in mills/kWh	Nominal	88.8	88.7	88.6	84.9	88.9	88.8
	Real	47.0	47.0	46.9	45.0	47.1	47.0
50-Year Nominal NPV ($M)							
Utility Cost		**47,338**	**47,273**	**46,768**	**45,723**	**47,152**	**47,164**
Total Resource Cost		**48,903**	**48,838**	**48,334**	**47,288**	**48,718**	**48,730**
50-year Real Levelized Cost in Mills/kWh							
Utility Cost		**47.1**	**47.1**	**46.6**	**45.5**	**46.9**	**47.0**
Total Resource Cost		**46.0**	**46.0**	**45.5**	**44.5**	**45.9**	**45.9**

Summary of Renewable Sensitivities

Financial Results for 2013 (including end effects to 2043)

Run against			#35 M.MG.MD.NC.AR						
				Geothermal	Wind				
			Lower	0% inflation	Inflation Rate		Reserve Contribution		20%
		m.mg	Renewable	Rate	on O & M		1.2 times	Set to	More
Sensitivities		md.nc.ar	Cost	on O & M	0%	2.5%	Higher	Winter	Energy
Case #		35	261	262	263	264	265	266	267
System Load (MWa)		8,297	8,297	8,297	8,297	8,297	8,297	8,297	8,297
Conservation (MWa)		613	613	613	613	613	613	613	613
After Conservation									
System Load (MWa)		7,684	7,684	7,684	7,684	7,684	7,684	7,684	7,684
Energy Sales (MWa)		6,963	6,963	6,963	6,963	6,963	6,963	6,963	6,963
Total Customers (000's)		1,725	1,725	1,725	1,725	1,725	1,725	1,725	1,725
Net Electric Plant ($M)		17,947	18,372	18,685	17,947	17,947	17,947	17,966	17,986
Net Conservation Assets ($M)		876	876	876	876	876	876	876	876
<u>Utility Cost</u>									
Operating Revenues ($M)	Nominal	5,499	5,567	5,563	5,499	5,499	5,499	5,520	5,512
	Real	2,913	2,949	2,947	2,913	2,913	2,913	2,924	2,920
Cost in mills/kWh	Nominal	90.2	91.3	91.2	90.2	90.2	90.2	90.5	90.4
	Real	47.8	48.4	48.3	47.8	47.8	47.8	47.9	47.9
Average Customer Bill ($)	Nominal	3,188	3,228	3,225	3,188	3,188	3,188	3,200	3,196
	Real	1,689	1,710	1,709	1,689	1,689	1,689	1,695	1,693
<u>Total Resource Cost</u>									
DSR Customer Cost ($M)		85	85	85	85	85	85	85	85
Levelized (20-year at 8.8%)		150	150	150	150	150	150	150	150
Energy Service Charge ($M)		141	141	141	141	141	141	141	141
Total Resource Cost ($M)	Nominal	5,790	5,858	5,854	5,790	5,790	5,790	5,811	5,803
	Real	3,068	3,103	3,101	3,068	3,068	3,068	3,078	3,074
Cost in mills/kWh	Nominal	87.9	88.9	88.8	87.9	87.9	87.9	88.2	88.0
	Real	46.5	47.1	47.1	46.5	46.5	46.5	46.7	46.6
50-Year Nominal NPV ($M)									
Utility Cost		46,894	47,078	47,139	46,894	46,894	46,894	47,018	47,056
Total Resource Cost		48,460	48,643	48,705	48,460	48,460	48,460	48,584	48,621
50-year Real Levelized Cost in Mills/kWh									
Utility Cost		46.7	46.9	46.9	46.7	46.7	46.7	46.8	46.8
Total Resource Cost		45.6	45.8	45.9	45.6	45.6	45.6	45.7	45.8

T5-42.financial sum-renew

Utility Costs of Base Plan (103 runs)

Financial Results

Table 5-43

Future		DSR	Real Levelized mills/kWh				Utility Cost 20-yr Net Present Value $M			
Load	Gas Price	Strategy	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR
Low	Medium	Medium	50.1	51.1	50.1	51.1	38,040	38,791	38,040	38,791
Medium Low	Medium	Medium	47.0	47.6	47.2	47.7	41,419	41,939	41,582	41,984
Medium	Low	Low	45.7	46.2	45.7	46.2	47,167	47,664	47,188	47,692
Medium	Low	Medium	46.2	46.7	46.2	46.7	46,379	46,878	46,406	46,901
Medium	Low	Accelerated	46.4	46.9	46.5	47.0	46,334	46,837	46,361	46,857
Medium	Low	High	46.5	47.0	46.6	47.1	46,096	46,598	46,112	46,612
Medium	Medium	Low	45.7	46.2	46.3	46.7	47,195	47,681	47,742	48,224
Medium	Medium	Medium	46.1	46.6	46.7	47.1	46,337	46,802	46,894	47,338
Medium	Medium	Accelerated	46.4	46.9	46.9	47.4	46,327	46,809	46,834	47,270
Medium	Medium	High	46.5	47.0	47.0	47.4	46,067	46,549	46,563	46,970
Medium	High	Low	45.7	46.2	48.5	48.4	47,153	47,652	50,053	49,925
Medium	High	Medium	46.2	46.4	48.3	48.3	46,403	46,607	48,541	48,474
Medium	High	Accelerated	46.4	46.8	48.6	48.6	46,305	46,687	48,469	48,534
Medium	High	High	46.4	46.8	48.5	48.6	45,945	46,381	48,015	48,106
Medium H	Low	Medium		45.8		46.0		52,410		52,682
Medium H	Medium	Low	45.3	45.7	46.4	46.6	53,278	53,767	54,588	54,811
Medium H	Medium	Medium	45.7	46.1	46.7	46.9	52,290	52,785	53,449	53,664
Medium H	Medium	Accelerated	45.8	46.2	46.7	47.0	52,137	52,627	53,125	53,504
Medium H	Medium	High	45.9	46.3	46.7	47.1	51,930	52,423	52,886	53,257
Medium H	High	Medium		46.3		49.3		53,043		56,461
High	Low	Medium		45.0		45.4		58,639		59,049
High	Medium	Low	44.9	45.2	46.3	46.4	59,980	60,428	61,809	62,024
High	Medium	Medium	45.2	45.5	46.5	46.6	58,788	59,243	60,508	60,733
High	Medium	Accelerated	45.2	45.6	46.6	46.7	58,519	58,982	60,250	60,469
High	Medium	High	45.2	45.6	46.6	46.7	58,255	58,722	59,984	60,201
High	High	Medium		46.0		50.0		59,903		65,092

Impact of moving from AC to NC Stretegy

Financial Results

Table 5-44

Future		DSR	Real Levelized mills/kWh				Utility Cost 20-yr NPV $M			
Load	Gas Price	Strategy	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR
Low	Medium	Medium								
Medium Low	Medium	Medium			0.19	0.05			163	45
Medium	Low	Low			0.02	0.03			21	28
Medium	Low	Medium			0.03	0.02			27	23
Medium	Low	Accelerated			0.03	0.02			27	20
Medium	Low	High			0.02	0.01			16	13
Medium	Medium	Low			0.53	0.53			547	542
Medium	Medium	Medium			0.55	0.53			558	536
Medium	Medium	Accelerated			0.51	0.47			507	461
Medium	Medium	High			0.51	0.43			496	420
Medium	High	Low			2.81	2.20			2,900	2,273
Medium	High	Medium			2.13	1.85			2,138	1,866
Medium	High	Accelerated			2.17	1.85			2,164	1,848
Medium	High	High			2.09	1.74			2,070	1,724
Medium H	Medium	Low			1.12	0.89			1,310	1,044
Medium H	Medium	Medium			1.01	0.77			1,159	879
Medium H	Medium	Accelerated			0.87	0.77			988	877
Medium H	Medium	High			0.85	0.74			956	834
High	Medium	Low			1.37	1.20			1,828	1,596
High	Medium	Medium			1.32	1.14			1,721	1,491
High	Medium	Accelerated			1.34	1.15			1,731	1,487
High	Medium	High			1.34	1.15			1,729	1,479

Average Impact 0.87 Mills / kWh $967 millions

Impact of moving from AR to SR Stretegy

Financial Results

Table 5-45

Future		DSR	Real Levelized mills/kWh				Utility Cost 20-yr NPV $M			
			Mills/kWh		Percent Change		$Million		Percent Change	
Load	Gas Price	Strategy	AC.SR	NC.SR	AC.SR	NC.SR	AC.SR	NC.SR	AC.SR	NC.SR
Low	Medium	Medium	0.99	0.99	1.98%	1.98%	751	751	1.97%	1.97%
Medium Low	Medium	Medium	0.59	0.45	1.25%	0.95%	521	402	1.26%	0.97%
Medium	Low	Low	0.48	0.49	1.05%	1.07%	497	504	1.05%	1.07%
Medium	Low	Medium	0.50	0.49	1.08%	1.06%	499	496	1.08%	1.07%
Medium	Low	Accelerated	0.50	0.49	1.08%	1.05%	503	496	1.09%	1.07%
Medium	Low	High	0.51	0.50	1.10%	1.07%	502	499	1.09%	1.08%
Medium	Medium	Low	0.47	0.47	1.03%	1.02%	487	482	1.03%	1.01%
Medium	Medium	Medium	0.46	0.44	1.00%	0.94%	465	443	1.00%	0.95%
Medium	Medium	Accelerated	0.48	0.44	1.03%	0.94%	482	436	1.04%	0.93%
Medium	Medium	High	0.49	0.41	1.05%	0.87%	483	407	1.05%	0.87%
Medium	High	Low	0.48	(0.13)	1.05%	-0.27%	499	(128)	1.06%	-0.26%
Medium	High	Medium	0.21	(0.07)	0.45%	-0.14%	204	(67)	0.44%	-0.14%
Medium	High	Accelerated	0.38	0.06	0.82%	0.12%	382	66	0.82%	0.14%
Medium	High	High	0.44	0.09	0.95%	0.19%	436	91	0.95%	0.19%
Medium H	Medium	Low	0.42	0.19	0.93%	0.41%	489	222	0.92%	0.41%
Medium H	Medium	Medium	0.43	0.19	0.94%	0.41%	495	214	0.95%	0.40%
Medium H	Medium	Accelerated	0.43	0.33	0.94%	0.71%	490	379	0.94%	0.71%
Medium H	Medium	High	0.44	0.33	0.96%	0.71%	492	371	0.95%	0.70%
High	Medium	Low	0.33	0.16	0.74%	0.35%	448	215	0.75%	0.35%
High	Medium	Medium	0.35	0.17	0.78%	0.37%	455	225	0.77%	0.37%
High	Medium	Accelerated	0.36	0.17	0.80%	0.37%	463	218	0.79%	0.36%
High	Medium	High	0.36	0.17	0.80%	0.37%	467	217	0.80%	0.36%
Average Impact			0.38		0.83%		$397		0.83%	

T5-43,44,45.financial results

Incremental Impact of Changing DSR Strategy

+ means costs more
— means costs less

Table 5-46

Future		NPV Utility Cost in $M				Price (mills/kWh)				NPV Ttl Resources Cost in $M			
		Coal & Renewable Strategy				Coal & Renewable Strategy				Coal & Renewable Strategy			
Load	Gas	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR
MD-LD													
M	LG	(788)	(786)	(782)	(791)	0.47	0.49	0.48	0.48	(126)	(124)	(121)	(129)
M	MG	(858)	(879)	(848)	(886)	0.40	0.39	0.42	0.39	(197)	(218)	(186)	(225)
M	HG	(750)	(1,045)	(1,512)	(1,451)	0.50	0.23	(0.18)	(0.12)	(88)	(384)	(850)	(790)
MH	MG	(988)	(982)	(1,139)	(1,147)	0.38	0.39	0.27	0.27	(186)	(179)	(336)	(344)
H	MG	(1,193)	(1,185)	(1,300)	(1,290)	0.27	0.29	0.22	0.23	(329)	(322)	(437)	(427)
Average					**(1,030)**				**0.31**				**(300)**
AD-MD													
M	LG	(45)	(41)	(45)	(44)	0.26	0.26	0.26	0.26	(154)	(150)	(153)	(152)
M	MG	(10)	7	(61)	(68)	0.29	0.31	0.25	0.25	(119)	(102)	(169)	(176)
M	HG	(98)	79	(72)	61	0.21	0.38	0.25	0.38	(207)	(29)	(181)	(48)
MH	MG	(153)	(158)	(325)	(160)	0.15	0.15	0.01	0.15	(345)	(349)	(516)	(351)
H	MG	(268)	(261)	(258)	(265)	0.08	0.09	0.10	0.10	(415)	(408)	(404)	(411)
Average					**(109)**				**0.21**				**(242)**
HD-AD													
M	LG	(238)	(239)	(249)	(246)	0.10	0.11	0.09	0.10	27	25	16	19
M	MG	(260)	(259)	(271)	(300)	0.08	0.09	0.08	0.05	4	5	(6)	(36)
M	HG	(360)	(305)	(454)	(429)	(0.02)	0.04	(0.10)	(0.07)	(95)	(41)	(189)	(164)
MH	MG	(206)	(204)	(238)	(247)	0.08	0.09	0.06	0.06	148	150	116	107
H	MG	(264)	(260)	(266)	(268)	0.00	0.00	0.00	0.00	418	422	416	414
Average					**(278)**				**0.04**				**88**
HD-MD													
M	LG	(283)	(280)	(293)	(290)	0.36	0.37	0.35	0.36	(127)	(124)	(137)	(134)
M	MG	(270)	(253)	(331)	(368)	0.37	0.40	0.33	0.30	(114)	(97)	(175)	(212)
M	HG	(458)	(226)	(526)	(368)	0.19	0.42	0.15	0.31	(302)	(70)	(370)	(212)
MH	MG	(359)	(362)	(563)	(407)	0.23	0.24	0.07	0.21	(197)	(199)	(400)	(244)
H	MG	(532)	(521)	(524)	(532)	0.08	0.09	0.10	0.10	3	15	11	3
Average					**(387)**				**0.25**				**(154)**

decrease price av. .25 mills/kWh

Incremental Impact of Changing DSR Strategy
Percent Change

Table 5-47

Future		NPV Utility Cost in $M				Price (mills/kWh)				NPV Ttl Resources Cost in $M			
		Coal & Renewable Strategy				Coal & Renewable Strategy				Coal & Renewable Strategy			
Load	Gas	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.S
MD-LD													
M	LG	-1.7%	-1.6%	-1.7%	-1.7%	1.0%	1.1%	1.0%	1.0%	-0.3%	-0.3%	-0.3%	-0.3
M	MG	-1.8%	-1.8%	-1.8%	-1.8%	0.9%	0.8%	0.9%	0.8%	-0.4%	-0.4%	-0.4%	-0.5
M	HG	-1.6%	-2.2%	-3.0%	-2.9%	1.1%	0.5%	-0.4%	-0.2%	-0.2%	-0.8%	-1.7%	-1.6
MH	MG	-1.9%	-1.8%	-2.1%	-2.1%	0.8%	0.9%	0.6%	0.6%	-0.3%	-0.3%	-0.6%	-0.6
H	MG	-2.0%	-2.0%	-2.1%	-2.1%	0.6%	0.6%	0.5%	0.5%	-0.5%	-0.5%	-0.7%	-0.7
Average					**-2.0%**				**0.7%**				**-0.6**
AD-MD													
M	LG	-0.1%	-0.1%	-0.1%	-0.1%	0.6%	0.6%	0.6%	0.6%	-0.3%	-0.3%	-0.3%	-0.3
M	MG	0.0%	0.0%	-0.1%	-0.1%	0.6%	0.7%	0.5%	0.5%	-0.2%	-0.2%	-0.3%	-0.4
M	HG	-0.2%	0.2%	-0.1%	0.1%	0.5%	0.8%	0.5%	0.8%	-0.4%	-0.1%	-0.4%	-0.1
MH	MG	-0.3%	-0.3%	-0.6%	-0.3%	0.3%	0.3%	0.0%	0.3%	-0.6%	-0.6%	-0.9%	-0.6
H	MG	-0.5%	-0.4%	-0.4%	-0.4%	0.2%	0.2%	0.2%	0.2%	-0.7%	-0.7%	-0.6%	-0.7
Average					**-0.2%**				**0.4%**				**-0.4**
HD-AD													
M	LG	-0.5%	-0.5%	-0.5%	-0.5%	0.2%	0.2%	0.2%	0.2%	0.1%	0.1%	0.0%	0.0
M	MG	-0.6%	-0.6%	-0.6%	-0.6%	0.2%	0.2%	0.2%	0.1%	0.0%	0.0%	0.0%	-0.1
M	HG	-0.8%	-0.7%	-0.9%	-0.9%	0.0%	0.1%	-0.2%	-0.1%	-0.2%	-0.1%	-0.4%	-0.3
MH	MG	-0.4%	-0.4%	-0.4%	-0.5%	0.2%	0.2%	0.1%	0.1%	0.3%	0.3%	0.2%	0.2
H	MG	-0.5%	-0.4%	-0.4%	-0.4%	0.0%	0.0%	0.0%	0.0%	0.7%	0.7%	0.7%	0.7
Average					**-0.6%**				**0.1%**				**0.1**
HD-MD													
M	LG	-0.6%	-0.6%	-0.6%	-0.6%	0.8%	0.8%	0.8%	0.8%	-0.3%	-0.3%	-0.3%	-0.3
M	MG	-0.6%	-0.5%	-0.7%	-0.8%	0.8%	0.9%	0.7%	0.6%	-0.2%	-0.2%	-0.4%	-0.4
M	HG	-1.0%	-0.5%	-1.1%	-0.8%	0.4%	0.9%	0.3%	0.6%	-0.6%	-0.1%	-0.7%	-0.4
MH	MG	-0.7%	-0.7%	-1.1%	-0.8%	0.5%	0.5%	0.2%	0.4%	-0.4%	-0.4%	-0.7%	-0.4
H	MG	-0.9%	-0.9%	-0.9%	-0.9%	0.2%	0.2%	0.2%	0.2%	0.0%	0.0%	0.0%	0.0
Average					**-0.8%**				**0.5%**				**-0.3**

T5-46,47.impact.ld-hd

Utility Cost after 20 Years (2013)

Table 5-48

Future		DSR	20 Year Real Levelized mills/kWh				Utility Cost 20 Year NPV ($M)			
Load	Gas Price	Strategy	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR
Low	Medium	Medium	48.3	49.4	48.3	49.4	25,512	26,107	25,512	26,107
Medium-L	Medium	Medium	46.3	47.0	46.4	47.1	27,436	27,868	27,502	27,892
Medium	Low	Low	45.6	46.2	45.4	46.1	30,636	31,048	30,500	30,941
Medium	Low	Medium	46.0	46.6	45.8	46.5	30,249	30,662	30,118	30,558
Medium	Low	Accelerated	46.4	47.0	46.2	46.8	30,221	30,637	30,095	30,536
Medium	Low	High	46.4	47.1	46.2	46.9	30,092	30,518	29,968	30,411
Medium	Medium	Low	45.6	46.2	45.7	46.3	30,645	31,048	30,671	31,098
Medium	Medium	Medium	46.0	46.6	46.0	46.7	30,228	30,629	30,267	30,679
Medium	Medium	Accelerated	46.4	47.0	46.4	47.0	30,219	30,628	30,233	30,642
Medium	Medium	High	46.4	47.0	46.4	47.1	30,082	30,485	30,097	30,498
Medium	High	Low	45.5	46.1	47.5	47.1	30,531	30,934	31,899	31,627
Medium	High	Medium	45.9	46.3	47.4	47.1	30,168	30,453	31,142	30,947
Medium	High	Accelerated	46.2	46.7	47.7	47.5	30,112	30,467	31,070	30,967
Medium	High	High	46.2	46.8	47.6	47.4	29,951	30,322	30,852	30,742
Medium-H	Low	Medium		46.2		46.2		33,677		33,691
Medium-H	Medium	Low	45.6	46.1	46.1	46.3	33,921	34,336	34,292	34,491
Medium-H	Medium	Medium	45.9	46.5	46.4	46.6	33,466	33,877	33,786	33,981
Medium-H	Medium	Accelerated	46.2	46.7	46.3	46.9	33,355	33,759	33,474	33,868
Medium-H	Medium	High	46.2	46.8	46.4	46.9	33,270	33,677	33,384	33,773
Medium-H	High	Medium		46.5		47.9		33,878		34,898
High	Low	Medium		45.0		45.4		37,284 ~~58,639~~		37,211 ~~59,049~~
High	Medium	Low	45.6	46.1	46.1	46.4	37,718	38,075	38,120	38,317
High	Medium	Medium	45.9	46.3	46.4	46.6	37,134	37,514	37,565	37,766
High	Medium	Accelerated	46.0	46.5	46.6	46.8	36,944	37,337	37,394	37,594
High	Medium	High	46.0	46.5	46.5	46.8	36,776	37,176	37,229	37,428
High	High	Medium		46.5		48.9		37,661		39,621

Total Resource Costs after 20 Years (2013)

Table 5-49

Future		DSR	20 Year Real Levelized mills/kWh				Total Resource Cost 20-yr NPV ($M)			
Load	Gas Price	Strategy	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR
Low	Medium	Medium	48.6	49.6	48.6	49.6	39,310	40,061	39,310	40,061
Medium-L	Medium	Medium	45.8	46.4	46.0	46.4	42,760	43,280	42,923	43,325
Medium	Low	Low	45.3	45.7	45.3	45.8	48,071	48,568	48,092	48,596
Medium	Low	Medium	45.1	45.6	45.2	45.6	47,945	48,444	47,971	48,467
Medium	Low	Accelerated	45.0	45.5	45.0	45.5	47,791	48,295	47,818	48,315
Medium	Low	High	45.0	45.5	45.0	45.5	47,818	48,320	47,834	48,333
Medium	Medium	Low	45.3	45.7	45.8	46.3	48,099	48,586	48,647	49,128
Medium	Medium	Medium	45.1	45.9	45.6	46.0	47,903	31,523	48,460	48,903
Medium	Medium	Accelerated	45.0	45.4	45.5	45.9	47,784	48,266	48,291	48,727
Medium	Medium	High	45.0	45.4	45.5	45.8	47,789	48,271	48,285	48,691
Medium	High	Low	45.2	45.7	48.0	47.9	48,057	48,557	50,957	50,829
Medium	High	Medium	45.2	45.4	47.2	47.1	47,969	48,173	50,107	50,039
Medium	High	Accelerated	45.0	45.3	47.0	47.1	47,762	48,144	49,926	49,992
Medium	High	High	44.9	45.3	46.8	46.9	47,667	48,103	49,737	49,827
Medium-H	Low	Medium		44.8		45.6		54,176		34,686
Medium-H	Medium	Low	44.8	45.2	45.9	46.1	54,241	54,730	55,552	55,774
Medium-H	Medium	Medium	44.7	45.1	45.6	45.8	54,056	54,551	55,215	55,430
Medium-H	Medium	Accelerated	44.4	44.8	45.2	45.5	53,711	54,202	54,699	55,078
Medium-H	Medium	High	44.5	44.9	45.3	45.6	53,859	54,352	54,815	55,186
Medium-H	High	Medium		45.8		48.1		54,038 ~~34,873~~		58,227
High	Low	Medium		44.1		44.4		60,535		60,945
High	Medium	Low	44.5	44.8	45.8	46.0	61,013	61,461	62,841	63,056
High	Medium	Medium	44.2	44.6	45.5	45.6	60,684	61,139	62,404	62,629
High	Medium	Accelerated	43.9	44.3	45.2	45.3	60,269	60,731	62,000	62,218
High	Medium	High	44.2	44.6	45.5	45.6	60,687	61,154	62,416	62,633
High	High	Medium		45.9		48.2		38,734		40,694

Utility Costs after 50 Years (2043)

Table 5-50

Future		DSR	50 Year Real Levelized mills/kWh				Utility Cost 50 Year NPV ($M)			
Load	Gas Price	Strategy	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR
Low	Medium	Medium	50.1	51.1	50.1	51.1	38,040	38,791	38,040	38,791
Medium-L	Medium	Medium	47.0	47.6	47.2	47.7	41,419	41,939	41,582	41,984
Medium	Low	Low	45.7	46.2	45.7	46.2	47,167	47,664	47,188	47,692
Medium	Low	Medium	46.2	46.7	46.2	46.7	46,379	46,878	46,406	46,901
Medium	Low	Accelerated	46.4	46.9	46.5	47.0	46,334	46,837	46,361	46,857
Medium	Low	High	46.5	47.0	46.6	47.1	46,096	46,598	46,112	46,612
Medium	Medium	Low	45.7	46.2	46.3	46.7	47,195	47,681	47,742	48,224
Medium	Medium	Medium	46.1	46.6	46.7	47.1	46,337	46,802	46,894	47,338
Medium	Medium	Accelerated	46.4	46.9	46.9	47.4	46,327	46,809	46,834	47,270
Medium	Medium	High	46.5	47.0	47.0	47.4	46,067	46,549	46,563	46,970
Medium	High	Low	45.7	46.2	48.5	48.4	47,153	47,652	50,053	49,925
Medium	High	Medium	46.2	46.4	48.3	48.3	46,403	46,607	48,541	48,474
Medium	High	Accelerated	46.4	46.8	48.6	48.6	46,305	46,687	48,469	48,534
Medium	High	High	46.4	46.8	48.5	48.6	45,945	46,381	48,015	48,106
Medium-H	Low	Medium		45.8		46.0		52,410		52,682
Medium-H	Medium	Low	45.3	45.7	46.4	46.6	53,278	53,767	54,588	54,811
Medium-H	Medium	Medium	45.7	46.1	46.7	46.9	52,290	52,785	53,449	53,664
Medium-H	Medium	Accelerated	45.8	46.2	46.7	47.0	52,137	52,627	53,125	53,504
Medium-H	Medium	High	45.9	46.3	46.7	47.1	51,930	52,423	52,886	53,257
Medium-H	High	Medium		46.3		49.3		53,043		56,461
High	Low	Medium		45.0		45.4		58,639		59,049
High	Medium	Low	44.9	45.2	46.3	46.4	59,980	60,428	61,809	62,024
High	Medium	Medium	45.2	45.5	46.5	46.6	58,788	59,243	60,508	60,733
High	Medium	Accelerated	45.2	45.6	46.6	46.7	58,519	58,982	60,250	60,469
High	Medium	High	45.2	45.6	46.6	46.7	58,255	58,722	59,984	60,201
High	High	Medium		46.0		50.0		59,903		65,092

T5-50.utility cost.50yr

Total Resource Costs after 50 Years (2043)

Table 5-51

Future		DSR	50 Year Real Levelized mills/kWh				Total Resource Cost 50 Year NPV ($M			
Load	Gas Price	Strategy	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR
Low	Medium	Medium	48.6	49.6	48.6	49.6	39,310	40,061	39,310	40,061
Medium-L	Medium	Medium	45.8	46.4	46.0	46.4	42,760	43,280	42,923	43,325
Medium	Low	Low	45.3	45.7	45.3	45.8	48,071	48,568	48,092	48,596
Medium	Low	Medium	45.1	45.6	45.2	45.6	47,945	48,444	47,971	48,467
Medium	Low	Accelerated	45.0	45.5	45.0	45.5	47,791	48,295	47,818	48,315
Medium	Low	High	45.0	45.5	45.0	45.5	47,818	48,320	47,834	48,333
Medium	Medium	Low	45.3	45.7	45.8	46.3	48,099	48,586	48,647	49,128
Medium	Medium	Medium	45.1	45.5	45.6	46.0	47,903	48,368	48,460	48,903
Medium	Medium	Accelerated	45.0	45.4	45.5	45.9	47,784	48,266	48,291	48,727
Medium	Medium	High	45.0	45.4	45.5	45.8	47,789	48,271	48,285	48,691
Medium	High	Low	45.2	45.7	48.0	47.9	48,057	48,557	50,957	50,829
Medium	High	Medium	45.2	45.4	47.2	47.1	47,969	48,173	50,107	50,039
Medium	High	Accelerated	45.0	45.3	47.0	47.1	47,762	48,144	49,926	49,992
Medium	High	High	44.9	45.3	46.8	46.9	47,667	48,103	49,737	49,827
Medium-H	Low	Medium		44.8		45.0		54,176		54,448
Medium-H	Medium	Low	44.8	45.2	45.9	46.1	54,241	54,730	55,552	55,774
Medium-H	Medium	Medium	44.7	45.1	45.6	45.8	54,056	54,551	55,215	55,430
Medium-H	Medium	Accelerated	44.4	44.8	45.2	45.5	53,711	54,202	54,699	55,078
Medium-H	Medium	High	44.5	44.9	45.3	45.6	53,859	54,352	54,815	55,186
Medium-H	High	Medium		45.3		48.1		54,809		58,227
High	Low	Medium		44.1		44.4		60,535		60,945
High	Medium	Low	44.5	44.8	45.8	46.0	61,013	61,461	62,841	63,056
High	Medium	Medium	44.2	44.6	45.5	45.6	60,684	61,139	62,404	62,629
High	Medium	Accelerated	43.9	44.3	45.2	45.3	60,269	60,731	62,000	62,218
High	Medium	High	44.2	44.6	45.5	45.6	60,687	61,154	62,416	62,633
High	High	Medium		45.0		48.8		61,799		66,988

T5-51.trc.50yr

Utility Cost
Difference Between 50 Years vs 20 Years

Table 5-52

Future		DSR	50 Year Real Levelized mills/kWh				Utility Cost 50 Year NPV ($M)			
Load	Gas Price	Strategy	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR
Low	Medium	Medium	1.8	1.7	1.8	1.7	12,529	12,684	12,529	12,684
Medium-L	Medium	Medium	0.7	0.6	0.8	0.6	13,983	14,072	14,080	14,092
Medium	Low	Low	0.1	0.0	0.3	0.1	16,530	16,616	16,688	16,751
Medium	Low	Medium	0.2	0.0	0.4	0.2	16,130	16,217	16,288	16,343
Medium	Low	Accelerated	0.1	-0.1	0.3	0.1	16,113	16,200	16,266	16,321
Medium	Low	High	0.1	0.0	0.3	0.1	16,005	16,080	16,144	16,201
Medium	Medium	Low	0.1	0.0	0.6	0.4	16,550	16,633	17,072	17,126
Medium	Medium	Medium	0.2	0.0	0.6	0.5	16,109	16,173	16,627	16,658
Medium	Medium	Accelerated	0.1	-0.1	0.6	0.4	16,108	16,180	16,601	16,627
Medium	Medium	High	0.1	0.0	0.6	0.4	15,985	16,065	16,466	16,472
Medium	High	Low	0.2	0.1	1.0	1.3	16,622	16,718	18,154	18,298
Medium	High	Medium	0.3	0.1	1.0	1.2	16,235	16,154	17,399	17,527
Medium	High	Accelerated	0.2	0.1	0.9	1.1	16,193	16,220	17,399	17,567
Medium	High	High	0.2	0.0	0.9	1.1	15,995	16,059	17,163	17,364
Medium-H	Low	Medium		-0.5		-0.2		18,733		18,991
Medium-H	Medium	Low	-0.3	-0.4	0.3	0.3	19,357	19,431	20,297	20,320
Medium-H	Medium	Medium	-0.3	-0.4	0.3	0.2	18,824	18,908	19,664	19,683
Medium-H	Medium	Accelerated	-0.4	-0.5	0.4	0.1	18,782	18,868	19,651	19,636
Medium-H	Medium	High	-0.3	-0.5	0.3	0.1	18,661	18,746	19,503	19,484
Medium-H	High	Medium		-0.2		1.4		19,165		21,563
High	Low	Medium		-1.1		-0.6		21,355		21,838
High	Medium	Low	-0.8	-0.9	0.1	0.0	22,263	22,353	23,689	23,706
High	Medium	Medium	-0.7	-0.8	0.1	0.0	21,654	21,729	22,943	22,968
High	Medium	Accelerated	-0.8	-0.9	0.0	-0.1	21,576	21,645	22,856	22,875
High	Medium	High	-0.7	-0.9	0.0	0.0	21,479	21,546	22,755	22,773
High	High	Medium		-0.5		1.1		22,242		25,471

Total Resource Cost
Difference Between 50 Years vs 20 Years

Table 5-53

Future		DSR	50 Year Real Levelized mills/kWh				Total Resource Cost 50 Year NPV ($M			
Load	Gas Price	Strategy	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.SR
Low	Medium	Medium	1.3	1.1	1.3	1.1	13,052	13,208	13,052	13,208
Medium Low	Medium	Medium	0.3	0.2	0.4	0.2	14,534	14,623	14,631	14,643
Medium	Low	Low	-0.1	-0.2	0.1	0.0	16,902	16,987	17,059	17,122
Medium	Low	Medium	-0.2	-0.3	0.0	-0.1	16,802	16,889	16,960	17,015
Medium	Low	Accelerated	-0.3	-0.4	-0.1	-0.2	16,698	16,785	16,851	16,906
Medium	Low	High	-0.2	-0.3	0.0	-0.2	16,747	16,822	16,886	16,943
Medium	Medium	Low	-0.1	-0.2	0.4	0.2	16,921	17,005	17,443	17,498
Medium	Medium	Medium	-0.2	-0.4	0.3	0.1	16,781	16,845	17,299	17,330
Medium	Medium	Accelerated	-0.3	-0.4	0.2	0.0	16,693	16,765	17,186	17,212
Medium	Medium	High	-0.2	-0.4	0.2	0.0	16,727	16,807	17,209	17,214
Medium	High	Low	0.0	-0.1	0.8	1.1	16,993	17,090	18,525	18,669
Medium	High	Medium	0.0	-0.3	0.6	0.8	16,907	16,826	18,071	18,199
Medium	High	Accelerated	-0.1	-0.3	0.5	0.7	16,778	16,805	17,984	18,152
Medium	High	High	-0.1	-0.3	0.5	0.8	16,737	16,802	17,905	18,106
Medium H	Low	Medium		-0.8		-0.6		19,504		19,762
Medium H	Medium	Low	-0.4	-0.6	0.1	0.1	19,756	19,830	20,695	20,719
Medium H	Medium	Medium	-0.6	-0.7	0.0	-0.1	19,595	19,679	20,435	20,454
Medium H	Medium	Accelerated	-0.7	-0.8	0.0	-0.2	19,401	19,487	20,270	20,255
Medium H	Medium	High	-0.6	-0.7	0.0	-0.2	19,497	19,582	20,338	20,320
Medium H	High	Medium		-0.5		1.0		19,936		22,334
High	Low	Medium		-1.3		-0.9		22,179		22,662
High	Medium	Low	-0.9	-1.0	0.0	-0.1	22,696	22,786	24,122	24,139
High	Medium	Medium	-1.0	-1.1	-0.3	-0.3	22,478	22,552	23,767	23,791
High	Medium	Accelerated	-1.1	-1.2	-0.3	-0.4	22,267	22,337	23,548	23,567
High	Medium	High	-0.9	-1.0	-0.2	-0.3	22,570	22,637	23,846	23,864
High	High	Medium		-0.9		0.6		23,065		26,294

T5-53.trc.50-20yr

Average Customer Bill (Real Annual $)

Financial Results (including end effects to 2043)

Table 5-54

Case Num	Future: Load	Future: Gas Price	Strategies: DSR	Strategies: Coal/Renew	1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	
2	Low	Med	MD	AC.AR	1648	1699	1674	1649	1613	1615	1584	1554	1513	1482	1540	1572	1595.25
3	Low	Med	MD	AC.SR	1648	1699	1674	1654	1632	1650	1636	1625	1586	1540	1581	1606	
4	Low	Med	MD	NC.AR	1648	1699	1674	1649	1613	1615	1584	1554	1513	1482	1540	1572	
5	Low	Med	MD	NC.SR	1648	1699	1674	1654	1632	1650	1636	1625	1586	1540	1581	1606	
7	Med Low	Med	MD	AC.AR	[illegible]	1682	1654	1628	1590	1591	1561	1531	1482	1493	1546	1615	
8	Med Low	Med	MD	AC.SR	1641	1682	1654	1631	1607	1622	1606	1591	1554	1515	1566	1632	
9	Med Low	Med	MD	NC.AR	1641	1682	1654	1628	1590	1591	1561	1531	1497	1486	1567	1640	
10	Med Low	Med	MD	NC.SR	1641	1682	1654	1631	1607	1622	1606	1591	1556	1514	1579	1638	
12	Med	Low	LD	AC.AR	1629	1654	1637	1609	1605	1608	1591	1577	1526	1589	1611	1726	
13	Med	Low	LD	AC.SR	1629	1654	1637	1612	1619	1632	1625	1622	1577	1616	1637	1740	
14	Med	Low	LD	NC.AR	1629	1654	1637	1609	1606	1607	1591	1573	1557	1568	1619	1701	
15	Med	Low	LD	NC.SR	1629	1654	1637	1612	1620	1632	1626	1619	1602	1600	1647	1719	
16	Med	Low	MD	AC.AR	1631	1657	1638	1609	1597	1595	1575	1555	1502	1561	1569	1690	
17	Med	Low	MD	AC.SR	1631	1657	1638	1612	1611	1622	1609	1600	1554	1588	1592	1705	
18	Med	Low	MD	NC.AR	1631	1657	1638	1609	1598	1595	1575	1554	1532	1537	1581	1662	
19	Med	Low	MD	NC.SR	1631	1657	1638	1612	1611	1622	1609	1600	1577	1570	1606	1680	
20	Med	Low	AD	AC.AR	1630	1658	1633	1613	1593	1592	1572	1552	1503	1558	1568	1688	
21	Med	Low	AD	AC.SR	1630	1658	1633	1616	1606	1619	1606	1598	1555	1585	1593	1703	
22	Med	Low	AD	NC.AR	1630	1658	1633	1613	1593	1592	1572	1552	1531	1537	1580	1659	
23	Med	Low	AD	NC.SR	1630	1658	1633	1616	1606	1619	1606	1597	1576	1570	1606	1678	
24	Med	Low	HD	AC.AR	1629	1658	1631	1612	1589	1588	1565	1545	1496	1551	1560	1675	
25	Med	Low	HD	AC.SR	1629	1658	1631	1615	1602	1614	1600	1591	1546	1578	1584	1693	
26	Med	Low	HD	NC.AR	1629	1658	1631	1612	1589	1588	1566	1544	1522	1528	1569	1649	
27	Med	Low	HD	NC.SR	1629	1658	1631	1615	1602	1614	1600	1590	1567	1561	1594	1668	
29	Med	Med	LD	AC.AR	1629	1654	1637	1608	1610	1613	1601	1568	1537	1589	1607	1707	
30	Med	Med	LD	AC.SR	1629	1654	1637	1611	1624	1636	1632	1616	1574	1618	1632	1725	
31	Med	Med	LD	NC.AR	1629	1654	1637	1609	1606	1608	1594	1583	1571	1576	1643	1727	
32	Med	Med	LD	NC.SR	1629	1654	1637	1612	1619	1632	1629	1628	1613	1605	1669	1749	
33	Med	Med	MD	AC.AR	1631	1657	1638	1608	1602	1599	1581	1551	1502	1559	1564	1676	
34	Med	Med	MD	AC.SR	1631	1657	1638	1611	1615	1625	1613	1598	1547	1585	1588	1691	
35	Med	Med	MD	NC.AR	1631	1657	1638	1609	1597	1595	1579	1561	1543	1542	1601	1689	
36	Med	Med	MD	NC.SR	1631	1657	1638	1612	1610	1620	1610	1603	1581	1572	1627	1708	
37	Med	Med	AD	AC.AR	1630	1658	1633	1612	1597	1596	1578	1548	1502	1558	1570	1675	
38	Med	Med	AD	AC.SR	1630	1658	1633	1615	1610	1622	1610	1594	1545	1585	1594	1693	
39	Med	Med	AD	NC.AR	1630	1658	1633	1613	1592	1591	1575	1557	1541	1542	1600	1687	
40	Med	Med	AD	NC.SR	1630	1658	1633	1616	1605	1617	1606	1599	1580	1570	1626	1705	
41	Med	Med	HD	AC.AR	1629	1658	1631	1611	1592	1591	1571	1541	1492	1551	1559	1662	
42	Med	Med	HD	AC.SR	1629	1658	1631	1614	1604	1616	1602	1587	1536	1578	1585	1678	
43	Med	Med	HD	NC.AR	1629	1658	1631	1612	1587	1586	1568	1548	1530	1532	1588	1676	
44	Med	Med	HD	NC.SR	1629	1658	1631	1614	1603	1615	1600	1591	1570	1561	1610	1690	
46	Med	High	LD	AC.AR	1629	1654	1637	1609	1611	1613	1602	1561	1539	1574	1593	1686	
47	Med	High	LD	AC.SR	1629	1654	1637	1613	1620	1635	1633	1611	1575	1603	1619	1705	
48	Med	High	LD	NC.AR	1629	1654	1637	1623	1670	1703	1702	1668	1645	1633	1733	1873	
49	Med	High	LD	NC.SR	1629	1654	1637	1611	1626	1637	1632	1635	1629	1626	1731	1886	
50	Med	High	MD	AC.AR	1631	1657	1638	1614	1589	1600	1586	1545	1510	1548	1559	1661	
51	Med	High	MD	AC.SR	1631	1657	1638	1611	1614	1624	1612	1596	1536	1570	1565	1659	
52	Med	High	MD	NC.AR	1631	1657	1638	1617	1647	1681	1682	1635	1597	1580	1664	1773	
53	Med	High	MD	NC.SR	1631	1657	1638	1610	1616	1626	1613	1605	1593	1576	1665	1786	

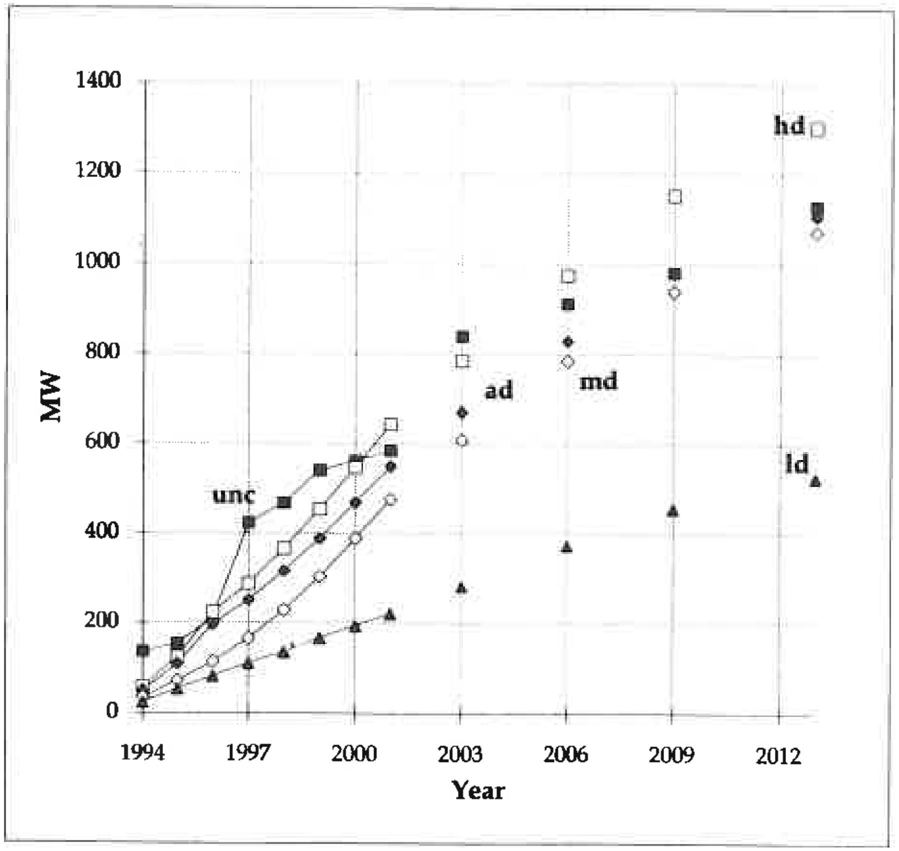
Case	Future		Strategies		Run Years											
Num	Load	Gas Price	DSR/Coal/Renew		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
54	Med	High	AD	AC.AR	1630	1658	1633	1613	1592	1594	1579	1539	1507	1544	1559	1655
55	Med	High	AD	AC.SR	1630	1658	1633	1615	1607	1619	1608	1592	1534	1570	1575	1668
56	Med	High	AD	NC.AR	1630	1658	1633	1621	1636	1672	1674	1627	1592	1578	1663	1769
57	Med	High	AD	NC.SR	1630	1658	1633	1614	1610	1620	1609	1600	1592	1577	1670	1799
58	Med	High	HD	AC.AR	1629	1658	1631	1610	1591	1590	1570	1532	1494	1535	1542	1641
59	Med	High	HD	AC.SR	1629	1658	1631	1613	1603	1614	1600	1584	1524	1562	1562	1656
60	Med	High	HD	NC.AR	1629	1658	1631	1621	1630	1666	1668	1623	1575	1565	1643	1739
61	Med	High	HD	NC.SR	1629	1658	1631	1613	1603	1614	1600	1591	1577	1564	1650	1770
62	Med High	Low	MD	AC.SR	1634	1665	1657	1600	1643	1646	1636	1623	1580	1570	1613	1686
63	Med High	Low	MD	NC.SR	1634	1665	1657	1600	1643	1644	1636	1623	1591	1582	1636	1692
65	Med High	Med	LD	AC.AR	1632	1664	1656	1614	1613	1642	1635	1597	1567	1593	1644	1731
66	Med High	Med	LD	AC.SR	1632	1664	1656	1616	1627	1663	1663	1641	1603	1619	1667	1747
67	Med High	Med	LD	NC.AR	1632	1664	1656	1608	1672	1664	1649	1630	1608	1619	1699	1775
68	Med High	Med	LD	NC.SR	1632	1664	1656	1604	1649	1663	1660	1656	1635	1637	1712	1783
69	Med High	Med	MD	AC.AR	1634	1665	1657	1612	1610	1627	1619	1575	1543	1565	1598	1689
70	Med High	Med	MD	AC.SR	1634	1665	1657	1613	1623	1648	1647	1621	1577	1591	1621	1707
71	Med High	Med	MD	NC.AR	1634	1665	1657	1606	1670	1650	1630	1606	1580	1582	1655	1723
72	Med High	Med	MD	NC.SR	1634	1665	1657	1602	1646	1648	1641	1631	1607	1599	1667	1732
73	Med High	Med	AD	AC.AR	1631	1661	1649	1608	1610	1617	1604	1567	1535	1560	1597	1685
74	Med High	Med	AD	AC.SR	1631	1661	1649	1610	1624	1638	1633	1614	1566	1585	1618	1703
75	Med High	Med	AD	NC.AR	1631	1661	1649	1599	1628	1616	1600	1579	1561	1571	1643	1718
76	Med High	Med	AD	NC.SR	1631	1661	1649	1602	1640	1640	1629	1621	1601	1594	1665	1726
77	Med High	Med	HD	AC.AR	1631	1661	1648	1608	1611	1616	1602	1565	1531	1556	1588	1675
78	Med High	Med	HD	AC.SR	1631	1661	1648	1610	1625	1637	1631	1612	1562	1581	1609	1694
79	Med High	Med	HD	NC.AR	1631	1661	1648	1599	1627	1615	1597	1576	1557	1565	1635	1706
80	Med High	Med	HD	NC.SR	1631	1661	1648	1602	1639	1639	1627	1617	1595	1588	1656	1715
81	Med High	High	MD	AC.SR	1634	1665	1657	1615	1625	1654	1652	1618	1585	1585	1615	1705
82	Med High	High	MD	NC.SR	1634	1665	1657	1605	1649	1651	1646	1642	1627	1636	1769	1924
83	High	Low	MD	AC.SR	1648	1683	1679	1620	1630	1700	1690	1678	1612	1617	1681	1746
84	High	Low	MD	NC.SR	1648	1683	1679	1620	1627	1697	1687	1672	1643	1629	1688	1747
86	High	Med	LD	AC.AR	1647	1681	1677	1638	1610	1705	1700	1652	1616	1644	1727	1796
87	High	Med	LD	AC.SR	1647	1681	1677	1639	1622	1724	1724	1694	1652	1662	1742	1806
88	High	Med	LD	NC.AR	1647	1681	1677	1627	1660	1720	1704	1691	1671	1681	1769	1862
89	High	Med	LD	NC.SR	1647	1681	1677	1624	1637	1720	1716	1713	1696	1697	1780	1869
90	High	Med	MD	AC.AR	1648	1683	1678	1636	1606	1691	1678	1636	1586	1613	1674	1747
91	High	Med	MD	AC.SR	1648	1683	1678	1637	1619	1710	1702	1672	1632	1631	1690	1758
92	High	Med	MD	NC.AR	1648	1683	1678	1626	1656	1707	1688	1666	1645	1644	1726	1809
93	High	Med	MD	NC.SR	1648	1683	1678	1623	1634	1707	1699	1690	1668	1660	1737	1817
94	High	Med	AD	AC.AR	1645	1678	1668	1629	1604	1678	1663	1624	1579	1604	1667	1737
95	High	Med	AD	AC.SR	1645	1678	1668	1631	1616	1697	1690	1661	1625	1623	1683	1750
96	High	Med	AD	NC.AR	1645	1678	1668	1619	1655	1694	1676	1655	1635	1637	1720	1800
97	High	Med	AD	NC.SR	1645	1678	1668	1617	1633	1693	1687	1677	1660	1652	1732	1807
98	High	Med	HD	AC.AR	1644	1674	1658	1616	1593	1666	1652	1613	1572	1599	1660	1733
99	High	Med	HD	AC.SR	1644	1674	1658	1618	1605	1685	1680	1651	1618	1618	1676	1746
100	High	Med	HD	NC.AR	1644	1674	1658	1606	1644	1683	1666	1644	1627	1631	1715	1796
101	High	Med	HD	NC.SR	1644	1674	1658	1604	1622	1681	1676	1667	1652	1647	1727	1803
102	High	High	MD	AC.SR	1648	1683	1678	1640	1622	1718	1715	1684	1625	1642	1703	1765
103	High	High	MD	NC.SR	1648	1683	1678	1626	1641	1714	1713	1711	1714	1757	1930	2079

Demand Side Resources (Medium Load)

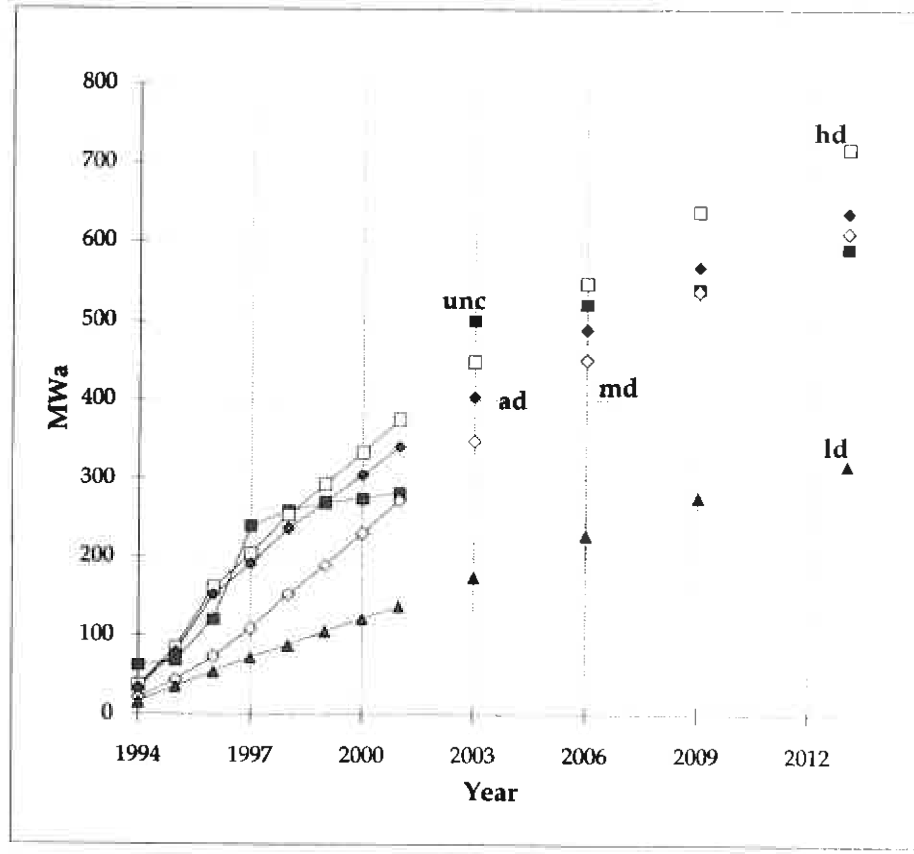
as calculated by IPM model

Table 5-55

Peak Reduction by Year



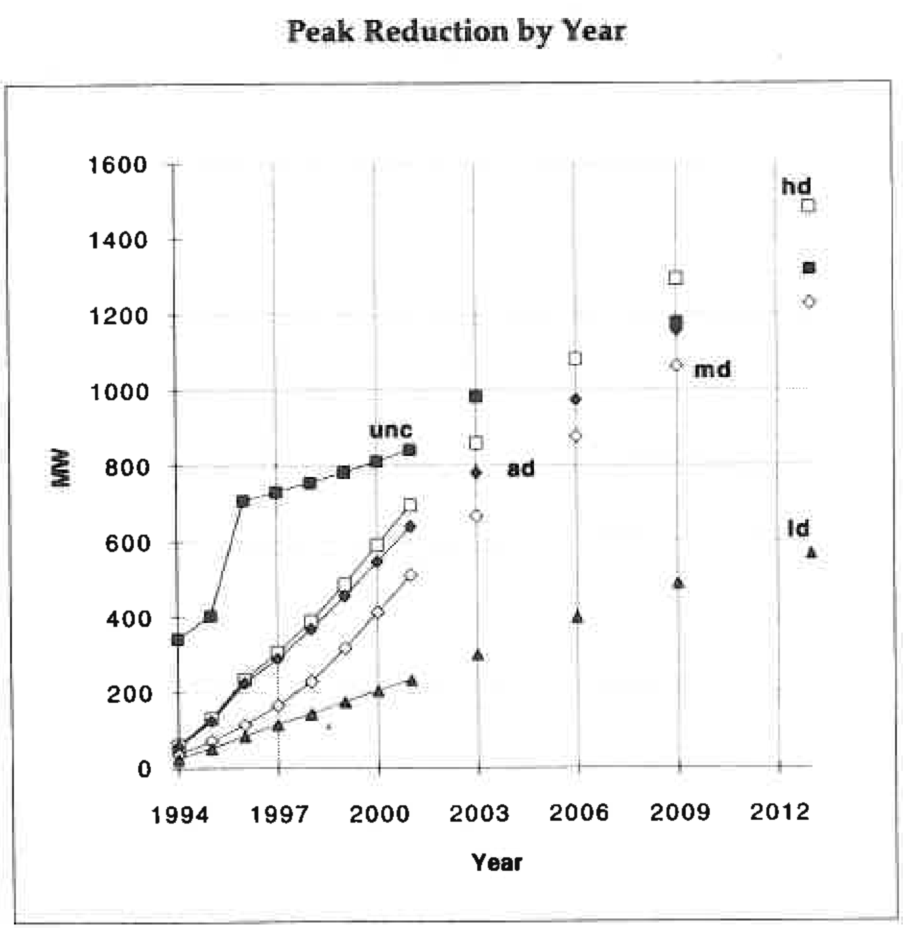
Energy Reduction by Year

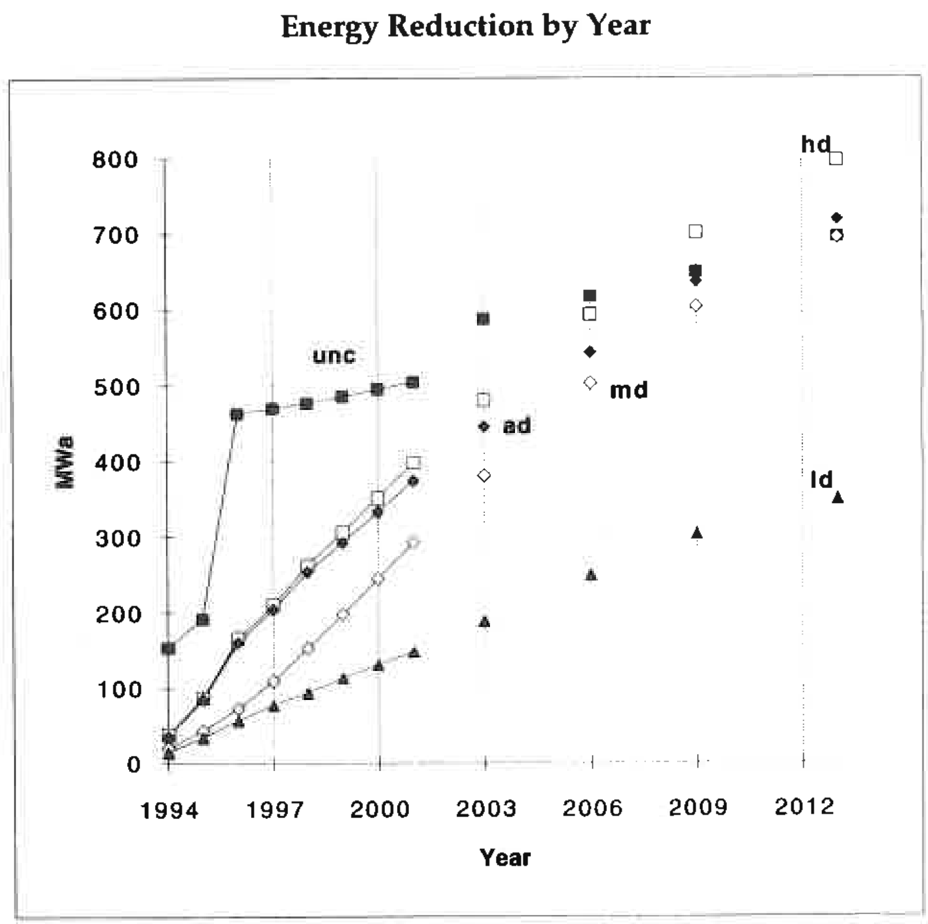


Demand Side Resources (Medium High Load)

as calculated by IPM model

Table 5-56



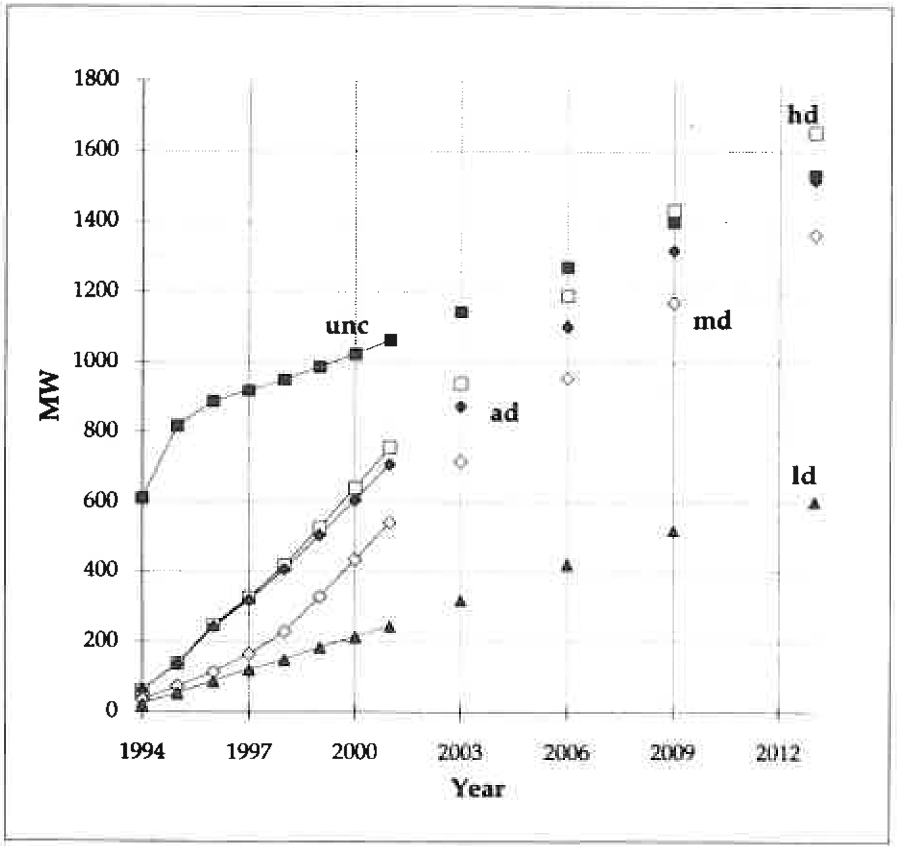


Demand Side Resources (High Load)

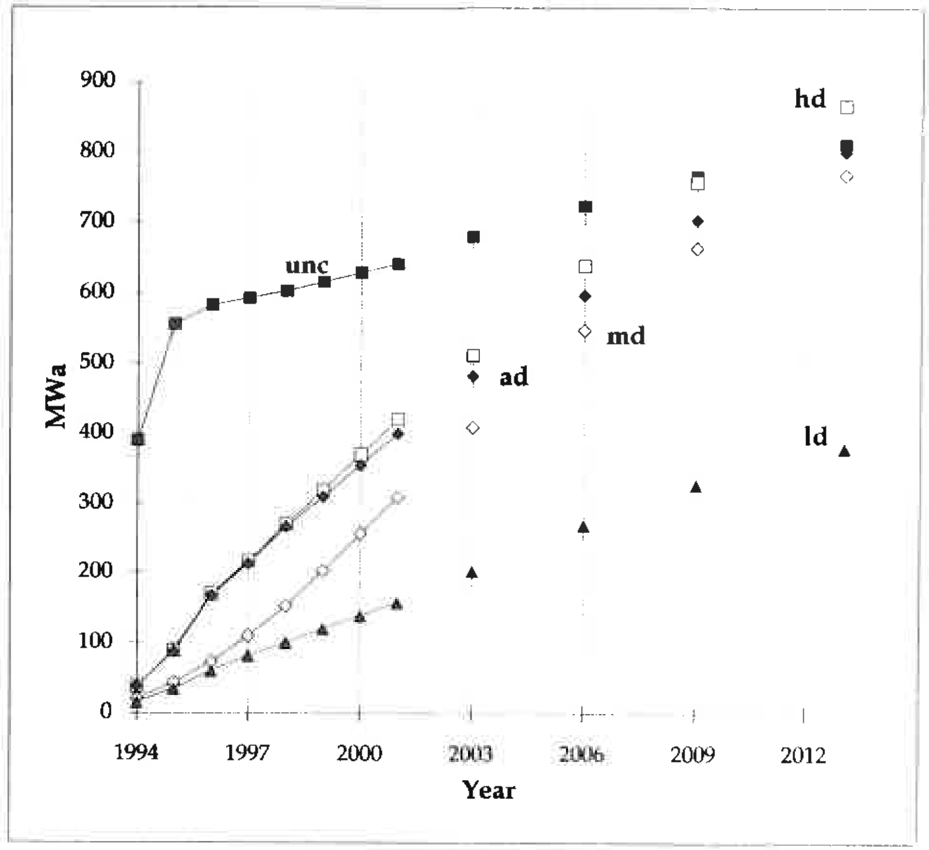
as calculated by IPM model

Table 5-57

Peak Reduction by Year



Energy Reduction by Year



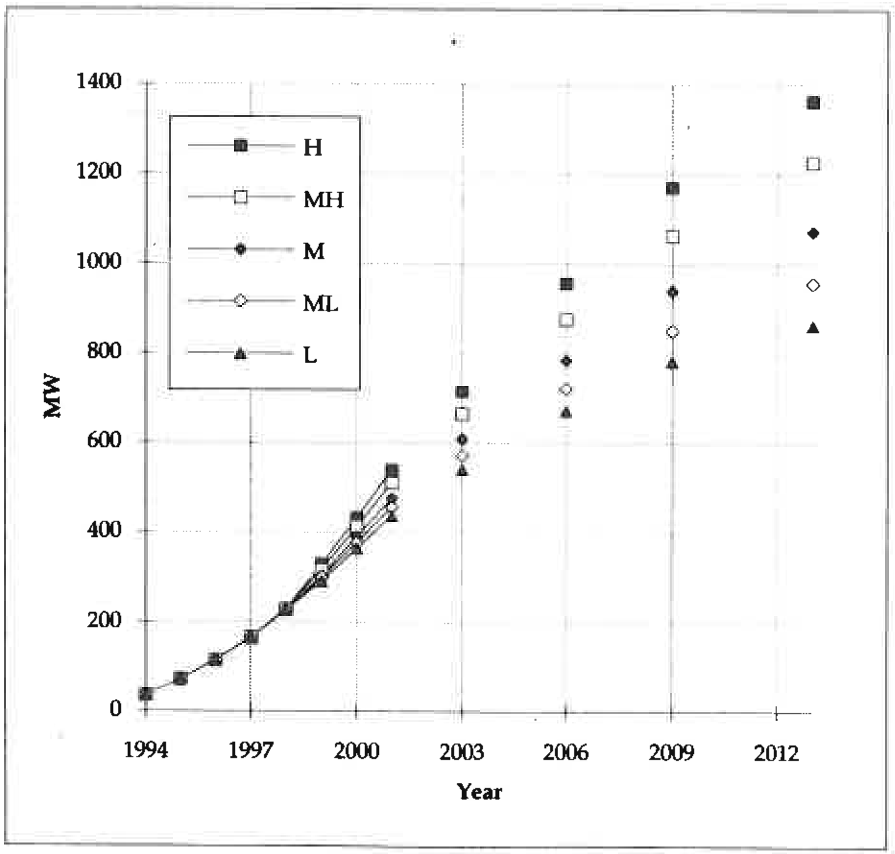
G5-57.peak reductions.h

Demand Side Resources (MD) by Load Level

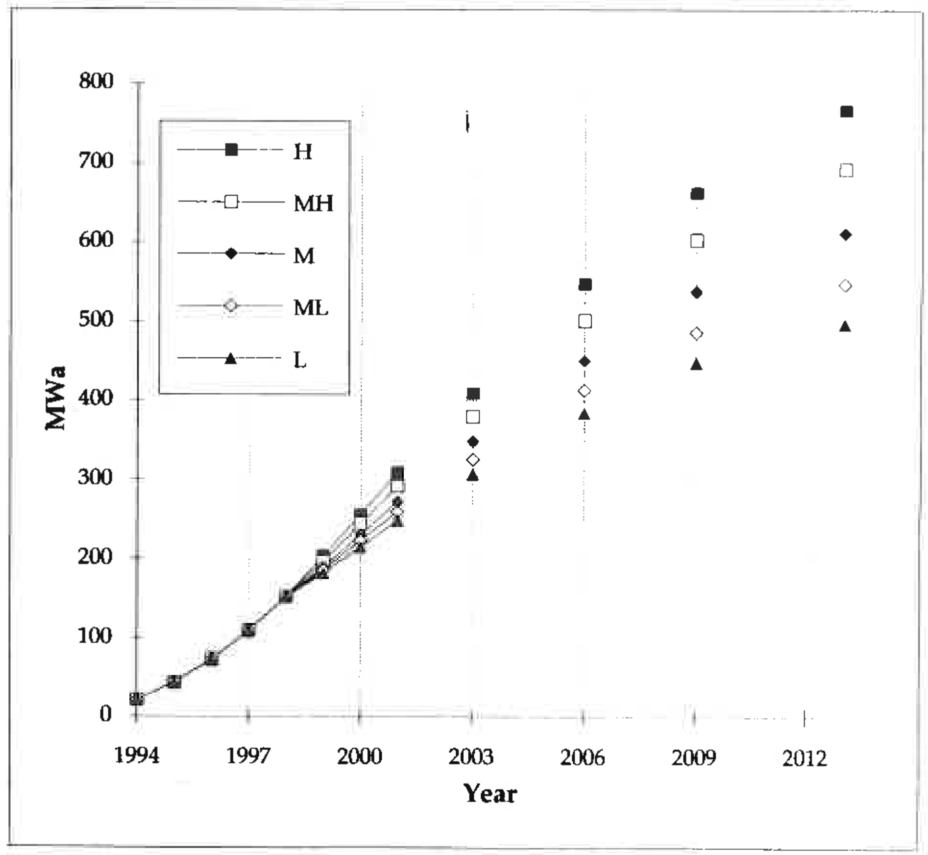
as calculated by IPM model

Table 5-58

Peak Reduction by Year



Energy Reduction by Year

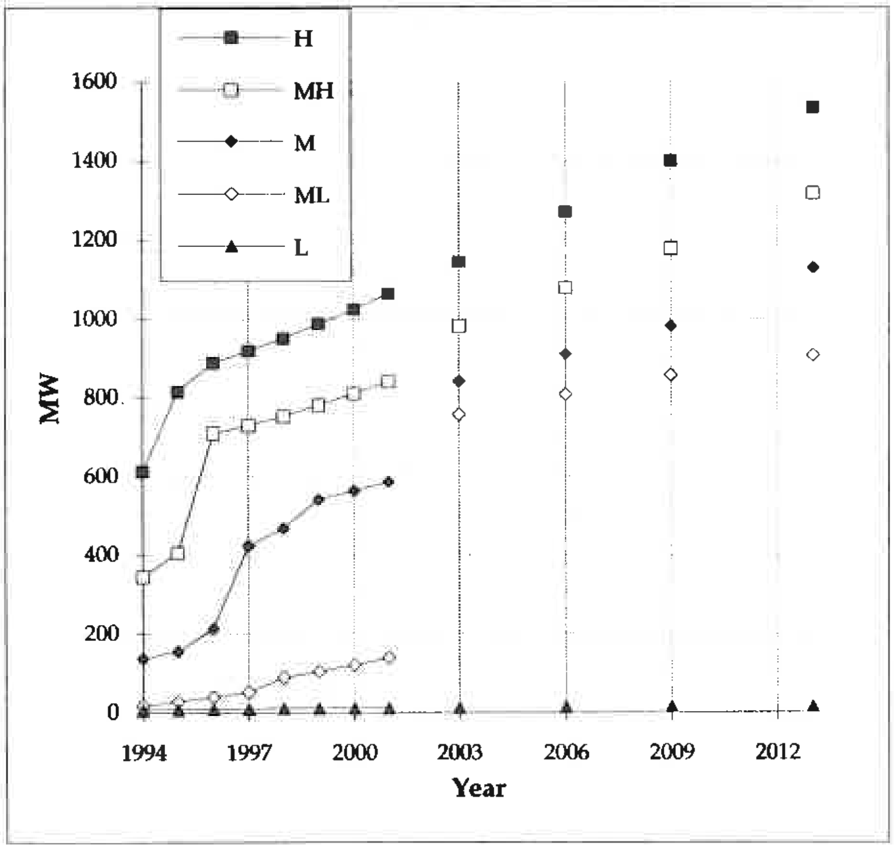


Demand Side Resources (Unconstrained) by Load Level

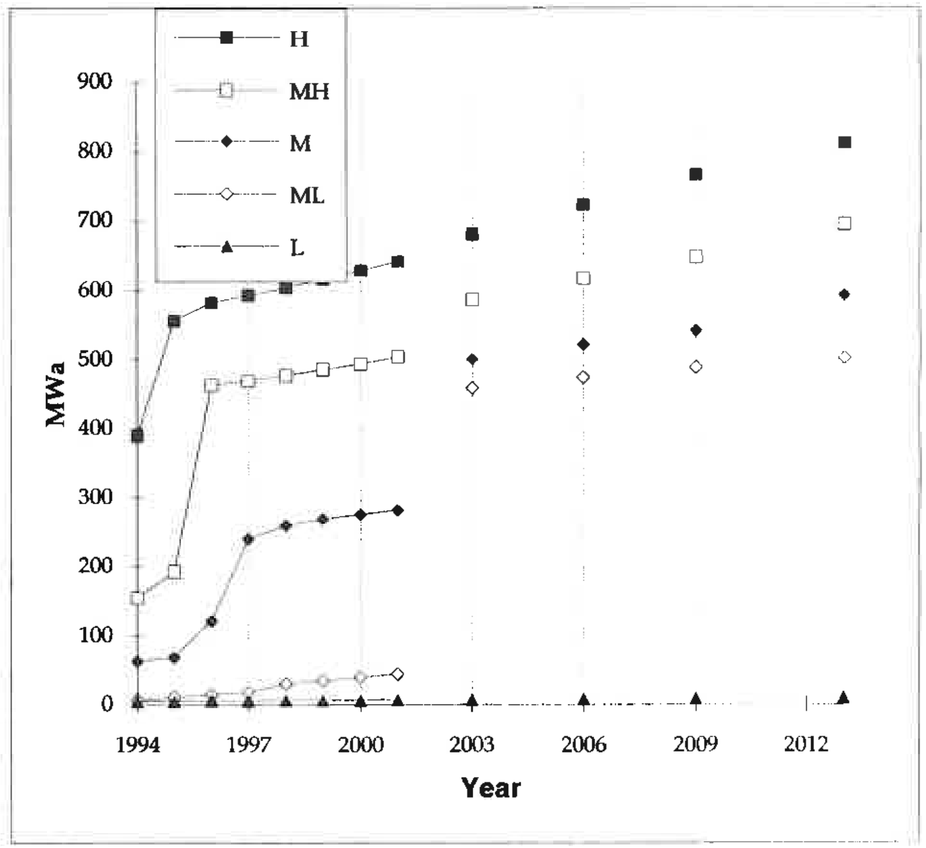
as calculated by IPM model

Table 5-59

Peak Reduction by Year



Energy Reduction by Year



G5-59.peak reductions.UNCs

Strategic Renewable Capacities

Table 5-60

Wind

Year	Peak Wind	Allocated to OWC MW	Allocated to Utah MW	Allocated to Wyoming MW	Generation OWC MWa	Generation Utah MWa	Generation Wyoming MWa	Generation Total MWa
Foote Creek and Rattlesnake				38.0			13.5	13.5
1996		0.0	0.0	0.0	0.0	0.0	0.0	0.0
1997	87.0	29.0	29.0	29.0	8.1	10.3	10.3	28.7
1998	108.0	36.0	36.0	36.0	10.1	12.8	12.8	35.6
1999	135.0	45.0	45.0	45.0	12.6	16.0	16.0	44.6
2000	87.0	29.0	29.0	29.0	8.1	10.3	10.3	28.7
2001	87.0	29.0	29.0	29.0	8.1	10.3	10.3	28.7
Total	504.00	168.00	168.00	168.00	47.0	59.6	59.6	179.8

	OWC	Utah	Wyoming	OWC	Utah	Wyoming
Allocation Factor	1/3	1/3	1/3			
Capacity Factor				28.0%	35.5%	35.5%

Geothermal

Year	Peak Wind	Allocated to OWC MW	Allocated to Utah MW	Allocated to Wyoming MW	Generation OWC MWa	Generation Utah MWa	Generation Wyoming MWa	Generation Total MWa
1996	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1997	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1998	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1999	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2001	25.0	13.0	12.0	0.0	11.7	10.8	0.0	22.5
Total	25.00	13.00	12.00	0.00	11.70	10.80	0.00	22.50

	OWC	Utah	Wyoming	OWC	Utah	Wyoming
Allocation Factor	1/2	1/2				
Capacity Factor				90.0%	90.0%	90.0%

Total Renewable Resources

Total	529.0	181.0	180.0	168.0	58.7	70.4	59.6	202.3

The strategic goal is 200 aMW of renewable resources by 2001.
Wind resources are split into with tax credit and without tax credit.
IPM will build the exact 1996 to 1999 MWs and build at least the 2000 to 2001 MWs.

Backup to Table 8-1 in the Report (Environmental Costs)

Table 5-61

Emissions

Resource			Fuel		Emissions (lbs/MMBTU)			Heat Rate	Emissions (lbs/MWh)		
#	Name	Description	Type	Proxy	NOX	TSP	CO2	(BTU/kWh)	NOX	TSP	CO2
1	APS	APS Sec CTs	GMCCE		0.09	0.0030	118	7,600	0.68	0.02	897
2	APT	APS NEW CTs	GMCCE		0.09	0.0030	118	8,530	0.77	0.03	1,007
3	ASE	APS Sea Ex(P)	PURCH	GAS	0.09	0.0030	118	7,160	0.64	0.02	845
4	BHC	Black Hills CT 1,2,	GMCCE		0.18	0.0030	155	10,334	1.86	0.03	1,602
5	BLU	Blundell Geothermal	PURCH								
6	BPA	BPA Peaking	PURCH								
7	BPS	BPA Supp Capacity	PURCH								
8	CAR	Carbon 1,2	CARBN		0.45	0.0400	198	11,103	5.00	0.44	2,198
9	CEN	Centralia 1,2	CENTR		0.45	0.0100	213	10,293	4.63	0.10	2,192
10	CHL	Cholla 4	CHOL4		0.45	0.0500	215	10,229	4.60	0.51	2,199
11	CLS	Colstrip 3,4	COLST		0.45	0.0300	215	10,500	4.73	0.32	2,258
12	CRG	Craig 1,2	CRAIG		0.45	0.0300	215	10,300	4.64	0.31	2,215
13	CRM	Cal Res Margin Unit	PURCH								
14	CSH	CSPE	PURCH								
15	DES	Deseret	PURCH	COAL	0.45	0.0150	204	10,020	4.51	0.15	2,045
16	DJN	Dave Johnston 1,2,3	DJOHN		0.48	0.0400	218	11,07[illegible]	5.31	0.44	2,414
17	GDS	Gadsby 1,2,3	GADSB		0.20	0.0030	118	11,372	2.27	0.03	1,342
18	GRT	Grant County	PURCH								
19	GST	Gem State	PURCH	COAL	0.45	0.0150	204	10,020	4.51	0.15	2,045
20	HAN	Hanford WNP 1	PURCH								
21	HAY	Hayden 1,2	HAYDN		0.45	0.0300	215	10,180	4.58	0.31	2,189
22	HTN	Huntington 1,2	HUNTN		0.45	0.0300	211	9,914	4.46	0.30	2,092
23	HTR	Hunter 1,2,3	HUNTR		0.45	0.0400	219	10,285	4.63	0.41	2,252
24	HYD	Hydro Pacific	PURCH								
25	HYU	Hydro Utah	PURCH								
26	JBR	Jim Bridger 1,2,3,4	JBRDG		0.45	0.0600	211	9,950	4.48	0.60	2,099
27	JRV	James River	PURCH	GAS	0.09	0.0030	118	4,381	0.39	0.01	517
28	LTL	Little Mountain	PURCH	GAS	0.09	0.0030	118	7,160	0.64	0.02	845
29	MID	Mid-Columbia	PURCH								
30	MPC	Montana Power Comp	PURCH	COAL	0.45	0.0150	204	10,020	4.51	0.15	2,045
31	NAU	Naughton 1,2,3	NAUGH		0.45	0.0500	210	10,25[illegible]	4.61	0.51	2,154
32	PGE	PGE Cove	PURCH								
33	QFN	QF NW	PURCH	GAS	0.09	0.0030	118	7,160	0.64	0.02	845
34	QFU	QF UPL	PURCH	GAS	0.09	0.0030	118	7,160	0.64	0.02	845
35	RFF	Request for Proposal	PURCH	GAS	0.09	0.0030	118	7,160	0.64	0.02	845
36	SCE	SCE Winter	PURCH	GAS	0.09	0.0030	118	7,160	0.64	0.02	845
37	SIE	So Idaho Ex(P)	PURCH	COAL	0.45	0.0150	204	10,020	4.51	0.15	2,045
38	TDN	T&D Eff PPL	PURCH								
39	TDU	T&D Eff UPL	PURCH								
40	TSB	Tri-State Basic	PURCH	COAL	0.45	0.0150	204	10,020	4.51	0.15	2,045
41	TSE	Tri-State Ex(P)	PURCH	COAL	0.45	0.0150	204	10,020	4.51	0.15	2,045
42	USB	USBR Greenspring	PURCH								
43	WAS	WWP Sandpoint	PURCH	GAS	0.09	0.0030	118	7,160	0.64	0.02	845
44	WAW	WWP	PURCH	GAS	0.09	0.0030	118	7,160	0.64	0.02	845
45	WFC	Wind FC & Rtl Snake	PURCH								
46	WTR	Water Budget	PURCH								
47	WYD	Wyodak	WYODK		0.50	0.0500	215	11,500	5.75	0.57	2,472
48	CPU	Cal Potential Unit	PURCH	GAS	0.09	0.0030	118	7,160	0.64	0.02	845
49	OC1	OWC Cogeneration 1	GMCCW		0.09	0.0030	118	5,500	0.50	0.02	649
50	OC2	OWC Cogeneration 2	GMCCW		0.09	0.0030	118	6,800	0.61	0.02	802
51	OCC	OWC Combined Cycle	GMCCW		0.09	0.0030	118	7,160	0.64	0.02	845
52	OCT	OWC Simple Cycle CT	GMSCW		0.09	0.0030	118	10,545	0.95	0.03	1,244
53	OCV	OWC CC CT Convert	GMCCW		0.09	0.0030	118	7,160	0.64	0.02	845
54	OGT	OWC Geothermal	GEOMD								
55	OPS	OWC Pump Storage	PURCH								
56	OW1	OWC Wind w Tax C	WIND								
57	OW2	OWC Wind w/o Tax C	WIND								
58	UC1	Utah Cogeneration 1	GMCCE		0.09	0.0030	118	5,500	0.50	0.02	649
59	UC2	Utah Cogeneration 2	GMCCE		0.09	0.0030	118	6,800	0.61	0.02	802
60	UCC	Utah Combined Cycle	GMCCE		0.09	0.0030	118	7,160	0.64	0.02	845
61	UCT	Utah Simple Cycle CT	GMSCE		0.09	0.0030	118	10,545	0.95	0.03	1,244
62	UCV	Utah CC CT Convert	GMCCE		0.09	0.0030	118	7,160	0.64	0.02	845
63	UCY	Utah IG CC	COALU		0.03	0.0030	202	8,628	0.29	0.03	1,739
64	UFB	Utah FB Coal	COALU		0.15	0.0150	208	9,105	1.37	0.14	1,890
65	UGC	Utah Coal	COALU		0.45	0.0150	204	10,020	4.51	0.15	2,045
66	UGT	Utah Geothermal	GEOMD								
67	UPS	Utah Pumped Storage	PURCH								
68	USL	Utah Solar	PURCH								
69	UW1	Utah Wind w Tax C	WIND								
70	UW2	Utah Wind w/o Tax C	WIND								
71	WCC	Wyo Combined Cycle	GMCCE		0.09	0.0030	118	7,160	0.64	0.02	845
72	WCT	Wyo Simple Cycle CT	GMSCE		0.09	0.0030	118	10,545	0.95	0.03	1,244
73	WCV	Wyo CC CT Convert	GMCCE		0.09	0.0030	118	7,160	0.64	0.02	845
74	WCY	Wyo IG CC	COALW		0.03	0.0030	202	8,754	0.29	0.03	1,765
75	WFB	Wyo FB Coal	COALW		0.15	0.0150	208	9,296	1.39	0.14	1,930
76	WGC	Wyo Coal	COALW		0.45	0.0150	204	11,346	5.11	0.17	2,316
77	WW1	Wyo Wind w Tax C	WIND								
78	WW2	Wyo Wind w/o Tax C	WIND								

Backup to Table 8-1 in the Report (Environmental Costs)

Table 5-61

Environmental Adders in Mills - given $/ton

Resource			NOX		TSP		CO2		
#	Name	Description	$2,000 (Low)	$5,000 (High)	$2,000 (Low)	$4,000 (High)	$10 (Low)	$25 (Med)	$40 (High)
1	APS	APS Sec CTs	0.68	1.71	0.02	0.05	4.48	11.21	17.94
2	APT	APS NEW CTs	0.77	1.92	0.03	0.05	5.03	12.58	20.13
3	ASE	APS Sea Ex(P)	0.64	1.61	0.02	0.04	4.22	10.56	16.90
4	BHC	Black Hills CT 1,2,	1.86	4.65	0.03	0.06	8.01	20.02	32.04
5	BLU	Blundell Geothermal							
6	BPA	BPA Peaking							
7	BPS	BPA Supp Capacity							
8	CAR	Carbon 1,2	5.00	12.49	0.44	0.89	10.99	27.48	43.97
9	CEN	Centralia 1,2	4.63	11.58	0.10	0.21	10.96	27.41	43.85
10	CHL	Cholla 4	4.60	11.51	0.51	1.02	11.00	27.49	43.98
11	CLS	Colstrip 3,4	4.73	11.81	0.32	0.63	11.29	28.22	45.15
12	CRG	Craig 1,2	4.64	11.59	0.31	0.62	11.07	27.68	44.29
13	CRM	Cal Res Margin Unit							
14	CSH	CSPE							
15	DES	Deseret	4.51	11.27	0.15	0.30	10.23	25.56	40.90
16	DJN	Dave Johnston 1,2,3	5.31	13.29	0.44	0.89	12.07	30.17	48.28
17	GDS	Gadsby 1,2,3	2.27	5.69	0.03	0.07	6.71	16.77	26.84
18	GRT	Grant County							
19	GST	Gem State	4.51	11.27	0.15	0.30	10.23	25.56	40.90
20	HAN	Hanford WNP 1							
21	HAY	Hayden 1,2	4.58	11.45	0.31	0.61	10.94	27.36	43.77
22	HTN	Huntington 1,2	4.46	11.15	0.30	0.59	10.46	26.15	41.84
23	HTR	Hunter 1,2,3	4.63	11.57	0.41	0.82	11.26	28.15	45.05
24	HYD	Hydro Pacific							
25	HYU	Hydro Utah							
26	JBR	Jim Bridger 1,2,3,4	4.48	11.19	0.60	1.19	10.50	26.24	41.99
27	JRV	James River	0.39	0.99	0.01	0.03	2.58	6.46	10.34
28	LTL	Little Mountain	0.64	1.61	0.02	0.04	4.22	10.56	16.90
29	MID	Mid-Columbia							
30	MPC	Montana Power Comp	4.51	11.27	0.15	0.30	10.23	25.56	40.90
31	NAU	Naughton 1,2,3	4.61	11.54	0.51	1.03	10.77	26.92	43.07
32	PGE	PGE Cove							
33	QFN	QF NW	0.64	1.61	0.02	0.04	4.22	10.56	16.90
34	QFU	QF UPL	0.64	1.61	0.02	0.04	4.22	10.56	16.90
35	RFF	Request for Proposal	0.64	1.61	0.02	0.04	4.22	10.56	16.90
36	SCE	SCE Winter	0.64	1.61	0.02	0.04	4.22	10.56	16.90
37	SIE	So Idaho Ex(P)	4.51	11.27	0.15	0.30	10.23	25.56	40.90
38	TDN	T&D Eff PPL							
39	TDU	T&D Eff UPL							
40	TSB	Tri-State Basic	4.51	11.27	0.15	0.30	10.23	25.56	40.90
41	TSE	Tri-State Ex(P)	4.51	11.27	0.15	0.30	10.23	25.56	40.90
42	USB	USBR Greenspring							
43	WAS	WWP Sandpoint	0.64	1.61	0.02	0.04	4.22	10.56	16.90
44	WAW	WWP	0.64	1.61	0.02	0.04	4.22	10.56	16.90
45	WFC	Wind FC & Rtl Snake							
46	WTR	Water Budget							
47	WYD	Wyodak	5.75	14.37	0.57	1.15	12.36	30.91	49.45
48	CPU	Cal Potential Unit	0.64	1.61	0.02	0.04	4.22	10.56	16.90
49	OC1	OWC Cogeneration 1	0.50	1.24	0.02	0.03	3.25	8.11	12.98
50	OC2	OWC Cogeneration 2	0.61	1.53	0.02	0.04	4.01	10.03	16.05
51	OCC	OWC Combined Cycle	0.64	1.61	0.02	0.04	4.22	10.56	16.90
52	OCT	OWC Simple Cycle CT	0.95	2.37	0.03	0.06	6.22	15.55	24.89
53	OCV	OWC CC CT Convert	0.64	1.61	0.02	0.04	4.22	10.56	16.90
54	OGT	OWC Geothermal							
55	OPS	OWC Pump Storage							
56	OW1	OWC Wind w Tax C							
57	OW2	OWC Wind w/o Tax C							
58	UC1	Utah Cogeneration 1	0.50	1.24	0.02	0.03	3.25	8.11	12.98
59	UC2	Utah Cogeneration 2	0.61	1.53	0.02	0.04	4.01	10.03	16.05
60	UCC	Utah Combined Cycle	0.64	1.61	0.02	0.04	4.22	10.56	16.90
61	UCT	Utah Simple Cycle CT	0.95	2.37	0.03	0.06	6.22	15.55	24.89
62	UCV	Utah CC CT Convert	0.64	1.61	0.02	0.04	4.22	10.56	16.90
63	UCY	Utah IG CC	0.29	0.71	0.03	0.05	8.70	21.74	34.79
64	UFB	Utah FB Coal	1.37	3.41	0.14	0.27	9.45	23.63	37.80
65	UGC	Utah Coal	4.51	11.27	0.15	0.30	10.23	25.56	40.90
66	UGT	Utah Geothermal							
67	UPS	Utah Pumped Storage							
68	USL	Utah Solar							
69	UW1	Utah Wind w Tax C							
70	UW2	Utah Wind w/o Tax C							
71	WCC	Wyo Combined Cycle	0.64	1.61	0.02	0.04	4.22	10.56	16.90
72	WCT	Wyo Simple Cycle CT	0.95	2.37	0.03	0.06	6.22	15.55	24.89
73	WCV	Wyo CC CT Convert	0.64	1.61	0.02	0.04	4.22	10.56	16.90
74	WCY	Wyo IG CC	0.29	0.72	0.03	0.05	8.82	22.06	35.30
75	WFB	Wyo FB Coal	1.39	3.49	0.14	0.28	9.65	24.12	38.59
76	WGC	Wyo Coal	5.11	12.76	0.17	0.34	11.58	28.95	46.31
77	WW1	Wyo Wind w Tax C							
78	WW2	Wyo Wind w/o Tax C							

Backup to Table 8-1 in the Report (Environmental Costs)

Table 5-61

Environmental Adders in Mills - Specific Cases

Resource			Low NOx and TSP			High NOx and TSP		
#	Name	Description	Low CO2	Med CO2	High CO2	Low CO2	Med CO2	High CO2
1	APS	APS Sec CTs	5.19	11.92	18.64	6.24	12.97	19.69
2	APT	APS NEW CTs	5.83	13.38	20.92	7.00	14.55	22.10
3	ASE	APS Sea Ex(P)	4.89	11.23	17.56	5.88	12.21	18.55
4	BHC	Black Hills CT 1,2,	9.90	21.91	33.93	12.72	24.73	36.75
5	BLU	Blundell Geothermal						
6	BPA	BPA Peaking						
7	BPS	BPA Supp Capacity						
8	CAR	Carbon 1,2	16.43	32.92	49.41	24.37	40.86	57.35
9	CEN	Centralia 1,2	15.70	32.14	48.58	22.75	39.19	55.64
10	CHL	Cholla 4	16.11	32.60	49.10	23.53	40.02	56.51
11	CLS	Colstrip 3,4	16.33	33.26	50.19	23.73	40.66	57.59
12	CRG	Craig 1,2	16.02	32.63	49.23	23.28	39.89	56.50
13	CRM	Cal Res Margin Unit						
14	CSH	CSPE						
15	DES	Deseret	14.88	30.22	45.56	21.80	37.14	52.47
16	DJN	Dave Johnston 1,2,3	17.83	35.93	54.03	26.24	44.35	62.45
17	GDS	Gadsby 1,2,3	9.02	19.08	29.15	12.46	22.53	32.59
18	GRT	Grant County						
19	GST	Gem State	14.88	30.22	45.56	21.80	37.14	52.47
20	HAN	Hanford WNP 1						
21	HAY	Hayden 1,2	15.83	32.25	48.66	23.01	39.42	55.84
22	HTN	Huntington 1,2	15.22	30.91	46.60	22.21	37.90	53.59
23	HTR	Hunter 1,2,3	16.30	33.19	50.09	23.65	40.55	57.44
24	HYD	Hydro Pacific						
25	HYU	Hydro Utah						
26	JBR	Jim Bridger 1,2,3,4	15.57	31.32	47.06	22.89	38.63	54.38
27	JRV	James River	2.99	6.87	10.75	3.60	7.47	11.35
28	LTL	Little Mountain	4.89	11.23	17.56	5.88	12.21	18.55
29	MID	Mid-Columbia						
30	MPC	Montana Power Comp	14.88	30.22	45.56	21.80	37.14	52.47
31	NAU	Naughton 1,2,3	15.90	32.05	48.20	23.33	39.48	55.64
32	PGE	PGE Cove						
33	QFN	QF NW	4.89	11.23	17.56	5.88	12.21	18.55
34	QFU	QF UPL	4.89	11.23	17.56	5.88	12.21	18.55
35	RFF	Request for Proposal	4.89	11.23	17.56	5.88	12.21	18.55
36	SCE	SCE Winter	4.89	11.23	17.56	5.88	12.21	18.55
37	SIE	So Idaho Ex(P)	14.88	30.22	45.56	21.80	37.14	52.47
38	TDN	T&D Eff PPL						
39	TDU	T&D Eff UPL						
40	TSB	Tri-State Basic	14.88	30.22	45.56	21.80	37.14	52.47
41	TSE	Tri-State Ex(P)	14.88	30.22	45.56	21.80	37.14	52.47
42	USB	USBR Greenspring						
43	WAS	WWP Sandpoint	4.89	11.23	17.56	5.88	12.21	18.55
44	WAW	WWP	4.89	11.23	17.56	5.88	12.21	18.55
45	WFC	Wind FC & Rtl Snake						
46	WTR	Water Budget						
47	WYD	Wyodak	18.69	37.23	55.77	27.89	46.43	64.97
48	CPU	Cal Potential Unit	4.89	11.23	17.56	5.88	12.21	18.55
49	OC1	OWC Cogeneration 1	3.76	8.62	13.49	4.52	9.38	14.25
50	OC2	OWC Cogeneration 2	4.64	10.66	16.68	5.58	11.60	17.62
51	OCC	OWC Combined Cycle	4.89	11.23	17.56	5.88	12.21	18.55
52	OCT	OWC Simple Cycle CT	7.20	16.53	25.87	8.66	17.99	27.32
53	OCV	OWC CC CT Convert	4.89	11.23	17.56	5.88	12.21	18.55
54	OGT	OWC Geothermal						
55	OPS	OWC Pump Storage						
56	OW1	OWC Wind w Tax C						
57	OW2	OWC Wind w/o Tax C						
58	UC1	Utah Cogeneration 1	3.76	8.62	13.49	4.52	9.38	14.25
59	UC2	Utah Cogeneration 2	4.64	10.66	16.68	5.58	11.60	17.62
60	UCC	Utah Combined Cycle	4.89	11.23	17.56	5.88	12.21	18.55
61	UCT	Utah Simple Cycle CT	7.20	16.53	25.87	8.66	17.99	27.32
62	UCV	Utah CC CT Convert	4.89	11.23	17.56	5.88	12.21	18.55
63	UCY	Utah IG CC	9.01	22.05	35.10	9.46	22.51	35.55
64	UFB	Utah FB Coal	10.95	25.13	39.30	13.14	27.31	41.49
65	UGC	Utah Coal	14.88	30.22	45.56	21.80	37.14	52.47
66	UGT	Utah Geothermal						
67	UPS	Utah Pumped Storage						
68	USL	Utah Solar						
69	UW1	Utah Wind w Tax C						
70	UW2	Utah Wind w/o Tax C						
71	WCC	Wyo Combined Cycle	4.89	11.23	17.56	5.88	12.21	18.55
72	WCT	Wyo Simple Cycle CT	7.20	16.53	25.87	8.66	17.99	27.32
73	WCV	Wyo CC CT Convert	4.89	11.23	17.56	5.88	12.21	18.55
74	WCY	Wyo IG CC	9.14	22.38	35.61	9.60	22.84	36.07
75	WFB	Wyo FB Coal	11.18	25.66	40.13	13.41	27.89	42.36
76	WGC	Wyo Coal	16.85	34.22	51.59	24.68	42.05	59.42
77	WW1	Wyo Wind w Tax C						
78	WW2	Wyo Wind w/o Tax C						

Backup to Table 8-1 in the Report (Environmental Costs)

Table 5-61

Variable O & M (Mills/kWh)

#	Name	Resource Description	Current	Low NOx and TSP Low CO2	Low NOx and TSP Med CO2	Low NOx and TSP High CO2	High NOx and TSP Low CO2	High NOx and TSP Med CO2	High NOx and TSP High CO2
1	APS	APS Sec CTs	14.49	19.68	26.41	33.13	20.73	27.46	34.18
2	APT	APS NEW CTs	3.50	9.33	16.88	24.42	10.50	18.05	25.60
3	ASE	APS Sea Ex(P)		4.89	11.23	17.56	5.88	12.21	18.55
4	BHC	Black Hills CT 1,2,		9.90	21.91	33.93	12.72	24.73	36.75
5	BLU	Blundell Geothermal		0.00	0.00	0.00	0.00	0.00	0.00
6	BPA	BPA Peaking		0.00	0.00	0.00	0.00	0.00	0.00
7	BPS	BPA Supp Capacity		0.00	0.00	0.00	0.00	0.00	0.00
8	CAR	Carbon 1,2		16.43	32.92	49.41	24.37	40.86	57.35
9	CEN	Centralia 1,2		15.70	32.14	48.58	22.75	39.19	55.64
10	CHL	Cholla 4		16.11	32.60	49.10	23.53	40.02	56.51
11	CLS	Colstrip 3,4		16.33	33.26	50.19	23.73	40.66	57.59
12	CRG	Craig 1,2		16.02	32.63	49.23	23.28	39.89	56.50
13	CRM	Cal Res Margin Unit		0.00	0.00	0.00	0.00	0.00	0.00
14	CSH	CSPE		0.00	0.00	0.00	0.00	0.00	0.00
15	DES	Deseret	19.50	34.38	49.72	65.06	41.30	56.64	71.97
16	DJN	Dave Johnston 1,2,3		17.83	35.93	54.03	26.24	44.35	62.45
17	GDS	Gadsby 1,2,3		9.02	19.08	29.15	12.46	22.53	32.59
18	GRT	Grant County		0.00	0.00	0.00	0.00	0.00	0.00
19	GST	Gem State		14.88	30.22	45.56	21.80	37.14	52.47
20	HAN	Hanford WNP 1	46.09	46.09	46.09	46.09	46.09	46.09	46.09
21	HAY	Hayden 1,2		15.83	32.25	48.66	23.01	39.42	55.84
22	HTN	Huntington 1,2		15.22	30.91	46.60	22.21	37.90	53.59
23	HTR	Hunter 1,2,3		16.30	33.19	50.09	23.65	40.55	57.44
24	HYD	Hydro Pacific		0.00	0.00	0.00	0.00	0.00	0.00
25	HYU	Hydro Utah		0.00	0.00	0.00	0.00	0.00	0.00
26	JBR	Jim Bridger 1,2,3,4		15.57	31.32	47.06	22.89	38.63	54.38
27	JRV	James River		2.99	6.87	10.75	3.60	7.47	11.35
28	LTL	Little Mountain	22.00	26.89	33.23	39.56	27.88	34.21	40.55
29	MID	Mid-Columbia		0.00	0.00	0.00	0.00	0.00	0.00
30	MPC	Montana Power Comp	46.21	61.09	76.43	91.77	68.01	83.35	98.68
31	NAU	Naughton 1,2,3		15.90	32.05	48.20	23.33	39.48	55.64
32	PGE	PGE Cove		0.00	0.00	0.00	0.00	0.00	0.00
33	QFN	QF NW		4.89	11.23	17.56	5.88	12.21	18.55
34	QFU	QF UPL		4.89	11.23	17.56	5.88	12.21	18.55
35	RFF	Request for Proposal	22.69	27.58	33.92	40.25	28.57	34.90	41.24
36	SCE	SCE Winter	39.91	44.80	51.14	57.47	45.79	52.12	58.46
37	SIE	So Idaho Ex(P)		14.88	30.22	45.56	21.80	37.14	52.47
38	TDN	T&D Eff PPL		0.00	0.00	0.00	0.00	0.00	0.00
39	TDU	T&D Eff UPL		0.00	0.00	0.00	0.00	0.00	0.00
40	TSB	Tri-State Basic	12.94	27.82	43.16	58.50	34.74	50.08	65.41
41	TSE	Tri-State Ex(P)		14.88	30.22	45.56	21.80	37.14	52.47
42	USB	USBR Greenspring	5.81	5.81	5.81	5.81	5.81	5.81	5.81
43	WAS	WWP Sandpoint		4.89	11.23	17.56	5.88	12.21	18.55
44	WAW	WWP	22.00	26.89	33.23	39.56	27.88	34.21	40.55
45	WFC	Wind FC & Rtl Snake	11.58	11.58	11.58	11.58	11.58	11.58	11.58
46	WTR	Water Budget		0.00	0.00	0.00	0.00	0.00	0.00
47	WYD	Wyodak		18.69	37.23	55.77	27.89	46.43	64.97
48	CPU	Cal Potential Unit	200.00	204.9	211.2	217.6	205.9	212.2	218.6
49	OC1	OWC Cogeneration 1	0.50	4.26	9.12	13.99	5.02	9.88	14.75
50	OC2	OWC Cogeneration 2	0.50	5.14	11.16	17.18	6.08	12.10	18.12
51	OCC	OWC Combined Cycle	1.00	5.89	12.23	18.56	6.88	13.21	19.55
52	OCT	OWC Simple Cycle CT	7.00	14.20	23.53	32.87	15.66	24.99	34.32
53	OCV	OWC CC CT Convert	1.00	5.89	12.23	18.56	6.88	13.21	19.55
54	OGT	OWC Geothermal	1.00	1.00	1.00	1.00	1.00	1.00	1.00
55	OPS	OWC Pump Storage		0.00	0.00	0.00	0.00	0.00	0.00
56	OW1	OWC Wind w Tax C	4.20	4.20	4.20	4.20	4.20	4.20	4.20
57	OW2	OWC Wind w/o Tax C	4.20	4.20	4.20	4.20	4.20	4.20	4.20
58	UC1	Utah Cogeneration 1	0.50	4.26	9.12	13.99	5.02	9.88	14.75
59	UC2	Utah Cogeneration 2	0.50	5.14	11.16	17.18	6.08	12.10	18.12
60	UCC	Utah Combined Cycle	1.00	5.89	12.23	18.56	6.88	13.21	19.55
61	UCT	Utah Simple Cycle CT	7.00	14.20	23.53	32.87	15.66	24.99	34.32
62	UCV	Utah CC CT Convert	1.00	5.89	12.23	18.56	6.88	13.21	19.55
63	UCY	Utah IG CC	1.00	10.01	23.05	36.10	10.46	23.51	36.55
64	UFB	Utah FB Coal	0.50	11.45	25.63	39.80	13.64	27.81	41.99
65	UGC	Utah Coal	0.24	15.12	30.46	45.80	22.04	37.38	52.71
66	UGT	Utah Geothermal	1.00	1.00	1.00	1.00	1.00	1.00	1.00
67	UPS	Utah Pumped Storage		0.00	0.00	0.00	0.00	0.00	0.00
68	USL	Utah Solar		0.00	0.00	0.00	0.00	0.00	0.00
69	UW1	Utah Wind w Tax C	4.20	4.20	4.20	4.20	4.20	4.20	4.20
70	UW2	Utah Wind w/o Tax C	4.20	4.20	4.20	4.20	4.20	4.20	4.20
71	WCC	Wyo Combined Cycle	1.00	5.89	12.23	18.56	6.88	13.21	19.55
72	WCT	Wyo Simple Cycle CT	7.00	14.20	23.53	32.87	15.66	24.99	34.32
73	WCV	Wyo CC CT Convert	1.00	5.89	12.23	18.56	6.88	13.21	19.55
74	WCY	Wyo IG CC	1.00	10.14	23.38	36.61	10.60	23.84	37.07
75	WFB	Wyo FB Coal	0.50	11.68	26.16	40.63	13.91	28.39	42.86
76	WGC	Wyo Coal	0.24	17.09	34.46	51.83	24.92	42.29	59.66
77	WW1	Wyo Wind w Tax C	4.20	4.20	4.20	4.20	4.20	4.20	4.20
78	WW2	Wyo Wind w/o Tax C	4.20	4.20	4.20	4.20	4.20	4.20	4.20

Load Segment Definitions

Table 5-62

Segment	Winter		Spring		Summer		Fall	
	%	Hours	%	Hours	%	Hours	%	Hours
BRI, OWC, CAL Regions								
1	2.1%	45.4	1.1%	24.3	1.4%	30.9	2.1%	45.9
2	9.3%	200.9	5.0%	110.4	15.9%	351.1	6.0%	131.0
3	22.7%	490.3	18.1%	399.6	29.7%	655.8	12.8%	279.6
4	40.5%	874.8	43.0%	949.4	45.3%	1000.2	36.6%	799.3
5	57.0%	1231.2	57.0%	1258.6	57.0%	1258.6	57.0%	1244.9
6	71.8%	1550.9	75.9%	1675.9	71.6%	1580.9	78.3%	1710.1
7	96.8%	2090.9	98.5%	2174.9	95.6%	2110.8	98.4%	2149.1
8	**100.0%**	**2160.0**	**100.0%**	**2208.0**	**100.0%**	**2208.0**	**100.0%**	**2184.0**
UTA, DSW Regions								
1	2.3%	49.7	1.4%	30.9	2.3%	50.8	2.3%	50.2
2	9.3%	200.9	2.9%	64.0	6.8%	150.1	9.2%	200.9
3	33.3%	719.3	22.6%	499.0	16.1%	355.5	22.9%	500.1
4	46.3%	1000.1	39.6%	874.4	36.2%	799.3	38.5%	840.8
5	57.0%	1231.2	57.0%	1258.6	57.0%	1258.6	57.0%	1244.9
6	76.9%	1661.0	78.8%	1739.9	77.0%	1700.2	77.8%	1699.2
7	93.5%	2019.6	97.4%	2150.6	91.5%	2020.3	98.4%	2149.1
8	**100.0%**	**2160.0**	**100.0%**	**2208.0**	**100.0%**	**2208.0**	**100.0%**	**2184.0**
WYO Region								
1	3.2%	69.1	2.3%	50.8	1.4%	30.9	1.1%	24.0
2	11.6%	250.6	15.9%	351.1	13.6%	300.3	11.4%	249.0
3	25.2%	544.3	27.2%	600.6	29.4%	649.2	25.2%	550.4
4	44.0%	950.4	45.3%	1000.2	43.0%	949.4	38.9%	849.6
5	57.0%	1231.2	57.0%	1258.6	57.0%	1258.6	57.0%	1244.9
6	73.1%	1579.0	77.0%	1700.2	83.6%	1845.9	82.4%	1799.6
7	95.4%	2060.6	96.9%	2139.6	97.4%	2150.6	96.6%	2109.7
8	**100.0%**	**2160.0**	**100.0%**	**2208.0**	**100.0%**	**2208.0**	**100.0%**	**2184.0**

Key Forecast Information by Region

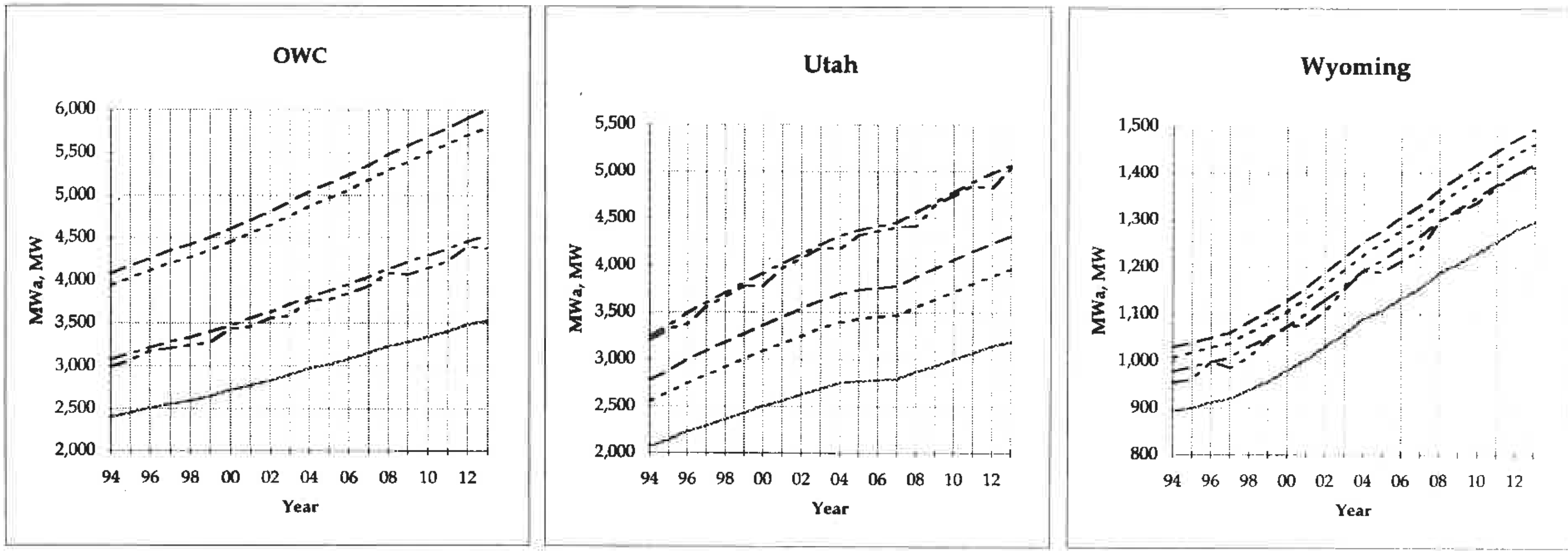
Table 5-63

Forecast	Energy			Coincidental Peaks						Noncoincidental Peaks					
				Winter Peaks			Summer Peaks			Winter Peaks			Summer Peaks		
	Growth Rate (%)	MWa at 2013	Total MWa Added	Growth Rate (%)	MW at 2013	Total MW Added	Growth Rate (%)	MW at 2013	Total MW Added	Growth Rate (%)	MW at 2013	Total MW Added	Growth Rate (%)	MW at 2013	Total MW Added
OWC															
Low	0.23	2,338	100	0.23	3,846	165	0.31	2,937	166	0.23	3,979	170	0.24	3,002	131
Medium Low	1.25	2,942	616	1.25	4,839	1,015	1.28	3,698	794	1.25	5,007	1,050	1.25	3,778	796
Reduced Load	1.23	2,919	606	1.23	4,801	996	1.27	3,669	781						
Medium	2.05	3,523	1,128	2.05	5,797	1,857	2.02	4,376	1,384	2.05	5,999	1,923	2.06	4,528	1,457
Economic Development	2.57	3,881	1,482	2.57	6,385	2,440	2.53	4,820	1,824						
Medium High	2.91	4,242	1,782	2.85	6,978	2,884	2.99	5,323	2,281	2.91	7,219	3,034	2.91	5,439	2,287
High	3.62	5,002	2,457	3.56	8,229	3,992	3.65	6,276	3,098	3.62	8,513	4,182	3.62	6,415	3,153
Electrification	4.43	5,599	3,140	4.41	9,293	5,199	4.50	7,025	3,983						
Utah															
Low	0.27	2,054	102	0.30	2,551	142	0.30	3,203	175	0.30	2,780	156	0.31	3,241	185
Medium Low	1.29	2,569	554	1.31	3,184	698	1.33	4,005	888	1.31	3,470	761	1.32	4,052	896
Reduced Load	2.06	3,016	970	2.10	3,743	1,219	2.15	4,745	1,579						
Medium	2.30	3,180	1,114	2.33	3,948	1,398	2.41	5,035	1,834	2.33	4,305	1,526	2.38	5,067	1,828
Economic Development	2.67	3,412	1,344	2.70	4,235	1,683	2.79	5,402	2,198						
Medium High	3.37	3,951	1,844	3.35	4,894	2,275	3.40	6,177	2,902	3.39	5,335	2,502	3.41	6,248	2,945
High	4.19	4,754	2,574	4.16	5,885	3,170	4.24	7,434	4,057	4.21	6,415	3,483	4.24	7,522	4,105
Electrification	4.76	5,096	2,989	4.90	6,502	3,883	4.79	7,968	4,693						
Wyoming															
Low	0.73	981	126	0.73	1,107	142	0.63	1,054	119	0.73	1,132	146	0.73	1,076	138
Medium Low	1.21	1,110	226	1.21	1,254	256	1.19	1,191	240	1.21	1,281	261	1.21	1,218	248
Reduced Load	1.86	1,261	373	1.86	1,423	421	1.83	1,349	394						
Medium	1.98	1,294	402	1.98	1,461	454	2.09	1,412	458	1.98	1,493	464	1.98	1,420	441
Economic Development	1.98	1,294	402	1.98	1,461	454	2.09	1,412	458						
Medium High	2.43	1,432	525	2.60	1,616	623	2.35	1,537	548	2.43	1,652	606	2.43	1,571	576
High	2.98	1,626	694	3.13	1,835	813	3.00	1,746	751	2.98	1,875	801	2.97	1,783	761
Electrification	3.94	1,890	983	3.95	2,072	1,079	3.83	2,019	1,030						
Total System															
Low	0.33	5,373	328	0.33	7,504	449	0.35	7,194	460	0.33	7,891	472	0.34	7,319	454
Medium Low	1.26	6,621	1,397	1.26	9,277	1,969	1.29	8,894	1,922	1.26	9,758	2,072	1.28	9,048	1,940
Reduced Load	1.68	7,195	1,949	1.63	9,967	2,636	1.76	9,763	2,754						
Medium	2.13	7,998	2,644	2.14	11,206	3,709	2.21	10,823	3,676	2.14	11,797	3,913	2.20	11,015	3,726
Economic Development	2.51	8,587	3,228	2.54	12,081	4,577	2.59	11,633	4,480						
Medium High	3.02	9,624	4,151	2.99	13,488	5,782	3.09	13,037	5,731	3.03	14,206	6,142	3.08	13,258	5,808
High	3.75	11,381	5,725	3.72	15,949	7,975	3.84	15,456	7,906	2.98	1,875	801	2.97	1,783	761
Electrification	4.48	12,584	7,112	4.53	17,867	10,161	4.55	17,012	9,706						

Energy, Winter Peaks and Summer Peaks by Region

(Medium Load Growth)

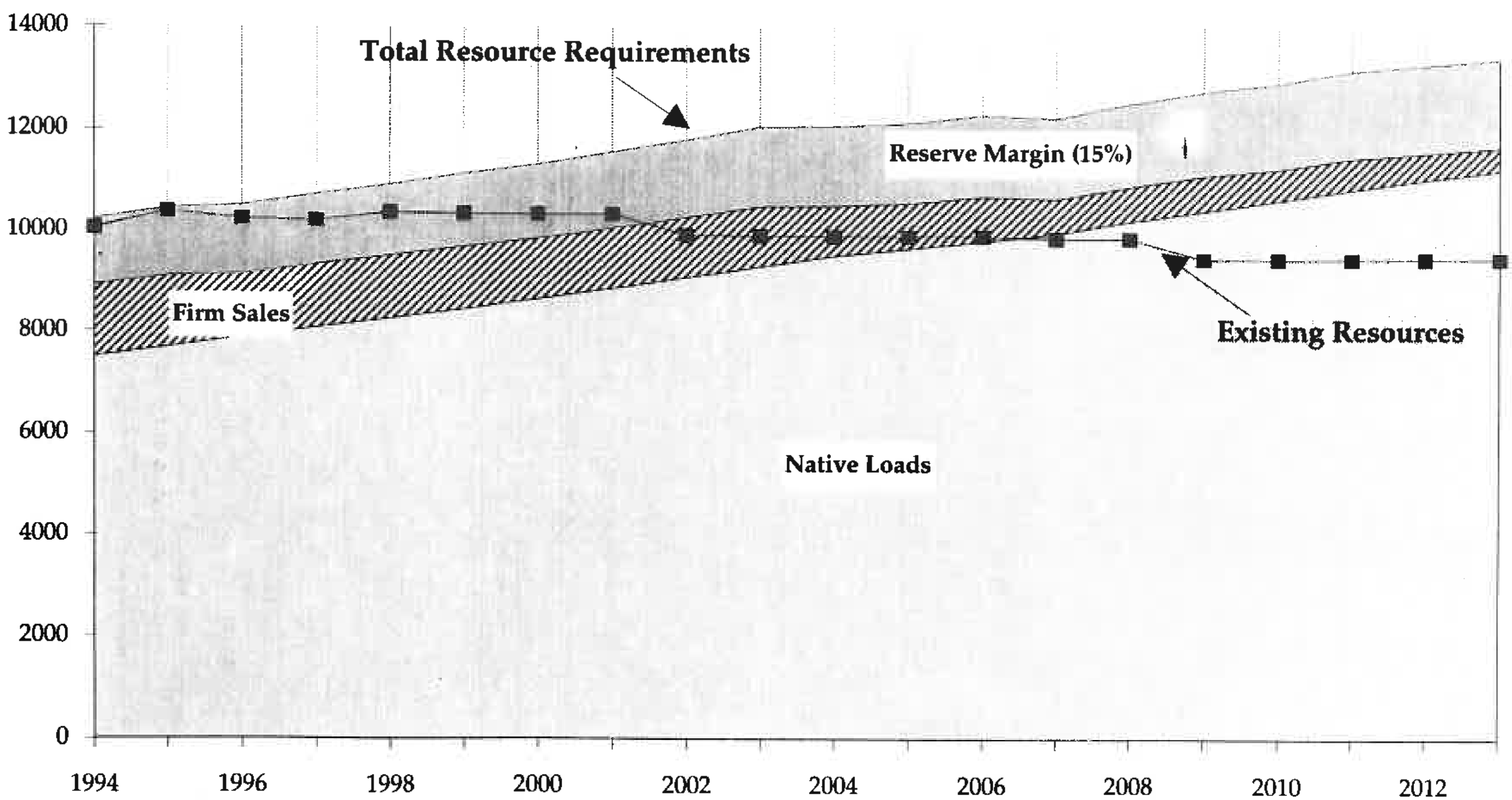
Table 5-64



Energy ——— **Winter Peaks** Coincidental — — — — Non-Coincidental - - - - - - - - **Summer Peaks** Coincidental — - — - — Non-Coincidental — - - — - -

Total Resource Requirements and Existing Resources
Winter Peaks of Medium Load Level

Graph 5-65



Section 6

Detailed Model Output

(Selected Representative Outputs)

Load = l Gas = mg DSR = md Coal = ac Renewables = ar

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,344	5,343	5,377	5,323	5,312	5,321	5,386	5,395	5,483	5,568	5,644	5,672
			Conservation (MWa)	20	43	72	109	152	183	215	248	307	384	449	498
			After Conservation												
			System Load (MWa)	5,324	5,300	5,304	5,215	5,160	5,139	5,171	5,147	5,176	5,184	5,195	5,174
	-0.08		**Energy Sales (MWa)**	4,817	4,797	4,774	4,719	4,665	4,642	4,640	4,642	4,662	4,660	4,663	4,636
			Total Customers (000's)	1,259	1,249	1,242	1,236	1,233	1,234	1,238	1,243	1,252	1,263	1,271	1,274
			Net Electric Plant ($M)	7,746	8,027	8,256	8,470	8,778	9,089	9,421	9,762	10,432	11,608	12,798	14,587
			Net Conservation Assets ($M)	57	113	175	243	327	398	478	552	641	711	729	636
			Utility Cost												
38,040	3.59	Nominal	**Operating Revenues ($M)**	2,075	2,195	2,224	2,253	2,272	2,355	2,397	2,440	2,558	2,795	3,233	3,778
	0.19	Real		2,075	2,122	2,080	2,038	1,987	1,993	1,961	1,931	1,894	1,871	1,958	2,002
	3.67	Nominal	Cost in mills/kWh	49.2	52.2	53.2	54.5	55.6	57.9	59.0	60.0	62.7	68.5	79.2	93.0
	0.27	Real		49.2	50.5	49.7	49.3	48.6	49.0	48.3	47.5	46.4	45.9	47.9	49.3
		Nominal	Average Customer Bill ($)	1,648	1,757	1,790	1,823	1,843	1,908	1,935	1,963	2,044	2,213	2,543	2,966
		Real		1,648	1,699	1,674	1,649	1,613	1,615	1,584	1,554	1,513	1,482	1,540	1,572
			Total Resource Cost												
			DSR Customer Cost ($M)	3.5	5.2	6.0	7.9	9.1	56.8	71.8	88.9	78.6	66.3	75.7	63.7
			Levelized (20-year at 8.8%)	0.4	0.9	1.6	2.5	3.4	9.6	17.3	26.9	43.6	67.1	92.2	122.5
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	25.7	32.1	39.6	55.4	78.4	98.0	105.1
39,310	3.70	Nominal	**Total Resource Cost ($M)**	2,079	2,203	2,237	2,271	2,296	2,390	2,446	2,506	2,657	2,941	3,424	4,006
	0.29	Real		2,079	2,131	2,093	2,054	2,008	2,022	2,002	1,983	1,967	1,969	2,073	2,122
	3.59	Nominal	Cost in mills/kWh	49.1	52.0	52.8	53.8	54.6	56.7	57.7	58.8	61.4	67.0	77.0	89.8
	0.18	Real		49.1	50.3	49.4	48.7	47.7	48.0	47.2	46.5	45.4	44.9	46.7	47.6

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 50.07

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 48.63

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Load = l Gas = mg DSR = md Coal = ac Renewables = ar

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	64,447	64,693	64,158	63,659	63,396	63,221	63,563	63,563	63,817	63,431	61,942	61,828
	MWa	7,357	7,385	7,324	7,267	7,237	7,217	7,256	7,256	7,285	7,241	7,071	7,058
	Total Annual Emissions (1000 Tons)												
0.17%	CO2	53,137	53,591	54,101	53,719	53,697	53,558	53,829	53,961	54,339	54,082	54,995	54,946
-0.76%	NOx	136.2	137.3	138.5	137.8	137.6	137.4	114.6	114.9	115.7	115.2	117.1	117.0
0.13%	TSP	10.2	10.2	10.3	10.2	10.2	10.2	10.2	10.2	10.3	10.3	10.5	10.4
	Annual System Emission Rates (Pounds/MWh)												
0.40%	CO2	1,649	1,657	1,686	1,688	1,694	1,694	1,694	1,698	1,703	1,705	1,776	1,777
-0.58%	NOx	4.23	4.24	4.32	4.33	4.34	4.35	3.61	3.62	3.63	3.63	3.78	3.78
0.35%	TSP	0.32	0.31	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.34	0.34
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.47	102.27	102.35	102.73	102.75	102.71	102.97	103.27	103.41	107.68	107.79
	NOx	100	100.40	102.14	102.39	102.70	102.80	85.33	85.56	85.81	85.89	89.44	89.52
	TSP	100	99.71	101.62	101.73	102.02	102.12	101.73	101.96	102.62	102.39	107.10	106.90

20 Year Emissions (1000 Tons)	Average	Total
CO2	54,226	1,084,516
NOx	122.4	2,449
TSP	10.3	206

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Case # 2

Load = l Gas = mg DSR = md Coal = ac Renewables = ar

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	24.9	23.9	26.3	36.7	38.3	45.5	45.8	53.1	55.9	41.6	33.3	449.7
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1													0.0
W	OWC Cogen 2													0.0
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage													0.0
	Total	**24.4**	**24.9**	[illegible]	**26.3**	**36.7**	**38.3**	**45.5**	**45.8**	**53.1**	**55.9**	**41.6**	**33.3**	**449.7**
	DSR	8.9	10.1	14.1	19.1	20.1	22.1	21.6	21.9	41.3	60.7	55.2	36.1	331.2
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal													0.0
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT													0.0
	Utah Pumped Storage													0.0
	Total	**8.9**	**10.1**	**14.1**	**19.1**	**20.1**	**22.1**	**21.6**	**21.9**	**41.3**	**60.7**	**55.2**	**36.1**	**331.2**
	DSR	1.8	1.1	3.9	5.0	6.1	5.3	4.9	4.9	9.5	14.4	14.2	12.0	83.1
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.1**	**3.9**	**5.0**	**6.1**	**5.3**	**4.9**	**4.9**	**9.5**	**14.4**	**14.2**	**12.0**	**83.1**
	DSR	35.1	36.1	41.9	50.4	62.9	65.7	72.0	72.6	103.9	131.0	111.0	81.4	864.0
T	Renewable													0.0
O	Cogen													0.0
T	Combined Cycle CT													0.0
A	Coal													0.0
L	Simple Cycle CT													0.0
	Pumped Storage													0.0
	Total	**35.1**	**36.1**	**41.9**	**50.4**	**62.9**	**65.7**	**72.0**	**72.6**	**103.9**	**131.0**	**111.0**	**81.4**	**864.0**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7055	7050	7057	7034	7020	7035	7084	7137	7255	7370	7472	7504
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-113	-164	-226	-292	-364	-437	-541	-672	-783	-864
S	**Total Requirements**	**8415**	**8374**	**8189**	**8116**	**8039**	**7988**	**7915**	**7895**	**7909**	**7585**	**7376**	**7077**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	0	0	0	0	0	0	0	0	0
L	**Total Resources**	**10068**	**10393**	**10249**	**10218**	**10372**	**10354**	**10337**	**10337**	**9899**	**9901**	**9446**	**9458**
&													
R	Reserves	1652	2018	2059	2102	2332	2365	2421	2439	1987	2314	2068	2379
	Reserve Margin (RM) (%)	19.6	24.1	25.1	25.9	29.0	29.6	30.6	30.9	25.1	30.5	28.0	33.6
	Capacity Below 15% RM												

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Load = l Gas = mg DSR = md Coal = ac Renewables = ar

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.2	25.5	38.8	54.3	73.7	86.2	100.8	115.3	139.3	165.6	183.7	198.5
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1												
C	OWC Cogen 2												
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	Total	**12.2**	**25.5**	**38.8**	**54.3**	**73.7**	**86.2**	**100.8**	**115.3**	**139.3**	**165.6**	**183.7**	**198.5**
	DSR	6.8	15.2	27.4	43.4	61.1	74.7	88.4	102.4	128.7	167.2	200.9	225.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage												
	Total	**6.8**	**15.2**	**27.4**	**43.4**	**61.1**	**74.7**	**88.4**	**102.4**	**128.7**	**167.2**	**200.9**	**225.0**
	DSR	1.3	2.3	6.1	10.9	16.9	21.7	26.0	30.4	38.8	51.6	64.0	74.4
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.3**	**2.3**	**6.1**	**10.9**	**16.9**	**21.7**	**26.0**	**30.4**	**38.8**	**51.6**	**64.0**	**74.4**
	DSR	20.3	43.0	72.3	108.6	151.7	182.6	215.2	248.1	306.8	384.4	448.6	497.9
T	Renewable												
O	Cogen												
T	Combined Cycle CT												
A	Coal												
L	Simple Cycle CT												
	Pumped Storage												
	Total	**20.3**	**43.0**	**72.3**	**108.6**	**151.7**	**182.6**	**215.2**	**248.1**	**306.8**	**384.4**	**448.6**	**497.9**
	Native Load	5045	5044	5077	5024	5013	5022	5086	5096	5183	5269	5345	5373
S	Pumped Storage	312	311	310	310	309	307	306	306	306	305	305	305
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	536	591	569	585	610	592	620	667	690	831	826	1036
T	DSR	-20	-43	-72	-109	-152	-183	-215	-248	-307	-384	-449	-498
E	**Total Requirements**	**7356**	**7383**	**7322**	**7265**	**7235**	**7215**	**7253**	**7255**	**7282**	**7241**	**7070**	**7057**
M													
	Existing Generation	6664	6731	6831	6807	6810	6798	6836	6853	6902	6881	6739	6735
L	Firm Purchases	623	608	440	423	407	399	389	385	363	360	336	335
&	Non-Firm Purchases	70	44	52	50	32	32	43	31	32	12	9	
R	New Resources												
	Total Resources	7357	7383	7323	7280	7249	7229	7268	7269	7297	7253	7084	7070

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Load = l Gas = mg DSR = md Coal = ac Renewables = ar

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	49.0	45.0	43.0	43.0	44.0	44.0	44.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
	OWC Geothermal												
O	OWC Cogen 1												
W	OWC Cogen 2												
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	DSR	76.0	80.0	82.0	83.0	84.0	79.0	76.0	74.0	71.0	69.0	68.0	68.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage												
	DSR	76.0	81.0	89.0	92.0	94.0	93.0	92.0	92.0	91.0	90.0	90.0	89.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.5	71.5	71.9	71.4	71.4	71.4	71.8	71.4	71.4	71.5	71.5	71.6
	Existing Generation	73.3	72.2	72.8	72.4	71.3	71.1	71.5	71.6	72.0	71.8	73.4	73.2
	New Resources												
	DSR	57.8	60.4	63.9	66.4	67.0	62.5	59.1	56.8	56.8	57.2	57.3	57.6

Load = ml Gas = mg DSR = md Coal = ac Renewables = ar

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,523	5,586	5,682	5,703	5,760	5,821	5,929	5,977	6,154	6,387	6,634	6,920
			Conservation (MWa)	20	43	72	109	152	186	223	259	325	414	487	548
			After Conservation												
			System Load (MWa)	5,502	5,542	5,609	5,594	5,608	5,635	5,707	5,718	5,829	5,974	6,147	6,372
	0.31		Energy Sales (MWa)	4,978	5,015	5,047	5,061	5,074	5,099	5,135	5,175	5,278	5,412	5,573	5,783
			Total Customers (000's)	1,281	1,283	1,287	1,290	1,297	1,308	1,321	1,334	1,361	1,400	1,439	1,485
			Net Electric Plant ($M)	7,747	8,027	8,256	8,485	8,819	9,206	9,686	10,236	11,186	12,544	14,301	16,199
			Net Conservation Assets ($M)	57	113	175	243	328	412	504	590	697	789	825	751
			Utility Cost												
41,419	3.74	Nominal	**Operating Revenues ($M)**	2,103	2,232	2,276	2,322	2,358	2,459	2,519	2,580	2,724	3,122	3,674	4,528
	0.33	Real		2,103	2,159	2,129	2,100	2,063	2,080	2,061	2,042	2,016	2,090	2,225	2,399
	3.42	Nominal	Cost in mills/kWh	48.2	50.8	51.5	52.4	53.0	55.1	56.0	56.9	58.9	65.9	75.3	89.4
	0.02	Real		48.2	49.1	48.2	47.4	46.4	46.6	45.8	45.0	43.6	44.1	45.6	47.4
		Nominal	Average Customer Bill ($)	1,641	1,739	1,768	1,800	1,818	1,880	1,907	1,934	2,002	2,230	2,554	3,049
		Real		1,641	1,682	1,654	1,628	1,590	1,591	1,561	1,531	1,482	1,493	1,546	1,615
			Total Resource Cost												
			DSR Customer Cost ($M)	3.5	5.3	6.1	8.0	9.3	61.3	76.7	79.3	80.8	71.1	76.8	71.0
			Levelized (20-year at 8.8%)	0.4	0.9	1.6	2.5	3.5	10.1	18.4	27.0	44.1	68.7	93.0	125.0
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	26.6	33.9	42.5	60.2	86.5	109.4	121.7
42,760	3.84	Nominal	**Total Resource Cost ($M)**	2,107	2,241	2,289	2,340	2,382	2,496	2,572	2,650	2,829	3,277	3,877	4,775
	0.42	Real		2,107	2,167	2,141	2,117	2,084	2,111	2,104	2,097	2,094	2,194	2,348	2,530
	3.35	Nominal	Cost in mills/kWh	48.1	50.6	51.1	51.8	52.1	54.1	55.0	55.9	57.9	64.6	73.5	86.7
	-0.05	Real		48.1	49.0	47.8	46.8	45.6	45.7	45.0	44.2	42.9	43.3	44.5	45.9

Notes:

3) 50-year Real Levelized

4) 50-year Real Levelized

Load = ml Gas = mg DSR = md Coal = ac Renewables = ar

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	65,420	65,980	65,814	65,569	65,788	65,884	66,278	66,357	67,548	67,908	68,214	69,248
	MWa	7,468	7,532	7,513	7,485	7,510	7,521	7,566	7,575	7,711	7,752	7,787	7,905
	Total Annual Emissions (1000 Tons)												
0.55%	CO_2	53,744	54,376	55,269	55,021	55,179	55,221	55,724	55,837	57,599	57,927	59,538	59,943
-0.41%	NO_x	138.3	139.7	142.1	141.6	141.7	141.8	118.5	118.8	122.7	123.4	126.7	127.5
0.32%	TSP	10.3	10.3	10.5	10.5	10.5	10.5	10.6	10.6	10.7	10.8	10.9	11.0
	Annual System Emission Rates (Pounds/MWh)												
0.28%	CO_2	1,643	1,648	1,680	1,678	1,677	1,676	1,682	1,683	1,705	1,706	1,746	1,731
-0.72%	NO_x	4.23	4.24	4.32	4.32	4.31	4.31	3.58	3.58	3.63	3.63	3.71	3.68
0.04%	TSP	0.32	0.31	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.32
	Emission Rates as Percent of 1994 Base												
	CO_2	100	100.32	102.22	102.14	102.10	102.02	102.34	102.43	103.79	103.83	106.24	105.37
	NO_x	100	100.18	102.11	102.14	101.91	101.84	84.61	84.68	85.95	85.94	87.87	87.09
	TSP	100	99.48	101.74	101.75	101.60	101.46	101.34	101.36	100.91	100.75	101.88	100.72

20 Year Emissions (1000 Tons)	Average	Total
CO_2	57,215	1,144,308
NO_x	129.1	2,581
TSP	10.7	214

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Case # 7

Load = ml Gas = mg DSR = md Coal = ac Renewables = ar

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.4	36.8	41.9	49.1	49.2	59.8	67.1	53.9	51.3	509.0
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1													0.0
W	OWC Cogen 2													0.0
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage													0.0
	Total	**24.4**	**25.0**	**24.1**	**26.4**	**36.8**	**41.9**	**49.1**	**49.2**	**59.8**	**67.1**	**53.9**	**51.3**	**509.0**
	DSR	8.9	10.1	14.1	19.1	20.1	24.1	23.6	23.9	45.4	66.7	59.9	41.0	356.9
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal									242.8		136.5		379.3
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT													0.0
	Utah Pumped Storage											185.0	50.4	235.4
	Total	**8.9**	**10.1**	**14.1**	**19.1**	**20.1**	**24.1**	**23.6**	**23.9**	**288.2**	**66.7**	**381.4**	**91.4**	**971.6**
	DSR	1.8	1.1	3.9	5.0	6.2	5.7	5.3	5.4	10.5	16.0	15.6	13.3	89.8
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.1**	**3.9**	**5.0**	**6.2**	**5.7**	**5.3**	**5.4**	**10.5**	**16.0**	**15.6**	**13.3**	**89.8**
	DSR	35.1	36.2	42.1	50.5	63.1	71.7	78.0	78.5	115.7	149.8	129.4	105.6	955.7
T	Renewable													0.0
O	Cogen													0.0
T	Combined Cycle CT													0.0
A	Coal									242.8		136.5		379.3
L	Simple Cycle CT													0.0
	Pumped Storage											185.0	50.4	235.4
	Total	**35.1**	**36.2**	**42.1**	**50.5**	**63.1**	**71.7**	**78.0**	**78.5**	**358.5**	**149.8**	**450.9**	**156.0**	**1570.4**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7308	7395	7487	7568	7647	7732	7838	7950	8194	8520	8867	9277
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-113	-164	-227	-299	-377	-455	-571	-721	-850	-956
S	**Total Requirements**	**8668**	**8719**	**8619**	**8649**	**8665**	**8678**	**8656**	**8690**	**8818**	**8686**	**8704**	**8758**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	0	0	0	0	0	243	243	564	615
L	**Total Resources**	**10068**	**10393**	**10249**	**10218**	**10372**	**10354**	**10337**	**10337**	**10142**	**10144**	**10010**	**10073**
&													
R	Reserves	1399	1673	1629	1568	1706	1675	1679	1645	1322	1456	1305	1313
	Reserve Margin (RM) (%)	16.1	19.2	18.9	18.1	19.7	19.3	19.4	18.9	15.0	16.8	15.0	15.0
	Capacity Below 15% RM												

PacifiCorp RAMPP-3 **Case # 7**

Load = ml Gas = mg DSR = md Coal = ac Renewables = ar

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.2	25.6	38.9	54.4	73.9	87.7	103.8	119.6	146.3	176.6	198.7	219.1
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1												
C	OWC Cogen 2												
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	Total	**12.2**	**25.6**	**38.9**	**54.4**	**73.9**	**87.7**	**103.8**	**119.6**	**146.3**	**176.6**	**198.7**	**219.1**
	DSR	6.8	15.2	27.4	43.4	61.1	76.5	92.0	107.8	137.7	181.5	219.2	247.6
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal									222.5	222.5	347.6	347.6
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage											34.4	53.3
	Total	**6.8**	**15.2**	**27.4**	**43.4**	**61.1**	**76.5**	**92.0**	**107.8**	**360.2**	**404.0**	**601.2**	**648.5**
	DSR	1.4	2.4	6.1	10.9	16.9	22.1	26.9	31.8	41.2	55.4	69.2	80.9
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**10.9**	**16.9**	**22.1**	**26.9**	**31.8**	**41.2**	**55.4**	**69.2**	**80.9**
	DSR	20.4	43.2	72.4	108.7	151.9	186.3	222.7	259.2	325.2	413.5	487.1	547.6
T	Renewable												
O	Cogen												
T	Combined Cycle CT												
A	Coal									222.5	222.5	347.6	347.6
L	Simple Cycle CT												
	Pumped Storage											34.4	53.3
	Total	**20.4**	**43.2**	**72.4**	**108.7**	**151.9**	**186.3**	**222.7**	**259.2**	**547.7**	**636.0**	**869.1**	**948.5**
	Native Load	5224	5286	5382	5404	5461	5522	5630	5678	5855	6088	6335	6620
S	Pumped Storage	312	311	309	310	309	307	306	306	306	305	349	373
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	469	496	455	423	435	400	394	415	463	551	546	617
T	DSR	-20	-43	-72	-109	-152	-186	-223	-259	-325	-414	-487	-548
E	**Total Requirements**	7468	7530	7512	7483	7508	7520	7563	7574	7709	7751	7786	7903
M													
	Existing Generation	6730	6818	6954	6947	6970	6983	7052	7068	7051	7095	6921	6979
L	Firm Purchases	641	628	451	435	411	403	392	388	364	361	344	386
&	Non-Firm Purchases	96	84	107	116	141	148	134	132	85	86	152	152
R	New Resources									222	222	381	400
	Total Resources	7467	7530	7512	7498	7522	7534	7578	7588	7722	7764	7798	7917

PacifiCorp RAMPP-3

Case # 7

Load = ml Gas = mg DSR = md Coal = ac Renewables = ar

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	49.0	45.0	43.0	43.0	43.0	43.0	43.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
	OWC Geothermal												
O	OWC Cogen 1												
W	OWC Cogen 2												
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	DSR	76.0	80.0	82.0	83.0	84.0	79.0	76.0	74.0	72.0	70.0	69.0	69.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal									91.0	91.0	91.0	91.0
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage											18.0	22.0
	DSR	76.0	81.0	89.0	92.0	94.0	93.0	92.0	92.0	91.0	90.0	90.0	90.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.5	71.5	71.9	71.4	71.4	71.4	71.8	71.4	71.5	71.5	71.4	71.4
	Existing Generation	74.1	73.1	74.1	73.9	72.9	73.1	73.7	73.8	73.6	74.0	75.4	75.9
	New Resources									91.4	91.4	67.5	65.1
	DSR	58.1	60.6	63.8	66.3	66.9	62.4	59.1	56.9	57.0	57.4	57.3	57.3

Load = m Gas = lg DSR = md Coal = ac Renewables = ar

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		**Energy Sales (MWa)**	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,759	8,149	8,530	8,819	9,285	9,873	10,619	11,527	12,973	14,838	17,497	19,935
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
46,379	3.91	Nominal	**Operating Revenues ($M)**	2,135	2,266	2,339	2,400	2,497	2,621	2,724	2,828	3,019	3,637	4,233	5,503
	0.50	Real		2,135	2,192	2,188	2,171	2,184	2,217	2,229	2,238	2,235	2,435	2,563	2,916
	3.25	Nominal	Cost in mills/kWh	47.8	49.8	50.4	50.9	52.2	53.9	55.1	56.2	57.8	67.1	74.4	90.2
	-0.14	Real		47.8	48.2	47.2	46.1	45.6	45.6	45.1	44.4	42.8	44.9	45.1	47.8
		Nominal	Average Customer Bill ($)	1,631	1,714	1,751	1,779	1,826	1,885	1,924	1,965	2,030	2,332	2,591	3,191
		Real		1,631	1,657	1,638	1,609	1,597	1,595	1,575	1,555	1,502	1,561	1,569	1,690
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
47,945	4.02	Nominal	**Total Resource Cost ($M)**	2,139	2,275	2,353	2,419	2,521	2,659	2,780	2,905	3,136	3,814	4,467	5,794
	0.60	Real		2,139	2,200	2,201	2,188	2,205	2,250	2,275	2,298	2,321	2,554	2,705	3,070
	3.20	Nominal	Cost in mills/kWh	47.8	49.7	50.1	50.4	51.4	53.0	54.2	55.3	57.0	66.0	73.0	87.9
	-0.19	Real		47.8	48.0	46.8	45.6	44.9	44.9	44.3	43.8	42.2	44.2	44.2	46.6

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **46.17**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **45.13**

md ac ar financial

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Load = m Gas = lg DSR = md Coal = ac Renewables = ar

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,207	68,197	68,661	69,511	70,518	71,333	75,099	76,081	77,745	79,558
	MWa	7,549	7,664	7,672	7,785	7,838	7,935	8,050	8,143	8,573	8,685	8,875	9,082
	Total Annual Emissions (1000 Tons)												
1.14%	CO2	54,170	54,960	55,957	56,087	56,379	56,718	57,465	57,828	61,803	62,627	66,967	67,971
0.13%	NOx	139.6	141.4	143.8	142.8	143.3	143.5	120.3	121.0	130.1	131.7	141.3	143.1
0.50%	TSP	10.4	10.5	10.7	10.6	10.6	10.6	10.7	10.8	11.0	11.2	11.4	11.5
	Annual System Emission Rates (Pounds/MWh)												
0.22%	CO2	1,638	1,637	1,665	1,645	1,642	1,632	1,630	1,621	1,646	1,646	1,723	1,709
-0.84%	NOx	4.22	4.21	4.28	4.19	4.17	4.13	3.41	3.39	3.46	3.46	3.64	3.60
-0.45%	TSP	0.31	0.31	0.32	0.31	0.31	0.31	0.30	0.30	0.29	0.29	0.29	0.29
	Emission Rates as Percent of 1994 Base												
	CO2	100	99.94	101.64	100.40	100.24	99.61	99.48	98.97	100.46	100.49	105.15	104.30
	NOx	100	99.80	101.37	99.23	98.87	97.83	80.83	80.38	82.06	82.03	86.12	85.24
	TSP	100	99.06	101.04	98.58	98.35	97.13	96.44	95.88	93.51	93.20	93.06	91.83

20 Year Emissions (1000 Tons)	Average	Total
CO2	61,259	1,225,176
NOx	136.5	2,729
TSP	11.0	220

PacifiCorp RAMPP-3 Case # 16

Load = m Gas = lg DSR = md Coal = ac Renewables = ar

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1													0.0
W	OWC Cogen 2				302.0		118.1	57.8						477.9
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											27.1	472.9	500.0
	Total	**24.4**	**25.0**	**24.1**	**328.3**	**36.8**	**164.1**	**111.3**	**53.7**	**69.2**	**82.3**	**96.3**	**539.3**	**1555.0**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal									563.9	29.6	614.0	14.9	1222.4
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT													0.0
	Utah Pumped Storage							38.7	142.5	217.6		101.2		500.0
	Total	**8.9**	**10.1**	**14.1**	**19.1**	**20.1**	**25.1**	**64.9**	**169.0**	**832.2**	**104.2**	**781.3**	**63.4**	**2112.4**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**4.9**	**6.3**	**6.4**	**12.5**	**19.1**	**19.1**	**17.7**	**104.1**
	DSR	**35.1**	**36.3**	**42.1**	**50.6**	**63.1**	**76.0**	**86.0**	**86.6**	**132.4**	**176.0**	**154.4**	**132.6**	**1071.2**
T	**Renewable**													0.0
O	Cogen				302.0		118.1	57.8						477.9
T	Combined Cycle CT													0.0
A	Coal									563.9	29.6	614.0	14.9	1222.4
L	Simple Cycle CT													0.0
	Pumped Storage							38.7	142.5	217.6		128.3	472.9	1000.0
	Total	**35.1**	**36.3**	**42.1**	**352.6**	**63.1**	**194.1**	**182.5**	**229.1**	**913.9**	**205.6**	**896.7**	**620.4**	**3771.5**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-606	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	302	302	420	517	659	1441	1470	2213	2700
L	**Total Resources**	**10068**	**10393**	**10249**	**10520**	**10674**	**10774**	**10854**	**10996**	**11340**	**11371**	**11659**	**12158**
&													
R	Reserves	1210	1388	1236	1371	1411	1405	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	15.0	15.2	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

PacifiCorp RAMPP-3

Case # 16

Load = m Gas = lg DSR = md Coal = ac Renewables = ar

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1												
C	OWC Cogen 2												
	OWC Combined Cycle CT				249.8	249.8	347.5	395.3	395.3	395.3	399.0	421.9	424.9
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											0.1	1.4
	Total	**12.3**	**25.7**	**39.0**	**304.3**	**323.8**	**437.1**	**502.7**	**520.4**	**550.7**	**590.5**	**640.8**	**670.7**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC									516.8	543.9	1106.6	1120.3
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage							7.2	34.0	74.0	74.0	93.7	94.8
	Total	**6.9**	**15.2**	**27.4**	**43.4**	**61.2**	**78.3**	**103.3**	**148.2**	**739.7**	**817.6**	**1443.1**	**1492.3**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**11.0**	**16.9**	**21.4**	**27.0**	**32.6**	**43.5**	**60.0**	**76.4**	**91.2**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable												
O	Cogen												
T	Combined Cycle CT				249.8	249.8	347.5	395.3	395.3	395.3	399.0	421.9	424.9
A	Coal												
L	Simple Cycle CT									516.8	543.9	1106.6	1120.3
	Pumped Storage							7.2	34.0	74.0	74.0	93.8	96.2
	Total	**20.6**	**43.3**	**72.5**	**358.7**	**401.9**	**536.8**	**633.0**	**701.2**	**1333.9**	**1468.1**	**2160.3**	**2254.2**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pumped Storage	312	311	309	310	309	307	316	350	401	399	425	428
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	336	369	334	315	300	307	474	528	533	427
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	**7547**	**7663**	**7672**	**7784**	**7836**	**7934**	**8049**	**8141**	**8571**	**8683**	**8874**	**9081**
M													
	Existing Generation	6776	6887	7037	6967	7007	7015	7091	7143	7058	7130	6799	6926
L	Firm Purchases	645	644	452	435	411	403	393	388	364	361	336	342
&	Non-Firm Purchases	128	133	183	147	182	181	177	195	177	190	131	186
R	New Resources				249	249	347	402	429	986	1016	1622	1641
	Total Resources	**7549**	**7664**	**7672**	**7798**	**7849**	**7946**	**8063**	**8155**	**8585**	**8697**	**8888**	**9095**

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Case # 16

Load = m Gas = lg DSR = md Coal = ac Renewables = ar

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
	OWC Geothermal												
O	OWC Cogen 1												
W	OWC Cogen 2				82.0	82.0	82.0	82.0	82.0	82.0	83.0	88.0	88.0
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal									91.0	91.0	91.0	91.0
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage							18.0	18.0	18.0	18.0	18.0	18.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	74.6	73.9	75.0	74.1	73.3	73.4	74.1	74.6	73.7	74.4	74.0	75.3
	New Resources				82.5	82.5	82.6	77.8	65.1	68.4	69.1	73.3	60.8
	DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Load = m Gas = lg DSR = md Coal = ac Renewables = sr

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		Energy Sales (MWa)	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,763	8,191	8,672	9,065	9,622	10,305	11,064	11,898	13,219	14,967	17,533	19,912
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
46,878	3.92	Nominal	**Operating Revenues ($M)**	2,135	2,266	2,339	2,405	2,518	2,664	2,783	2,909	3,123	3,699	4,295	5,551
	0.51	Real		2,135	2,192	2,188	2,175	2,202	2,254	2,277	2,302	2,312	2,476	2,601	2,941
	3.26	Nominal	Cost in mills/kWh	47.8	49.8	50.4	51.0	52.6	54.8	56.3	57.8	59.8	68.3	75.5	91.0
	-0.13	Real		47.8	48.2	47.2	46.1	46.0	46.4	46.0	45.7	44.3	45.7	45.7	48.2
		Nominal	Average Customer Bill ($)	1,631	1,714	1,751	1,782	1,841	1,917	1,966	2,022	2,100	2,372	2,629	3,219
		Real		1,631	1,657	1,638	1,612	1,611	1,622	1,609	1,600	1,554	1,588	1,592	1,705
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
48,444	4.03	Nominal	**Total Resource Cost ($M)**	2,139	2,275	2,353	2,423	2,542	2,703	2,839	2,986	3,241	3,876	4,530	5,842
	0.61	Real		2,139	2,200	2,201	2,192	2,224	2,287	2,323	2,363	2,398	2,595	2,743	3,095
	3.21	Nominal	Cost in mills/kWh	47.8	49.7	50.1	50.5	51.8	53.9	55.3	56.8	58.9	67.0	74.0	88.6
	-0.18	Real		47.8	48.0	46.8	45.6	45.3	45.6	45.3	45.0	43.6	44.9	44.8	47.0

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 2.40% ...

3) 50-year Real Levelized

4) 50-year Real Levelized

Load = m Gas = lg DSR = md Coal = ac Renewables = sr

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,207	68,214	68,836	69,493	70,571	71,324	75,143	76,107	77,684	79,585
	MWa	7,549	7,664	7,672	7,787	7,858	7,933	8,056	8,142	8,578	8,688	8,868	9,085
	Total Annual Emissions (1000 Tons)												
1.05%	CO_2	54,170	54,960	55,957	55,986	56,131	56,262	56,977	57,047	60,474	61,405	65,467	66,708
0.04%	NO_x	139.6	141.4	143.8	142.7	142.8	142.9	119.7	119.7	127.4	129.2	138.2	140.6
0.46%	TSP	10.4	10.5	10.7	10.6	10.6	10.6	10.6	10.6	10.9	11.1	11.3	11.4
	Annual System Emission Rates (Pounds/MWh)												
0.12%	CO_2	1,638	1,637	1,665	1,641	1,631	1,619	1,615	1,600	1,610	1,614	1,685	1,676
-0.93%	NO_x	4.22	4.21	4.28	4.18	4.15	4.11	3.39	3.36	3.39	3.40	3.56	3.53
-0.49%	TSP	0.31	0.31	0.32	0.31	0.31	0.30	0.30	0.30	0.29	0.29	0.29	0.29
	Emission Rates as Percent of 1994 Base												
	CO_2	100	99.94	101.64	100.19	99.55	98.83	98.56	97.64	98.25	98.50	102.88	102.33
	NO_x	100	99.80	101.37	99.13	98.25	97.40	80.33	79.50	80.31	80.45	84.30	83.71
	TSP	100	99.06	101.04	98.50	97.76	96.82	95.92	94.86	92.62	92.48	92.19	91.10

20 Year Emissions (1000 Tons)	Average	Total
CO_2	60,366	1,207,316
NO_x	134.7	2,694
TSP	10.9	218

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Load = m Gas = lg DSR = md Coal = ac Renewables = sr

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C				29.0	36.0	45.0							110.0
	OWC Wind without Tax C							29.0	29.0					58.0
	OWC Geothermal								13.0					13.0
O	OWC Cogen 1													0.0
W	OWC Cogen 2				275.6		44.3	70.2	35.0					425.1
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											64.1	435.9	500.0
	Total	**24.4**	**25.0**	**24.1**	**331.1**	**72.8**	**135.3**	**132.7**	**130.7**	**69.2**	**82.3**	**133.3**	**502.3**	**1683.2**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C				29.0	36.0	45.0							110.0
	Utah Wind without Tax C							29.0	29.0					58.0
	Utah Geothermal								12.0					12.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal									427.9	29.6	587.8	52.0	1097.3
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT													0.0
	Utah Pumped Storage								56.1	353.5		90.3		499.9
	Total	**8.9**	**10.1**	**14.1**	**48.1**	**56.1**	**70.1**	**55.2**	**123.6**	**832.1**	**104.2**	**744.2**	**100.5**	**2167.2**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C				29.0	36.0	45.0							110.0
Y	Wyo Wind without Tax C							29.0	29.0					58.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**34.0**	**42.2**	**49.9**	**35.3**	**35.4**	**12.5**	**19.1**	**19.1**	**17.7**	**272.1**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable				87.0	108.0	135.0	87.0	112.0					529.0
O	Cogen				275.6		44.3	70.2	35.0					425.1
T	Combined Cycle CT													0.0
A	Coal									427.9	29.6	587.8	52.0	1097.3
L	Simple Cycle CT													0.0
	Pumped Storage								56.1	353.5		154.4	435.9	999.9
	Total	**35.1**	**36.3**	**42.1**	**413.2**	**171.1**	**255.3**	**243.2**	**289.7**	**913.8**	**205.6**	**896.6**	**620.5**	**4122.5**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	363	471	650	807	1010	1792	1821	2563	3051
L	**Total Resources**	**10068**	**10393**	**10249**	**10581**	**10843**	**11004**	**11144**	**11347**	**11691**	**11722**	**12009**	**12509**
&													
R	Reserves	1210	1388	1236	1371	1444	1405	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	15.0	15.6	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

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Load = m Gas = lg DSR = md Coal = ac Renewables = sr

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C				6.9	15.5	26.2	26.2	26.2	26.2	26.3	26.3	26.3
	OWC Wind without Tax C							6.9	13.8	13.8	13.9	13.9	13.9
O	OWC Geothermal								10.8	10.4	10.3	11.0	11.4
W	OWC Cogen 1												
C	OWC Cogen 2				228.0	228.0	264.7	322.7	351.7	351.7	356.0	375.7	378.0
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											0.2	1.5
	Total	**12.3**	**25.7**	**39.0**	**289.4**	**317.5**	**380.5**	**463.2**	**527.6**	**557.5**	**598.0**	**645.9**	**675.5**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C				10.2	22.8	38.6	38.6	38.6	38.6	38.6	38.6	38.6
	Utah Wind without Tax C							10.2	20.4	20.4	20.4	20.4	20.4
	Utah Geothermal								10.1	9.5	9.5	9.3	9.6
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal									392.2	419.3	958.0	1005.6
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage								10.4	76.1	76.1	87.2	94.3
	Total	**6.9**	**15.2**	**27.4**	**53.6**	**84.0**	**116.9**	**144.9**	**193.7**	**685.7**	**763.6**	**1356.3**	**1445.7**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C				10.2	22.8	38.6	38.6	38.6	38.6	38.6	38.6	38.6
Y	Wyo Wind without Tax C							10.2	20.3	20.4	20.4	20.4	20.4
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**21.2**	**39.7**	**60.0**	**75.8**	**91.5**	**102.5**	**119.0**	**135.4**	**150.2**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable				27.3	61.1	103.4	130.7	178.8	177.9	178.0	178.5	179.2
O	Cogen				228.0	228.0	264.7	322.7	351.7	351.7	356.0	375.7	378.0
T	Combined Cycle CT												
A	Coal									392.2	419.3	958.0	1005.6
L	Simple Cycle CT												
	Pumped Storage								10.4	76.1	76.1	87.4	95.8
	Total	**20.6**	**43.3**	**72.5**	**364.2**	**441.2**	**557.4**	**683.9**	**812.8**	**1345.7**	**1480.6**	**2137.6**	**2271.4**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pumped Storage	312	311	309	310	309	307	306	320	404	402	417	427
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	336	370	355	313	315	337	477	528	533	430
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	**7547**	**7663**	**7672**	**7785**	**7857**	**7932**	**8054**	**8141**	**8577**	**8686**	**8866**	**9083**
M													
	Existing Generation	6776	6887	7037	6964	6988	6995	7065	7062	7050	7136	6801	6915
L	Firm Purchases	645	644	452	434	411	403	393	388	364	361	336	345
&	Non-Firm Purchases	128	133	183	146	182	178	157	164	179	174	144	179
R	New Resources				255	289	368	453	540	997	1029	1599	1658
	Total Resources	**7549**	**7664**	**7672**	**7799**	**7870**	**7944**	**8068**	**8154**	**8590**	**8700**	**8880**	**9097**

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Case # 17

Load = m Gas = lg DSR = md Coal = ac Renewables = sr

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C				23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
	OWC Wind without Tax C							23.0	23.0	23.0	23.0	23.0	23.0
	OWC Geothermal								83.0	80.0	79.0	84.0	87.0
O	OWC Cogen 1												
W	OWC Cogen 2				82.0	82.0	82.0	82.0	82.0	82.0	83.0	88.0	88.0
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C				35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
	Utah Wind without Tax C							35.0	35.0	35.0	35.0	35.0	35.0
	Utah Geothermal								83.0	79.0	78.0	77.0	80.0
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal									91.0	91.0	91.0	91.0
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage								18.0	18.0	18.0	17.0	18.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C				35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Y	Wyo Wind without Tax C							35.0	35.0	35.0	35.0	35.0	35.0
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												

Total System

	1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
Existing Generation	74.6	73.9	75.0	74.1	73.1	73.2	73.9	73.8	73.6	74.4	74.1	75.2
New Resources				70.3	61.4	56.6	56.1	53.5	55.6	56.5	62.4	54.3
DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Load = m Gas = lg DSR = md Coal = nc Renewables = sr

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		**Energy Sales (MWa)**	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,763	8,193	8,678	9,047	9,568	10,150	10,709	11,392	12,478	13,646	15,644	18,056
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
46,901	3.99	Nominal	**Operating Revenues ($M)**	2,135	2,266	2,339	2,404	2,518	2,665	2,784	2,909	3,169	3,656	4,334	5,471
	0.57	Real		2,135	2,192	2,188	2,175	2,203	2,255	2,278	2,302	2,346	2,448	2,625	2,898
	3.32	Nominal	Cost in mills/kWh	47.8	49.8	50.4	51.0	52.6	54.8	56.3	57.8	60.7	67.5	76.2	89.7
	-0.07	Real		47.8	48.2	47.2	46.1	46.0	46.4	46.0	45.7	44.9	45.2	46.1	47.5
		Nominal	Average Customer Bill ($)	1,631	1,714	1,751	1,782	1,841	1,917	1,967	2,022	2,131	2,344	2,652	3,172
		Real		1,631	1,657	1,638	1,612	1,611	1,622	1,609	1,600	1,577	1,570	1,606	1,680
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
48,467	4.09	Nominal	**Total Resource Cost ($M)**	2,139	2,275	2,353	2,423	2,542	2,703	2,840	2,986	3,287	3,833	4,568	5,762
	0.67	Real		2,139	2,200	2,201	2,191	2,224	2,287	2,324	2,363	2,433	2,566	2,766	3,053
	3.27	Nominal	Cost in mills/kWh	47.8	49.7	50.1	50.5	51.8	53.9	55.3	56.8	59.7	66.3	74.6	87.4
	-0.12	Real		47.8	48.0	46.8	45.6	45.3	45.6	45.3	45.0	44.2	44.4	45.2	46.3

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **46.69**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **45.63**

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md nc sr financial

Load = m Gas = lg DSR = md Coal = nc Renewables = sr

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,207	68,240	68,827	69,458	70,588	71,263	74,810	75,800	77,745	80,207
	MWa	7,549	7,664	7,672	7,790	7,857	7,929	8,058	8,135	8,540	8,653	8,875	9,156
	Total Annual Emissions (1000 Tons)												
0.62%	CO2	54,170	54,960	55,957	55,971	56,116	56,229	56,979	56,938	58,503	59,293	60,640	61,327
-0.58%	NOx	139.6	141.4	143.8	142.7	142.7	142.8	119.7	119.3	120.5	121.9	123.5	124.3
0.25%	TSP	10.4	10.5	10.7	10.6	10.6	10.6	10.6	10.6	10.7	10.8	10.9	10.9
	Annual System Emission Rates (Pounds/MWh)												
-0.36%	CO2	1,638	1,637	1,665	1,640	1,631	1,619	1,614	1,598	1,564	1,564	1,560	1,529
-1.61%	NOx	4.22	4.21	4.28	4.18	4.15	4.11	3.39	3.35	3.22	3.22	3.18	3.10
-0.75%	TSP	0.31	0.31	0.32	0.31	0.31	0.30	0.30	0.30	0.29	0.28	0.28	0.27
	Emission Rates as Percent of 1994 Base												
	CO2	100	99.94	101.64	100.13	99.53	98.83	98.54	97.54	95.47	95.49	95.22	93.34
	NOx	100	99.80	101.37	99.04	98.23	97.40	80.31	79.30	76.30	76.21	75.24	73.40
	TSP	100	99.06	101.04	98.43	97.75	96.84	95.88	94.50	90.69	90.47	89.22	86.60

20 Year Emissions (1000 Tons)	Average	Total
CO2	58,274	1,165,482
NOx	128.1	2,561
TSP	10.7	214

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Load = m Gas = lg DSR = md Coal = nc Renewables = sr

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C				29.0	36.0	45.0							110.0
	OWC Wind without Tax C							29.0	29.0					58.0
	OWC Geothermal								13.0					13.0
O	OWC Cogen 1													0.0
W	OWC Cogen 2				232.7		29.0	70.2	36.0	556.6	29.6	273.0		1227.1
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											12.1	487.9	500.0
	Total	**24.4**	**25.0**	**24.1**	**288.2**	**72.8**	**120.0**	**152.7**	**131.7**	**625.8**	**111.9**	**354.3**	**554.3**	**2485.2**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C				29.0	36.0	45.0							110.0
	Utah Wind without Tax C							29.0	29.0					58.0
	Utah Geothermal								12.0					12.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2				42.9		15.4		55.1					113.4
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal													0.0
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT											182.0		182.0
	Utah Pumped Storage									224.8		275.2		500.0
	Total	**8.9**	**10.1**	**14.1**	**91.0**	**56.1**	**85.5**	**55.2**	**122.6**	**275.5**	**74.6**	**523.3**	**48.5**	**1365.4**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C				29.0	36.0	45.0							110.0
Y	Wyo Wind without Tax C							29.0	29.0					58.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**34.0**	**42.2**	**49.9**	**35.3**	**35.4**	**12.5**	**19.1**	**19.1**	**17.7**	**272.1**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable				87.0	108.0	135.0	87.0	112.0					529.0
O	Cogen				275.6		44.4	70.2	91.1	556.6	29.6	273.0		1340.5
T	Combined Cycle CT													0.0
A	Coal													0.0
L	Simple Cycle CT											182.0		182.0
	Pumped Storage									224.8		287.3	487.9	1000.0
	Total	**35.1**	**36.3**	**42.1**	**413.2**	**171.1**	**255.4**	**243.2**	**289.7**	**913.8**	**205.6**	**896.7**	**620.5**	**4122.7**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	363	471	650	807	1010	1792	1821	2564	3052
L	**Total Resources**	**10068**	**10393**	**10249**	**10581**	**10843**	**11004**	**11144**	**11347**	**11691**	**11722**	**12010**	**12510**
&													
R	Reserves	1210	1388	1236	1371	1444	1405	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	15.0	15.6	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

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Case # 19

Load = m Gas = lg DSR = md Coal = nc Renewables = sr

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C				6.9	15.5	26.2	26.2	26.2	26.2	26.2	26.3	26.3
	OWC Wind without Tax C							6.9	13.8	13.8	13.8	13.9	13.9
O	OWC Geothermal								10.9	10.2	10.1	10.4	10.9
W	OWC Cogen 1												
C	OWC Cogen 2				192.5	192.5	216.5	274.5	304.3	757.5	781.8	1027.8	1095.2
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											1.9	50.8
	Total	**12.3**	**25.7**	**39.0**	**253.9**	**282.0**	**332.3**	**415.0**	**480.3**	**963.1**	**1023.4**	**1299.1**	**1441.5**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C				10.2	22.8	38.6	38.6	38.6	38.6	38.6	38.6	38.6
	Utah Wind without Tax C							10.2	20.4	20.4	20.4	20.4	20.4
	Utah Geothermal								10.1	9.9	9.7	10.0	10.2
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2				35.5	35.5	48.2	48.2	93.8	93.2	93.4	99.7	104.3
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											10.1	10.1
	Utah Pumped Storage									42.5	41.8	92.4	83.5
	Total	**6.9**	**15.2**	**27.4**	**89.1**	**119.5**	**165.1**	**193.1**	**277.1**	**353.5**	**403.6**	**514.0**	**544.3**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C				10.2	22.8	38.6	38.6	38.6	38.6	38.6	38.6	38.6
Y	Wyo Wind without Tax C							10.2	20.3	20.4	20.4	20.4	20.4
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**21.2**	**39.7**	**60.0**	**75.8**	**91.5**	**102.5**	**119.0**	**135.4**	**150.2**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable				27.3	61.1	103.4	130.7	178.9	178.1	177.8	178.6	179.3
O	Cogen				228.0	228.0	264.7	322.7	398.1	850.7	875.2	1127.5	1199.5
T	Combined Cycle CT												
A	Coal												
L	Simple Cycle CT											10.1	10.1
	Pumped Storage									42.5	41.8	94.3	134.3
	Total	**20.6**	**43.3**	**72.5**	**364.2**	**441.2**	**557.4**	**683.9**	**848.9**	**1419.1**	**1546.0**	**1948.5**	**2136.0**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pumped Storage	312	311	309	310	309	307	306	306	361	358	425	477
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	336	373	353	310	317	343	481	538	532	452
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	**7547**	**7663**	**7672**	**7788**	**7855**	**7929**	**8056**	**8133**	**8538**	**8652**	**8873**	**9155**
M													
	Existing Generation	6776	6887	7037	6962	6986	6990	7066	7029	7031	7123	6927	7006
L	Firm Purchases	645	644	452	434	411	403	393	388	364	361	336	374
&	Non-Firm Purchases	128	133	183	150	183	180	159	154	86	88	214	265
R	New Resources				255	289	368	453	577	1071	1094	1410	1523
	Total Resources	**7549**	**7664**	**7672**	**7801**	**7869**	**7941**	**8071**	**8148**	**8552**	**8666**	**8887**	**9168**

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Load = m Gas = lg DSR = md Coal = nc Renewables = sr

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C				23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
	OWC Wind without Tax C							23.0	23.0	23.0	23.0	23.0	23.0
	OWC Geothermal								83.0	78.0	77.0	80.0	83.0
O	OWC Cogen 1												
W	OWC Cogen 2				82.0	82.0	82.0	82.0	82.0	81.0	81.0	83.0	89.0
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											15.0	10.0
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C				35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
	Utah Wind without Tax C							35.0	35.0	35.0	35.0	35.0	35.0
	Utah Geothermal								83.0	82.0	80.0	83.0	84.0
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2				82.0	82.0	82.0	82.0	82.0	82.0	82.0	87.0	91.0
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											5.0	5.0
	Utah Pumped Storage									18.0	18.0	18.0	16.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C				35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Y	Wyo Wind without Tax C							35.0	35.0	35.0	35.0	35.0	35.0
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	74.6	73.9	75.0	74.0	73.1	73.1	73.9	73.4	73.4	74.3	75.4	76.2
	New Resources				70.3	61.4	56.6	56.1	57.1	59.8	60.1	55.0	49.9
	DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Case #28

NO FINANCIAL RUN

Load = m Gas = mg DSR = unc Coal = ac Renewables = ar

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	65,901	67,014	67,049	66,742	67,364	68,451	69,712	70,947	73,496	75,187	77,298	80,040
	MWa	7,523	7,650	7,654	7,619	7,690	7,814	7,958	8,099	8,390	8,583	8,824	9,137
	Total Annual Emissions (1000 Tons)												
1.26%	CO2	54,082	54,900	55,816	55,565	56,256	56,583	57,234	58,717	62,342	63,960	67,500	69,498
0.30%	NOx	139.4	141.3	143.5	143.2	144.5	144.7	120.9	124.3	132.5	136.0	143.8	148.0
0.56%	TSP	10.4	10.4	10.7	10.6	10.7	10.7	10.8	10.9	11.1	11.2	11.4	11.6
													2
	Annual System Emission Rates (Pounds/MWh)												0
0.30%	CO2	1,641	1,638	1,665	1,665	1,670	1,653	1,642	1,655	1,696	1,701	1,746	1,737
-0.71%	NOx	4.23	4.22	4.28	4.29	4.29	4.23	3.47	3.51	3.61	3.62	3.72	3.70
-0.43%	TSP	0.32	0.31	0.32	0.32	0.32	0.31	0.31	0.31	0.30	0.30	0.29	0.29
													0
	Emission Rates as Percent of 1994 Base												0
	CO2	100	99.83	101.44	101.45	101.76	100.73	100.04	100.85	103.36	103.66	106.41	105.80
	NOx	100	99.70	101.24	101.43	101.41	99.97	82.04	82.88	85.25	85.50	88.00	87.42
	TSP	100	98.91	100.91	101.07	101.01	99.47	98.42	97.33	95.47	94.55	93.54	92.12

20 Year Emissions (1000 Tons)	Average	Total
CO2	61,812	1,236,239
NOx	138.8	2,776
TSP	11.0	221

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Case # 28

Load = m Gas = mg DSR = unc Coal = ac Renewables = ar

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	18.0	16.6	57.9	140.9	42.2	72.1	20.3	21.6	43.0	66.5	64.9	141.1	705.1
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1						144.8	47.3						192.1
W	OWC Cogen 2													0.0
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											50.3	341.3	391.6
	Total	**18.0**	**16.6**	**57.9**	**140.9**	**42.2**	**216.9**	**67.6**	**21.6**	**43.0**	**66.5**	**115.2**	**482.4**	**1288.8**
	DSR	116.3	0.4	0.4	69.2	0.4	0.2	0.2	0.2	130.8	0.7	0.8	0.7	320.3
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal								215.9	551.4	150.1	499.8	129.5	1546.7
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT													0.0
	Utah Pumped Storage							123.3		87.1		289.5		499.9
	Total	**116.3**	**0.4**	**0.4**	**69.2**	**0.4**	**0.2**	**123.5**	**216.1**	**769.3**	**150.8**	**790.1**	**130.2**	**2366.9**
	DSR	1.2	0.8	0.9	0.9	0.9	1.0	1.1	1.2	81.9	3.9	4.2	4.7	102.7
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.2**	**0.8**	**0.9**	**0.9**	**0.9**	**1.0**	**1.1**	**1.2**	**81.9**	**3.9**	**4.2**	**4.7**	**102.7**
	DSR	135.5	17.8	59.2	211.0	43.5	73.3	21.6	23.0	255.7	71.1	69.9	146.5	1128.1
T	Renewable													0.0
O	Cogen						144.8	47.3						192.1
T	Combined Cycle CT													0.0
A	Coal								215.9	551.4	150.1	499.8	129.5	1546.7
L	Simple Cycle CT													0.0
	Pumped Storage							123.3		87.1		339.8	341.3	891.5
	Total	**135.5**	**17.8**	**59.2**	**211.0**	**43.5**	**218.1**	**192.2**	**238.9**	**894.2**	**221.2**	**909.5**	**617.3**	**3758.4**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-136	-153	-213	-424	-467	-540	-562	-585	-841	-912	-982	-1128
S	**Total Requirements**	**8757**	**8923**	**8914**	**8889**	**9022**	**9132**	**9265**	**9452**	**9627**	**9760**	**10094**	**10515**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	0	0	145	315	531	1170	1320	2160	2630
L	**Total Resources**	**10068**	**10393**	**10249**	**10218**	**10372**	**10499**	**10652**	**10868**	**11069**	**11221**	**11606**	**12088**
&													
R	Reserves	1311	1469	1335	1329	1349	1366	1386	1414	1439	1459	1509	1572
	Reserve Margin (RM) (%)	15.0	16.5	15.0	15.0	15.0	15.0	15.0	15.0	14.9	14.9	14.9	15.0
	Capacity Below 15% RM												

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Case # 28

Load = m Gas = mg DSR = unc Coal = ac Renewables = ar

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	5.6	10.0	61.9	145.3	164.2	172.9	178.2	184.0	195.5	213.3	230.8	278.3
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1						134.3	178.3	178.3	173.5	174.8	178.8	178.8
C	OWC Cogen 2												
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											0.3	1.6
	Total	**5.6**	**10.0**	**61.9**	**145.3**	**164.2**	**307.2**	**356.5**	**362.3**	**369.0**	**388.1**	**409.9**	**458.7**
	DSR	56.1	56.4	56.7	91.8	92.1	92.3	92.5	92.7	221.7	222.5	223.4	224.2
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal								197.8	703.2	840.7	1298.8	1417.4
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage							22.9	22.9	47.7	44.4	103.0	122.8
	Total	**56.1**	**56.4**	**56.7**	**91.8**	**92.1**	**92.3**	**115.4**	**313.4**	**972.6**	**1107.6**	**1625.2**	**1764.4**
	DSR	0.7	1.2	1.7	2.2	2.8	3.4	4.0	4.7	83.5	85.6	87.7	90.1
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**0.7**	**1.2**	**1.7**	**2.2**	**2.8**	**3.4**	**4.0**	**4.7**	**83.5**	**85.6**	**87.7**	**90.1**
	DSR	62.4	67.6	120.3	239.3	259.1	268.6	274.7	281.4	500.7	521.4	541.9	592.6
T	Renewable												
O	Cogen						134.3	178.3	178.3	173.5	174.8	178.8	178.8
T	Combined Cycle CT												
A	Coal								197.8	703.2	840.7	1298.8	1417.4
L	Simple Cycle CT												
	Pumped Storage							22.9	22.9	47.7	44.4	103.3	124.4
	Total	**62.4**	**67.6**	**120.3**	**239.3**	**259.1**	**402.9**	**475.9**	**680.4**	**1425.1**	**1581.3**	**2122.8**	**2313.2**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pumped Storage	312	311	310	310	309	307	336	336	368	361	430	456
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	436	441	364	333	293	274	232	288	477	534	481	433
T	DSR	-62	-68	-120	-239	-259	-269	-275	-281	-501	-521	-542	-593
E	**Total Requirements**	**7522**	**7648**	**7653**	**7618**	**7688**	**7813**	**7956**	**8099**	**8388**	**8581**	**8823**	**9135**
M													
	Existing Generation	6766	6881	7019	7006	7104	7101	7168	7134	7046	7095	6782	6904
L	Firm Purchases	645	644	452	435	411	403	393	388	364	361	336	370
&	Non-Firm Purchases	111	124	183	191	186	187	208	190	68	80	138	154
R	New Resources						134	201	399	924	1059	1580	1720
	Total Resources	**7522**	**7649**	**7654**	**7632**	**7701**	**7825**	**7970**	**8111**	**8402**	**8595**	**8836**	**9148**

PacifiCorp RAMPP-3 **Case # 28**

Load = m Gas = mg DSR = unc Coal = ac Renewables = ar

Annual Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	31.0	28.0	66.0	62.0	59.0	49.0	48.0	47.0	45.0	42.0	40.0	39.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
	OWC Geothermal												
O	OWC Cogen 1						92.0	92.0	92.0	90.0	91.0	93.0	93.0
W	OWC Cogen 2												
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	DSR	48.0	48.0	48.0	49.0	49.0	49.0	49.0	49.0	69.0	69.0	69.0	69.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal								91.0	91.0	91.0	91.0	91.0
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage							18.0	18.0	22.0	21.0	20.0	24.0
	DSR	56.0	59.0	60.0	60.0	60.0	60.0	60.0	59.0	92.0	91.0	89.0	87.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	74.4	73.8	74.8	74.5	74.3	74.3	74.9	74.5	73.5	74.0	73.8	75.1
	New Resources						92.5	63.7	75.1	79.0	80.2	73.2	65.4
	DSR	46.1	44.1	56.6	56.5	35.5	49.7	48.9	48.1	59.6	57.2	55.2	52.5

Load = m Gas = mg DSR = ld Coal = ac Renewables = ar

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	16	35	54	72	87	106	121	137	175	228	277	318
			After Conservation												
			System Load (MWa)	5,637	5,748	5,906	5,986	6,102	6,217	6,385	6,484	6,758	7,058	7,434	7,979
	0.72		**Energy Sales (MWa)**	5,099	5,199	5,314	5,416	5,523	5,628	5,748	5,872	6,121	6,392	6,733	7,233
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,745	8,192	8,685	9,088	9,731	10,419	11,291	12,167	13,652	15,620	18,413	21,210
			Net Conservation Assets ($M)	37	82	150	216	285	312	338	364	422	481	501	481
			<u>Utility Cost</u>												
47,195	3.95	Nominal	**Operating Revenues ($M)**	2,132	2,262	2,339	2,399	2,517	2,650	2,770	2,850	3,089	3,701	4,336	5,556
	0.53	Real		2,132	2,188	2,188	2,170	2,202	2,242	2,266	2,256	2,287	2,478	2,626	2,943
	3.21	Nominal	Cost in mills/kWh	47.7	49.7	50.3	50.6	52.0	53.8	55.0	55.4	57.6	66.1	73.5	87.7
	-0.18	Real		47.7	48.0	47.0	45.8	45.5	45.5	45.0	43.9	42.6	44.3	44.5	46.5
		Nominal	Average Customer Bill ($)	1,629	1,710	1,751	1,778	1,841	1,906	1,956	1,981	2,077	2,373	2,654	3,221
		Real		1,629	1,654	1,637	1,608	1,610	1,613	1,601	1,568	1,537	1,589	1,607	1,707
			<u>Total Resource Cost</u>												
			DSR Customer Cost ($M)	3.7	5.1	5.5	7.6	6.6	38.7	35.0	40.5	46.2	44.4	51.1	56.4
			Levelized (20-year at 8.8%)	0.4	1.0	1.5	2.4	3.1	7.3	11.0	15.4	25.2	39.9	56.0	84.3
			Energy Svc Charge ($M)	2.5	5.7	10.9	15.6	20.2	24.3	28.3	32.5	42.8	58.9	73.0	74.5
48,099	4.01	Nominal	**Total Resource Cost ($M)**	2,135	2,269	2,351	2,417	2,541	2,681	2,809	2,898	3,158	3,800	4,464	5,714
	0.59	Real		2,135	2,194	2,199	2,187	2,223	2,268	2,298	2,293	2,337	2,544	2,704	3,027
	3.20	Nominal	Cost in mills/kWh	47.7	49.5	50.1	50.3	51.8	53.5	54.7	55.2	57.4	65.7	73.0	86.7
	-0.20	Real		47.7	47.9	46.8	45.5	45.3	45.2	44.8	43.7	42.5	44.0	44.2	45.9

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 45.73

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 45.28

ld ac ar financial

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Load = m Gas = mg DSR = ld Coal = ac Renewables = ar

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,156	67,198	67,277	68,600	69,589	70,684	71,666	73,111	77,202	78,691	80,172	83,220
	MWa	7,552	7,671	7,680	7,831	7,944	8,069	8,181	8,346	8,813	8,983	9,152	9,500
	Total Annual Emissions (1000 Tons)												
1.43%	CO2	54,179	54,978	56,033	56,218	56,789	57,344	57,877	59,685	64,493	66,068	69,730	71,987
0.45%	NOx	139.6	141.5	144.0	143.0	143.8	145.4	121.5	125.6	136.4	139.7	147.9	152.8
0.55%	TSP	10.4	10.5	10.7	10.6	10.6	10.8	10.8	10.9	11.3	11.4	11.4	11.6
	Annual System Emission Rates (Pounds/MWh)												
0.29%	CO2	1,638	1,636	1,666	1,639	1,632	1,623	1,615	1,633	1,671	1,679	1,740	1,730
-0.73%	NOx	4.22	4.21	4.28	4.17	4.13	4.12	3.39	3.44	3.53	3.55	3.69	3.67
-0.63%	TSP	0.31	0.31	0.32	0.31	0.31	0.30	0.30	0.30	0.29	0.29	0.29	0.28
	Emission Rates as Percent of 1994 Base												
	CO2	100	99.90	101.70	100.07	99.65	99.06	98.61	99.68	102.00	102.52	106.20	105.62
	NOx	100	99.74	101.43	98.75	97.94	97.49	80.34	81.42	83.71	84.12	87.44	87.00
	TSP	100	99.00	101.12	98.09	97.24	96.78	96.18	95.12	92.76	92.18	90.79	88.69

20 Year Emissions (1000 Tons)	Average	Total
CO2	63,320	1,266,404
NOx	141.4	2,827
TSP	11.1	222

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Case # 29

Load = m Gas = mg DSR = ld Coal = ac Renewables = ar

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	15.2	18.0	18.1	16.4	16.1	11.5	12.5	13.3	28.2	38.4	34.1	32.9	254.7
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1				160.0	20.9	16.4							197.3
W	OWC Cogen 2				204.7									204.7
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											168.9	331.1	500.0
	Total	**15.2**	**18.0**	**18.1**	**381.1**	**37.0**	**27.9**	**12.5**	**13.3**	**28.2**	**38.4**	**203.0**	**364.0**	**1156.7**
	DSR	7.3	9.8	10.6	11.5	8.5	17.8	12.2	12.5	28.3	43.0	39.6	29.6	230.7
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal								252.1	660.0	128.0	656.2	228.5	1924.8
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT													0.0
	Utah Pumped Storage						175.4	164.8		159.8				500.0
	Total	**7.3**	**9.8**	**10.6**	**11.5**	**8.5**	**193.2**	**177.0**	**264.6**	**848.1**	**171.0**	**695.8**	**258.1**	**2655.5**
	DSR	1.4	1.0	0.2	0.2	0.2	2.7	2.1	2.1	5.9	9.0	8.7	7.5	41.0
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.4**	**1.0**	**0.2**	**0.2**	**0.2**	**2.7**	**2.1**	**2.1**	**5.9**	**9.0**	**8.7**	**7.5**	**41.0**
	DSR	23.9	28.8	28.9	28.1	24.8	32.0	26.8	27.9	62.4	90.4	82.4	70.0	526.4
T	Renewable													0.0
O	Cogen				364.7	20.9	16.4							402.0
T	Combined Cycle CT													0.0
A	Coal								252.1	660.0	128.0	656.2	228.5	1924.8
L	Simple Cycle CT													0.0
	Pumped Storage						175.4	164.8		159.8		168.9	331.1	1000.0
	Total	**23.9**	**28.8**	**28.9**	**392.8**	**45.7**	**223.8**	**191.6**	**280.0**	**882.2**	**218.4**	**907.5**	**629.6**	**3853.2**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-24	-53	-82	-110	-135	-167	-193	-221	-284	-374	-456	-526
S	**Total Requirements**	**8868**	**9023**	**9044**	**9202**	**9355**	**9506**	**9634**	**9816**	**10184**	**10298**	**10620**	**11117**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	365	386	577	742	994	1814	1942	2767	3327
L	**Total Resources**	**10068**	**10393**	**10249**	**10583**	**10738**	**10931**	**11079**	**11331**	**11713**	**11843**	**12213**	**12785**
&													
R	Reserves	1199	1369	1204	1379	1402	1425	1444	1513	1527	1544	1592	1666
	Reserve Margin (RM) (%)	13.5	15.2	13.3	15.0	15.0	15.0	15.0	15.4	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	130		152									

PacifiCorp RAMPP-3 Case # 29

Load = m Gas = mg DSR = ld Coal = ac Renewables = ar

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	8.5	19.1	29.3	38.4	47.2	53.1	59.4	65.9	79.1	95.9	110.4	124.3
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				138.6	165.6	182.9	183.6	182.9	175.4	176.6	183.7	183.7
C	OWC Cogen 2				169.3	169.3	169.3	174.9	169.3	169.3	170.6	182.0	182.0
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											0.7	3.9
	Total	**8.5**	**19.1**	**29.3**	**346.3**	**382.1**	**405.3**	**417.9**	**418.1**	**423.8**	**443.1**	**476.8**	**493.9**
	DSR	5.8	13.9	22.7	31.2	37.6	47.6	54.9	62.5	81.3	110.0	135.7	156.2
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal								231.0	835.9	953.1	1554.4	1763.8
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage						33.8	61.8	63.2	99.8	105.0	111.5	118.4
	Total	**5.8**	**13.9**	**22.7**	**31.2**	**37.6**	**81.4**	**116.7**	**356.7**	**1017.0**	**1168.1**	**1801.6**	**2038.4**
	DSR	1.2	2.1	2.2	2.3	2.5	4.9	6.8	8.7	14.2	22.5	30.6	37.6
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.2**	**2.1**	**2.2**	**2.3**	**2.5**	**4.9**	**6.8**	**8.7**	**14.2**	**22.5**	**30.6**	**37.6**
	DSR	15.5	35.1	54.2	71.9	87.3	105.6	121.1	137.1	174.6	228.4	276.7	318.1
T	Renewable												
O	Cogen				307.9	334.9	352.2	358.5	352.2	344.7	347.2	365.7	365.7
T	Combined Cycle CT												
A	Coal								231.0	835.9	953.1	1554.4	1763.8
L	Simple Cycle CT												
	Pumped Storage						33.8	61.8	63.2	99.8	105.0	112.2	122.3
	Total	**15.5**	**35.1**	**54.2**	**379.8**	**422.2**	**491.6**	**541.4**	**783.5**	**1455.0**	**1633.7**	**2309.0**	**2569.9**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pumped Storage	311	311	309	310	309	350	386	387	434	439	448	460
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	419	429	325	378	376	322	251	338	508	563	524	517
T	DSR	-16	-35	-54	-72	-87	-106	-121	-137	-175	-228	-277	-318
E	**Total Requirements**	**7551**	**7669**	**7679**	**7830**	**7943**	**8067**	**8179**	**8344**	**8811**	**8981**	**9149**	**9498**
M													
	Existing Generation	6775	6890	7044	6969	7042	7103	7165	7138	7077	7146	6709	6761
L	Firm Purchases	645	644	452	435	411	403	393	388	364	361	335	346
&	Non-Firm Purchases	132	137	183	132	168	189	215	186	104	83	88	153
R	New Resources				307	334	386	420	646	1280	1405	2032	2251
	Total Resources	**7552**	**7671**	**7679**	**7843**	**7955**	**8081**	**8193**	**8358**	**8825**	**8995**	**9164**	**9511**

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Load = m Gas = mg DSR = ld Coal = ac Renewables = ar

Annual Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	55.0	57.0	57.0	56.0	56.0	55.0	55.0	54.0	53.0	51.0	49.0	48.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
	OWC Geothermal												
O	OWC Cogen 1				86.0	91.0	92.0	93.0	92.0	88.0	89.0	93.0	93.0
W	OWC Cogen 2				82.0	82.0	82.0	85.0	82.0	82.0	83.0	88.0	88.0
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	DSR	78.0	80.0	81.0	79.0	78.0	72.0	70.0	69.0	68.0	68.0	67.0	67.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah Simple Cycle CT												
	Utah CC CT Convert												
	Utah Coal								91.0	91.0	91.0	91.0	91.0
	Utah IG CC												
	Utah FB Coal												
	Utah Pumped Storage						19.0	18.0	18.0	19.0	21.0	22.0	23.0
	DSR	84.0	88.0	86.0	85.0	83.0	87.0	88.0	88.0	89.0	90.0	91.0	91.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												

Total System	1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
Existing Generation	74.5	73.9	75.1	74.1	73.7	74.3	74.9	74.6	73.9	74.5	73.1	73.5
New Resources				84.2	86.6	66.9	56.6	65.0	70.6	72.3	73.4	67.7
DSR	64.9	66.6	66.4	65.5	64.9	63.4	62.6	62.0	61.6	61.1	60.6	60.4

Load = m Gas = mg DSR = md Coal = ac Renewables = ar

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		Energy Sales (MWa)	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,763	8,191	8,624	8,952	9,488	10,137	10,983	11,914	13,383	15,187	17,797	20,223
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
46,337	3.91	Nominal	**Operating Revenues ($M)**	2,135	2,266	2,339	2,399	2,504	2,628	2,736	2,821	3,019	3,631	4,220	5,456
	0.49	Real		2,135	2,192	2,188	2,170	2,190	2,223	2,239	2,232	2,235	2,431	2,555	2,891
	3.25	Nominal	Cost in mills/kWh	47.8	49.8	50.4	50.9	52.3	54.1	55.3	56.0	57.8	67.0	74.2	89.5
	-0.14	Real		47.8	48.2	47.2	46.0	45.8	45.7	45.3	44.3	42.8	44.9	44.9	47.4
		Nominal	Average Customer Bill ($)	1,631	1,714	1,751	1,777	1,831	1,891	1,933	1,960	2,030	2,328	2,583	3,164
		Real		1,631	1,657	1,638	1,608	1,602	1,599	1,581	1,551	1,502	1,559	1,564	1,676
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
47,903	4.02	Nominal	**Total Resource Cost ($M)**	2,139	2,275	2,353	2,417	2,528	2,666	2,792	2,898	3,137	3,808	4,454	5,747
	0.60	Real		2,139	2,200	2,201	2,186	2,211	2,256	2,285	2,293	2,321	2,549	2,697	3,045
	3.20	Nominal	Cost in mills/kWh	47.8	49.7	50.1	50.3	51.5	53.2	54.4	55.2	57.0	65.9	72.8	87.2
	-0.19	Real		47.8	48.0	46.8	45.5	45.1	45.0	44.5	43.7	42.2	44.1	44.1	46.2

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 46.13

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 45.09

Load = m Gas = mg DSR = md Coal = ac Renewables = ar

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,189	68,214	69,011	69,712	70,500	71,315	75,161	76,151	77,806	80,058
	MWa	7,549	7,664	7,670	7,787	7,878	7,958	8,048	8,141	8,580	8,693	8,882	9,139
	Total Annual Emissions (1000 Tons)												
1.22%	CO2	54,170	54,960	55,955	56,054	56,584	57,001	57,547	58,486	63,187	64,012	67,705	68,983
0.24%	NOx	139.6	141.4	143.8	142.9	143.7	145.0	121.2	123.4 x2	133.9 x3	135.5 x3	143.8 x4	146.3
0.53%	TSP	10.4	10.5	10.7	10.6	10.6	10.7	10.8	10.9	11.1	11.2	11.4	11.6
	Annual System Emission Rates (Pounds/MWh)												
0.27%	CO2	1,638	1,637	1,666	1,643	1,640	1,635	1,633	1,640	1,681	1,681	1,740	1,723
-0.76%	NOx	4.22	4.21	4.28	4.19	4.16	4.16	3.44	3.46	3.56	3.56	3.70	3.65
-0.45%	TSP	0.31	0.31	0.32	0.31	0.31	0.31	0.31	0.30	0.30	0.30	0.29	0.29
	Emission Rates as Percent of 1994 Base												
	CO2	100	99.94	101.67	100.32	100.10	99.82	99.65	100.12	102.63	102.62	106.23	105.19
	NOx	100	99.80	101.41	99.22	98.62	98.57	81.44	81.95	84.38	84.32	87.56	86.58
	TSP	100	99.06	101.08	98.62	98.03	97.92	97.58	96.78	94.21	93.93	92.98	91.85

20 Year Emissions (1000 Tons)	Average	Total
CO2	61,972	1,239,430
NOx	138.6	2,773
TSP	11.0	221

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Load = m Gas = mg DSR = md Coal = ac Renewables = ar

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
														0.0
O	OWC Cogen 1				160.0									160.0
W	OWC Cogen 2				142.0									142.0
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage												461.4	461.4
	Total	**24.4**	**25.0**	**24.1**	**328.5**	**36.8**	**46.0**	**53.5**	**53.7**	**69.2**	**82.3**	**69.2**	**527.8**	**1340.5**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal								142.5	660.0	29.6	578.3	26.5	1436.9
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT													0.0
	Utah Pumped Storage						118.1	96.6		121.5		163.9		500.1
	Total	**8.9**	**10.1**	**14.1**	**19.1**	**20.1**	**143.2**	**122.8**	**169.0**	**832.2**	**104.2**	**808.3**	**75.0**	**2327.0**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**4.9**	**6.3**	**6.4**	**12.5**	**19.1**	**19.1**	**17.7**	**104.1**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable													0.0
O	Cogen				302.0									302.0
T	Combined Cycle CT													0.0
A	Coal								142.5	660.0	29.6	578.3	26.5	1436.9
L	Simple Cycle CT													0.0
	Pumped Storage						118.1	96.6		121.5		163.9	461.4	961.5
	Total	**35.1**	**36.3**	**42.1**	**352.6**	**63.1**	**194.1**	**182.6**	**229.1**	**913.9**	**205.6**	**896.6**	**620.5**	**3771.6**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	Total Requirements	8857	9005	9013	9148	9262	9369	9438	9561	9860	9888	10137	10572
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	302	302	420	517	659	1441	1470	2213	2700
L	Total Resources	10068	10393	10249	10520	10674	10774	10854	10996	11340	11371	11659	12158
&													
R	Reserves	1210	1388	1236	1371	1411	1405	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	15.0	15.2	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

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Load = m Gas = mg DSR = md Coal = ac Renewables = ar

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				138.6	146.4	146.9	148.3	148.3	142.2	145.3	148.9	148.9
C	OWC Cogen 2				117.5	117.5	117.5	117.5	117.5	117.5	123.3	126.2	126.2
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												1.6
	Total	**12.3**	**25.7**	**39.0**	**310.6**	**337.9**	**354.0**	**373.2**	**390.9**	**415.1**	**460.1**	**493.9**	**521.1**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal								130.6	735.4	762.6	1292.6	1316.9
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage						22.2	39.8	39.8	68.3	70.1	101.1	117.3
	Total	**6.9**	**15.2**	**27.4**	**43.4**	**61.2**	**100.5**	**135.9**	**284.6**	**952.6**	**1032.4**	**1636.5**	**1711.4**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**11.0**	**16.9**	**21.4**	**27.0**	**32.6**	**43.5**	**60.0**	**76.4**	**91.2**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable												
O	Cogen				256.1	263.9	264.4	265.8	265.8	259.7	268.6	275.1	275.1
T	Combined Cycle CT												
A	Coal								130.6	735.4	762.6	1292.6	1316.9
L	Simple Cycle CT												
	Pumped Storage						22.2	39.8	39.8	68.3	70.1	101.1	118.9
	Total	**20.6**	**43.3**	**72.5**	**365.0**	**416.0**	**475.9**	**536.1**	**708.1**	**1411.2**	**1552.5**	**2206.8**	**2323.7**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pumped Storage	312	311	309	310	309	335	358	358	394	394	434	455
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	334	371	374	310	256	298	488	541	529	456
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	7547	7663	7670	7786	7876	7957	8047	8140	8578	8691	8879	9137
M													
	Existing Generation	6776	6887	7035	6971	7046	7096	7164	7139	7069	7136	6777	6914
L	Firm Purchases	645	644	452	435	411	403	393	388	364	361	336	375
&	Non-Firm Purchases	128	133	183	138	169	185	197	191	97	107	112	152
R	New Resources				256	263	286	305	436	1063	1101	1668	1710
	Total Resources	7549	7664	7670	7800	7889	7970	8059	8154	8593	8705	8893	9151

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Load = m Gas = mg DSR = md Coal = ac Renewables = ar

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
	OWC Geothermal												
O	OWC Cogen 1				86.0	91.0	91.0	92.0	92.0	88.0	90.0	93.0	93.0
W	OWC Cogen 2				82.0	82.0	82.0	82.0	82.0	82.0	86.0	88.0	88.0
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal								91.0	91.0	91.0	91.0	91.0
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage						18.0	18.0	18.0	20.0	20.0	20.0	23.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	74.6	73.9	75.0	74.1	73.7	74.2	74.9	74.6	73.8	74.4	73.8	75.2
	New Resources				84.8	87.1	68.1	59.0	66.1	73.8	74.9	75.4	63.3
	DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Load = m Gas = mg DSR = md Coal = ac Renewables = sr

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		Energy Sales (MWa)	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,766	8,229	8,758	9,182	9,795	10,545	11,423	12,305	13,684	15,343	17,811	20,100
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
46,802	3.92	Nominal	**Operating Revenues ($M)**	2,135	2,266	2,339	2,403	2,525	2,670	2,791	2,905	3,108	3,693	4,284	5,506
	0.50	Real		2,135	2,192	2,188	2,174	2,208	2,259	2,284	2,299	2,301	2,473	2,595	2,917
	3.26	Nominal	Cost in mills/kWh	47.8	49.8	50.4	51.0	52.8	54.9	56.4	57.7	59.5	68.1	75.3	90.3
	-0.13	Real		47.8	48.2	47.2	46.1	46.2	46.5	46.2	45.7	44.1	45.6	45.6	47.8
		Nominal	Average Customer Bill ($)	1,631	1,714	1,751	1,781	1,846	1,921	1,972	2,019	2,090	2,368	2,622	3,192
		Real		1,631	1,657	1,638	1,611	1,615	1,625	1,613	1,598	1,547	1,585	1,588	1,691
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
48,368	4.03	Nominal	**Total Resource Cost ($M)**	2,139	2,275	2,353	2,421	2,549	2,708	2,847	2,982	3,226	3,870	4,519	5,797
	0.61	Real		2,139	2,200	2,201	2,190	2,230	2,291	2,330	2,360	2,387	2,591	2,737	3,071
	3.21	Nominal	Cost in mills/kWh	47.8	49.7	50.1	50.4	51.9	54.0	55.5	56.8	58.6	66.9	73.8	88.0
	-0.18	Real		47.8	48.0	46.8	45.6	45.4	45.7	45.4	44.9	43.4	44.8	44.7	46.6

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 46.59

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 45.53

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Load = m Gas = mg DSR = md Coal = ac Renewables = sr

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,189	68,232	69,046	69,730	70,597	71,447	75,275	76,282	77,824	80,075
	MWa	7,549	7,664	7,670	7,789	7,882	7,960	8,059	8,156	8,593	8,708	8,884	9,141
	Total Annual Emissions (1000 Tons)												
1.11%	CO2	54,170	54,960	55,955	55,967	56,319	56,470	57,009	57,669	62,112	62,821	66,326	67,523
0.13%	NOx	139.6	141.4	143.8	142.8	143.2	143.6	120.2	121.7	131.6	133.1	140.9	143.2
0.48%	TSP	10.4	10.5	10.7	10.6	10.6	10.6	10.7	10.8	11.0	11.1	11.3	11.5
	Annual System Emission Rates (Pounds/MWh)												
0.15%	CO2	1,638	1,637	1,666	1,641	1,631	1,620	1,615	1,614	1,650	1,647	1,705	1,687
-0.87%	NOx	4.22	4.21	4.28	4.19	4.15	4.12	3.41	3.41	3.50	3.49	3.62	3.58
-0.50%	TSP	0.31	0.31	0.32	0.31	0.31	0.31	0.30	0.30	0.29	0.29	0.29	0.29
	Emission Rates as Percent of 1994 Base												
	CO2	100	99.94	101.67	100.14	99.57	98.86	98.58	98.54	100.73	100.54	104.04	102.94
	NOx	100	99.80	101.41	99.14	98.24	97.58	80.66	80.71	82.85	82.66	85.76	84.73
	TSP	100	99.06	101.08	98.57	97.67	97.01	96.52	95.67	93.25	92.81	92.12	90.95

20 Year Emissions (1000 Tons)	Average	Total	
CO2	61,102	1,222,047	
NOx	136.8	2,737	2736
TSP	11.0	219	

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Load = m Gas = mg DSR = md Coal = ac Renewables = sr

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C				29.0	36.0	45.0							110.0
	OWC Wind without Tax C							29.0	29.0					58.0
	OWC Geothermal								13.0					13.0
O	OWC Cogen 1				160.0									160.0
W	OWC Cogen 2				115.6									115.6
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage												472.5	472.5
	Total	**24.4**	**25.0**	**24.1**	**331.1**	**72.8**	**91.0**	**82.5**	**95.7**	**69.2**	**82.3**	**69.2**	**538.9**	**1506.2**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C				29.0	36.0	45.0							110.0
	Utah Wind without Tax C							29.0	29.0					58.0
	Utah Geothermal								12.0					12.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal								91.1	608.6	29.6	529.6	15.3	1274.2
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT													0.0
	Utah Pumped Storage						44.3	70.2		172.9		212.6		500.0
	Total	**8.9**	**10.1**	**14.1**	**48.1**	**56.1**	**114.4**	**125.4**	**158.6**	**832.2**	**104.2**	**808.3**	**63.8**	**2344.2**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C				29.0	36.0	45.0							110.0
Y	Wyo Wind without Tax C							29.0	29.0					58.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**34.0**	**42.2**	**49.9**	**35.3**	**35.4**	**12.5**	**19.1**	**19.1**	**17.7**	**272.1**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable				87.0	108.0	135.0	87.0	112.0					529.0
O	Cogen				275.6									275.6
T	Combined Cycle CT													0.0
A	Coal								91.1	608.6	29.6	529.6	15.3	1274.2
L	Simple Cycle CT													0.0
	Pumped Storage						44.3	70.2		172.9		212.6	472.5	972.5
	Total	**35.1**	**36.3**	**42.1**	**413.2**	**171.1**	**255.3**	**243.2**	**289.7**	**913.9**	**205.6**	**896.6**	**620.4**	**4122.5**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	363	471	650	807	1010	1792	1821	2564	3051
L	**Total Resources**	**10068**	**10393**	**10249**	**10581**	**10843**	**11004**	**11144**	**11347**	**11691**	**11722**	**12010**	**12509**
&													
R	Reserves	1210	1388	1236	1371	1444	1405	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	15.0	15.6	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

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Load = m Gas = mg DSR = md Coal = ac Renewables = sr

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C				6.9	15.5	26.3	26.3	26.3	26.3	26.3	26.3	26.3
	OWC Wind without Tax C							6.9	13.9	13.9	13.9	13.9	13.9
O	OWC Geothermal								10.7	10.2	10.2	11.0	11.4
W	OWC Cogen 1				138.6	146.4	146.4	148.3	144.2	140.1	140.9	148.9	148.9
C	OWC Cogen 2				95.6	95.6	95.6	95.6	95.6	95.6	98.0	102.8	102.8
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												1.4
	Total	**12.3**	**25.7**	**39.0**	**295.6**	**331.5**	**357.9**	**384.5**	**415.8**	**441.5**	**480.8**	**521.7**	**549.1**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C				10.2	22.8	38.6	38.6	38.6	38.6	38.6	38.6	38.6
	Utah Wind without Tax C							10.2	20.4	20.4	20.4	20.3	20.4
	Utah Geothermal								9.8	9.3	9.3	9.2	9.6
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal								83.5	641.2	668.4	1153.7	1167.8
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage						8.4	21.3	21.3	64.0	65.1	101.0	109.3
	Total	**6.9**	**15.2**	**27.4**	**53.6**	**84.0**	**125.3**	**166.2**	**287.8**	**922.4**	**1001.5**	**1565.6**	**1622.9**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C				10.2	22.8	38.6	38.6	38.6	38.6	38.6	38.6	38.6
Y	Wyo Wind without Tax C							10.2	20.4	20.4	20.4	20.3	20.4
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**21.2**	**39.7**	**60.0**	**75.8**	**91.6**	**102.5**	**119.0**	**135.3**	**150.2**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable				27.3	61.1	103.5	130.8	178.7	177.7	177.7	178.2	179.2
O	Cogen				234.2	242.0	242.0	243.9	239.8	235.7	238.9	251.7	251.7
T	Combined Cycle CT												
A	Coal								83.5	641.2	668.4	1153.7	1167.8
L	Simple Cycle CT												
	Pumped Storage						8.4	21.3	21.3	64.0	65.1	101.0	110.7
	Total	**20.6**	**43.3**	**72.5**	**370.4**	**455.2**	**543.2**	**626.5**	**795.2**	**1466.4**	**1601.3**	**2222.6**	**2322.2**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pumped Storage	312	311	309	310	309	317	334	334	389	388	434	447
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	334	372	378	329	291	337	507	562	532	467
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	**7547**	**7663**	**7670**	**7787**	**7880**	**7958**	**8058**	**8155**	**8592**	**8706**	**8882**	**9140**
M													
	Existing Generation	6776	6887	7035	6970	7021	7043	7112	7105	7053	7109	6774	6911
L	Firm Purchases	645	644	452	434	411	403	393	388	364	361	335	381
&	Non-Firm Purchases	128	133	183	136	158	171	171	153	71	100	103	152
R	New Resources				261	303	353	395	523	1118	1150	1684	1709
	Total Resources	**7549**	**7664**	**7670**	**7801**	**7893**	**7970**	**8071**	**8169**	**8606**	**8720**	**8896**	**9153**

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Load = m Gas = mg DSR = md Coal = ac Renewables = sr

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C				23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
	OWC Wind without Tax C							23.0	23.0	23.0	23.0	23.0	23.0
	OWC Geothermal								82.0	78.0	78.0	84.0	87.0
O	OWC Cogen 1				86.0	91.0	91.0	92.0	90.0	87.0	88.0	93.0	93.0
W	OWC Cogen 2				82.0	82.0	82.0	82.0	82.0	82.0	84.0	88.0	88.0
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C				35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
	Utah Wind without Tax C							35.0	35.0	35.0	35.0	35.0	35.0
	Utah Geothermal								81.0	77.0	77.0	76.0	80.0
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal								91.0	91.0	91.0	91.0	91.0
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage						18.0	18.0	18.0	22.0	22.0	20.0	21.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C				35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Y	Wyo Wind without Tax C							35.0	35.0	35.0	35.0	35.0	35.0
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	74.6	73.9	75.0	74.1	73.5	73.7	74.4	74.2	73.6	74.1	73.8	75.2
	New Resources				72.0	64.4	54.3	48.9	51.8	62.4	63.1	65.7	56.0
	DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Load = m Gas = mg DSR = md Coal = nc Renewables = ar

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		**Energy Sales (MWa)**	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,760	8,154	8,543	8,824	9,295	9,803	10,323	11,041	12,184	13,437	15,412	17,947
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
46,894	4.04	Nominal	**Operating Revenues ($M)**	2,135	2,266	2,339	2,400	2,497	2,620	2,732	2,838	3,101	3,593	4,320	5,499
	0.61	Real		2,135	2,192	2,188	2,171	2,184	2,217	2,235	2,246	2,295	2,406	2,616	2,913
	3.37	Nominal	Cost in mills/kWh	47.8	49.8	50.4	50.9	52.2	53.9	55.2	56.4	59.4	66.3	75.9	90.2
	-0.03	Real		47.8	48.2	47.2	46.1	45.6	45.6	45.2	44.6	44.0	44.4	46.0	47.8
		Nominal	Average Customer Bill ($)	1,631	1,714	1,751	1,778	1,826	1,885	1,930	1,972	2,085	2,304	2,644	3,188
		Real		1,631	1,657	1,638	1,609	1,597	1,595	1,579	1,561	1,543	1,542	1,601	1,689
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
48,460	4.14	Nominal	**Total Resource Cost ($M)**	2,139	2,275	2,353	2,418	2,521	2,658	2,788	2,915	3,219	3,770	4,554	5,790
	0.71	Real		2,139	2,200	2,201	2,187	2,205	2,249	2,281	2,307	2,382	2,524	2,758	3,068
	3.32	Nominal	Cost in mills/kWh	47.8	49.7	50.1	50.4	51.4	53.0	54.3	55.5	58.5	65.2	74.4	87.9
	-0.08	Real		47.8	48.0	46.8	45.6	44.9	44.9	44.4	43.9	43.3	43.7	45.1	46.5

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 46.68

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 45.62

Load = m Gas = mg DSR = md Coal = nc Renewables = ar

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,189	68,267	68,985	69,756	70,649	71,385	75,021	75,888	77,342	78,849
	MWa	7,549	7,664	7,670	7,793	7,875	7,963	8,065	8,149	8,564	8,663	8,829	9,001
	Total Annual Emissions (1000 Tons)												
0.61%	CO_2	54,170	54,960	55,955	56,101	56,622	56,841	57,467	57,760	59,345	59,778	60,674	61,190
-0.57%	NO_x	139.6	141.4	143.8	142.8	143.6	143.7	120.3	120.5	122.3	123.0	123.8	124.5
0.24%	TSP	10.4	10.5	10.7	10.6	10.6	10.6	10.7	10.7	10.9	10.9	10.9	10.9
	Annual System Emission Rates (Pounds/MWh)												
-0.28%	CO_2	1,638	1,637	1,666	1,644	1,642	1,630	1,627	1,618	1,582	1,575	1,569	1,552
-1.52%	NO_x	4.22	4.21	4.28	4.18	4.16	4.12	3.40	3.37	3.26	3.24	3.20	3.16
-0.67%	TSP	0.31	0.31	0.32	0.31	0.31	0.30	0.30	0.30	0.29	0.29	0.28	0.28
	Emission Rates as Percent of 1994 Base												
	CO_2	100	99.94	101.67	100.32	100.20	99.48	99.30	98.78	96.57	96.16	95.77	94.74
	NO_x	100	99.80	101.41	99.13	98.65	97.63	80.65	79.94	77.24	76.80	75.83	74.82
	TSP	100	99.06	101.08	98.52	98.09	96.89	96.15	95.10	91.98	91.30	89.72	88.06

20 Year Emissions (1000 Tons)	Average	Total
CO_2	58,589	1,171,789
NO_x	128.8	2,575
TSP	10.8	215

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Case # 35

Load = m Gas = mg DSR = md Coal = nc Renewables = ar

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1						118.1	96.6	105.4					320.1
W	OWC Cogen 2				228.2					396.6	29.6	92.9		747.3
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											12.1	487.9	500.0
	Total	**24.4**	**25.0**	**24.1**	**254.7**	**36.8**	**164.1**	**150.1**	**159.1**	**465.8**	**111.9**	**174.2**	**554.3**	**2144.5**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1								37.2	1.8				39.0
T	Utah Cogen 2				73.8									73.8
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal													0.0
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT											520.3		520.3
	Utah Pumped Storage									383.0		117.0		500.0
	Total	**8.9**	**10.1**	**14.1**	**92.9**	**20.1**	**25.1**	**26.2**	**63.7**	**435.5**	**74.6**	**703.4**	**48.5**	**1523.1**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**4.9**	**6.3**	**6.4**	**12.5**	**19.1**	**19.1**	**17.7**	**104.1**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable													0.0
O	Cogen				302.0		118.1	96.6	142.6	398.4	29.6	92.9		1180.2
T	Combined Cycle CT													0.0
A	Coal													0.0
L	Simple Cycle CT											520.3		520.3
	Pumped Storage									383.0		129.1	487.9	1000.0
	Total	**35.1**	**36.3**	**42.1**	**352.6**	**63.1**	**194.1**	**182.6**	**229.2**	**913.8**	**205.6**	**896.7**	**620.5**	**3771.7**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	302	302	420	517	659	1441	1470	2213	2701
L	**Total Resources**	**10068**	**10393**	**10249**	**10520**	**10674**	**10774**	**10854**	**10996**	**11340**	**11371**	**11659**	**12159**
&													
R	Reserves	1210	1388	1236	1371	1411	1405	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	15.0	15.2	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

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Load = m Gas = mg DSR = md Coal = nc Renewables = ar

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1						107.2	192.8	281.3	279.7	281.7	296.8	297.9
C	OWC Cogen 2				188.8	188.8	188.8	188.8	188.8	512.0	536.2	634.6	666.1
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											1.9	35.0
	Total	**12.3**	**25.7**	**39.0**	**243.3**	**262.8**	**385.6**	**489.0**	**595.2**	**947.1**	**1009.4**	**1152.1**	**1243.4**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1								32.3	34.2	34.6	36.1	36.3
T	Utah Cogen 2				61.0	61.0	61.1	61.0	61.0	61.0	60.6	63.9	67.8
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											28.9	28.9
	Utah Pumped Storage									77.1	71.5	92.8	86.1
	Total	**6.9**	**15.2**	**27.4**	**104.4**	**122.2**	**139.4**	**157.1**	**207.5**	**321.2**	**366.4**	**464.5**	**496.3**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**11.0**	**16.9**	**21.4**	**27.0**	**32.6**	**43.5**	**60.0**	**76.4**	**91.2**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable												
O	Cogen				249.8	249.8	357.1	442.6	563.4	886.9	913.1	1031.4	1068.1
T	Combined Cycle CT												
A	Coal												
L	Simple Cycle CT											28.9	28.9
	Pumped Storage									77.1	71.5	94.7	121.1
	Total	**20.6**	**43.3**	**72.5**	**358.7**	**401.9**	**546.4**	**673.1**	**835.3**	**1311.8**	**1435.8**	**1693.0**	**1830.9**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pumped Storage	312	311	309	310	309	307	306	306	405	396	426	460
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	334	376	372	343	324	357	461	509	485	313
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	**7547**	**7663**	**7670**	**7791**	**7874**	**7962**	**8063**	**8147**	**8562**	**8661**	**8827**	**8999**
M													
	Existing Generation	6776	6887	7035	6969	7044	7040	7090	7086	7141	7187	7020	7087
L	Firm Purchases	645	644	452	434	411	403	393	388	364	379	423	442
&	Non-Firm Purchases	128	133	183	151	183	175	152	124	108	125	242	266
R	New Resources				249	249	357	442	563	964	984	1155	1218
	Total Resources	**7549**	**7664**	**7670**	**7803**	**7887**	**7975**	**8077**	**8161**	**8577**	**8675**	**8840**	**9013**

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PacifiCorp RAMPP-3 **Case # 35**

Load = m Gas = mg DSR = md Coal = nc Renewables = ar

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
	OWC Geothermal												
O	OWC Cogen 1						90.0	89.0	87.0	87.0	88.0	92.0	93.0
W	OWC Cogen 2				82.0	82.0	82.0	82.0	82.0	81.0	81.0	84.0	89.0
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											15.0	7.0
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1								87.0	87.0	88.0	92.0	93.0
T	Utah Cogen 2				82.0	82.0	82.0	82.0	82.0	82.0	82.0	86.0	91.0
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											5.0	5.0
	Utah Pumped Storage									20.0	18.0	18.0	17.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	74.6	73.9	75.0	74.1	73.7	73.7	74.1	74.0	74.5	75.0	76.4	77.1
	New Resources				82.5	82.5	85.0	85.5	85.4	66.9	66.9	52.2	45.1
	DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Load = m Gas = mg DSR = md Coal = nc Renewables = sr

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		**Energy Sales (MWa)**	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,763	8,191	8,673	9,052	9,600	10,217	10,800	11,521	12,646	13,813	15,669	18,071
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
47,338	4.04	Nominal	**Operating Revenues ($M)**	2,135	2,266	2,339	2,405	2,516	2,662	2,785	2,914	3,177	3,663	4,390	5,560
	0.61	Real		2,135	2,192	2,188	2,176	2,201	2,252	2,279	2,306	2,352	2,452	2,659	2,946
	3.37	Nominal	Cost in mills/kWh	47.8	49.8	50.4	51.0	52.6	54.8	56.3	57.9	60.8	67.6	77.2	91.2
	-0.03	Real		47.8	48.2	47.2	46.1	46.0	46.3	46.1	45.8	45.0	45.3	46.7	48.3
		Nominal	Average Customer Bill ($)	1,631	1,714	1,751	1,782	1,840	1,915	1,967	2,025	2,136	2,349	2,687	3,224
		Real		1,631	1,657	1,638	1,612	1,610	1,620	1,610	1,603	1,581	1,572	1,627	1,708
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
48,903	4.14	Nominal	**Total Resource Cost ($M)**	2,139	2,275	2,353	2,423	2,541	2,701	2,841	2,991	3,294	3,840	4,625	5,851
	0.71	Real		2,139	2,200	2,201	2,192	2,222	2,285	2,325	2,367	2,438	2,571	2,801	3,100
	3.32	Nominal	Cost in mills/kWh	47.8	49.7	50.1	50.5	51.8	53.9	55.4	56.9	59.9	66.4	75.6	88.8
	-0.08	Real		47.8	48.0	46.8	45.7	45.3	45.6	45.3	45.1	44.3	44.5	45.8	47.0

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 47.12

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 46.04

md nc sr financial 1/26/94 3:07 PM

Load = m Gas = mg DSR = md Coal = nc Renewables = sr

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,189	68,240	69,064	69,747	70,676	71,464	75,213	76,081	77,123	78,586
	MWa	7,549	7,664	7,670	7,790	7,884	7,962	8,068	8,158	8,586	8,685	8,804	8,971
	Total Annual Emissions (1000 Tons)												
0.55%	CO2	54,170	54,960	55,955	56,058	56,389	56,464	57,070	57,199	58,761	59,202	60,000	60,490
-0.59%	NOx	139.6	141.4	143.8	142.9	143.3	143.3	119.9	119.9	121.8	122.6	123.3	124.0
0.24%	TSP	10.4	10.5	10.7	10.6	10.6	10.6	10.7	10.6	10.8	10.9	10.9	10.9
	Annual System Emission Rates (Pounds/MWh)												
-0.33%	CO2	1,638	1,637	1,666	1,643	1,633	1,619	1,615	1,601	1,563	1,556	1,556	1,539
-1.52%	NOx	4.22	4.21	4.28	4.19	4.15	4.11	3.39	3.36	3.24	3.22	3.20	3.16
-0.66%	TSP	0.31	0.31	0.32	0.31	0.31	0.30	0.30	0.30	0.29	0.29	0.28	0.28
	Emission Rates as Percent of 1994 Base												
	CO2	100	99.94	101.67	100.28	99.67	98.83	98.58	97.71	95.37	94.99	94.97	93.97
	NOx	100	99.80	101.41	99.19	98.27	97.32	80.36	79.48	76.74	76.33	75.75	74.75
	TSP	100	99.06	101.08	98.60	97.68	96.67	95.92	94.67	91.58	90.97	89.84	88.21

20 Year Emissions (1000 Tons)	Average	Total
CO2	58,130	1,162,600
NOx	128.4	2,568
TSP	10.8	215

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Case # 36

Load = m Gas = mg DSR = md Coal = nc Renewables = sr

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C				29.0	36.0	45.0							110.0
	OWC Wind without Tax C							29.0	29.0					58.0
	OWC Geothermal								13.0					13.0
O	OWC Cogen 1						44.3	70.2	91.1	114.3				319.9
W	OWC Cogen 2				275.6					247.7	11.6	54.6		589.5
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											12.1	487.9	500.0
	Total	**24.4**	**25.0**	**24.1**	**331.1**	**72.8**	**135.3**	**152.7**	**186.8**	**431.2**	**93.9**	**135.9**	**554.3**	**2167.5**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C				29.0	36.0	45.0							110.0
	Utah Wind without Tax C							29.0	29.0					58.0
	Utah Geothermal								12.0					12.0
	Utah Solar													0.0
U	Utah Cogen 1									21.0	18.0			39.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal													0.0
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT											574.0		574.0
	Utah Pumped Storage									398.5		101.5		500.0
	Total	**8.9**	**10.1**	**14.1**	**48.1**	**56.1**	**70.1**	**55.2**	**67.5**	**470.2**	**92.6**	**741.6**	**48.5**	**1683.0**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C				29.0	36.0	45.0							110.0
Y	Wyo Wind without Tax C							29.0	29.0					58.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**34.0**	**42.2**	**49.9**	**35.3**	**35.4**	**12.5**	**19.1**	**19.1**	**17.7**	**272.1**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable				87.0	108.0	135.0	87.0	112.0					529.0
O	Cogen				275.6		44.3	70.2	91.1	383.0	29.6	54.6		948.4
T	Combined Cycle CT													0.0
A	Coal													0.0
L	Simple Cycle CT											574.0		574.0
	Pumped Storage									398.5		113.6	487.9	1000.0
	Total	**35.1**	**36.3**	**42.1**	**413.2**	**171.1**	**255.3**	**243.2**	**289.7**	**913.9**	**205.6**	**896.6**	**620.5**	**4122.6**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	363	471	650	807	1010	1792	1821	2564	3051
L	**Total Resources**	**10068**	**10393**	**10249**	**10581**	**10843**	**11004**	**11144**	**11347**	**11691**	**11722**	**12010**	**12509**
&													
R	Reserves	1210	1388	1236	1371	1444	1405	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	15.0	15.6	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

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Case # 36

Load = m Gas = mg DSR = md Coal = nc Renewables = sr

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C				6.9	15.5	26.3	26.3	26.3	26.3	26.3	26.3	26.3
	OWC Wind without Tax C							6.9	13.9	13.9	13.9	13.9	13.9
O	OWC Geothermal								10.2	10.1	10.1	10.8	10.9
W	OWC Cogen 1						40.3	102.4	176.9	277.5	280.1	297.3	297.9
C	OWC Cogen 2				228.0	228.0	228.0	228.0	228.0	428.8	438.3	497.9	524.1
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											1.9	31.8
	Total	**12.3**	**25.7**	**39.0**	**289.4**	**317.5**	**384.2**	**471.0**	**580.4**	**912.0**	**960.2**	**1066.9**	**1149.3**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C				10.2	22.8	38.6	38.6	38.6	38.6	38.6	38.6	38.6
	Utah Wind without Tax C							10.2	20.4	20.4	20.4	20.4	20.4
	Utah Geothermal								9.8	9.7	9.8	10.0	10.1
	Utah Solar												
U	Utah Cogen 1									18.4	34.6	36.2	36.2
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											31.9	31.9
	Utah Pumped Storage									83.3	78.1	92.8	81.2
	Total	**6.9**	**15.2**	**27.4**	**53.6**	**84.0**	**116.9**	**144.9**	**183.0**	**319.3**	**381.2**	**472.7**	**495.6**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C				10.2	22.8	38.6	38.6	38.6	38.6	38.6	38.6	38.6
Y	Wyo Wind without Tax C							10.2	20.4	20.4	20.4	20.4	20.4
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**21.2**	**39.7**	**60.0**	**75.8**	**91.6**	**102.5**	**119.0**	**135.4**	**150.2**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable				27.3	61.1	103.5	130.8	178.2	178.0	178.1	179.0	179.2
O	Cogen				228.0	228.0	268.3	330.4	404.9	724.7	753.0	831.4	858.2
T	Combined Cycle CT												
A	Coal												
L	Simple Cycle CT											31.9	31.9
	Pumped Storage									83.3	78.1	94.7	113.0
	Total	**20.6**	**43.3**	**72.5**	**364.2**	**441.2**	**561.1**	**691.7**	**855.0**	**1333.8**	**1460.4**	**1675.0**	**1795.1**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pumped Storage	312	311	309	310	309	307	306	306	413	405	426	449
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	334	374	380	343	327	366	475	523	460	294
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	**7547**	**7663**	**7670**	**7789**	**7882**	**7962**	**8066**	**8156**	**8584**	**8684**	**8802**	**8969**
M													
	Existing Generation	6776	6887	7035	6971	7025	7026	7082	7078	7138	7182	7021	7090
L	Firm Purchases	645	644	452	434	411	403	393	388	364	379	423	442
&	Non-Firm Purchases	128	133	183	141	171	173	144	122	111	128	236	269
R	New Resources				255	289	371	461	582	985	1009	1136	1182
	Total Resources	**7549**	**7664**	**7670**	**7801**	**7896**	**7973**	**8080**	**8170**	**8598**	**8698**	**8816**	**8983**

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PacifiCorp RAMPP-3 **Case # 36**

Load = m Gas = mg DSR = md Coal = nc Renewables = sr

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C				23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
	OWC Wind without Tax C							23.0	23.0	23.0	23.0	23.0	23.0
	OWC Geothermal								78.0	77.0	77.0	83.0	83.0
O	OWC Cogen 1						90.0	89.0	86.0	86.0	87.0	92.0	93.0
W	OWC Cogen 2				82.0	82.0	82.0	82.0	82.0	81.0	81.0	84.0	88.0
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											15.0	6.0
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C				35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
	Utah Wind without Tax C							35.0	35.0	35.0	35.0	35.0	35.0
	Utah Geothermal								81.0	80.0	81.0	83.0	83.0
	Utah Solar												
U	Utah Cogen 1									87.0	88.0	92.0	92.0
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											5.0	5.0
	Utah Pumped Storage									20.0	19.0	18.0	16.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C				35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Y	Wyo Wind without Tax C							35.0	35.0	35.0	35.0	35.0	35.0
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												

Total System

	1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
Existing Generation	74.6	73.9	75.0	74.1	73.5	73.5	74.0	74.0	74.5	74.9	76.4	77.1
New Resources				70.3	61.4	57.1	57.1	57.6	55.0	55.4	44.3	38.7
DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Load = m Gas = mg DSR = ad Coal = ac Renewables = ar

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	34	79	152	191	236	270	305	341	404	490	570	638
			After Conservation												
			System Load (MWa)	5,619	5,704	5,809	5,867	5,953	6,053	6,201	6,281	6,529	6,797	7,141	7,659
	0.64		Energy Sales (MWa)	5,082	5,159	5,223	5,305	5,384	5,476	5,578	5,684	5,910	6,152	6,465	6,940
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,791	8,231	8,699	9,039	9,595	10,236	11,073	11,996	13,448	15,200	17,773	20,269
			Net Conservation Assets ($M)	90	193	337	407	497	577	663	741	828	890	909	851
			Utility Cost												
46,327	3.91	Nominal	**Operating Revenues ($M)**	2,133	2,268	2,333	2,404	2,496	2,622	2,731	2,815	3,018	3,630	4,235	5,454
	0.49	Real		2,133	2,193	2,182	2,175	2,184	2,218	2,234	2,228	2,233	2,430	2,565	2,890
	3.25	Nominal	Cost in mills/kWh	47.9	50.2	51.0	51.7	52.9	54.7	55.9	56.5	58.3	67.4	74.8	89.7
	-0.14	Real		47.9	48.5	47.7	46.8	46.3	46.2	45.7	44.7	43.1	45.1	45.3	47.5
		Nominal	Average Customer Bill ($)	1,630	1,715	1,746	1,782	1,825	1,886	1,929	1,957	2,029	2,327	2,592	3,162
		Real		1,630	1,658	1,633	1,612	1,597	1,596	1,578	1,548	1,502	1,558	1,570	1,675
			Total Resource Cost												
			DSR Customer Cost ($M)	6.6	8.5	9.9	11.9	13.5	58.0	76.1	93.8	81.2	74.9	88.6	79.4
			Levelized (20-year at 8.8%)	0.7	1.6	2.7	4.0	5.4	11.7	19.9	30.1	47.6	72.8	101.6	138.1
			Energy Svc Charge ($M)	4.4	9.2	13.9	19.0	25.2	31.6	39.2	48.1	66.2	93.3	118.7	131.5
47,784	4.01	Nominal	**Total Resource Cost ($M)**	2,138	2,278	2,349	2,427	2,527	2,665	2,790	2,893	3,131	3,796	4,455	5,724
	0.59	Real		2,138	2,204	2,197	2,196	2,210	2,255	2,283	2,290	2,318	2,541	2,698	3,032
	3.19	Nominal	Cost in mills/kWh	47.7	49.7	50.0	50.6	51.5	53.1	54.4	55.1	56.9	65.7	72.8	86.8
	-0.20	Real		47.7	48.1	46.8	45.7	45.0	45.0	44.5	43.6	42.1	44.0	44.1	46.0

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 46.42

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 44.98

Load = m Gas = mg DSR = ad Coal = ac Renewables = ar

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,033	66,900	66,848	67,505	68,249	69,003	69,852	70,728	74,653	75,669	77,263	79,506
	MWa	7,538	7,637	7,631	7,706	7,791	7,877	7,974	8,074	8,522	8,638	8,820	9,076
	Total Annual Emissions (1000 Tons)												
1.21%	CO2	54,160	54,900	55,648	55,742	56,267	56,666	57,238	58,283	63,035	63,880	67,335	68,837
0.24%	NOx	139.5	141.3	143.0	142.6	143.3	144.5	120.8	123.2	133.8	135.6	143.3	146.3
0.53%	TSP	10.4	10.4	10.6	10.6	10.6	10.7	10.8	10.8	11.1	11.2	11.4	11.5
	Annual System Emission Rates (Pounds/MWh)												
0.29%	CO2	1,640	1,641	1,665	1,652	1,649	1,642	1,639	1,648	1,689	1,688	1,743	1,732
-0.72%	NOx	4.23	4.22	4.28	4.22	4.20	4.19	3.46	3.48	3.59	3.58	3.71	3.68
-0.42%	TSP	0.31	0.31	0.32	0.31	0.31	0.31	0.31	0.31	0.30	0.30	0.29	0.29
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.05	101.50	100.68	100.52	100.12	99.90	100.47	102.95	102.93	106.25	105.56
	NOx	100	99.93	101.26	99.93	99.37	99.11	81.86	82.45	84.84	84.80	87.79	87.10
	TSP	100	99.19	100.96	99.42	98.87	98.53	98.13	97.37	94.74	94.28	93.32	92.24

20 Year Emissions (1000 Tons)	Average	Total
CO2	61,752	1,235,038
NOx	138.4	2,769
TSP	11.0	221

PacifiCorp RAMPP-3 **Case # 37**

Load = m Gas = mg DSR = ad Coal = ac Renewables = ar

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	30.2	34.9	43.2	27.6	37.6	43.2	50.6	50.9	63.6	75.8	66.5	63.1	587.2
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1				160.0		23.4							183.4
W	OWC Cogen 2				43.7									43.7
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											36.3	434.1	470.4
	Total	**30.2**	**34.9**	**43.2**	**231.3**	**37.6**	**66.6**	**50.6**	**50.9**	**63.6**	**75.8**	**102.8**	**497.2**	**1284.7**
	DSR	16.8	23.7	40.5	21.0	21.7	23.8	23.4	23.9	44.1	64.3	63.7	47.3	414.2
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal								149.1	660.0	48.9	545.6	59.5	1463.1
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT													0.0
	Utah Pumped Storage						94.9	103.0		135.4		166.7		500.0
	Total	**16.8**	**23.7**	**40.5**	**21.0**	**21.7**	**118.7**	**126.4**	**173.0**	**839.5**	**113.2**	**776.0**	**106.8**	**2377.3**
	DSR	1.8	1.2	3.9	5.0	6.2	6.5	6.2	6.4	12.4	19.1	18.8	16.7	104.2
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**6.5**	**6.2**	**6.4**	**12.4**	**19.1**	**18.8**	**16.7**	**104.2**
	DSR	48.8	59.8	87.6	53.6	65.5	73.5	80.2	81.2	120.1	159.2	149.0	127.1	1105.6
T	Renewable													0.0
O	Cogen				203.7		23.4							227.1
T	Combined Cycle CT													0.0
A	Coal								149.1	660.0	48.9	545.6	59.5	1463.1
L	Simple Cycle CT													0.0
	Pumped Storage						94.9	103.0		135.4		203.0	434.1	970.4
	Total	**48.8**	**59.8**	**87.6**	**257.3**	**65.5**	**191.8**	**183.2**	**230.3**	**915.5**	**208.1**	**897.6**	**620.7**	**3766.2**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-49	-109	-196	-250	-315	-389	-469	-550	-670	-830	-979	-1106
S	**Total Requirements**	**8843**	**8967**	**8930**	**9062**	**9174**	**9283**	**9358**	**9487**	**9798**	**9843**	**10098**	**10537**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	204	204	322	425	574	1370	1418	2167	2661
L	**Total Resources**	**10068**	**10393**	**10249**	**10422**	**10576**	**10676**	**10762**	**10911**	**11269**	**11319**	**11613**	**12119**
&													
R	Reserves	1224	1425	1318	1359	1401	1392	1403	1422	1469	1475	1514	1579
	Reserve Margin (RM) (%)	13.8	15.9	14.8	15.0	15.3	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	102		20									

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Case # 37

Load = m Gas = mg DSR = ad Coal = ac Renewables = ar

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	17.6	40.2	71.3	87.9	108.1	120.9	136.0	151.0	176.0	205.7	230.4	252.9
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				137.5	146.4	167.8	170.1	170.2	163.1	166.9	170.7	170.7
C	OWC Cogen 2				36.2	36.2	36.2	37.6	37.0	37.1	38.0	38.9	38.9
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage			—								0.2	1.9
	Total	**17.6**	**40.2**	**71.3**	**261.6**	**290.7**	**324.9**	**343.7**	**358.2**	**376.2**	**410.6**	**440.2**	**464.4**
	DSR	14.6	36.3	74.4	92.1	111.3	125.8	140.6	155.8	183.2	222.5	261.7	293.7
	Utah Wind with Tax C		-14.6										
	Utah Wind without Tax C		=21.7										
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal								136.6	741.4	786.3	1286.3	1340.8
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage						17.9	36.7	36.7	69.1	64.9	101.7	113.3
	Total	**14.6**	**36.3**	**74.4**	**92.1**	**111.3**	**143.7**	**177.3**	**329.1**	**993.7**	**1073.7**	**1649.7**	**1747.8**
	DSR	1.4	2.4	6.1	11.0	16.9	22.8	28.4	33.9	44.8	61.3	77.5	91.5
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**11.0**	**16.9**	**22.8**	**28.4**	**33.9**	**44.8**	**61.3**	**77.5**	**91.5**
	DSR	33.6	78.9	151.8	191.0	236.3	269.5	305.0	340.7	404.0	489.5	569.6	638.1
T	Renewable												
O	Cogen				173.7	182.6	204.0	207.7	207.2	200.2	204.9	209.6	209.6
T	Combined Cycle CT												
A	Coal								136.6	741.4	786.3	1286.3	1340.8
L	Simple Cycle CT												
	Pumped Storage						17.9	36.7	36.7	69.1	64.9	101.9	115.2
	Total	**33.6**	**78.9**	**151.8**	**364.7**	**418.9**	**491.4**	**549.4**	**721.2**	**1414.7**	**1545.6**	**2167.4**	**2303.7**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pumped Storage	312	311	309	310	309	330	354	354	395	388	434	445
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	422	440	374	371	371	314	260	304	486	531	500	429
T	DSR	-34	-79	-152	-191	-236	-270	-305	-341	-404	-490	-570	-638
E	**Total Requirements**	7536	7636	7630	7704	7789	7876	7972	8073	8521	8637	8818	9075
M													
	Existing Generation	6774	6880	6996	6968	7043	7083	7155	7134	7070	7126	6769	6896
L	Firm Purchases	645	643	452	435	411	403	393	388	364	361	336	374
&	Non-Firm Purchases	118	114	183	141	167	181	194	183	90	107	130	154
R	New Resources				173	182	221	244	380	1010	1056	1597	1665
	Total Resources	7537	7637	7631	7717	7803	7888	7986	8085	8534	8650	8832	9089

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Load = m Gas = mg DSR = ad Coal = ac Renewables = ar

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	58.0	61.0	65.0	64.0	62.0	55.0	50.0	47.0	46.0	44.0	43.0	43.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
	OWC Geothermal												
O	OWC Cogen 1				85.0	91.0	91.0	92.0	92.0	88.0	91.0	93.0	93.0
W	OWC Cogen 2				82.0	82.0	82.0	85.0	84.0	84.0	86.0	88.0	88.0
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	DSR	86.0	89.0	91.0	90.0	89.0	85.0	82.0	79.0	76.0	73.0	71.0	70.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal								91.0	91.0	91.0	91.0	91.0
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage						18.0	18.0	18.0	20.0	19.0	20.0	22.0
	DSR	76.0	81.0	89.0	92.0	93.0	92.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	74.5	73.8	74.6	74.1	73.7	74.1	74.8	74.5	73.8	74.3	73.7	75.0
	New Resources				84.9	89.3	68.6	57.4	66.2	73.7	74.5	73.7	62.6
	DSR	68.9	72.7	77.4	76.5	74.9	69.3	65.0	61.9	60.3	59.0	58.2	57.7

Load = m Gas = mg DSR = hd Coal = ac Renewables = ar

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
				1/20	1/20	1/20	1/20	1/20	1/20	1/20	1/20	2/20	3/20	3/20	4/20
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	36	84	161	204	254	292	334	375	448	547	639	718
			After Conservation												
			System Load (MWa)	5,616	5,698	5,799	5,854	5,936	6,030	6,173	6,246	6,485	6,739	7,071	7,578
	0.62		**Energy Sales (MWa)**	5,080	5,154	5,214	5,294	5,369	5,455	5,552	5,653	5,870	6,100	6,402	6,868
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,795	8,223	8,674	9,002	9,534	10,168	11,002	11,924	13,360	15,051	17,602	20,129
			Net Conservation Assets ($M)	95	203	354	430	527	619	718	808	917	1,002	1,034	979
			Utility Cost												
46,067	3.90	Nominal	**Operating Revenues ($M)**	2,132	2,267	2,331	2,403	2,489	2,614	2,718	2,802	2,999	3,613	4,207	5,409
	0.48	Real		2,132	2,193	2,180	2,173	2,177	2,212	2,224	2,217	2,220	2,419	2,548	2,866
	3.26	Nominal	Cost in mills/kWh	47.9	50.2	51.0	51.8	52.9	54.7	55.9	56.6	58.3	67.6	75.0	89.9
	-0.13	Real		47.9	48.6	47.7	46.9	46.3	46.3	45.7	44.8	43.2	45.3	45.4	47.6
		Nominal	Average Customer Bill ($)	1,629	1,715	1,744	1,780	1,820	1,881	1,920	1,947	2,016	2,316	2,575	3,136
		Real		1,629	1,658	1,631	1,611	1,592	1,591	1,571	1,541	1,492	1,551	1,559	1,662
			Total Resource Cost												
			DSR Customer Cost ($M)	8.5	11.0	12.6	16.1	16.9	64.6	84.4	103.5	92.3	86.2	107.0	106.2
			Levelized (20-year at 8.8%)	0.9	2.1	3.5	5.2	7.0	14.0	23.1	34.3	54.1	82.9	116.8	163.6
			Energy Svc Charge ($M)	4.7	9.8	14.9	20.5	27.1	34.3	43.0	52.8	73.1	103.0	130.8	145.6
47,789	4.03	Nominal	**Total Resource Cost ($M)**	2,137	2,279	2,349	2,428	2,523	2,663	2,784	2,889	3,126	3,799	4,454	5,718
	0.61	Real		2,137	2,204	2,197	2,197	2,207	2,253	2,278	2,286	2,314	2,543	2,697	3,030
	3.21	Nominal	Cost in mills/kWh	47.7	49.7	50.0	50.6	51.4	53.1	54.3	55.0	56.8	65.7	72.8	86.8
	-0.18	Real		47.7	48.1	46.8	45.7	45.0	44.9	44.4	43.5	42.1	44.0	44.1	46.0

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **46.50**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **44.99**

hd ac ar financial

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Load = m Gas = mg DSR = hd Coal = ac Renewables = ar

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,024	66,874	66,795	67,321	68,056	68,617	69,467	70,203	73,969	74,845	76,413	78,639
	MWa	7,537	7,634	7,625	7,685	7,769	7,833	7,930	8,014	8,444	8,544	8,723	8,977
	Total Annual Emissions (1000 Tons)												
1.16%	CO2	54,160	54,900	55,608	55,636	56,223	56,512	57,075	58,007	62,651	63,264	66,674	68,218
0.20%	NOx	139.5	141.3	142.9	142.5	143.5	144.4	120.6	122.8	133.2	134.4	142.1	145.2
0.51%	TSP	10.4	10.4	10.6	10.6	10.6	10.7	10.8	10.8	11.1	11.2	11.3	11.5
	Annual System Emission Rates (Pounds/MWh)												
0.29%	CO2	1,641	1,642	1,665	1,653	1,652	1,647	1,643	1,653	1,694	1,691	1,745	1,735
-0.71%	NOx	4.23	4.23	4.28	4.23	4.22	4.21	3.47	3.50	3.60	3.59	3.72	3.69
-0.39%	TSP	0.31	0.31	0.32	0.31	0.31	0.31	0.31	0.31	0.30	0.30	0.30	0.29
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.08	101.49	100.75	100.71	100.40	100.16	100.73	103.25	103.04	106.37	105.75
	NOx	100	99.96	101.25	100.16	99.74	99.54	82.17	82.77	85.20	84.99	87.97	87.35
	TSP	100	99.22	100.96	99.68	99.27	98.99	98.53	97.95	95.26	94.90	94.13	92.92

20 Year Emissions (1000 Tons)	Average	Total
CO2	61,372	1,227,447
NOx	137.8	2,756
TSP	11.0	220

PacifiCorp RAMPP-3 **Case # 41**

Load = m Gas = mg DSR = hd Coal = ac Renewables = ar

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	37.4	41.3	51.2	36.2	48.0	53.0	61.2	61.6	78.7	94.1	82.7	78.8	724.2
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1				160.0		19.2							179.2
W	OWC Cogen 2				0.3									0.3
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage												348.2	348.2
	Total	**37.4**	**41.3**	**51.2**	**196.5**	**48.0**	**72.2**	**61.2**	**61.6**	**78.7**	**94.1**	**82.7**	**427.0**	**1251.9**
	DSR	17.6	24.6	41.9	22.4	23.1	27.3	26.8	27.2	50.5	74.1	73.5	54.5	463.5
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal								132.4	660.0	14.9	516.6	82.3	1406.2
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT													0.0
	Utah Pumped Storage						67.8	86.7		109.5		200.2	35.9	500.1
	Total	**17.6**	**24.6**	**41.9**	**22.4**	**23.1**	**95.1**	**113.5**	**159.6**	**820.0**	**89.0**	**790.3**	**172.7**	**2369.8**
	DSR	2.4	1.8	4.7	5.9	7.0	7.4	6.8	6.9	13.5	20.6	20.3	17.9	115.2
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**2.4**	**1.8**	**4.7**	**5.9**	**7.0**	**7.4**	**6.8**	**6.9**	**13.5**	**20.6**	**20.3**	**17.9**	**115.2**
	DSR	57.4	67.7	97.8	64.5	78.1	87.7	94.8	95.7	142.7	188.8	176.5	151.2	1302.9
T	Renewable													0.0
O	Cogen				160.3		19.2							179.5
T	Combined Cycle CT													0.0
A	Coal								132.4	660.0	14.9	516.6	82.3	1406.2
L	Simple Cycle CT													0.0
	Pumped Storage						67.8	86.7		109.5		200.2	384.1	848.3
	Total	**57.4**	**67.7**	**97.8**	**224.8**	**78.1**	**174.7**	**181.5**	**228.1**	**912.2**	**203.7**	**893.3**	**617.6**	**3736.9**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-57	-125	-223	-287	-366	-453	-548	-644	-786	-975	-1152	-1303
S	**Total Requirements**	**8835**	**8951**	**8903**	**9025**	**9124**	**9219**	**9279**	**9393**	**9682**	**9697**	**9924**	**10340**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	160	160	247	334	466	1236	1251	1968	2434
L	**Total Resources**	**10068**	**10393**	**10249**	**10378**	**10532**	**10601**	**10671**	**10803**	**11135**	**11152**	**11414**	**11892**
&													
R	Reserves	1233	1441	1345	1353	1408	1382	1391	1408	1451	1454	1488	1550
	Reserve Margin (RM) (%)	14.0	16.1	15.1	15.0	15.4	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	91											

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Case # 41

Load = m Gas = mg DSR = hd Coal = ac Renewables = ar

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	19.4	43.6	76.7	95.4	118.1	133.8	152.2	170.4	200.9	237.0	266.9	294.3
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				140.0	146.4	164.1	166.4	166.4	162.7	163.1	166.8	166.8
C	OWC Cogen 2				0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage			—									1.5
	Total	19.4	43.6	76.7	235.6	264.7	298.1	318.9	337.1	363.9	400.4	434.0	462.9
	DSR	15.2	37.6	76.9	95.6	115.9	132.5	149.3	166.5	197.7	242.8	287.9	324.5
	Utah Wind with Tax C		- 15.2										
	Utah Wind without Tax C		= 22.4										
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC								121.3	726.1	739.7	1213.1	1288.5
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage						12.8	28.7	28.7	53.2	50.6	91.9	108.3
	Total	15.2	37.6	76.9	95.6	115.9	145.3	178.0	316.5	977.0	1033.1	1592.9	1721.3
	DSR	1.8	3.2	7.5	12.9	19.5	26.1	32.0	38.0	49.7	67.4	84.6	99.5
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	1.8	3.2	7.5	12.9	19.5	26.1	32.0	38.0	49.7	67.4	84.6	99.5
	DSR	36.4	84.4	161.1	203.9	253.5	292.4	333.5	374.9	448.3	547.2	639.4	718.3
T	Renewable												
O	Cogen				140.2	146.6	164.3	166.7	166.7	163.0	163.4	167.1	167.1
T	Combined Cycle CT												
A	Coal								121.3	726.1	739.7	1213.1	1288.5
L	Simple Cycle CT												
	Pumped Storage						12.8	28.7	28.7	53.2	50.6	91.9	109.8
	Total	36.4	84.4	161.1	344.1	400.1	469.5	528.9	691.6	1390.6	1500.9	2111.5	2283.7

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pumped Storage	312	311	309	310	309	323	343	343	375	369	420	437
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	424	442	377	364	366	300	255	288	472	513	487	418
T	DSR	-36	-84	-161	-204	-254	-292	-334	-375	-448	-547	-639	-718
E	**Total Requirements**	7536	7633	7624	7684	7767	7832	7928	8012	8443	8542	8722	8976
M													
	Existing Generation	6774	6879	6992	6971	7052	7081	7155	7135	7058	7119	6783	6894
L	Firm Purchases	645	643	452	435	411	403	393	388	364	361	336	375
&	Non-Firm Purchases	118	112	181	152	171	183	199	187	92	122	144	154
R	New Resources				140	146	177	195	316	942	953	1472	1565
	Total Resources	7537	7634	7625	7698	7780	7844	7942	8026	8456	8555	8735	8988

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Load = m Gas = mg DSR = hd Coal = ac Renewables = ar

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	51.0	55.0	59.0	57.0	55.0	50.0	46.0	43.0	42.0	42.0	41.0	40.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
	OWC Geothermal												
O	OWC Cogen 1				87.0	91.0	91.0	92.0	92.0	90.0	91.0	93.0	93.0
W	OWC Cogen 2				82.0	82.0	82.0	86.0	86.0	86.0	86.0	88.0	88.0
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	DSR	86.0	89.0	91.0	89.0	89.0	84.0	81.0	78.0	75.0	72.0	70.0	70.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal								91.0	91.0	91.0	91.0	91.0
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage						18.0	18.0	18.0	20.0	19.0	19.0	21.0
	DSR	74.0	77.0	84.0	87.0	89.0	89.0	88.0	88.0	88.0	87.0	86.0	86.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	74.5	73.8	74.5	74.1	73.8	74.1	74.8	74.5	73.7	74.2	73.9	75.0
	New Resources				87.3	91.1	71.6	58.4	67.8	76.2	76.2	74.8	64.3
	DSR	63.4	67.5	72.3	70.9	69.4	64.5	60.9	58.2	57.0	56.1	55.5	55.1

Case # 50

Load = m Gas = hg DSR = md Coal = ac Renewables = ar

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		Energy Sales (MWa)	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,757	8,145	8,569	8,998	9,608	10,345	11,300	12,167	13,555	15,315	17,926	20,466
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
46,403	3.95	Nominal	Operating Revenues ($M)	2,135	2,266	2,339	2,408	2,484	2,629	2,744	2,809	3,035	3,606	4,207	5,407
	0.53	Real		2,135	2,192	2,188	2,178	2,173	2,225	2,245	2,223	2,247	2,414	2,548	2,865
	3.29	Nominal	Cost in mills/kWh	47.8	49.8	50.4	51.1	51.9	54.1	55.5	55.8	58.1	66.5	74.0	88.6
	-0.11	Real		47.8	48.2	47.2	46.2	45.4	45.8	45.4	44.1	43.0	44.5	44.8	47.0
		Nominal	Average Customer Bill ($)	1,631	1,714	1,751	1,784	1,817	1,891	1,938	1,952	2,041	2,312	2,575	3,135
		Real		1,631	1,657	1,638	1,614	1,589	1,600	1,586	1,545	1,510	1,548	1,559	1,661
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
47,969	4.05	Nominal	Total Resource Cost ($M)	2,139	2,275	2,353	2,426	2,508	2,668	2,800	2,886	3,153	3,782	4,441	5,698
	0.63	Real		2,139	2,200	2,201	2,195	2,194	2,257	2,291	2,284	2,333	2,532	2,690	3,019
	3.24	Nominal	Cost in mills/kWh	47.8	49.7	50.1	50.5	51.1	53.2	54.6	54.9	57.3	65.4	72.6	86.5
	-0.16	Real		47.8	48.0	46.8	45.7	44.7	45.0	44.6	43.5	42.4	43.8	44.0	45.8

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized

4) 50-year Real Levelized

Load = m Gas = hg DSR = md Coal = ac Renewables = ar

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,189	67,969	68,915	69,414	70,211	71,709	75,126	76,081	77,272	79,453
	MWa	7,549	7,664	7,670	7,759	7,867	7,924	8,015	8,186	8,576	8,685	8,821	9,070
	Total Annual Emissions (1000 Tons)												
1.24%	CO_2	54,170	54,960	55,955	56,024	56,742	56,915	57,271	59,204	63,795	64,548	67,524	69,269
0.28%	NO_x	139.6	141.4	143.8	143.4	145.1	145.6	121.1	125.5	135.8	137.3	144.1	147.7
0.52%	TSP	10.4	10.5	10.7	10.6	10.7	10.8	10.8	11.0	11.2	11.3	11.3	11.5
	Annual System Emission Rates (Pounds/MWh)												
0.33%	CO_2	1,638	1,637	1,666	1,649	1,647	1,640	1,631	1,651	1,698	1,697	1,748	1,744
-0.67%	NO_x	4.22	4.21	4.28	4.22	4.21	4.19	3.45	3.50	3.61	3.61	3.73	3.72
-0.42%	TSP	0.31	0.31	0.32	0.31	0.31	0.31	0.31	0.31	0.30	0.30	0.29	0.29
	Emission Rates as Percent of 1994 Base												
	CO_2	100	99.94	101.67	100.63	100.51	100.10	99.58	100.79	103.67	103.57	106.68	106.43
	NO_x	100	99.80	101.41	99.93	99.72	99.37	81.75	82.94	85.63	85.50	88.33	88.06
	TSP	100	99.06	101.08	99.42	99.16	98.93	98.16	97.10	94.83	94.31	93.19	92.25

20 Year Emissions (1000 Tons)	Average	Total
CO_2	62,174	1,243,482
NO_x	139.7	2,793
TSP	11.1	221

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Load = m Gas = hg DSR = md Coal = ac Renewables = ar

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1				160.0									160.0
W	OWC Cogen 2													0.0
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											115.2	330.2	445.4
	Total	**24.4**	**25.0**	**24.1**	**186.5**	**36.8**	**46.0**	**53.5**	**53.7**	**69.2**	**82.3**	**184.4**	**396.6**	**1182.5**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal								264.0	660.0	29.6	541.4	100.0	1595.0
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT													0.0
	Utah Pumped Storage					118.8	141.2	96.6				85.7	57.7	500.0
	Total	**8.9**	**10.1**	**14.1**	**19.1**	**138.9**	**166.3**	**122.8**	**290.5**	**710.7**	**104.2**	**693.2**	**206.2**	**2485.0**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**4.9**	**6.3**	**6.4**	**12.5**	**19.1**	**19.1**	**17.7**	**104.1**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable													0.0
O	Cogen				160.0									160.0
T	Combined Cycle CT													0.0
A	Coal								264.0	660.0	29.6	541.4	100.0	1595.0
L	Simple Cycle CT													0.0
	Pumped Storage					118.8	141.2	96.6				200.9	387.9	945.4
	Total	**35.1**	**36.3**	**42.1**	**210.6**	**181.9**	**217.2**	**182.6**	**350.6**	**792.4**	**205.6**	**896.7**	**620.5**	**3771.6**

Annual Winter Peak Capacity (MW)

	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	160	279	420	517	781	1441	1470	2213	2700
L	**Total Resources**	**10068**	**10393**	**10249**	**10378**	**10651**	**10774**	**10854**	**11118**	**11340**	**11371**	**11659**	**12158**
&													
R	**Reserves**	1210	1388	1236	1229	1388	1405	1415	1555	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	13.4	15.0	15.0	15.0	16.3	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115	142								

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Load = m Gas = hg DSR = md Coal = ac Renewables = ar

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				138.8	146.6	148.6	148.9	148.6	145.5	141.2	148.9	148.9
C	OWC Cogen 2												
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											0.6	2.4
	Total	**12.3**	**25.7**	**39.0**	**193.3**	**220.6**	**238.2**	**256.3**	**273.7**	**300.9**	**332.7**	**368.3**	**395.7**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal								241.9	846.8	873.9	1370.0	1461.7
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage					22.1	48.5	59.4	66.2	73.8	71.3	102.0	113.5
	Total	**6.9**	**15.2**	**27.4**	**43.4**	**83.3**	**126.8**	**155.5**	**422.3**	**1069.5**	**1144.9**	**1714.8**	**1852.4**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**11.0**	**16.9**	**21.4**	**27.0**	**32.6**	**43.5**	**60.0**	**76.4**	**91.2**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable												
O	Cogen				138.8	146.6	148.6	148.9	148.6	145.5	141.2	148.9	148.9
T	Combined Cycle CT												
A	Coal								241.9	846.8	873.9	1370.0	1461.7
L	Simple Cycle CT												
	Pumped Storage					22.1	48.5	59.4	66.2	73.8	71.3	102.6	115.9
	Total	**20.6**	**43.3**	**72.5**	**247.7**	**320.8**	**386.4**	**438.8**	**728.6**	**1413.9**	**1537.6**	**2159.5**	**2339.3**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pumped Storage	312	311	309	310	337	369	383	391	401	396	436	445
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	334	343	335	242	198	309	477	531	467	398
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	**7547**	**7663**	**7670**	**7758**	**7865**	**7923**	**8014**	**8184**	**8574**	**8683**	**8819**	**9069**
M													
	Existing Generation	6776	6887	7034	7021	7110	7129	7179	7150	7070	7143	6735	6842
L	Firm Purchases	645	644	452	435	411	403	393	392	364	377	341	363
&	Non-Firm Purchases	128	133	183	177	189	207	247	200	88	91	136	151
R	New Resources				138	168	197	208	456	1066	1086	1621	1726
	Total Resources	**7549**	**7664**	**7669**	**7771**	**7878**	**7936**	**8027**	**8198**	**8588**	**8697**	**8833**	**9082**

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Case # 50

Load = m Gas = hg DSR = md Coal = ac Renewables = ar

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
	OWC Geothermal												
O	OWC Cogen 1				86.0	91.0	92.0	93.0	92.0	90.0	88.0	93.0	93.0
W	OWC Cogen 2												
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal								91.0	91.0	91.0	91.0	91.0
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage					18.0	18.0	16.0	18.0	20.0	20.0	23.0	22.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	74.6	73.9	75.0	74.7	74.4	74.6	75.1	74.7	73.8	74.5	73.3	74.4
	New Resources				86.3	60.3	46.9	40.3	58.4	74.0	73.9	73.3	63.9
	DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Load = mh Gas = mg DSR = md Coal = ac Renewables = ar

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,772	5,994	6,255	6,430	6,616	6,808	7,055	7,230	7,689	8,355	9,056	9,923
			Conservation (MWa)	21	43	73	109	152	197	244	292	380	502	604	694
			After Conservation												
			System Load (MWa)	5,751	5,950	6,182	6,321	6,464	6,610	6,811	6,939	7,309	7,854	8,453	9,229
	0.97		Energy Sales (MWa)	5,201	5,382	5,561	5,717	5,848	5,980	6,126	6,278	6,613	7,108	7,652	8,360
			Total Customers (000's)	1,331	1,358	1,384	1,410	1,442	1,479	1,519	1,557	1,636	1,756	1,875	2,018
			Net Electric Plant ($M)	7,777	8,349	9,108	9,730	10,471	11,280	12,334	13,353	15,238	18,120	21,657	25,140
			Net Conservation Assets ($M)	57	113	176	244	329	447	569	681	835	992	1,073	1,026
			Utility Cost												
52,290	4.13	Nominal	**Operating Revenues ($M)**	2,175	2,338	2,451	2,512	2,653	2,845	3,006	3,099	3,410	4,104	4,948	6,432
	0.70	Real		2,175	2,261	2,293	2,273	2,321	2,407	2,459	2,452	2,524	2,748	2,996	3,408
	3.12	Nominal	Cost in mills/kWh	47.7	49.6	50.3	50.2	51.8	54.3	56.0	56.4	58.9	65.9	73.8	87.8
	-0.27	Real		47.7	48.0	47.1	45.4	45.3	45.9	45.8	44.6	43.6	44.1	44.7	46.5
		Nominal	Average Customer Bill ($)	1,634	1,722	1,771	1,782	1,840	1,924	1,979	1,991	2,085	2,337	2,639	3,188
		Real		1,634	1,665	1,657	1,612	1,610	1,627	1,619	1,575	1,543	1,565	1,598	1,689
			Total Resource Cost												
			DSR Customer Cost ($M)	4.0	5.6	6.5	8.5	9.8	73.5	95.2	114.0	106.5	95.1	106.6	99.0
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.7	3.7	11.7	21.9	34.3	56.8	90.1	125.0	169.6
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	28.9	38.7	49.8	73.1	108.3	139.9	164.1
54,056	4.23	Nominal	**Total Resource Cost ($M)**	2,179	2,347	2,465	2,531	2,677	2,885	3,066	3,183	3,540	4,302	5,213	6,766
	0.81	Real		2,179	2,269	2,305	2,289	2,342	2,441	2,509	2,519	2,620	2,880	3,157	3,585
	3.08	Nominal	Cost in mills/kWh	47.7	49.4	50.0	49.7	51.1	53.5	55.1	55.5	58.1	64.9	72.5	85.9
	-0.31	Real		47.7	47.8	46.8	44.9	44.7	45.2	45.1	43.9	43.0	43.5	43.9	45.5

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 45.65

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 44.68

md ac ar financial

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Load = mh Gas = mg DSR = md Coal = ac Renewables = ar

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,795	68,197	68,127	71,324	73,155	74,591	75,616	77,281	82,213	85,874	89,186	93,820
	MWa	7,625	7,785	7,777	8,142	8,351	8,515	8,632	8,822	9,385	9,803	10,181	10,710
	Total Annual Emissions (1000 Tons)												
1.93%	CO2	54,453	55,490	56,589	57,297	58,286	58,881	59,363	61,817	66,891	70,747	76,142	79,878
0.89%	NOx	140.4	142.8	145.4	144.3	145.7	146.6	122.5	128.0	139.3	147.8	159.6	167.7
0.67%	TSP	10.5	10.5	10.8	10.6	10.7	10.8	10.9	11.0	11.4	11.7	11.8	12.0
	Annual System Emission Rates (Pounds/MWh)												
0.23%	CO2	1,630	1,627	1,661	1,607	1,594	1,579	1,570	1,600	1,627	1,648	1,707	1,703
-0.85%	NOx	4.20	4.19	4.27	4.05	3.98	3.93	3.24	3.31	3.39	3.44	3.58	3.57
-1.08%	TSP	0.31	0.31	0.32	0.30	0.29	0.29	0.29	0.28	0.28	0.27	0.26	0.25
	Emission Rates as Percent of 1994 Base												
	CO2	100	99.81	101.89	98.54	97.74	96.83	96.30	98.12	99.81	101.06	104.73	104.44
	NOx	100	99.60	101.55	96.23	94.74	93.49	77.06	78.80	80.63	81.85	85.14	85.01
	TSP	100	98.78	101.18	95.25	93.80	92.50	91.68	90.88	88.46	86.78	84.33	81.39

20 Year Emissions (1000 Tons)	Average	Total
CO2	66,937	1,338,746
NOx	147.5	2,949
TSP	11.3	226

PacifiCorp RAMPP-3 **Case # 69**

Load = mh Gas = mg DSR = md Coal = ac Renewables = ar

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.1	24.3	26.6	36.9	51.7	60.1	60.7	83.6	105.1	91.9	89.6	680.0
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1				160.0	12.3	147.7							320.0
W	OWC Cogen 2				470.0	174.7								644.7
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT												232.1	232.1
	OWC Pumped Storage									48.2		251.9	199.9	500.0
	Total	**24.4**	**25.1**	**24.3**	**656.6**	**223.9**	**199.4**	**60.1**	**60.7**	**131.8**	**105.1**	**343.8**	**521.6**	**2376.8**
	DSR	9.0	10.1	14.1	19.1	20.2	29.8	29.2	29.5	56.8	83.5	73.2	55.0	429.5
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal								330.0	660.0	437.2	884.0	476.3	2787.5
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT							148.1				13.3		161.4
	Utah Pumped Storage					169.6	98.4	35.5		196.5				500.0
	Total	**9.0**	**10.1**	**14.1**	**19.1**	**189.8**	**128.2**	**212.8**	**359.5**	**913.3**	**520.7**	**970.5**	**531.3**	**3878.4**
	DSR	1.8	1.2	3.9	5.0	6.2	7.3	7.0	7.2	14.1	21.9	21.8	20.1	117.5
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**7.3**	**7.0**	**7.2**	**14.1**	**21.9**	**21.8**	**20.1**	**117.5**
	DSR	35.2	36.4	42.3	50.7	63.3	88.8	96.3	97.4	154.5	210.5	186.9	164.7	1227.0
T	Renewable													0.0
O	Cogen				630.0	187.0	147.7							964.7
T	Combined Cycle CT													0.0
A	Coal								330.0	660.0	437.2	884.0	476.3	2787.5
L	Simple Cycle CT							148.1				13.3	232.1	393.5
	Pumped Storage					169.6	98.4	35.5		244.7		251.9	199.9	1000.0
	Total	**35.2**	**36.4**	**42.3**	**680.7**	**419.9**	**334.9**	**279.9**	**427.4**	**1059.2**	**647.7**	**1336.1**	**1073.0**	**6372.7**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7706	8050	8379	8660	8860	9147	9438	9740	10382	11283	12273	13488
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-72	-114	-165	-228	-317	-413	-510	-665	-875	-1062	-1227
S	**Total Requirements**	**9066**	**9373**	**9510**	**9740**	**9877**	**10075**	**10220**	**10425**	**10912**	**11295**	**11898**	**12698**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	630	987	1233	1416	1746	2651	3088	4237	5146
L	**Total Resources**	**10068**	**10393**	**10249**	**10848**	**11359**	**11587**	**11753**	**12083**	**12550**	**12989**	**13683**	**14604**
&													
R	Reserves	1002	1019	737	1106	1481	1510	1532	1657	1636	1693	1784	1904
	Reserve Margin (RM) (%)	11.0	10.9	7.8	11.4	15.0	15.0	15.0	15.9	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	357	386	688	354								

PacifiCorp RAMPP-3

Case # 69

Load = mh Gas = mg DSR = md Coal = ac Renewables = ar

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.1	54.6	74.2	92.1	112.5	132.9	168.7	213.0	247.6	280.8
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				145.1	156.3	287.2	290.2	283.5	277.5	284.3	297.9	297.9
C	OWC Cogen 2				388.8	533.3	533.3	533.3	533.3	532.0	518.7	567.7	573.2
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												17.3
	OWC Pumped Storage									8.9	6.3	2.0	3.6
	Total	**12.3**	**25.7**	**39.1**	**588.5**	**763.8**	**912.6**	**936.0**	**949.7**	**987.1**	**1022.3**	**1115.2**	**1172.8**
	DSR	6.9	15.3	27.5	43.5	61.3	81.6	102.1	122.9	163.0	221.7	270.9	311.4
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal								302.4	907.2	1307.9	2118.0	2554.4
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT							8.2	8.2	8.2	8.2	9.0	9.0
	Utah Pumped Storage					36.3	66.1	66.0	58.3	99.4	106.4	109.9	124.1
	Total	**6.9**	**15.3**	**27.5**	**43.5**	**97.6**	**147.7**	**176.3**	**491.8**	**1177.8**	**1644.2**	**2507.8**	**2998.9**
	DSR	1.4	2.4	6.1	11.0	16.9	23.5	29.7	36.0	48.2	66.8	85.2	101.5
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**11.0**	**16.9**	**23.5**	**29.7**	**36.0**	**48.2**	**66.8**	**85.2**	**101.5**
	DSR	20.6	43.4	72.7	109.1	152.4	197.2	244.3	291.8	379.9	501.5	603.7	693.7
T	Renewable												
O	Cogen				533.9	689.6	820.5	823.5	816.8	809.5	803.0	865.6	871.1
T	Combined Cycle CT												
A	Coal								302.4	907.2	1307.9	2118.0	2554.4
L	Simple Cycle CT							8.2	8.2	8.2	8.2	9.0	26.3
	Pumped Storage					36.3	66.1	66.0	58.3	108.3	112.7	111.9	127.7
	Total	**20.6**	**43.4**	**72.7**	**643.0**	**878.3**	**1083.8**	**1142.0**	**1477.5**	**2213.1**	**2733.3**	**3708.2**	**4273.2**
	Native Load	5472	5694	5955	6130	6317	6508	6756	6931	7390	8056	8757	9623
S	Pumped Storage	312	311	308	310	356	391	391	381	445	449	448	468
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	376	342	147	355	374	334	272	366	518	578	535	469
T	DSR	-21	-43	-73	-109	-152	-197	-244	-292	-380	-502	-604	-694
E	**Total Requirements**	**7622**	**7784**	**7775**	**8141**	**8350**	**8513**	**8631**	**8820**	**9383**	**9802**	**10179**	**10707**
M													
	Existing Generation	6809	6953	7114	7011	7064	7093	7150	7126	7091	7137	6675	6653
L	Firm Purchases	645	644	452	435	411	403	393	388	364	361	335	338
&	Non-Firm Purchases	170	187	210	175	162	144	204	135	110	85	78	151
R	New Resources				533	725	886	897	1185	1833	2231	3104	3579
	Total Resources	**7624**	**7784**	**7776**	**8154**	**8362**	**8526**	**8644**	**8834**	**9398**	**9814**	**10192**	**10721**

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PacifiCorp RAMPP-3 **Case # 69**

Load = mh Gas = mg DSR = md Coal = ac Renewables = ar

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	42.0	42.0	42.0	41.0	41.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
	OWC Geothermal												
O	OWC Cogen 1				90.0	90.0	89.0	90.0	88.0	86.0	88.0	93.0	93.0
W	OWC Cogen 2				82.0	82.0	82.0	82.0	82.0	82.0	80.0	88.0	88.0
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												7.0
	OWC Pumped Storage									18.0	13.0		
	DSR	76.0	79.0	82.0	83.0	84.0	79.0	77.0	76.0	74.0	73.0	72.0	72.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal								91.0	91.0	91.0	91.0	91.0
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT							5.0	5.0	5.0	5.0	5.0	5.0
	Utah Pumped Storage					21.0	24.0	21.0	19.0	19.0	21.0	21.0	24.0
	DSR	76.0	81.0	89.0	92.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0	86.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.0	70.7	71.1	70.8	71.3	71.1	71.6	71.2	71.2	71.4	71.4	71.3
	Existing Generation	74.9	74.6	75.8	74.6	73.9	74.2	74.8	74.5	74.0	74.4	72.7	72.3
	New Resources				84.6	73.5	71.9	63.3	67.9	69.1	72.2	73.3	69.6
	DSR	58.5	60.6	63.8	66.3	66.9	62.3	59.2	57.2	57.1	57.3	56.8	56.5

Case # 90

Load = h Gas = mg DSR = md Coal = ac Renewables = ar

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,955	6,266	6,608	6,886	7,145	7,401	7,721	7,968	8,587	9,495	10,457	11,680
			Conservation (MWa)	21	43	73	109	153	203	256	309	409	548	664	769
			After Conservation												
			System Load (MWa)	5,934	6,223	6,535	6,777	6,992	7,198	7,465	7,658	8,179	8,947	9,793	10,911
	1.25		Energy Sales (MWa)	5,366	5,627	5,877	6,129	6,325	6,511	6,713	6,928	7,399	8,095	8,862	9,878
			Total Customers (000's)	1,356	1,399	1,440	1,482	1,526	1,573	1,624	1,673	1,776	1,929	2,080	2,263
			Net Electric Plant ($M)	7,777	8,391	9,509	10,604	11,368	12,279	13,487	14,762	17,242	20,928	25,117	29,617
			Net Conservation Assets ($M)	57	114	176	244	330	468	606	732	911	1,100	1,201	1,164
			Utility Cost												
58,788	4.31	Nominal	**Operating Revenues ($M)**	2,235	2,435	2,585	2,681	2,802	3,145	3,330	3,459	3,805	4,646	5,749	7,462
	0.88	Real		2,235	2,355	2,417	2,425	2,451	2,661	2,724	2,737	2,816	3,111	3,482	3,953
	3.01	Nominal	Cost in mills/kWh	47.6	49.4	50.2	49.9	50.6	55.2	56.6	57.0	58.7	65.5	74.1	86.2
	-0.37	Real		47.6	47.8	47.0	45.2	44.2	46.7	46.3	45.1	43.5	43.9	44.9	45.7
		Nominal	Average Customer Bill ($)	1,648	1,740	1,795	1,809	1,836	1,999	2,051	2,068	2,143	2,409	2,764	3,297
		Real		1,648	1,683	1,678	1,636	1,606	1,691	1,678	1,636	1,586	1,613	1,674	1,747
			Total Resource Cost												
			DSR Customer Cost ($M)	4.2	5.8	6.7	8.7	10.1	80.2	104.8	108.9	114.4	105.1	112.3	108.9
			Levelized (20-year at 8.8%)	0.5	1.1	1.8	2.7	3.8	12.5	23.8	35.6	59.8	96.0	131.7	179.1
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	30.2	41.3	53.7	79.9	119.7	155.5	185.6
60,684	4.41	Nominal	**Total Resource Cost ($M)**	2,239	2,444	2,598	2,700	2,826	3,188	3,395	3,549	3,945	4,862	6,037	7,827
	0.97	Real		2,239	2,363	2,430	2,442	2,472	2,697	2,778	2,808	2,920	3,255	3,656	4,147
	2.98	Nominal	Cost in mills/kWh	47.5	49.2	49.9	49.5	49.9	54.3	55.8	56.2	57.9	64.6	72.8	84.5
	-0.41	Real		47.5	47.6	46.7	44.8	43.7	46.0	45.6	44.5	42.9	43.2	44.1	44.7

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 45.15

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 44.2[illegible]

Load = h Gas = mg DSR = md Coal = ac Renewables = ar

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	67,382	68,854	69,940	73,172	77,657	79,532	81,380	83,369	89,843	96,001	101,511	108,869
	MWa	7,692	7,860	7,984	8,353	8,865	9,079	9,290	9,517	10,256	10,959	11,588	12,428
	Total Annual Emissions (1000 Tons)												
2.58%	CO2	54,888	56,114	56,892	58,186	60,161	60,870	61,771	64,229	71,236	77,918	84,888	91,290
1.45%	NOx	141.5	144.4	145.9	146.3	147.9	148.4	124.5	130.1	145.9	160.7	175.2	188.8
0.86%	TSP	10.6	10.7	10.8	10.8	10.9	10.9	10.9	11.1	11.6	12.1	12.3	12.5
	Annual System Emission Rates (Pounds/MWh)												
0.15%	CO2	1,629	1,630	1,627	1,590	1,549	1,531	1,518	1,541	1,586	1,623	1,672	1,677
-1.00%	NOx	4.20	4.19	4.17	4.00	3.81	3.73	3.06	3.12	3.25	3.35	3.45	3.47
-1.61%	TSP	0.31	0.31	0.31	0.30	0.28	0.27	0.27	0.27	0.26	0.25	0.24	0.23
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.05	99.86	97.62	95.10	93.96	93.18	94.58	97.34	99.64	102.66	102.94
	NOx	100	99.87	99.31	95.23	90.72	88.85	72.87	74.34	77.33	79.69	82.19	82.57
	TSP	100	99.14	98.69	94.18	89.30	87.19	85.75	84.92	82.61	80.40	77.44	73.52

20 Year Emissions (1000 Tons)	Average	Total
CO2	72,120	1,442,403
NOx	156.3	3,126
TSP	11.6	232

PacifiCorp RAMPP-3

Case # 90

Load = h Gas = mg DSR = md Coal = ac Renewables = ar

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.2	24.4	26.7	37.0	57.7	65.7	66.1	95.6	124.2	109.6	108.8	765.4
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1				160.0	160.0								320.0
W	OWC Cogen 2				470.0	470.0	271.8	108.2						1320.0
C	OWC Combined Cycle CT											160.3	20.3	180.6
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT											86.4	464.3	550.7
	OWC Pumped Storage					109.4				99.1		291.5		500.0
	Total	**24.4**	**25.2**	**24.4**	**656.7**	**776.4**	**329.5**	**173.9**	**66.1**	**194.7**	**124.2**	**647.8**	**593.4**	**3636.7**
	DSR	9.0	10.2	14.1	19.2	20.2	32.9	32.2	32.4	62.8	92.2	79.6	61.4	466.2
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal								330.0	660.0	823.5	990.0	818.0	3621.5
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT					370.0		87.0	17.1	32.8		38.1		545.0
	Utah Pumped Storage					200.0	37.4	48.8		213.8				500.0
	Total	**9.0**	**10.2**	**14.1**	**19.2**	**590.2**	**70.3**	**168.0**	**379.5**	**969.4**	**915.7**	**1107.7**	**879.4**	**5132.7**
	DSR	1.8	1.2	3.9	5.0	6.2	8.2	8.0	8.1	16.0	24.9	25.0	23.5	131.8
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal									216.6			64.6	281.2
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**8.2**	**8.0**	**8.1**	**232.6**	**24.9**	**25.0**	**88.1**	**413.0**
	DSR	35.2	36.6	42.4	50.9	63.4	98.8	105.9	106.6	174.4	241.3	214.2	193.7	1363.4
T	Renewable													0.0
O	Cogen				630.0	630.0	271.8	108.2						1640.0
T	Combined Cycle CT											160.3	20.3	180.6
A	Coal								330.0	876.6	823.5	990.0	882.6	3902.7
L	Simple Cycle CT					370.0		87.0	17.1	32.8		124.5	464.3	1095.7
	Pumped Storage					309.4	37.4	48.8		312.9		291.5		1000.0
	Total	**35.2**	**36.6**	**42.4**	**680.9**	**1372.8**	**408.0**	**349.9**	**453.7**	**1396.7**	**1064.8**	**1780.5**	**1560.9**	**9182.4**

Annual Winter Peak Capacity (MW)

	Native Load	7974	8463	8913	9323	9689	10041	10394	10802	11658	12926	14306	15949
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-72	-114	-165	-229	-327	-433	-540	-714	-956	-1170	-1363
S	**Total Requirements**	**9334**	**9786**	**10044**	**10403**	**10706**	**10959**	**11156**	**11457**	**12139**	**12858**	**13823**	**15023**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	630	1939	2249	2493	2840	4062	4886	6452	7819
L	**Total Resources**	**10068**	**10393**	**10249**	**10848**	**12311**	**12603**	**12830**	**13177**	**13961**	**14787**	**15898**	**17277**
&													
R	**Reserves**	733	606	205	445	1605	1643	1672	1717	1820	1927	2073	2252
	Reserve Margin (RM) (%)	7.9	6.2	2.0	4.3	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	666	861	1301	1116								

PacifiCorp RAMPP-3 **Case # 90**

Load = h Gas = mg DSR = md Coal = ac Renewables = ar

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.2	54.8	74.4	94.6	117.2	139.7	180.2	231.6	272.2	311.9
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				148.3	290.2	286.4	289.2	287.8	283.5	284.2	284.5	297.9
C	OWC Cogen 2				404.2	777.6	994.8	1098.1	1092.0	1074.7	1063.4	1117.6	1153.0
	OWC Combined Cycle CT											138.2	168.0
	OWC CC CT Convert												
	OWC Simple Cycle CT											6.2	40.0
	OWC Pumped Storage					16.6	16.6	17.2	16.6	35.3	31.4	20.5	5.4
	Total	**12.3**	**25.7**	**39.2**	**607.3**	**1158.8**	**1392.4**	**1521.7**	**1536.1**	**1573.7**	**1610.6**	**1839.2**	**1976.2**
	DSR	6.9	15.3	27.6	43.6	61.4	84.5	107.7	131.1	176.6	243.1	298.0	344.2
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal								302.4	907.2	1661.8	2569.1	3318.7
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT					20.6	20.6	25.4	26.4	28.2	28.2	30.3	30.3
	Utah Pumped Storage					49.6	58.9	71.1	71.1	100.0	107.8	114.6	124.1
	Total	**6.9**	**15.3**	**27.6**	**43.6**	**131.6**	**164.0**	**204.2**	**531.0**	**1212.0**	**2040.9**	**3012.0**	**3817.3**
	DSR	1.4	2.4	6.1	11.0	17.0	24.3	31.2	38.3	52.0	73.0	93.8	112.6
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal									198.5	198.5	198.5	257.7
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**11.0**	**17.0**	**24.3**	**31.2**	**38.3**	**250.5**	**271.5**	**292.3**	**370.3**
	DSR	20.6	43.4	72.9	109.4	152.8	203.4	256.1	309.1	408.8	547.7	664.0	768.7
T	Renewable												
O	Cogen				552.5	1067.8	1281.2	1387.3	1379.8	1358.2	1347.6	1402.1	1450.9
T	Combined Cycle CT											138.2	168.0
A	Coal								302.4	1105.7	1860.3	2767.6	3576.4
L	Simple Cycle CT					20.6	20.6	25.4	26.4	28.2	28.2	36.5	70.3
	Pumped Storage					66.2	75.5	88.3	87.7	135.3	139.2	135.1	129.5
	Total	**20.6**	**43.4**	**72.9**	**661.9**	**1307.4**	**1580.7**	**1757.1**	**2105.4**	**3036.2**	**3923.0**	**5143.5**	**6163.8**
	Native Load	5656	5967	6309	6587	6846	7102	7422	7668	8288	9196	10158	11380
S	Pumped Storage	309	310	293	310	394	403	419	419	480	483	478	471
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	264	146	16	109	322	298	247	304	485	608	571	503
T	DSR	-21	-43	-73	-109	-153	-203	-256	-309	-409	-548	-664	-769
E	**Total Requirements**	**7691**	**7860**	**7983**	**8352**	**8864**	**9077**	**9288**	**9516**	**10254**	**10959**	**11586**	**12426**
M													
	Existing Generation	6856	7019	7149	7109	7132	7138	7210	7179	7134	7136	6688	6554
L	Firm Purchases	645	644	458	437	411	403	392	388	364	361	335	338
&	Non-Firm Purchases	191	196	376	266	179	173	199	167	144	100	97	154
R	New Resources				552	1154	1377	1500	1796	2627	3375	4479	5394
	Total Resources	**7692**	**7859**	**7983**	**8364**	**8876**	**9091**	**9301**	**9530**	**10269**	**10972**	**11599**	**12440**

PacifiCorp RAMPP-3

Case # 90

Load = h Gas = mg DSR = md Coal = ac Renewables = ar

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	44.0	42.0	42.0	42.0	41.0	40.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
	OWC Geothermal												
O	OWC Cogen 1				92.0	90.0	89.0	90.0	89.0	88.0	88.0	88.0	93.0
W	OWC Cogen 2				86.0	82.0	82.0	83.0	82.0	81.0	80.0	84.0	87.0
C	OWC Combined Cycle CT											86.0	93.0
	OWC CC CT Convert												
	OWC Simple Cycle CT											7.0	7.0
	OWC Pumped Storage					15.0	15.0	15.0	15.0	16.0	15.0	4.0	1.0
	DSR	76.0	79.0	82.0	83.0	84.0	79.0	78.0	77.0	75.0	74.0	73.0	73.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal								91.0	91.0	91.0	91.0	91.0
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT					5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	Utah Pumped Storage					24.0	24.0	24.0	24.0	20.0	21.0	22.0	24.0
	DSR	76.0	80.0	89.0	92.0	93.0	92.0	91.0	90.0	89.0	87.0	86.0	85.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal									91.0	91.0	91.0	91.0
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	70.9	70.5	70.8	70.7	70.7	70.7	71.4	71.0	71.1	71.1	71.0	71.4
	Existing Generation	75.4	75.3	76.2	75.6	74.6	74.7	75.4	75.0	74.5	74.4	72.8	71.3
	New Resources				87.6	59.5	61.2	60.2	63.2	64.7	69.1	69.4	69.0
	DSR	58.5	60.4	63.8	66.3	66.9	62.1	59.1	57.3	57.2	57.3	56.8	56.4

SCE Modeled As A Potential Unit

(run against -m.mg/md.nc.sr-)

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		**Energy Sales (MWa)**	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,763	8,191	8,673	9,052	9,619	10,402	11,180	11,718	12,610	13,763	15,621	18,027
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
47,354	4.04	Nominal	**Operating Revenues ($M)**	2,135	2,266	2,339	2,405	2,516	2,662	2,785	2,911	3,230	3,656	4,382	5,552
	0.61	Real		2,135	2,191	2,188	2,176	2,201	2,252	2,279	2,303	2,391	2,448	2,654	2,941
	3.37	Nominal	Cost in mills/kWh	47.8	49.8	50.4	51.0	52.6	54.8	56.3	57.8	61.9	67.5	77.0	91.0
	-0.03	Real		47.8	48.2	47.2	46.1	46.0	46.3	46.1	45.8	45.8	45.2	46.7	48.2
		Nominal	Average Customer Bill ($)	1,631	1,713	1,751	1,782	1,840	1,915	1,967	2,023	2,172	2,344	2,682	3,219
		Real		1,631	1,657	1,638	1,612	1,610	1,620	1,610	1,601	1,608	1,569	1,624	1,705
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
48,920	4.14	Nominal	**Total Resource Cost ($M)**	2,139	2,275	2,353	2,423	2,541	2,701	2,841	2,988	3,348	3,832	4,616	5,843
	0.71	Real		2,139	2,200	2,201	2,192	2,222	2,285	2,325	2,364	2,478	2,566	2,795	3,096
	3.32	Nominal	Cost in mills/kWh	47.8	49.6	50.1	50.5	51.8	53.9	55.4	56.9	60.8	66.3	75.4	88.7
	-0.08	Real		47.8	48.0	46.8	45.7	45.3	45.6	45.3	45.0	45.0	44.4	45.7	47.0

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **47.14**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **46.05**

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new sce financial

SCE modeled as a potential unit

(run against -m.mg/md.nc.sr-)

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,189	68,240	69,064	69,747	70,676	72,498	75,222	76,089	77,123	78,586
	MWa	7,549	7,664	7,670	7,790	7,884	7,962	8,068	8,276	8,587	8,686	8,804	8,971
	Total Annual Emissions (1000 Tons)												
0.46%	CO2	54,170	54,966	55,955	55,906	56,236	56,198	56,628	56,722	57,739	58,152	58,859	59,331
-0.63%	NOx	139.6	141.4	143.8	142.8	143.1	143.1	119.5	119.4	121.1	121.8	122.4	123.1
0.22%	TSP	10.4	10.5	10.7	10.6	10.6	10.6	10.7	10.6	10.8	10.9	10.9	10.9
	Annual System Emission Rates (Pounds/MWh)												
-0.43%	CO2	1,638	1,637	1,666	1,638	1,629	1,611	1,602	1,565	1,535	1,529	1,526	1,510
-1.56%	NOx	4.22	4.21	4.28	4.18	4.15	4.10	3.38	3.29	3.22	3.20	3.18	3.13
-0.67%	TSP	0.31	0.31	0.32	0.31	0.31	0.30	0.30	0.29	0.29	0.29	0.28	0.28
	Emission Rates as Percent of 1994 Base												
	CO2	100	99.95	101.67	100.01	99.40	98.36	97.81	95.51	93.70	93.30	93.17	92.17
	NOx	100	99.81	101.41	99.11	98.19	97.18	80.13	78.04	76.25	75.82	75.22	74.21
	TSP	100	99.06	101.08	98.57	97.65	96.61	95.82	93.11	91.37	90.73	89.60	87.97

20 Year Emissions (1000 Tons)	Average	Total
CO2	57,414	1,148,276
NOx	127.8	2,557
TSP	10.7	215

PacifiCorp RAMPP-3 Case # 211

Sce Modeled As A Potential Unit

(run against -m.mg/md.nc.sr-)

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C				29.0	36.0	45.0							110.0
	OWC Wind without Tax C							29.0	29.0					58.0
	OWC Geothermai								13.0					13.0
O	OWC Cogen 1						44.3	70.2	160.0	45.5				320.0
W	OWC Cogen 2				275.6				68.1	162.5	29.6	53.6		589.4
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											12.1	487.9	500.0
	SCE Winter	322.0	62.3	37.7					(322.0)	(100.0)				0.0
	Total	**346.4**	**87.3**	**61.8**	**331.1**	**72.8**	**135.3**	**152.7**	**1.8**	**177.2**	**111.9**	**134.9**	**554.3**	**2167.5**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.2
	Utah Wind with Tax C				29.0	36.0	45.0							110.0
	Utah Wind without Tax C							29.0	29.0					58.0
	Utah Geothermai								12.0					12.0
	Utah Solar													
U	Utah Cogen 1								39.0					39.0
T	Utah Cogen 2													
A	Utah Combined Cycle CT													
H	Utah CC CT Convert													
	Utah Coal													
	Utah IG CC													
	Utah FB Coal													
	Utah Simple Cycle CT											574.0		574.0
	Utah Pumped Storage								146.0	251.5		102.5		500.0
	Total	**8.9**	**10.1**	**14.1**	**48.1**	**56.1**	**70.1**	**55.2**	**252.5**	**302.2**	**74.6**	**742.6**	**48.5**	**1683.0**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	103.9
W	Wyo Wind with Tax C				29.0	36.0	45.0							110.0
Y	Wyo Wind without Tax C							29.0	29.0					58.0
O	Wyo Combined Cycle CT													
M	Wyo CC CT Convert													
I	Wyo Coal													
N	Wyo IG CC													
G	Wyo FB Coal													
	Wyo Simple Cycle CT													
	Total	**1.8**	**1.2**	**3.9**	**34.0**	**42.2**	**49.9**	**35.3**	**35.4**	**12.5**	**19.1**	**19.1**	**17.7**	**271.9**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable				87.0	108.0	135.0	87.0	112.0					529.0
O	Cogen				275.6		44.3	70.2	267.1	208.0	29.6	53.6		948.4
T	Combined Cycle CT													0.0
A	Coal													0.0
L	Simple Cycle CT											574.0		574.0
	Pumped Storage								146.0	251.5		114.6	487.9	1000.0
	SCE Winter	322.0	62.3	37.7					(322.0)	(100.0)				0.0
	Total	**357.1**	**98.6**	**79.8**	**413.2**	**171.1**	**255.3**	**243.2**	**289.7**	**491.9**	**205.6**	**896.6**	**620.5**	**4122.6**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	658	649	445	394	395	375	351	344	317	312	262	262
	New Resources	322	384	422	785	893	1072	1229	1432	1792	1821	2564	3051
L	**Total Resources**	**10068**	**10355**	**10249**	**10581**	**10843**	**11004**	**11144**	**11347**	**11691**	**11722**	**12010**	**12509**
&													
R	Reserves	1210	1350	1236	1371	1444	1405	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.0	13.7	15.0	15.6	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

PacifiCorp RAMPP-3

Case # 211

SCE modeled as a potential unit

(run against -m.mg/md.nc.sr-)

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C				6.9	15.5	26.3	26.3	26.3	26.3	26.3	26.3	26.3
	OWC Wind without Tax C							6.9	13.9	13.9	13.9	13.9	13.9
	OWC Geothermal								10.1	10.1	10.1	10.8	10.9
O	OWC Cogen 1						40.3	102.4	228.5	277.5	279.9	297.3	297.9
W	OWC Cogen 2				228.0	228.0	228.0	228.0	281.7	414.8	439.0	497.9	524.1
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											1.9	31.8
	SCE Winter	8.5	10.1	11.1	11.1	11.1	11.1	11.1	2.6				
	Total	**20.8**	**35.8**	**50.1**	**300.5**	**328.6**	**395.3**	**482.1**	**688.2**	**898.0**	**960.7**	**1066.9**	**1149.3**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C				10.2	22.8	38.6	38.6	38.6	38.6	38.6	38.6	38.6
	Utah Wind without Tax C							10.2	20.4	20.4	20.4	20.4	20.4
	Utah Geothermal								9.8	9.7	9.8	10.0	10.1
U	Utah Solar												
T	Utah Cogen 1								33.5	34.2	34.6	36.2	36.2
A	Utah Cogen 2												
H	Utah Combined Cycle CT												
	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											31.9	31.9
	Utah Pumped Storage								33.1	83.1	78.0	92.8	81.2
	Total	**6.9**	**15.2**	**27.4**	**53.6**	**84.0**	**116.9**	**144.9**	**249.6**	**334.9**	**381.1**	**472.7**	**495.6**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C				10.2	22.8	38.6	38.6	38.6	38.6	38.6	38.6	38.6
Y	Wyo Wind without Tax C							10.2	20.4	20.4	20.4	20.4	20.4
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**21.2**	**39.7**	**60.0**	**75.8**	**91.6**	**102.5**	**119.0**	**135.4**	**150.2**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable				27.3	61.1	103.5	130.8	178.1	178.0	178.1	179.0	179.2
O	Cogen				228.0	228.0	268.3	330.4	543.7	726.5	753.5	831.4	858.2
T	Combined Cycle CT												
A	Coal												
L	Simple Cycle CT											31.9	31.9
	Pumped Storage								33.1	83.1	78.0	94.7	113.0
	SCE Winter	8.5	10.1	11.1	11.1	11.1	11.1	11.1	2.6				
	Total	**29.1**	**53.4**	**83.6**	**375.3**	**452.3**	**572.2**	**702.8**	**1029.4**	**1335.4**	**1460.8**	**1675.0**	**1795.1**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pump Storage/Peak Return	312	311	309	310	309	307	306	349	413	405	426	449
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	334	374	380	343	327	442	476	524	460	294
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	7547	7663	7670	7789	7882	7962	8066	8275	8585	8685	8802	8969
M													
	Existing Generation	6776	6887	7035	6971	7025	7026	7082	7060	7138	7182	7021	7090
L	Firm Purchases	636	632	441	423	400	392	382	377	364	381	423	442
&	Non-Firm Purchases	128	133	183	141	171	173	144	95	110	125	236	269
R	New Resources	9	10	11	266	300	383	472	757	988	1010	1137	1182
	Total Resources	7549	7662	7670	7801	7896	7974	8080	8290	8600	8696	8817	8983

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PacifiCorp RAMPP-3

Case # 211

Sce Modeled As A Potential Unit

(run against -m.mg/md.nc.sr-)

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C				23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
	OWC Wind without Tax C							23.0	23.0	23.0	23.0	23.0	23.0
O	OWC Geothermal								77.0	77.0	77.0	83.0	83.0
W	OWC Cogen 1						90.0	89.0	83.0	86.0	87.0	92.0	93.0
C	OWC Cogen 2				82.0	82.0	82.0	82.0	81.0	81.0	81.0	84.0	88.0
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											15.0	6.0
	SCE Winter	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0				
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C				35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
	Utah Wind without Tax C							35.0	35.0	35.0	35.0	35.0	35.0
	Utah Geothermal								81.0	80.0	81.0	83.0	83.0
	Utah Solar												
U	Utah Cogen 1								85.0	87.0	88.0	92.0	92.0
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											5.0	5.0
	Utah Pumped Storage								22.0	20.0	19.0	18.0	16.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C				35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Y	Wyo Wind without Tax C							35.0	35.0	35.0	35.0	35.0	35.0
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	74.6	73.9	75.0	74.1	73.5	73.5	74.0	73.8	74.5	74.9	76.4	77.1
	New Resources	2.6	2.6	2.6	34.0	33.6	35.7	38.4	52.9	55.1	55.4	44.4	38.7
	DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Hermiston Modeled As A Potential Unit

(run against -m.mg/md.ac.ar-)

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		**Energy Sales (MWa)**	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,791	8,177	8,492	8,800	9,305	9,932	10,746	11,668	13,128	14,924	17,662	20,507
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
45,332	3.90	Nominal	**Operating Revenues ($M)**	2,135	2,266	2,316	2,371	2,444	2,548	2,637	2,721	2,913	3,503	4,066	5,192
	0.48	Real		2,135	2,192	2,166	2,145	2,138	2,156	2,158	2,153	2,156	2,345	2,462	2,750
	3.24	Nominal	Cost in mills/kWh	47.8	49.8	49.9	50.3	51.1	52.4	53.3	54.0	55.8	64.6	71.5	85.1
	-0.16	Real		47.8	48.2	46.7	45.5	44.7	44.3	43.6	42.8	41.3	43.3	43.3	45.1
		Nominal	Average Customer Bill ($)	1,631	1,714	1,733	1,757	1,787	1,833	1,863	1,891	1,959	2,246	2,488	3,010
		Real		1,631	1,657	1,621	1,589	1,563	1,551	1,524	1,496	1,450	1,504	1,507	1,595
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
46,898	4.01	Nominal	**Total Resource Cost ($M)**	2,139	2,275	2,329	2,390	2,468	2,587	2,694	2,798	3,031	3,680	4,300	5,483
	0.59	Real		2,139	2,200	2,179	2,162	2,159	2,189	2,204	2,214	2,243	2,464	2,604	2,905
	3.19	Nominal	Cost in mills/kWh	47.8	49.7	49.6	49.8	50.3	51.6	52.5	53.3	55.1	63.6	70.3	83.2
	-0.20	Real		47.8	48.0	46.4	45.0	44.0	43.6	42.9	42.1	40.8	42.6	42.6	44.1

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 45.13

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 44.15

Hermiston Modeled As A Potential Unit

(run against -m.mg/md.ac.ar-)

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,680	68,284	69,055	69,817	70,711	71,543	75,213	76,212	78,060	81,372
	MWa	7,549	7,664	7,726	7,795	7,883	7,970	8,072	8,167	8,586	8,700	8,911	9,289
	Total Annual Emissions (1000 Tons)												
1.19%	CO2	54,170	54,960	55,594	55,194	55,658	55,637	56,140	57,051	61,520	62,318	66,282	68,608
0.26%	NOx	139.6	141.4	143.0	142.1	142.8	142.8	119.4	121.4	131.4	133.0	141.9	147.0
0.51%	TSP	10.4	10.5	10.6	10.5	10.6	10.6	10.7	10.7	11.0	11.1	11.4	11.5
	Annual System Emission Rates (Pounds/MWh)												
0.15%	CO2	1,638	1,637	1,643	1,617	1,612	1,594	1,588	1,595	1,636	1,635	1,698	1,686
-0.82%	NOx	4.22	4.21	4.22	4.16	4.14	4.09	3.38	3.39	3.49	3.49	3.63	3.61
-0.56%	TSP	0.31	0.31	0.31	0.31	0.31	0.30	0.30	0.30	0.29	0.29	0.29	0.28
	Emission Rates as Percent of 1994 Base												
	CO2	100	99.94	100.28	98.68	98.39	97.28	96.92	97.35	99.85	99.82	103.66	102.93
	NOx	100	99.80	100.08	98.56	97.98	96.88	79.99	80.40	82.78	82.71	86.11	85.57
	TSP	100	99.06	99.68	98.21	97.60	96.47	95.95	95.47	93.33	92.96	92.57	89.95

20 Year Emissions (1000 Tons)	Average	Total
CO2	60,860	1,217,194
NOx	137.2	2,745
TSP	11.0	220

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PacifiCorp RAMPP-3

Case # 213

Hermiston Modeled As A Potential Unit

(run against -m.mg/md.ac.ar-)

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1													0.0
W	OWC Cogen 2													0.0
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage												153.6	153.6
	OWC Hermiston			115.1	186.9		118.1	51.9						472.0
	Total	**24.4**	**25.0**	**139.2**	**213.4**	**36.8**	**164.1**	**105.4**	**53.7**	**69.2**	**82.3**	**69.2**	**220.0**	**1202.7**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal								104.3	616.9	29.6	552.5	271.4	1574.7
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT													0.0
	Utah Pumped Storage							44.6	38.3	164.5		189.8	62.8	500.0
	Total	**8.9**	**10.1**	**14.1**	**19.1**	**20.1**	**25.1**	**70.8**	**169.1**	**832.1**	**104.2**	**808.4**	**382.7**	**2464.7**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**4.9**	**6.3**	**6.4**	**12.5**	**19.1**	**19.1**	**17.7**	**104.1**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable													0.0
O	Cogen													0.0
T	Combined Cycle CT													0.0
A	Coal								104.3	616.9	29.6	552.5	271.4	1574.7
L	Simple Cycle CT													0.0
	Pumped Storage							44.6	38.3	164.5		189.8	216.4	653.6
	OWC Hermiston			115.1	186.9		118.1	51.9						472.0
	Total	**35.1**	**36.3**	**157.2**	**237.5**	**63.1**	**194.1**	**182.5**	**229.2**	**913.8**	**205.6**	**896.7**	**620.4**	**3771.5**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	115	302	302	420	517	659	1441	1470	2213	2700
L	**Total Resources**	**10068**	**10393**	**10364**	**10520**	**10674**	**10774**	**10854**	**10996**	**11340**	**11371**	**11659**	**12158**
&													
R	Reserves	1210	1388	1351	1371	1411	1405	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	15.0	15.0	15.2	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117											

PacifiCorp RAMPP-3 Case # 213

Hermiston Modeled As A Potential Unit

(run against -m.mg/md.ac.ar-)

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C												
	OWC Wind without Tax C												
	OWC Geothermal												
O	OWC Cogen 1												
W	OWC Cogen 2												
C	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												1.4
	OWC Hermiston			[illegible]6.6	277.2	277.7	380.8	430.5	431.0	427.9	435.2	436.3	438.8
	Total	**12.3**	**25.7**	**145.6**	**331.7**	**351.7**	**470.4**	**537.9**	**556.1**	**583.3**	**626.7**	**655.1**	**684.6**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1												
A	Utah Cogen 2												
H	Utah Combined Cycle CT												
	Utah CC CT Convert												
	Utah Coal								95.6	660.9	688.0	1194.3	1443.1
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage							8.3	15.4	54.5	53.7	91.3	107.2
	Total	**6.9**	**15.2**	**27.4**	**43.4**	**61.2**	**78.3**	**104.4**	**225.2**	**864.3**	**941.4**	**1528.4**	**1827.5**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**11.0**	**16.9**	**21.4**	**27.0**	**32.6**	**43.5**	**60.0**	**76.4**	**91.2**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable												
O	Cogen												
T	Combined Cycle CT												
A	Coal								95.6	660.9	688.0	1194.3	1443.1
L	Simple Cycle CT												
	Pumped Storage							8.3	15.4	54.5	53.7	91.3	108.6
	OWC Hermiston			106.6	277.2	277.7	380.8	430.5	431.0	427.9	435.2	436.3	438.8
	Total	**20.6**	**43.3**	**179.1**	**386.1**	**429.8**	**570.1**	**669.3**	**813.9**	**1491.1**	**1628.1**	**2259.9**	**2603.3**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pump Storage/Peak Return	312	311	309	310	309	307	317	326	376	373	422	444
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	390	378	378	350	321	355	512	569	571	618
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	7547	7663	7726	7793	7880	7969	8071	8165	8584	8698	8909	9288
M													
	Existing Generation	6776	6887	6992	6965	7034	7037	7101	7108	7045	7115	6809	6828
L	Firm Purchases	645	644	452	435	411	403	393	388	364	361	336	353
&	Non-Firm Purchases	128	133	174	130	172	161	152	141	47	59	56	130
R	New Resources			107	277	278	381	439	542	1143	1177	1722	1991
	Total Resources	7549	7664	7725	7807	7895	7982	8085	8179	8599	8712	8923	9302

PacifiCorp RAMPP-3

Case # 213

Hermiston Modeled As A Potential Unit

(run against -m.mg/md.ac.ar-)

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1												
C	OWC Cogen 2												
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	OWC Hermiston			92.0	91.0	91.0	90.0	91.0	91.0	90.0	92.0	92.0	92.0
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC								91.0	91.0	91.0	91.0	91.0
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage							18.0	18.0	22.0	21.0	20.0	21.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	74.6	73.9	74.5	74.1	73.6	73.6	74.2	74.3	73.5	74.2	74.1	74.2
	New Resources			92.6	91.8	92.0	90.6	84.9	82.2	79.4	80.1	77.8	73.7
	DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Reduce Wind Costs By $600 kW

(run against -m.mg/md.nc.ar-)

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		**Energy Sales (MWa)**	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,763	8,191	8,697	9,090	9,500	9,863	10,311	11,072	12,257	13,489	15,825	18,372
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
47,078	4.02	Nominal	**Operating Revenues ($M)**	2,135	2,266	2,339	2,407	2,519	2,673	2,780	2,857	3,092	3,601	4,352	5,567
	0.60	Real		2,135	2,192	2,188	2,177	2,204	2,261	2,275	2,260	2,289	2,411	2,636	2,949
	3.36	Nominal	Cost in mills/kWh	47.8	49.8	50.4	51.1	52.6	55.0	56.2	56.7	59.2	66.4	76.5	91.3
	-0.04	Real		47.8	48.2	47.2	46.2	46.1	46.5	46.0	44.9	43.8	44.5	46.3	48.4
		Nominal	Average Customer Bill ($)	1,631	1,714	1,751	1,784	1,842	1,923	1,964	1,985	2,079	2,309	2,664	3,228
		Real		1,631	1,657	1,638	1,613	1,612	1,627	1,607	1,571	1,539	1,546	1,613	1,710
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
48,643	4.13	Nominal	**Total Resource Cost ($M)**	2,139	2,275	2,353	2,425	2,543	2,711	2,836	2,934	3,210	3,778	4,587	5,858
	0.70	Real		2,139	2,200	2,201	2,194	2,225	2,294	2,321	2,321	2,376	2,529	2,778	3,103
	3.31	Nominal	Cost in mills/kWh	47.8	49.7	50.1	50.5	51.8	54.1	55.3	55.8	58.3	65.3	74.9	88.9
	-0.09	Real		47.8	48.0	46.8	45.7	45.3	45.7	45.2	44.2	43.2	43.7	45.4	47.1

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **46.86**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **45.79**

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Case # 261

Reduce Wind Costs By $600 kW
(run against -m.mg/md.nc.ar-)

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,189	68,319	69,405	70,360	70,965	71,560	75,187	76,098	76,965	78,411
	MWa	7,549	7,664	7,670	7,799	7,923	8,032	8,101	8,169	8,583	8,687	8,786	8,951
	Total Annual Emissions (1000 Tons)												
0.43%	CO2	54,170	54,960	55,955	55,641	55,714	55,519	56,128	56,407	57,764	58,246	58,624	59,040
-0.64%	NOx	139.6	141.4	143.8	142.4	142.2	141.7	118.7	119.2	121.1	121.9	122.2	122.8
0.22%	TSP	10.4	10.5	10.7	10.6	10.5	10.5	10.6	10.6	10.8	10.9	10.9	10.9
	Annual System Emission Rates (Pounds/MWh)												
-0.44%	CO2	1,638	1,637	1,666	1,629	1,605	1,578	1,582	1,576	1,537	1,531	1,523	1,506
-1.56%	NOx	4.22	4.21	4.28	4.17	4.10	4.03	3.35	3.33	3.22	3.20	3.17	3.13
-0.66%	TSP	0.31	0.31	0.32	0.31	0.30	0.30	0.30	0.30	0.29	0.29	0.28	0.28
	Emission Rates as Percent of 1994 Base												
	CO2	100	99.94	101.67	99.42	98.00	96.33	96.56	96.23	93.79	93.44	92.99	91.92
	NOx	100	99.80	101.41	98.74	97.05	95.39	79.28	78.91	76.28	75.89	75.21	74.22
	TSP	100	99.06	101.08	98.25	96.61	94.81	94.83	94.31	91.40	90.69	89.72	88.11

20 Year Emissions (1000 Tons)	Average	Total
CO2	57,231	1,144,630
NOx	127.6	2,552
TSP	10.7	214

PacifiCorp RAMPP-3 Case # 261

Reduce Wind Costs By $600 kW

(run against -m.mg/md.nc.ar-)

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C				150.0	150.0	150.0							450.0
	OWC Wind without Tax C											378.3	194.6	572.9
	OWC Geothermal													0.0
O	OWC Cogen 1								52.6	267.4				320.0
W	OWC Cogen 2				165.5					22.7				188.2
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											60.8	439.2	500.0
	Total	**24.4**	**25.0**	**24.1**	**342.0**	**186.8**	**196.0**	**53.5**	**106.3**	**359.3**	**82.3**	**508.3**	**700.2**	**2608.2**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C				150.0	150.0	150.0							450.0
	Utah Wind without Tax C											135.1		135.1
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1									1.7				1.7
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal													0.0
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT									89.8		503.5		593.3
	Utah Pumped Storage								31.5	400.0	29.6	38.9		500.0
	Total	**8.9**	**10.1**	**14.1**	**169.1**	**170.1**	**175.1**	**26.2**	**58.0**	**542.2**	**104.2**	**743.6**	**48.5**	**2070.1**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C				150.0	150.0	150.0							450.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**155.0**	**156.2**	**154.9**	**6.3**	**6.4**	**12.5**	**19.1**	**19.1**	**17.7**	**554.1**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable				450.0	450.0	450.0					513.4	194.6	2058.0
O	Cogen				165.5				52.6	291.8				509.9
T	Combined Cycle CT													0.0
A	Coal													0.0
L	Simple Cycle CT									89.8		503.5		593.3
	Pumped Storage								31.5	400.0	29.6	99.7	439.2	1000.0
	Total	**35.1**	**36.3**	**42.1**	**666.1**	**513.1**	**526.0**	**86.0**	**170.7**	**914.0**	**205.6**	**1271.0**	**766.4**	**5232.4**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	616	1066	1516	1516	1600	2381	2411	3527	4161
L	**Total Resources**	**10068**	**10393**	**10249**	**10834**	**11438**	**11870**	**11853**	**11937**	**12280**	**12312**	**12973**	**13619**
&													
R	Reserves	1210	1388	1236	1371	1548	1560	1473	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	15.0	16.7	16.7	15.6	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

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PacifiCorp RAMPP-3

Case # 261

Reduce Wind Costs By $600 kW

(run against -m.mg/md.nc.ar-)

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C				35.8	71.6	107.4	107.5	107.5	107.5	107.5	107.5	107.5
	OWC Wind without Tax C											90.4	136.8
O	OWC Geothermal												
W	OWC Cogen 1								46.7	280.1	288.0	297.9	297.9
C	OWC Cogen 2				136.9	136.9	136.9	136.9	136.9	154.5	155.5	164.6	167.3
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											4.9	17.2
	Total	**12.3**	**25.7**	**39.0**	**227.2**	**282.5**	**333.9**	**351.8**	**416.2**	**697.5**	**742.5**	**884.1**	**971.1**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C				52.6	105.2	158.0	158.0	158.0	158.0	158.0	158.0	158.0
	Utah Wind without Tax C											47.4	47.4
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1									1.5	1.5	1.5	1.5
A	Utah Cogen 2												
H	Utah Combined Cycle CT												
	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT									5.0	5.0	33.0	33.0
	Utah Pumped Storage								5.9	86.6	85.6	89.4	77.9
	Total	**6.9**	**15.2**	**27.4**	**96.0**	**166.4**	**236.3**	**254.1**	**278.1**	**400.0**	**449.8**	**572.1**	**595.0**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C				52.7	105.2	157.9	158.0	158.0	158.0	158.0	158.0	158.0
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**63.7**	**122.1**	**179.3**	**185.0**	**190.6**	**201.5**	**218.0**	**234.4**	**249.2**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable				141.1	282.0	423.3	423.5	423.5	423.5	423.5	561.3	607.7
O	Cogen				136.9	136.9	136.9	136.9	183.6	436.1	445.0	464.0	466.7
T	Combined Cycle CT												
A	Coal												
L	Simple Cycle CT									5.0	5.0	33.0	33.0
	Pumped Storage								5.9	86.6	85.6	94.3	95.1
	Total	**20.6**	**43.3**	**72.5**	**386.9**	**571.0**	**749.5**	**790.9**	**884.9**	**1299.0**	**1410.3**	**1690.6**	**1815.3**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pump Storage/Peak Return	312	311	309	310	309	307	306	314	418	414	425	427
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	334	383	419	412	360	369	468	515	443	297
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	**7547**	**7663**	**7670**	**7798**	**7921**	**8031**	**8099**	**8167**	**8582**	**8685**	**8784**	**8950**
M													
	Existing Generation	6776	6887	7035	6962	6980	6969	7043	7061	7133	7201	7001	7071
L	Firm Purchases	645	644	452	434	411	403	393	388	367	387	417	435
&	Non-Firm Purchases	128	133	183	137	125	112	118	120	144	152	229	255
R	New Resources				278	419	560	560	613	951	959	1153	1203
	Total Resources	**7549**	**7664**	**7670**	**7811**	**7935**	**8044**	**8114**	**8182**	**8595**	**8699**	**8800**	**8964**

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 Case # 261

Reduce Wind Costs By $600 kW

(run against -m.mg/md.nc.ar-)

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C				23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
	OWC Wind without Tax C											23.0	23.0
O	OWC Geothermal												
W	OWC Cogen 1								88.0	87.0	89.0	93.0	93.0
C	OWC Cogen 2				82.0	82.0	82.0	82.0	82.0	82.0	82.0	87.0	88.0
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											8.0	3.0
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C				35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
	Utah Wind without Tax C											35.0	35.0
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1									88.0	90.0	91.0	91.0
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT									5.0	5.0	5.0	5.0
	Utah Pumped Storage								18.0	20.0	18.0	17.0	15.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C				35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	74.6	73.9	75.0	74.0	73.1	72.9	73.6	73.8	74.4	75.1	76.2	76.9
	New Resources				45.2	39.3	37.0	37.0	38.3	39.9	39.8	32.7	28.9
	DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Case # 262

Geothermal with 0% Real Inflation On O&M
(run against -m.mg/md.nc.ar-)

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		**Energy Sales (MWa)**	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,759	8,149	8,532	8,813	9,281	9,785	10,298	11,015	12,154	13,415	15,433	18,685
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
47,139	4.04	Nominal	**Operating Revenues ($M)**	2,135	2,266	2,339	2,401	2,495	2,619	2,731	2,839	3,103	3,599	4,353	5,563
	0.62	Real		2,135	2,192	2,188	2,172	2,183	2,216	2,235	2,246	2,297	2,409	2,637	2,947
	3.38	Nominal	Cost in mills/kWh	47.8	49.8	50.4	50.9	52.2	53.9	55.2	56.4	59.4	66.4	76.5	91.2
	-0.02	Real		47.8	48.2	47.2	46.1	45.6	45.6	45.2	44.6	44.0	44.5	46.4	48.3
		Nominal	Average Customer Bill ($)	1,631	1,714	1,751	1,779	1,825	1,884	1,929	1,973	2,086	2,307	2,665	3,225
		Real		1,631	1,657	1,638	1,609	1,596	1,594	1,579	1,561	1,544	1,545	1,614	1,709
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
48,705	4.14	Nominal	**Total Resource Cost ($M)**	2,139	2,275	2,353	2,419	2,520	2,658	2,787	2,915	3,220	3,775	4,588	5,854
	0.72	Real		2,139	2,200	2,201	2,188	2,204	2,249	2,281	2,307	2,384	2,528	2,778	3,101
	3.32	Nominal	Cost in mills/kWh	47.8	49.7	50.1	50.4	51.3	53.0	54.3	55.5	58.5	65.3	75.0	88.8
	-0.08	Real		47.8	48.0	46.8	45.6	44.9	44.8	44.4	43.9	43.3	43.7	45.4	47.1

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized

4) 50-year Real Levelized

Geothermal with 0% Real Inflation On O&M

(run against -m.mg/md.nc.ar-)

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,189	68,223	69,038	69,747	70,588	71,306	74,714	75,721	76,335	78,752
	MWa	7,549	7,664	7,670	7,788	7,881	7,962	8,058	8,140	8,529	8,644	8,714	8,990
	Total Annual Emissions (1000 Tons)												
0.54%	CO_2	54,170	54,960	55,955	56,136	56,672	56,878	57,479	57,863	59,087	59,489	60,185	60,354
-0.59%	NO_x	139.6	141.4	143.8	142.9	143.8	143.9	120.3	120.7	122.3	122.9	123.6	123.9
0.23%	TSP	10.4	10.5	10.7	10.6	10.7	10.6	10.7	10.7	10.9	10.9	10.9	10.9
	Annual System Emission Rates (Pounds/MWh)												
-0.35%	CO_2	1,638	1,637	1,666	1,646	1,642	1,631	1,629	1,623	1,582	1,571	1,577	1,533
-1.54%	NO_x	4.22	4.21	4.28	4.19	4.16	4.13	3.41	3.39	3.27	3.25	3.24	3.15
-0.67%	TSP	0.31	0.31	0.32	0.31	0.31	0.31	0.30	0.30	0.29	0.29	0.29	0.28
	Emission Rates as Percent of 1994 Base												
	CO_2	100	99.94	101.67	100.45	100.21	99.55	99.41	99.06	96.54	95.91	96.25	93.56
	NO_x	100	99.80	101.41	99.26	98.66	97.75	80.76	80.20	77.52	76.90	76.69	74.53
	TSP	100	99.06	101.08	98.65	98.08	97.01	96.31	95.48	92.47	91.49	90.80	87.99

20 Year Emissions (1000 Tons)	Average	Total
CO_2	58,338	1,166,762
NO_x	128.7	2,573
TSP	10.8	215

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PacifiCorp RAMPP-3

Case # 262

Geothermal with 0% Real Inflation On O&M

(run against -m.mg/md.nc.ar-)

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal												141.6	141.6
O	OWC Cogen 1						110.8	96.6	112.7					320.1
W	OWC Cogen 2				302.0					251.6				553.6
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											258.5	241.5	500.0
	Total	**24.4**	**25.0**	**24.1**	**328.5**	**36.8**	**156.8**	**150.1**	**166.4**	**320.8**	**82.3**	**327.7**	**449.5**	**2092.4**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal												104.8	104.8
	Utah Solar													0.0
U	Utah Cogen 1								16.5	22.5				39.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal													0.0
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT									107.4		434.0		541.4
	Utah Pumped Storage						7.3		13.4	400.0	29.6	49.7		500.0
	Total	**8.9**	**10.1**	**14.1**	**19.1**	**20.1**	**32.4**	**26.2**	**56.4**	**580.6**	**104.2**	**549.8**	**153.3**	**1375.2**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**4.9**	**6.3**	**6.4**	**12.5**	**19.1**	**19.1**	**17.7**	**104.1**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable												246.4	246.4
O	Cogen				302.0		110.8	96.6	129.2	274.1				912.7
T	Combined Cycle CT													0.0
A	Coal													0.0
L	Simple Cycle CT									107.4		434.0		541.4
	Pumped Storage						7.3		13.4	400.0	29.6	308.2	241.5	1000.0
	Total	**35.1**	**36.3**	**42.1**	**352.6**	**63.1**	**194.1**	**182.6**	**229.2**	**913.9**	**205.6**	**896.6**	**620.5**	**3771.7**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	302	302	420	517	659	1441	1470	2213	2701
L	**Total Resources**	**10068**	**10393**	**10249**	**10520**	**10674**	**10774**	**10854**	**10996**	**11340**	**11371**	**11659**	**12159**
&													
R	Reserves	1210	1388	1236	1371	1411	1405	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	15.0	15.2	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

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PacifiCorp RAMPP-3 Case # 262

Geothermal with 0% Real Inflation On O&M

(run against -m.mg/md.nc.ar-)

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												134.3
W	OWC Cogen 1						100.6	183.3	281.3	283.9	296.8	297.9	297.9
C	OWC Cogen 2				249.8	249.8	249.8	249.8	249.8	457.9	463.6	491.0	492.2
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											21.7	31.7
	Total	**12.3**	**25.7**	**39.0**	**304.3**	**323.8**	**440.0**	**540.5**	**656.2**	**897.2**	**951.9**	**1029.4**	**1200.5**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												99.4
U	Utah Solar												
T	Utah Cogen 1								14.3	34.6	36.2	36.3	36.3
A	Utah Cogen 2												
H	Utah Combined Cycle CT												
	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT									6.0	6.0	30.1	30.1
	Utah Pumped Storage						1.4	1.4	3.9	78.1	83.6	83.0	82.2
	Total	**6.9**	**15.2**	**27.4**	**43.4**	**61.2**	**79.7**	**97.5**	**132.4**	**267.6**	**325.5**	**392.2**	**525.2**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**11.0**	**16.9**	**21.4**	**27.0**	**32.6**	**43.5**	**60.0**	**76.4**	**91.2**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable												233.7
O	Cogen				249.8	249.8	350.4	433.1	545.4	776.4	796.6	825.2	826.4
T	Combined Cycle CT												
A	Coal												
L	Simple Cycle CT									6.0	6.0	30.1	30.1
	Pumped Storage						1.4	1.4	3.9	78.1	83.6	104.7	113.9
	Total	**20.6**	**43.3**	**72.5**	**358.7**	**401.9**	**541.1**	**665.0**	**821.2**	**1208.3**	**1337.4**	**1498.0**	**1816.9**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pump Storage/Peak Return	312	311	309	310	309	308	308	311	407	412	439	451
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	334	371	377	341	316	343	425	475	357	312
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	**7547**	**7663**	**7670**	**7786**	**7879**	**7961**	**8057**	**8138**	**8528**	**8643**	**8712**	**8989**
M													
	Existing Generation	6776	6887	7035	6972	7050	7046	7094	7105	7151	7204	7062	7087
L	Firm Purchases	645	644	452	435	411	403	393	388	368	386	432	442
&	Non-Firm Purchases	128	133	183	144	182	173	149	110	162	180	272	269
R	New Resources				250	250	352	435	549	861	886	960	1204
	Total Resources	**7549**	**7664**	**7670**	**7801**	**7893**	**7974**	**8071**	**8152**	**8542**	**8656**	**8726**	**9002**

PacifiCorp RAMPP-3

Case # 262

Geothermal with 0% Real Inflation On O&M

(run against -m.mg/md.nc.ar-)

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												94.0
W	OWC Cogen 1						90.0	88.0	87.0	88.0	92.0	93.0	93.0
C	OWC Cogen 2				82.0	82.0	82.0	82.0	82.0	82.0	83.0	88.0	88.0
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											8.0	6.0
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												94.0
	Utah Solar												
U	Utah Cogen 1								87.0	88.0	92.0	93.0	93.0
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT									5.0	5.0	5.0	5.0
	Utah Pumped Storage						19.0	18.0	18.0	18.0	18.0	16.0	16.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	74.6	73.9	75.0	74.2	73.8	73.7	74.2	74.2	74.6	75.1	76.9	77.1
	New Resources				82.7	82.7	83.7	84.1	83.3	59.7	60.3	43.4	44.6
	DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Wind At 0% Real Inflation On O&M

(run against -m.mg/md.nc.ar-)

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		Energy Sales (MWa)	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,760	8,154	8,543	8,824	9,295	9,803	10,323	11,041	12,184	13,437	15,412	17,947
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
46,894	4.04	Nominal	**Operating Revenues ($M)**	2,135	2,266	2,339	2,400	2,497	2,620	2,732	2,838	3,101	3,593	4,320	5,499
	0.61	Real		2,135	2,192	2,188	2,171	2,184	2,217	2,235	2,246	2,295	2,406	2,616	2,913
	3.37	Nominal	Cost in mills/kWh	47.8	49.8	50.4	50.9	52.2	53.9	55.2	56.4	59.4	66.3	75.9	90.2
	-0.03	Real		47.8	48.2	47.2	46.1	45.6	45.6	45.2	44.6	44.0	44.4	46.0	47.8
		Nominal	Average Customer Bill ($)	1,631	1,714	1,751	1,778	1,826	1,885	1,930	1,972	2,085	2,304	2,644	3,188
		Real		1,631	1,657	1,638	1,609	1,597	1,595	1,579	1,561	1,543	1,542	1,601	1,689
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
48,460	4.14	Nominal	**Total Resource Cost ($M)**	2,139	2,275	2,353	2,418	2,521	2,658	2,788	2,915	3,219	3,770	4,554	5,790
	0.71	Real		2,139	2,200	2,201	2,187	2,205	2,249	2,281	2,307	2,382	2,524	2,758	3,068
	3.32	Nominal	Cost in mills/kWh	47.8	49.7	50.1	50.4	51.4	53.0	54.3	55.5	58.5	65.2	74.4	87.9
	-0.08	Real		47.8	48.0	46.8	45.6	44.9	44.9	44.4	43.9	43.3	43.7	45.1	46.5

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **46.68**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **45.62**

Wind At 0% Real Inflation On O&M

(run against -m.mg/md.nc.ar-)

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,189	68,267	68,985	69,756	70,649	71,385	75,021	75,888	77,342	78,849
	MWa	7,549	7,664	7,670	7,793	7,875	7,963	8,065	8,149	8,564	8,663	8,829	9,001
	Total Annual Emissions (1000 Tons)												
0.61%	CO2	54,170	54,960	55,955	56,101	56,622	56,841	57,467	57,760	59,345	59,778	60,674	61,190
-0.57%	NOx	139.6	141.4	143.8	142.8	143.6	143.7	120.3	120.5	122.3	123.0	123.8	124.5
0.24%	TSP	10.4	10.5	10.7	10.6	10.6	10.6	10.7	10.7	10.9	10.9	10.9	10.9
	Annual System Emission Rates (Pounds/MWh)												
-0.28%	CO2	1,638	1,637	1,666	1,644	1,642	1,630	1,627	1,618	1,582	1,575	1,569	1,552
-1.52%	NOx	4.22	4.21	4.28	4.18	4.16	4.12	3.40	3.37	3.26	3.24	3.20	3.16
-0.67%	TSP	0.31	0.31	0.32	0.31	0.31	0.30	0.30	0.30	0.29	0.29	0.28	0.28
	Emission Rates as Percent of 1994 Base												
	CO2	100	99.94	101.67	100.32	100.20	99.48	99.30	98.78	96.57	96.16	95.77	94.74
	NOx	100	99.80	101.41	99.13	98.65	97.63	80.65	79.94	77.24	76.80	75.83	74.82
	TSP	100	99.06	101.08	98.52	98.09	96.89	96.15	95.10	91.98	91.30	89.72	88.06

20 Year Emissions (1000 Tons)	Average	Total
CO2	58,589	1,171,789
NOx	128.8	2,575
TSP	10.8	215

PacifiCorp RAMPP-3

Case # 263

Wind At 0% Real Inflation On O&M

(run against -m.mg/md.nc.ar-)

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1						118.1	96.6	105.4					320.1
W	OWC Cogen 2				228.2					396.6	29.6	92.9		747.3
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											12.1	487.9	500.0
	Total	**24.4**	25.0	**24.1**	**254.7**	**36.8**	164.1	150.1	159.1	**465.8**	**111.9**	174.2	**554.3**	**2144.5**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1								37.2	1.8				39.0
T	Utah Cogen 2				73.8									73.8
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal													0.0
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT											520.3		520.3
	Utah Pumped Storage									383.0		117.0		500.0
	Total	**8.9**	10.1	**14.1**	**92.9**	**20.1**	**25.1**	**26.2**	**63.7**	**435.5**	**74.6**	**703.4**	**48.5**	**1523.1**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**4.9**	**6.3**	**6.4**	**12.5**	**19.1**	**19.1**	**17.7**	**104.1**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable													0.0
O	Cogen				302.0		118.1	96.6	142.6	398.4	29.6	92.9		1180.2
T	Combined Cycle CT													0.0
A	Coal													0.0
L	Simple Cycle CT											520.3		520.3
	Pumped Storage									383.0		129.1	487.9	1000.0
	Total	**35.1**	**36.3**	**42.1**	**352.6**	**63.1**	**194.1**	**182.6**	**229.2**	**913.8**	**205.6**	**896.7**	**620.5**	**3771.7**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	**Firm Sales**	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	**DSR**	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	**Firm Purchases**	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	302	302	420	517	659	1441	1470	2213	2701
L	**Total Resources**	**10068**	**10393**	**10249**	**10520**	**10674**	**10774**	**10854**	**10996**	**11340**	**11371**	**11659**	**12159**
&													
R	**Reserves**	1210	1388	1236	1371	1411	1405	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	15.0	15.2	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

PacifiCorp RAMPP-3

Case # 263

Wind At 0% Real Inflation On O&M

(run against -m.mg/md.nc.ar-)

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1						107.2	192.8	281.3	279.7	281.7	296.8	297.9
C	OWC Cogen 2				188.8	188.8	188.8	188.8	188.8	512.0	536.2	634.6	666.1
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT			—									
	OWC Pumped Storage											1.9	35.0
	Total	**12.3**	**25.7**	**39.0**	**243.3**	**262.8**	**385.6**	**489.0**	**595.2**	**947.1**	**1009.4**	**1152.1**	**1243.4**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1								32.3	34.2	34.6	36.1	36.3
A	Utah Cogen 2				61.0	61.0	61.1	61.0	61.0	61.0	60.6	63.9	67.8
H	Utah Combined Cycle CT												
	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											28.9	28.9
	Utah Pumped Storage									77.1	71.5	92.8	86.1
	Total	**6.9**	**15.2**	**27.4**	**104.4**	**122.2**	**139.4**	**157.1**	**207.5**	**321.2**	**366.4**	**464.5**	**496.3**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**11.0**	**16.9**	**21.4**	**27.0**	**32.6**	**43.5**	**60.0**	**76.4**	**91.2**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable												
O	Cogen				249.8	249.8	357.1	442.6	563.4	886.9	913.1	1031.4	1068.1
T	Combined Cycle CT												
A	Coal												
L	Simple Cycle CT											28.9	28.9
	Pumped Storage									77.1	71.5	94.7	121.1
	Total	**20.6**	**43.3**	**72.5**	**358.7**	**401.9**	**546.4**	**673.1**	**835.3**	**1311.8**	**1435.8**	**1693.0**	**1830.9**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pump Storage/Peak Return	312	311	309	310	309	307	306	306	405	396	426	460
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	334	376	372	343	324	357	461	509	485	313
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	**7547**	**7663**	**7670**	**7791**	**7874**	**7962**	**8063**	**8147**	**8562**	**8661**	**8827**	**8999**
M													
	Existing Generation	6776	6887	7035	6969	7044	7040	7090	7086	7141	7187	7020	7087
L	Firm Purchases	645	644	452	434	411	403	393	388	364	379	423	442
&	Non-Firm Purchases	128	133	183	151	183	175	152	124	108	125	242	266
R	New Resources				250	250	357	443	563	964	985	1155	1218
	Total Resources	**7549**	**7664**	**7670**	**7804**	**7888**	**7975**	**8078**	**8161**	**8577**	**8676**	**8840**	**9013**

PacifiCorp RAMPP-3 Case # 263

Wind At 0% Real Inflation On O&M

(run against -m.mg/md.nc.ar-)

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1						90.0	89.0	87.0	87.0	88.0	92.0	93.0
C	OWC Cogen 2				82.0	82.0	82.0	82.0	82.0	81.0	81.0	84.0	89.0
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											15.0	7.0
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1								87.0	87.0	88.0	92.0	93.0
T	Utah Cogen 2				82.0	82.0	82.0	82.0	82.0	82.0	82.0	86.0	91.0
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											5.0	5.0
	Utah Pumped Storage									20.0	18.0	18.0	17.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	74.6	73.9	75.0	74.1	73.7	73.7	74.1	74.0	74.5	75.0	76.4	77.1
	New Resources				82.7	82.7	85.0	85.7	85.5	66.9	67.0	52.2	45.1
	DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Case # 264

Wind with 2.5% Real Inflation On O&M

(run against -m.mg/md.nc.ar-)

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		Energy Sales (MWa)	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,760	8,154	8,543	8,824	9,295	9,803	10,323	11,041	12,184	13,437	15,412	17,947
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
46,894	4.04	Nominal	**Operating Revenues ($M)**	2,135	2,266	2,339	2,400	2,497	2,620	2,732	2,838	3,101	3,593	4,320	5,499
	0.61	Real		2,135	2,192	2,188	2,171	2,184	2,217	2,235	2,246	2,295	2,406	2,616	2,913
	3.37	Nominal	Cost in mills/kWh	47.8	49.8	50.4	50.9	52.2	53.9	55.2	56.4	59.4	66.3	75.9	90.2
	-0.03	Real		47.8	48.2	47.2	46.1	45.6	45.6	45.2	44.6	44.0	44.4	46.0	47.8
		Nominal	Average Customer Bill ($)	1,631	1,714	1,751	1,778	1,826	1,885	1,930	1,972	2,085	2,304	2,644	3,188
		Real		1,631	1,657	1,638	1,609	1,597	1,595	1,579	1,561	1,543	1,542	1,601	1,689
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
48,460	4.14	Nominal	**Total Resource Cost ($M)**	2,139	2,275	2,353	2,418	2,521	2,658	2,788	2,915	3,219	3,770	4,554	5,790
	0.71	Real		2,139	2,200	2,201	2,187	2,205	2,249	2,281	2,307	2,382	2,524	2,758	3,068
	3.32	Nominal	Cost in mills/kWh	47.8	49.7	50.1	50.4	51.4	53.0	54.3	55.5	58.5	65.2	74.4	87.9
	-0.08	Real		47.8	48.0	46.8	45.6	44.9	44.9	44.4	43.9	43.3	43.7	45.1	46.5

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 46.68

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 45.62

Wind with 2.5% Real Inflation On O&M

(run against -m.mg/md.nc.ar-)

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,189	68,267	68,985	69,756	70,649	71,385	75,021	75,888	77,342	78,849
	MWa	7,549	7,664	7,670	7,793	7,875	7,963	8,065	8,149	8,564	8,663	8,829	9,001
	Total Annual Emissions (1000 Tons)												
0.61%	CO_2	54,170	54,960	55,955	56,101	56,622	56,841	57,467	57,760	59,345	59,778	60,674	61,190
-0.57%	NO_x	139.6	141.4	143.8	142.8	143.6	143.7	120.3	120.5	122.3	123.0	123.8	124.5
0.24%	TSP	10.4	10.5	10.7	10.6	10.6	10.6	10.7	10.7	10.9	10.9	10.9	10.9
	Annual System Emission Rates (Pounds/MWh)												
-0.28%	CO_2	1,638	1,637	1,666	1,644	1,642	1,630	1,627	1,618	1,582	1,575	1,569	1,552
-1.52%	NO_x	4.22	4.21	4.28	4.18	4.16	4.12	3.40	3.37	3.26	3.24	3.20	3.16
-0.67%	TSP	0.31	0.31	0.32	0.31	0.31	0.30	0.30	0.30	0.29	0.29	0.28	0.28
	Emission Rates as Percent of 1994 Base												
	CO_2	100	99.94	101.67	100.32	100.20	99.48	99.30	98.78	96.57	96.16	95.77	94.74
	NO_x	100	99.80	101.41	99.13	98.65	97.63	80.65	79.94	77.24	76.80	75.83	74.82
	TSP	100	99.06	101.08	98.52	98.09	96.89	96.15	95.10	91.98	91.30	89.72	88.06

20 Year Emissions (1000 Tons)	Average	Total
CO_2	58,589	1,171,789
NO_x	128.8	2,575
TSP	10.8	215

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PacifiCorp RAMPP-3

Case # 264

Wind with 2.5% Real Inflation On O&M

(run against -m.mg/md.nc.ar-)

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1													0.0
W	OWC Cogen 2						118.1	96.6	105.4					320.1
C	OWC Combined Cycle CT				228.2					396.6	29.6	92.9		747.3
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											12.1	487.9	500.0
	Total	**24.4**	**25.0**	**24.1**	**254.7**	**36.8**	**164.1**	**150.1**	**159.1**	**465.8**	**111.9**	**174.2**	**554.3**	**2144.5**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2								37.2	1.8				39.0
A	Utah Combined Cycle CT				73.8									73.8
H	Utah CC CT Convert													0.0
	Utah Coal													0.0
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT											520.3		520.3
	Utah Pumped Storage									383.0		117.0		500.0
	Total	**8.9**	**10.1**	**14.1**	**92.9**	**20.1**	**25.1**	**26.2**	**63.7**	**435.5**	**74.6**	**703.4**	**48.5**	**1523.1**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**4.9**	**6.3**	**6.4**	**12.5**	**19.1**	**19.1**	**17.7**	**104.1**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable													0.0
O	Cogen				302.0		118.1	96.6	142.6	398.4	29.6	92.9		1180.2
T	Combined Cycle CT													0.0
A	Coal													0.0
L	Simple Cycle CT											520.3		520.3
	Pumped Storage									383.0		129.1	487.9	1000.0
	Total	**35.1**	**36.3**	**42.1**	**352.6**	**63.1**	**194.1**	**182.6**	**229.2**	**913.8**	**205.6**	**896.7**	**620.5**	**3771.7**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	302	302	420	517	659	1441	1470	2213	2701
L	**Total Resources**	**10068**	**10393**	**10249**	**10520**	**10674**	**10774**	**10854**	**10996**	**11340**	**11371**	**11659**	**12159**
&													
R	Reserves	1210	1388	1236	1371	1411	1405	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	15.0	15.2	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

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PacifiCorp RAMPP-3 Case # 264

Wind with 2.5% Real Inflation On O&M

(run against -m.mg/md.nc.ar-)

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1						107.2	192.8	281.3	279.7	281.7	296.8	297.9
C	OWC Cogen 2				188.8	188.8	188.8	188.8	188.8	512.0	536.2	634.6	666.1
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											1.9	35.0
	Total	**12.3**	**25.7**	**39.0**	**243.3**	**262.8**	**385.6**	**489.0**	**595.2**	**947.1**	**1009.4**	**1152.1**	**1243.4**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1								32.3	34.2	34.6	36.1	36.3
A	Utah Cogen 2				61.0	61.0	61.1	61.0	61.0	61.0	60.6	63.9	67.8
H	Utah Combined Cycle CT												
	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											28.9	28.9
	Utah Pumped Storage									77.1	71.5	92.8	86.1
	Total	**6.9**	**15.2**	**27.4**	**104.4**	**122.2**	**139.4**	**157.1**	**207.5**	**321.2**	**366.4**	**464.5**	**496.3**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**11.0**	**16.9**	**21.4**	**27.0**	**32.6**	**43.5**	**60.0**	**76.4**	**91.2**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable												
O	Cogen				249.8	249.8	357.1	442.6	563.4	886.9	913.1	1031.4	1068.1
T	Combined Cycle CT												
A	Coal												
L	Simple Cycle CT											28.9	28.9
	Pumped Storage									77.1	71.5	94.7	121.1
	Total	**20.6**	**43.3**	**72.5**	**358.7**	**401.9**	**546.4**	**673.1**	**835.3**	**1311.8**	**1435.8**	**1693.0**	**1830.9**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pump Storage/Peak Return	312	311	309	310	309	307	306	306	405	396	426	460
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	334	376	372	343	324	357	461	509	485	313
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	**7547**	**7663**	**7670**	**7791**	**7874**	**7962**	**8063**	**8147**	**8562**	**8661**	**8827**	**8999**
M													
	Existing Generation	6776	6887	7035	6969	7044	7040	7090	7086	7141	7187	7020	7087
L	Firm Purchases	645	644	452	434	411	403	393	388	364	379	423	442
&	Non-Firm Purchases	128	133	183	151	183	175	152	124	108	125	242	266
R	New Resources				250	250	357	443	563	964	985	1155	1218
	Total Resources	**7549**	**7664**	**7670**	**7804**	**7888**	**7975**	**8078**	**8161**	**8577**	**8676**	**8840**	**9013**

Case # 264

Wind with 2.5% Real Inflation On O&M

(run against -m.mg/md.nc.ar-)

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1						90.0	89.0	87.0	87.0	88.0	92.0	93.0
C	OWC Cogen 2				82.0	82.0	82.0	82.0	82.0	81.0	81.0	84.0	89.0
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											15.0	7.0

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1								87.0	87.0	88.0	92.0	93.0
T	Utah Cogen 2				82.0	82.0	82.0	82.0	82.0	82.0	82.0	86.0	91.0
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											5.0	5.0
	Utah Pumped Storage									20.0	18.0	18.0	17.0

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												

Total System

	1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
Existing Generation	74.6	73.9	75.0	74.1	73.7	73.7	74.1	74.0	74.5	75.0	76.4	77.1
New Resources				82.7	82.7	85.0	85.7	85.5	66.9	67.0	52.2	45.1
DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Increase Wind Reserve Margin Contribution 1.2 Times

(run against -m.mg/md.nc.ar-)

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		Energy Sales (MWa)	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,760	8,154	8,543	8,824	9,295	9,803	10,323	11,041	12,184	13,437	15,412	17,947
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
46,894	4.04	Nominal	**Operating Revenues ($M)**	2,135	2,266	2,339	2,400	2,497	2,620	2,732	2,838	3,101	3,593	4,320	5,499
	0.61	Real		2,135	2,192	2,188	2,171	2,184	2,217	2,235	2,246	2,295	2,406	2,616	2,913
	3.37	Nominal	Cost in mills/kWh	47.8	49.8	50.4	50.9	52.2	53.9	55.2	56.4	59.4	66.3	75.9	90.2
	-0.03	Real		47.8	48.2	47.2	46.1	45.6	45.6	45.2	44.6	44.0	44.4	46.0	47.8
		Nominal	Average Customer Bill ($)	1,631	1,714	1,751	1,778	1,826	1,885	1,930	1,972	2,085	2,304	2,644	3,188
		Real		1,631	1,657	1,638	1,609	1,597	1,595	1,579	1,561	1,543	1,542	1,601	1,689
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
48,460	4.14	Nominal	**Total Resource Cost ($M)**	2,139	2,275	2,353	2,418	2,521	2,658	2,788	2,915	3,219	3,770	4,554	5,790
	0.71	Real		2,139	2,200	2,201	2,187	2,205	2,249	2,281	2,307	2,382	2,524	2,758	3,068
	3.32	Nominal	Cost in mills/kWh	47.8	49.7	50.1	50.4	51.4	53.0	54.3	55.5	58.5	65.2	74.4	87.9
	-0.08	Real		47.8	48.0	46.8	45.6	44.9	44.9	44.4	43.9	43.3	43.7	45.1	46.5

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **46.68**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **45.62**

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Increase wind reserve margin contribution 1.2 times

(run against -m.mg/md.nc.ar-)

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,189	68,267	68,985	69,756	70,649	71,385	75,021	75,888	77,342	78,849
	MWa	7,549	7,664	7,670	7,793	7,875	7,963	8,065	8,149	8,564	8,663	8,829	9,001
	Total Annual Emissions (1000 Tons)												
0.61%	CO2	54,170	54,960	55,955	56,101	56,622	56,841	57,467	57,760	59,345	59,778	60,674	61,190
-0.57%	NOx	139.6	141.4	143.8	142.8	143.6	143.7	120.3	120.5	122.3	123.0	123.8	124.5
0.24%	TSP	10.4	10.5	10.7	10.6	10.6	10.6	10.7	10.7	10.9	10.9	10.9	10.9
	Annual System Emission Rates (Pounds/MWh)												
-0.28%	CO2	1,638	1,637	1,666	1,644	1,642	1,630	1,627	1,618	1,582	1,575	1,569	1,552
-1.52%	NOx	4.22	4.21	4.28	4.18	4.16	4.12	3.40	3.37	3.26	3.24	3.20	3.16
-0.67%	TSP	0.31	0.31	0.32	0.31	0.31	0.30	0.30	0.30	0.29	0.29	0.28	0.28
	Emission Rates as Percent of 1994 Base												
	CO2	100	99.94	101.67	100.32	100.20	99.48	99.30	98.78	96.57	96.16	95.77	94.74
	NOx	100	99.80	101.41	99.13	98.65	97.63	80.65	79.94	77.24	76.80	75.83	74.82
	TSP	100	99.06	101.08	98.52	98.09	96.89	96.15	95.10	91.98	91.30	89.72	88.06

20 Year Emissions (1000 Tons)	Average	Total
CO2	58,589	1,171,789
NOx	128.8	2,575
TSP	10.8	215

PacifiCorp RAMPP-3 Case # 265

Increase wind reserve margin contribution 1.2 times

(run against -m.mg/md.nc.ar-)

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1						118.1	96.6	105.4					320.1
W	OWC Cogen 2				228.2					396.6	29.6	92.9		747.3
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											12.1	487.9	500.0
	Total	**24.4**	**25.0**	**24.1**	**254.7**	**36.8**	**164.1**	**150.1**	**159.1**	**465.8**	**111.9**	**174.2**	**554.3**	**2144.5**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1								37.2	1.8				39.0
T	Utah Cogen 2				73.8									73.8
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal													0.0
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT											520.3		520.3
	Utah Pumped Storage									383.0		117.0		500.0
	Total	**8.9**	**10.1**	**14.1**	**92.9**	**20.1**	**25.1**	**26.2**	**63.7**	**435.5**	**74.6**	**703.4**	**48.5**	**1523.1**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**4.9**	**6.3**	**6.4**	**12.5**	**19.1**	**19.1**	**17.7**	**104.1**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable													0.0
O	Cogen				302.0		118.1	96.6	142.6	398.4	29.6	92.9		1180.2
T	Combined Cycle CT													0.0
A	Coal													0.0
L	Simple Cycle CT											520.3		520.3
	Pumped Storage									383.0		129.1	487.9	1000.0
	Total	**35.1**	**36.3**	**42.1**	**352.6**	**63.1**	**194.1**	**182.6**	**229.2**	**913.8**	**205.6**	**896.7**	**620.5**	**3771.7**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	302	302	420	517	659	1441	1470	2213	2701
L	**Total Resources**	**10068**	**10393**	**10249**	**10520**	**10674**	**10774**	**10854**	**10996**	**11340**	**11371**	**11659**	**12159**
&													
R	Reserves	1210	1388	1236	1371	1411	1405	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	15.0	15.2	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

PacifiCorp RAMPP-3

Case # 265

Increase wind reserve margin contribution 1.2 times

(run against -m.mg/md.nc.ar-)

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1						107.2	192.8	281.3	279.7	281.7	296.8	297.9
C	OWC Cogen 2				188.8	188.8	188.8	188.8	188.8	512.0	536.2	634.6	666.1
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											1.9	35.0
	Total	**12.3**	**25.7**	**39.0**	**243.3**	**262.8**	**385.6**	**489.0**	**595.2**	**947.1**	**1009.4**	**1152.1**	**1243.4**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1								32.3	34.2	34.6	36.1	36.3
A	Utah Cogen 2				61.0	61.0	61.1	61.0	61.0	61.0	60.6	63.9	67.8
H	Utah Combined Cycle CT												
	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											28.9	28.9
	Utah Pumped Storage									77.1	71.5	92.8	86.1
	Total	**6.9**	**15.2**	**27.4**	**104.4**	**122.2**	**139.4**	**157.1**	**207.5**	**321.2**	**366.4**	**464.5**	**496.3**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**11.0**	**16.9**	**21.4**	**27.0**	**32.6**	**43.5**	**60.0**	**76.4**	**91.2**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable												
O	Cogen				249.8	249.8	357.1	442.6	563.4	886.9	913.1	1031.4	1068.1
T	Combined Cycle CT												
A	Coal												
L	Simple Cycle CT											28.9	28.9
	Pumped Storage									77.1	71.5	94.7	121.1
	Total	**20.6**	**43.3**	**72.5**	**358.7**	**401.9**	**546.4**	**673.1**	**835.3**	**1311.8**	**1435.8**	**1693.0**	**1830.9**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	**Pump Storage/Peak Return**	312	311	309	310	309	307	306	306	405	396	426	460
Y	**Firm Sales**	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	**Non-Firm Sales**	420	431	334	376	372	343	324	357	461	509	485	313
T	**DSR**	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	**7547**	**7663**	**7670**	**7791**	**7874**	**7962**	**8063**	**8147**	**8562**	**8661**	**8827**	**8999**
M													
	Existing Generation	6776	6887	7035	6969	7044	7040	7090	7086	7141	7187	7020	7087
L	**Firm Purchases**	645	644	452	434	411	403	393	388	364	379	423	442
&	**Non-Firm Purchases**	128	133	183	151	183	175	152	124	108	125	242	266
R	**New Resources**				250	250	357	443	563	964	985	1155	1218
	Total Resources	**7549**	**7664**	**7670**	**7804**	**7888**	**7975**	**8078**	**8161**	**8577**	**8676**	**8840**	**9013**

PacifiCorp RAMPP-3 Case # 265

Increase wind reserve margin contribution 1.2 times

(run against -m.mg/md.nc.ar-)

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1						90.0	89.0	87.0	87.0	88.0	92.0	93.0
C	OWC Cogen 2				82.0	82.0	82.0	82.0	82.0	81.0	81.0	84.0	89.0
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											15.0	7.0
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1								87.0	87.0	88.0	92.0	93.0
T	Utah Cogen 2				82.0	82.0	82.0	82.0	82.0	82.0	82.0	86.0	91.0
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											5.0	5.0
	Utah Pumped Storage									20.0	18.0	18.0	17.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	74.6	73.9	75.0	74.1	73.7	73.7	74.1	74.0	74.5	75.0	76.4	77.1
	New Resources				82.7	82.7	85.0	85.7	85.5	66.9	67.0	52.2	45.1
	DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Case # 266

Wind Res Margin Set To Winter Capacity Factor

(run against -m.mg/md.nc.ar-)

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		**Energy Sales (MWa)**	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,761	8,162	8,570	8,932	9,479	9,921	10,428	11,165	12,327	13,539	15,484	17,966
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
47,018	4.03	Nominal	**Operating Revenues ($M)**	2,135	2,266	2,339	2,400	2,498	2,638	2,776	2,862	3,116	3,614	4,339	5,520
	0.61	Real		2,135	2,192	2,188	2,171	2,186	2,232	2,272	2,265	2,306	2,419	2,628	2,924
	3.37	Nominal	Cost in mills/kWh	47.8	49.8	50.4	50.9	52.2	54.3	56.1	56.9	59.7	66.7	76.3	90.5
	-0.03	Real		47.8	48.2	47.2	46.1	45.7	45.9	45.9	45.0	44.2	44.6	46.2	47.9
		Nominal	Average Customer Bill ($)	1,631	1,714	1,751	1,778	1,827	1,898	1,961	1,989	2,095	2,317	2,656	3,200
		Real		1,631	1,657	1,638	1,609	1,598	1,606	1,605	1,574	1,551	1,551	1,608	1,695
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
48,584	4.14	Nominal	**Total Resource Cost ($M)**	2,139	2,275	2,353	2,418	2,523	2,677	2,833	2,939	3,233	3,790	4,574	5,814
	0.71	Real		2,139	2,200	2,201	2,188	2,207	2,265	2,318	2,326	2,393	2,538	2,770	3,078
	3.32	Nominal	Cost in mills/kWh	47.8	49.7	50.1	50.4	51.4	53.4	55.2	56.0	58.8	65.6	74.7	68.2
	-0.08	Real		47.8	48.0	46.8	45.6	45.0	45.2	45.2	44.3	43.5	43.9	45.3	46.7

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **46.81**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **45.74**

Wind Res Margin Set To Winter Capacity Factor

(run against -m.mg/md.nc.ar-)

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,189	68,214	69,029	69,686	70,448	71,245	74,898	75,756	77,114	78,612
	MWa	7,549	7,664	7,670	7,787	7,880	7,955	8,042	8,133	8,550	8,648	8,803	8,974
	Total Annual Emissions (1000 Tons)												
0.57%	CO_2	54,170	54,960	55,955	56,111	56,641	56,432	57,112	57,403	58,895	59,378	60,249	60,744
-0.58%	NO_x	139.6	141.4	143.8	142.9	143.7	143.3	120.1	120.3	121.9	122.7	123.5	124.2
0.24%	TSP	10.4	10.5	10.7	10.6	10.6	10.6	10.7	10.7	10.8	10.9	10.9	10.9
	Annual System Emission Rates (Pounds/MWh)												
-0.31%	CO_2	1,638	1,637	1,666	1,645	1,641	1,620	1,621	1,611	1,573	1,568	1,563	1,545
-1.51%	NO_x	4.22	4.21	4.28	4.19	4.16	4.11	3.41	3.38	3.25	3.24	3.20	3.16
-0.66%	TSP	0.31	0.31	0.32	0.31	0.31	0.30	0.30	0.30	0.29	0.29	0.28	0.28
	Emission Rates as Percent of 1994 Base												
	CO_2	100	99.94	101.67	100.42	100.17	98.86	98.97	98.36	95.99	95.69	95.38	94.33
	NO_x	100	99.80	101.41	99.26	98.64	97.42	80.77	79.99	77.10	76.73	75.88	74.84
	TSP	100	99.06	101.08	98.65	98.07	96.80	96.51	95.35	91.93	91.38	89.90	88.23

20 Year Emissions (1000 Tons)	Average	Total
CO_2	58,279	1,165,587
NO_x	128.5	2,571
TSP	10.8	215

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PacifiCorp RAMPP-3

Case # 266

Wind Res Margin Set To Winter Capacity Factor
(run against -m.mg/md.nc.ar-)

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1				60.2			37.6	142.5	79.6				319.9
W	OWC Cogen 2				241.8					320.9	29.6	81.2		673.5
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											12.1	487.9	500.0
	Total	**24.4**	**25.0**	**24.1**	**328.5**	**36.8**	**46.0**	**91.1**	**196.2**	**469.7**	**111.9**	**162.5**	**554.3**	**2070.5**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C						150.0							150.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1									39.0				39.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal													0.0
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT											490.9		490.9
	Utah Pumped Storage									341.9		158.1		500.0
	Total	**8.9**	**10.1**	**14.1**	**19.1**	**20.1**	**175.1**	**26.2**	**26.5**	**431.6**	**74.6**	**715.1**	**48.5**	**1569.9**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C						150.0							150.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**154.9**	**6.3**	**6.4**	**12.5**	**19.1**	**19.1**	**17.7**	**254.1**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable						300.0							300.0
O	Cogen				302.0			37.6	142.5	439.5	29.6	81.2		1032.4
T	Combined Cycle CT													0.0
A	Coal													0.0
L	Simple Cycle CT											490.9		490.9
	Pumped Storage									341.9		170.2	487.9	1000.0
	Total	**35.1**	**36.3**	**42.1**	**352.6**	**63.1**	**376.0**	**123.6**	**229.1**	**913.8**	**205.6**	**896.7**	**620.5**	**3894.5**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	302	302	602	640	782	1564	1593	2335	2823
L	**Total Resources**	**10068**	**10393**	**10249**	**10520**	**10674**	**10956**	**10977**	**11119**	**11463**	**11494**	**11781**	**12281**
&													
R	**Reserves**	1210	1388	1236	1371	1411	1464	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	15.0	15.2	15.6	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

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PacifiCorp RAMPP-3 Case # 266

Wind Res Margin Set To Winter Capacity Factor

(run against -m.mg/md.nc.ar-)

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				52.2	55.1	54.7	90.7	213.2	278.2	279.2	297.4	297.9
C	OWC Cogen 2				200.0	200.0	200.0	200.0	200.0	461.0	485.3	568.9	602.7
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											1.9	31.5
	Total	**12.3**	**25.7**	**39.0**	**306.7**	**329.1**	**344.3**	**398.1**	**538.3**	**894.6**	**956.0**	**1087.0**	**1176.5**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C						52.7	52.7	52.7	52.7	52.7	52.7	52.7
	Utah Wind without Tax C												
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1									33.9	34.2	36.2	36.2
A	Utah Cogen 2												
H	Utah Combined Cycle CT												
	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											27.3	27.3
	Utah Pumped Storage									69.2	64.5	92.8	84.4
	Total	**6.9**	**15.2**	**27.4**	**43.4**	**61.2**	**131.0**	**148.8**	**166.9**	**304.7**	**351.1**	**451.8**	**477.8**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C						52.7	52.7	52.7	52.7	52.7	52.7	52.7
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**11.0**	**16.9**	**74.1**	**79.7**	**85.3**	**96.2**	**112.7**	**129.1**	**143.9**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable						105.4	105.4	105.4	105.4	105.4	105.4	105.4
O	Cogen				252.2	255.1	254.7	290.7	413.2	773.1	798.7	902.5	936.8
T	Combined Cycle CT												
A	Coal												
L	Simple Cycle CT											27.3	27.3
	Pumped Storage									69.2	64.5	94.7	115.9
	Total	**20.6**	**43.3**	**72.5**	**361.1**	**407.2**	**549.4**	**626.6**	**790.5**	**1295.5**	**1419.8**	**1667.9**	**1798.2**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pump Storage/Peak Return	312	311	309	310	309	307	306	306	395	387	426	453
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	334	371	376	335	301	341	457	503	459	293
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	**7547**	**7663**	**7670**	**7786**	**7878**	**7954**	**8040**	**8131**	**8548**	**8646**	**8801**	**8972**
M													
	Existing Generation	6776	6887	7035	6972	7049	7028	7104	7100	7135	7186	7025	7091
L	Firm Purchases	645	644	452	435	411	403	393	388	364	382	424	442
&	Non-Firm Purchases	128	133	183	141	177	176	161	139	116	123	237	269
R	New Resources				252	255	360	396	519	948	969	1130	1185
	Total Resources	**7549**	**7664**	**7670**	**7800**	**7892**	**7967**	**8054**	**8146**	**8563**	**8660**	**8816**	**8987**

PacifiCorp RAMPP-3

Case # 266

Wind Res Margin Set To Winter Capacity Factor

(run against -m.mg/md.nc.ar-)

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				86.0	91.0	90.0	92.0	88.0	86.0	87.0	92.0	93.0
C	OWC Cogen 2				82.0	82.0	82.0	82.0	82.0	81.0	81.0	84.0	89.0
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											15.0	6.0
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C						35.0	35.0	35.0	35.0	35.0	35.0	35.0
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1									86.0	87.0	92.0	92.0
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											5.0	5.0
	Utah Pumped Storage									20.0	18.0	18.0	16.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C						35.0	35.0	35.0	35.0	35.0	35.0	35.0
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												

Total System

	1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
Existing Generation	74.6	73.9	75.0	74.2	73.8	73.5	74.3	74.2	74.5	74.9	76.5	77.1
New Resources				83.5	84.5	59.8	61.9	66.3	60.6	60.8	48.4	42.0
DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

35% More Wind Energy

(run against -m.mg/md.nc.ar-)

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		**Energy Sales (MWa)**	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,767	8,222	8,702	9,059	9,623	10,091	10,587	11,301	12,426	13,637	15,543	17,986
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
47,056	4.03	Nominal	**Operating Revenues ($M)**	2,135	2,266	2,339	2,408	2,523	2,654	2,789	2,881	3,131	3,617	4,343	5,512
	0.61	Real		2,135	2,192	2,188	2,178	2,207	2,246	2,282	2,280	2,318	2,422	2,630	2,920
	3.37	Nominal	Cost in mills/kWh	47.8	49.8	50.4	51.1	52.7	54.6	56.4	57.2	60.0	66.7	76.3	90.4
	-0.03	Real		47.8	48.2	47.2	46.2	46.1	46.2	46.1	45.3	44.4	44.7	46.2	47.9
		Nominal	Average Customer Bill ($)	1,631	1,714	1,751	1,784	1,845	1,909	1,970	2,002	2,105	2,319	2,658	3,196
		Real		1,631	1,657	1,638	1,614	1,614	1,615	1,612	1,584	1,558	1,553	1,610	1,693
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
48,621	4.13	Nominal	**Total Resource Cost ($M)**	2,139	2,275	2,353	2,426	2,547	2,693	2,845	2,958	3,249	3,794	4,577	5,803
	0.71	Real		2,139	2,200	2,201	2,194	2,228	2,278	2,328	2,341	2,404	2,540	2,772	3,074
	3.31	Nominal	Cost in mills/kWh	47.8	49.7	50.1	50.5	51.9	53.7	55.4	56.3	59.0	65.6	74.8	88.0
	-0.08	Real		47.8	48.0	46.8	45.7	45.4	45.4	45.4	44.6	43.7	43.9	45.3	46.6

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 46.84

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 45.77

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wind mwh financial

35% More Wind Energy

(run against -m.mg/md.nc.ar-)

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,137	67,189	68,381	69,029	70,036	70,877	71,718	75,292	76,230	77,421	78,752
	MWa	7,549	7,664	7,670	7,806	7,880	7,995	8,091	8,187	8,595	8,702	8,838	8,990
	Total Annual Emissions (1000 Tons)												
0.54%	CO_2	54,170	54,960	55,955	55,847	56,316	56,165	56,830	57,111	58,600	59,055	59,926	60,372
-0.59%	NO_x	139.6	141.4	143.8	142.7	143.4	143.1	119.8	119.9	121.7	122.4	123.3	123.9
0.23%	TSP	10.4	10.5	10.7	10.6	10.6	10.6	10.7	10.7	10.8	10.9	10.9	10.9
	Annual System Emission Rates (Pounds/MWh)												
-0.35%	CO_2	1,638	1,637	1,666	1,633	1,632	1,604	1,604	1,593	1,557	1,549	1,548	1,533
-1.54%	NO_x	4.22	4.21	4.28	4.17	4.16	4.09	3.38	3.34	3.23	3.21	3.18	3.15
-0.67%	TSP	0.31	0.31	0.32	0.31	0.31	0.30	0.30	0.30	0.29	0.29	0.28	0.28
	Emission Rates as Percent of 1994 Base												
	CO_2	100	99.94	101.67	99.70	99.60	97.90	97.88	97.21	95.01	94.57	94.49	93.59
	NO_x	100	99.80	101.41	98.86	98.45	96.78	80.05	79.23	76.55	76.09	75.43	74.53
	TSP	100	99.06	101.08	98.32	97.94	96.27	95.72	94.51	91.47	90.76	89.48	88.00

20 Year Emissions (1000 Tons)

	Average	Total
CO_2	58,012	1,160,244
NO_x	128.3	2,566
TSP	10.8	215

PacifiCorp RAMPP-3 Case # 267

35% More Wind Energy

(run against -m.mg/md.nc.ar-)

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1				20.7			79.6	142.5	77.2				320.0
W	OWC Cogen 2				194.7					317.9		58.9		571.5
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											12.1	487.9	500.0
	Total	**24.4**	**25.0**	**24.1**	**241.9**	**36.8**	**46.0**	**133.1**	**196.2**	**464.3**	**82.3**	**140.2**	**554.3**	**1968.6**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C				150.0		150.0							300.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1										29.6	9.4		39.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal													0.0
	Utah IG CC													0.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT											548.3		548.3
	Utah Pumped Storage									386.4		113.6		500.0
	Total	**8.9**	**10.1**	**14.1**	**169.1**	**20.1**	**175.1**	**26.2**	**26.5**	**437.1**	**104.2**	**737.4**	**48.5**	**1777.3**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C				42.5		150.0							192.5
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**47.5**	**6.2**	**154.9**	**6.3**	**6.4**	**12.5**	**19.1**	**19.1**	**17.7**	**296.6**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable				192.5		300.0							492.5
O	Cogen				215.4			79.6	142.5	395.1	29.6	68.3		930.5
T	Combined Cycle CT													0.0
A	Coal													0.0
L	Simple Cycle CT											548.3		548.3
	Pumped Storage									386.4		125.7	487.9	1000.0
	Total	**35.1**	**36.3**	**42.1**	**458.5**	**63.1**	**376.0**	**165.6**	**229.1**	**913.9**	**205.6**	**896.7**	**620.5**	**4042.5**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	408	408	708	788	930	1712	1741	2483	2971
L	**Total Resources**	**10068**	**10393**	**10249**	**10626**	**10780**	**11062**	**11125**	**11267**	**11611**	**11642**	**11929**	**12429**
&													
R	Reserves	1210	1388	1236	1371	1411	1422	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	15.0	15.2	15.2	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

PacifiCorp RAMPP-3

Case # 267

35% More Wind Energy

(run against -m.mg/md.nc.ar-)

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				18.7	18.9	18.8	93.0	210.9	277.5	278.8	297.4	297.9
C	OWC Cogen 2				161.1	161.1	161.1	161.1	161.1	415.7	415.7	484.8	508.1
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											1.9	30.5
	Total	**12.3**	**25.7**	**39.0**	**234.3**	**254.0**	**269.5**	**361.5**	**497.1**	**848.6**	**886.0**	**1002.9**	**1080.9**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C				66.7	66.9	142.1	142.1	142.1	142.1	142.1	142.1	142.1
	Utah Wind without Tax C												
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1										26.3	36.2	36.2
A	Utah Cogen 2												
H	Utah Combined Cycle CT												
	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											30.5	30.5
	Utah Pumped Storage									76.7	71.7	92.8	77.3
	Total	**6.9**	**15.2**	**27.4**	**110.1**	**128.1**	**220.4**	**238.2**	**256.3**	**367.7**	**439.8**	**544.4**	**563.3**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C				18.9	18.9	91.2	91.2	91.2	91.2	91.2	91.2	91.2
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**29.9**	**35.8**	**112.6**	**118.2**	**123.8**	**134.7**	**151.2**	**167.6**	**182.4**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable				85.6	85.8	233.3	233.3	233.3	233.3	233.3	233.3	233.3
O	Cogen				179.8	180.0	179.9	254.1	372.0	693.2	720.8	818.4	842.2
T	Combined Cycle CT												
A	Coal												
L	Simple Cycle CT											30.5	30.5
	Pumped Storage									76.7	71.7	94.7	107.8
	Total	**20.6**	**43.3**	**72.5**	**374.3**	**417.9**	**602.5**	**717.9**	**877.2**	**1351.0**	**1477.0**	**1714.9**	**1826.6**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pump Storage/Peak Return	312	311	309	310	309	307	306	306	405	397	426	443
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	334	389	376	375	350	395	493	548	494	319
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	**7547**	**7663**	**7670**	**7804**	**7878**	**7994**	**8089**	**8185**	**8594**	**8701**	**8836**	**8988**
M													
	Existing Generation	6776	6887	7035	6968	7034	7023	7081	7077	7124	7175	7015	7079
L	Firm Purchases	645	644	452	434	411	403	393	388	364	384	427	442
&	Non-Firm Purchases	128	133	183	150	181	168	142	129	116	129	232	267
R	New Resources				265	266	413	487	605	1003	1026	1177	1214
	Total Resources	**7549**	**7664**	**7670**	**7817**	**7892**	**8007**	**8103**	**8199**	**8607**	**8714**	**8851**	**9002**

wind.mwh.avg_mw

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PacifiCorp RAMPP-3

Case # 267

35% More Wind Energy

(run against -m.mg/md.nc.ar-)

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				90.0	91.0	90.0	92.0	86.0	86.0	87.0	92.0	93.0
C	OWC Cogen 2				82.0	82.0	82.0	82.0	82.0	81.0	81.0	84.0	88.0
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											15.0	6.0
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C				44.0	44.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1										88.0	92.0	92.0
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal												
	Utah Simple Cycle CT											5.0	5.0
	Utah Pumped Storage									19.0	18.0	18.0	15.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C				44.0	44.0	47.0	47.0	47.0	47.0	47.0	47.0	47.0
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	74.6	73.9	75.0	74.1	73.6	73.5	74.0	73.9	74.3	74.8	76.4	77.0
	New Resources				65.1	65.2	58.4	61.9	65.1	58.6	58.9	47.4	40.9
	DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Case # 301

Low Nox - Low CO2

(run against -m.mg/md.ac.ar-)

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		**Energy Sales (MWa)**	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,763	8,183	8,606	8,884	9,346	9,897	10,524	11,582	13,096	14,382	17,295	20,104
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
46,980	3.88	Nominal	**Operating Revenues ($M)**	2,177	2,316	2,383	2,441	2,547	2,665	2,770	2,861	3,101	3,677	4,297	5,480
	0.46	Real		2,177	2,240	2,228	2,208	2,228	2,255	2,267	2,264	2,295	2,462	2,602	2,903
	3.22	Nominal	Cost in mills/kWh	48.8	50.9	51.4	51.8	53.2	54.8	56.0	56.8	59.4	67.8	75.5	89.9
	-0.17	Real		48.8	49.3	48.0	46.8	46.6	46.4	45.8	45.0	44.0	45.4	45.8	47.6
		Nominal	Average Customer Bill ($)	1,663	1,752	1,783	1,809	1,862	1,917	1,957	1,988	2,085	2,357	2,630	3,178
		Real		1,663	1,694	1,668	1,636	1,629	1,622	1,601	1,573	1,543	1,578	1,593	1,683
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
48,545	3.99	Nominal	**Total Resource Cost ($M)**	2,181	2,325	2,396	2,459	2,571	2,703	2,827	2,938	3,218	3,853	4,531	5,771
	0.57	Real		2,181	2,249	2,241	2,225	2,249	2,287	2,313	2,325	2,382	2,580	2,744	3,058
	3.17	Nominal	Cost in mills/kWh	48.7	50.7	51.0	51.2	52.4	53.9	55.1	55.9	58.5	66.6	74.0	87.6
	-0.22	Real		48.7	49.1	47.7	46.3	45.8	45.6	45.1	44.3	43.3	44.6	44.8	46.4

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 46.77

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 45.70

Low Nox - Low Co2

(run against -m.mg/md.ac.ar-)

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	63,221	63,764	64,456	66,024	66,707	67,969	69,134	69,992	73,575	75,099	76,781	79,409
	MWa	7,217	7,279	7,358	7,537	7,615	7,759	7,892	7,990	8,399	8,573	8,765	9,065
	Total Annual Emissions (1000 Tons)												
1.57%	CO2	47,978	48,368	50,412	50,576	51,351	52,189	53,461	54,659	57,955	59,342	62,970	65,459
-0.08%	NOx	122.2	123.0	128.5	127.5	129.6	131.6	112.1	112.8	113.6	116.0	117.9	120.1
0.74%	TSP	9.2	9.2	9.5	9.5	9.7	9.8	10.0	10.0	10.1	10.2	10.5	10.6
	Annual System Emission Rates (Pounds/MWh)												
0.44%	CO2	1,518	1,517	1,564	1,532	1,540	1,536	1,547	1,562	1,575	1,580	1,640	1,649
-1.28%	NOx	3.86	3.86	3.99	3.86	3.89	3.87	3.24	3.22	3.09	3.09	3.07	3.03
-0.42%	TSP	0.29	0.29	0.30	0.29	0.29	0.29	0.29	0.29	0.27	0.27	0.27	0.27
	Emission Rates as Percent of 1994 Base												
	CO2	100	99.95	103.06	100.94	101.44	101.18	101.90	102.90	103.79	104.12	108.07	108.62
	NOx	100	99.82	103.19	99.96	100.57	100.18	83.91	83.40	79.93	79.96	79.47	78.30
	TSP	100	99.00	101.85	99.50	100.05	99.65	100.01	98.87	94.33	93.96	93.85	92.31

20 Year Emissions (1000 Tons)	Average	Total
CO2	57,164	1,143,277
NOx	119.4	2,389
TSP	10.1	201

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Low Nox - Low Co2
(run against -m.mg/md.ac.ar-)

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1													0.0
W	OWC Cogen 2				160.0		118.1	18.1						296.2
C	OWC Combined Cycle CT				142.0									142.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											221.4	278.6	500.0
	Total	**24.4**	**25.0**	**24.1**	**328.5**	**36.8**	**164.1**	**71.6**	**53.7**	**69.2**	**82.3**	**290.6**	**345.0**	**1515.3**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal													0.0
	Utah IG CC													0.0
	Utah FB Coal								142.5	450.0	29.6	430.8	209.3	1262.2
	Utah Simple Cycle CT													0.0
	Utah Pumped Storage							78.4		331.5		90.1		500.0
	Total	**8.9**	**10.1**	**14.1**	**19.1**	**20.1**	**25.1**	**104.6**	**169.0**	**832.2**	**104.2**	**587.0**	**257.8**	**2152.2**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**4.9**	**6.3**	**6.4**	**12.5**	**19.1**	**19.1**	**17.7**	**104.1**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable													0.0
O	Cogen				302.0		118.1	18.1						438.2
T	Combined Cycle CT													0.0
A	Coal								142.5	450.0	29.6	430.8	209.3	1262.2
L	Simple Cycle CT													0.0
	Pumped Storage							78.4		331.5		311.5	278.6	1000.0
	Total	**35.1**	**36.3**	**42.1**	**352.6**	**63.1**	**194.1**	**182.5**	**229.1**	**913.9**	**205.6**	**896.7**	**620.5**	**3771.6**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	302	302	420	517	659	1441	1470	2213	2700
L	**Total Resources**	**10068**	**10393**	**10249**	**10520**	**10674**	**10774**	**10854**	**10996**	**11340**	**11371**	**11659**	**12158**
&													
R	Reserves	1210	1388	1236	1371	1411	1405	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	15.0	15.2	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

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Case # 301

Low Nox - Low Co2

(run against -m.mg/md.ac.ar-)

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				148.9	148.9	258.8	275.7	275.7	275.7	275.7	275.7	275.7
C	OWC Cogen 2				132.1	132.1	132.1	132.1	124.0	121.3	120.3	126.0	126.2
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											0.3	1.3
	Total	**12.3**	**25.7**	**39.0**	**335.5**	**355.0**	**480.5**	**515.2**	**524.8**	**552.4**	**587.5**	**620.8**	**647.6**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1												
A	Utah Cogen 2												
H	Utah Combined Cycle CT												
	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC								129.3	537.4	564.2	954.9	1144.7
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage							8.1	4.9	37.1	44.8	84.6	90.4
	Total	**6.9**	**15.2**	**27.4**	**43.4**	**61.2**	**78.3**	**104.2**	**248.4**	**723.4**	**808.7**	**1282.3**	**1512.3**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**11.0**	**16.9**	**21.4**	**27.0**	**32.6**	**43.5**	**60.0**	**76.4**	**91.2**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable												
O	Cogen				281.0	281.0	390.9	407.8	399.7	397.0	396.0	401.7	401.9
T	Combined Cycle CT												
A	Coal								129.3	537.4	564.2	954.9	1144.7
L	Simple Cycle CT												
	Pumped Storage							8.1	4.9	37.1	44.8	84.9	91.7
	Total	**20.6**	**43.3**	**72.5**	**389.9**	**433.1**	**580.2**	**646.4**	**805.8**	**1319.3**	**1456.2**	**1979.5**	**2251.1**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pump Storage/Peak Return	312	311	310	310	309	307	317	313	354	362	413	422
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	87	46	20	120	111	139	141	192	348	453	434	416
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	7214	7278	7357	7535	7613	7758	7891	7989	8398	8571	8763	9064
M													
	Existing Generation	6134	6197	6451	6396	6481	6539	6673	6699	6730	6875	6695	6826
L	Firm Purchases	718	717	542	525	519	511	500	495	471	468	443	443
&	Non-Firm Purchases	364	364	364	348	347	331	316	275	239	237	199	171
R	New Resources				281	281	390	415	533	971	1004	1441	1638
	Total Resources	7216	7278	7357	7550	7628	7771	7904	8002	8411	8584	8778	9078

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Low Nox - Low Co2

(run against -m.mg/md.ac.ar-)

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0
C	OWC Cogen 2				93.0	93.0	93.0	93.0	87.0	85.0	84.0	88.0	88.0
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal								90.0	90.0	90.0	90.0	90.0
	Utah Simple Cycle CT												
	Utah Pumped Storage												
								10.0	6.0	9.0	10.0	16.0	18.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	67.5	66.5	68.8	68.0	67.8	68.4	69.8	70.0	70.2	71.7	72.9	74.2
	New Resources				93.0	93.0	92.8	80.3	80.9	67.4	68.3	65.1	60.7
	DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Low Nox - Low CO2

(run against -m.mg/hd.ac.ar-)

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	36	84	161	204	254	292	334	375	448	547	639	718
			After Conservation												
			System Load (MWa)	5,616	5,698	5,799	5,854	5,936	6,030	6,173	6,246	6,485	6,739	7,071	7,578
	0.62		Energy Sales (MWa)	5,080	5,154	5,214	5,294	5,369	5,455	5,552	5,653	5,870	6,100	6,402	6,868
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,795	8,215	8,657	8,930	9,386	9,936	10,547	11,597	13,093	14,313	17,203	19,785
			Net Conservation Assets ($M)	95	203	354	430	527	619	718	808	917	1,002	1,034	979
			Utility Cost												
46,668	3.87	Nominal	Operating Revenues ($M)	2,174	2,317	2,380	2,443	2,530	2,650	2,749	2,842	3,078	3,654	4,269	5,466
	0.45	Real		2,174	2,240	2,226	2,210	2,214	2,242	2,249	2,249	2,278	2,446	2,586	2,896
	3.23	Nominal	Cost in mills/kWh	48.9	51.3	52.1	52.7	53.8	55.5	56.5	57.4	59.9	68.4	76.1	90.9
	-0.17	Real		48.9	49.6	48.7	47.7	47.1	46.9	46.3	45.4	44.3	45.8	46.1	48.1
		Nominal	Average Customer Bill ($)	1,661	1,752	1,781	1,810	1,850	1,906	1,942	1,975	2,070	2,343	2,613	3,169
		Real		1,661	1,694	1,666	1,638	1,619	1,613	1,589	1,563	1,532	1,569	1,583	1,679
			Total Resource Cost												
			DSR Customer Cost ($M)	8.5	11.0	12.6	16.1	16.9	64.6	84.4	103.5	92.3	86.2	107.0	106.2
			Levelized (20-year at 8.8%)	0.9	2.1	3.5	5.2	7.0	14.0	23.1	34.3	54.1	82.9	116.8	163.6
			Energy Svc Charge ($M)	4.7	9.8	14.9	20.5	27.1	34.3	43.0	52.8	73.1	103.0	130.8	145.6
48,390	3.99	Nominal	Total Resource Cost ($M)	2,179	2,329	2,399	2,469	2,564	2,699	2,815	2,929	3,205	3,840	4,517	5,775
	0.57	Real		2,179	2,252	2,243	2,233	2,243	2,283	2,303	2,318	2,373	2,571	2,736	3,059
	3.18	Nominal	Cost in mills/kWh	48.7	50.8	51.1	51.4	52.3	53.8	54.9	55.8	58.3	66.4	73.8	87.6
	-0.22	Real		48.7	49.1	47.8	46.5	45.7	45.5	44.9	44.1	43.1	44.5	44.7	46.4

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **47.11**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **45.55**

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Low Nox - Low Co2

(run against -m.mg/hd.ac.ar-)

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	63,133	63,589	63,694	65,157	65,753	66,830	68,135	68,985	72,612	74,013	75,564	77,824
	MWa	7,207	7,259	7,271	7,438	7,506	7,629	7,778	7,875	8,289	8,449	8,626	8,884
	Total Annual Emissions (1000 Tons)												
1.50%	CO2	47,880	48,229	49,580	50,407	51,112	51,927	52,980	54,201	57,502	58,829	62,349	64,523
-0.07%	NOx	121.9	122.6	125.9	128.0	130.0	131.9	111.6	112.5	113.3	115.8	117.3	120.3
0.77%	TSP	9.2	9.1	9.4	9.5	9.7	9.8	10.0	10.0	10.1	10.2	10.4	10.7
	Annual System Emission Rates (Pounds/MWh)												
0.47%	CO2	1,517	1,517	1,557	1,547	1,555	1,554	1,555	1,571	1,584	1,590	1,650	1,658
-1.16%	NOx	3.86	3.86	3.95	3.93	3.95	3.95	3.28	3.26	3.12	3.13	3.11	3.09
-0.29%	TSP	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.28	0.28	0.28	0.27
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.01	102.64	102.01	102.50	102.45	102.53	103.60	104.42	104.81	108.80	109.32
	NOx	100	99.91	102.43	101.80	102.41	102.25	84.87	84.45	80.83	81.05	80.44	80.06
	TSP	100	99.11	101.55	101.02	101.37	101.40	101.17	100.02	95.51	95.41	95.13	94.55

20 Year Emissions (1000 Tons)

	Average	Total
CO2	56,659	1,133,186
NOx	119.1	2,383
TSP	10.0	201

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Low Nox - Low Co2

(run against -m.mg/hd.ac.ar-)

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	37.4	41.3	51.2	36.2	48.0	53.0	61.2	61.6	78.7	94.1	82.7	78.8	724.2
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1				160.0		87.0	73.0						320.0
W	OWC Cogen 2				0.3									0.3
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											111.4	357.0	468.4
	Total	**37.4**	**41.3**	**51.2**	**196.5**	**48.0**	**140.0**	**134.2**	**61.6**	**78.7**	**94.1**	**194.1**	**435.8**	**1512.9**
	DSR	17.6	24.6	41.9	22.4	23.1	27.3	26.8	27.2	50.5	74.1	73.5	54.5	463.5
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal													0.0
	Utah IG CC								132.4	450.0	14.9	438.5	109.4	1145.2
	Utah FB Coal													0.0
	Utah Simple Cycle CT													0.0
	Utah Pumped Storage							13.7		319.5		166.8		500.0
	Total	**17.6**	**24.6**	**41.9**	**22.4**	**23.1**	**27.3**	**40.5**	**159.6**	**820.0**	**89.0**	**678.8**	**163.9**	**2108.7**
	DSR	2.4	1.8	4.7	5.9	7.0	7.4	6.8	6.9	13.5	20.6	20.3	17.9	115.2
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**2.4**	**1.8**	**4.7**	**5.9**	**7.0**	**7.4**	**6.8**	**6.9**	**13.5**	**20.6**	**20.3**	**17.9**	**115.2**
	DSR	57.4	67.7	97.8	64.5	78.1	87.7	94.8	95.7	142.7	188.8	176.5	151.2	1302.9
T	Renewable													0.0
O	Cogen				160.3		87.0	73.0						320.3
T	Combined Cycle CT													0.0
A	Coal								132.4	450.0	14.9	438.5	109.4	1145.2
L	Simple Cycle CT													0.0
	Pumped Storage							13.7		319.5		278.2	357.0	968.4
	Total	57.4	67.7	97.8	224.8	78.1	174.7	181.5	228.1	912.2	203.7	893.2	617.6	3736.8

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-57	-125	-223	-287	-366	-453	-548	-644	-786	-975	-1152	-1303
S	**Total Requirements**	**8835**	**8951**	**8903**	**9025**	**9124**	**9219**	**9279**	**9393**	**9682**	**9697**	**9924**	**10340**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	160	160	247	334	466	1236	1251	1968	2434
L	**Total Resources**	**10068**	**10393**	**10249**	**10378**	**10532**	**10601**	**10671**	**10803**	**11135**	**11152**	**11414**	**11892**
&													
R	Reserves	1233	1441	1345	1353	1408	1382	1391	1408	1451	1454	1488	1550
	Reserve Margin (RM) (%)	14.0	16.1	15.1	15.0	15.4	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	91											

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Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	19.4	43.6	76.7	95.4	118.1	133.8	152.2	170.4	200.9	237.0	266.9	294.3
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				148.9	148.9	229.9	297.9	297.9	297.9	297.9	297.9	297.9
C	OWC Cogen 2				0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												0.8
	Total	**19.4**	**43.6**	**76.7**	**244.6**	**267.3**	**364.0**	**450.4**	**468.6**	**499.1**	**535.2**	**565.1**	**593.3**
	DSR	15.2	37.6	76.9	95.6	115.9	132.5	149.3	166.5	197.7	242.8	287.9	324.5
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1												
A	Utah Cogen 2												
H	Utah Combined Cycle CT												
	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal								120.0	528.1	541.6	939.3	1038.5
	Utah Simple Cycle CT												
	Utah Pumped Storage							1.2	1.2	32.9	41.0	82.4	89.4
	Total	**15.2**	**37.6**	**76.9**	**95.6**	**115.9**	**132.5**	**150.5**	**287.7**	**758.7**	**825.4**	**1309.6**	**1452.4**
	DSR	1.8	3.2	7.5	12.9	19.5	26.1	32.0	38.0	49.7	67.4	84.6	99.5
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.8**	**3.2**	**7.5**	**12.9**	**19.5**	**26.1**	**32.0**	**38.0**	**49.7**	**67.4**	**84.6**	**99.5**
	DSR	36.4	84.4	161.1	203.9	253.5	292.4	333.5	374.9	448.3	547.2	639.4	718.3
T	Renewable												
O	Cogen				149.2	149.2	230.2	298.2	298.2	298.2	298.2	298.2	298.2
T	Combined Cycle CT												
A	Coal								120.0	528.1	541.6	939.3	1038.5
L	Simple Cycle CT												
	Pumped Storage							1.2	1.2	32.9	41.0	82.4	90.2
	Total	**36.4**	**84.4**	**161.1**	**353.1**	**402.7**	**522.6**	**632.9**	**794.3**	**1307.5**	**1428.0**	**1959.3**	**2145.2**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pump Storage/Peak Return	312	311	309	310	309	307	308	308	349	357	410	420
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	94	67	23	117	104	113	138	185	343	431	399	342
T	DSR	-36	-84	-161	-204	-254	-292	-334	-375	-448	-547	-639	-718
E	**Total Requirements**	7206	7258	7270	7437	7505	7629	7776	7874	8288	8448	8624	8883
M													
	Existing Generation	6124	6182	6364	6427	6305	6569	6664	6697	6732	6876	6679	6853
L	Firm Purchases	718	717	542	525	519	511	500	495	471	468	443	443
&	Non-Firm Purchases	364	359	364	350	346	332	327	276	239	237	197	173
R	New Resources				149	149	230	299	419	859	880	1319	1426
	Total Resources	7206	7258	7270	7451	7519	7642	7790	7887	8301	8461	8638	8895

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Low Nox - Low Co2

(run against -m.mg/hd.ac.ar-)

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	51.0	55.0	59.0	57.0	55.0	50.0	46.0	43.0	42.0	42.0	41.0	40.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0
C	OWC Cogen 2				93.0	93.0	93.0	93.0	87.0	87.0	88.0	88.0	88.0
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	DSR	86.0	89.0	91.0	89.0	89.0	84.0	81.0	78.0	75.0	72.0	70.0	70.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC								90.0	90.0	90.0	90.0	90.0
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage							8.0	8.0	9.0	12.0	16.0	17.0
	DSR	74.0	77.0	84.0	87.0	89.0	89.0	88.0	88.0	88.0	87.0	86.0	86.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	67.4	66.3	67.8	68.4	68.1	68.7	69.7	70.0	70.3	71.7	72.7	74.5
	New Resources				93.0	93.0	93.0	89.5	89.8	69.5	70.4	67.0	58.6
	DSR	63.4	67.5	72.3	70.9	69.4	64.5	60.9	58.2	57.0	56.1	55.5	55.1

Case # 313

Low Nox - Low CO2
(run against -m.hg/md.ac.ar-)

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	21	43	73	109	152	189	231	272	348	451	538	613
			After Conservation												
			System Load (MWa)	5,632	5,740	5,888	5,949	6,037	6,134	6,276	6,349	6,585	6,835	7,173	7,684
	0.64		**Energy Sales (MWa)**	5,094	5,192	5,297	5,382	5,463	5,551	5,647	5,748	5,962	6,187	6,494	6,963
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,765	8,208	8,694	9,010	9,451	10,086	10,821	11,846	13,315	14,596	17,943	20,463
			Net Conservation Assets ($M)	57	113	176	243	328	427	532	629	757	880	937	876
			Utility Cost												
47,064	3.89	Nominal	**Operating Revenues ($M)**	2,177	2,316	2,383	2,451	2,554	2,678	2,779	2,862	3,125	3,657	4,259	5,489
	0.48	Real		2,177	2,240	2,228	2,217	2,234	2,266	2,273	2,265	2,313	2,448	2,579	2,908
	3.23	Nominal	Cost in mills/kWh	48.8	50.9	51.4	52.0	53.4	55.1	56.2	56.8	59.8	67.5	74.9	90.0
	-0.16	Real		48.8	49.3	48.0	47.0	46.7	46.6	46.0	45.0	44.3	45.2	45.3	47.7
		Nominal	Average Customer Bill ($)	1,663	1,752	1,783	1,816	1,867	1,927	1,963	1,989	2,101	2,344	2,607	3,183
		Real		1,663	1,694	1,668	1,643	1,634	1,630	1,606	1,574	1,555	1,570	1,579	1,686
			Total Resource Cost												
			DSR Customer Cost ($M)	3.8	5.4	6.3	8.3	9.6	66.9	85.2	103.3	94.5	82.8	93.4	85.1
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.6	3.6	10.8	20.0	31.2	51.2	80.3	111.0	149.9
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	27.6	36.1	45.8	66.1	96.4	123.3	141.1
48,630	4.00	Nominal	**Total Resource Cost ($M)**	2,181	2,325	2,396	2,469	2,578	2,716	2,835	2,939	3,242	3,833	4,493	5,780
	0.58	Real		2,181	2,249	2,241	2,234	2,255	2,298	2,319	2,326	2,399	2,566	2,721	3,062
	3.18	Nominal	Cost in mills/kWh	48.7	50.7	51.0	51.4	52.5	54.2	55.2	55.9	58.9	66.3	73.4	87.7
	-0.21	Real		48.7	49.1	47.7	46.5	46.0	45.8	45.2	44.3	43.6	44.4	44.5	46.5

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = 46.85

4) 50-year Real Levelized Total Resource Cost in mills/kWh = 45.78

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Low Nox - Low CO2

(run against -m.hg/md.ac.ar-)

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	63,221	63,764	64,456	65,945	66,830	68,127	69,327	70,544	73,873	75,862	76,895	79,532
	MWa	7,217	7,279	7,358	7,528	7,629	7,777	7,914	8,053	8,433	8,660	8,778	9,079
	Total Annual Emissions (1000 Tons)												
1.63%	CO_2	47,978	48,368	50,412	50,936	51,687	53,328	54,676	55,921	58,759	60,913	64,250	66,255
-0.13%	NOx	122.2	123.0	128.5	129.6	131.4	135.5	115.5	115.1	114.7	118.8	116.7	119.1
0.72%	TSP	9.2	9.2	9.5	9.7	9.8	10.1	10.2	10.2	10.2	10.6	10.4	10.6
	Annual System Emission Rates (Pounds/MWh)												
0.49%	CO_2	1,518	1,517	1,564	1,545	1,547	1,566	1,577	1,585	1,591	1,606	1,671	1,666
-1.33%	NOx	3.86	3.86	3.99	3.93	3.93	3.98	3.33	3.26	3.11	3.13	3.04	3.00
-0.45%	TSP	0.29	0.29	0.30	0.29	0.29	0.30	0.30	0.29	0.28	0.28	0.27	0.27
	Emission Rates as Percent of 1994 Base												
	CO_2	100	99.95	103.06	101.78	101.91	103.15	103.92	104.46	104.81	105.80	110.10	109.77
	NOx	100	99.82	103.19	101.72	101.76	102.93	86.26	84.46	80.37	81.07	78.57	77.52
	TSP	100	99.00	101.85	100.86	100.81	102.09	101.71	99.46	94.81	96.02	93.05	91.73

20 Year Emissions (1000 Tons)	Average	Total
CO_2	58,071	1,161,418
NOx	120.4	2,408
TSP	10.1	203

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Low Nox - Low CO2

(run against -m.hg/md.ac.ar-)

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C				150.0									150.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1				160.0	45.3								205.3
W	OWC Cogen 2													0.0
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											67.3	358.9	426.2
	Total	**24.4**	**25.0**	**24.1**	**336.5**	**82.1**	**46.0**	**53.5**	**53.7**	**69.2**	**82.3**	**136.5**	**425.3**	**1358.6**
	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1													0.0
T	Utah Cogen 2													0.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal													0.0
	Utah IG CC													0.0
	Utah FB Coal								225.0	450.0	29.6	675.0	129.0	1508.6
	Utah Simple Cycle CT													0.0
	Utah Pumped Storage					36.0	141.2	96.6		226.2				500.0
	Total	**8.9**	**10.1**	**14.1**	**19.1**	**56.1**	**166.3**	**122.8**	**251.5**	**726.9**	**104.2**	**741.1**	**177.5**	**2398.6**
	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal									22.8				22.8
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**4.9**	**6.3**	**6.4**	**35.3**	**19.1**	**19.1**	**17.7**	**126.9**
	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
T	Renewable				150.0									150.0
O	Cogen				160.0	45.3								205.3
T	Combined Cycle CT													0.0
A	Coal								225.0	472.8	29.6	675.0	129.0	1531.4
L	Simple Cycle CT													0.0
	Pumped Storage					36.0	141.2	96.6		226.2		67.3	358.9	926.2
	Total	**35.1**	**36.3**	**42.1**	**360.6**	**144.4**	**217.2**	**182.6**	**311.6**	**831.4**	**205.6**	**896.7**	**620.5**	**3884.1**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
S	**Total Requirements**	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	310	391	533	629	854	1553	1583	2325	2813
L	**Total Resources**	**10068**	**10393**	**10249**	**10528**	**10763**	**10887**	**10966**	**11191**	**11452**	**11484**	**11771**	**12271**
&													
R	**Reserves**	1210	1388	1236	1267	1388	1405	1415	1516	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	13.8	15.0	15.0	15.0	15.9	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115	105								

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PacifiCorp RAMPP-3 **Case # 313**

Low Nox - Low CO2

(run against -m.hg/md.ac.ar-)

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C				35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				148.9	191.1	191.1	191.1	191.1	191.1	191.0	191.1	191.1
C	OWC Cogen 2												
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											0.2	1.9
	Total	**12.3**	**25.7**	**39.0**	**239.2**	**300.9**	**316.5**	**334.3**	**352.0**	**382.3**	**418.3**	**445.9**	**473.2**
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1												
A	Utah Cogen 2												
H	Utah Combined Cycle CT												
	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC								204.1	612.2	639.0	1251.2	1368.1
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage					0.2	13.0	20.1	29.8	60.3	83.7	82.3	110.8
	Total	**6.9**	**15.2**	**27.4**	**43.4**	**61.4**	**91.3**	**116.2**	**348.1**	**821.4**	**922.4**	**1576.3**	**1756.1**
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC									20.7	20.7	20.7	20.7
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**11.0**	**16.9**	**21.4**	**27.0**	**32.6**	**64.2**	**80.7**	**97.1**	**111.9**
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable				35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8	35.8
O	Cogen				148.9	191.1	191.1	191.1	191.1	191.1	191.0	191.1	191.1
T	Combined Cycle CT												
A	Coal								204.1	632.9	659.7	1271.9	1388.8
L	Simple Cycle CT												
	Pumped Storage					0.2	13.0	20.1	29.8	60.3	83.7	82.5	112.7
	Total	**20.6**	**43.3**	**72.5**	**293.6**	**379.2**	**429.2**	**477.5**	**732.7**	**1267.9**	**1421.4**	**2119.3**	**2341.2**
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pump Storage/Peak Return	312	311	310	310	309	323	332	345	384	412	410	441
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	87	46	20	112	125	140	148	223	352	491	450	411
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	**7214**	**7278**	**7357**	**7527**	**7627**	**7775**	**7913**	**8052**	**8432**	**8659**	**8776**	**9078**
M													
	Existing Generation	6134	6197	6451	6482	6552	6724	6887	6857	6818	7034	6650	6773
L	Firm Purchases	718	717	542	525	519	511	500	495	471	468	443	443
&	Non-Firm Purchases	364	364	364	349	344	314	292	252	237	200	116	147
R	New Resources				185	227	240	247	461	920	970	1581	1728
	Total Resources	**7216**	**7278**	**7357**	**7541**	**7642**	**7789**	**7926**	**8065**	**8446**	**8672**	**8790**	**9091**

PacifiCorp RAMPP-3

Case # 313

Low Nox - Low CO2

(run against -m.hg/md.ac.ar-)

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C				23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0	23.0
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0
C	OWC Cogen 2												
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage												
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC								90.0	90.0	90.0	90.0	90.0
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage						7.0	7.0	10.0	12.0	16.0	16.0	22.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC									90.0	90.0	90.0	90.0
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
	Existing Generation	67.5	66.5	68.8	68.9	68.6	70.4	72.0	71.6	71.2	73.4	72.4	73.7
	New Resources				59.6	58.0	45.1	39.3	54.0	59.2	61.3	68.0	61.4
	DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Low Nox - Low CO2
(run against -mh.mg/md.ac.ar-)

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,772	5,994	6,255	6,430	6,616	6,808	7,055	7,230	7,689	8,355	9,056	9,923
			Conservation (MWa)	21	43	73	109	152	197	244	292	380	502	604	694
			After Conservation												
			System Load (MWa)	5,751	5,950	6,182	6,321	6,464	6,610	6,811	6,939	7,309	7,854	8,453	9,229
	0.97		**Energy Sales (MWa)**	5,201	5,382	5,561	5,717	5,848	5,980	6,126	6,278	6,613	7,108	7,652	8,360
			Total Customers (000's)	1,331	1,358	1,384	1,410	1,442	1,479	1,519	1,557	1,636	1,756	1,875	2,018
			Net Electric Plant ($M)	7,790	8,449	9,249	9,628	10,155	10,839	11,588	12,707	14,345	16,806	20,147	24,821
			Net Conservation Assets ($M)	57	113	176	244	329	447	569	681	835	992	1,073	1,026
			Utility Cost												
53,168	4.10	Nominal	**Operating Revenues ($M)**	2,216	2,376	2,475	2,548	2,745	2,904	3,045	3,157	3,485	4,168	5,095	6,450
	0.68	Real		2,216	2,298	2,315	2,305	2,401	2,457	2,492	2,498	2,580	2,790	3,086	3,417
	3.10	Nominal	Cost in mills/kWh	48.7	50.4	50.8	50.9	53.6	55.4	56.7	57.4	60.2	66.9	76.0	88.1
	-0.29	Real		48.7	48.7	47.5	46.0	46.9	46.9	46.4	45.4	44.5	44.8	46.0	46.7
		Nominal	Average Customer Bill ($)	1,665	1,750	1,789	1,807	1,903	1,964	2,005	2,028	2,131	2,374	2,718	3,197
		Real		1,665	1,692	1,673	1,635	1,665	1,661	1,640	1,604	1,577	1,589	1,646	1,694
			Total Resource Cost												
			DSR Customer Cost ($M)	4.0	5.6	6.5	8.5	9.8	73.5	95.2	114.0	106.5	95.1	106.6	99.0
			Levelized (20-year at 8.8%)	0.4	1.0	1.7	2.7	3.7	11.7	21.9	34.3	56.8	90.1	125.0	169.6
			Energy Svc Charge ($M)	3.8	7.9	11.7	15.8	20.6	28.9	38.7	49.8	73.1	108.3	139.9	164.1
54,934	4.21	Nominal	**Total Resource Cost ($M)**	2,221	2,385	2,489	2,567	2,769	2,944	3,106	3,241	3,615	4,366	5,360	6,784
	0.78	Real		2,221	2,306	2,328	2,322	2,422	2,491	2,541	2,565	2,676	2,923	3,246	3,594
	3.06	Nominal	Cost in mills/kWh	48.6	50.2	50.5	50.4	52.8	54.6	55.8	56.5	59.3	65.9	74.6	86.1
	-0.33	Real		48.6	48.6	47.2	45.6	46.2	46.2	45.7	44.7	43.9	44.1	45.2	45.6

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized Utility Cost in mills/kWh = **46.41**

4) 50-year Real Levelized Total Resource Cost in mills/kWh = **45.41**

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Low Nox - Low Co2
(run against -mh.mg/md.ac.ar-)

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	63,747	65,358	66,865	69,388	70,702	72,638	74,276	75,949	80,329	84,569	87,828	93,513
	MWa	7,277	7,461	7,633	7,921	8,071	8,292	8,479	8,670	9,170	9,654	10,026	10,675
	Total Annual Emissions (1000 Tons)												
2.13%	CO2	48,557	50,152	52,677	50,963	51,790	52,905	54,604	56,465	60,556	64,422	69,160	74,054
-0.19%	NOx	123.8	128.2	134.8	124.8	126.5	128.8	110.6	111.7	114.2	116.4	120.3	119.1
0.57%	TSP	9.3	9.5	9.9	9.3	9.5	9.6	9.8	9.9	10.1	10.2	10.6	10.4
	Annual System Emission Rates (Pounds/MWh)												
0.20%	CO2	1,523	1,535	1,576	1,469	1,465	1,457	1,470	1,487	1,508	1,524	1,575	1,584
-2.20%	NOx	3.88	3.92	4.03	3.60	3.58	3.55	2.98	2.94	2.84	2.75	2.74	2.55
-1.41%	TSP	0.29	0.29	0.30	0.27	0.27	0.26	0.27	0.26	0.25	0.24	0.24	0.22
	Emission Rates as Percent of 1994 Base												
	CO2	100	100.74	103.42	96.42	96.16	95.62	96.51	97.60	98.97	100.01	103.38	103.96
	NOx	100	101.00	103.87	92.64	92.18	91.32	76.72	75.77	73.25	70.87	70.56	65.58
	TSP	100	99.94	102.05	92.21	92.09	90.92	90.93	89.77	86.09	82.61	82.47	76.35

20 Year Emissions (1000 Tons)	Average	Total
CO2	60,910	1,218,196
NOx	119.9	2,399
TSP	10.0	201

PacifiCorp RAMPP-3 **Case # 316**

Low Nox - Low Co2

(run against -mh.mg/md.ac.ar-)

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
	DSR	24.4	25.1	24.3	26.6	36.9	51.7	60.1	60.7	83.6	105.1	91.9	89.6	680.0
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
O	OWC Cogen 1				160.0	107.6	52.4							320.0
W	OWC Cogen 2				470.0		193.7	145.6						809.3
C	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT												70.5	70.5
	OWC Pumped Storage											500.0		500.0
	Total	**24.4**	**25.1**	**24.3**	**656.6**	**144.5**	**297.8**	**205.7**	**60.7**	**83.6**	**105.1**	**591.9**	**160.1**	**2379.8**
	DSR	9.0	10.1	14.1	19.1	20.2	29.8	29.2	29.5	56.8	83.5	73.2	55.0	429.5
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
U	Utah Cogen 1				39.0									39.0
T	Utah Cogen 2				210.0									210.0
A	Utah Combined Cycle CT													0.0
H	Utah CC CT Convert													0.0
	Utah Coal													0.0
	Utah IG CC								225.0	450.0	437.2	442.0	837.8	2392.0
	Utah FB Coal													0.0
	Utah Simple Cycle CT							37.9	11.1	255.9				304.9
	Utah Pumped Storage									292.8		207.2		500.0
	Total	**9.0**	**10.1**	**14.1**	**268.1**	**20.2**	**29.8**	**67.1**	**265.6**	**1055.5**	**520.7**	**722.4**	**892.8**	**3875.4**
	DSR	1.8	1.2	3.9	5.0	6.2	7.3	7.0	7.2	14.1	21.9	21.8	20.1	117.5
W	Wyo Wind with Tax C													0.0
Y	Wyo Wind without Tax C													0.0
O	Wyo Combined Cycle CT													0.0
M	Wyo CC CT Convert													0.0
I	Wyo Coal													0.0
N	Wyo IG CC													0.0
G	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**7.3**	**7.0**	**7.2**	**14.1**	**21.9**	**21.8**	**20.1**	**117.5**
	DSR	35.2	36.4	42.3	50.7	63.3	88.8	96.3	97.4	154.5	210.5	186.9	164.7	1227.0
T	Renewable													0.0
O	Cogen				879.0	107.6	246.1	145.6						1378.3
T	Combined Cycle CT													0.0
A	Coal								225.0	450.0	437.2	442.0	837.8	2392.0
L	Simple Cycle CT							37.9	11.1	255.9			70.5	375.4
	Pumped Storage									292.8		707.2		1000.0
	Total	**35.2**	**36.4**	**42.3**	**929.7**	**170.9**	**334.9**	**279.8**	**333.5**	**1153.2**	**647.7**	**1336.1**	**1073.0**	**6372.7**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Native Load	7706	8050	8379	8660	8860	9147	9438	9740	10382	11283	12273	13488
S	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
Y	DSR	-35	-72	-114	-165	-228	-317	-413	-510	-665	-875	-1062	-1227
S	**Total Requirements**	**9066**	**9373**	**9510**	**9740**	**9877**	**10075**	**10220**	**10425**	**10912**	**11295**	**11898**	**12698**
T													
E	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
M	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	879	987	1233	1416	1652	2651	3088	4237	5146
L	**Total Resources**	**10068**	**10393**	**10249**	**11097**	**11359**	**11587**	**11753**	**11989**	**12550**	**12989**	**13683**	**14604**
&													
R	Reserves	1002	1019	737	1355	1481	1510	1532	1563	1636	1693	1784	1904
	Reserve Margin (RM) (%)	11.0	10.9	7.8	13.9	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	357	386	688	105								

PacifiCorp RAMPP-3

Case # 316

Low Nox - Low Co2

(run against -mh.mg/md.ac.ar-)

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.1	54.6	74.2	92.1	112.5	132.9	168.7	213.0	247.6	280.8
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				148.9	249.1	297.9	297.9	297.9	297.9	297.9	297.9	297.9
C	OWC Cogen 2				437.3	437.3	596.8	702.3	677.9	669.5	668.5	691.0	719.6
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												5.1
	OWC Pumped Storage											2.6	12.0
	Total	**12.3**	**25.7**	**39.1**	**640.8**	**760.6**	**985.8**	**1112.7**	**1108.7**	**1136.1**	**1179.4**	**1239.1**	**1315.4**
	DSR	6.9	15.3	27.5	43.5	61.3	81.6	102.1	122.9	163.0	221.7	270.9	311.4
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1				36.3	36.3	36.3	36.3	36.3	36.3	36.3	36.0	34.3
A	Utah Cogen 2				195.4	195.4	195.4	195.2	190.0	182.8	177.2	173.7	168.0
H	Utah Combined Cycle CT												
	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal								204.1	612.2	1008.6	1409.5	2169.3
	Utah Simple Cycle CT							2.1	2.7	16.9	16.9	16.9	16.9
	Utah Pumped Storage									33.7	45.2	90.2	97.5
	Total	**6.9**	**15.3**	**27.5**	**275.2**	**293.0**	**313.3**	**335.7**	**556.0**	**1044.9**	**1505.9**	**1997.2**	**2797.4**
	DSR	1.4	2.4	6.1	11.0	16.9	23.5	29.7	36.0	48.2	66.8	85.2	101.5
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	**1.4**	**2.4**	**6.1**	**11.0**	**16.9**	**23.5**	**29.7**	**36.0**	**48.2**	**66.8**	**85.2**	**101.5**
	DSR	20.6	43.4	72.7	109.1	152.4	197.2	244.3	291.8	379.9	501.5	603.7	693.7
T	Renewable												
O	Cogen				817.9	918.1	1125.4	1231.7	1202.1	1186.5	1179.9	1198.6	1219.8
T	Combined Cycle CT												
A	Coal								204.1	612.2	1008.6	1409.5	2169.3
L	Simple Cycle CT							2.1	2.7	16.9	16.9	16.9	22.0
	Pumped Storage									33.7	45.2	92.8	109.5
	Total	**20.6**	**43.4**	**72.7**	**927.0**	**1070.5**	**1322.6**	**1478.1**	**1700.7**	**2229.2**	**2752.1**	**3321.5**	**4214.3**
	Native Load	5472	5694	5955	6130	6317	6508	6756	6931	7390	8056	8757	9623
S	Pump Storage/Peak Return	312	311	308	310	309	306	306	306	350	362	423	445
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	29	18	3	134	141	196	203	289	399	516	404	457
T	DSR	-21	-43	-73	-109	-152	-197	-244	-292	-380	-502	-604	-694
E	**Total Requirements**	**7275**	**7460**	**7631**	**7920**	**8070**	**8290**	**8477**	**8668**	**9169**	**9653**	**10023**	**10672**
M													
	Existing Generation	6194	6379	6693	6245	6304	6353	6497	6538	6646	6757	6681	6586
L	Firm Purchases	718	717	542	525	519	511	500	495	471	468	443	443
&	Non-Firm Purchases	364	364	397	346	342	316	260	241	216	191	197	138
R	New Resources				817	918	1125	1233	1408	1849	2250	2717	3520
	Total Resources	**7276**	**7460**	**7632**	**7933**	**8083**	**8305**	**8490**	**8682**	**9182**	**9666**	**10038**	**10687**

ln.l2.mh.avg_ww

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PacifiCorp RAMPP-3 **Case # 316**

Low Nox - Low Co2

(run against -mh.mg/md.ac.ar-)

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	42.0	42.0	42.0	41.0	41.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0	93.0
C	OWC Cogen 2				93.0	93.0	89.0	86.0	83.0	82.0	82.0	85.0	88.0
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												7.0
	OWC Pumped Storage												2.0
	DSR	76.0	79.0	82.0	83.0	84.0	79.0	77.0	76.0	74.0	73.0	72.0	72.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1				93.0	93.0	93.0	93.0	93.0	93.0	93.0	92.0	88.0
T	Utah Cogen 2				93.0	93.0	93.0	92.0	90.0	87.0	84.0	82.0	80.0
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC								90.0	90.0	90.0	90.0	90.0
	Utah FB Coal												
	Utah Simple Cycle CT							5.0	5.0	5.0	5.0	5.0	5.0
	Utah Pumped Storage									11.0	15.0	18.0	19.0
	DSR	76.0	81.0	89.0	92.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0	86.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total System												
	Native Load	71.0	70.7	71.1	70.8	71.3	71.1	71.6	71.2	71.2	71.4	71.4	71.3
	Existing Generation	68.2	68.4	71.3	66.4	66.0	66.5	67.9	68.3	69.4	70.5	72.7	71.6
	New Resources				92.9	93.0	91.3	87.1	85.2	69.7	72.9	64.1	68.4
	DSR	58.5	60.6	63.8	66.3	66.9	62.3	59.2	57.2	57.1	57.3	56.8	56.5

Case # 324

Dispatch adder case ln.12.md w/o adders

(run against -m.mg/md.ac.ar-)

Financial Model Output for 1994-2013 (including end effects to 2043)

50-year NPV at 8.8% ($M)	50-year Annual Growth Rate (%)			1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
			System Load (MWa)	5,653	5,783	5,960	6,058	6,189	6,323	6,506	6,621	6,933	7,287	7,711	8,297
			Conservation (MWa)	34	82	161	208	265	299	336	373	438	528	605	674
			After Conservation												
			System Load (MWa)	5,618	5,701	5,800	5,850	5,924	6,024	6,170	6,249	6,495	6,758	7,106	7,623
	0.63		Energy Sales (MWa)	5,082	5,156	5,215	5,290	5,358	5,450	5,550	5,655	5,879	6,117	6,432	6,907
			Total Customers (000's)	1,309	1,322	1,336	1,350	1,368	1,390	1,416	1,439	1,487	1,560	1,634	1,725
			Net Electric Plant ($M)	7,794	8,259	8,772	9,064	9,541	10,076	10,686	11,725	13,198	14,421	17,258	20,055
			Net Conservation Assets ($M)	88	190	341	423	524	606	694	772	859	920	900	827
			Utility Cost												
46,763	3.92	Nominal	Operating Revenues ($M)	2,136	2,274	2,356	2,422	2,528	2,654	2,765	2,855	3,094	3,667	4,285	5,460
	0.50	Real		2,136	2,199	2,204	2,191	2,212	2,245	2,263	2,259	2,290	2,455	2,595	2,893
	3.27	Nominal	Cost in mills/kWh	48.0	50.3	51.6	52.3	53.9	55.6	56.9	57.6	60.1	68.4	76.1	90.2
	-0.13	Real		48.0	48.7	48.2	47.3	47.1	47.0	46.5	45.6	44.5	45.8	46.1	47.8
		Nominal	Average Customer Bill ($)	1,632	1,720	1,763	1,795	1,849	1,909	1,954	1,984	2,080	2,351	2,623	3,166
		Real		1,632	1,663	1,649	1,624	1,617	1,615	1,598	1,570	1,540	1,574	1,588	1,677
			Total Resource Cost												
			DSR Customer Cost ($M)	7.6	10.4	14.3	18.5	22.1	60.7	79.3	95.4	83.6	80.3	71.5	83.7
			Levelized (20-year at 8.8%)	0.8	1.9	3.5	5.5	7.9	14.4	23.0	33.3	51.3	77.0	101.6	136.3
			Energy Svc Charge ($M)	4.2	8.8	14.3	21.1	28.7	35.4	43.5	52.5	71.2	99.2	121.9	130.1
48,309	4.02	Nominal	Total Resource Cost ($M)	2,141	2,285	2,374	2,449	2,565	2,704	2,832	2,941	3,217	3,843	4,509	5,726
	0.60	Real		2,141	2,210	2,220	2,215	2,244	2,288	2,317	2,327	2,381	2,573	2,731	3,034
	3.20	Nominal	Cost in mills/kWh	47.8	49.9	50.5	51.0	52.3	53.9	55.2	56.0	58.5	66.5	73.7	86.9
	-0.19	Real		47.8	48.2	47.3	46.1	45.7	45.6	45.2	44.3	43.3	44.5	44.6	46.0

Notes:

1) $M = millions of dollars

2) General Inflation Rate is 3.40% annually

3) 50-year Real Levelized
Utility Cost in mills/kWh = 47.06

4) 50-year Real Levelized

Dispatch adder case ln.l2.md w/o adders

(run against -m.mg/md.ac.ar-)

Total Projected Emissions

Annual Growth Rate		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	Total Requirements												
	GWh	66,129	67,128	67,198	68,214	69,020	69,712	70,579	71,447	75,170	76,186	77,868	80,347
	MWa	7,549	7,663	7,671	7,787	7,879	7,958	8,057	8,156	8,581	8,697	8,889	9,172
	Total Annual Emissions (1000 Tons)												
1.05%	CO_2	54,170	54,960	55,955	56,054	56,584	56,793	57,421	58,338	61,486	62,113	64,976	66,805
-0.63%	NO_x	139.6	141.4	143.8	142.9	143.7	143.7	120.5	120.6	121.1	122.0	122.0	122.9
0.25%	TSP	10.4	10.5	10.7	10.6	10.6	10.6	10.7	10.7	10.8	10.9	10.9	10.9
	Annual System Emission Rates (Pounds/MWh)												
0.08%	CO_2	1,638	1,637	1,665	1,643	1,640	1,629	1,627	1,633	1,636	1,631	1,669	1,663
-1.68%	NO_x	4.22	4.21	4.28	4.19	4.16	4.12	3.41	3.37	3.22	3.20	3.13	3.06
-0.76%	TSP	0.31	0.31	0.32	0.31	0.31	0.30	0.30	0.30	0.29	0.29	0.28	0.27
	Emission Rates as Percent of 1994 Base												
	CO_2	100	99.95	101.65	100.32	100.08	99.45	99.32	99.68	99.86	99.53	101.87	101.50
	NO_x	100	99.81	101.40	99.22	98.61	97.67	80.89	79.94	76.35	75.85	74.25	72.47
	TSP	100	99.08	101.07	98.62	98.01	96.94	96.62	95.41	91.50	90.83	88.93	86.45

20 Year Emissions (1000 Tons)	Average	Total
CO_2	60,696	1,213,926
NO_x	128.0	2,560
TSP	10.8	215

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PacifiCorp RAMPP-3

Case # 324

Dispatch adder case ln.12.md w/o adders

(run against -m.mg/md.ac.ar-)

Incremental Winter Capacity (MW) of Resource Additions

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013	Total
OWC	DSR	24.4	25.0	24.1	26.5	36.8	46.0	53.5	53.7	69.2	82.3	69.2	66.4	577.1
	OWC Wind with Tax C													0.0
	OWC Wind without Tax C													0.0
	OWC Geothermal													0.0
	OWC Cogen 1				160.0		118.1	18.1						296.2
	OWC Cogen 2				142.0									142.0
	OWC Combined Cycle CT													0.0
	OWC CC CT Convert													0.0
	OWC Simple Cycle CT													0.0
	OWC Pumped Storage											221.3	278.6	499.9
	Total	**24.4**	**25.0**	**24.1**	**328.5**	**36.8**	**164.1**	**71.6**	**53.7**	**69.2**	**82.3**	**290.5**	**345.0**	**1515.2**
UTAH	DSR	8.9	10.1	14.1	19.1	20.1	25.1	26.2	26.5	50.7	74.6	66.1	48.5	390.0
	Utah Wind with Tax C													0.0
	Utah Wind without Tax C													0.0
	Utah Geothermal													0.0
	Utah Solar													0.0
	Utah Cogen 1													0.0
	Utah Cogen 2													0.0
	Utah Combined Cycle CT													0.0
	Utah CC CT Convert													0.0
	Utah Coal													0.0
	Utah IG CC								142.5	450.0	29.6	430.8	209.3	1262.2
	Utah FB Coal													0.0
	Utah Simple Cycle CT													0.0
	Utah Pumped Storage							78.4		331.5		90.1		500.0
	Total	**8.9**	**10.1**	**14.1**	**19.1**	**20.1**	**25.1**	**104.6**	**169.0**	**832.2**	**104.2**	**587.0**	**257.8**	**2152.2**
WYOMING	DSR	1.8	1.2	3.9	5.0	6.2	4.9	6.3	6.4	12.5	19.1	19.1	17.7	104.1
	Wyo Wind with Tax C													0.0
	Wyo Wind without Tax C													0.0
	Wyo Combined Cycle CT													0.0
	Wyo CC CT Convert													0.0
	Wyo Coal													0.0
	Wyo IG CC													0.0
	Wyo FB Coal													0.0
	Wyo Simple Cycle CT													0.0
	Total	**1.8**	**1.2**	**3.9**	**5.0**	**6.2**	**4.9**	**6.3**	**6.4**	**12.5**	**19.1**	**19.1**	**17.7**	**104.1**
TOTAL	DSR	35.1	36.3	42.1	50.6	63.1	76.0	86.0	86.6	132.4	176.0	154.4	132.6	1071.2
	Renewable													0.0
	Cogen				302.0		118.1	18.1						438.2
	Combined Cycle CT													0.0
	Coal								142.5	450.0	29.6	430.8	209.3	1262.2
	Simple Cycle CT													0.0
	Pumped Storage							78.4		331.5		311.4	278.6	999.9
	Total	**35.1**	**36.3**	**42.1**	**352.6**	**63.1**	**194.1**	**182.5**	**229.1**	**913.9**	**205.6**	**896.6**	**620.5**	**3771.5**

Annual Winter Peak Capacity (MW)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
SYST	Native Load	7497	7681	7881	8067	8244	8427	8632	8842	9273	9785	10389	11206
	Firm Sales	1395	1395	1245	1245	1245	1245	1195	1195	1195	887	687	437
	DSR	-35	-71	-114	-164	-227	-303	-389	-476	-608	-784	-939	-1071
	Total Requirements	**8857**	**9005**	**9013**	**9148**	**9262**	**9369**	**9438**	**9561**	**9860**	**9888**	**10137**	**10572**
EM	Existing Generation	9088	9322	9382	9402	9555	9557	9564	9571	9582	9589	9184	9196
	Firm Purchases	980	1071	867	816	817	797	773	766	317	312	262	262
	New Resources	0	0	0	302	302	420	517	659	1441	1470	2212	2700
L&	**Total Resources**	**10068**	**10393**	**10249**	**10520**	**10674**	**10774**	**10854**	**10996**	**11340**	**11371**	**11658**	**12158**
R	**Reserves**	1210	1388	1236	1371	1411	1405	1415	1433	1478	1482	1519	1585
	Reserve Margin (RM) (%)	13.7	15.4	13.7	15.0	15.2	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	Capacity Below 15% RM	117		115									

PacifiCorp RAMPP-3

Case # 324

Dispatch adder case ln.l2.md w/o adders

(run against -m.mg/md.ac.ar-)

Cumulative Annual Energy (MWa)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	12.3	25.7	39.0	54.5	74.0	89.6	107.4	125.1	155.4	191.5	218.8	244.4
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				138.6	146.4	252.5	269.9	264.1	264.9	268.8	275.7	275.7
C	OWC Cogen 2				117.5	117.5	117.5	117.5	117.5	117.5	117.5	126.0	126.3
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage											0.3	1.3
	Total	12.3	25.7	39.0	310.6	337.9	459.6	494.8	506.7	537.8	577.8	620.8	647.7
	DSR	6.9	15.2	27.4	43.4	61.2	78.3	96.1	114.2	148.9	199.7	242.8	277.2
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
U	Utah Solar												
T	Utah Cogen 1												
A	Utah Cogen 2												
H	Utah Combined Cycle CT												
	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC								129.2	537.3	564.2	954.9	1144.7
	Utah FB Coal												
	Utah Simple Cycle CT												
	Utah Pumped Storage							14.6	14.6	77.4	78.6	96.3	113.7
	Total	6.9	15.2	27.4	43.4	61.2	78.3	110.7	258.0	763.6	842.5	1294.0	1535.6
	DSR	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												
	Total	1.4	2.4	6.1	11.0	16.9	21.4	27.0	32.6	43.5	60.0	76.4	91.2
	DSR	20.6	43.3	72.5	108.9	152.1	189.3	230.5	271.9	347.8	451.2	538.0	612.8
T	Renewable												
O	Cogen				256.1	263.9	370.0	387.4	381.6	382.4	386.3	401.7	402.0
T	Combined Cycle CT												
A	Coal								129.2	537.3	564.2	954.9	1144.7
L	Simple Cycle CT												
	Pumped Storage							14.6	14.6	77.4	78.6	96.6	115.0
	Total	20.6	43.3	72.5	365.0	416.0	559.3	632.5	797.3	1344.9	1480.3	1991.2	2274.5
	Native Load	5353	5484	5661	5759	5890	6024	6207	6322	6634	6987	7411	7998
S	Pump Storage/Peak Return	312	310	309	310	309	307	325	325	406	405	428	452
Y	Firm Sales	1483	1480	1438	1455	1455	1477	1456	1434	1410	1220	1043	841
S	Non-Firm Sales	420	431	334	371	374	338	297	346	478	534	542	493
T	DSR	-21	-43	-73	-109	-152	-189	-231	-272	-348	-451	-538	-613
E	**Total Requirements**	7547	7662	7670	7786	7876	7957	8055	8155	8580	8695	8886	9171
M													
	Existing Generation	6776	6886	7035	6971	7046	7041	7111	7108	7116	7169	6917	6981
L	Firm Purchases	645	644	452	435	411	403	393	388	364	374	359	388
&	Non-Firm Purchases	128	133	183	138	169	156	163	148	117	138	172	155
R	New Resources				256	264	370	402	525	997	1029	1453	1662
	Total Resources	7549	7663	7670	7800	7890	7970	8069	8169	8594	8710	8901	9186

PacifiCorp RAMPP-3

Case # 324

Dispatch adder case ln.l2.md w/o adders

(run against -m.mg/md.ac.ar-)

Annual Cumulative Capacity Factors (%)

		1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
	DSR	50.0	51.0	52.0	54.0	54.0	48.0	45.0	43.0	43.0	43.0	42.0	42.0
	OWC Wind with Tax C												
	OWC Wind without Tax C												
O	OWC Geothermal												
W	OWC Cogen 1				86.0	91.0	90.0	91.0	89.0	89.0	90.0	93.0	93.0
C	OWC Cogen 2				82.0	82.0	82.0	82.0	82.0	82.0	82.0	88.0	88.0
	OWC Combined Cycle CT												
	OWC CC CT Convert												
	OWC Simple Cycle CT												
	OWC Pumped Storage							16.0	18.0	18.0	18.0		
	DSR	76.0	79.0	82.0	83.0	84.0	80.0	77.0	76.0	74.0	72.0	71.0	71.0
	Utah Wind with Tax C												
	Utah Wind without Tax C												
	Utah Geothermal												
	Utah Solar												
U	Utah Cogen 1												
T	Utah Cogen 2												
A	Utah Combined Cycle CT												
H	Utah CC CT Convert												
	Utah Coal												
	Utah IG CC												
	Utah FB Coal								90.0	90.0	90.0	90.0	90.0
	Utah Simple Cycle CT												
	Utah Pumped Storage							18.0	18.0	18.0	19.0	19.0	22.0
	DSR	76.0	81.0	89.0	92.0	93.0	93.0	92.0	91.0	90.0	89.0	88.0	87.0
W	Wyo Wind with Tax C												
Y	Wyo Wind without Tax C												
O	Wyo Combined Cycle CT												
M	Wyo CC CT Convert												
I	Wyo Coal												
N	Wyo IG CC												
G	Wyo FB Coal												
	Wyo Simple Cycle CT												

Total System

	1994	1995	1996	1997	1998	1999	2000	2001	2003	2006	2009	2013
Native Load	71.4	71.4	71.8	71.4	71.4	71.5	71.9	71.5	71.5	71.4	71.3	71.4
Existing Generation	74.6	73.9	75.0	74.1	73.7	73.7	74.4	74.3	74.3	74.8	75.3	75.9
New Resources				84.8	87.4	88.1	77.8	79.7	69.2	70.0	65.7	61.5
DSR	58.7	60.6	63.9	66.4	66.9	62.4	59.2	57.1	57.2	57.5	57.3	57.2

Section 7

Portfolio Cost Components

(Back-up to Table #4-7)

Portfolio: Cost Components

Backup for Table 4-7

} VARIABLE?

Description	Capital Cost				Fixed Cost			Energy Cost in 1998			Variable O&M (Mills/kWh)	TOTAL COST (Mills/kWh)
	Unit Cost ($/kW)	Trans-mission ($/kW)	Payment Factor (%)	Annual Payment ($/kW Year)	O&M ($/kW Year)	Expected Utilization Rate	Ttl. Capital & Fixed (Mills/kWh)	1st Year (Cent/ MMBTU)	Levelized (Cent/ MMBTU)	Levelized (Mills/ kWh)		
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
OWC Wind with Tax C	805	120	9.84	91.02	9.50	28%	40.98	126.1	152.2	15.22	4.20	60.40
Utah Wind with Tax C	750	212	9.84	94.66	9.50	36%	33.49	126.1	152.2	15.22	4.20	52.91
Wyo Wind with Tax C	750	212	9.84	94.66	9.50	36%	33.49	126.1	152.2	15.22	4.20	52.91
OWC Wind without Tax C	1,120	120	9.84	122.02	9.50	28%	53.62	126.1	152.2	15.22	4.20	73.04
Utah Wind without Tax C	1,150	212	9.84	134.02	9.50	36%	46.15	126.1	152.2	15.22	4.20	65.57
Wyo Wind without Tax C	1,150	212	9.84	134.02	9.50	36%	46.15	126.1	152.2	15.22	4.20	65.57
	(1)								(12)		(12)	
OWC Geothermal	2,076	120	8.95	196.54	58.00	90%	32.29	220.4	415.0	41.50	1.00	74.78
Utah Geothermal	2,076	120	8.95	196.54	58.00	90%	32.29	220.4	415.0	41.50	1.00	74.78
									(13)		(13)	
Utah Solar	4,283	120	9.84	433.26	49.40	40%	137.74					137.74
	(2)				(9)							
OWC Cogeneration 1	1,100		8.95	98.45	5.00	85%	13.89	289.8	492.6	27.09	0.50	41.49
Utah Cogeneration 1	1,293		8.95	115.72	5.00	85%	16.21	264.8	475.0	26.12	0.50	42.84
OWC Cogeneration 2	663	60	8.95	64.71	5.00	85%	9.36	289.8	492.6	33.50	0.50	43.36
Utah Cogeneration 2	779	60	8.95	75.09	5.00	85%	10.76	264.8	475.0	32.30	0.50	43.55
	(3)				(3)						(3)	
OWC Combined Cycle CT	687	60	8.95	66.86	10.00	80%	10.97	289.8	492.6	35.27	1.00	47.23
Utah Combined Cycle CT	742	60	8.95	71.78	10.00	80%	11.67	264.8	475.0	34.00	1.00	46.67
Wyo Combined Cycle CT	819	60	8.95	78.67	10.00	80%	12.65	264.8	475.0	34.00	1.00	47.66
	(4)											
OWC CC CT Convert	1,188	60	8.95	111.72	10.00	80%	17.37	289.8	492.6	35.27	1.00	53.64
Utah CC CT Convert	1,287	60	8.95	120.58	10.00	80%	18.63	264.8	475.0	34.00	1.00	53.64
Wyo CC CT Convert	1,412	60	8.95	131.77	10.00	80%	20.23	264.8	475.0	34.00	1.00	55.23
	(5)											
Utah Coal	1,795	60	8.32	154.34	28.40	92%	22.58	52.2	52.2	5.23	0.24	28.05
Wyo Coal	1,942	60	8.32	166.57	28.40	90%	24.73	46.6	53.9	6.11	0.24	31.08
	(6)				(10)							
Utah IG CC	1,941	60	8.95	179.09	39.40	92%	26.99	52.2	52.2	4.50	1.00	32.50
Wyo IG CC	2,035	60	8.95	187.50	39.40	92%	28.03	46.6	53.9	4.72	1.00	33.75
Utah FB Coal	2,454	60	8.32	209.16	32.20	92%	29.82	52.2	52.2	4.75	0.50	35.07
Wyo FB Coal	2,355	60	8.32	200.89	32.20	92%	28.80	46.6	53.9	5.01	0.50	34.31
	(6)											
OWC Pumped Storage	800		8.12	64.96	10.00	17%	50.11					50.11
Utah Pumped Storage	800		8.12	64.96	10.00	17%	50.11					50.11
	(7)											
OWC Simple Cycle CT	479	60	9.16	49.37	35.76	5%	194.37	255.8	458.6	48.36	3.50	246.22
Utah Simple Cycle CT	518	60	9.16	52.94	21.80	5%	170.65	269.8	480.0	50.61	3.50	224.76
Wyo Simple Cycle CT	571	60	9.16	57.80	21.80	5%	181.73	269.8	480.0	50.61	3.50	235.85
	(8)				(11)							

Footnotes for Portfolio: Cost Components

Column Footnotes

(A) See - Generation Engineering March 1994 Revision 2.
(B) See - Transmission Modeling
(C) See - Mark Paul Memo dated September 7, 1993
(D) Columns [(A)+(B)] x (C)
(E) See - Generation Engineering March 1994 Revision 2.
(F) Estimated, except as noted
(G) Columns [(D)+(E)] / [8.760 x (F)]
(H) See - Fuel Costs in Nominal Cents per MMBTU.
Since the first potential units become availiable in 1997 and 1998, fuel costs are 1998 costs expressed in 1994 dollars.
(I) See - Fuel Costs in Nominal Cents per MMBTU
(J) Column (I) x Heat Rate / 100,000
(K) See - Generation Engineering March 1994 Revision 2. Except as noted
(L) Columns (G)+(J)+(K)

Row Footnotes

(1) See - Wind Resources Modeling
(2) See - Generation Engineering March 1994 Revision 2.
Composite of Solar (Thermal) units used to minimize potential units.
($3446+$5201+$4203) / 3=$4283
(3) See - Cogeneration Modeling
(4) See - Generation Engineering March 1994 Revision 2.
OWC is an average of OWC and Utah units used to adjust for OWC altitude, since OWC locations range from 0 feet to 4,500 feet elevation. ($631+742) / 2=$687
(5) See - Generation Engineering March 1994 Revision 2.
Conversion costs calculated
((CC CCost x CC MW) - (SC CCost x SC MW)) / (CC MW - SC MW)
((687 x 208) - (479 x 147)) / (208 - 147) = $1,188
((742 x 182) - (518 x 129)) / (182 - 129) = $1,287
((819 x 173) - (571 x 122)) / (173 - 122) = $1,412
(6) See - Coal Modeling Capital Cost
(7) See - Modeling of Pumped Storage
(8) See - Generation Engineering March 1994 Revision 2.
OWC is a composite of OWC and Utah units used to adjust for OWC altitude.
($440+518) / 2=$479
(9) See - Generation Engineering March 1994 Revision 2.
Composite of Solar (Thermal) units ($51.48+$57.79+$38.88) / 3=$49.40 Rounded
(10) See - Generation Engineering March 1994 Revision 2.
Composite of Coal units ($20.75+$32.16+$32.16) / 3=$28.40 Rounded
(11) SCCT O&M modeling costs includes fixed gas transmission & storage costs

	Transportation	Storage	Fixed O&M	Total
West Side	$24.13	$10.63	$1.00	$35.76
East Side	$0.00	$20.83	$1.00	$21.83

RAMP-3 CT Cost - Prepared by Jim Henry - 7/15/93
(12) See - Wind Resources Modeling
12 mills/kWh of variable O&M costs are expected to increase 1.25% faster than inflation. This portion of variable O&M has been modeled as a fuel.
(13) 19 mills/kWh of purchased steam and variable O&M costs are expected to increase at the same rate as gas prices. This portion of variable O&M has been modeled as a fuel.

PACIFICORP

RAMPP-3

GENERATION RESOURCES

GENERATION ENGINEERING

MARCH 1994
Revision 2

RAMPP-3

GENERATION RESOURCES

MARCH 1994
Revision 2

I. SUMMARY

Technology options for PacifiCorp new generation additions to be included in RAMPP-3 have been reviewed. Capital, O&M, fuel efficiency, and expected emissions are presented. Tables 1 through 6 show the expected capital and operating costs in January 1994 dollars. Emissions are projected for each technology and heat rates are given in average expected values. Information is given for three regions of the RAMPP study (OWC West Coast areas, Wyoming, and Utah). It is assumed that no coal-fired generation will be done in the OWC region. Table 6 compares the RAMPP-2 generation technology costs with updated information for RAMPP-3, but utilizing the RAMPP-2 cost of capital, capacity factors, and fuel costs. These results will be refined when the RAMPP-3 fuel costs, capacity factors, and capital recovery rates are added.

II. GENERATION OPTIONS

Tables 1 through 4 outline the generation technology options and the expected costs, heat rates, and emissions. Costs were developed from in-house estimates based on actual projects/plants or from specific studies to develop generic plant costs. Costs include AFUDC and fuel transportation and storage. Costs are in January 1994 dollars. Heat rates are on an average annual basis. Design heat rates have been increased by 3.5% for base load plants, 5% for intermediate load plants, and 7.5% for peaking resources to account for startups and part-load inefficiencies. Costs are divided into three RAMPP regions. The principle difference between the regions is elevation. Especially for the combustion turbine based options, the elevation differences affected the projected output and capacity. For Plants located in the OWC region an elevation of sea level (to give a reference ISO rating) was assumed for the Tables while in the RAMPP3 report an elevation of 2250 feet was used for OWC to reflect the variable potential site locations. For the Utah region an elevation of 4500 feet was assumed. The Wyoming elevation is assumed to be 7000 feet. It is recognized that actual sites will be different between various regions and actual elevations will vary. Coal quality varied between the Utah and Wyoming regions resulting in different heat rates and emissions.

The following generation technologies are considered.

GAS-FIRED PLANTS

Combined Cycle Combustion Turbine (CC CT)

Natural gas is fired in a combustion turbine generator. Hot exhaust gases from the turbine pass through a heat recovery steam generator that produces steam for a conventional steam turbine generator. This technology is considered mature and commercially available. Construction lead times are approximately two years from release of purchase order. Siting and permitting will require two to three years depending on location.

The use of the combined cycle greatly improves the heat rate of the combustion turbine technology and makes the use of natural gas for moderate or base load generation possible. NOx emissions can be controlled through the use of steam injection or dry low-NOx burners. The presence of a heat recovery steam generator allows the potential use of SCR for NOx reduction.

Simple Cycle Combustion Turbine (SC CT)

Natural gas is fired in a combustion turbine generator. The hot exhaust gases are wasted to atmosphere. This technology is considered mature and commercially available. Construction lead times are approximately two years with a two year lead time for the necessary permits. Environmental impact is low with the greatest problem being NOx. The use of water injection or dry low-NOx burners can be used for NOx control. The principle disadvantages of a simple cycle combustion turbine are heat rate and the cost of fuel. Because of higher fuel cost these machines are usually only used for peaking power and typically do not have capacity factors higher than 15-20%. On many utility systems peaking combustion turbines operate less than 5% of their capacity.

Fuel Cell

Fuel cell power plants convert the energy of a hydrocarbon based fuel, normally natural gas, directly into electricity through an electrochemical process. Because the same electrochemical reactions occur in each individual cell, power efficiency is virtually independent of the number of cells and plant size. First-generation phosphoric acid fuel cells are on the verge of commercialization with more advanced molten carbonate and solid oxide systems approaching the demonstration stage.

Costs for a molten carbonate fuel cell have been included. This technology is not yet demonstrated and it is not expected to be available until the year 2005.

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COAL-FIRED PLANTS

Pulverized Coal (PC)

Pulverized coal power plants use conventional technology and are based upon a subcritical steam boiler burning subbituminous or bituminous coal. Particulate removal, 90% SO_2 removal, and low-NOx burners are included. Additional costs to achieve 93-95% SO_2 removal will not be significant although costs to add Selective Catalytic NOx Reduction (SCR) will add at least $100/kW to the estimates. The use of SCR has not been included in the estimates because compliance with the CAAA of 1990 will be possible through the use of low-NOx combustion techniques.

This technology is considered mature and reflects our current power plants. Construction lead times will be four to five years from permits depending largely on the weather conditions in the installation area. Permitting would require three additional years minimum unless installed at an existing plant site, in which case the permit could be issued in as little as two years.

Costs have been included for four PC cases. These cases are: 1. A fourth unit at the Hunter Plant, 2. A second unit at the Wyodak Plant, an 165 MW initial unit at a generic Plant site, and a 350 MW initial unit at a generic Plant site. The addition of additional units to an existing plant site, such as a Hunter 4, represents the cost of a second unit which may be added at a generic plant site. It is anticipated that capacity factors for a new PC plant or other new coal based option will approach 90%.

Atmospheric Fluidized-Bed Combustion (AFBC)

Crushed coal is burned with limestone in an atmospheric pressure fluid-bed suspended by air blown in from below. The calcium in the limestone captures most of the sulfur released from the coal during combustion. Particulates are captured in a series of cyclones followed by a baghouse or electrostatic precipitator. The balance of plant would be identical to a conventional power plant.

This technology is considered in the early stages of commercialization. Several small plants (less than 100 MW) have been built and are now operating. A number of larger systems are just completing startup. This technology is available.

Major unresolved issues with fluid-bed combustion include the required maintenance level for the boiler system and the limestone use required for SO_2 capture. Construction lead times for this system are the same as that for conventional pulverized coal plants. The principal benefits associated with the fluid-bed boiler are its ability to burn a wider variety of coals and the lower NOx levels associated its operation.

Pressurized Fluidized-Bed Combustion (PFBC)

Crushed coal is burned with dolomite in a pressurized fluid-bed suspended by air blown in from below. The pressure in the combustion chamber is at a level of 6 to 16 times atmospheric pressure. Calcium in the dolomite captures most of the sulfur released from the coal during combustion. The hot pressurized gases leaving the combustor pass through a filter to remove suspended particulates and then drive a gas turbine generator. Steam generated in tubes in the bed and in a waste heat boiler drive a conventional steam turbine generator.

This technology is just entering the demonstration phase and is not yet mature. It will be several years before the limitations and development problems become clear. Commerciality is not foreseen before well into the next century. The promise is that as the technology develops capital costs will decrease along with heat rate.

Construction lead times and permit periods are expected to be similar to those of conventional coal plants. Environmental advantages are similar to an AFBC plant with the added benefit of a reduced need for Plant makeup water since there is less cooling tower makeup water required.

Integrated Gasification Combined Cycle (IGCC)

Pulverized coal is fed into a gasifier where it reacts with oxygen to produce an intermediate BTU gas. After the gas passes through a cooling section, sulfur and nitrogen compounds are removed and the clean gas is fired in a combustion turbine. The hot exhaust gases generate steam in heat recovery boilers. The steam is used to drive a steam turbine generator. The sulfur compounds are reduced to elemental sulfur in a Claus plant. Costs for the oxygen plant are included in total plant costs. Major pollutants are an order of magnitude less from an IGCC plant as compared to a conventional coal Plant.

This technology has been demonstrated at the Cool Water Plant in California and in facilities built at major refineries. A number of commercial and demonstration projects are now in the planning and construction stages. Commitment to this technology should not occur until these projects have been built (late 1990's). Because the technology is radically different from that of conventional power plants, operational risks are high with traditional utility personnel. It may prove desirable to have a third party operate such a plant in the early years of its operation.

The major advantage of such a plant stems from its low pollution levels. It will be easier to permit and site an IGCC facility as compared to the other coal options. IGCC might also be considered as an add-on technology to natural gas fired combustion turbines if gas prices ever rise enough to make it economical. Advanced versions of the gasifier concept are being developed but are farther into the future than the intermediate-Btu systems. The IGCC plant used is an oxygen-blown Destec gasifier combined with a GE 7F combined cycle similar to the Public Service of Indiana (PSI) project being built in Terre Haute, IN. Because of the elevation of PacifiCorp's coal regions this technology is derated as compared to the PSI project.

COGENERATION

Two cogeneration options are identified. These options represent existing or potential projects within PacifiCorp's service territory. They represent limited opportunities because of the limited number of available industrial hosts which can accommodate such systems. It is felt that the two systems described represent the most attractive opportunities to PacifiCorp and represent systems which PacifiCorp would be interested in owning in conjunction with an appropriate steam host.

Cogen 1

Cogen 1 represents units with relatively high capital costs and low heat rates, such as a backpressure steam turbine or small combustion turbine, but with a high percentage of thermal matching. For the combustion turbine application an aeroderivitive GE LM6000 was assumed.

Cogen 2

Cogen 2 represents units with relatively low capital costs and higher heat rates, typically large CC CT configurations, with varying amounts of process steam extraction from the steam cycle. The cost for these systems assumed an industrial frame type gas turbine utilizing the GE or Westinghouse "F" advanced technology.

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RENEWABLES

Geothermal

Generation of electricity from geothermal resources has been in use for many years at various locations around the world. Flashed steam plants are used when geothermal fluids are of sufficient temperature to flash to steam when raised to the surface and partially depressurized. This steam is used to drive a steam turbine generator. Binary cycle plants are used for geothermal fluids which are too cool to produce useful amounts of steam. In these plants the geothermal fluid is used to vaporize a secondary working fluid having a low boiling point. The secondary working fluid is used to drive a turbine generator. Both flashed steam and binary cycle units are demonstrated and commercially available.

Environmentally the use of geothermal energy is a plus but the number of suitable geothermal sites is limited. Development of a steam resource is a risky proposition. The options included do not assume that PacifiCorp will be the developer of the steam resource. Geothermal generation is largely a mature technology but is highly site specific in application.

Wind

Intermediate sized wind energy conversion systems (ie. 50 to 500 kW wind turbines) have evolved into a proven generation technology. Wind power generation has minimum environmental impacts and a short lead time for construction. Problems associated with wind generation are related to the low capacity factor, unreliability of most wind sources, and the aesthetics of large numbers of wind machines on local vistas. A 50 MW wind park is considered the minimal practical system.

The costs for wind reflect the current and future potential for wind energy. Current costs reflect the recent contracts under consideration with U.S. Windpower in Washington and Wyoming. For some Wyoming sites the capacity factor will exceed 30% which will help the economics. Future wind costs reflect the development of lighter lower cost machines. Recently enacted tax credits which would apply over the next ten years are not included in the spreadsheets. The net effect of these credits would be a reduction in the real levelized cost of approximately $15/MWh.

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Solar Power

Various systems exist for the conversion of solar energy to electricity. Photovoltaic (PV) systems have improved in efficiency and cost in recent years but are still not comparable to conventional coal-fired generation (roughly three times the cost). PV systems are economic choices for low power use, remote locations where transmission costs can be excessive. The advantages of PV systems include: direct energy conversion with no moving parts, no fuel cost, modular design, siting flexibility, no pollution and short construction time. The disadvantages of PV systems include high capital cost, intermittent availability, long term reliability, and minimal commercial experience. A reliable, economic PV system is still more than 10 plus years away. Because PV is viewed as a remote system and PV is not envisioned for central station service no costs for PV systems are included.

Thermal solar systems are more attuned to the needs of central power stations. The molten salt storage systems hold promise since the power produced would be dispatchable, even in partly cloudy conditions. PacifiCorp is following the progress of this concept with its investment in Solar II. The costs for various configurations of a mature Solar II type plant are included in the cost comparisons. Options are given at 100 and 200 MW sizes with low (40%) capacity factors and high (63%) capacity factors. LUZ type parabolic trough solar collector systems are included for comparison with the Solar II technology.

Tax credits have not been included with the solar technologies because it is felt that the tax credits would no longer apply in the early 2000's when these type of facilities would be built.

HYDRO

Hydro

Representative of a hydro plant resource available to PacifiCorp is the addition of 140 MW of capacity at the Company's Yale hydroelectric facility. This addition is largely capacity since no water is spilled currently at Yale. The extra capacity would be used as a peaking resource.

Pumped Hydro

Pumped hydro uses off-peak coal-based electricity to pump water to an upper reservoir. The water is then discharged as needed through a reversible pump-turbine to a lower reservoir producing electricity. The lower reservoir can be above ground or underground, if a suitable underground cavern or reservoir can be located. This technology is mature with 37 facilities now in operation but it is very site specific. Costs given reflect proposals made to PacifiCorp for pumped hydro concepts in our service territory. The 100 MW size is more related to PacifiCorp's share of a future project than the absolute size of a facility.

III. ENVIRONMENTAL CONSIDERATIONS

In comparing various generation options one of the most important considerations is the environmental impact each will have. The current fluid state of permitting and regulations, in light of the recent passage of the Clean Air Act Amendments of 1990, has clouded the issue considerably. Coal fired generation emits more pollutants than the other options identified. The ability to obtain and purchase pollution allowances will be a factor in new resource planning. The incremental cost to purchase or utilize existing SO_2 allowances have not been included in the costs presented in the attached tables, but these costs must be considered in the overall RAMPP plan.

JNL/18-Mar-94

PACIFICORP - RAMPP3

SUPPLY-SIDE PORTFOLIO

TABLE 1

OPTIONS:	LEAD TIME	CAPACITY (MW) OWC	CAPACITY (MW) UTAH	CAPACITY (MW) WYOMING	DISPATCHABLE	EXPECTED CF	CAPITAL COST ($/KW) OWC	CAPITAL COST ($/KW) UTAH	CAPITAL COST ($/KW) WYOMING	COMMENTS
GAS-FIRED PLANTS:										
LARGE CC CT	4-5 YEARS	225	191	173	YES	50-80%	$631	$742	$819	ONE 7F CT/ONE ST
MEDIUM CC CT	4-5 YEARS	150	128	118	YES	50-80%	$747	$879	$970	ONE 501D/ONE ST
LARGE SC CT	4-5 YEARS	159	135	122	YES	0-20%	$440	$518	$571	ONE 7F CT
MEDIUM SC CT	4-5 YEARS	84	68	62	YES	0-20%	$514	$605	$668	ONE 7EA CT
FUEL CELL (MC)	2-3 YEARS	10	10	10	YES	80%	$1,500	$1,500	$1,500	NOT COMMERCIALLY AVAILABLE TILL 2005
COAL-FIRED PLANTS:										
HUNTER 4 - PC	7-10 YEARS	N/A	400	N/A	YES	80-90%	N/A	$1,598	NA	BASED ON HUNTER 3 COSTS
WYODAK 2 - PC	7-10 YEARS	N/A	N/A	320	YES	80-90%	N/A	N/A	$1,881	BASED ON WYODAK 1 COSTS
GENERIC PC	7-10 YEARS	N/A	155	153	YES	80-90%	N/A	$2,321	$2,380	INITIAL UNIT (INCLUDES SOME COMMON FACILITIES)
GENERIC PC	7-10 YEARS	N/A	331	327	YES	80-90%	N/A	$1,789	$1,805	INITIAL UNIT (INCLUDES SOME COMMON FACILITIES)
AFBC	7-10 YEARS	N/A	152	152	YES	80-90%	N/A	$2,328	$2,298	CURRENT TECHNOLOGY
PFBC	7-10 YEARS	N/A	152	156	YES	80-90%	N/A	$2,580	$2,413	NOT COMMERCIALLY AVAILABLE TILL 2000
IGCC	7-10 YEARS	N/A	225	204	YES	80-90%	N/A	$1,941	$2,035	ADVANCED CT/ENTRAINED GASIFIER
COGENERATION RESOURCES (TYPICAL):										
COGEN 1	2-4 YEARS	46	39	N/A	NO	87%	$1,100	$1,293	N/A	LM6000 WITH STEAM TURBINE (LIMITED)
COGEN 2	2-4 YEARS	214	181	N/A	NO	85%	$663	$779	N/A	7F CCCT WITH HRSG (LIMITED)
RENEWABLES:										
BINARY GEOTHERMAL	4-5 YEARS	25	25	N/A	NO	85%	$2,265	$2,265	N/A	COSTS VERY SITE SPECIFIC
FLASH GEOTHERMAL	4-5 YEARS	50	50	N/A	NO	80%	$2,076	$2,076	N/A	COSTS VERY SITE SPECIFIC
WIND (CURRENT TECH.)	2-4 YEARS	50	50	50	NO	27%	$1,000	$900	$1,000	VARIABLE O&M FOR OWC = $17.9/MWH
WIND (FUTURE TECH)	2-4 YEARS	50	50	50	NO	27%	$850	$765	$850	VARIABLE O&M FOR OWC = $17.9/MWH
SOLAR (THERMAL)	3-5 YEARS	N/A	100	N/A	YES	40%	N/A	$3,448	N/A	NOT AVAILABLE BEFORE 2002 - 40% CF
SOLAR (THERMAL)	3-5 YEARS	N/A	100	N/A	YES	63%	N/A	$5,201	N/A	NOT AVAILABLE BEFORE 2002 - 63% CF
SOLAR (THERMAL)	3-5 YEARS	N/A	200	N/A	YES	63%	N/A	$4,203	N/A	NOT AVAILABLE BEFORE 2002 - 63% CF
SOLAR (SEGS LS-3)	2-4 YEARS	N/A	80	N/A	YES	40%	N/A	$3,332	N/A	SOLAR ONLY CF - 24% (EXCESS GAS FIRED)
SOLAR (SEGS LS-4)	2-4 YEARS	N/A	80	N/A	YES	40%	N/A	$3,052	N/A	SOLAR ONLY CF - 24% (PILOT PLANT ONLY)
HYDRO:										
HYDRO (YALE 3)	4-5 YEARS	140	N/A	N/A	YES	15%	$695	N/A	N/A	SITE SPECIFIC/PERMITTING
PUMPED STORAGE	4-5 YEARS	100	N/A	N/A	YES	30%	$1,200	N/A	N/A	SITE SPECIFIC/PERMITTING

NOTES:

CAPITAL COSTS INCLUDE AFUDC AT AN ANNUAL RATE OF 7%
CAPITAL COSTS IN 1/1/94 $
CT RATINGS ARE FOR NOMINAL NET OUTPUTS
COMBUSTION TURBINE RATINGS ARE AT 59 DEGREES F AND AT REGIONAL ELEV.
REGIONAL ELEVATION:

OWC ELEV. = 0 FEET (DERATE CT'S BY 0.00%)
UTAH ELEV. = 4500 FEET (DERATE CT'S BY 15.00%)
WYOMING ELEV. = 7000 FEET (DERATE CT'S BY 23% 23.00%)

GAS-FIRED PLANTS INCLUDE PIPELINE COSTS

PACIFICORP - RAMPP3

SUPPLY-SIDE PORTFOLIO
TABLE 2 - OWC

OPTIONS:	MW CAPACITY	AVERAGE NET PLANT HEAT RATE (BTU/KWH)	EMISSIONS (LB/MWH) SO2	PART.	NOx	CO2	O & M FIXED ($/KW-YR)	VARIABLE ($/MWH)
GAS-FIRED PLANTS:								
LARGE CC CT	225	7,518	0.0043	0.0218	0.6781	895	$10.00	$1.00
MEDIUM CC CT	150	8,234	0.0047	0.0239	0.7427	980	$10.00	$1.00
LARGE SC CT	159	11,338	0.0065	0.0329	1.0224	1,349	$1.00	$3.50
MEDIUM SC CT	84	12,505	0.0071	0.0363	1.1279	1,488	$1.00	$3.50
FUEL CELL (MC)	10	6,650	0.0039	N/A	0.0206	788	$90.00	$2.00
COAL-FIRED PLANTS:								
HUNTER 4 - PC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
WYODAK 2 - PC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
GENERIC PC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
GENERIC PC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
AFBC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
PFBC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
IGCC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
COGENERATION RESOURCES (TYPICAL):								
COGEN 1	48	5,500	0.0031	0.0160	0.86-2.24	655	$5.00	$0.50
COGEN 2	214	6,800	0.0039	0.0197	0.5-1.5	809	$5.00	$0.50
RENEWABLES:								
BINARY GEOTHERMAL	25	10,000	N/A	N/A	N/A	N/A	$62.00	$25.00
FLASH GEOTHERMAL	50	10,000	N/A	N/A	N/A	N/A	$58.00	$20.00
WIND (CURRENT TECH.)	50	N/A	N/A	N/A	N/A	N/A	$9.50	$16.20
WIND (FUTURE TECH)	50	N/A	N/A	N/A	N/A	N/A	$9.50	$16.20
SOLAR (THERMAL)	N/A	N/A	N/A	N/A	N/A	N/A	$51.48	$0.00
SOLAR (THERMAL)	N/A	N/A	N/A	N/A	N/A	N/A	$57.79	$0.00
SOLAR (THERMAL)	N/A	N/A	N/A	N/A	N/A	N/A	$38.88	$0.00
SOLAR (SEGS LS-3)	N/A	N/A	N/A	N/A	N/A	N/A	$40.03	$4.68
SOLAR (SEGS LS-4)	N/A	N/A	N/A	N/A	N/A	N/A	$37.95	$4.16
HYDRO:								
HYDRO (YALE 3)	140	N/A	N/A	N/A	N/A	N/A	$0.00	$0.80
PUMPED STORAGE	100	13,077	0.8360	0.2083	2.9060	3043	$0.00	$1.04

NOTES:

- O & M COSTS BASED ON EXPECTED CAPACITY FACTOR (COGENERATION COSTS SHARED)
- COMBUSTION TURBINES ASSUME 25 PPM NOx
- EMISSIONS BASED ON AVERAGE AS-DELIVERED MOUNTAIN FUEL ANALYSIS
- PLANT CAPACITY REFLECTS NET MW OUTPUT RATING
- PUMPED HYDRO COSTS REFLECT COAL-FIRED GENERATION (PUMPED HYDRO EFF. = 78%)
- PUMPED HYDRO O&M COSTS REFLECT HYDRO OPERATIONS & VARIABLE COAL (350 MW GENERIC PC)
- COAL PLANT HEAT RATES (HHV) AND EMISSIONS HAVE BEEN ADJUSTED 3.5% TO ACCOUNT FOR AVERAGE VALUES
- NATURAL GAS HEAT RATES (HHV) AND EMISSIONS HAVE BEEN ADJUSTED 5% TO 7.5% BASED ON INTERMEDIATE/PEAKING USE

JNL/18-Mar-94

PACIFICORP - RAMPP3

SUPPLY-SIDE PORTFOLIO
TABLE 3 - UTAH

OPTIONS:	MW CAPACITY	AVERAGE NET PLANT HEAT RATE (BTU/KWH)	EMISSIONS (LB/MWH)				O & M	
			SO2	PART.	NOx	CO2	FIXED ($/KW-YR)	VARIABLE ($/MWH)
GAS-FIRED PLANTS:								
LARGE CC CT	191	7,518	0.0043	0.0218	0.6781	895	$10.00	$1.00
MEDIUM CC CT	128	8,234	0.0047	0.0239	0.7427	980	$10.00	$1.00
LARGE SC CT	135	11,336	0.0065	0.0329	1.0224	1,349	$1.00	$3.50
MEDIUM SC CT	68	12,505	0.0071	0.0363	1.1279	1,488	$1.00	$3.50
FUEL CELL (MC)	10	6,650	0.0039	N/A	0.0206	786	$90.00	$2.00
COAL-FIRED PLANTS:								
HUNTER 4 - PC	400	10,300	0.5072	0.1521	2.1218	2,102	$20.75	$0.24
WYODAK 2 - PC	N/A	N/A	0.4968	0.1449	2.0700	2,049	$20.75	$0.24
GENERIC PC	155	10,123	0.5072	0.1521	2.1218	2,102	$32.16	$0.24
GENERIC PC	331	9,869	0.4968	0.1449	2.0700	2,049	$32.16	$0.24
AFBC	152	10,336	1.0350	0.1552	1.5525	2,146	$32.16	$0.50
PFBC	152	9,178	0.9212	0.1346	1.3766	1,913	$32.16	$0.50
IGCC	204	9,056	0.0931	0.0290	0.3002	1,828	$39.40	$1.00
COGENERATION RESOURCES (TYPICAL):								
COGEN 1	39	5,500	0.0031	0.0160	0.86-2.24	655	$5.00	$0.50
COGEN 2	181	6,800	0.0039	0.0197	0.5-1.5	809	$5.00	$0.50
RENEWABLES:								
BINARY GEOTHERMAL	25	10,000	N/A	N/A	N/A	N/A	$62.00	$25.00
FLASH GEOTHERMAL	50	10,000	N/A	N/A	N/A	N/A	$58.00	$20.00
WIND (CURRENT TECH.)	50	N/A	N/A	N/A	N/A	N/A	$9.50	$18.20
WIND (FUTURE TECH)	50	N/A	N/A	N/A	N/A	N/A	$9.50	$16.20
SOLAR (THERMAL)	100	N/A	N/A	N/A	N/A	N/A	$51.48	$0.00
SOLAR (THERMAL)	100	N/A	N/A	N/A	N/A	N/A	$57.79	$0.00
SOLAR (THERMAL)	200	N/A	N/A	N/A	N/A	N/A	$38.88	$0.00
SOLAR (SEGS LS-3)	80	11,700	0.00057	0.0029	0.06	119	$40.03	$4.68
SOLAR (SEGS LS-4)	80	11,100	0.00057	0.0029	0.06	119	$37.95	$4.16
HYDRO:								
HYDRO (YALE 3)	N/A	N/A	N/A	N/A	N/A	N/A	$0.00	$0.80
PUMPED STORAGE	N/A	13,077	0.6360	0.2083	2.9060	3043	$0.00	$1.04

NOTES:

O & M COSTS BASED ON EXPECTED CAPACITY FACTOR (COGENERATION COSTS SHARED)
COMBUSTION TURBINES ASSUME 25 PPM NOx
EMISSIONS BASED ON AVERAGE AS-DELIVERED MOUNTAIN FUEL ANALYSIS
PLANT CAPACITY REFLECTS NET MW OUTPUT RATING
PUMPED HYDRO COSTS REFLECT COAL-FIRED GENERATION (PUMPED HYDRO EFF. = 78%)
PUMPED HYDRO O&M COSTS REFLECT HYDRO OPERATIONS & VARIABLE COAL (350 MW GENERIC PC)
COAL PLANT HEAT RATES (HHV) AND EMISSIONS HAVE BEEN ADJUSTED 3.5% TO ACCOUNT FOR AVERAGE VALUES
NATURAL GAS HEAT RATES (HHV) AND EMISSIONS HAVE BEEN ADJUSTED 5% TO 7.5% BASED ON INTERMEDIATE/PEAKING USE

JNL/18-Mar-94

PACIFICORP - RAMPP3

SUPPLY-SIDE PORTFOLIO

TABLE 4 - WYOMING

OPTIONS:	MW CAPACITY	AVERAGE NET PLANT HEAT RATE (BTU/KWH)	EMISSIONS (LB/MWH) SO2	PART.	NOx	CO2	O & M FIXED ($/KW-YR)	VARIABLE ($/MWH)
GAS-FIRED PLANTS:								
LARGE CC CT	173	7,518	0.0043	0.0218	0.6781	895	$10.00	$1.00
MEDIUM CC CT	116	8,234	0.0047	0.0239	0.7427	980	$10.00	$1.00
LARGE SC CT	122	11,336	0.0065	0.0329	1.0224	1,349	$1.00	$3.50
MEDIUM SC CT	62	12,505	0.0071	0.0363	1.1279	1,488	$1.00	$3.50
FUEL CELL (MC)	10	6,850	0.0039	N/A	0.0208	788	$90.00	$2.00
COAL-FIRED PLANTS:								
HUNTER 4 - PC	N/A	N/A	N/A	N/A	N/A	N/A	$20.75	$0.24
WYODAK 2 - PC	320	11,800	0.6314	0.1552	2.2149	2,314	$20.75	$0.24
GENERIC PC	153	10,812	0.6521	0.1625	2.2667	2,373	$32.16	$0.24
GENERIC PC	327	10,539	0.6314	0.1552	2.2149	2,314	$32.16	$0.24
AFBC	152	10,959	1.3041	0.1656	1.6457	2,401	$32.16	$0.50
PFBC	156	9,262	1.1075	0.1387	1.3869	2,042	$32.16	$0.50
IGCC	204	9,192	0.1139	0.0445	0.3002	1,826	$39.40	$1.00
COGENERATION RESOURCES (TYPICAL):								
COGEN 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
COGEN 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
RENEWABLES:								
BINARY GEOTHERMAL	N/A	10,000	N/A	N/A	N/A	N/A	$62.00	$25.00
FLASH GEOTHERMAL	N/A	10,000	N/A	N/A	N/A	N/A	$58.00	$20.00
WIND (CURRENT TECH.)	50	N/A	N/A	N/A	N/A	N/A	$9.50	$16.20
WIND (FUTURE TECH)	50	N/A	N/A	N/A	N/A	N/A	$9.50	$16.20
SOLAR (THERMAL)	N/A	N/A	N/A	N/A	N/A	N/A	$51.48	$0.00
SOLAR (THERMAL)	N/A	N/A	N/A	N/A	N/A	N/A	$57.79	$0.00
SOLAR (THERMAL)	N/A	N/A	N/A	N/A	N/A	N/A	$38.88	$0.00
SOLAR (SEGS LS-3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SOLAR (SEGS LS-4)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HYDRO:								
HYDRO (YALE 3)	N/A	N/A	N/A	N/A	N/A	N/A	$0.00	$0.80
PUMPED STORAGE	N/A	13,077	0.8360	0.2083	2.9060	3043	$0.00	$1.04

NOTES:

O & M COSTS BASED ON EXPECTED CAPACITY FACTOR (COGENERATION COSTS SHARED)
COMBUSTION TURBINES ASSUME 25 PPM NOx
EMISSIONS BASED ON AVERAGE AS-DELIVERED MOUNTAIN FUEL ANALYSIS
PLANT CAPACITY REFLECTS NET MW OUTPUT RATING
PUMPED HYDRO COSTS REFLECT COAL-FIRED GENERATION (PUMPED HYDRO EFF. = 78%)
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NATURAL GAS HEAT RATES (HHV) AND EMISSIONS HAVE BEEN ADJUSTED 5% TO 7.5% BASED ON INTERMEDIATE/PEAKING USE

PacifiCorp
Internal Correspondence

To: IMP File

From: Laren Hale

Subject: Transmission Modeling

Transmission costs have been grouped into four transmission groups

Resources with existing transmission facilities	\$0.
Resources in remote locations (large)	\$60.
Resources in remote locations (small)	\$120.
Resources in very remote locations (small)	\$212.

Source is Transmission Assumptions and Estimates for RAMPP III, dated February 24, 1993. Attachment #6A - Intra-bubble transmission for peaking units, Assumed 50 miles to transmission interconnect.

Resources in remote locations (large)

\$23,926 million / 400 MW = \$59.82 / kW OWC
\$23,718 million / 400 MW = \$59.30 / kW Utah
\$23,758 million / 400 MW = \$59.40 / kW Wyoming
\$60.00 / kW Rounded

Resources in remote locations (small)

\$24,606 million / 200 MW = \$123.03 / kW OWC
\$23,913 million / 200 MW = \$119.65 / kW Utah
\$24,430 million / 200 MW = \$122.15 / kW Wyoming
\$120.00 / kW Rounded

Assumed remote location plus 200 miles.

Resources in very remote locations (small)

\$68,800 million / 500 MW = \$138.00 / kW Rounded

2/3 of remote transmission = \$ 92. / kW
\$120. / kW
\$212. / kW

ljh IPM Notes

March 15, 1994

PACIFICORP
PACIFIC POWER UTAH POWER

INTERNAL CORRESPONDENCE

Date: September 7, 1993

To: Hui Shu, 424 PSB

From: Mark Paul, 1226 PSB MP

Subject: RAMPP 3 Resource Costs - Social Discount Rate

Financial Analysis has updated the June 28 annual revenue requirement factors for RAMPP 3 resources to based on a 6.5% nominal and 3.0% real social discount rate. The revised factors for each plant type is as follows:

Plant Type	Real Carrying Charge @ 8.8%	Real Carrying Charge @ 6.5%	Depreciation Life	Useful Life	MACRS Tax Life
Coal Plants	8.32%	7.13%	45	45	20
Cogeneration	8.95%	7.96%	35	35	20
Combined Cycle	8.95%	7.96%	35	35	20
Geothermal	9.48%	8.61%	30	30	20
Hydro	8.12%	6.84%	50	50	20
Simple Cycle	9.16%	8.30%	30	30	15
Solar	9.84%	9.31%	20	20	5
Wind	9.84%	9.31%	20	20	5

Details of these calculations are attached. The attached revenue requirements are based on an incremental cost of capital of 10.43% and a 36.91% combined income tax rate. "Real" and "nominal" levelized first year revenue requirements were calculated using a discount rate of 8.8% or 6.5% and an inflation rate of 3.4%.

If you have any questions, please call me at Portland 5072.

Attachments

c: C. Aaberg, 1226 PSB
S. Sayler, 1226 PSB
D, Swan, 1226 PSB
B. Versari, 1226 PSB

Fuel Costs in Nominal Cents per MMBTU

Year	Potential		Low Gas Price				Medium Gas Price				High Gas Price				Geothermal Units			Wind
	Utah Coal UCL	Wyo Coal WCL	Combined West	Peaker West	Combined East	Peaker East	Combined West	Peaker West	Combined East	Peaker East	Combined West	Peaker West	Combined East	Peaker East	Low 1.71%	Med 3.78%	High 5.56%	1.25%
1994	52.2	44.8	256.0	222.0	231.0	236.0	256.0	222.0	231.0	236.0	256.0	222.0	231.0	236.0	190.0	190.0	190.0	120.0
1995	54.0	46.8	268.4	233.3	242.6	247.8	273.0	237.8	247.1	252.3	276.8	241.7	251.0	256.2	199.8	203.9	207.4	125.6
1996	55.8	48.8	281.5	245.1	254.8	260.1	291.1	254.7	264.4	269.7	299.5	263.1	272.8	278.1	210.1	218.8	226.4	131.5
1997	57.7	51.0	295.2	257.6	267.5	273.1	310.5	272.9	282.8	288.4	324.1	286.5	296.5	302.0	221.0	234.8	247.1	137.7
1998	59.7	53.2	309.6	270.7	281.0	286.7	331.2	292.4	302.6	308.4	350.9	312.1	322.3	328.1	232.4	251.9	269.7	144.2
1999	61.7	55.6	324.6	284.5	295.1	301.0	353.4	313.2	323.9	329.8	380.1	339.9	350.5	356.4	244.4	270.3	294.3	150.9
2000	63.8	58.0	340.5	298.9	309.9	316.0	377.2	335.6	346.6	352.7	411.8	370.2	381.2	387.3	257.1	290.1	321.3	158.0
2001	66.0	60.6	355.2	312.3	324.7	331.0	400.7	357.7	370.2	376.5	444.4	401.5	413.9	420.2	270.4	311.3	350.7	165.4
2002	68.2	63.3	370.8	326.3	340.2	346.7	426.0	381.6	395.4	402.0	480.0	435.6	449.5	456.0	284.3	334.1	382.7	173.2
2003	70.5	66.1	387.1	341.1	356.5	363.3	453.1	407.2	422.5	429.3	518.9	473.0	488.4	495.1	299.0	358.5	417.8	181.3
2004	72.9	69.0	404.2	356.7	373.7	380.7	482.2	434.7	451.6	458.6	561.4	513.9	530.8	537.8	314.5	384.7	456.0	189.8
2005	75.4	72.0	422.3	373.2	391.7	399.0	513.4	464.3	482.9	490.1	607.7	558.6	577.2	584.4	330.7	412.8	497.7	198.7
2006	78.0	75.2	441.3	390.5	410.7	418.2	546.9	496.1	516.4	523.8	658.3	607.5	627.7	635.2	347.8	443.0	543.2	208.1
2007	80.6	78.5	461.2	408.7	430.7	438.4	582.9	530.4	552.3	560.0	713.5	661.0	682.9	690.6	365.8	475.3	592.9	217.8
2008	83.4	82.0	482.2	427.9	451.7	459.7	621.4	567.2	590.9	598.9	773.7	719.4	743.2	751.2	384.7	510.1	647.2	228.0
2009	86.2	85.6	504.3	448.2	473.8	482.0	662.8	606.7	632.3	640.5	839.5	783.3	808.9	817.2	404.6	547.4	706.4	238.7
2010	89.1	89.4	527.5	469.5	497.0	505.5	707.3	649.2	676.7	685.3	911.2	853.2	880.7	889.2	425.5	587.4	771.0	249.9
2011	92.2	93.3	551.9	491.9	521.4	530.2	754.9	694.9	724.4	733.2	989.6	929.6	959.0	967.9	447.5	630.3	841.6	261.7
2012	95.3	97.5	577.6	515.6	547.1	556.2	806.1	744.0	775.5	784.7	1075.1	1013.0	1044.5	1053.7	470.6	676.3	918.6	273.9
2013	98.5	101.8	604.6	540.5	574.1	583.5	861.0	796.8	830.4	839.9	1168.4	1104.2	1137.9	1147.3	494.9	725.8	1002.6	286.8
2014	101.9	106.3	633.0	566.7	602.5	612.3	919.9	853.5	889.3	899.1	1270.3	1203.9	1239.7	1249.5	520.5	778.8	1094.3	300.3
2015	105.3	110.9	662.9	594.3	632.4	642.5	983.1	914.5	952.6	962.6	1381.5	1312.9	1350.9	1361.0	547.4	835.7	1194.5	314.3
2016	108.9	115.8	694.3	623.4	663.8	674.2	1050.9	980.0	1020.4	1030.8	1502.8	1431.9	1472.3	1482.7	575.7	896.8	1303.7	329.1
2017	112.6	120.9	727.4	654.0	696.8	707.6	1123.7	1050.4	1093.2	1104.0	1635.3	1561.9	1604.7	1615.5	605.5	962.4	1423.0	344.5
2018	116.5	126.3	762.1	686.3	731.6	742.7	1201.8	1126.0	1171.3	1182.4	1779.9	1704.0	1749.3	1760.5	636.8	1032.7	1553.2	360.7
2019	120.4	131.9	798.7	720.2	768.1	779.7	1285.7	1207.2	1255.1	1266.6	1937.7	1859.3	1907.1	1918.7	669.7	1108.2	1695.3	377.6
2020	124.5	137.7	837.1	756.0	806.6	818.5	1375.6	1294.5	1345.0	1357.0	2109.9	2028.8	2079.4	2091.3	704.3	1189.2	1850.4	395.4
2021	128.7	143.8	877.5	793.7	847.0	859.3	1472.1	1388.3	1441.6	1453.9	2298.0	2214.1	2267.4	2279.7	740.7	1276.1	2019.7	413.9
2022	133.1	150.1	920.0	833.3	889.5	902.2	1575.7	1489.0	1545.1	1557.9	2503.2	2416.5	2472.6	2485.4	779.0	1369.3	2204.5	433.3
2023	137.6	156.7	964.8	875.1	934.2	947.4	1686.8	1597.2	1656.3	1669.5	2727.1	2637.5	2696.6	2709.8	819.2	1469.4	2406.2	453.7
2024	142.3	163.6	1011.8	919.1	981.2	994.8	1806.1	1713.4	1775.5	1789.2	2971.6	2878.9	2941.1	2954.7	861.5	1576.8	2626.3	475.0
2025	147.2	170.9	1061.2	965.4	1030.7	1044.8	1934.1	1838.2	1903.5	1917.6	3238.5	3142.6	3207.9	3222.0	906.1	1692.1	2866.6	497.2
2026	152.2	178.4	1113.2	1014.1	1082.7	1097.2	2071.4	1972.3	2040.8	2055.4	3529.7	3430.6	3499.2	3513.7	952.9	1815.7	3128.9	520.6
2027	157.3	186.3	1167.9	1065.4	1137.4	1152.4	2218.8	2116.3	2188.2	2203.3	3847.6	3745.1	3817.1	3832.1	1002.1	1948.4	3415.2	545.0
2028	162.7	194.5	1225.4	1119.5	1194.9	1210.5	2376.9	2270.9	2346.4	2361.9	4194.6	4088.6	4164.1	4179.6	1053.9	2090.8	3727.6	570.6
2029	168.2	203.1	1285.9	1176.3	1255.4	1271.5	2546.6	2437.0	2516.1	2532.2	4573.3	4463.8	4542.8	4558.9	1108.4	2243.6	4068.7	597.3
2030	173.9	212.0	1349.5	1236.2	1319.0	1335.6	2728.7	2615.4	2698.2	2714.8	4986.7	4873.4	4956.2	4972.8	1165.7	2407.6	4440.9	625.4
2031	179.9	221.4	1416.4	1299.3	1385.9	1403.1	2924.1	2807.0	2893.6	2910.8	5437.9	5320.8	5407.4	5424.6	1225.9	2583.6	4847.2	654.7
2032	186.0	231.2	1486.8	1365.7	1456.2	1474.1	3133.8	3012.7	3103.2	3121.1	5930.4	5809.3	5899.9	5917.7	1289.3	2772.4	5290.7	685.4
2033	192.3	241.4	1560.8	1435.5	1530.2	1548.7	3358.8	3233.6	3328.3	3346.7	6468.0	6342.7	6437.4	6455.8	1355.9	2975.0	5774.7	717.6
2034	198.8	252.0	1638.6	1509.1	1608.1	1627.1	3600.3	3470.8	3569.7	3588.8	7054.7	6925.2	7024.1	7043.2	1426.0	3192.4	6303.0	751.3
2035	205.6	263.2	1720.5	1586.5	1689.9	1709.6	3859.4	3725.5	3828.8	3848.5	7695.1	7561.2	7664.5	7684.2	1499.7	3425.8	6879.7	786.5
2036	212.6	274.8	1806.5	1668.1	1776.0	1796.3	4137.4	3999.0	4106.9	4127.2	8394.1	8255.6	8363.5	8383.9	1577.2	3676.1	7509.1	823.4
2037	219.8	286.9	1897.1	1753.9	1866.5	1887.6	4435.8	4292.6	4405.2	4426.3	9157.0	9013.9	9126.5	9147.5	1658.7	3944.8	8196.2	862.1
2038	227.3	299.6	1992.3	1844.2	1961.7	1983.5	4756.0	4607.9	4725.4	4747.2	9989.8	9841.8	9959.2	9981.0	1744.4	4233.1	8946.0	902.5
2039	235.0	312.8	2092.4	1939.3	2061.8	2084.3	5099.5	4946.5	5069.0	5091.5	10898.7	10745.7	10868.2	10890.7	1834.6	4542.5	9764.5	944.9
2040	243.0	326.6	2197.7	2039.4	2167.1	2190.4	5468.2	5309.9	5437.7	5460.9	11890.8	11732.5	11860.3	11883.6	1929.4	4874.5	10657.9	989.2
2041	251.3	341.0	2308.4	2144.7	2277.8	2301.9	5863.8	5700.2	5833.3	5857.4	12973.7	12810.0	12943.1	12967.2	2029.1	5230.7	11632.9	1035.7
2042	259.8	356.0	2424.9	2255.6	2394.3	2419.2	6288.4	6119.2	6257.8	6282.7	14155.6	13986.4	14125.1	14150.0	2134.0	5613.0	12697.3	1084.2
2043	268.6	371.8	2547.3	2372.4	2516.8	2542.5	6744.0	6569.0	6713.4	6739.1	15445.7	15270.7	15415.1	15440.9	2244.3	6023.2	13858.9	1135.1
NPV	1,087	1,122	6,771	6,063	6,404	6,508	10,254	9,546	9,887	9,991	15,479	14,772	15,112	15,216	5,502	8,638	13,344	3,168
Levelized	52.20	53.88	325.28	291.28	307.65	312.65	492.59	458.59	474.95	479.95	743.61	709.61	725.98	730.98	264.32	414.98	641.03	152.20

ljh

Nominal Gas Turbine Price Forecast

Year	Fuel Cost			Transport & Storage				Low				Medium				High			
				Transport		Storage		CC	SC	CC	SC	CC	SC	CC	SC	CC	SC	CC	SC
	1.71%	3.78%	5.56%	West	East	West	East	West	West	East	East	West	West	East	East	West	West	East	East
	5.17%	7.31%	9.15%																
1994	211.0	211.0	211.0	45.0	20.0	-34.0	5.0	256.0	222.0	231.0	236.0	256.0	222.0	231.0	236.0	256.0	222.0	231.0	236.0
1995	221.9	226.4	230.3	46.5	20.7	-35.2	5.2	268.4	233.3	242.6	247.8	273.0	237.8	247.1	252.3	276.8	241.7	251.0	256.2
1996	233.4	243.0	251.4	48.1	21.4	-36.4	5.3	281.5	245.1	254.8	260.1	291.1	254.7	264.4	269.7	299.5	263.1	272.8	278.1
1997	245.4	260.7	274.4	49.7	22.1	-37.6	5.5	295.2	257.6	267.5	273.1	310.5	272.9	282.8	288.4	324.1	286.5	296.5	302.0
1998	258.1	279.8	299.5	51.4	22.9	-38.9	5.7	309.6	270.7	281.0	286.7	331.2	292.4	302.6	308.4	350.9	312.1	322.3	328.1
1999	271.5	300.2	326.9	53.2	23.6	-40.2	5.9	324.6	284.5	295.1	301.0	353.4	313.2	323.9	329.8	380.1	339.9	350.5	356.4
2000	285.5	322.2	356.8	55.0	24.4	-41.6	6.1	340.5	298.9	309.9	316.0	377.2	335.6	346.6	352.7	411.8	370.2	381.2	387.3
2001	300.2	345.7	389.4	55.0	24.4	-43.0	6.3	355.2	312.3	324.7	331.0	400.7	357.7	370.2	376.5	444.4	401.5	413.9	420.2
2002	315.8	371.0	425.1	55.0	24.4	-44.4	6.5	370.8	326.3	340.2	346.7	426.0	381.6	395.4	402.0	480.0	435.6	449.5	456.0
2003	332.1	398.1	463.9	55.0	24.4	-45.9	6.8	387.1	341.1	356.5	363.3	453.1	407.2	422.5	429.3	518.9	473.0	488.4	495.1
2004	349.2	427.2	506.4	55.0	24.4	-47.5	7.0	404.2	356.7	373.7	380.7	482.2	434.7	451.6	458.6	561.4	513.9	530.8	537.8
2005	367.3	458.4	552.7	55.0	24.4	-49.1	7.2	422.3	373.2	391.7	399.0	513.4	464.3	482.9	490.1	607.7	558.6	577.2	584.4
2006	386.3	491.9	603.3	55.0	24.4	-50.8	7.5	441.3	390.5	410.7	418.2	546.9	496.1	516.4	523.8	658.3	607.5	627.7	635.2
2007	406.2	527.9	658.5	55.0	24.4	-52.5	7.7	461.2	408.7	430.7	438.4	582.9	530.4	552.3	560.0	713.5	661.0	682.9	690.6
2008	427.2	566.4	718.7	55.0	24.4	-54.3	8.0	482.2	427.9	451.7	459.7	621.4	567.2	590.9	598.9	773.7	719.4	743.2	751.2
2009	449.3	607.8	784.5	55.0	24.4	-56.1	8.3	504.3	448.2	473.8	482.0	662.8	606.7	632.3	640.5	839.5	783.3	808.9	817.2
2010	472.5	652.3	856.3	55.0	24.4	-58.1	8.5	527.5	469.5	497.0	505.5	707.3	649.2	676.7	685.3	911.2	853.2	880.7	889.2
2011	497.0	699.9	934.6	55.0	24.4	-60.0	8.8	551.9	491.9	521.4	530.2	754.9	694.9	724.4	733.2	989.6	929.6	959.0	967.9
2012	522.6	751.1	1,020	55.0	24.4	-62.1	9.1	577.6	515.6	547.1	556.2	806.1	744.0	775.5	784.7	1075.1	1013.0	1044.5	1053.7
2013	549.6	806.0	1,113	55.0	24.4	-64.2	9.4	604.6	540.5	574.1	583.5	861.0	796.8	830.4	839.9	1168.4	1104.2	1137.9	1147.3
2014	578.1	864.9	1,215	55.0	24.4	-66.4	9.8	633.0	566.7	602.5	612.3	919.9	853.5	889.3	899.1	1270.3	1203.9	1239.7	1249.5
2015	607.9	928.1	1,326	55.0	24.4	-68.6	10.1	662.9	594.3	632.4	642.5	983.1	914.5	952.6	962.6	1381.5	1312.9	1350.9	1361.0
2016	639.3	996	1,448	55.0	24.4	-70.9	10.4	694.3	623.4	663.8	674.2	1050.9	980.0	1020.4	1030.8	1502.8	1431.9	1472.3	1482.7
2017	672.4	1,069	1,580	55.0	24.4	-73.4	10.8	727.4	654.0	696.8	707.6	1123.7	1050.4	1093.2	1104.0	1635.3	1561.9	1604.7	1615.5
2018	707.1	1,147	1,725	55.0	24.4	-75.9	11.2	762.1	686.3	731.6	742.7	1201.8	1126.0	1171.3	1182.4	1779.9	1704.0	1749.3	1760.5
2019	743.7	1,231	1,883	55.0	24.4	-78.4	11.5	798.7	720.2	768.1	779.7	1285.7	1207.2	1255.1	1266.6	1937.7	1859.3	1907.1	1918.7
2020	782.1	1,321	2,055	55.0	24.4	-81.1	11.9	837.1	756.0	806.6	818.5	1375.6	1294.5	1345.0	1357.0	2109.9	2028.8	2079.4	2091.3
2021	822.5	1,417	2,243	55.0	24.4	-83.9	12.3	877.5	793.7	847.0	859.3	1472.1	1388.3	1441.6	1453.9	2298.0	2214.1	2267.4	2279.7
2022	865.0	1,521	2,448	55.0	24.4	-86.7	12.8	920.0	833.3	889.5	902.2	1575.7	1489.0	1545.1	1557.9	2503.2	2416.5	2472.6	2485.4
2023	909.8	1,632	2,672	55.0	24.4	-89.7	13.2	964.8	875.1	934.2	947.4	1686.8	1597.2	1656.3	1669.5	2727.1	2637.5	2696.6	2709.8
2024	956.8	1,751	2,917	55.0	24.4	-92.7	13.6	1011.8	919.1	981.2	994.8	1806.1	1713.4	1775.5	1789.2	2971.6	2878.9	2941.1	2954.7
2025	1,006	1,879	3,183	55.0	24.4	-95.9	14.1	1061.2	965.4	1030.7	1044.8	1934.1	1838.2	1903.5	1917.6	3238.5	3142.6	3207.9	3222.0
2026	1,058	2,016	3,475	55.0	24.4	-99.1	14.6	1113.2	1014.1	1082.7	1097.2	2071.4	1972.3	2040.8	2055.4	3529.7	3430.6	3499.2	3513.7
2027	1,113	2,164	3,793	55.0	24.4	-102.5	15.1	1167.9	1065.4	1137.4	1152.4	2218.8	2116.3	2188.2	2203.3	3847.6	3745.1	3817.1	3832.1
2028	1,170	2,322	4,140	55.0	24.4	-106.0	15.6	1225.4	1119.5	1194.9	1210.5	2376.9	2270.9	2346.4	2361.9	4194.6	4088.6	4164.1	4179.6
2029	1,231	2,492	4,518	55.0	24.4	-109.6	16.1	1285.9	1176.3	1255.4	1271.5	2546.6	2437.0	2516.1	2532.2	4573.3	4463.8	4542.8	4558.9
2030	1,295	2,674	4,932	55.0	24.4	-113.3	16.7	1349.5	1236.2	1319.0	1335.6	2728.7	2615.4	2698.2	2714.8	4986.7	4873.4	4956.2	4972.8
2031	1,361	2,869	5,383	55.0	24.4	-117.1	17.2	1416.4	1299.3	1385.9	1403.1	2924.1	2807.0	2893.6	2910.8	5437.9	5320.8	5407.4	5424.6
2032	1,432	3,079	5,875	55.0	24.4	-121.1	17.8	1486.8	1365.7	1456.2	1474.1	3133.8	3012.7	3103.2	3121.1	5930.4	5809.3	5899.9	5917.7
2033	1,506	3,304	6,413	55.0	24.4	-125.3	18.4	1560.8	1435.5	1530.2	1548.7	3358.8	3233.6	3328.3	3346.7	6468.0	6342.7	6437.4	6455.8
2034	1,584	3,545	7,000	55.0	24.4	-129.5	19.0	1638.6	1509.1	1608.1	1627.1	3600.3	3470.8	3569.7	3588.8	7054.7	6925.2	7024.1	7043.2
2035	1,665	3,804	7,640	55.0	24.4	-133.9	19.7	1720.5	1586.5	1689.9	1709.6	3859.4	3725.5	3828.8	3848.5	7695.1	7561.2	7664.5	7684.2
2036	1,752	4,082	8,339	55.0	24.4	-138.5	20.4	1806.5	1668.1	1776.0	1796.3	4137.4	3999.0	4106.9	4127.2	8394.1	8255.6	8363.5	8383.9
2037	1,842	4,381	9,102	55.0	24.4	-143.2	21.1	1897.1	1753.9	1866.5	1887.6	4435.8	4292.6	4405.2	4426.3	9157.0	9013.9	9126.5	9147.5
2038	1,937	4,701	9,935	55.0	24.4	-148.0	21.8	1992.3	1844.2	1961.7	1983.5	4756.0	4607.9	4725.4	4747.2	9989.8	9841.8	9959.2	9981.0
2039	2,037	5,045	10,844	55.0	24.4	-153.1	22.5	2092.4	1939.3	2061.8	2084.3	5099.5	4946.5	5069.0	5091.5	10898.7	10745.7	10868.2	10890.7
2040	2,143	5,413	11,836	55.0	24.4	-158.3	23.3	2197.7	2039.4	2167.1	2190.4	5468.2	5309.9	5437.7	5460.9	11890.8	11732.5	11860.3	11883.6
2041	2,253	5,809	12,919	55.0	24.4	-163.7	24.1	2308.4	2144.7	2277.8	2301.9	5863.8	5700.2	5833.3	5857.4	12973.7	12810.0	12943.1	12967.2
2042	2,370	6,233	14,101	55.0	24.4	-169.2	24.9	2424.9	2255.6	2394.3	2419.2	6288.4	6119.2	6257.8	6282.7	14155.6	13986.4	14125.1	14150.0
2043	2,492	6,689	15,391	55.0	24.4	-175.0	25.7	2547.3	2372.4	2516.8	2542.5	6744.0	6569.0	6713.4	6739.1	15445.7	15270.7	15415.1	15440.9

PacifiCorp

Internal Correspondence

Date: July 9, 1993

To: IPM File

From: Laren Hale

Subject: Wind Resources

Jim Henry and I talked with Craig Schnabel X5630.

Wind Modeling

The Foote Creek project has come in at $1,227 in 1996 dollars. This should be discounted to 1994 dollars by 3.4% ($1,148 round to $1,150). When asked about difference in cost between OWC and Utah / Wyoming, he indicated that the capital cost difference was the cold weather package which we estimated at $30 per kW. The $1,227 includes transmission costs and substation ($8.9 million for the project).

Foote Creek generation kWh per kW is 35.5% which is a good approximation for future plants in Utah and Wyoming. Winds are less in OWC and should be modeled at 28%.

Maintenance of the wind is covered by contract at 11.4 mills/kWh in 1991 dollars plus inflation or 12.6 mills in 1994 dollars. This includes all O&M including wind generator replace in case of failure.

Wind Tax Credit

The tax credit is 1.5 cents per kWh for each kWh generated during the first 10 year of wind operation. To get the credit, the plant must be built by July 1 1999. For our modeling purposes we will present value the tax credit impact and deduct the amount from capital costs. The calculation was made in the Excel sheet "Foote Creek Tax Credit" and is $400 per kW. (See attached)

Wind Tax Credit Estimate

Hours	8760
CF	35.5%
kWh	3110
Credit per kWh	$0.015
Inflation to 1994	1.0692
Credit per year	49.87

Inflation_Rate	3.40%
Discount_Rate	8.80%
Real CC	5.22%

Utah / Wyoming

Year	Tax Credit	Inflation Index	Nominal Tax Credit	Deflator	Present Value
1	49.87	1.0000	49.87	1.0000	49.87
2	49.87	1.0340	51.57	0.9191	47.40
3	49.87	1.0692	53.32	0.8448	45.05
4	49.87	1.1055	55.13	0.7764	42.81
5	49.87	1.1431	57.01	0.7136	40.68
6	49.87	1.1820	58.95	0.6559	38.67
7	49.87	1.2221	60.95	0.6029	36.75
8	49.87	1.2637	63.02	0.5541	34.92
9	49.87	1.3067	65.17	0.5093	33.19
10	49.87	1.3511	67.38	0.4681	31.54
					$400.88

Rounded PV of tax credit per kW $400

Hours	8760
CF	28.0%
kWh	2453
Credit per kWh	$0.015
Inflation to 1994	1.0692
Credit per year	39.34

OWC

Year	Tax Credit	Inflation Index	Nominal Tax Credit	Deflator	Present Value
1	39.34	1.0000	39.34	1.0000	39.34
2	39.34	1.0340	40.67	0.9191	37.38
3	39.34	1.0692	42.06	0.8448	35.53
4	39.34	1.1055	43.49	0.7764	33.77
5	39.34	1.1431	44.97	0.7136	32.09
6	39.34	1.1820	46.49	0.6559	30.50
7	39.34	1.2221	48.07	0.6029	28.98
8	39.34	1.2637	49.71	0.5541	27.54
9	39.34	1.3067	51.40	0.5093	26.18
10	39.34	1.3511	53.15	0.4681	24.88
					$316.18

Rounded PV of tax credit per kW $315

	OWC	Utah	Wyoming
Capital Cost per kW	$1,150	$1,150	$1,150
Adjustment for Cold Weather Package	($30)		
Wind Capital Cost with out Tax Credit	$1,120	$1,150	$1,150
Tax Credit	($315)	($400)	($400)
Adjusted Capital Cost w Tax Credit	$805	$750	$750

7/12/93 12:11 PM

PacifiCorp
Internal Correspondence

To: IPM File

From: Laren Hale

Subject: Cogeneration Modeling

Per conversations between Jim Henry and Tom Ramish, IPM cogeneration should be modeled into two type Cogen 1 (small unit, high capital cost, low heat rate) and Cogen 2 (large unit, low capital cost, high heat rate).

Cogen 1 is based upon LM6000 with waste heat boiler & steam turbine

Cogen 2 is based upon 7FA CCCT similar to Hermiston

State	Unit	Capital Cost	Heat Rate	Annual Max	Total Max
OWC	Cogen 1	$1,100	5,500	160	320
OWC	Cogen 2	663	6,800	470	1320
UT	Cogen 1	$1,293	5,500	39	39
UT	Cogen 2	779	6,800	210	420

Fixed O&M is assumed to be 50% of the cost for a combined cycle combustion turbine ($10.00 x 50% = $5/kW). It is assumed that the host product would picked up some fixed O&M costs.

Variable O&M costs are assumed to be .5 mills per kWh.

ljh IPM Notes

March 15, 1994

PacifiCorp

Internal Correspondence

TO: IPM File

From: Laren Hale

Subject: Coal Modeling Capital Cost

In order to reduce the number of potential units to save computer run time, several units were consolidated. Listed below is the calculation for the Coal Units

Pulverized Coal

Utah

UNIT Name	Unit Size	Unit Cap Cost	Weighted Cap Cost
Hunter 4	400	1,596	638,400
Generic Small	155	2,321	359,755
Generic Large	331	1,789	592,159
Total	886		1,590,314

Average Cap Cost 1590314 / 886 1,795

Wyoming

UNIT Name	Unit Size	Unit Cap Cost	Weighted Cap Cost
Wyodak 2	320	1,881	601,920
Generic Small	153	2,360	361,080
Generic Large	327	1,805	590,235
Total	800		1,553,235

Average Cap Cost 1553235 / 800 1,942

Fluidized-bed Combustion

Utah

UNIT Name	Unit Size	Unit Cap Cost	Weighted Cap Cost
AFBC	152	2,328	353,856
PFBC	152	2,580	392,160
Total	304		746,016

Average Cap Cost 746016 / 304 2,454

Wyoming

UNIT Name	Unit Size	Unit Cap Cost	Weighted Cap Cost
AFBC	152	2,298	349,296
PFBC	152	2,413	366,776
Total	304		716,072

Average Cap Cost 716072 / 304 2,356

Source: Generation Engineering April 1993 Revision 1

PacifiCorp

Internal Correspondence

To: IPM File

From: Laren Hale

Subject: Modeling of Pumped Storage

Per conversations between Doug Spalloine and Jim Henry, and documentation provided by Doug Spalloine. Documentation is the Lorella Pumped Storage Project prepared by Energy Storage Partners dated April 1993. Price are assuming a Pacific owned unit.

Pumped Storage capital costs are about $770 in 1993 dollars. Round to $800 in 1994 for RAMPP-3 purposes. Costs include transmission to the grid.

Expected useful life should be comparable with Hydro.

Fixed O&M should be about $10 in 1994 dollars.

No variable O&M since O&M costs do not vary significantly with production.

Cycle efficiency is 78%.

Pumping Efficiency is 88%

Forced outage should be about 4%

ljh IPM Notes

March 15, 1994

POSITIONING
FOR
COMPETITION
AND
UNCERTAINTY
RAMPP

Resource and Market Planning Program
RAMPP - 3

PUBLIC PROCESS APPENDIX

APRIL, 1994

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POSITIONING FOR COMPETITION AND UNCERTAINTY

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Letters Received from Advisory Group Participants

Written Comments on Draft Report

Letters received

from

Advisory Group Participants

PP 1

TO: PacifiCorp Executive Officers
RAMPP-3 Advisory Group (RAG)

FROM: John M. Goroski JMG

DATE: January 27, 1992

RE: Role of RAG and Objectives of RAMPP-3

I have attended the last four meetings of the RAMMP Advisory Group, and like many participants of RAG, I have major concerns about the objectives of RAMPP-3 and the role of RAG. At the October 2, 1992 RAG meeting, several participants presented their concerns. Most of these concerns address the interpretation and implementation of the least cost plan (LCP) and have important implications on corporate decision-making policies.

1) What is the relationship between the LCP process and the planning process that drives the corporate goals?
2) Does management of PacifiCorp take the LCP process seriously, because there is very little evidence to show any connection between the LCP process and management decisions?
3) What factors were considered and how were these factors evaluated in PacifiCorp decision making process?
4) Can a productive working relationship be developed between RAG and the company?
5) Why aren't some of RAG's suggestions followed?
6) Why aren't more of PacifiCorp's decision makers attending the RAG meetings?

I believe these concerns can be alleviated by expanding the current role of RAG and by explicitly specifying the objectives of RAMPP-3.

The role of RAG should be to review the development of RAMMP-3, but more importantly, advise PacifiCorp on the broader issues of interpretation and implementation of their LCP. This advice should have direct implications on corporate decision making policies.

Currently, RAG gives advice primary on model development. I believe that advice on model development is better suited for specialized subgroups. Further, I believe that RAG should be more concerned about the interpretation and implementation of LCP findings, as well as how these findings are incorporated into the company's decision making process. I do not want this statement to be construed as micro-management, but rather, as responsible and thorough advising from PacifiCorp's RAMPP Advisory Group.

PP

I propose that we (PacifiCorp's LCP group and other RAG members) expand the role of RAG through the following ways.

1) I propose that RAG expand the scope of issues that are discussed at RAMPP meetings.

   a) Issues such as decoupling, loss revenue adjustment measures, and merger and acquisition policies should be discussed. I understand that these issues may be addressed in other forums. But because PacifiCorp has service territory in seven states and because of the diverse nature of the regulatory policies in those states, the diverse nature of RAG provides an ideal forum for the discussion of such issues.

   b) Establish a work plan that meets PacifiCorp's LCP needs, while allowing for thorough and complete discussions on other issues that are of importance to RAG participants.

2) I propose that an independent-mutual facilitator conduct the RAG meetings.

   a) The facilitator would write formal comments for RAG which could then be sent to PUCs/PSCs, as well as to PacifiCorp's top-level management. RAG participants would be certain their concerns were heard without putting PacifiCorp's LCP group members in an uncomfortable situation. This does not exclude RAG participants from dissenting on particular LCP issues.

   b) The facilitator would allow for a more independent advisory group and would allow RAG the opportunity to increase its credibility as an advisory group.

Again, I understand that RAG is an <u>advisory</u> group and not a decision making group. But if RAG is going to take the LCP process seriously, and for that matter, make ourselves credible, we must..

1) advise not only on model development through specialized subgroups, but MORE IMPORTANTLY, advise PacifiCorp on the interpretation and implementation of the LCP with the more diverse RAMPP Advisory Group;

2) convince PacifiCorp's top-level management to also take the LCP process seriously.

In order to accomplish this, the LCP must explicitly address PacifiCorp's, the various states' LCP rules, and other interested RAG members' multiple objectives. We (PacifiCorp's LCP group and other RAG members) have an opportunity to develop RAMPP-3, so that it could be used by top-management of PacifiCorp, while satisfying the LCP rules of the various states. This would not only benefit PacifiCorp's investor and customers, but would avoid the costly drawn out rate case, siting act, and FERC processes.

I propose that RAG explicitly list and include in the RAMMP-3 the criteria needed to satisfy the multiple objectives of PacifiCorp, the various states, and other interested RAG members. I do not want this to be confused with PacifiCorp's Multi-Attribute Trade-Off Discussion Paper (Draft 1/18/93), which identifies scenarios using alternative strategies, futures, and sensitivities. I believe that title should be changed because it may be confused with what the least cost planning community refers to as the multi-attribute decision rule. The multi-attribute decision rule is an explicit list of weighted criteria needed to satisfy the multiple objectives of the LCP. Further, I propose that the scenarios that are analyzed be ranked and summarized according to each category in the multi-attribute decision rule.

As for Montana, the multi-attribute decision rule should include at a minimum those objectives listed in 38.5.2007 ARM. More specifically, the objectives that should be included are customer concerns, owner concerns, uncertainties of load, fuel quantity and price, DSM quantity, and economy sales price, environmental, transmission, reliability and debt equivalent equity. I believe these are important issues that warrant a group discussion as soon as possible.

PP

PP 5

PACIFICORP
PACIFIC POWER UTAH POWER

March 3, 1993

John M. Goroski
Montana Department of Natural Resources
and Conservation
1520 East Sixth Avenue
Helena, Montana 59620-2301

Re: Your letter dated January 27, 1992[3]

Dear John:

Thank you for your January letter discussing the role of RAG and objectives of RAMPP-3. We will allow time on the March 12 RAG meeting agenda for discussion of the issues you raise. This letter is to respond in writing to your letter, consistent with the Company's commitment to provide written responses to letters from RAG participants.

You suggest expanding the role of RAG and explicitly specifying the objectives of RAMPP-3. You also suggest that PacifiCorp upper management does not take the RAMPP process seriously.

The role of RAG is to be an advisory body for the Company's least cost planning effort. It deals with issues of DSR resource cost and availability, supply-side resource cost and availability, renewable resources, discount rate, gas prices and related matters, load forecasts, modeling, analysis strategies, and others. Issues often arise which may be related in some way to least cost planning, and a particular Commission will open a proceeding to address that issue, which may include workshops and/or a collaborative process. The Company believes that this is appropriate. RAG cannot address every issue of concern to all of the participants. First, RAG should be limited in scope so that those whose interest is limited to least cost planning can spend their time most efficiently. Second, RAG should be limited in scope so that the least cost planning process can occur on a timely basis (every two years).

PP

The objectives of RAMPP are to develop a document which is useful to both the Company and the various state regulatory Commissions. This document identifies the process, input assumptions, analysis framework, long-range resource plans under alternative futures, and a two-year action plan. The RAMPP process becomes the framework used by the Company in its evaluation of alternative resource choices that become available as the future unfolds. The Company uses a multi-attribute perspective in developing resource plans, which includes minimizing revenue requirements, minimizing total resource costs, providing reliable service, achieving efficiencies, meeting its environmental responsibilities, achieving flexibility and diversity in resource choices, and fostering innovation. The final action plan is not intended to be a roadmap, rather, given an uncertain future, it is a framework to assist in decision making.

I can assure you that PacifiCorp's upper management does take the RAMPP process very seriously. We include officers in RAMPP meetings whenever possible. Mike Henderson, Vice President of Community and Energy Services, presented material and invited questions about the Company's DSR programs at the January 29 RAG meeting. Chuck Adams, Senior Vice President of Power Supply, will discuss the Company's coal plant strategy at the March 12 RAG meeting. Harry Haycock, Senior Vice President and Chief Engineer will discuss the Company's efforts to achieve efficiencies on its transmission and distribution system at the April 23 RAG meeting. In addition, the Company's senior management regularly reviews RAMPP progress; uses the RAMPP framework, including avoided costs, for ongoing resource decisions; incorporates RAMPP conclusions in its strategic planning; and incorporates RAMPP action plan items in the operating plans of the various affected departments.

Thank you for your thoughtful letter, and for the discussion it has engendered. The Company welcomes open review of its RAMPP process and inputs.

Sincerely,

Nancy

Nancy Esteb, Manager
Integrated Resource Planning

NE/ja

PP 7

SOLAR ENERGY ASSOCIATION of OREGON

working for a sustainable energy future

Date: January 29, 1993

To: Nancy Esteb
Pacific Power

From: Melanie Proctor
SEA of O

Re: Response for RAMPP-3

In the last meeting, you requested our response recommending the number of scenarios and sensitivity studies to be analyzed. You also requested that we recommend the objective function and methodology to be used in selecting the preferred alternative. Finally you promised that the Company would provide a written response to any other questions we might raise.

1. Number of scenarios and sensitivity studies.

The number of scenarios suggested in your MATO discussion draft is clearly too large for a reasonable planning process. Furthermore, the scenarios suggested do not always appear to make sense. We suggest that the analysis focus on "random walk" simulations to investigate the uncertainty in major growth and fuel price assumptions and with sensitivity comparisons against the base case for most of the resource questions proposed. We recommend the following:

(a) Base case should be retiring existing coal plants, high level of DSR, strategic level of renewables including externality costs, medium high load growth, medium gas costs and reduced costs for future renewables.

(b) With regard to the other sensitivities you propose:

Retaining existing plants should be examined as a supply side option, with inclusion of externality costs. Scenarios are not needed.

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Levels of DSR can be examined as sensitivities from the base case.

Allowing the model to pick any amount of coal is meaningless unless the externality cost is included, sensitivities are not needed. Sensitivity of the refurbish cost being low/high can be applied. This option is particularly important given the likelihood of a carbon tax.

Examining the impact of high/low load growth and gas prices is an important part of the uncertainty analysis. These uncertainties should be explored fully with a number of random walk simulations

(c) Reduced cost for renewables is likely. Pacific should be prepared to provide a technology forecast for future renewables that recognizes technology trends just as the load forecast recognizes economic trends.

(d) Additional resource options must be included such as setting rates to encourage conservation. Pacific should examine the effect of hookup fees and inverted tailblock rates as sensitivities.

(e) Ramp-up rate of DSR programs has been previously mentioned as a sensitivity case. Run the base case with high and low ramp-up.

2. The objective function should minimize societal costs including externalities. For that reason, the base <u>cannot</u> ignore externalities. The methodology should apply a post-tax discount rate to present value costs. This means that tax treatment should not be included in program costs, as was done in RAMPP-2. Since the resources are long-lived, care must be taken to include the full end effects of actions that extend past the planning horizon.

3. Other questions.

Please explain the current status of the Montana agreement between Pacific and NRDC. Is the stipulation still in effect? Have the requirements been accomplished? One of those requirements called for reconsideration of inverted rates when Pacific was within three years of a resource acquisition. Based on the resource plans from RAMPP-2, isn't it time to begin that reconsideration?

PP 9

PACIFICORP
PACIFIC POWER UTAH POWER

March 3, 1993

Melanie Proctor
Solar Energy Association of Oregon
027 SW Arthur Street
Portland, OR 97201

Re: Your Letter dated January 29, 1993

Dear Melanie:

Thank you for your January letter regarding the Company's recommended study plan for RAMPP-3. I will respond to each item in your letter separately.

The number of scenarios suggested in our MATO discussion draft is too large.
Response: We recognize that 200 separate scenarios appears large, but other parties believe it is much too few. Although the number of scenarios exceeds 200, a large number is needed to take advantage of the multi-attribute approach to finding the robust strategies which lead to minimizing emissions while minimizing revenue requirements. The Company seeks strategies that are optimum in the face of uncertain futures.

We should focus on random walk simulations, with a base case composed of retiring existing coal plants, a high level of DSR, strategic level of renewables, medium high load growth, medium gas costs, and reduced costs for future renewables.
Response: The Company is still examining which variables can be addressed through random walk simulations, and which can best be addressed through scenario or sensitivity analysis. A base case needs to reflect the Company's most likely future. Otherwise, our planning would be based on assumptions that are not likely to occur, and would not be as useful to the Company or to the state regulatory

Commissions. Therefore, a base case will assume that existing coal plants will continue to operate as long as they are cost effective, DSR will be at a cost-effective level, renewables will be added at the strategic level (as you suggest), medium high load growth (as you suggest), medium gas costs (as you suggest), and expected costs for future renewables. We will be testing the issues you raise either through scenarios or sensitivities, including maintaining/retiring existing coal plants, the appropriate level of DSR, and reduced costs for future renewables.

Retaining existing plants should be examined as a supply side option, with inclusion of externality costs. Scenarios are not needed.
Response: Retaining existing plants will be examined as a supply side option, and the impact of externality costs will be tested against a case of retaining existing plants.

Levels of DSR can be examined as sensitivities from the base case.
Response: They will be.

Allowing the model to pick any amount of coal is meaningless unless the externality cost is included, sensitivities are not needed.
Response: The impact of exernality costs on coal plant selection for future resource needs will be tested.

High/low load growth and gas price ... should be explored fully with a number of random walk simulations.
Response: Load growth and gas prices will be explored through scenario analysis. Scenarios are created by combining alternative strategies with alternative futures. The three middle load forecasts (medium low, medium, and medium high) will be used with two or three gas price forecasts to create multiple scenarios.

Pacific should [include a renewables price forecast] that recognizes technology trends.
Response: One of the sensitivities will be a case with a reduced cost for renewables, to recognize the technology trends that may well lead to lower costs in the future.

Pacific should examine the effect of hookup fees and inverted tailblock rates as sensitivities.
Response: One of the sensitivities will be a case with a reduce load growth level, such as might occur if tailblock rates were in effect, and/or hookup fees were in effect.

Run the base case with high and low ramp-up rate [for DSR programs].
Response: By definition, a base case cannot be run with two opposing assumptions. The issue of ramp-up rate will be examined through scenario analysis.

The objective function should minimize societal costs including externalities. For that reason, the base cannot ignore externalities.
Response: The objective function includes a balancing of minimizing societal costs and revenue requirements. Although the base case will not include externalities, the impact of external costs on resource plans will be fully explored through the multi-attribute trade-off analysis and through the inclusion of sensitivities based on six levels of external costs.

The methodology should apply a post-tax discount rate to present value costs. This means that tax treatment should not be included in program costs, as was done in RAMPP-2.
Response: A post-tax discount rate will be used to present value costs. Our definition of total resource costs for DSR includes taxes. Although some would argue that these are merely transfer payments, they are real costs to our customers.

Since the resources are long-lived, care must be taken to include the full end effects of actions that extend past the planning horizon.
Response: The two models being considered do include end effects.

Please explain the current status of the Montana agreement between Pacific and NRDC.
Response: The Company is reviewing this issue, and will be able to respond after that review is complete.

We appreciate your interest in our planning process.

Sincerely,

Nancy

Nancy Esteb, Manager
Integrated Resource Planning

NE/ja

PP 1

PP 13

PACIFICORP
PACIFIC POWER UTAH POWER

May 20, 1993

Ms. Melanie Proctor
Solar Energy Association of Oregon
027 S.W. Arthur Street
Portland, OR 97201

Dear Ms. Proctor:

In a recent letter to Nancy Esteb, you inquired about the status of the "Montana agreement between Pacific and NRDC." The agreement stems from the stipulation reached by the Montana Consumer Counsel, the Natural Resources Defense Council and the Company in 1987 and includes what is called a "Rate Design Evaluation Trigger." To give you some background on this trigger mechanism, it calls for the upward adjustment or elimination of the residential declining block rate under either of the following circumstances:

1. Pacific is buying power under BPA's New Resource Rate to meet its retail load requirements, and BPA acquires an option for a new resource(s) whose projected cost per kilowatt-hour would exceed both the current New Resources Rate and Pacific's tailblock rates.

2. Pacific determines that, within three years, there is a substantial possibility that to meet its retail load requirements the Company will have to invest in new generating capacity or power purchase contracts with costs exceeding system average costs.

The stipulation is still in effect, and we have concluded that the stipulation has not been triggered. The Company agrees, however, that it may be time to begin to reconsider residential declining block rates. We intend to propose the gradual phasing out of the declining block rate for Montana residential customers at the time of our next general rate case.

As mentioned, neither condition of the rate design trigger has occurred. The Company is not buying power under BPA's New Resources Rate to meet retail load requirements. Second, it is not likely that new resources will be acquired within the next three years at a cost greater than system average cost. To estimate the cost of prospective new resource additions over the next three years, we analyzed the costs of recently acquired resources and used this as a proxy for the cost the Company might reasonably expect to pay for resources in the near future.

To Melanie Proctor
May 20, 1993
Page Two

One of the ways the Company is able to keep new resource costs low is through marketing power in the wholesale power market and by use of its resource pool pricing mechanism. A significant advantage of the pool pricing mechanism from the perspective of retail customers is that when new resources are added to meet growing retail load requirements, lower cost resources may be rolled out of the pools while the higher costs of the new resources are rolled in and reflected in prices charged to wholesale customers. These wholesale revenues are then used to reduce the effective cost of new resources to retail customers. By the time the resource is rolled out of the wholesale pricing pool, the net book value remaining in rate base is lower than the original investment cost. The result is that retail customers see lower costs associated with new resource additions than they would without the Company's wholesale marketing activities.

Although estimating the cost of future resource acquisitions is somewhat uncertain, our review of recent acquisitions in conjunction with the Company's pool pricing mechanism indicates that the cost of future resources will be less than system average cost. To further support this conclusion, discussions with potential new suppliers regarding the availability of long-term firm power indicate that the 1993 real levelized cost of new long-term firm power is below system average cost. Even though we have concluded that the stipulation you mention has not been triggered, it is timely to begin to reconsider declining block rates for Montana residential customers.

Thank you for your interest.

Sincerely,

Anne E. Eakin

Anne E. Eakin,
Assistant Vice President, Regulation

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PP 15

February 22, 1993

COMMENTS OF
THE UTAH DIVISION OF PUBLIC UTILITIES
REGARDING PACIFICORP'S
INTEGRATED RESOURCE PLANS: RAMPP-2 & RAMPP-3

The purpose of this document is to raise concerns and questions of clarification regarding RAMPP-2 and RAMPP-3 that the Utah Division of Public Utilities is interested in having the Company address in the near future.

OPTIMIZATION MODEL

The Company is still not using an appropriate optimization methodology. The Company indicated that the two models currently being tested have "optimization features and each has the capability to simultaneously address both resource acquisitions and operations". ["Comments of Utah Parties on RAMPP-2 Acknowledgment", PacifiCorp, p.6] It would be useful for the Company to elaborate on the optimization features of these models. In any case, the Company's current approach is not a legitimate optimizing approach. The following discussion describes the Company's optimization methodology and subsequently explains the shortcomings of that approach.

The Company's "PacifiCorp RAMPP-3 Multi-Attribute Trade-off Discussion" paper indicates that PacifiCorp intends to run 223 models. The Company identifies 216 scenarios (i.e. a set of strategies combined with a set of futures) and 17 additional sensitivities to generate these 223 models. These models have been selected to cover a broad range of possible scenarios and to limit the number of runs that are conducted to a manageable number.

The first model that the Company should run is an unconstrained model. This would serve as the appropriate benchmark for assessing the impact of each constraint on costs. The Company indicated that the model run designated as MH-1 in the RAMPP-2 Report "is a base-line run without constraining assumptions". [p.1] Is this truly an unconstrained model? It would be useful for the Company to clearly state all assumptions and any explicit or implicit constraints in the base case scenario for RAMPP-3 and provide the rationale for adopting this as the base case.

The Company biases the results in determining the least cost strategy by preselecting strategies and hard wiring these into the model prior to running the model under various futures. The model should select the optimal strategy, not the analyst who inputs the parameters. Ideally, the model should be solved by first examining, for a given future, the impact of cost as one alters a strategy (i.e. the choice variable under the decision-maker's control) incrementally. This approach would permit the Company to determine the true least cost strategy under a given future. Currently, the Company does not allow for incremental alterations of a strategy. The problem with this approach is that allowing for only a few values with respect to a particular choice variable and comparing the impact on costs with only those few strategies is not likely to result in the least cost plan. For example, in the case of allowing for strategies regarding existing coal plants, the

Company permits only two strategies: (strategy 1) keep <u>all</u> existing coal plants operating at their current availability level or (strategy 2) retire existing coal plants as maintenance/refurbishment costs increase. Thus, the Company does not consider a strategy of operating only some of the existing coal plants and retiring the remaining coal plants. Ideally, under an incremental approach the Company would have a range of strategies for coal plant retirements. For example, given 3 coal plants, X, Y, and Z, the possible strategies would be (strategy 1) operate X, Y, and Z; (strategy 2) operate X and Y, and retire Z; (strategy 3) operate X and Z and retire Y; (strategy 4) operate Y and Z, and retire X; (strategy 5) operate X, and retire Y and Z; (strategy 6) operate Y, and retire X and Z; (strategy 7) operate Z, and retire X and Y; (strategy 8) retire X, Y, and Z. The Division can appreciate that it is costly to consider every conceivable strategy. However, at present, the Company is considering far too few strategies.

Assessing the cost of various possible strategies under a given future would enable the Company to determine the optimal least cost strategy for that future. This same process should be repeated for each possible future. This allows the analyst to assess the sensitivity of the choice of strategy 1 which is optimal under future A on costs if strategy 1 is adopted and future B occurs, given that strategy 2 is optimal under future B. This sensitivity analysis would indicate how robust strategy 1 is under alternative futures. This process could then be repeated for each optimal strategy (for a given future) to assess how sensitive cost is under alternative futures for that particular strategy.

This debate regarding methodology should be resolved prior to the Company's investing resources to conduct these 223 runs. It would be useful for the Company to elaborate on: 1) its decision to consider models PMDAM and IPM; 2) other optimization programs available on the market; and 3) the potential for the Company to develop its own optimization model in house.

PROBABILITY OF FUTURES

Least Cost Planning should include some consideration of the probability that a particular future will occur. RAMPP-3 and earlier versions have not considered the probability that a particular event will occur in the modeling. Implicitly, this assumes that there is an equal probability that each event occurs. The Company indicated that these probabilities are considered in PacifiCorp's Strategic Short-Term Action Plan. PacifiCorp offered to provide a discussion of the Company's view of the probability that the futures examined will occur. It would also be useful to ascertain the confidence that one has in the probability assigned to a particular future. For example, if the probability of a carbon tax is deemed to be 30%, one would want to assess if there is a large or small variance, (degree of reliability) assigned to that number.

PRICE ELASTICITY OF DEMAND

Price elasticity of demand has not been considered in modeling (forecasting load) for residential service. In the minutes for the last RAMPP Advisory Group (RAG) meeting the Company indicated that it omitted price elasticity of demand because it is the Company's goal to keep prices low. This response does not appropriately address the concern regarding the omission of price elasticity of demand. Prices may be relatively low and yet change. While they may remain relatively low it is still important to consider how sensitive quantity demanded is to a given price increase (decrease). The Company also indicated that in 1994 they expect Bonneville Power Administration's price increase to impact PacifiCorp. They indicated that this would directly impact OR, WA, and ID. This will indirectly impact UT because of interjurisdictional allocations. Thus, anticipating this price increase, price elasticity of demand should definitely be included in the modeling to assess the impact of this price increase on quantity demanded.

In response to the concern that RAMPP-3 should incorporate the effects of price elasticity of demand for electricity into the analysis, the Company stated that "forecasts of industrial sector sales and end use choices by residential and commercial customers incorporate the effect of electric price elasticity". [p.23] This response suggests that load forecasts for residential do not include price elasticity effects. It is not clear why they have not been included here.

The Company also stated that rate design issues are not appropriate for the RAMPP-3 process. [p.23] It is not clear that this is an appropriate view. Rate design can certainly affect load shape and can be used as a tool to encourage investment in Demand Side Resources (DSR). It seems that this should be taken into account to the extent that it affects the optimal choice of least cost resources. This warrants further discussion with the Company.

DSR PROGRAMS

It is important to carefully assess the DSR programs that the Company considers since this directly affects whether DSR will appear attractive or not in RAMPP. A concern here is that the degree to which DSR is selected as a least cost resource depends critically on the programs that the Company selects for consideration. Furthermore, for any given program the savings in kW and kWh depend critically upon program design, implementation, etc. In theory, the Company could impede the selection of DSR as a least cost resource by biasing the types of DSR programs included for consideration to those that are relatively cost ineffective. Resolving the uncertainty regarding the regulatory treatment for cost recovery is very likely to affect the DSR programs considered in integrated resource planning (IRP).

In response to a request for the Company to place all DSRs in the resource stack for selection without pre-screening, thereby allowing the model to select them, the Company stated that the "portfolio of resources consists of programs, not measures" because DSR is acquired on a program by program basis, not according to measures. [p.19] This approach requires further elaboration.

AVOIDED COSTS

In response to a request to utilize more than one set of avoided costs as a screening device for DSR the Company indicated that:

"Avoided costs can be computed for any assumed load growth scenario. For each such level, a capacity expansion plan must be established as input to the avoided cost calculation. However, multiple avoided costs would not be useful to the company's decision-making and would be confusing because avoided costs are used in a variety of contexts, where consistency is needed...." [p.12]

It may be appropriate to use more than one set of avoided costs. Further elaboration is required on how the Company calculates avoided cost and its rationale for using only one set of avoided costs.

The Company was criticized for its methodology in computing avoided costs when assessing the economics of DSR for not including credits for marginal (rather than average) line losses for avoidable transmission and distribution investments. The Company responded by saying that "using average or marginal methods to calculate losses will provide similar results". [p.12] It is appropriate for the Company to use marginal methods. The results of average and marginal analysis are equal only when line losses are given by a linear function. These line losses may be linear under certain conditions that may change over time. Given that line losses appear to be appropriately represented by a quadratic function, marginal and average analysis will not yield equivalent results. It is not clear that the Company has provided any evidence demonstrating that the results of marginal and average methods are similar.

The Company was asked to address the concern that avoided costs should be determined by the IRP which requires a cost-effectiveness level for DSR, and yet cost-effectiveness levels for DSR should be based on avoided cost estimates (referred to as the chicken and the egg problem). The Company responded by saying that the modeling tools to address this issue "are not now available and the time required to do such an iterative process would be prohibitive". [p.24] It would be useful for the Company to elaborate on this response since it appears that this is not an analytically intractable problem.

AVERAGE WATER SENSITIVITY

The Company indicated that one of the sensitivities in RAMPP-3 will be based on average water, and the results of that sensitivity will be compared to the base case run using critical water. [p.7] It would be useful for the Company to clarify which model(s) are run based on average water, i.e. explicitly state the strategy and futures assumed.

One justification that the Company offered for using an extreme water year for planning is that "Planning on average hydro energy would mean that about half the time actual hydro generation would be less than expected" [p.8]. This is not necessarily true. It depends on the distribution of actual hydro generation. If this distribution is distributed normally then this statement is true. If the distribution is distributed e.g. log normal, then this statement is false. What is the shape of this distribution? Even if the assumption stated above is true, it does not necessarily invalidate using an approach based on an average water year, nor does it provide sufficient justification for using an extreme water year. Without adequate review, we don't know which approach results in lower costs. Furthermore, it would be appropriate to compare the expected value for costs given an extreme water year with the expected value for costs given an average water year.

EXTERNALITIES

In response to the Division's request that the Company consider externalities besides environmental externalities, the Company indicated that it will discuss this with the public advisory group. [p.8] It would be useful to discuss the externalities that are appropriate to consider.

MINIMIZE TOTAL RESOURCE COST

It would be useful to have the Company clarify what the optimization model minimizes. It appears to be minimizing total resource cost (TRC) as opposed to minimizing the Company's system costs alone. Explicitly define TRC and discuss how this compares to total societal cost (TSC). Provide examples of ratepayer costs that would be included in the calculation of TRC.

The 10% credit applied toward DSR in RAMPP-2 suggests that perhaps some of societal costs have been included in least cost planning. What is the Company's rationale for the 10% credit for DSR?

In general, what is the Company's view of the appropriate role for considering TSC? Information can be garnered regarding the cost to ratepayers of minimizing TSC by examining the cost of the optimal strategy that minimizes TRC and comparing that to the cost of the optimal strategy that minimizes TSC. Comparing the impact on revenue requirement of the two approaches permits one to explicitly calculate the additional cost to ratepayers of paying for the costs incurred by society.

PRICE AND BILL IMPACTS OF DSR

The Company plans to examine price and bill impacts of DSR as one of the plan performance measures in RAMPP. While this information is useful to regulators it is not essential for determining the strategy that minimizes TRC. In theory, a plan that minimizes TRC could also minimize rate and bill impacts. It may require some creative redistribution of resources, but the plan that provides the greatest total savings relative to alternative plans would potentially minimize rate impact. The concern here is that DSR programs that are not least cost may be selected based on other criteria such as price or bill impacts when these impacts may have been narrowly examined with respect to potential impacts. What does the Company view as the appropriate role for using the results of the analysis of price and bill impacts?

EXCLUSION OF LOST OPPORTUNITIES AND FIRM WHOLESALE SALES

The Company indicated that "Considerations such as lost opportunities and associated firm wholesale sales which help bear part of the costs of the acquisition, especially in the early years, are not modeled". [p.10] What is the Company's rationale for not considering these factors in determining the appropriate least cost strategy given that taking these factors into account may alter the optimal strategy?

ACQUISITIONS

In response to a request for the Company to defend Colorado Ute and Cholla acquisitions by showing that they would be chosen by the RIM model, the Company indicated that "the function of RAMPP is planning; it is not an after-the-fact evaluation of resource acquisitions". [p.9] It is not clear that this is an appropriate view. If the Company views it as inappropriate to examine such issues in the IRP process then when does the Company consider it appropriate to examine if resource acquisitions are consistent with the IRP? Does the Company consider rate cases or prudency reviews the appropriate arenas to examine if these purchases are consistent with least cost planning? Title I, Subtitle B, Sec. III (7), of the 1992 Energy Policy Act requires that "All [IRP] plans and filings before a State regulatory authority ... contain a requirement that the plan be implemented". It appears that compliance with this provision necessitates that a process exists that ensures that the IRP is followed. It would be useful to discuss this controversial issue.

Once resource acquisitions have been made, what is the Company's rationale for not including these purchases in the Company's SSR that it has available when conducting least cost planning?

CONFIDENCE INTERVALS ON LOAD FORECASTS

In response to a request to provide empirical evidence to back up assertions on confidence levels of load forecasts, the Company indicated that the confidence intervals "cannot be mathematically derived". [p.19] Why can't these intervals be mathematically derived?

CONSISTENCY BETWEEN THE COMPANY'S IRP AND BUSINESS PLAN

At the last Utah DSR Evaluation Taskforce meeting the Taskforce discussed a prototype list of questions that the Company should be prepared to answer when approaching the Utah Public Service Commission regarding approval of a specific DSR program. The Company indicated that it is inappropriate to address the issue of whether or not the DSR program is consistent with the Company's business plan when examining a specific program. They indicated that it is appropriate to examine this issue in the IRP process. Given the Company's view and the importance of this issue, this issue should be addressed at the RAG meetings.

In response to questions regarding the relationship of the Company's financial growth and other strategic goals to the IRP the Company provided very general answers. [p.16 & p.22] Their response does not really address specific concerns, e.g. shareholder incentives to invest in DSR.

PP 2

PP 29

PACIFICORP
PACIFIC POWER UTAH POWER

March 29, 1993

Audrey Curtiss
Utah Division of Public Utilities
Heber M. Wells Building
160 East 300 South
Salt Lake City, Utah 84145

Re: Your letter dated February 22, 1993

Dear Audrey:

Thank you for your February letter regarding the Company's RAMPP-2 and RAMPP-3 processes. I will respond to your concerns in the order they are discussed in your letter.

Optimization Model

PacifiCorp received substantial criticism of the model used for RAMPP-2. It was critiqued because it was not an optimization model, and because it did not integrate production costs with resource selections. The Company was concerned that the model did not adequately represent the geographically dispersed nature of the system and the transmission constraints that exist within the system.

In preparing for RAMPP-3, the Company surveyed what other electric utilities were using for the modeling task in their least cost planning. We found that there were two dominant patterns. One pattern was the creation, by analysts and company management, of trial plans based on their own expertise. These trial plans were then tested against alternative futures with a production cost model, to determine which one(s) performed the best. The second pattern was the use of a capacity expansion model, which was linked to a production cost model, to develop a unique resource plan for each future.

PacifiCorp had three primary criteria in looking for a new model. First, it needed to be an optimization model, to satisfy concerns of regulatory Commissions and other parties. Second, it needed to integrate production costs with resource selections to satisfy concerns of regulatory Commissions and other parties. Third, it needed to recognize the geographic dispersion of the Company's loads and resources, and the transmission constraints that exist among those geographic areas.

We found that only two models were on the market that met these three criteria: IPM from a company called ICF Resources, and PMDAM from an individual named Ed Cazalet who owned the code he had written for BPA. We acquired the code for both, to enable us to test them for possible use for RAMPP-3. A final decision has not yet been made.

This section of your letter also addresses various concerns with the MATO study plan discussion paper distributed by the Company. A new version of that paper was mailed to all parties on March 1. The changes made in this version reflect most of the concerns you expressed in your letter. In addition, the MATO study plan was discussed at the March 11 RAMPP Advisory Group (RAG) technical meetings and at the March 12 RAG meeting. It will be discussed again at the April 9 RAG meeting.

Probability of Futures

Multiple futures are used in RAMPP to prepare the Company for an uncertain future. A unique resource plan is created for each future. The Company then examines those resource plans, and evaluates the commonalities and differences, to develop a two-year action plan. Implicitly some assumptions are made in that decision making, for example, the medium-low and medium-high load forecast results in RAMPP-2 were given more weight than the low and high load forecast results. The Company has not assigned precise probabilities to the alternative futures it has proposed, in RAMPP-1, RAMPP-2 or RAMPP-3. There are two principal reasons for this. First, we have not been persuaded that any of the methods available to do this will produce a result that would improve decision making better than the current method. Second, we have not been persuaded that there is a technique available to use such probabilities that would improve decision-making. Any such technique would be a mechanistic formula. A workable method would need to incorporate the judgment of Company management, which represents an enormous amount of utility experience. The Company is currently re-evaluating approaches to incorporate some estimation of probabilities.

Price Elasticity of Demand

You asked about iteration between the prices resulting from the planning model runs and those used in the load forecasting model. While iterating the models is conceptually correct, we question its value relative to the time that would be required. In our view, the degree of anticipated price variation between scenarios would cause little change in demand, and would dramatically slow the RAMPP process. In addition, the prices resulting from a RAMPP process are checked against the input price assumptions, to assure that there is reasonable consistency. Similarly, when new avoided costs are calculated from a RAMPP process, the resulting conservation cost effectiveness level is checked against the level used for that RAMPP process. The conservation cost effectiveness level derived from RAMPP-2 was very close to that used for RAMPP-2, which was derived from the avoided costs from RAMPP-1. Therefore, an iteration step would not have changed the results of RAMPP-2.

The second concern is the lack of price elasticity estimates for the residential and commercial sectors. Recent flat and declining prices, preceded by increasing prices, coupled with efficiency improvements (many mandated by the Government), make it difficult, if not impossible, to determine price elasticity estimates that are meaningful and representative of the future. We believe that the best way to determine the impact of price on usage is through carefully controlled experiments which vary price design in the marketplace. Such experiments have not been done, and would be difficult to implement given customers' concerns about price levels and price stability. Another concern is the estimation of background conservation. This will vary as usage and prices vary, and has embedded in it many consumer choices which could be categorized as price effects. This may lead to double counting of price effects.

Regarding rate design, the Company is preparing a peak management report, which it will file with the Oregon Commission in September of 1993. One of the options being explored in that report is rate design. The information contained in the report on this issue will be incorporated into a discussion of the issue in the RAMPP-3 Report.

DSR Programs

DSR programs are developed from individual measures. The Company includes for consideration in program development all measures which cost less than the conservation cost effectiveness ceiling. That ceiling is calculated using avoided costs as a base, and then adding a capacity credit, T&D savings, line losses, and the 10% regional credit. A 55 mill cut-off was used for RAMPP-2. The regional credit raises the cost effectiveness cutoff level from about 50 mills to 55. This resulted in programs that tended to average about 30 mills in cost. As a result, DSR resources, which entered the resource portfolio as 30 mill programs, were selected first to fill resource needs in all of the futures, because we did not have supply-side resources which cost less than 30 mills. Therefore, all of the cost effective DSR programs were included in the resource plans for RAMPP-2.

Avoided Costs

As described in the preceding paragraph, avoided costs, with various adjustments, are used as a screening device for DSR measures. It does present a "chicken and egg" problem, as you describe, in that avoided costs from the preceding RAMPP must be used as a screening device for the subsequent RAMPP. However, until better modeling tools are available, the chicken and egg problem will remain. As discussed above, we have found that the generation gap between the chicken and its egg is very small.

The problem is not as large as it may first appear. If the Company had used a 70 mill cut-off for cost effectiveness, it would have increased the amount of DSR resources in the plan by only about 10 percent. This is because the supply curve flattens out above about 55 mills, and so moving up the cost axis brings fewer and fewer additional resources.

Modifying DSR acquisition rates and amounts, incrementally, would not have much effect on avoided costs. This is because the incremental resource wouldn't change (gas-fired combustion turbines); the only change would be minor shifts in timing of a year or two.

The issue of whether marginal or average line losses are used has been debated widely within the Company. The consensus from our engineering staff was that there was not a large difference, and the impact of using one versus the other would not be large. We therefore turned our attention to issues which would have a substantial impact on the total DSR resources in the plan, the cost of those resources, and implementation issues.

In RAMPP-3, our intention is to use three different cost effectiveness levels, and two different ramp-up rates, to test the amount of DSR resources available to fill system needs, the amount of supply-side resources that are required, and the impact of on system costs.

Average Water Sensitivity

As described in the MATO study plan discussion paper which was mailed out earlier to RAG participants, the Company intends to include in its sensitivities one based on average water. In addition, at the April 30 RAG meeting, a Company representative will discuss the differences between average and critical water. Any questions which you may have can be addressed further at that time.

Externalities

An extensive discussion of externalities during RAMPP-2 led to the conclusion by the RAG advisory group that analysis should focus on air pollutants. We believe that that judgment is still valid for RAMPP-3. We believe that formal analysis of other externalities should wait until the methods for addressing air pollutants are better developed, and more consensus exists that an appropriate methodology is being used.

Minimize Total Resource Cost

Resources are selected by the capacity expansion model based on their contribution to system costs. The Company also evaluates the total resource costs, customer prices, and total societal costs of the specific resource plans in developing its short-term action plan.

The 10 percent credit for DSR is based on the Pacific Northwest Electric Power Planning and Conservation Act enacted into Federal law in 1980. It created the Regional Council, among other things. The 10 percent credit must be used by the Council in identifying the amount of conservation which Bonneville should acquire. The Oregon and Washington Commissions have approved tariffs using the 10 percent credit. The Company has adopted it as well.

Price and Bill Impacts of DSR

The Company's desire to explore the price and bill impacts of DSR stems from a desire to minimize price impacts to our customers. Until the analysis is completed, we cannot predict how large a role it will have in developing and implementing DSR resources.

Acquisitions

Acquisitions are evaluated for their cost effectiveness and benefit to customers through investigations such as that conducted by RMI for the Utah Commission, and through rate cases, where the Company would present testimony and evidence in support of their benefit to customers.

Confidence Intervals on Load Forecasts

You asked about assigning probabilities to the five load forecasts. Since the inputs to the five load forecasts are deterministic and subjective, probabilities cannot be mathematically derived for the five load forecasts. You also asked about confidence intervals around a particular forecast. Each individual regression model equation in the load forecasting model has 95 percent confidence intervals around each of the coefficients. Our model has over five hundred equations. However, because of the interdependency between the equations, it cannot be asserted that the results represent 95 percent confidence intervals around each of the forecasts.

Consistency Between the Company's IRP and Business Plan

This issue has been a topic discussed by the Utah DSR Task Force. The Task Force has been developing a standard data request, which Utah Power would respond to when it files a new DSR program. Included in a draft of the data request was a question regarding the consistency of the DSR program with the Company's strategic goals. We believe that the strategic goals are not specific enough that a particular DSR program can be either consistent or inconsistent with them. The group decided that the question really relates to the Company's DSR effort as a whole, and that the question should be left to a separate discussion. The group did not decide definitely that this discussion should take place in the RAG, but that might be a reasonable place for it. If the RAG members believe that time should be spent on this topic, that can be arranged for the June meeting. The agendas for the two April meetings are quite full.

Thank you for your interest in the Company's IRP process.

Sincerely,

Nancy Esteb

Nancy Esteb, Manager
Integrated Resource Planning

PP 35

STATE OF WASHINGTON

WASHINGTON STATE ENERGY OFFICE

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February 22, 1993

Ms. Nancy Esteb
Manager, Integrated Resource Planning
Pacificorp
920 S.W. Sixth Avenue
Portland, OR 97204-1256

Subject: Planned Multi-Attribute Trade-Off Analysis

Dear Ms. Esteb:

The purpose of this letter is to provide review and comment on the planned multi-attribute analysis for the Resource and Market Planning Program (RAMPP)-3. We believe this analysis will be critical to the development of a comprehensive integrated resource plan, and wish to work closely with Pacificorp to ensure its ultimate success.

After careful review of the Draft Multi-Attribute Trade-Off Discussion Paper, dated January 18, 1993, we are concerned that the current proposal to use the multi-attribute technique will not produce meaningful information. As such, Pacificorp's planned resource analysis for RAMPP-3 appears inadequate and seems unable to provide the basis for any integrated resource cost plan in its current form.

To correct the proposed analysis, we recommend the following adjustments:

Clear specification of the attributes to be traded off;
Systematic development of alternative strategies that can be compared;
A large increase in the number of strategies; and
Proper treatment of alternative strategies across uncertain futures.

In order to develop a manageable number of model runs, we suggest that the strategies described in this letter initially be examined using only one future. By doing so, Pacificorp should be able to better ascertain the robustness of the resulting data points, and further refine the development of alternative strategies. We also recommend that the "base case" scenario be run with economic constraints only, rather than requiring the model to select specific amounts of any given resource.

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These corrections and specific recommendations are discussed in more detail as follows:

Overview of Multi-Attribute Models

The treatment of external costs appeared to be the initial reasoning for Pacificorp's decision to use this type of model. With reference to the papers presented by Mr. Stephen Connors of MIT, Pacificorp has claimed that multi-attribute models can weigh different external costs without the need to explicitly monetize them. In that way, according to Pacificorp, arguments over the reasonableness and the uncertainty of monetary values are avoided, because known regulator preferences will be substituted for unknown public preferences. Pacificorp has previously argued that it does not want to use environmental adders, but rather apply a multi-attribute approach, as advocated by Mr. Connors.

Our understanding is that multi-attribute models are part of a larger class of decision analysis models (e.g., linear programming, non-linear programming, etc.) in which a feasible choice set is mapped based on constraints that are imposed. Efficient solutions lie along the frontier of the mapping. Then, depending on the specific goal selected (e.g., maximize profits, minimize costs, etc.), a point on the frontier is selected. This frontier will not necessarily be limited to two dimensions, but may exist in far higher dimensions, depending on the number of attributes to be traded off.

We believe that multi-attribute models applied to energy resources will work the same way. Different resources will have different characteristics. Specifically, they will have different environmental attributes, as well as different internal costs, availability factors, etc. Using the multi-attribute approach, an efficient frontier of resources could conceivably be determined *for a given future*, so that only dominant resource choice options remain. Once the efficient frontier is created, decision makers must somehow weigh the different attributes and thereby arrive at the desired resource choice for the particular future.

We are especially concerned that this approach does not resolve the question of *how* to choose a single point on the efficient frontier. Any choice would lead to an implicit valuation of various trade-offs. In some cases, such heuristic trade-offs may be valid. In others, however, such as environmental costs, they may be no better than random guesses. Nevertheless, use of this approach may in fact allow Pacificorp and Public Utility Commission (PUC) decision makers a more intuitive view of the types of resource trade-offs that may be necessary, even if it does not provide any algorithm for actual choices.

Misinterpretation of the Multi-Attribute Method

We are concerned that the January 18, 1993 Discussion Draft paper indicates that either Pacificorp may have misinterpreted what constitutes a multi-attribute trade-off analysis, or failed to successfully explain how the analysis will be performed. As we understand it, the Pacificorp proposal is to examine 12 alternative resource strategies, applied to 18 different futures. Our interpretation of the paper indicates that only 8 robust strategies are identified, although several of these strategies would be properly interpreted as a "base case" scenario. We believe that, as developed, this approach will not result in a meaningful multi-attribute analysis.

First, it is not clear what attributes are to be traded-off. Presumably, one attribute would be the present value of revenue requirements. If this were the only attribute Pacificorp intended to use, the multi-attribute comparison would collapse into a standard comparison of present values for the different scenarios and futures. **Such comparisons, however, would be valid only across identical futures.** It would be expected, for example, that the costs associated with a given resource strategy would be lower with lower future load growth and energy prices. Otherwise, comparisons of alternative resource strategies are "apples and oranges" comparisons. Thus, as identified in the January 18 Discussion Draft, the Pacificorp proposal will be unable to identify any sort of "efficient" frontier.

In the paper by Connors (distributed at the December 11, 1992 meeting), Figure A-1(2) refers to "impacts for a discrete future." We interpret this to mean that a trade-off curve is being developed for a given future, not a range of futures. There are methodologies that can be adopted to address *uncertainties* across different futures, but we believe the current proposal does not adequately do this.

We suggest that Pacificorp clearly *identify the entire set of attributes to trade-off* and *systematically develop strategies that can be compared.* We would be happy to work with Pacificorp to do this. Subsequently, we could also help Pacificorp develop a set of future uncertainties to examine.

Inadequacy of Resource Strategies

Even if the current 12 resource strategies were compared for each future, it is unlikely that there would be sufficient choices to identify a clear trade-off curve. One reason for this is that the alternative Demand Side Management (DSM) strategies will yield only two useful points for the multi-attribute analysis. Based on our understanding, Pacificorp intends to try three cut-off points on a single DSM supply curve. One of these points will be below the cost-effective level of 5.5 cents/kWh (real levelized), another will be above, and the third will be at the cost-effective level.

We believe that only two of the cut-off points will yield potentially useful information for a trade-off curve. The low cut-off point strategy (**LD**), where DSM is restricted to less than the cost-effective level, will always lie in the interior of the efficient frontier. It may be interesting for some questions, but it adds nothing to a multi-attribute evaluation of NPV and externalities.

The two coal plant strategies, **KC** and **RC**, represent "base case" and accelerated retirement scenarios. It is not clear from the paper how different these will be. If there is little difference in the retirement dates of plants, little will be learned.

Combining the two coal strategies, the two renewable strategies (**SRAC** and **ARIC**), and the two DSM strategies will yield only eight points with which to construct trade-off frontiers. Even if there are only two attributes considered (e.g., NPV and emissions of a given pollutant), these eight points will not be enough for a robust analysis. (Connors use of hundreds of points with which to construct trade-off frontiers.) If more than two attributes are used, the eight points will be even less likely to define any reasonable frontier, revealing dominant strategies.

<u>Recommended Modifications to the Pacificorp Analysis</u>

We believe that if the multi-attribute analysis is to provide meaningful results, it will need to incorporate many more well-defined strategies. We suggest at least three DSM strategies, three coal retirement strategies, and three renewable strategies. This would provide 27 points for a trade-off curve. While this number of strategies is still quite low in comparison with Connors' work, it has the potential for providing useful information, and represents the minimum of analysis that Pacificorp should undertake for a simple two-attribute analysis.

The first DSM strategy should include all currently cost-effective programs. The two (or more) others should go beyond that level. Similarly, Pacificorp should evaluate three renewable strategies: one that acquires all cost-effective renewables, and two others that go beyond that level of acquisition. Furthermore, we recommend that one renewable strategy should explicitly ban any new coal plants.

For the existing coal plants, as we have stated, a "base case" strategy should be to retire them when it is cost-effective to do so. The other strategies should retire these plants on an accelerated schedule that is sufficiently aggressive to provide adequate differentiation from the base case.

In all cases, Pacificorp will need to compare these strategies for a given future. Uncertainties inherent across different futures (e.g., low versus high gas prices) will have to be dealt with either by adopting some measures of uncertainty as a specific attribute, or using other analytical techniques. Again, we would be happy to work with you towards the development of appropriate techniques.

We believe that, by adopting our suggestions, Pacificorp will be able to complete a credible multi-attribute analysis. Again, however, while such an analysis may provide a well-defined efficient frontier, it will not provide a means of choosing a given strategy on that frontier.

We hope our suggestions will help Pacificorp to thoroughly examine the relationships between alternative resource strategies, and look forward to working with you in the future.

Thank you for this opportunity to provide comment.

Sincerely,

for

Jonathan A. Lesser, Ph.D.
Senior Economist Washington
State Energy Office

Philip H.Carver, Ph.D.
Senior Policy Analyst
Oregon Dept. of Energy

Rebecca L. Wilson
Senior Analyst
Utah Division of Energy

JL/ay
O-L1-44W

cc: RAG members
Philip H. Carver, Ph.D.
Rebecca L. Wilson

PP 4

PP 41

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March 29, 1993

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Rebecca L. Wilson
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Salt Lake City, Utah 84180-1204

Re: Your letter dated February 22, 1993

Dear Jonathan, Phil, and Rebecca:

Thank you for your February letter regarding the Company's planned multi-attribute trade-off analysis. I will address your four suggestions.

First, you recommend a clear specification of the attributes to be traded off.

One of the greatest strengths of the multi-attribute approach is the ability to examine the performance of alternative resource plans along several attributes. The alternative resource plans are created to meet new resource needs under alternative scenarios and sensitivities. The Company intends to discuss with the RAG group which attributes should be examined to evaluate the comparative performance of the alternative resource plans.

NEVER DONE.

You are especially concerned that the Company's approach does not resolve the question of how to choose a single point on the efficient frontier. LCP does not require the choice of one single plan to the exclusion of all others. Rather, it requires the choice of near term actions that ought to be compatible with a wide range of plans. The goal in a multi-attribute trade-off analysis is to compare the performance of alternative resource plans across several attributes and across multiple futures. If a few strategies consistently out-perform other strategies, that will be a worthwhile result.

We recognize that this method does not, by itself, automatically arrive at a single clear, unambiguous solution point. Its strength is that it provides an unambiguous depiction of the choices: what is the direct cost increase incurred to achieve emission reductions and what are the least costly means to achieve such reductions.

While the analysis may identify the cost-emission trade-off, it does not provide information on the issue of whether a particular emission reduction is worth the direct cost incurred to achieve that reduction. That is in the realm of policy decisions.

<u>Second, you recommend systematic development of alternative strategies.</u>

The Company believes it has undergone a systematic development of alternative strategies. We first reviewed all of the issues identified by the RAG participants as possibilities to address in our analysis. We then prioritized that list, based on comments we received from the RAG participants in response to RAMPP-2, regulatory concerns, and Company concerns. That process led us to four primary issues: existing coal plants, new coal plants, renewable resources, and DSR levels. We have determined that the existing coal plant issue can be adequately analyzed through the scenarios and sensitivities. The other three issues will be analyzed through specific strategy alternatives. Many more issues could be addressed through the multi-attribute approach; however, the limited time and resources available forced us to limit our analysis to these three issues.

<u>Third, you recommend a large increase in the number of strategies.</u>

Finding the right balance between incorporating strategies to address all of the participants' concerns and limiting strategies to the amount which can be handled given the time and resources available is difficult. Until the Company is further along the path of refining the model and has a better idea of how much time each run will take to do and analyze, we have been reluctant to commit to more than about 250 runs.

Fourth, you recommend proper treatment of alternative strategies across uncertain futures.

The Company believes that an examination of the 24 alternative strategy combinations across nine different futures will allow an adequate treatment of alternative strategies across uncertain futures. It is useful and important to compare strategies across different futures, to separate robust strategies from ones whose performance shows too much variation across futures.

The Company appreciates your comments and concerns. As you read the March 2 and March 26 versions of the study plan discussion paper, you can see the changes the Company has made in response to your letter and the concerns expressed by other parties:

Added an unconstrained strategy alternative
Expanded the DSR strategies to include ramp-up rates
Expanded the strategies from 18 to 24 for each future
Expanded the sensitivities based on external costs from 6 to 24

At the April 9 RAG meeting, we anticipate additional discussion of the study plan.

Sincerely,

Nancy Esteb

Nancy Esteb, Manager
Integrated Resource Planning

NE/ja

PP 4

PP 45

SOLAR
ENERGY
ASSOCIATION
of
OREGON

working for a sustainable energy future

Date: February 26, 1993

To: Nancy Esteb

From: Solar Energy Association of Oregon

Subject: RAMPP-3 Comments

After the last Advisory Group meeting, we believe it is important to provide a response on important issues.

(1) We are concerned by a statement that the integration model, since it optimizes assuming perfect knowledge of the future, will be unable to address planning under uncertainty. Yet this is the most important part of the planning process. We believe it is most important that the planning develop the risk-minimizing strategy given that the future is uncertain. This strategy may not necessarily be "optimal" under one specific scenario.

We do not support Pacific's intention of running hundreds of scenarios. We suggest a reasonable number would be 20-30. We stress that the analysis should quantify the impact of accelerated DSM given future uncertainty. We previously suggested that a number of random walk games should be considered. An alternative would be to assign probabilities to a set of futures and derive the expected value of a particular strategy across all the scenarios.

(2) Oregon PUC recently invited Shimon Auerbach to Portland to explain his concept of treating risk in the discount rate. Will Pacific try Mr. Auerbach's methodology?

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March 29, 1993

Melanie Proctor
Solar Energy Association of Oregon
027 SW Arthur Street
Portland, OR 97201

Re: SEAofO Letter dated February 26, 1993

Dear Melanie:

The SEAofO letter of February 26 expresses concern that the integration model will not add.ess uncertainty.
Response: We share your concern. In fact, that very concern led us to use the RIM model for RAMPP-2; that model allowed us to analyze resource planning when load forecasts change in the middle of the planning horizon. However, simultaneously solving a resource planning model recognizing uncertainty while using optimization is one of the most intractable problems facing modelers, for which there is not yet a practical solution. However, the approach we have proposed for RAMPP-3, whereby we use multiple scenarios to test alternative strategies does allow us to recognize uncertainty.

You stress that our analysis would quantify the impact of accelerated DSM given future uncertainty.
Response: The revised study plan distributed to the RAG participants on March 2 includes two accelerated DSR strategies in the strategy alternatives to be tested against multiple futures. One accelerated DSR strategy uses a higher cost effectiveness level. The other uses a higher ramp-up rate. We believe that these will allow us to examine the impact of accelerated DSR given future uncertainty.

Will Pacific try Dr. Awerbuch's methodology of treating risk in the discount rate?

Response: The Company has reviewed Dr. Awerbuch's work, and, like many in the field of least cost planning, finds it intriguing. However, we do not yet see a way to implement it. We invite parties to propose specific measurements of differential risk, and how those would be balanced with risk assessments for the entire portfolio of resources.

Thank you for your interest in the Company's RAMPP process.

Sincerely,

Nancy Esteb

Nancy Esteb, Manager
Integrated Resource Planning

NE/ja

DEPARTMENT OF NATURAL RESOURCES AND CONSERVATION

PP 49

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TO: RAMPP-3 Advisory Group (RAG)

FROM: John M. Goroski JMG

DATE: March 3, 1993

RE: Scenario-Based Multi-Attribute Tradeoff Analysis

INTRODUCTION

On several occasions I have stated that RAG should explicitly identify the multiple objectives and decision criteria of RAMPP-3. I firmly believe that this is an essential task in developing a usable action plan for PacifiCorp, as well as allowing relevant concerns of RAG members to be addressed. Further, identification of multiple objectives and decision criteria should be a primary task that precedes scenario development.

I recommend that RAG members reread the appendix of Stephen Connors' paper titled "Side-Stepping the Adder: Planning for Least-Social Cost Electric Service". Connors clearly states that Scenario-Based Multi-Attribute Tradeoff Analysis **begins** by identifying important issues (objectives) and by developing a set of attributes (decision criteria) with which to measure performance relative to those issues. Connors also states that concurrent with the description of issues and their attributes, multi-option strategies and related uncertainties are identified. It should be noted that the inverse is not true. Identifying multi-option strategies and uncertainties will not necessarily identify all relevant multiple objectives and decision criteria nor multi-option strategies for the matter.

MULTIPLE OBJECTIVES AND MULTI-ATTRIBUTE DECISION CRITERIA

The multiple objectives should include at a minimum owner concerns, customer concerns and societal concerns. The following is a list of possible multiple objectives.

Owner Concerns:

1. return on equity,
2. customer price and bill impacts,
3. total system costs,
4. market share (maintenance and expansion),
5. environmental regulatory and litigation risk,
6. debt equivalent equity.

Customer Concerns:

1. short-term rates,
2. short-term revenue requirements,
3. present-value of long-term revenue requirements,
4. service reliability.

Societal Concerns:

1. present value of long-term societal resource cost,
2. non-quantifiable environmental risk,
3. pollutant emissions.

Multi-attribute decision criteria can than be derived from the above objectives. These decision criteria would be either set limits or minimizing/maximizing functions. I strongly recommend that RAG discuss and explicitly identify the multiple objectives and decision criteria of RAMPP-3 before we precede to scenario development.

UNCERTAINTIES

As Connors stated, concurrent with the above identification process, future uncertainties become apparent. The following is a list of a obvious uncertainties.

1. load (non-discretionary growth and declines),
2. fuel (price variability, quantity reliability),
3. DSM (cost effectiveness and attainability),
4. water availability,
5. wholesale market price.

I recommend that concurrent with the above identification process that a more detailed list of future uncertainties be developed.

MULTI-OPTION STRATEGIES

Multi-option strategies are developed to satisfy the decision criteria of the multiple objectives. These strategies are evaluated across a range of future uncertainties to yield a set of scenarios. In determining strategies, Connors' statement is worth reiterating, "Scenario analysis is performed by the simulation of a given system, following each strategy, and for the combination of futures. The scenario analysis yields an attribute database with which strategies can be evaluated and compared. At this point better combinations of options may be identified, or various attributes and uncertainties may be added or dropped from the analysis." Therefore, I recommend that the development of multi-option strategies be an on-going process which evolves as scenarios are evaluated. Further, I recommend that RAG avoid the process of trying to predetermine constrained strategies.

SCENARIO DEVELOPMENT AND EVALUATION

I propose that the initial strategy to be evaluated be an unconstrained strategy. In other words, renewables and demand-side resources are not forced in, nor coal facilities forced out. At this point, if identified decision criteria are not satisfied under these scenarios, constrained strategies could be developed. These constrained strategies do not necessarily have to be analyzed against all of the potential futures. This would limit the number of constrained strategy scenarios that would have to be analyzed.

The following is a list of important future uncertainties in which to test the unconstrained strategy.

1. analyze 3 levels of non-discretionary (n.d.) load growth,
2. analyze 3 levels of fuel price,
3. analyze 2 levels of water availability.

Therefore in addressing PacifiCorp's concern about the number of computer runs that need to be made, the initial number of runs is 18. These initial scenario runs will establish a base case in which to develop and evaluate constrained strategies. In addition to constrained strategies, other future uncertainties may also be evaluated. This process would help limit the number of computer runs, while allowing RAG members the opportunity to develop and evaluate specific scenarios. The following is a list of possible constrained strategies and sensitivities that could be evaluated.

1. force in ?? levels of cost effective DSM,
2. force in ?? levels of coal resources,
3. force in ?? levels of renewable resources,
4. force in ?? levels of environmental cost adders,
5. force in ?? levels of pollutant emissions,
6. force in ?? levels of wholesale market revenue,
7. force in ?? levels of extreme fuel price,
8. force in ?? levels of extreme n.d. load growth.

I strongly recommend that RAG avoid predetermining the above constrained strategies. I have included these strategies in this discussion only to let RAG know the direction in which we should be heading.

ADDITIONAL SCENARIOS

RAMPP-3 should include an analysis that explicitly excludes acquired resources and discretionary loads not included in the RAMPP-2 process. Further, RAMPP-3 should analyze potential resources and discretionary loads which are not currently included in the planning process but are public knowledge. RAMPP-3 should also include an analysis that treats all current and proposed resources as discretionary resources. These analyses could use base case assumption to limit the number of computer runs. The three additional constrained strategies that should be evaluated are as follows:

1. force out levels of discretionary loads/resources between RAMPP-2 and RAMPP-3 processes,
2. force in levels of discretionary loads/resources not included in the RAMPP-3 process,
3. force in all current and proposed resources as discretionary resources.

I recommend that these additional scenarios be discussed by RAG. These additional scenarios are relevant in discussing PacifiCorp's mergers and acquisitions, and least cost planning objectives.

SUMMARY

I have made several recommendations to RAG throughout this paper. These recommendations primarily outline how RAG should precede in a scenario-based multi-attribute tradeoff process. These recommendations are as follows:

1) RAG must first discuss and explicitly identify the multiple objectives and decision criteria of RAMPP-3.

2) RAG must concurrently identify future uncertainties.

3) RAG must avoid predetermining constrained strategies.

4) In scenario development and evaluation, RAG must first evaluate an unconstrained strategy against future uncertainties.

5) RAG must discuss the inclusion or exclusion of discretionary loads and resources as additional scenarios.

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March 29, 1993

John Goroski
Department of Natural Resources and Conservation
State of Montana
1520 East Sixth Avenue
Helena, MT 596_0-2301

Re: Your letter of March 3, 1993

Dear John:

Thank you for your letter of March 3. You have five recommendations. I will address each.

RAG must first discuss and explicitly identify the multiple objectives and decision criteria of RAMPP-3.

At the special half-day RAG meeting scheduled for April 9, we will discuss the Company's objectives and decision criteria. The Company believes that IRP needs to balance the interests of the utility, the customer, and society. Therefore, the decision criteria that are used incorporate these concerns. The Company balances measures of utility cost, total resource cost, customer prices, and total societal costs.

RAG must concurrently identify future uncertainties.

The Company has identified the two primary uncertainties facing it in resource planning. They are load growth and gas prices. Therefore, five levels of load growth are being prepared, and three levels of gas prices. These create fifteen alternative futures. At the April 9 RAG meeting, we will discuss which of those fifteen futures should be used to test alternative strategies.

RAG must avoid predetermining constrained strategies.

The Company believes that it must test constrained strategies, such as limiting a resource plan to only one new coal plant, or requiring a resource plan to include the early renewable projects that are included in the Company's strategic goals. If RAMPP is to be useful to the Company, we must develop strategies which can be tested against alternative futures. The information gained from these analyses will enable the Company to evaluate the trade-offs from one strategy relative to another.

In scenario development and evaluation, RAG must first evaluate an unconstrained strategy against future uncertainties.

The March 1 version of the Company's MATO study plan draft includes an unconstrained strategy. It will be tested against multiple futures.

RAG must discuss the inclusion or exclusion of discretionary loads and resources as additional scenarios.

At the April 9 special RAG meeting, we will discuss alternative sensitivities. The March 1 version of the Company's MATO study plan draft includes several sensitivities. However, if the RAG group determines that additional ones are essential, they can possibly be added to the list.

Thank you for your continuing interest in the Company's RAMPP process.

Sincerely,

Nancy Esteb

Nancy Esteb, Manager
Integrated Resource Planning

NE/ja

PP 55

*** Internal Memo ***

Date: March 8, 1993

To: Nancy Esteb, PacifiCorp, Resource Planning
FAX 275-2878

From: Phil Carver, ODOE Lee Sparling, OPUC
if problems call: 378-4040

Subject: **Pacific's 1/18/93 Proposed Use of Environmental Adders**

As Phil stated in the January 29 meeting, Pacific's proposed use of environmental adders as a sensitivity does not meet with the requirements of the draft UM-424 order.

Use of Adders
The draft order requires that Pacific devise an optimal strategy treating each level of costs as if they were financial costs. As shown on page 6 and 7 of the 1/18/93 draft, Pacific would use the same base strategy of renewables, DSM and use of existing coal plants in its sensitivity runs for the six levels of adders. The result will not be different strategies for different CO2 costs, only different levels of cost.

Pacific instead needs to provide an optimal strategy for each level of adders. It should create various levels of DSM and combine the best one with the optimized supply side resource strategy for each level of adders. The DSM scenarios should go beyond simple cost-effective levels. Only HD does that now. Pacific should also run a scenario that optimizes operations of existing plant for each level of adders. This is done by changing fuel prices to incorporate the adders.

Futures
Pacific should reinstate the cheap renewable future (CR). This future is important to decisions about the timing and value of developing and supporting a market for renewables. In RAMP2 we established the need for a minimum level of renewable development. We need better definition of when this base level might need to quickly expand.

The CR future would also help estimate a potential benefits of delaying a coal plant. If renewable costs are falling, a coal plant might be the cheapest resource available but still not minimize total resource costs. A superior strategy might be to build a CT or purchase power while renewable costs fell. After a few years build base load renewables and use the CT or a capacity contract to meet peak.

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PP 5(

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March 29, 1993

Phil Carver
Oregon Department of Energy
625 Marion Street, N.E.
Salem, Oregon 97310

Lee Sparling
Public Utilities Commission of Oregon
Labor & Industries Building
350 Winter St. N.E., Rm 300
Salem, Oregon 97310-0335

Re: Your letter dated March 8, 1993

Dear Phil and Lee:

Thank you for your letter of March 8, regarding PacifiCorp's proposed use of environmental adders in its RAMPP-3 analysis.

You believe that to be consistent with the UM 424 draft order, the Company must develop an optimal strategy for each of the six levels of environmental cost adders specified in that draft order. The Company's March 2 draft of its MATO study plan identifies 18 sensitivity runs which will create resource plans for each of the six levels of adders under three alternative futures. The model would be allowed to select the optimal level of DSR and supply-side resources to meet resource needs under each level of adders. The adders will be treated as additions to fuel costs. Therefore, the Company believes that in RAMPP-3 the Company will be developing an optimal resource plan (and implicitly an optimal strategy) for each of the six levels of environmental cost adders specified in the UM 424 draft order.

You state that we should reinstate the cheap renewable future. The March 2 draft of the MATO study plan specifies a sensitivity to be done using the cheap renewable assumption. By treating the cheap renewable future as a sensitivity, the impact of cheap renewable prices on resource planning can be tested. At the April 9 special RAG meeting, this and other suggestions for changes to the proposed study plan can be discussed.

Thank you for your interest in the Company's RAMPP process.

Sincerely,

Nancy Esteb

Nancy Esteb, Manager
Integrated Resource Planning

NE/ja

Date: April 9, 1993

To: Nancy Esteb
Pacific Power

From: Melanie Proctor
Solar Energy Association of Oregon

Subject: Comments on PP&L Rag Proceedings

1. Criterion for LCP:

- SEA of O believes that there should be minimum societal cost consistent with OPUC order. PP&L must include environmental externalities cost using a range of adders. Zero is not the correct cost for CO2.

- If PP&L wants to consider rate impacts and emission tradeoffs, those are secondary objectives. Planning process must meet requirements for societal cost analysis first. Then we can consider additional time and resources to explore other concerns of PP&L.

- Analysis must include end effects properly.

2. Plan for scenarios:

- It is important to consider the benefits of an accelerated demand side programs. PP&L needs to include program scenarios with accelerated ramp up.

- We feel it is important to quantify the value of reduced risk from demand side programs. At a minimum, you must include some probability weighing of alternative futures.

- SEA of O feels that you must include recent coal plant acquisitions as supply side options -- not as part of PP&L's base resources. These plants have not yet been approved by regulators. PP&L needs to demonstrate that acquiring these plants is consistent with Least Cost principles, including environmental externalities.

- PP&L needs to include refurbishment of existing coal plants as supply side options -- not assumed to be part of future base resources. PP&L needs to demonstrate that continuation of these plants is consistent with economic dispatch including environmental externalities. Consider repowering with gas as an option to reduce emissions.

- Include rate options as possible demand side programs. PP&L is committed to consider inverted rates as part of the Montana agreement, as well as being ordered by OPUC and other state agencies. SEAO also recommends hookup fees for consideration. There are investigations looking at pricing issues however they will not consider the demand side impact. Thus, the LCP must include rate options from a resource perspective while the other proceedings work out details.

- Other demand side programs include fuel switching, which should be included in any analysis that looks at higher cost programs or high cost standards for CO2.

- There must be consideration of risk. SEAO suggests that PP&L utilize the method of multiple discount rates proposed by Shimon Auerbach. Under this approach, fuel cost would be discounted less and environmental cost would be discounted at a zero discount rate.

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PACIFICORP
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May 11, 1993

Melanie Proctor
Solar Energy Association of Oregon
027 SW Arthur Street
Portland, OR 97201

Re: SEAofO Letter dated April 9, 1993

Dear Melanie:

Your letter of April 9 provides comments in several areas of the Company's LCP process. I'll quote the comments in the order they are listed in your letter, and then address each.

Societal Cost and Environmental Adders:

SEAofO believes that there should be minimum <u>*societal*</u> *cost consistent with OPUC order. PP&L must include environmental externalities cost using a range of adders. Zero is not the correct cost for CO2.*

<u>Response</u>: The Company's March 26, 1993, version of its MATO study plan discussion identifies the six levels of environmental costs that will be used in the external cost sensitivities. The three values for CO2 that will be used are $10, $25, and $40, consistent with the OPUC's draft order on UM 424.

Societal Cost Primary:

If PP&L wants to consider rate impacts and emission tradeoffs, those are secondary objectives. Planning process must meet requirements for societal cost analysis first. Then we can consider additional time and resources to explore other concerns of PP&L.

<u>Response</u>: The Company believes that the RAMPP process and planning documents should meet both Commission and company objectives. Our understanding is that Commission objectives include a balancing of company, customer, and societal goals. The Company objectives include minimizing price impacts on our customers of future resource acquisitions, and minimizing future risks. We do not

believe that rate impacts are secondary objectives. Integrated resource planning involves a balancing of multiple objectives, including rate impacts, emission tradeoffs, and societal cost.

End Effects:

Analysis must include end effects properly.

Response: The analysis will include end effects.

Accelerated DSR:

It is important to consider the benefits of an accelerated demand side programs. PP&L needs to include program scenarios with accelerated ramp up.

Response: The Company's March 26, 1993, version of its MATO study plan discussion identifies four levels of DSR implementation that will be tested. Two of them include accelerated ramp rates.

Probability of Futures:

We feel it is important to quantify the value of reduced risk from demand side programs. At a minimum, you must include some probability weighing of alternative futures.

Response: Demand side programs reduce risk in some ways, and increase risk in other ways. They can reduce risk by delaying the need for supply-side resource additions; and they can be added in small increments. They can increase risk because the performance of many DSR measures and programs have not yet been adequately tested. Multiple futures, and a unique resource plan for each future, are used in RAMPP to prepare the Company for an uncertain future. The Company then examines those resource plans, and evaluates the commonalities and differences, to develop a two-year action plan. Implicitly some assumptions are made in that decision making, for example, the medium-low and medium-high load forecast results in RAMPP-2 were given more weight than the low and high load forecast results. The Company has not assigned precise probabilities to the alternative futures it has proposed, in RAMPP-1, RAMPP-2 or RAMMP-3 because we have not been persuaded that any of the methods available to do this will produce a result that would improve decision making better than the current method.

Acquisitions:

SEAofO feels that you must include recent coal plant acquisitions as supply side options -- not as part of PP&L's base resources. These plants have not yet been approved by regulators. PP&L needs to demonstrate that acquiring these *plants is consistent with Least Cost principles, including environmental externalities.*

Response: The appropriate forum for a complete evaluation of recent acquisitions' cost effectiveness and benefits to customers is in a rate case. The integrated resource plan provides a consistent framework against which specific actions or opportunities are compared. We describe this general view of the future and what we think our incremental resource costs are. We use that as a standard against which to compare opportunities such as the recent acquisitions, because we are in a dynamic decision making environment.

The RAMPP modeling process would not be an appropriate or reasonable "test" of these acquisitions. This is because those transactions are complex. For example, the Colorado-Ute transaction involved a couple generating units, transmission access, wholesale sales and a seasonal exchange. This is a much more complex decision than the decisions the model is designed to make, such as whether it is better to add a combined cycle combustion turbine or a wind plant in a specific year. The capacity expansion models used for least cost planning aren't intended to evaluate a complex transaction.

Regarding externalities, the model says nothing about how the existing resources acquired in an acquisition transaction would have been run had we not acquired them, and they certainly would have been run. We have no way of measuring how the system would have been dispatched, but we believe that our acquisition of those resources does not have an environmental impact, because those resources are going to be run no matter who owns them.

Refurbishment of Existing Plants:

PP&L needs to include refurbishment of existing coal plants as supply side options -- not assumed to be part of future base resources. PP&L needs to demonstrate that continuation of these plants is consistent with economic dispatch including environmental externalities. Consider repowering with gas as an option to reduce emissions.

Response: We are examining two categories of capital expenditures which the Company makes on the plants, to compare them to the cost of new resources. The first category is to refurbish the plants so that their existing capacity can be maintained. When we talk about the useful life for a power plant, it isn't a single large unit. A power plant actually represents a large number of different systems and components. Each component has a different useful life. Refurbishment and replacement of individual components occurs throughout the life of the plant. As we replace components, plants may produce and perform well at lives greater than the original estimated life. Some of the units that were built in the 50's are either approaching or are exceeding their original estimated life, but they are still performing. The second category is to increase the efficiency of an existing plant. These investments either improve reliability or remove bottlenecks that allow the effective capacity to increase. We will also examine the impact of externality costs on the cost effectiveness of both of these categories of capital expenditures on the plants.

Rate Design:

Include rate options as possible demand side programs. PP&L is committed to consider inverted rates as part of the Montana agreement, as well as being ordered by OPUC and other state agencies. SEAO also recommends hookup fees for consideration. There are investigations looking at pricing issues however they will not consider the demand side impact. Thus, the LCP must include rate options from a resource perspective while the other proceedings work out details.

Response: As we stated in our response to your January 1993 letter, one of the resource plan sensitivities will be a case with a reduce load growth level, such as might occur if tailblock rates were in effect, and/or hookup fees were in effect.

Fuel Switching:

Other demand side programs include fuel switching, which should be included in any analysis that looks at higher cost programs or high cost standards for CO2.

Response: As we stated in our response to your January 1993 letter, one of the sensitivities will be a case with a reduce load growth level, such as might occur if fuel switching were in effect.

Multiple Discount Rates:

There must be a consideration of risk. SEAO suggests that PP&L utilize the method of multiple discount rates proposed by Shimon Auerbach. Under this approach, fuel cost would be discounted less and environmental cost would be discounted at a zero discount rate.

Response: As we stated in our response to your February 1993 letter, the Company has reviewed Dr. Awerbuch's work, and, like many in the field of least cost planning, finds it intriguing. However, we do not yet see a way to implement it. We invite parties to propose specific measurements of differential risk, and how those would be balanced with risk assessments for the entire portfolio of resources.

Thank you for your continuing interest in the Company's integrated resource planning process.

Sincerely,

Nancy Esteb

Nancy Esteb, Manager
Integrated Resource Planning

NE/ja

cc: RAMPP Advisory Group

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PACIFICORP
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June 17, 1993

Dr. Phil Carver
Oregon Department of Energy
625 Marion Street, N.E.
Salem, Oregon 97310

Dear Phil:

At the RAG meeting on June 4 you requested information on the derivation of the carbon costs associated with our rural reforestation project in Southern Oregon. I have asked our consultant Dr. Mark Trexler, to prepare some background material on the assumptions used to calculate our carbon costs. Although you are quite familiar with "carbon forestry", I thought it would be useful to provide a brief background to put these calculations into context.

1. The goal of a carbon sequestration project is to change the otherwise prevailing amount of biomass in the system. In principle, potential activities could range from an educational campaign on the benefits of tree planting, to the purchasing and reforesting of agricultural land. Right now there are no standards for what constitutes a "quality" offset, so pilot efforts such as ours are attempting to explore a variety of options.

2. The Oregon project is premised on cost-sharing the cost of reforestation on private land. This is a much cheaper alternative to renting or purchasing the land outright, but does not necessarily result in any less biomass being grown on the land. As a result, we see it as a very cost-effective alternative to renting or purchasing land, which yields cost estimates in the range of \$15 - \$30/ton. There are some additional risks involved in cost-sharing with landowners, but the contract we have developed attempts to compensate for that risk to the degree possible.

3. There are different ways that carbon can be counted and valued even once you know the net accumulation rate. These methods have significant implications for the estimated cost of a carbon offset. For example, summing total carbon accumulation with no discounting leads to a much lower perceived cost per ton than discounting the carbon accumulation at 4%, in effect creating a Net Present Carbon Value. In the case of the Oregon project, \$/ton estimates vary from roughly \$2 - \$6/ton based on the accounting method used.

4. One of the most difficult questions involved in thinking about carbon offset projects is the "but for" question. In the case of our Oregon project, would those lands have been reforested anyway? We argue that given the limited nature of federal cost-sharing programs, the answer for practical purposes is no. Even if the acres we reforest would have ultimately qualified for cost share funds, this would simply mean that some other acreage would have gone without. Another part of the "but for" question relates to the potential indirect impacts of timber production. For example, some published work suggests that large scale tree planting for carbon sequestration in the U.S. would depress timber prices, and presumably result in the removal of some lands from tree production. These results are tentative and we have chosen not to include them in the analysis of our small scale pilot project.

The attached material from Mark Trexler further explains the details of our calculations. I appreciate your interest in our ongoing work to demonstrate low cost methods of offsetting CO_2 emissions. I will plan to keep you posted as we refine our analysis and as we set out to explore other offset arrangements. If you have any questions, do not hesitate to give me a call (ph 464-5773).

Sincerely,

Bill Edmonds

Bill Edmonds

cc: Tom Imeson -1600 POP
Attachment
BE/gk

Trexler & Associates

Developing Carbon Offset Strategies

1131 S.E. River Forest Road • Oak Grove, OR 97267 • U.S.A.
Phone: (503) 786-0559 • Fax (503) 786-9859
Internet: 75236.3411@compuserve.com

Domestic Reforestation Carbon Assessment
Description of a Model
June 16, 1993

Trexler and Associates has developed a spreadsheet based model of carbon offset quantification associated with domestic reforestation projects. This model is for use by PacifiCorp and other clients.

Basic Spreadsheet Purpose

The model is designed to estimate the carbon storage and cost of carbon for domestic forestry projects on a per acre basis. The model includes three sets of variables: biomass accumulation, soil carbon accumulation, and financing costs. The biomass and carbon figures interact to calculate total carbon storage per acre. This figure is then used to yield costs per ton of carbon offset. The model can be manipulated in a variety of ways to assess the carbon and cost implications of alternative assumptions regarding growth rates, project costs, project longevity, harvests, and product disposition.

Variables Considered

Biomass Accumulation:

- Growth data for the trees themselves: The model is set up to use values for the total cubic feet per acre at year 15, and every 10 years thereafter (25, 35, etc.) Data was supplied by the Oregon Dept. of Forestry for Douglas fir Class II, III, and IV sites.

- Harvests: At a designated year, a fraction of the merchantable wood can be harvested. The spreadsheet allows a portion of the harvested wood to be placed into long-term storage, thus continuing the offset.

Carbon Accumulation:

Carbon is divided into three categories: carbon stored in merchantable wood, carbon stored in non-merchantable wood, and other carbon, which includes leaves, stems, underbrush, and soils. There are five variables used to calculate carbon accumulation and loss per year:

- Carbon in biomass: Metric tons of carbon per cubic foot of wood for the species under consideration. For Douglas fir this equals 0.00682, based on the work of Richard Birdsey from the USDA Forest Service.

- Wood/Stemwood Ratio: this number is used to calculate the amount of wood in stems, leaves, etc. that is not classed as merchantable or non-merchantable wood. This number is used when figuring the total amount of carbon stored in non-merchantable wood. This value is 0.58 for Douglas fir, also based on the research of Richard Birdsey.

- Biomass Multiplier: This is the ratio used to calculate the amount of additional carbon is stored in the acre beyond what is just in the tree, such as carbon in soils and underbrush. This number changes every 10 years, and is again based on the work of Richard Birdsey.

- Merchantable Harvest Loss: This is the percentage of carbon stored in merchantable wood which is released shortly after a harvest, and thus does not continue to be sequestered. We have used a figure of 10%, since Douglas Fir is historically used quite efficiently for long-term building and other materials.

- Non-Merchantable Harvest Loss: The percentage of non-merchantable carbon, including carbon stored in non-merchantable wood, which is lost during the harvest process and eventually oxidizes. This is estimated at 75% in the spreadsheet.

Financial Calculations

- Expenses. These include potential expenses related to site preparation, planting, vegetation control, animal control, thinning, rent and other miscellaneous expenditures. Total costs for the PacifiCorp program are preliminary estimated at \$364/acre. This includes \$60 in site preparation, \$180 in planting costs, \$55 for vegetation control, and \$69 for animal control. The choice of low-cost reforestation opportunities may reduce this figure.

- Cost shares: the percentage of each category paid by PacifiCorp. Under the current cost share program, if a landowner maintains the trees for 45 years, Pacificorp pays 75% of the planting and vegetation control costs for a total of \$273/acre. If a landowner agrees to keep the trees for 65 years, then PacifiCorp pays the full estimated \$364/acre. In both cases, the landowner assumes

$$C_i = C_{merch} + C_{non_{merch}} + C_{other} - C_{harvest}$$

The total carbon can be calculated by summing each year's net carbon. Under a zero discount rate, this number can then simply be divided into the cost per acre of PacifiCorp's participation in the project. This yields a result of just under $2.00/ton of carbon. Because it can be argued that carbon accumulation should be subject to economic discounting, and that 0% is not an appropriate discount rate, the spreadsheet also is able to discount annual carbon benefit as it accrues. This discounted carbon stream can then be totalled and divided by upfront costs. At a 4% discount rate this yields a per ton cost of $5-6/ton for a 45-65 year projects in which PacifiCorp is paying 75-100% of reforestation costs.

As previously stated, the pilot projects currently being engaged in by PacifiCorp are clearly at the very bottom of the supply curve for such projects domestically. It is unknown how steeply this carbon supply curve should be expected to rise as the demand for carbon offsets increases or is institutionalized through national policy. However, PacifiCorp's participation in these pilot efforts will certainly give it a competitive advantage in moving quickly to take advantage of the most cost-effective projects when the time comes.

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STATE OF WASHINGTON

WASHINGTON STATE ENERGY OFFICE

925 Plum St. SE, Town Square Bldg #4 • PO Box 43165 • Olympia, Washington 98504-3165

July 15, 1993

Ms. Nancy Esteb
Manager, Integrated Resource Planning
Pacificorp
920 S.W. Sixth Avenue
Portland, OR 97204-1256

Subject: Aaberg Memo on Discount Rate Sensitivities

Dear Ms. Esteb:

We understand that Chris Aaberg recently provided corrected values for generic demand side management (DSM) resource costs that were originally attached to his memo, dated May 21. As we understand it, the original gross levelized cost values shown on the table for the 5.2 percent and 3.0 percent discount rate cases reflected levelization periods of 45 years, not 15 years as indicated. As a consequence, the $/MWh costs of the DSM resources increased by about 30 percent.

Apparently, this comparison was performed so as to demonstrate the "true" relative cost-effectiveness of DSM versus coal- and natural gas-fired generation. However, *direct present value comparisons between resources with different lifetimes are invalid.* One cannot directly compare a 15 year resource and a 45 year resource. What we would recommend is that Pacific "repeat" the shorter lived resource until multiple investments in DSM (in this case three) yield an equivalent lifetime. The values that were presented in the memo, and subsequently at the June 4 meeting, do not correctly reflect DSM cost-effectiveness.

We are also concerned about the argument that using a low discount rate would move forward capital intensive projects and result in price increases that move Pacificorp away from its strategic goal of being a low cost supplier. While the first part of this statement is indisputable, there are two fundamental problems with the argument and its implications.

In our view, the strategic goal of being a low-cost supplier is potentially incompatible with least cost planning. The central purpose of the IRP process is to examine alternative system costs over an *entire* planning horizon and invest in resources that yield the lowest present value cost. It gives us great concern to see resources that yield lower present value costs discarded because they may have higher capital requirements or increase short term rates.

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The second problem with the argument is Pacificorp's flawed cost methodology that includes income tax payments in resource costs streams and then discounts those cost streams at after tax rates. It is methodologically inconsistent, as much so as comparing resources with different lifetimes.

Taken together, the combination of a flawed methodology and a shifting optimization is greatly troubling. It implies that the company might defer needed system maintenance, reduce system reliability, and adopt other short-term cost saving measures at the expense of long-term societal and customer benefits. If this is not the case, RAG (Resource Advisory Group) should be so informed. This is also the case if the approach is only being applied to DSM or other capital intensive resources.

Pacificorp may indeed have capital constraints, and legitimate rate issues should be addressed. However, these issues should be dealt with in the IRP process openly, rather than through methodological fixes or plans with multiple countervailing objectives. All of Pacificorp's customers can conceivably benefit if the company is able to secure energy resources that have a lower present value cost. The test for the IRP or other collaborative processes is to ensure that costs for such resources are *allocated* among different customers in such a way that they all benefit.

We look forward to discussing these issues in more detail at our next meeting.

Sincerely,

Jonathan A. Lesser, Ph.D.
Senior Economist

JAL/ay
O-L2-41W

cc: RAG group
Judith Merchant
Jim Harding

PP 75

PACIFICORP
PACIFIC POWER UTAH POWER

August 17, 1993

Mr. Jonathan A. Lesser, Ph.D.
Senior Economist
Washington State Energy Office
925 Plum St. SE, Town Square Bldg. #4
P.O. Box 43165
Olympia, WA 98504-3165

Dear Jonathan:

We have received a copy of your July 15, 1993, letter to Nancy Esteb regarding discount rates.

First, let me address the issue you raised regarding comparing a project with a 45-year life to a project with a 15-year life. As I stated in my cover letter to that analysis, the purpose of my calculations was only to show the impact of changing discount rates and tax assumptions on various types of resource options, which was what we understood you had requested. It was not to compare alternative resources against each other. We have performed some subsequent calculations, however, to address the concerns expressed in your July 15 letter.

You are absolutely right in saying that a 15-year versus a 45-year comparison is invalid, but it is invalid only if you are comparing nominal levelized revenue requirements. The purpose of using real levelized numbers is that the projects are put on an comparative basis regardless of the length of the projects. In order to demonstrate this, we ran the scenario you suggested. We repeated the investment in the 15-year life project three times (every 15 years) to yield the equivalent 45-year life. While the nominal levelized revenue requirement increased, the real levelized revenue actually decreased slightly for both the 5.2 percent and the 3.0 percent cases. We have attached a summary which now includes the case you suggested.

Regarding your concern with using after-tax rates to discount what you feel are pre-tax cost streams, let me reiterate that taxes are the same as fuel or any other operating expense. That is, they are collected from the customer and then paid out by the company. They are simply a pass-through. We have tried to demonstrate this in the RAMPP process through our models and by providing articles which detail the mathematics behind the process. We feel that we are using the correct methodology by using the after-tax discount rate in calculating our levelized revenue requirements.

Your letter also states that "In our view, the strategic goal of being a low-cost supplier is potentially incompatible with least cost planning." It appears that you believe that the company would reject a resource simply because it had higher capital requirements and thus increased short term prices. A response needs to address two areas: how does the RAMPP-3 model make resource selections, and how does the company make resource decisions. The model being used for RAMPP-3 selects resources based on the present value of the costs over the 20-year planning horizon, and even longer, because it also considers end effects for another 30 years. The company takes the information provided by the model for multiple futures and strategies, and develops an action plan for the next two years. In developing that action plan, the company examines cost consequences for both the short term and the long term. The degree to which those two are balanced depends on the degree of cost consequences. For example, if a particular resource choice had very high short term costs, but substantial long term savings, it would be a very attractive resource. However, if a particular resource choice had very high short term costs, without substantial long term savings, it would not be considered attractive. The company views its low-cost producer strategy as a long-term strategy, not just for the next quarter or the next year.

You indicate concern that the company would ". . . defer needed system maintenance, reduce system reliability, and adopt other short-term cost saving measures at the expense of long-term societal and customer benefits." The company's low-cost producer strategy results in great attention to system maintenance. It is much less expensive in the long run to maintain existing facilities than to allow them to deteriorate and have to spend a great deal later to replace them. As you can see in Mr. Gleason's July 28, 2993, response to the Washington Commission's letter acknowledging RAMPP-2, the company views ongoing maintenance and refurbishment as a critical part of its overall strategy.

We understand that you are leaving Washington to accept a new position in Vermont. We wish you much success in your new endeavors.

Sincerely,

Chris Aaberg, Director
Financial Planning & Analysis

Attachments

cc: RAMPP Advisory Group

GROSS LEVELIZED COST 1/
($/MWh)

	5.2% REAL DISCOUNT RATE		3.0% REAL SOCIETAL DISCOUNT RATE		CHANGE IN REAL	% CHANGE
	NOMINAL	REAL	NOMINAL	REAL		
45–YEAR PROJECT LIFE 20–YEAR TAX LIFE 100 MW $1500/KW 80% LOAD FACTOR FUEL $10/MWh O&M = 5% OF GROSS PLANT	$55.72	$37.20	$54.51	$33.28	($3.92)	–10.5%
45–YEAR PROJECT LIFE 20–YEAR TAX LIFE 100 MW $500/KW 80% LOAD FACTOR FUEL $20/MWh O&M = 5% OF GROSS PLANT	$43.54	$29.06	$45.47	$27.76	($1.30)	–4.5%
15–YEAR GENERIC RESOURCE 7–YEAR TAX LIFE 100 MW $3300/KW 70% LOAD FACTOR FUEL = 0 O&M = 0	$70.96	$58.53	$68.28	$55.60	($2.93)	–5.0%
45–YEAR GENERIC RESOURCE (3 CONSECUTIVE 15–YEAR PROJECTS) 7–YEAR TAX LIFE ON EACH 100 MW $3300/KW, IST PROJECT 2/ 70% LOAD FACTOR FUEL = 0 O&M = 0	$85.75	$57.23	$89.16	$54.43	($2.80)	–4.9%

1/ IGNORES TAXES IN THE 3% CASES
2/ CAPITAL COSTS ARE ESCALATED AT INFLATION TO 2009 AND 2024 FOR 2ND & 3RD PROJECTS.

DISCOUNT RATE = 8.8%

GEN'RIC RESOURCE

ASSUMPTIONS		
IN SERVICE DATE		1994
TOTAL CAPACITY (MW)		100
CAPACITY FACTOR		70.0%
ANNUAL GENERATION		613,200
CAPITAL COST $/KW		3,300
CAPITAL INVESTMENT		330,000
INFLATION		3.4%
O&M (% OF GROSS PLANT)	0.0%	0.0
FUEL	1.0	0.0
DEPRECIABLE LIFETIME		15
TAX LIFE		7
TAX RATE		38.91%
INTEREST RATE		8.99%
DISCOUNT RATE		8.80%
REAL DISCOUNT RATE		5.23%
RETURN ON RATE BASE		10.43%
LEVELIZED PAYMENT YEARS		15

	COST OF CAPITAL		
	CAPITAL STRUCTURE	COST	WEIGHTED COST
DEBT	49.0%	8.99%	4.41%
PREFERRED	6.0%	8.93%	0.54%
C. EQUITY	45.0%	12.20%	5.49%
TOTAL	100.00%		10.43%

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DEPRECIATION		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
BEGINNING BOOK VALUE		330,000	308,000	286,000	264,000	242,000	220,000	198,000	176,000	154,000	132,000	110,000	88,000	66,000	44,000	22,000	544,907	508,579	472,252
BOOK DEPRECIATION		22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	36,327	36,327	36,327
ACCUMULATED BOOK DEPRECIATION		22,000	44,000	66,000	88,000	110,000	132,000	154,000	176,000	198,000	220,000	242,000	264,000	286,000	308,000	330,000	36,327	72,654	108,981
ENDING BOOK VALUE		308,000	286,000	264,000	242,000	220,000	198,000	176,000	154,000	132,000	110,000	88,000	66,000	44,000	22,000	0	508,579	472,252	435,925

TAX DEPRECIATION		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
7 YEAR MACRES		20.00%	32.00%	19.20%	11.52%	11.52%	5.76%										20.00%	32.00%	19.20%
NEW PLANT	330,000	(66,000)	(105,600)	(63,360)	(38,016)	(38,016)	(19,008)	0	0	0	0	0	0	0	0	0	(108,981)	(174,370)	(104,622)
TOTAL TAX DEPRECIATION		(66,000)	(105,600)	(63,360)	(38,016)	(38,016)	(19,008)	0	0	0	0	0	0	0	0	0	(108,981)	(174,370)	(104,622)
BOOK DEPRECIATION		22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	36,327	36,327	36,327
INCREASE/(DECREASE) IN TAXABLE INCOME		(44,000)	(83,600)	(41,360)	(16,016)	(16,016)	2,992	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	(72,654)	(138,043)	(68,295)
DEFERRED TAXES		(16,240)	(30,857)	(15,266)	(5,912)	(5,912)	1,104	8,120	8,120	8,120	8,120	8,120	8,120	8,120	8,120	8,120	(26,817)	(50,952)	(25,208)
CUMULATIVE DEFERRED TAXES		(16,240)	(47,097)	(62,363)	(68,275)	(74,186)	(73,082)	(64,962)	(56,841)	(48,721)	(40,601)	(32,481)	(24,361)	(16,240)	(8,120)	(0)	(26,817)	(77,768)	(102,976)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
435,925	399,598	363,271	326,944	290,617	254,290	217,963	181,636	145,308	108,981	72,654	36,327	899,767	839,783	779,798	719,814	659,829	599,845	539,860	479,876	419,891	359,907	299,922	239,938	179,953	119,969	59,984
36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984
145,308	181,636	217,963	254,290	290,617	326,944	363,271	399,598	435,925	472,252	508,579	544,907	59,984	119,969	179,953	239,938	299,922	359,907	419,891	479,876	539,860	599,845	659,829	719,814	779,798	839,783	899,767
399,598	363,271	326,944	290,617	254,290	217,963	181,636	145,308	108,981	72,654	36,327	0	839,783	779,798	719,814	659,829	599,845	539,860	479,876	419,891	359,907	299,922	239,938	179,953	119,969	59,984	(0)

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
11.52%	11.52%	5.76%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	20.00%	32.00%	19.20%	11.52%	11.52%	5.76%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(62,773)	(62,773)	(31,387)										(179,953)	(167,957)	(155,960)	(143,963)	(131,966)	(119,969)									

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
(62,773)	(62,773)	(31,387)	0	0	0	0	0	0	0	0	0	(179,953)	(167,957)	(155,960)	(143,963)	(131,966)	(119,969)	0	0	0	0	0	0	0	0	0
36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984
(26,446)	(26,446)	4,940	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	(119,969)	(107,972)	(95,976)	(83,979)	(71,981)	(59,984)	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984
(9,761)	(9,761)	1,824	13,408	13,408	13,408	13,408	13,408	13,408	13,408	13,408	13,408	(44,281)	(39,852)	(35,424)	(30,996)	(26,568)	(22,140)	22,140	22,140	22,140	22,140	22,140	22,140	22,140	22,140	22,140
(112,737)	(122,498)	(120,675)	(107,267)	(93,858)	(80,450)	(67,042)	(53,633)	(40,225)	(26,817)	(13,408)	0	(44,281)	(84,133)	(119,557)	(150,554)	(177,122)	(199,262)	(177,122)	(154,982)	(132,842)	(110,701)	(88,561)	(66,421)	(44,281)	(22,140)	0

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RATE BASE				1/1/94	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
UTILITY PLANT				330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	544,907	544,907	544,907
ACCUMULATED DEPRECIATION					(22,000)	(44,000)	(66,000)	(88,000)	(110,000)	(132,000)	(154,000)	(176,000)	(198,000)	(220,000)	(242,000)	(264,000)	(286,000)	(308,000)	(330,000)	(36,327)	(72,654)	(108,981)
ACCUM DEF INCOME TAXES					(16,240)	(47,097)	(62,363)	(68,275)	(74,186)	(73,082)	(64,962)	(56,841)	(48,721)	(40,601)	(32,481)	(24,361)	(16,240)	(8,120)	(0)	(26,817)	(77,769)	(102,976)
TOTAL RATE BASE				330,000	291,760	238,903	201,637	173,725	145,814	124,918	111,038	97,159	83,279	69,399	55,519	41,639	27,760	13,880	(0)	481,763	394,484	332,949
AVERAGE					310,880	265,331	220,270	187,681	159,770	135,366	117,978	104,099	90,219	76,339	62,459	48,579	34,700	20,820	6,940	240,881	438,123	363,717
ALLOWED RETURN ON AVERAGE RATE BASE		10.43%			32,426	27,676	22,976	19,577	16,665	14,120	12,306	10,858	9,411	7,963	6,515	5,067	3,619	2,172	724	25,126	45,700	37,938
COMMON AND PREFERRED PORTION	6.026%																					
REVENUES					65,387	59,030	52,741	48,193	44,298	40,892	38,465	36,528	34,591	32,654	30,717	28,780	26,843	24,906	22,969	69,945	97,473	87,086
LESS OPERATING EXPENSES					(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(36,327)	(36,327)	(36,327)
LESS TAXES	3.53%				(10,959)	(9,354)	(7,765)	(6,616)	(5,632)	(4,772)	(4,159)	(3,670)	(3,180)	(2,691)	(2,202)	(1,713)	(1,223)	(734)	(245)	(8,492)	(15,446)	(12,822)
NET RETURN ON RATE BASE					32,426	27,676	22,976	19,577	16,665	14,120	12,306	10,858	9,411	7,963	6,515	5,067	3,619	2,172	724	25,126	45,700	37,938
LEVELIZED REVENUE REQUIREMENT																						
RATE BASE					310,880	265,331	220,270	187,681	159,770	135,366	117,978	104,099	90,219	76,339	62,459	48,579	34,700	20,820	6,940	240,881	438,123	363,717
RETURN ON RATE BASE					32,426	27,676	22,976	19,577	16,665	14,120	12,306	10,858	9,411	7,963	6,515	5,067	3,619	2,172	724	25,126	45,700	37,938
ADD OPERATING EXPENSES:																						
O&M					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FUEL					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BOOK DEPRECIATION					22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	36,327	36,327	36,327
TAXES					10,959	9,354	7,765	6,616	5,632	4,772	4,159	3,670	3,180	2,691	2,202	1,713	1,223	734	245	8,492	15,446	12,822
REVENUE REQUIREMENT	DISCOUNT RATE:	8.80%	NPV	583,764	65,387	59,030	52,741	48,193	44,298	40,892	38,465	36,528	34,591	32,654	30,717	28,780	26,843	24,906	22,969	69,945	97,473	87,086
TOTAL MWH	DISCOUNT RATE:	8.80%	NPV	6,808,043	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200
NOMINAL GROSS LEVELIZED				85.75																		
REAL LEVELIZED:	REAL DISCOUNT RATE:	5.23%																				
REAL PMT OF REVENUES			33,942	583,764	35,096	36,290	37,523	38,799	40,118	41,482	42,893	44,351	45,859	47,418	49,031	50,698	52,421	54,204	56,047	57,952	59,923	61,960
REAL NPV OF MWH			10,546,287																			
REAL PMT OF NPV OF MWH			613,200	10,546,287	634,049	655,606	677,897	700,946	724,778	749,420	774,900	801,247	828,489	856,658	885,784	915,901	947,042	979,241	1,012,535	1,046,962	1,082,558	1,119,365
REAL GROSS LEVELIZED REVENUE REQUIREMENT			57.23	583,764	35,096	36,290	37,523	38,799	40,118	41,482	42,893	44,351	45,859	47,418	49,031	50,698	52,421	54,204	56,047	57,952	59,923	61,960

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2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
544,907	544,907	544,907	544,907	544,907	544,907	544,907	544,907	544,907	544,907	544,907	544,907	899,767	899,767
(145,309)	(181,636)	(217,963)	(254,290)	(290,617)	(326,944)	(363,271)	(399,598)	(435,925)	(472,252)	(508,579)	(544,907)	(59,984)	(119,969)
(112,737)	(122,499)	(120,675)	(107,267)	(93,858)	(80,450)	(67,042)	(53,633)	(40,225)	(26,817)	(13,408)	0	(44,281)	(84,133)
286,861	240,772	206,269	183,350	160,431	137,513	114,594	91,675	68,758	45,838	22,919	0	795,502	695,665
309,905	263,817	223,521	194,810	171,891	148,972	126,053	103,134	80,216	57,297	34,378	11,459	397,751	745,584
32,328	27,518	23,315	20,320	17,930	15,539	13,148	10,758	8,367	5,977	3,586	1,195	41,489	77,771
79,578	73,146	67,522	63,515	60,317	57,118	53,919	50,721	47,522	44,324	41,125	37,926	115,495	164,040
(36,327)	(36,327)	(36,327)	(36,327)	(36,327)	(36,327)	(36,327)	(36,327)	(36,327)	(36,327)	(36,327)	(36,327)	(59,984)	(59,984)
(10,926)	(9,300)	(7,880)	(6,868)	(6,060)	(5,252)	(4,444)	(3,636)	(2,828)	(2,020)	(1,212)	(404)	(14,022)	(26,284)
32,328	27,518	23,315	20,320	17,930	15,539	13,148	10,758	8,367	5,977	3,586	1,195	41,489	77,771
309,905	263,817	223,521	194,810	171,891	148,972	126,053	103,134	80,216	57,297	34,378	11,459	397,751	745,584
32,328	27,518	23,315	20,320	17,930	15,539	13,148	10,758	8,367	5,977	3,586	1,195	41,489	77,771
0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0
36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	59,984	59,984
10,926	9,300	7,880	6,868	6,060	5,252	4,444	3,636	2,828	2,020	1,212	404	14,022	26,284
79,578	73,146	67,522	63,515	60,317	57,118	53,919	50,721	47,522	44,324	41,125	37,926	115,495	164,040
613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200
64,067	66,245	68,497	70,826	73,234	75,724	78,299	80,961	83,714	86,560	89,503	92,546	95,692	98,946
1,157,424	1,196,776	1,237,467	1,279,540	1,323,045	1,368,029	1,414,541	1,462,636	1,512,365	1,563,788	1,616,954	1,671,931	1,728,776	1,787,555
64,067	66,245	68,497	70,826	73,234	75,724	78,299	80,961	83,714	86,560	89,503	92,546	95,692	98,946

2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
899,767	899,767	899,767	899,767	899,767	899,767	899,767	899,767	899,767	899,767	899,767	899,767	899,767
(179,953)	(239,938)	(299,922)	(359,907)	(419,891)	(479,876)	(539,860)	(599,845)	(659,829)	(719,814)	(779,798)	(839,783)	(899,767)
(119,557)	(150,554)	(177,122)	(199,262)	(177,122)	(154,982)	(132,842)	(110,701)	(88,561)	(66,421)	(44,281)	(22,140)	0
600,258	509,275	422,723	340,598	302,754	264,909	227,065	189,221	151,377	113,533	75,688	37,844	(0)
647,981	554,766	465,999	381,660	321,676	283,832	245,987	208,143	170,299	132,455	94,611	56,766	18,922
67,588	57,867	48,608	39,811	33,554	29,606	25,658	21,711	17,764	13,816	9,869	5,921	1,974
150,415	137,409	125,020	113,250	104,878	99,597	94,316	89,033	83,752	78,470	73,189	67,907	62,626
(59,984)	(59,984)	(59,984)	(59,984)	(59,984)	(59,984)	(59,984)	(59,984)	(59,984)	(59,984)	(59,984)	(59,984)	(59,984)
(22,843)	(19,557)	(16,428)	(13,455)	(11,340)	(10,006)	(8,672)	(7,338)	(6,004)	(4,669)	(3,335)	(2,001)	(667)
67,588	57,867	48,608	39,811	33,554	29,606	25,658	21,711	17,764	13,816	9,869	5,921	1,974
647,981	554,766	465,999	381,660	321,676	283,832	245,987	208,143	170,299	132,455	94,611	56,766	18,922
67,588	57,867	48,608	39,811	33,554	29,606	25,658	21,711	17,764	13,816	9,869	5,921	1,974
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984
22,843	19,557	16,428	13,456	11,340	10,006	8,672	7,338	6,004	4,669	3,335	2,001	667
150,415	137,409	125,020	113,250	104,878	99,597	94,316	89,033	83,752	78,470	73,189	67,907	62,626
613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200
102,310	105,789	109,386	113,105	116,950	120,926	125,038	129,289	133,685	138,230	142,930	147,790	152,815
1,848,332	1,911,175	1,976,155	2,043,344	2,112,818	2,184,654	2,258,932	2,335,736	2,415,151	2,497,268	2,582,173	2,669,967	2,760,746
102,310	105,789	109,386	113,105	116,950	120,926	125,038	129,289	133,685	138,230	142,930	147,790	152,815

PP 83

SOCIETAL DISCOUNT RATE = 6.5%

ASSUMPTIONS		
IN SERVICE DATE		1994
TOTAL CAPACITY (MW)		100
CAPACITY FACTOR		70.0%
ANNUAL GENERATION		613,200
CAPITAL COST $/KW		3,300
CAPITAL INVESTMENT		330,000
INFLATION		3.4%
O&M	0.0%	0.0
FUEL	1.0	0.0
DEPRECIABLE LIFETIME		15
TAX LIFE		7
TAX RATE		38.91%
INTEREST RATE		8.99%
DISCOUNT RATE		6.50%
REAL DISCOUNT RATE		3.00%
RETURN ON RATE BASE		10.43%
LEVELIZED PAYMENT YEARS		15

COST OF CAPITAL

	CAPITAL STRUCTURE	COST	WEIGHTED COST
DEBT	49.0%	8.99%	4.41%
PREFERRED	6.0%	8.93%	0.54%
C. EQUITY	45.0%	12.20%	5.49%
TOTAL	100.00%		10.43%

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
DEPRECIATION																		
BEGINNING BOOK VALUE	330,000	308,000	286,000	264,000	242,000	220,000	198,000	176,000	154,000	132,000	110,000	88,000	66,000	44,000	22,000	544,907	508,579	472,252
BOOK DEPRECIATION	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	36,327	36,327	36,327
ACCUMULATED BOOK DEPRECIATION	22,000	44,000	66,000	88,000	110,000	132,000	154,000	176,000	198,000	220,000	242,000	264,000	286,000	308,000	330,000	36,327	72,654	108,981
ENDING BOOK VALUE	308,000	286,000	264,000	242,000	220,000	198,000	176,000	154,000	132,000	110,000	88,000	66,000	44,000	22,000	0	508,579	472,252	435,925

		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
TAX DEPRECIATION																			
20 YEAR MACRES		20.00%	32.00%	19.20%	11.52%	11.52%	5.76%	0.00%	0.00%										
NEW PLANT	0	0	0	0	0	0	0	0	0	0	0	0							
TOTAL TAX DEPRECIATION		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BOOK DEPRECIATION		22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	36,327	36,327	36,327
INCREASE/(DECREASE) IN TAXABLE INCOME		22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	36,327	36,327	36,327
DEFERRED TAXES		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CUMULATIVE DEFERRED TAXES		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

PP 85

2012	2013	2014	2015	2016	2017	2018	2019	2020
435,925	399,598	363,271	326,944	290,617	254,290	217,963	181,636	145,308
36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327
145,308	181,635	217,963	254,290	290,617	326,944	363,271	399,598	435,925
399,598	363,271	326,944	290,617	254,290	217,963	181,636	145,308	108,981

2021	2022	2023	2024	2025	2026	2027	2028	2029
108,981	72,654	36,327	899,767	839,783	779,798	719,814	659,829	599,845
36,327	36,327	36,327	59,984	59,984	59,984	59,984	59,984	59,984
472,252	508,579	544,907	59,984	119,969	179,953	239,938	299,922	359,907
72,654	36,327	0	839,783	779,798	719,814	659,829	599,845	539,860

2030	2031	2032	2033	2034	2035	2036	2037	2038
539,860	479,876	419,891	359,907	299,922	239,938	179,953	119,969	59,984
59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984
419,891	479,876	539,860	599,845	659,829	719,814	779,798	839,783	899,767
479,876	419,891	359,907	299,922	239,938	179,953	119,969	59,984	(0)

2012	2013	2014	2015	2016	2017	2018	2019	2020
0	0	0	0	0	0	0	0	0
36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327
36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327
0	0	0	0	0	0	0	0	- 0
0	0	0	0	0	0	0	0	0

2021	2022	2023	2024	2025	2026	2027	2028	2029
0	0	0	0	0	0	0	0	0
36,327	36,327	36,327	59,984	59,984	59,984	59,984	59,984	59,984
36,327	36,327	36,327	59,984	59,984	59,984	59,984	59,984	59,984
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0

2030	2031	2032	2033	2034	2035	2036	2037	2038
0	0	0	0	0	0	0	0	0
59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984
59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0

					1/1/94	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
RATE BASE																							
UTILITY PLANT					330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	544,907	544,907	544,907
ACCUMULATED DEPRECIATION						(22,000)	(44,000)	(66,000)	(88,000)	(110,000)	(132,000)	(154,000)	(176,000)	(198,000)	(220,000)	(242,000)	(264,000)	(286,000)	(308,000)	(330,000)	(36,327)	(72,654)	(108,981)
ACCUM DEF INCOME TAXES						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL RATE BASE					330,000	308,000	286,000	264,000	242,000	220,000	198,000	176,000	154,000	132,000	110,000	88,000	66,000	44,000	22,000	0	508,580	472,253	435,926
AVERAGE						319,000	297,000	275,000	253,000	231,000	209,000	187,000	165,000	143,000	121,000	99,000	77,000	55,000	33,000	11,000	254,290	490,416	454,089
ALLOWED RETURN ON AVERAGE RATE BASE		10.43%				33,275	30,980	28,685	26,390	24,095	21,801	19,506	17,211	14,916	12,621	10,327	8,032	5,737	3,442	1,147	26,525	51,155	47,366
COMMON AND PREFERRED PORTION	8.026%																						
REVENUES						55,275	52,980	50,685	48,390	46,095	43,801	41,506	39,211	36,916	34,621	32,327	30,032	27,737	25,442	23,147	62,852	87,482	83,693
LESS OPERATING EXPENSES						(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(22,000)	(36,327)	(36,327)	(36,327)
LESS TAXES	0.00%					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NET RETURN ON RATE BASE						33,275	30,980	28,685	26,390	24,095	21,801	19,506	17,211	14,916	12,621	10,327	8,032	5,737	3,442	1,147	26,525	51,155	47,366
LEVELIZED REVENUE REQUIREMENT																							
RATE BASE						319,000	297,000	275,000	253,000	231,000	209,000	187,000	165,000	143,000	121,000	99,000	77,000	55,000	33,000	11,000	254,290	490,416	454,089
RETURN ON RATE BASE						33,275	30,980	28,685	26,390	24,095	21,801	19,506	17,211	14,916	12,621	10,327	8,032	5,737	3,442	1,147	26,525	51,155	47,366
ADD OPERATING EXPENSES:																							
O&M						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FUEL						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BOOK DEPRECIATION						22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	36,327	36,327	36,327
TAXES						0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
REVENUE REQUIREMENT	DISCOUNT RATE:	6.50%	NPV		791,687	55,275	52,980	50,685	48,390	46,095	43,801	41,506	39,211	36,916	34,621	32,327	30,032	27,737	25,442	23,147	62,852	87,482	83,693
TOTAL MWH	DISCOUNT RATE:	6.50%	NPV		8,879,276	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200
NOMINAL GROSS LEVELIZED					89.18																		
REAL LEVELIZED:	REAL DISCOUNT RATE:	3.00%																					
REAL PMT OF REVENUES				32,278	791,687	33,376	34,510	35,684	36,897	38,151	39,448	40,790	42,177	43,611	45,093	46,627	48,212	49,851	51,546	53,298	55,111	56,985	58,922
REAL NPV OF MWH				16,040,002																			
REAL PMT OF NPV OF MWH				613,200	16,040,002	634,049	655,606	677,897	700,946	724,778	749,420	774,900	801,247	828,489	856,658	885,784	915,901	947,042	979,241	1,012,535	1,046,962	1,082,558	1,119,365
REAL GROSS LEVELIZED REVENUE REQUIREMENT				54.43	791,687	33,376	34,510	35,684	36,897	38,151	39,448	40,790	42,177	43,611	45,093	46,627	48,212	49,851	51,546	53,298	55,111	56,985	58,922

PP 87

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
544,907	544,907	544,907	544,907	544,907	544,907	544,907	544,907	544,907	544,907	544,907	544,907	899,767	899,767
(145,308)	(181,636)	(217,963)	(254,290)	(290,617)	(326,944)	(363,271)	(399,598)	(435,925)	(472,252)	(508,579)	(544,907)	(59,984)	(119,969)
0	0	0	0	0	0	0	0	0	0	0	0	0	0
399,598	363,271	326,944	290,617	254,290	217,963	181,636	145,308	108,981	72,654	36,327	0	839,783	779,798
417,762	381,435	345,107	308,780	272,453	236,126	199,799	163,472	127,145	90,818	54,491	18,164	419,891	809,790
43,576	39,787	35,998	32,209	28,419	24,630	20,841	17,052	13,262	9,473	5,684	1,895	43,798	84,468
79,903	76,114	72,325	68,536	64,746	60,957	57,168	53,379	49,589	45,800	42,011	38,222	103,783	144,453
(36,327)	(36,327)	(36,327)	(36,327)	(36,327)	(36,327)	(36,327)	(36,327)	(36,327)	(36,327)	(36,327)	(36,327)	(59,984)	(59,984)
0	0	0	0	0	0	0	0	0	0	0	0	0	0
43,576	39,787	35,998	32,209	28,419	24,630	20,841	17,052	13,262	9,473	5,684	1,895	43,798	84,468
417,762	381,435	345,107	308,780	272,453	236,126.	199,799	163,472	127,145	90,818	54,491	18,164	419,891	809,790
43,576	39,787	35,998	32,209	28,419	24,630	20,841	17,052	13,262	9,473	5,684	1,895	43,798	84,468
0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0	0
36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	36,327	59,984	59,984
0	0	0	0	0	0	0	0	0	0	0	0	0	0
79,903	76,114	72,325	68,536	64,746	60,957	57,168	53,379	49,589	45,800	42,011	38,222	103,783	144,453
613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200
60,925	62,997	65,139	67,353	69,643	72,011	74,460	76,991	79,609	82,316	85,115	88,008	91,001	94,096
1,157,424	1,196,776	1,237,467	1,279,540	1,323,045	1,368,028	1,414,541	1,462,636	1,512,365	1,563,788	1,616,954	1,671,931	1,728,778	1,787,555
60,925	62,997	65,139	67,353	69,643	72,011	74,460	76,991	79,609	82,316	85,115	88,008	91,001	94,096
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
602,398	622,880	644,058	665,956	688,598	712,010	736,219	761,250	787,133	813,895	841,568	870,181	899,767	930,359

2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
899,767	899,767	899,767	899,767	899,767	899,767	899,767	899,767	899,767	899,767	899,767	899,767	899,767
(179,953)	(239,938)	(299,922)	(359,907)	(419,891)	(479,876)	(539,860)	(599,845)	(659,829)	(719,814)	(779,798)	(839,783)	(899,767)
0	0	0	0	0	0	0	0	0	0	0	0	0
719,814	659,829	599,845	539,860	479,876	419,891	359,907	299,922	239,938	179,953	119,969	59,984	(0)
749,806	689,821	629,837	569,852	509,868	449,884	389,899	329,915	269,930	209,946	149,961	89,977	29,992
78,212	71,956	65,698	59,441	53,184	46,927	40,670	34,413	28,156	21,899	15,642	9,385	3,128
138,196	131,939	125,682	119,425	113,168	106,911	100,654	94,398	88,141	81,884	75,627	69,370	63,113
(59,984)	(59,984)	(59,984)	(59,984)	(59,984)	(59,984)	(59,984)	(59,984)	(59,984)	(59,984)	(59,984)	(59,984)	(59,984)
0	0	0	0	0	0	0	0	0	0	0	0	0
78,212	71,956	65,698	59,441	53,184	46,927	40,670	34,413	28,156	21,899	15,642	9,385	3,128
749,806	689,821	629,837	569,852	509,868	449,884	389,899	329,915	269,930	209,946	149,961	89,977	29,992
78,212	71,956	65,698	59,441	53,184	46,927	40,670	34,413	28,156	21,899	15,642	9,385	3,128
0	0	0	0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0	0	0	0
59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984	59,984
0	0	0	0	0	0	0	0	0	0	0	0	0
138,196	131,939	125,682	119,425	113,168	106,911	100,654	94,398	88,141	81,884	75,627	69,370	63,113
613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200	613,200
97,294	100,602	104,022	107,559	111,216	114,998	118,907	122,950	127,131	131,453	135,922	140,544	145,322
1,848,332	1,911,176	1,976,155	2,043,344	2,112,816	2,184,654	2,258,932	2,335,736	2,415,151	2,497,268	2,582,173	2,669,967	2,760,746
97,294	100,602	104,022	107,559	111,216	114,998	118,907	122,950	127,131	131,453	135,922	140,544	145,322
2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
961,991	994,699	1,028,519	1,063,488	1,099,647	1,137,035	1,175,694	1,215,668	1,257,001	1,299,739	1,343,930	1,389,623	1,436,871

PP 88

PP 89

Oregon

DEPARTMENT OF ENERGY

July 15, 1993

Nancy Esteb
PacifiCorp
920 SW Sixth Avenue
Portland, OR 97204-1256

Dear Nancy:

We have three concerns about Pacific's demand-side analysis and planning for RAMPP-3. We would like to take this opportunity to offer recommendations to improve the analysis.

Industrial
The planning assumptions for industrial programs propose to capture only a 50 percent penetration over the 20-year forecast period. This is too low. The assumed maximum annual penetration rate of 3 percent is also too low.

Assuming these low penetration and ramp-up rates is tantamount to planning not to acquire significant amounts of a 27 mill TRC resource. The amount of energy in the balance is probably on the order of 100 to 150 MWa compared to a penetration rate of 75 or 85 percent. Our concern is that Pacific will never succeed a acquiring these inexpensive megawatts if it does not target them. For example, targeting the lower amount means that budgets and staff will not be allocated to pursue the higher amounts, even though this should be a very high priority resource.

The company's reason for using a low penetration rate apparently is that it has little experience in this sector, so a low rate is somehow prudent. We argue a high rate is prudent for a resource of low cost like industrial DSM. If multi-year experience at Pacific shows higher penetration is impossible after serious efforts are made, then the supply curves, and targets can be revised. There is experience in other utilities that show higher industrial penetration and ramp rates are achievable.

We recommend using a higher penetration rate, between 70 and 80 percent, for industrial conservation in the base line runs, for program planning and target setting. Ramp-up rates should be at least 8 - 10% of the total potential per year. This level is already being achieved by one regional utility in its industrial sector. Such an effort

Barbara Roberts
Governor

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will require program staff and budget as well as management commitment like any new resource acquisition.

Showerheads in New Construction
Pacific assumes no conservation potential for efficient showerheads in new building stock in Oregon because of Oregon law which requires 2.5 gpm showerheads. Pacific's proposed showerhead program uses 2.0 gpm showerheads. The lower-flow showerheads should be part of appliance package for new home's in Oregon. Savings are significant and the cost is minimal.

New Commercial
We urge Pacific to do a consistency review of planning estimates of savings per square foot and measured savings data from Commercial Energy FinAnswer experience. Program savings are very high compared to IRP estimates on a per square foot basis for some building types. For example, estimated program savings on 13 schools was 5.6 kWh/sf while planning assumptions were 0.12 kWh/sf. We cannot tell whether the DOE 2.1 modeled baseline estimates for program participants are too high, planning assumptions are too low, or the 13 schools are not representative. Either way a detailed evaluation of actual performance is needed. As the company proceeds with impact evaluation, planning assumptions should be updated.

Please call if you have any questions.

Charlie Grist

Margie Gardner
BY CG

Charlie Grist, Energy Analyst
Policy & Planning Division, ODOE

Margie Gardner, Conservation Analyst
Power Planning Division, NPPC

cc: Christine Ervin
Angus Duncan

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PP 91

PACIFICORP
PACIFIC POWER UTAH POWER

August 24, 1993

Margie Gardner
NPPC
851 SW 6th, 1100 PFFC
Portland, Oregon 97204

Charlie Grist
Oregon Department of Energy
625 Marion Street NE
Salem, Oregon 97310

Charlie and Margie:

Thank you for your letter of July 15, 1993. PacifiCorp appreciates your comments as part of our RAMPP 3 planning process. Before responding to specific concerns regarding planning assumptions pointed out in your memo, let me make one overall point. The changes which were incorporated into RAMPP-3 do not in any way reflect a lack of commitment to acquiring low cost demand side resources. In fact, although the overall program technical potential in the industrial sector was reduced for the twenty year period, the emphasis on resources committed to acquiring industrial demand side resources and the annual acquisition targets have increased. A distinction needs to be made between commitment to action versus perceived available potential. In PacifiCorp's RAMPP-3 assumptions, we revised our perception of program technical potential for the reasons cited later in this response, but this should not be mis-construed as a desire to back away from acquisition of this resource. With this in mind, we have reviewed your letter, reflected on our input assumptions, and offer the following comments for your consideration.

Industrial

Issue: *The penetration assumption used by PacifiCorp (50% overall and 3% per year) were understated and should be revised to reflect a 70% to 80% overall penetration rate and a higher annual penetration rate.*

The assumption for the amount of achievable program potential was reduced slightly from RAMPP-2, resulting in an overall reduction of 120 MWa over the twenty year period. Despite this reduction, the industrial sector remains the highest priority due to its status as the single largest source of DSM resource in the plan. The reduction results from two primary changes that have occurred between RAMPP-2 and RAMPP-3; 1) changes in the economic outlook for some of our industrial customers and 2) our initial experiences with the industrial initiatives. Both of these issues are critical, but overall I must emphasize that it has been our experience to date that industrial projects are more difficult to bring to fruition and in general take much longer than expected. Recruitment of qualified industrial participants due to the risk adverse nature of these customers and their reluctance to incorporate changes to their production processes, has turned out to be more difficult than assumed in previous planning efforts. In addition to these barriers, the time frame involved to complete a project has averaged nearly 22 months, much longer than assumed in RAMPP-2. Our reduction of RAMPP-3 penetration rates reflects this extension in time frame for project completion and the generally slow nature of DSM technology adoption in the industrial sector.

Issue: *Assumptions of low penetration rates would be tantamount to not planning to acquire low cost resource and that setting lower penetration rates would translate into lower levels of DSM funding and staffing.*

The reduction in overall industrial technical program potential does not reflect a change in commitment to work with these customers to achieve or exceed our planning assumptions. Budgets and resources can be adjusted to target cost effective resources as more receptivity is demonstrated. On the other hand, It would be careless for the Company to include DSM resources in the twenty year modeling effort which would not materialize at a later date when the actual resource is needed. As far as near term efforts, Company initiatives have increased in this sector under the acknowledgement that this sector is extremely cost effective and warrants further attention. As Table 1 demonstrates, the incremental resource addition assumed in the draft RAMPP-3 medium growth scenario (28.7 MWa in 1998) is actually higher than that assumed under the mean of the medium high and medium-low case for RAMPP-2 (24.9 MWa by 1998). RAMPP-2 did not have an explicit medium case as does RAMPP-3. This increase in the portion of DSM investments allocated to the industrial sector reflects our recognition of the importance and the cost effectiveness of the sector. Despite this increased emphasis achieving penetration rates in the range suggested by the ODOE and the Council (70 - 80%) does not seem likely.

Issue: *Other regional utilities have achieved 70 to 80 % penetration rates.*

The comparison with the other regional utility is interesting, but may not be relevant. Few regional IOUs have as large of fraction of total sales directed to major industrial customers as does PacfiCorp. To target a 70 to 80 percent penetration rate among a relatively small industrial base is one thing, but to assume this level of penetration for an industrial sector which is as large and geographically diverse as PacifiCorp's does not seem to be entirely prudent. PacifiCorp has over 40% of its Mwh sales in the industrial class. These sales are spread among over 3,000 customers of various sizes and industrial segments. Over 13 major two-digit SIC categories are represented in our industrial mix. The current and forecasted outlook for many of these industries appears to reflect marginal economic conditions. Firms in segments such as lumber and wood products and oil and gas are extremely risk adverse and are minimizing capital investments as a whole. Faced with tough economic conditions, incenting DSM investment and achieving high penetration rates becomes far less feasible.

Showerheads in New Construction.

Issue: PacifiCorp assumes no conservation potential for efficient showerheads in new construction beyond the 2.5 gpm code requirement.

Your suggestion of using 2.0 gpm showerheads is a good one and was omitted due to oversight. We are currently evaluating the cost effectiveness of distributing 2.0 gpm showerheads through the Super Good Cents program, but had not included them explicitly in the forecast. The size of this resource is relatively small, but can be added to the program technical potential after completion of the cost effectiveness analysis.

New Commercial

Issue: *The estimates of savings per square foot and the planning assumptions used to estimate technical potential vary significantly and warrant a detailed evaluation of actual performance and updating of planning assumptions.*

We always strive for consistency between planning assumptions and program results. For that reason, we included a discussion of planning assumptions and actual results in the 1992 evaluation reports for Energy FinAnswer and Pacific Environments, and we expect to continue that practice. Your suggestion that planning assumptions need to be updated with evaluation results is a good one and a practice we fully intend to pursue. As our knowledge base and experience with DSM increases we will be tracking evaluation results very closely to determine updates which need to occur to the models. With a limited dataset, we do not feel comfortable altering planning assumptions, at this point. In the meantime, we can offer the same insight into the possible source of the discrepancy.

There are several reasons why the planning models may be different, specifically as they relate to the schools example which was pointed out. Most of the discrepancy can be traced to the issue of prototypes used to represent a given segment. The planning model looks at one prototype, applies a rigid cost-effectiveness cutoff and applies the result to the entire sector. In the real world, buildings are not necessarily a match for the prototype. Some measures fail to meet TRC in the planning model. Within the program, those measures that fail TRC may still be implemented using supplemental funding. The result is more savings than are indicated in the planning model.

We have pointed out in RAG presentations that the planning models should be viewed as a representative proxy for what we will find in the real world. It is not surprising to find differences between the limited number of prototypes used and the real world experiences of the programs. Overall, we expect that the planning models are reasonable albeit somewhat conservative estimates of the technical potential.

Comparing our planning assumptions against NPPC plan shows areas where we are different. NPPC shows most of the savings for school buildings coming from shell measures. Our planning model shows lower savings for shell measures in Oregon because the climate is milder and the saturation of electricity for space heating is lower. Since early program participants tend to be customers already using electric heating, it is not surprising that the program has found higher savings. It would, however, be careless to change the planning assumptions until a more robust sample of participants has been constructed.

We did explore areas where we thought more development of technical potential was needed. Our planning model shows most of the savings coming from a T8 lighting package which NPPC did not itemize. The result of the reassessment led to adding nearly 70 MWa of program technical potential in commercial retrofit. This addition is indicative of our overall desire to more accurately reflect the DSM potential in the marketplace.

Although there may not be total agreement on all of the assumptions used to date in RAMPP-3, we hope that you can understand our desire to more accurately reflect the deliverable potential from demand side management. The changes do not represent a reduction in commitment, but rather, a more accurate assessment provided by experiences to date. Please let me know if we can provide more clarity regarding the concerns you have raised or answer any additional questions that you may have.

Sincerely,

Scott Robinson
Manager, Demand Side Policy and Strategy

Table 1

RAMPP-2
Incremental Energy - MWa

	1991	1992	1993	1994	1995	1996	1997	1998
Med High	1.0	2.0	3.0	5.2	8.9	17.7	23.6	29.5
Med Low	1.0	1.4	2.1	3.5	6.1	12.2	16.2	20.3
Mean	1.0	1.7	2.6	4.4	7.5	15.0	19.9	24.9

RAMPP-3
Incremental Energy - MWa

	1991	1992	1993	1994	1995	1996	1997	1998
Med	1.0	2.0	4.0	6.7	11.7	18.6	[illegible]	28.7
RAMPP - 3 vs RAMPP -2	0.0	0.3	1.5	2.4	4.2	3.7	3.7	3.8

RMP3Ind

PP 9

PP 97

Date: September 2, 1993

To: Nancy Esteb, Manager, Integrated Resource Planning
PacifiCorp, 920 SW 6th Ave.
Portland OR 97204-1256

From: Phil Carver and Charlie Grist, OR Dept. of Energy
Margie Gardner, NW Power Planning Council
Connie Colter, OR Public Utility Commission

Subject: Data Request: Comparison of RAMPP2 and RAMPP3 Conservation Estimates and Targets

1. Please provide an updated side-by-side comparison of the estimates of technical and achievable conservation potential (aMW and peak MW) by sector and region for RAMPP2 and RAMPP3. Please explain any substantive differences.

2. Please provide a year-by-year comparison of the 170 aMW cumulative conservation target by the end of 1996 in RAMPP2, and the proposed targets for RAMPP3. Please explain any substantive differences.

3. Please reconcile the July 30 Table "Potential Resources - Ranked by Total Resource Cost" (MW) and the graphs on pages 9 - 17 of the July 30 handout, "Preliminary Draft Results - Medium Load, Medium Gas Price" (aMW).

4. Why does the base case (MD) incremental industrial conservation drop from roughly 30 aMW to 15 aMW between 1998 and 1999 (see graph on p. 13, ibid)?

5. What constrains the incremental commercial retrofit conservation during 1994-1998 (ibid)?

6. What assumptions are made about background conservation included in the RAMPP3 forecast? Are these savings included in the base case MD demand side resources? How do these assumptions differ from RAMPP2?

Thank you for your assistance.

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PP 9

PP 99

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PACIFIC POWER UTAH POWER

September 24, 1993

Phil Carver, Charlie Grist
Oregon Department of Energy
625 Marion Street NE
Salem, OR 97310

Margie Gardner
NW Power Planning Council
851 SW 6th, 1100 PFFC
Portland, OR 97204

Connie Colter, PhD
Electric Rates and Planning
Public Utility Commission of Oregon
550 Capitol Street, NE
Salem, OR 97310-1380

Dear Phil, Charlie, Margie and Connie,

Enclosed please find the responses to your September 2 data request regarding comparisons of RAMPP 2 and RAMPP 3 conservation estimates and targets.

If you have any questions please don't hesitate to call me at 464-6523 or Doug Ballou at 464-5047.

Sincerely,

Scott Robinson

Scott Robinson
Manager, Demand Side Policy and Strategy

Responses to
ODOE, NWPPC, OPUC RAMPP Data Request - Dated: September 2, 1993
Comparison of RAMPP 2 and RAMPP 3 Conservation Estimates and Targets

1. Please provide an updated side-by-side comparison of the estimates of technical and achievable conservation potential (aMW and peak MW) by sector and region for RAMPP 2 and RAMPP 3. Please explain any substantive differences.

Response: The comparisons of the RAMPP 2 and RAMPP 3 technical potential are shown in attachment A. These conservation supply curves were distributed and discussed in the March 12 subgroup meeting.

A table showing achievable potential comparisons was discussed at the April 30 advisory group meeting. Updated tables comparing RAMPP-2 and RAMPP-3 achievable conservation potential (aMW and peak MW) by sector and region are shown in attachment B. The table below provides explanations of the with variances from RAMPP 2 plan to RAMPP 3 as follows:

Sector	Variance (MWa)	Variance (MW)	Explanation
Industrial	(99)	(343)	Change estimate of achievable pentration rate from 65 % to 55%.
New Commercial	4	99	Update measure cost information which impacts background conservation assumptions. Net effect is little change to potential.
Commercial Retro	35	104	Retrofit potential is larger.
New Residential	(27)	(42)	Assume MAP manufactured housing in forecast.Change estimate of achievable penetration rate from 60% to 40% in Long Term Super Good Cents due to widespread code adoption and more difficulty in persuading builders to go beyond code. Include solar access and appliance savings in program impact although these are small.Result is large decrease in potential estimate.
Residential Weatherization	(36)	(63)	Update costs to include more low-e windows, water conservation measures and manufactured home potential. Reduce estimate of achievable program penetration rate from 58% to 40%.
Residential Appliance	(15)	(22)	Includes new Federal standards in forecast.Reduce estimate of achievable program penetration rate from 17% to 14%. Result is reduced program potential.
Water Heater Load Control	-	(90)	
Total	(139)	(356)	

The achievable potential MWa and peak MW savings were impacted in Industrial, New Commercial and Residential construction by the forecast change from medium-high in RAMPP 2 to medium as the most likely case in RAMPP 3.

2. Please provide a year-by-year comparison of the 170 aMW cumulative conservation target by the end of 1996 in RAMPP 2, and the proposed targets for RAMPP 3. Please explain any substantive differences.

Response: The target of 170 aMW is based on RAMPP 2, but includes savings other than programmatic. RAMPP2 included about 120 aMW of programs for planning purposes. In addition, the target included estimates of the background conservation and conservation programs beyond those included in RAMPP2. A detailed explanation of the differences is provided in attachment C.

3. Please reconcile the July 30 Table "Potential Resources - Ranked by Total Resource Cost" (MW) and the graphs on pages 9 - 17 of the July 30 handout, "Preliminary Draft Results - Medium Load, Medium Gas Price" (aMW).

Response: The tables distributed at the July 30 meeting represented work in process. Some items have been revised as part of on-going work. The table "Potential Resources Ranked by TRC" was produced by Power Planning to demonstrate the resource choices the integration model is facing. The graphs on pages 9-17 present background information on the Demand Side Resources (DSR). The information is consistent with the DSR being used in the integration runs.

4. Why does the base case (MD) incremental industrial conservation drop from roughly 30 aMW to 15 aMW between 1998 and 1999 (see graph on page 13, ibid)?

Response: Industrial conservation in the first 5 years of the 20 year plan targets large industrial plant facilities where a significant amount of the technical potential for demand side resources exists within this sector at a very cost effective level. Once much of this resource is captured within the first five years, the amount of resource potential in these facilities drops off dramatically leaving most remaining potential in the small and medium industries and new industrial development. In addition, the industrial resources are assumed to be captured over a extended period primarily because they tend not to be retrofit, but occur when processes are changed or plant expansion occurs through their capital budgeting cycle.

5. What constrains the incremental commercial retrofit conservation during 1994-1998 (ibid)?

Response: The commercial retrofit conservation efforts ramp up during the 1994 through 1998 period as the company develops the capability to offer a system-wide program, achieving high participation levels and market acceptance. In addition, the program will not be offered in all states until after 1998. Our first effort at a state-wide commercial remodel program will start in Oregon in 1994. Program experience has shown that program delivery and implimentation issues will need to be worked out as the program evolves through this capability building phase which includes building strong trade ally relationships and increasing customer awareness of the program and services offered.

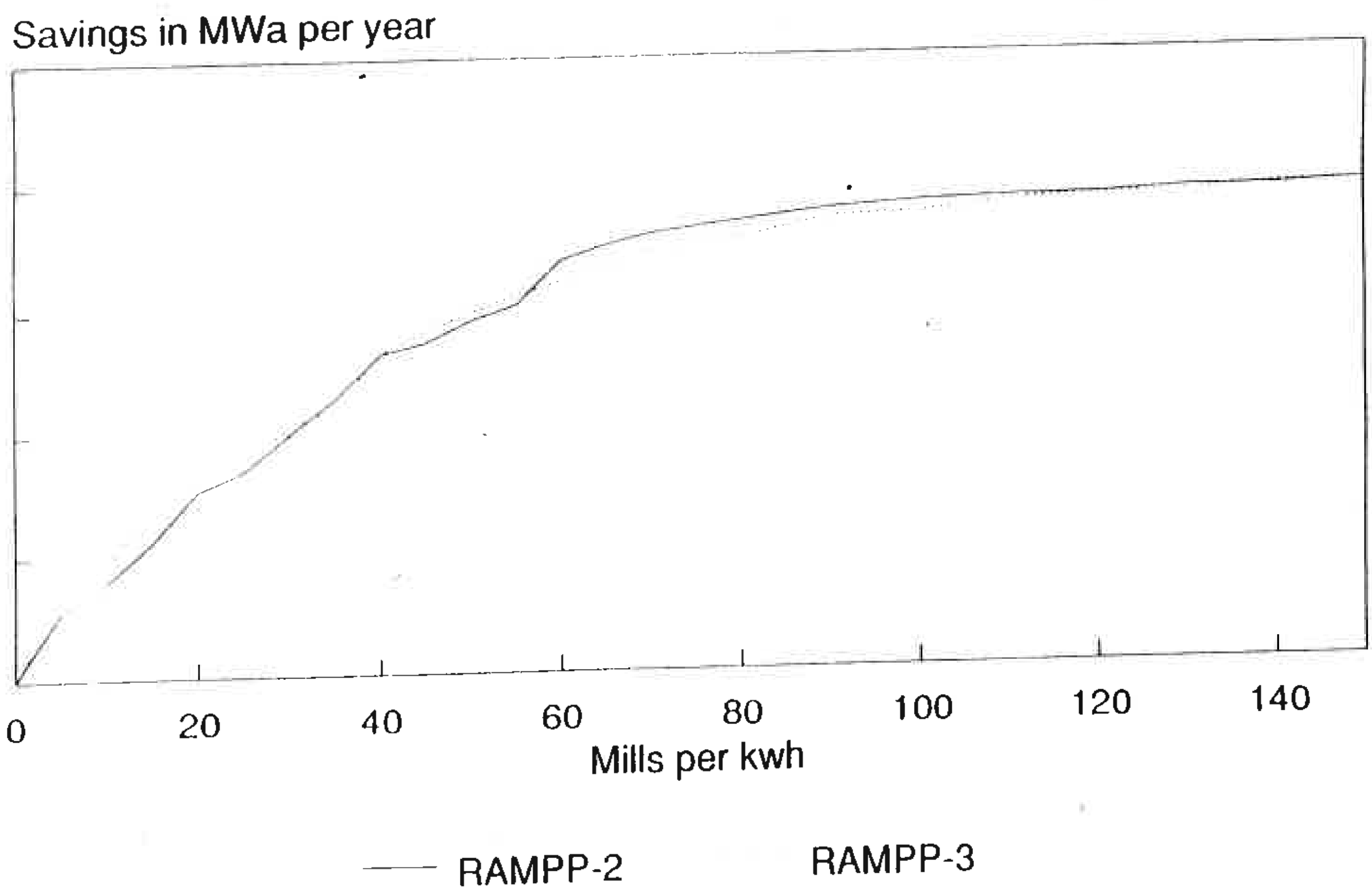
6. What assumptions are made about background conservation included in the RAMPP 3 forecast? Are these savings included in the base case MD demand side resources? How do these assumptions differ from RAMPP 2?

Response: Background conservation is estimated by assuming that measures costing 10 mills or less will be adopted by consumers. The methodological assumptions have been discussed previously with the Advisory Group. Savings from background conservation must be subtracted from programmatic estimates to avoid double-counting. The background that would have occurred from program participants is not included in program impacts. This is the same procedure followed in RAMPP2.

Responses to
ODOE, NWPPC, OPUC RAMPP Data Request - Dated: September 2, 1993
Comparison of RAMPP 2 and RAMPP 3 Conservation Estimates and Targets

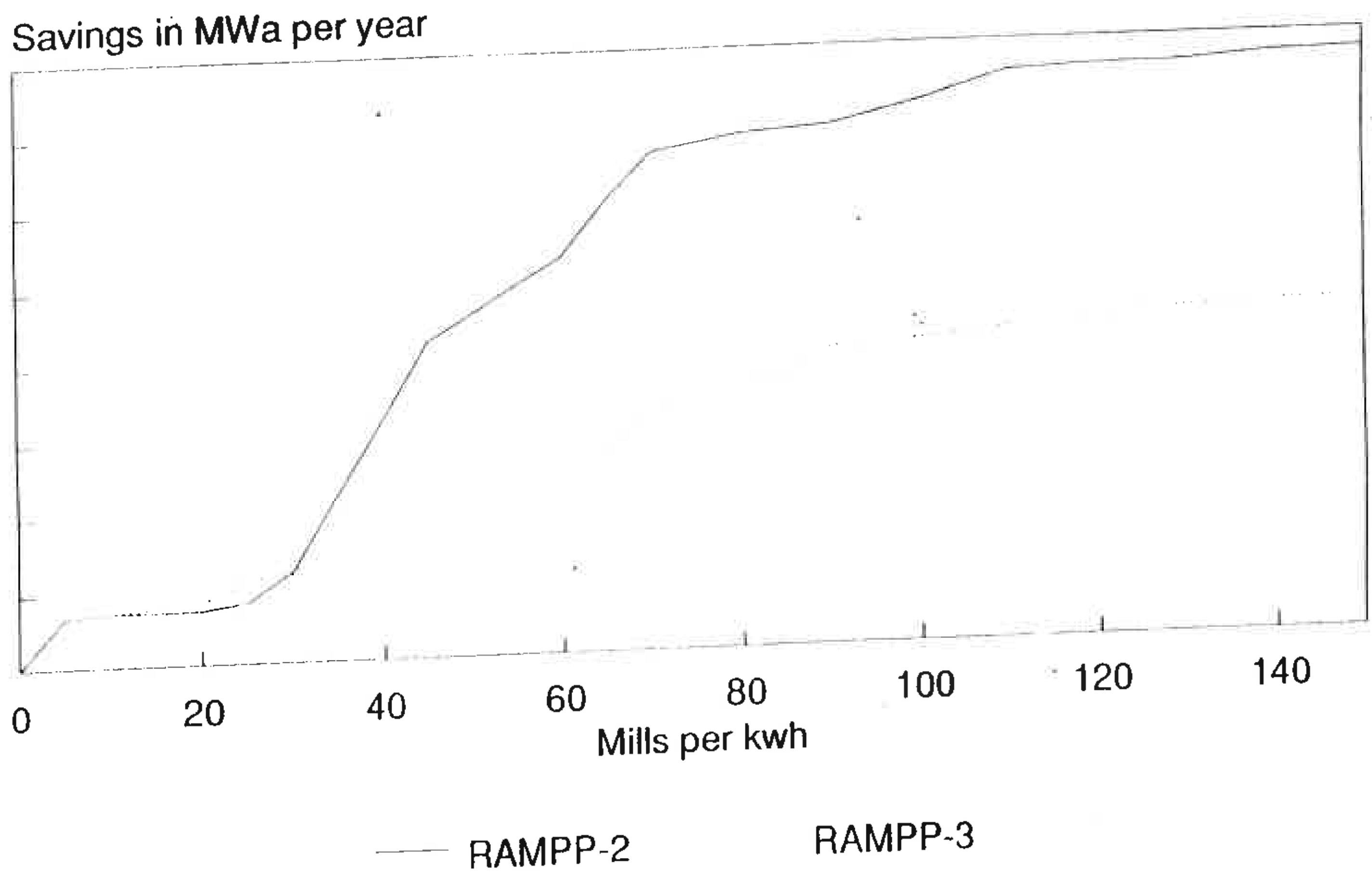
Attachment A - Conservation Supply Curve Comparisons

Conservation Supply Curve
Commercial Sector, New and Existing
Relative Scale, RAMPP-2 and RAMPP-3



Draft 2/5/93

Conservation Supply Curve
New Residential Space Heat
Relative Size



Draft 3/6/93

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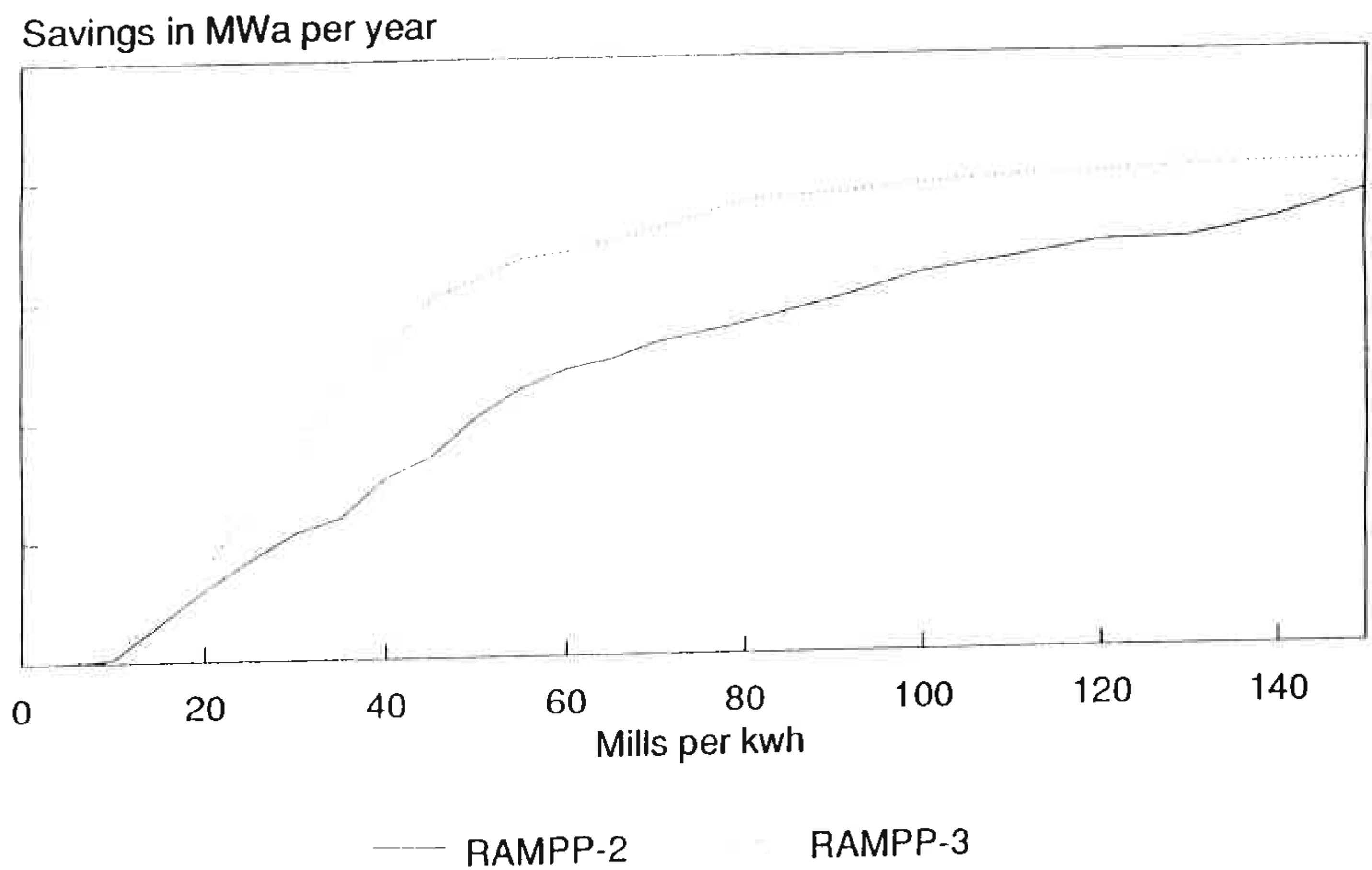
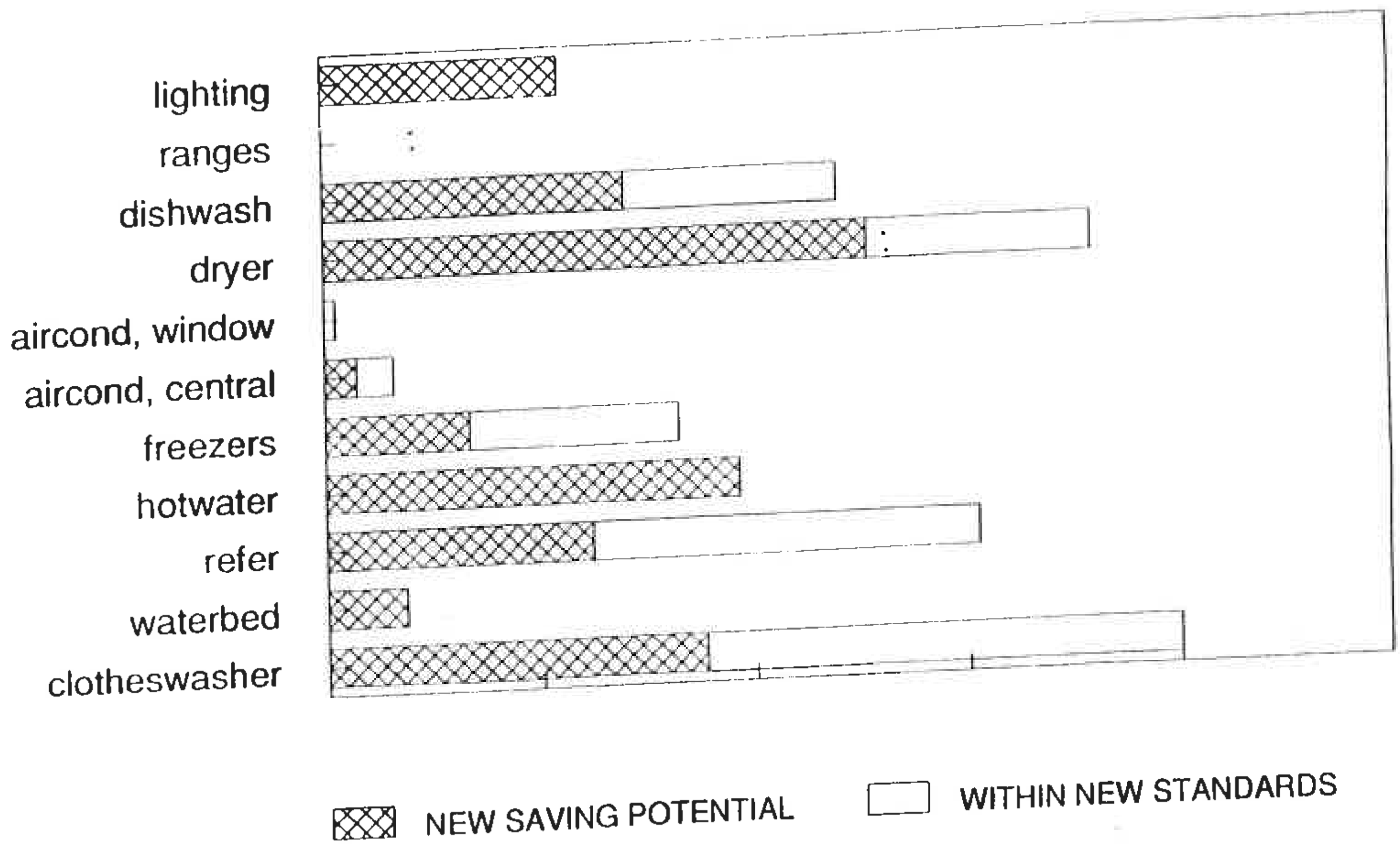
Conservation Supply Curve
Existing Residential Space Heat
Relative Size



Draft 3/6/93

TECHNICAL POTENTIAL FROM APPLIANCES
NEW APPLIANCES



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Attachment B - Achievable Conservation Potential Comparisons

RAMPP2 POTENTIAL ESTIMATE aMW DSR BY 2011

	COMPANY	PP&L	UP&L
APPLIANCE	28	18	10
RESIDENTIAL WX	56	36	20
INDUSTRIAL	375	180	195
NEW COMMERCIAL	140	76	64
NEW RESIDENTIAL	53	47	6
COMMERCIAL RETROFIT	129	89	40
ALL PROGRAMS	781	446	335

RAMPP2 POTENTIAL ESTIMATE WINTER PEAK MW, DSR BY 2011

	COMPANY	PP&L	UP&L
APPLIANCE	46	29	17
RESIDENTIAL WX	91	58	33
INDUSTRIAL	625	300	325
NEW COMMERCIAL	216	117	99
NEW RESIDENTIAL	78	69	9
COMMERCIAL RETROFIT	215	148	67
WATER HEATER LOAD CONTR	213	213	0
ALL PROGRAMS	1484	935	549

RAMPP3 POTENTIAL ESTIMAT aMW DSR BY 2013

	COMPANY	OWC	UTAH	WYOMING
APPLIANCE	13	6	5	1
RESIDENTIAL WX	20	19	0	0
INDUSTRIAL	276	68	143	65
NEW COMMERCIAL	144	68	64	12
NEW RESIDENTIAL	26	21	2	3
COMMERCIAL RETROFIT	164	66	82	16
ALL PROGRAMS	642	248	297	97

RAMPP3 POTENTIAL ESTIMAT WINTER PEAK MW, DSR BY 2011

	COMPANY	OWC	UTAH	WYOMING
APPLIANCE	24	12	10	2
RESIDENTIAL WX	28	28	1	0
INDUSTRIAL	282	73	145	65
NEW COMMERCIAL	315	170	117	28
NEW RESIDENTIAL	36	31	2	3
COMMERCIAL RETROFIT	319	140	150	30
WATER HEATER LOAD CONTR	123	123		
ALL PROGRAMS	1128	577	424	128

Responses to
ODOE, NWPPC, OPUC RAMPP Data Request - Dated: September 2, 1993
Comparison of RAMPP 2 and RAMPP 3 Conservation Estimates and Targets

Attachment C - PacifiCorp DSR Opportunities Changes Since RAMPP 2

Figure 1 shows the Company's current cumulative demand side resource acquisition goal of 170 MWa by 1996, and a current estimate for RAMPP 3 of 98 MWa by 1996 and 180 MWa by 1998. The RAMPP 3 plan includes actual resource acquisition of 9 MWa ("signed contract basis) in 1992, a goal for 1993 of 11 MWa, and a five year plan of 157 MWa for 1994 through 1998. The comparison to PacifiCorps' strategic DSR acquisition

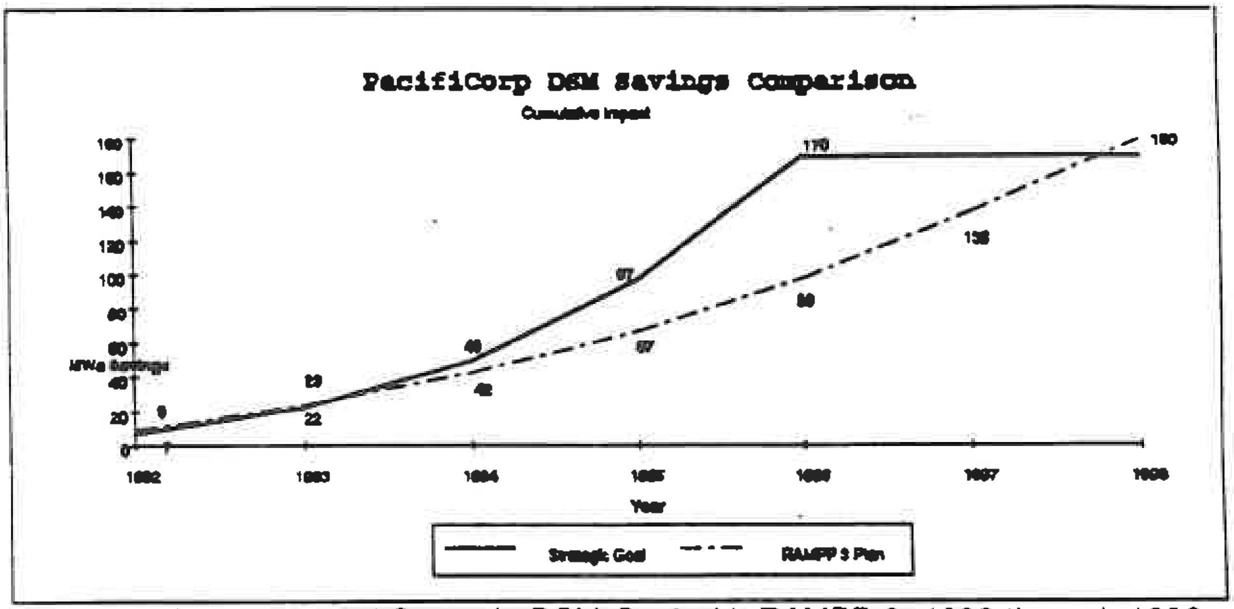

Figure 1 Comparison of Strategic DSM Goal with RAMPP 3, 1992 through 1996.

goal established in 1992 for the period 1992 through 1996 shows that the RAMPP 3 plan estimate falls short of the goal by approximately 72 MWa in 1996, but reaches the 170 MWa goal in mid 1997, with an expected cumulative savings of 180 MWa by in 1998.

This difference in the forecasted demand side resource acquisition ramp rate between the RAMPP 2 Medium High (Company strategic goal) and RAMPP 3 Medium forecast can be attributed to the following factors.

- **Revised economics (summarized below)**
- **Revision of ramp rate to reflect net savings rather than gross savings (summarized below).**

- **Revised program costs, savings and penetration assumptions (summarized below)**

- **Revision of goals to reflect installed versus signed energy efficiency measures (discussed below).**

Underlying Economics behind RAMPP 2 and 3

The opportunity to acquire cost effective resources is heavily influenced by the long term system load forecast, which in turn is driven by economic, demographic and competitive assumptions. The potential savings available to be targeted through program activity depends on the economic forecast, and its effect on the number of housing units, new commercial floor space, and industrial production expected over the planning horizon. The long term sales forecast is driven by a national economic forecast provided by DRI. State specific forecasts are developed from this national economic projection. Table 1 provides national comparisons of GNP growth, housing starts, Company MWh sales growth, electric housing starts, commercial floor space construction, and industrial customer MWh sales growth over the 20 year planning horizon. The difference primarily reflects the Company's movement from a Medium-High forecast in RAMPP 2 to a Medium case in RAMPP 3 (The Company did not produce a Medium Case for RAMPP 2).

Table 1: Changes in Key Economic Assumptions - RAMPP 2 to RAMPP 3 (20 Year Period).

Indicator	RAMPP 2	RAMPP 3	CHANGE
National GNP	2.3	2.2	(0.1)
National Housing Starts (Millions)	1.27	1.46	0.19
Company MWh Sales Growth	2.9%	2.1%	(0.8%)
New Electric Housing Starts (annual avg.)	16,183	14,452	(1,731)
Commercial Floor Space Added (Millions Sq. Ft.)	512	535	23
Industrial Sales (MWH)	39,223,802	29,447,577	(9,776,225)

The economy drives the Company's sales forecast and influences potential and need for demand side resource acquisition. The amount of kWh savings is tied directly to the number of homes, businesses and industries served. An economic downturn reduces the amount of potential savings from conservation efforts, while an upturn increases the potential opportunity for savings from programs. Overall, the underlying assumptions behind RAMPP II which lead to the development of a strategic goal of acquiring 170 aMW between 1992 and 1996 have changed, revising downward the savings potential in many program areas.

Gross to Net Savings

The 1992 to 1996, five year goal of 170 MWa goal is gross savings and includes free riders savings of approximately 36 MWa. Free riders is defined as those participants who would have installed energy conservation measures in the absence of a utility program offering. In other words, the utility DSM program had no impact on the customers decision to make energy efficiency improvements. The RAMPP 3 forecast is net savings (net of free riders), rather than gross savings as included in the Company's Strategic goal. To put the Company's Strategic Goal on a comparable basis with RAMPP 3, the free rider savings needs to be removed. Removing free riders of 36 MWa from the Company goal places RAMPP 2 net savings at approximately 134 MWa. Comparing RAMPP 2 and RAMPP 3 net savings, RAMPP 3 is 36 MWa lower. The following Table 2 shows the differences by program area in the two forecasts.

Table 2: Comparison of RAMPP 2 to RAMPP 3 - MWa Savings 1992 through 1996

PROGRAM	RAMPP 2 - Net Savings MWa	RAMPP 3 - Net Savings MWa	CHANGE in MWa
Appliance	6	5	(1)
Residential Wx	20	13	(7)
Industrial	52	43	(9)
New Commercial	24	14	(10)
New Residential	8	12	4
Commercial Retrofit	24	11	(13)
TOTAL	134	98	(36)

Revised program costs, savings and penetration assumptions

Overall, each program area was effected by the change from Medium-High load forecast in RAMPP 2 to the Medium forecast being used for RAMPP 3. In total, the amount was 105 MWa over the 20 year planning horizon, and represented a 13 percent decrease. This explains part of the 36 MWa decrease shown in table 2, but there are other factors which affect the short term program ramp up rate. These are discussed by program area as follows:

Appliance:	Change in Federal Standards for appliances.
Residential Retrofit:	High cost of the resource and fewer opportunities because of partial weatherization.
Industrial:	Lower penetration rate assumption and difficulty in influencing customer decisions.
New Commercial:	Lower penetration rate assumption based on program experience. Down from 85 percent in RAMPP 2 to 75 percent in RAMPP 3.
New Residential:	The short term plan includes mobile home (MAP) savings of 8 MWa. In RAMPP 3 MAP is included in the base sales forecast, eliminating any potential savings. Removing the 8 MWa for MAP from the numbers, new residential savings drop from 8 MWa in RAMPP 2 plan to 4 MWa in RAMPP 3 plan. The change is due primarily to code changes.
Commercial Retrofit:	RAMPP 2 assumed retrofit in all states and beginning in 1992. RAMPP 3 reflects the delay in starting commercial retrofit activities and limited offering in Utah and Oregon only.

Table 3 provides a estimated breakout of the variances in MWa savings between the Company's strategic goal of 170 MWa and the RAMPP 3 of 98.

Table 3: Variance Explanations- Company Goal to RAMPP 3

Company Goal - MWa by 1996		170
Explanation	Percentage	MWa Variance
Free Riders Adjustment	50%	(36)
Lower Econ. Outlook, Codes and Appl. Std	24%	(17)
Lower Industrial Penetration	7%	(5)
Commercial Retrofit Delay	11%	(8)
New Commercial Penetration rate lower/Other Misc	8%	(6)
RAMPP 3 - MWa by 1996		98

The main factors which resulted in a lower estimate of MWa savings acquired by 1996 in RAMPP 3 were the removal of free riders (50%), the lower economic outlook (24%), and reduced penetration rates in industrial and commercial (15%).

Revision of goals to reflect installed versus signed

In developing the short term action plan for the Company's resource acquisition plan, targets were set based upon the desire to incent energy service representatives to secure agreements for participation in the Energy Service Charge (ESC) programs. After having two years of experience, it has become increasingly evident that a substantial time lag exists between the time that an ESC is signed and when the project is completed and all measures fully installed. The lag varies substantially by sector, but overall substantially influences the acquisition of installed demand side resources. Time lags vary by sector as follows; Industrial Energy FinAnswer - 22 months, Retrofit Commercial - 8 months, and Energy FinAnswer - 18 months. All time lags represent average mwh weighted elapsed time between ESC signed and project completion. Since the value of DSM is reflected in the ability to count on the savings, the Company has reflected this time lag in its new targets for RAMPP 3. Goals stated now indicate installed versus ESC signed. Taking this effect into account flattens the delivery curve from its previous steep path implied by the 170 MWa target.

PP 115

PACIFICORP
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October 29, 1993

Phil Carver
Oregon Department of Energy
625 Marion Street
Salem, Or 97310

Dear Phil,

Attached are the year by year cumulative MWa DSR additions by sector for each of the four DSR strategies. In addition, for each DSR strategy, the alternative load growth scenarios are shown for those load growth scenarios for which a DSR strategy was produced. The DSR acquisitions are broken down by sector and by new versus retrofit in the case of commercial and residential. The residential retrofit column includes both residential retrofit weatherization and appliance activity rolled together.

If there is any additional information or assistance that I can provide, please let me know.

Sincerely,

Scott Robinson

Scott Robinson
Manager, Demand Side Policy and Strategy

UNCONSTRAINED, MEDIUM GROWTH

CUMMULATIVE MWa

	COMPANY IND	NEW COML	COML RETRO	NEW RES	RES RETRO	TOTAL DSM
1994	266.9	4.6	0.0	0.4	4.6	276.5
1995	266.9	10.7	0.0	0.9	5.3	283.9
1996	275.9	17.4	65.6	1.5	6.0	366.5
1997	275.9	23.6	65.6	2.1	6.8	374.0
1998	275.9	29.7	160.0	2.8	7.5	476.0
1999	275.9	36.3	160.0	3.8	7.8	483.8
2000	275.9	43.3	160.0	4.9	8.1	492.2
2001	275.9	50.7	160.0	6.2	8.4	501.3
2002	275.9	57.6	160.0	7.6	8.8	510.0
2003	275.9	64.9	160.0	9.0	28.6	538.4
2004	275.9	72.1	160.0	10.5	29.0	547.5
2005	275.9	79.2	160.0	12.0	29.4	556.5
2006	275.9	86.4	160.0	13.5	29.8	565.7
2007	275.9	93.5	160.0	15.0	30.2	574.7
2008	275.9	100.9	160.0	16.7	30.7	584.3
2009	275.9	108.3	160.0	18.3	31.0	593.5
2010	275.9	115.3	160.0	19.7	31.2	602.2
2011	275.9	122.3	160.0	21.1	31.5	610.9
2012	275.9	129.4	160.0	22.6	31.8	619.7
2013	275.9	136.4	160.0	24.0	32.1	628.4

MEDIUM RAMP (MD), MEDIUM GROWTH

CUMMULATIVE MWa

	COMPANY IND	NEW COML	COML RETRO	NEW RES	RES RETRO	TOTAL DSM
1994	6.7	2.6	2.5	0.5	8.0	20.3
1995	17.6	5.6	6.8	1.1	12.0	43.0
1996	35.3	8.8	11.3	1.7	14.9	72.1
1997	59.0	12.3	17.3	2.5	17.5	108.6
1998	89.4	15.7	23.4	3.4	19.7	151.5
1999	105.4	21.4	35.4	4.5	21.5	188.1
2000	120.8	28.1	49.5	5.8	23.9	228.1
2001	136.2	35.4	63.4	7.4	25.8	268.2
2002	151.6	42.2	77.1	9.0	26.8	306.7
2003	167.0	49.3	90.4	10.6	27.8	345.2
2004	182.5	56.3	103.6	12.4	28.3	383.1
2005	197.9	63.3	113.2	14.2	28.9	417.4
2006	209.6	70.3	122.6	16.0	29.4	447.9
2007	221.3	77.1	131.9	17.8	30.0	478.0
2008	230.9	84.2	141.0	19.8	30.5	506.4
2009	240.5	91.3	149.9	21.7	30.9	534.2
2010	250.0	97.9	158.6	23.4	31.3	561.3
2011	259.6	104.5	161.2	25.1	31.7	582.0
2012	268.1	111.1	162.9	26.8	32.1	601.0
2013	275.9	117.7	163.8	28.5	32.5	618.4

MEDIUM RAMP (MD), MEDIUM HIGH GROWTH CUMMULATIVE MWa

	COMPANY IND	NEW COML	COML RETRO	NEW RES	RES RETRO	TOTAL DSM
1994	6.7	2.6	2.5	0.5	8.1	20.4
1995	17.6	5.5	6.8	1.1	12.1	43.1
1996	35.3	8.8	11.3	1.7	15.1	72.3
1997	59.0	12.3	17.3	2.5	17.7	108.8
1998	89.4	15.7	23.4	3.4	20.0	151.8
1999	109.0	22.8	36.8	5.0	21.8	195.4
2000	128.0	31.3	50.9	6.9	24.3	241.4
2001	147.0	40.3	64.8	9.1	26.3	287.5
2002	166.0	49.1	78.4	11.4	27.3	332.2
2003	185.0	58.0	91.8	13.8	28.4	376.9
2004	204.0	67.0	104.9	16.3	29.0	421.2
2005	223.0	76.1	114.5	19.0	29.6	462.1
2006	237.3	85.1	123.9	21.6	30.2	498.0
2007	251.5	93.9	133.1	24.3	30.8	533.7
2008	263.0	103.2	142.2	27.2	31.5	567.1
2009	274.6	112.4	151.1	30.0	32.0	600.0
2010	286.2	121.1	159.3	32.5	32.4	631.5
2011	297.7	129.6	161.5	35.1	32.9	656.8
2012	307.9	138.2	163.0	37.6	33.4	680.2
2013	317.5	146.8	163.9	40.2	33.9	702.3

MEDIUM RAMP (MD), HIGH GROWTH CUMMULATIVE MWa

	COMPANY IND	NEW COML	COML RETRO	NEW RES	RES RETRO	TOTAL DSM
1994	6.7	2.6	2.5	0.5	8.1	20.4
1995	17.6	5.5	6.8	1.1	12.2	43.2
1996	35.3	8.8	11.3	1.7	15.3	72.5
1997	59.0	12.3	17.3	2.5	18.0	109.1
1998	89.4	15.7	23.4	3.4	20.3	152.1
1999	112.7	24.3	36.8	5.6	22.2	201.6
2000	135.3	34.2	50.9	8.0	24.7	253.2
2001	157.9	44.6	64.8	10.8	26.8	304.9
2002	180.5	54.9	78.4	13.7	27.9	355.5
2003	203.2	65.4	91.8	16.8	29.0	406.1
2004	225.8	76.0	104.9	20.1	29.6	456.4
2005	248.4	86.8	114.5	23.5	30.3	503.4
2006	265.3	97.4	123.9	26.9	31.0	544.5
2007	282.3	107.7	133.1	30.3	31.7	585.1
2008	296.0	118.5	142.2	34.0	32.4	623.1
2009	309.7	129.2	151.1	37.6	32.9	660.5
2010	323.4	139.3	159.3	41.0	33.5	696.4
2011	337.1	149.3	161.5	44.3	34.0	726.2
2012	349.2	159.3	163.0	47.6	34.5	753.6
2013	360.7	169.3	163.9	51.0	35.1	779.9

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MEDIUM RAMP (MD), MEDIUM LOW GROWTH — CUMMULATIVE MWa

	COMPANY IND	NEW COML	COML RETRO	NEW RES	RES RETRO	TOTAL DSM
1994	6.7	2.6	2.5	0.5	8.0	20.3
1995	17.6	5.5	6.8	1.1	11.9	42.8
1996	35.3	8.8	11.3	1.7	14.7	71.9
1997	59.0	12.2	17.3	2.5	17.3	108.4
1998	89.4	15.7	23.4	3.4	19.5	151.2
1999	102.4	20.3	36.8	3.9	21.2	184.5
2000	114.8	25.7	50.9	4.7	23.5	219.7
2001	127.3	31.7	64.8	5.7	25.4	254.9
2002	139.7	37.2	78.4	6.8	26.3	288.3
2003	152.2	42.8	91.8	7.7	27.3	321.7
2004	164.6	48.4	104.9	8.8	27.7	354.4
2005	177.1	53.8	114.5	9.9	28.2	383.4
2006	186.6	59.2	123.9	11.0	28.6	409.3
2007	196.1	64.5	133.1	12.0	29.1	434.8
2008	204.0	70.1	142.2	13.2	29.6	459.0
2009	211.8	75.5	151.1	14.2	30.0	482.6
2010	219.7	80.6	159.3	15.2	30.3	505.1
2011	227.6	85.7	161.5	16.2	30.6	521.6
2012	234.5	90.9	163.0	17.2	31.0	536.5
2013	240.9	96.0	163.9	18.2	31.3	550.3

MEDIUM RAMP (MD), LOW GROWTH — CUMMULATIVE MWa

	COMPANY IND	NEW COML	COML RETRO	NEW RES	RES RETRO	TOTAL DSM
1994	6.7	2.6	2.5	0.5	7.9	20.3
1995	17.6	5.6	6.8	1.1	11.8	42.8
1996	35.3	8.8	11.3	1.7	14.6	71.8
1997	59.0	12.3	17.3	2.5	17.1	108.2
1998	89.4	15.6	23.4	3.4	19.3	151.0
1999	99.9	19.2	36.8	3.9	21.0	180.8
2000	110.0	23.5	50.9	4.6	23.2	212.3
2001	120.1	28.3	64.8	5.6	25.1	243.9
2002	130.2	32.6	78.4	6.6	26.0	273.7
2003	140.3	37.0	91.8	7.5	26.9	303.5
2004	150.4	41.3	104.9	8.5	27.3	332.4
2005	160.5	45.5	114.5	9.5	27.7	357.6
2006	168.2	49.6	123.9	10.4	28.1	380.3
2007	175.9	53.7	133.1	11.3	28.6	402.6
2008	182.4	57.9	142.2	12.3	29.0	423.8
2009	188.8	62.1	151.1	13.1	29.3	444.3
2010	195.2	65.8	159.3	13.7	29.6	463.6
2011	201.6	69.5	161.5	14.4	29.9	476.9
2012	207.2	73.1	163.0	15.0	30.2	488.5
2013	212.3	76.7	163.9	15.6	30.4	498.9

LOW COST, LOW RAMP (LD), MEDIUM GROWTH CUMMULATIVE MWa

	COMPANY IND	NEW COML	COML RETRO	NEW RES	RES RETRO	TOTAL DSM
1994	6.7	2.4	2.5	0.0	3.6	15.2
1995	17.6	5.2	6.8	0.0	5.1	34.6
1996	27.3	8.3	11.3	0.0	6.6	53.5
1997	34.8	11.5	17.3	0.0	7.6	71.1
1998	40.0	14.7	23.4	0.0	8.2	86.2
1999	44.8	16.6	34.5	0.0	8.4	104.3
2000	49.2	19.0	42.8	0.0	8.6	119.7
2001	53.6	22.0	51.0	0.0	8.9	135.5
2002	60.9	25.1	59.1	0.0	9.2	154.3
2003	68.3	28.6	67.0	0.0	9.4	173.3
2004	75.7	32.2	74.7	0.0	9.7	192.4
2005	83.0	35.8	80.7	0.0	10.1	209.6
2006	90.4	39.4	86.6	0.0	10.4	226.7
2007	97.7	42.9	92.3	0.0	10.7	243.7
2008	103.7	46.6	97.9	0.0	11.1	259.3
2009	109.6	50.3	103.4	0.0	11.3	274.6
2010	115.5	53.7	108.6	0.0	11.5	289.3
2011	121.4	57.1	110.6	0.0	11.7	300.8
2012	127.3	60.6	112.1	0.0	11.9	311.9
2013	131.3	64.0	113.4	0.0	12.1	320.8

LOW COST, LOW RAMP (LD), MEDIUM HIGH GROWTH CUMMULATIVE MWa

	COMPANY IND	NEW COML	COML RETRO	NEW RES	RES RETRO	TOTAL DSM
1994	6.7	2.5	2.5	0.0	3.6	15.3
1995	17.6	5.3	6.8	0.0	5.1	34.8
1996	30.0	8.5	11.3	0.0	6.7	56.5
1997	39.6	11.9	17.3	0.0	7.6	76.4
1998	46.3	15.2	23.4	0.0	8.2	93.1
1999	52.1	17.1	34.5	0.0	8.5	112.2
2000	57.5	19.7	42.8	0.0	8.7	128.8
2001	62.9	22.9	51.0	0.0	9.0	145.8
2002	71.9	26.3	59.1	0.0	9.3	166.5
2003	80.9	30.1	67.0	0.0	9.6	187.6
2004	89.9	34.1	74.7	0.0	9.9	208.6
2005	98.9	38.0	80.7	0.0	10.2	227.9
2006	108.0	41.9	86.6	0.0	10.6	247.0
2007	117.0	45.7	92.3	0.0	10.9	266.0
2008	124.2	49.8	97.9	0.0	11.3	283.2
2009	131.3	53.8	103.4	0.0	11.6	300.1
2010	138.5	57.5	108.6	0.0	11.8	316.4
2011	145.7	61.3	110.6	0.0	12.0	329.6
2012	152.9	65.0	112.1	0.0	12.2	342.2
2013	157.8	68.8	113.4	0.0	12.5	352.5

LOW COST, LOW RAMP (LD), HIGH GROWTH CUMMULATIVE MWa

	COMPANY IND	NEW COML	COML RETRO	NEW RES	RES RETRO	TOTAL DSM
1994	6.7	2.5	2.5	0.0	3.6	15.3
1995	17.6	5.4	6.8	0.0	5.2	35.0
1996	32.4	8.7	11.3	0.0	6.7	59.2
1997	43.9	12.1	17.3	0.0	7.7	81.0
1998	51.9	15.6	23.4	0.0	8.3	99.1
1999	58.7	17.5	34.5	0.0	8.6	119.3
2000	65.1	20.3	42.8	0.0	8.8	137.0
2001	71.5	23.6	51.0	0.0	9.1	155.8
2002	82.3	27.2	59.1	0.0	9.4	178.0
2003	93.0	31.3	67.0	0.0	9.7	201.0
2004	103.8	35.5	74.7	0.0	10.1	224.1
2005	114.5	39.7	80.7	0.0	10.4	245.4
2006	125.3	43.9	86.6	0.0	10.8	266.5
2007	136.0	48.0	92.3	0.0	11.2	287.4
2008	144.5	52.2	97.9	0.0	11.6	306.3
2009	153.0	56.5	103.4	0.0	11.8	324.8
2010	161.5	60.5	108.6	0.0	12.1	342.7
2011	170.0	64.4	110.6	0.0	12.3	357.4
2012	178.6	68.4	112.1	0.0	12.6	371.6
2013	184.4	72.3	113.4	0.0	12.8	383.1

ACCELERATED RAMP (AD), MEDIUM GROWTH CUMMULATIVE MWa

	COMPANY IND	NEW COML	COML RETRO	NEW RES	RES RETRO	TOTAL DSM
1994	19.7	4.5	2.5	0.4	8.0	35.2
1995	53.2	9.2	6.8	1.0	12.0	82.1
1996	114.8	15.1	11.3	1.5	14.9	157.7
1997	140.9	21.1	17.3	2.2	17.5	199.0
1998	172.8	27.5	23.4	3.0	19.7	246.4
1999	181.8	34.7	35.4	3.9	21.5	277.3
2000	190.7	42.4	49.5	5.1	23.9	311.6
2001	199.7	50.7	63.4	6.5	25.8	346.1
2002	208.6	58.4	77.1	8.0	26.8	378.9
2003	215.7	66.4	90.4	9.4	27.8	409.8
2004	222.8	74.4	103.6	11.0	28.3	440.2
2005	230.0	82.3	113.2	12.7	28.9	467.0
2006	237.1	90.2	122.6	14.3	29.4	493.6
2007	244.2	97.9	131.9	15.9	30.0	519.9
2008	251.0	106.0	141.0	17.7	30.5	546.2
2009	257.8	114.0	149.9	19.4	30.9	572.0
2010	264.7	121.5	158.6	20.9	31.3	597.0
2011	271.5	128.9	161.2	22.4	31.7	615.7
2012	277.2	136.4	162.9	24.0	32.1	632.6
2013	282.9	143.9	163.9	25.5	32.5	648.7

ACCELERATED RAMP (AD), MEDIUM HIGH GROWTH CUMMULATIVE MWa

	COMPANY IND	NEW COML	COML RETRO	NEW RES	RES RETRO	TOTAL DSM
1994	19.7	5.3	2.5	0.5	8.1	36.1
1995	53.2	11.1	6.8	1.1	12.1	84.1
1996	114.8	18.4	11.3	1.7	15.1	161.3
1997	140.9	26.1	17.3	2.5	17.7	204.5
1998	172.8	34.2	23.4	3.4	20.0	253.8
1999	184.2	43.4	36.8	5.0	21.8	291.2
2000	194.9	53.1	50.9	6.9	24.3	330.1
2001	205.6	63.4	64.8	9.1	26.3	369.2
2002	216.3	73.3	78.4	11.4	27.3	406.7
2003	224.7	83.4	91.8	13.8	28.4	442.0
2004	233.1	93.6	104.9	16.3	29.0	476.8
2005	241.5	103.8	114.5	19.0	29.6	508.3
2006	249.8	114.1	123.9	21.6	30.2	539.6
2007	258.2	124.1	133.1	24.3	30.8	570.5
2008	266.2	134.6	142.2	27.2	31.5	601.7
2009	274.2	145.0	151.1	30.0	32.0	632.3
2010	282.2	154.9	159.3	32.5	32.4	661.4
2011	290.3	164.6	161.5	35.1	32.9	684.3
2012	296.9	174.3	163.0	37.6	33.4	705.3
2013	303.0	184.0	163.9	40.2	33.9	725.0

ACCELERATED RAMP (AD), HIGH GROWTH CUMMULATIVE MWa

	COMPANY IND	NEW COML	COML RETRO	NEW RES	RES RETRO	TOTAL DSM
1994	19.7	6.7	2.5	0.5	8.1	37.5
1995	53.2	14.6	6.8	1.1	12.2	87.8
1996	114.8	24.6	11.3	1.7	15.3	167.7
1997	140.9	35.0	17.3	2.5	18.0	213.7
1998	172.8	45.9	23.4	3.4	20.3	265.8
1999	186.3	57.9	36.8	5.6	22.2	308.8
2000	199.0	70.2	50.9	8.0	24.7	352.8
2001	211.7	82.9	64.8	10.8	26.8	397.0
2002	224.4	95.5	78.4	13.7	27.9	439.9
2003	234.3	108.3	91.8	16.8	29.0	480.2
2004	244.2	121.5	104.9	20.1	29.6	520.3
2005	254.1	134.6	114.5	23.5	30.3	557.0
2006	264.0	147.6	123.9	26.9	31.0	593.4
2007	273.9	160.3	133.1	30.3	31.7	629.3
2008	283.4	173.5	142.2	34.0	32.4	665.4
2009	292.8	186.6	151.1	37.6	32.9	701.0
2010	302.3	199.0	159.3	41.0	33.5	734.9
2011	311.7	211.2	161.5	44.3	34.0	762.7
2012	319.6	223.4	163.0	47.6	34.5	788.2
2013	326.9	235.8	163.9	51.0	35.1	812.5

IGH COST, ACCELERATED RAMP (HD), MEDIUM GROWTH CUMMULATIVE MWa

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	COMPANY IND	NEW COML	COML RETRO	NEW RES	RES RETRO	TOTAL DSM
1994	19.7	5.3	2.5	0.4	8.4	36.3
1995	53.2	10.8	6.8	1.0	12.7	84.4
1996	114.8	17.5	11.3	1.5	16.2	161.4
1997	140.9	24.5	17.3	2.2	19.4	204.4
1998	172.8	31.9	23.4	3.0	22.3	253.5
1999	181.8	40.3	37.9	3.9	25.0	288.9
2000	190.7	49.2	55.0	5.1	28.5	328.5
2001	199.7	58.7	71.9	6.5	31.5	368.2
2002	208.6	67.6	88.5	8.0	33.4	406.2
2003	215.7	76.8	104.9	9.4	35.5	442.4
2004	222.8	86.0	121.0	11.0	37.1	477.9
2005	230.0	95.1	132.7	12.7	38.7	509.1
2006	237.1	104.2	144.2	14.3	40.4	540.1
2007	244.2	113.0	155.5	15.9	42.2	570.8
2008	251.0	122.3	166.7	17.7	44.0	601.6
2009	257.8	131.4	177.6	19.4	45.6	631.8
2010	264.7	140.0	188.4	20.9	47.2	661.2
2011	271.5	148.5	191.9	22.4	48.8	683.1
2012	277.2	157.1	194.4	24.0	50.5	703.1
2013	282.9	165.6	196.0	25.5	52.2	722.1

IGH COST, ACCELERATED RAMP (HD), MEDIUM HIGH GROWTH CUMMULATIVE MWa

	COMPANY IND	NEW COML	COML RETRO	NEW RES	RES RETRO	TOTAL DSM
1994	19.7	6.2	2.5	0.5	8.4	37.4
1995	53.2	12.9	6.8	1.1	12.9	86.8
1996	114.8	21.4	11.3	1.7	16.4	165.7
1997	140.9	30.3	17.3	2.5	19.7	210.7
1998	172.8	39.7	23.4	3.4	22.8	262.0
1999	184.2	50.2	39.5	5.0	25.5	304.4
2000	194.9	61.4	56.6	6.9	29.1	348.9
2001	205.6	73.2	73.4	9.1	32.3	393.6
2002	216.3	84.6	90.0	11.4	34.4	436.7
2003	224.7	96.2	106.3	13.8	36.6	477.6
2004	233.1	107.9	122.4	16.3	38.3	518.0
2005	241.5	119.6	134.1	19.0	40.2	554.3
2006	249.8	131.3	145.6	21.6	42.1	590.4
2007	258.2	142.8	156.9	24.3	44.1	626.2
2008	266.2	154.8	168.0	27.2	46.1	662.3
2009	274.2	166.6	179.0	30.0	47.9	697.7
2010	282.2	177.8	189.2	32.5	49.8	731.5
2011	290.3	188.9	192.3	35.1	51.6	758.2
2012	296.9	200.0	194.6	37.6	53.6	782.6
2013	303.0	211.0	196.0	40.2	55.5	805.7

HIGH COST, ACCELERATED RAMP (HD), HIGH GROWTH

CUMMULATIVE MWa

	COMPANY IND	NEW COML	COML RETRO	NEW RES	RES RETRO	TOTAL DSM
1994	19.7	6.9	2.5	0.5	8.5	38.1
1995	53.2	15.1	6.8	1.1	13.0	89.1
1996	114.8	25.6	11.3	1.7	16.7	170.1
1997	140.9	36.6	17.3	2.5	20.1	217.4
1998	172.8	48.0	23.4	3.4	23.3	270.9
1999	186.3	60.8	39.5	5.6	26.1	318.3
2000	199.0	73.9	56.6	8.0	29.8	367.3
2001	211.7	87.4	73.4	10.8	33.1	416.4
2002	224.4	100.8	90.0	13.7	35.3	464.3
2003	234.3	114.3	106.3	16.8	37.7	509.4
2004	244.2	128.2	122.4	20.1	39.6	554.4
2005	254.1	142.1	134.1	23.5	41.6	595.3
2006	264.0	155.8	145.6	26.9	43.6	635.9
2007	273.9	169.2	156.9	30.3	45.7	676.0
2008	283.4	183.1	168.0	34.0	47.9	716.4
2009	292.8	196.9	179.0	37.6	49.9	756.3
2010	302.3	210.0	189.2	41.0	52.0	794.4
2011	311.7	222.9	192.3	44.3	54.0	825.2
2012	319.6	235.8	194.6	47.6	56.1	853.7
2013	326.9	248.7	196.0	51.0	58.3	880.8

PP 125

STATEMENT OF UTAH INDUSTRIAL ENERGY CONSUMERS* REGARDING RATE DESIGN RECOMMENDATIONS IN DRAFT RAMPP-3 ACTION PLAN

UIEC has reviewed PacifiCorp's draft RAMPP-3 Action Plan, which was distributed on December 3, 1993. UIEC hereby advises PacifiCorp and the members of the RAG that it strenuously objects to Item 7 in the draft Action Plan.

Item 7, and in particular 7(c), addresses rate design issues that are well beyond the bounds of what is appropriate for RAMPP-3. The appropriate basis for developing energy and demand charges for commercial and industrial customers, and the current relationship of these charges to either embedded or marginal costs has never been addressed in the RAMPP-3 discussions.

Furthermore, UIEC would note that the Utah Public Service Commission has not accepted the concept of marginal costs for either cost of service or rate design. And, even if marginal costs had been adopted as a pricing principle, it has not been established whether existing energy charges should increase or decrease relative to demand charges.

UIEC recommends striking Item 7 in its entirety. Rate design should be addressed in state PSC hearings, not in RAMPP. If PacifiCorp wishes to incorporate a rate design comment, it should be limited to the following:

> "Continue to study, and implement as appropriate, rate design changes which will move rates closer to cost and assist customers to improve the efficiency of their use of electric power."

At this time, UIEC takes no position on the other items included in the draft RAMPP-3 Action Plan.

December 17, 1993

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* Utah Industrial Energy Consumers (UIEC) consists of nine large industrial Rate Schedule and Contract customers of Utah Power & Light Company in Utah. Collectively, these companies purchase in excess of 1.3 billion kilowatthours per year from UP&L.

PP 12

Northwest
Conservation
Act
Coalition

PP 127

Ms. Nancy Esteb
Manager, Integrated Resource Planning
Pacificorp
920 SW Sixth Ave.
Portland, OR 97204-1256

COMMENTS OF THE NORTHWEST CONSERVATION ACT COALITION
ON PACIFIC POWER & LIGHT'S 1993 DRAFT ACTION PLAN
JANUARY 4, 1994

PP&L staff have done some significant analytical work in this planning round, and the company has made some real advances especially in the area of renewables. However, in many respects there is a disconnect between the staff's analytical results and the company's resultant Plan.

Our most serious concern is that management has added internal financial criteria which emphasize a rate impact test and lost revenue accounting which are clearly contrary to Oregon PUC policy. Not only are these new criteria contrary to the suppositions of Least-Cost Planning mandated by most Northwest states, they specifically contradict company pledges given during the RAMPP-3 process to abandon the "no losers" test in favor of Total Resource Cost as the basis for policy.

It is our understanding that fears of retail competition are to blame for this renewed emphasis on short-term rate impacts. However there has been no analysis to measure the impacts of increased rates. This is no easy task, given the multiple factors of load elasticity, decoupling and the trade-off of more available power for the secondary market. However the net cost or benefit has not at all been demonstrated. Certainly not enough to justify the higher utility and societal costs which will inevitably result from abandoning true least cost planning principles.

In any case it is incumbent upon the company to demonstrate such an analysis before making so radical a change in policy. And, we would expect the OPUC to demand justification before allowing it.

We understand that this is just a draft plan, and more data and explanations will be provided. Our comments are also preliminary, but we hope the company will incorporate them in its final version.

PP&L's Plan is commendable in several areas:

1) The company is demonstrating a fair commitment to renewables. Given the company's very weak statements on renewables in its last plan, its actions are very heartening. However, we are wary of repeated "if cost effective" caveats. We propose more site study and optioning to position the company better to be able to acquire all needed resources commencing in 2000 without relying on fossil-fueled plants (as per UM550.) Indeed, the company should adopt this goal in compliance with Oregon legislative mandate.

217 Pine St., Suite 1020 • Seattle, WA 98101-1520 • (206) 621-0094 • Fax (206) 621-0097

2) Analytic data now calculate the TRC, as ordered by OPUC, which was notably missing in RAMPP-2.

3) The company is proposing to eliminate declining block energy pricing for residential customers in Montana and Utah.

However the process was far less successful in other areas:

New internal financial standard for comparing supply and demand side resources

As indicated above, this is our most serious concern. At the Dec. 15th meeting, company management apparently decided that a 1% rate impact test will replace OPUC's (and other states') Total Resource Cost test. In addition, though the new policy was not well explained at the meeting, lost revenues will no longer be treated as a neutral transfer payment, but will influence the resource decision against DSR.

We strongly urge the company to reconsider this new policy and trust that the OPUC will disallow it. Pacific's stated goal of being the low rate provider, while understandable, is incompatible with least cost planning which seeks the lowest present value cost rather than the lowest rate.

Since bills matter more than rates to customers, the answer to Pacific's conundrum of charging non-participants in DSR programs for benefits received by participants, is to make sure that all customers receive benefits. If the company offers a wide enough array of DSR programs, there need not be any non-participants, and the company's competitiveness is guaranteed.

It was also stated at the same meeting that another new financial "screen" would be that all DSR programs must produce an internal rate of return of greater than 9%. If this is a problem, instead of using this criterion to screen out certain programs the company should go to the Commission and ask for relief to ensure that all DSR investments are properly accounted for.

Failure to connect modeling results clearly to the Action Plan

It was unclear how the computer runs led to the plan results. In response to a question asking why computer data pointing to higher DSR use didn't push the Action Plan in that direction, for example, the company said one problem was that the 20-year runs we had weren't used internally. Instead 30- and 50-year runs were used. Given their high capital, no-fuel cost nature, it would seem that longer runs should favor DSR and renewables even more. But in any case, why were we not given the same information the company used for its decision-making? Thus the RAMPP group had few tools to verify if the Action Plan was the most prudent action.

Every combination of runs which used high DSR had a lower utility cost (NPV), lower customer bills, and lower TRC than other DSR strategies, but the Action Plan chose a medium DSR portfolio. This result alone, without other evidence, would seem to say that the Action Plan was not developed from the analytical results, but came from other considerations.

One such consideration was the new financial test, discussed above, which limits programs which have a more than 1% rate impact. However, even with this restriction the high DSR strategy should have been chosen. For instance runs 33 and 41 compare medium to high DSR while keeping all other factors the same. The rate rises only .6%, from 48.0 to 48.3 mills/kWh. (Meanwhile customers' bills went down by about the same amount.) This is true in case after case, but still the company picked medium DSR as its strategy. We are forced to wonder if the Action Plan was based on the data at all. We urge the company to clearly dilineate the logical steps from the staff's computer analysis to its Action Plan.

Failure to analyze a wide array of DSR strategies

Despite the urging of many parties, a truly aggressive DSR strategy was not analyzed. The company labeled its strategies as Low, Medium, Accelerated and High, but these were misnomers. Their low strategy is barely more than the required low-income programs, and the medium strategy is what we would consider minimal. Given that every run showed more DSR produced lower bills and lower total costs, it is incumbent on the company to analyze even higher DSR rates. Interestingly, in the few unconstrained runs done, the computer did pick more DSR than even in the High strategy.

The company replied that it is simply impossible to do more conservation and has reduced penetration goals from its RAMPP-2 plan, citing lower regional economic growth as the principal reason. We suggest that Pacific's narrow focus on rate impact reduces its DSR acquisition efficiency. This rate focus limits its tools to the energy service charge which may not be, in every instance, the best way to acquire DSR.

Inadequate tracking of DSR acquisitions

The draft Plan changes the way DSR acquisitions will be counted from the present method of counting when contracts are signed. We are very concerned about this "change." We see this as an admission that the previous DSR targets were not really met. It was never our understanding that RAMPP-2 DSR acquisition goals were not installed measures. Indeed, the RAMPP-2 cumputer runs counted them as load reduction in the year they are counted, not in a future year. In addition, besides occurring later than in the planning models, some signed measures surely are never installed, and there is a real danger that some signed, but delayed, measures will be counted twice when the work is finally done.

The company's admission that many MWs counted in the planning process to reduce load in '92-3 have not yet been installed is a serious misrepresentation of its intentions. We urge OPUC to look into this matter. The company should detail how it intends to "catch up" to its goals, and reclassify previous years' DSR results to count only installed measures.

We would also like the company to break down its DSR targets by year, sector, price and state so that each commission can track progress.

Failure to consider fuel conversion to direct use

Fuel switching should have been analyzed as a more efficient use of natural gas than burning it in CTs. The company is violating a specific OPUC order by not considering this issue. The plan totally ignores this resource choice estimated by the NWPPC to be hundreds of megawatts. This is another example of where a rate impact focus leads to higher total resource costs.

Analysis of environmental externalities very confusing

Though we were given numerous computer runs detailing the effect of various environmental cost adders, it was very difficult to judge the costs and benefits of various defensive strategies. What is needed is a rough measure of how much an extra dollar or mill/kWr spent on DSR or renewables would save society under each environmental cost scenario.

One strategy in particular should be analytically pursued: a "most prudent" portfolio of acquisitions which would aggressively avoid environmental tax consequences. This high DSR and renewables strategy, coupled with a phase-down of coal, and targeted co-gen of inefficient boilers, could be operated at least-dollar cost until taxes were enacted. We would like to see the costs and "insurance benefit" of this strategy.

Also of serious concern is that the environmental analysis did not have enough effect on the policy choices in the action plan. As we have said, we are heartened by Pacific's first steps toward renewables, but more should be done given the magnitude of liability facing any strategy based mainly on fossil-fuels.

A most important need is for renewable resource site identification and climatic monitoring. Without this information, future facilities cannot be designed and sited. Since it takes years to develop sufficient data, the monitoring process must start now. It is not expensive. As suitable sites are located, options can be obtained. Only in this way can the company be positioned to acquire all cost-effective renewables by the year 2000.

Load-building activities still part of company policy

It remains to be seen how decoupling will be implemented. However load-building and load-retention continue to be driving forces for the company.

It is obvious that the lack of serious consideration for fuel switching is evidence of these forces while the utility aggressively pursues the acquisition of gas CTs, such as the in-name-only cogen project at Hermiston.

The determination of societal benefit and cost is best done as part of a least cost plan. If load-building and load-retention marketing does not provide a societal benefit, it should not be permitted by the Commission. Cessation of marketing activities should be considered as a Demand Side Resource option. It is hard to understand how building a SGC home with a gas water heater can be construed as anything else but load-building.

Failure to fully explore rate design options

It is to the company's credit that it is eliminating declining block price structures for its residential customers. It should go further to embrace realistic market price signals by establishing inverted rates. Since decoupling would protect the company against revenue erosion, there is no major reason beyond the general utility-culture distrust of lost load that would prevent its adoption of residential inverted rates. Inverted rates would have significant effects on both long term demand and DSR program effectivness. Given Pacific's stated frustration with the low penetration rates of existing programs, one would think it would welcome a no-cost (under decoupling) way of encouraging customer participation in these programs.

The Action Plan is short on specifics

As we have said, it would be very helpful to have breakdowns of DSR programs by state, sector, etc. In addition, in the third paragraph of the Action Plan's first page, the company "plans on issuing another RFP after the RAMPP-3 process, and anticipates that some of the resource needs identified in this action [plan] could be met through that bidding process." We would like to know about this RFP. Will it be for all-resources, in all states?

We assume that the lack of specificity will be corrected in more detailed versions of the Plan to follow.

We look forward to our next meeting and appreciate the opportunity to comment.

Sincerely,

Steven Weiss

Steven Weiss

cc: RAMPP-3 Participants

PP 132

PP 133

PACIFICORP
PACIFIC POWER UTAH POWER

February 22, 1994

Steven Weiss
Northwest Conservation Act Coalition
217 Pine Street, Suite 1020
Seattle, WA 98101-1520

Dear Steven:

Thank you for your letter of January 4, 1994. We would like to apologize for not providing a written answer sooner. Our attention was focused on completing the RAMPP-3 Draft Report mailed to interested parties on January 28, and then on getting the Draft Appendices ready for the February 17-18 RAG meetings.

Your letter addresses several concerns, which this letter will discuss in the same order you did.

Internal Financial Standards for DSR

First, I'd like to restate the three-part financial standard:

1) The internal rate of return of the utility's cash flow from the DSR program must exceed 9 percent.

2) Real levelized DSR program costs must be less than PacifiCorp's incremental power cost after adjusting for losses and adding 15 percent.

3) Total DSR program activity must not create more than a 1 percent price increase.

These standards developed from management's concern that demand-side and supply-side resources were not being evaluated on a consistent basis. These standards provide needed consistency, and reduce internal review and debate of specific DSR programs.

The inclusion of a price impact standard arises from the company's long-standing concern with the price impacts associated with DSR programs. The increasingly competitive marketplace has made that concern more important to the company. In addition, the experience of utilities with large scale DSR investments has not been favorable in terms of price and non-participant impacts. It is appropriate for management to exercise it's business judgment regarding the course of action best suited to balance the desire to pursue cost-effective DSR while recognizing its potential impacts on the company's competitive position.

The 1 percent price impact limit should not be compared to the RAMPP model outputs, since RAMPP is a 50-year real levelized analysis, whereas the financial standards model looks at year-by-year price impacts. The internal standards provide information necessary for the company to modify demand-side programs where it can to achieve the most cost-effective DSR while mitigating year-by-year price impacts to keep the total cumulative price increase by 1997 under 1 percent.

These standards enable the company to rank DSR programs to identify where to focus more effort, and how to modify programs so that they can achieve the greatest benefit for the least cost. Thus the company is pursuing the most cost effective programs first, and delaying more expensive programs until they become more cost effective. The net result of using these standards over the next five years would be a 9 MWa reduction in DSR acquisitions compared to a level based only on an avoided cost standard.

PacifiCorp believes that least cost planning incorporates the goal of serving customers at the lowest cost, and price is an important component of lowest cost. For some customers, bills may be more important, but for many of our customers, price is their principal criteria.

Development of Action Plan

The company used the modeling results along with management experience and judgment to develop the action plan. The modeling results provide useful information for management; they do not dictate company actions.

The RAMPP report does not link a specific run to a specific action plan item. Nor should it. Information gained from the process was used to support each action plan item. For example, the action plan item to evaluate clean coal technologies arose from the model's selection of pulverized coal as the lowest cost supply-side resource, and the model's selection of IGCC coal technology in the environmental adder cases.

Levels of DSR Tested

For RAMPP testing, the company selected a range of DSR amounts that bounds the achievable and cost effective limits of DSR in PacifiCorp's service territory. The amount and timing of DSR acquisition in the high DSR strategy was based on the maximum amount of DSR the company believes it could acquire without excessive cost increases for DSR programs.

It is true, as you note in your letter, that each of the runs with a higher amount of DSR had a lower total utility cost and a lower total resource cost. However, they also had a trade-off in the form of higher prices for customers. The trade-off in price impacts led the company to select an amount of DSR that best balanced price and revenue requirement trade-offs. The level of DSR selected was lower than the level tested in the high DSR strategy.

Tracking of DSR acquisitions

The company developed its short term action plan for RAMPP-2 with a clear priority toward capturing lost opportunities in new construction. Secondary in importance was "capability building" to prepare the company to deliver discretionary or dispatchable conservation when the resource was required. Since the focus of the DSR effort in the 1992-1993 action plan was on new construction, the ability to deliver installed capability was at least partially a function of the marketplace.

Due to the very misunderstanding cited by your letter, the Company has moved to a project management approach to tracking demand-side initiatives. The lengthy time lags between initiation of a project and subsequent completion (18 months for commercial projects and up to 22 months for industrial) has dictated a more detailed tracking system. For 1993, the company tracked and reported projects on a signed, installed and pipeline (yet to be completed) basis. This method of tracking enables the company to report pipeline as well as completed results, thereby giving an indication of present and future DSR impacts. RAMPP-3 short term action plan items are stated on an installed basis.

Fuel Switching

One of the RAMPP-3 sensitivities, Case #201, examined the impacts of reduced load, which could occur from fuel switching. The Q&A chapter of the draft Report also discusses the issue. The company believes that the marketplace is the appropriate place to determine fuel choice. Appropriate price signals create a situation in which consumers will choose that fuel which best meets their needs. To date, our experience suggests that the marketplace is working properly and that price differentials are being recognized.

External Cost Analysis

The company is preparing an insurance cost analysis for environmental risk, which will be included in the final RAMPP-3 report. That analysis indicates that it costs about $40 to avoid the risk of $100 in environmental taxes. Furthermore, the $40/$100 ratio is consistent across all environmental externalities cases tested in RAMPP-3. Another method to address the risk of environmental taxes is to acquire experience with renewable technologies, which the company is doing through its Washington and Wyoming wind projects, four photovoltaic projects, participation in Solar II, and negotiations with geothermal developers.

Load Building

The RAMPP study includes five different levels of load growth in the base study plan, plus three additional levels in sensitivities. These bound the likely level of load growth in PacifiCorp's service territory. The analyses provide a useful tool to evaluate the impact of different load growth futures. The company believes that it should recognize and be responsive to customer choices. Some of those choices will cause increased usage of electricity while others will result in decreased usage. The company does not believe that efficient applications of electricity which provide additional benefits in the form of increased productivity or environmental pollution mitigation are inconsistent with the principles of least cost planning. The company does not intend to actively promote any one future but should be ready to provide whatever power is required efficiently and at low cost. The company is pleased that the RAMPP-3 results indicate that higher levels of load growth would generally not cause customer prices to increase faster than inflation.

Rate Design

The RAMPP analysis provides a framework which will allow the study of rate design impacts. One of the sensitivities was designed to address reduced load, which could result from a rate design change. Rate design is also discussed in the Q&A chapter, where the company notes that rate design must consider many factors in addition to DSR acquisition.

Specifics in the Action Plan

The action plan presents the goals that the company has adopted for the next two years, but not always the precise steps needed to accomplish the goals. The action plan provides sufficient detail to define the goal, while leaving the company flexibility in meeting the goal in the most cost effective way available at the time action needs to be taken.

Again, thank you for your letter. The company appreciates the opportunity to respond to these issues in writing, and will be distributing this letter to all members of the RAMPP public advisory group.

Sincerely,

Nancy

Nancy Esteb, Manager
Integrated Resource Planning

NE/ja

PP 13

State of Utah
DEPARTMENT OF NATURAL RESOURCES

Michael O. Leavitt
Governor

Ted Stewart
Executive Director

Richard Anderson, Ph.D.
Director

Office of Energy and Resource Planning
355 West North Temple
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PP 139

January 13, 1994

Ms. Nancy Esteb
920 S.W. Sixth Avenue
Portland, Oregon 97204-1256

RE: Recommendations for RAMPP-3 Draft Report

Dear Nancy:

As requested in the December RAMPP-3 Advisory Group meeting, we provide you with recommendations for your draft RAMPP-3 report.

1. We recommend that all model runs be presented in the report. At the last meeting, I had thought that some of the runs that did not yield unique results could be excluded from the draft report in the interest of reducing data overload to the reader. However, I was unable to pinpoint any for exclusion. The data overload concern could be addressed by presenting easy to read summary tables. See the attached tables for example.

2. We request that you present the financial data for the TRC perspective in one or more summary tables. (Again, see the attached tables for example.)

3. We request that you analyze the results of the model runs from the perspective of least total resource cost and that you present the results of this analysis. The Utah Public Service Commission Report and Order on Standards and Guidelines on PacifiCorp IRP defines "lowest cost" to mean total resource cost. The Utah PSC order further states that, "If different strategies have the same total resource costs, the Company should choose that strategy that has the lowest total revenue requirement."

As the selected strategy (or action plan) deviates from lowest total resource cost, we request that you identify and quantify or dimension the risks and uncertainties that are mitigated by the deviation from the lowest cost strategy. For instance, if diversity of resource mix is a goal, please define your diversity goal, that is, define what you consider will achieve resource diversity. Please document all supporting analysis. Again, the Commission order gives guidance on this point... "the [IRP] process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty."

We also request that you discuss who will bear the cost of the risk mitigation as requested in the Commission order directive: "PacifiCorp's future integrated resource plans will include: ...An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The Company will identify who should bear such risk, the ratepayer or the stockholder."

4. Please discuss the treatment of the "end-effects" of resource acquisition strategies both in the resource selection model and in the financial summary analysis.

PP 14

Ms. Nancy Esteb
January 13, 1994
Page 2

5. Since no emissions data is presented for SO_x; please include discussion of SO_x mitigation for the "any coal" strategies; that is, please include discussion of the need for and use of emissions allowances and any resultant cost trade-off between use of or sale of emissions allowances associated with the coal strategies.

We appreciate the opportunity to provide some up-front recommendations for what we would like to see included in the draft RAMPP-3 report. I apologize for not providing this sooner and hope that you still have adequate time to assure that the requested analysis is included in the draft report.

Sincerely,

Rebecca

Rebecca L. Wilson
Senior Energy Economist

mc

Attachments

cc: Richard Anderson
Jeffrey S. Burks
Rich Collins, PSC
Ken Powell, DPU

FUTURES		Load	L			ML			M			MH			H		
		Gas	LG	MG	HG	LG	MG	HG	LG	MG	HG	LG	MG	HG	LG	MG	HG
UNCONSTRAINED																	
LD	AC	AR							$20,969	$20,979	$20,909		$21,246			$21,870	
		SR							$21,242	$21,245	$21,175		$21,494			$22,068	
	NC	AR							$20,887	$20,995	$21,794		$21,468			$22,087	
		SR							$21,179	$21,276	$21,599		$21,581			$22,190	
MD	AC	AR		$20,437			$20,352		$20,691	$20,680	$20,644		$20,924			$21,498	
		SR		$20,910			$20,668		$20,965	$20,946	$20,837	$21,057	$21,168	$21,172	$21,586	$21,709	$21,788
	NC	AR		$20,437			$20,398		$20,612	$20,706	$21,283		$21,117			$21,729	
		SR		$20,910			$20,685		$20,903	$20,977	$21,141	$21,067	$21,228	$21,715	$21,553	$21,834	$22,737
AD	AC	AR							$20,638	$20,639	$20,573		$20,859			$21,391	
		SR							$20,914	$20,910	$20,809		$21,100			$21,609	
	NC	AR							$20,563	$20,649	$21,200		$20,926			$21,633	
		SR							$20,855	$20,919	$21,116		$21,163			$21,737	
HD	AC	AR							$20,564	$20,560	$20,479		$20,809			$21,286	
		SR							$20,846	$20,827	$20,724		$21,052			$21,507	
	NC	AR							$20,490	$20,570	$21,071		$20,873			$21,528	
		SR							$20,782	$20,836	$20,982		$21,108			$21,632	

RAMPP-3 Total Resource Cost NPV over 20 years at 8.8%

FUTURES		Load	L			ML			M			MH			H		
		Gas	LG	MG	HG	LG	MG	HG	LG	MG	HG	LG	MG	HG	LG	MG	HG
UNCONSTRAINED																	
LD	AC	AR							$31,243	$31,251	$31,137		$34,551			$38,390	
		SR							$31,653	$31,654	$31,539		$34,965			$38,746	
	NC	AR							$31,107	$31,277	$32,503		$34,921			$38,792	
		SR							$31,547	$31,703	$32,232		$35,120			$38,989	
MD	AC	AR		$26,164			$28,139		$31,102	$31,081	$31,021		$34,307			$38,049	
		SR		$26,758			$28,569		$31,513	$31,480	$31,304	$34,518	$34,718	$34,719	$38,198	$38,429	$38,576
	NC	AR		$26,164			$28,205		$30,970	$31,120	$31,992		$34,627			$38,481	
		SR		$26,758			$28,594		$31,410	$31,531	$31,798	$34,533	$34,822	$35,738	$38,126	$38,681	$40,534
AD	AC	AR							$30,942	$30,940	$30,834		$34,143			$37,914	
		SR							$31,358	$31,349	$31,187		$34,546			$38,306	
	NC	AR							$30,817	$30,954	$31,790		$34,623			$38,364	
		SR							$31,257	$31,363	$31,688		$34,656			$38,564	
HD	AC	AR							$30,916	$30,906	$30,774		$34,122			$37,852	
		SR							$31,341	$31,308	$31,145		$34,528			$38,251	
	NC	AR							$30,792	$30,921	$31,674		$34,236			$38,305	
		SR							$31,234	$31,321	$31,565		$34,625			$38,504	

PP 14

FUTURES		Load	L			ML			M			MH			H		
		Gas	LG	MG	HG	LG	MG	HG	LG	MG	HG	LG	MG	HG	LG	MG	HG
UNCONSTRAINED																	
LD	AC	AR							45.46	45.48	45.31		45.38			45.44	
		SR							46.06	46.06	45.89		45.92			45.86	
	NC	AR							45.26	45.51	47.30		45.86			45.92	
		SR							45.91	46.13	46.90		46.12			46.15	
MD	AC	AR		47.18			45.37		45.26	45.23	45.14		45.06			45.04	
		SR		48.25			46.06		45.86	45.81	45.55	45.33	45.60	45.60	45.21	45.49	45.66
	NC	AR		47.18			45.47		45.07	45.28	46.55		45.48			45.55	
		SR		48.25			46.10		45.71	45.88	46.27	45.35	45.73	46.94	45.13	45.79	47.98
AD	AC	AR							45.03	45.02	44.87		44.84			44.88	
		SR							45.63	45.62	45.38		45.37			45.34	
	NC	AR							44.84	45.04	46.26		45.00			45.41	
		SR							45.48	45.64	46.11		45.51			45.65	
HD	AC	AR							44.99	44.97	44.78		44.81			44.80	
		SR							45.61	45.56	45.32		45.35			45.28	
	NC	AR							44.81	44.99	46.09		44.96			45.34	
		SR							45.45	45.88	45.93		45.47			45.58	

PP 14

PP 145

PACIFICORP
PACIFIC POWER UTAH POWER

February 15, 1994

Department of Natural Resources
Office of Energy and Resource Planning
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This responds to a January 13, 1994, letter we received from Rebecca Wilson. We understand that Rebecca is now employed by the Division of Public Utilities, rather than the Department of Natural Resources. However, we are sending the response to your Department, since it was sent by Rebecca while she was an employee of the Department. I would like to apologize for not providing a written answer sooner, but we first focused on getting the RAMPP-3 Draft Report mailed to interested parties on January 28, and then on getting the Draft Appendices ready for the February 17-18 RAG meetings.

Rebecca's letter addresses several concerns, which this letter will discuss in the same order Rebecca did.

1. **All Model Runs in the Report:** The various summary tables in the final report capture all of the model runs we have made. The technical appendix will contain further detail on model runs.

2. **Financial Data Under TRC Perspective:** All summary tables include both Utility Cost and Total Resource Cost for all model runs.

3. **Analysis Under TRC Perspective:** The company evaluated all resource runs, and the benefits of alternative resource strategies, from the perspective of both Total Utility Cost and Total Resource Cost. Because the action plan is not derived in any formulistic way, it is difficult to quantify how it was derived from the results in any particular model run. However, adoption of the strategic-renewables strategy provides a good example of the company's use of results from the RAMPP-3 analyses. Although the strategic-renewables strategy results in higher utility costs, higher customer prices, and higher total resource costs, the company believes that its other benefits (gaining experience with renewable

resource technologies and positioning the company for greater resource diversity) justify those additional costs. The company can sometimes reduce its risk in areas such as renewable resource development by purchasing resources on a "turn key" basis. This can enable the Company to reduce the level of the construction and, in the case of geothermal projects, "dry hole" risk faced by both customers and shareholders.

The company can best address risk sharing in the context of a specific expenditure. When the company makes an application for cost recovery of specific costs, the benefits of those expenditures to customers, the company, and shareholders, and the appropriate sharing of the costs, can be explained. The company believes that responsibility for costs are best addressed on a case-by-case basis, when all the facts for the particular case are available.

4. End Effects: Both the IPM model and the financial model utilized a 50-year study period to properly account for end effects. We modeled two run years (2022 and 2036) beyond the 20th year in the IPM resource selection model. The results of these run years were used to calculate annual operating costs for the years 2016 through 2043.

5. SO2 Mitigation: RAMPP-3 considered SO2 allowances in two ways. First, the cost for all new coal resources included the current selling price of $150/ton for SO2 allowances. Secondly, the Question and Answer chapter of the draft Report, pages 5-6, discusses the company's strategy for Clean Air Act compliance. The fourth paragraph on page 6 discusses the trade-offs related to selling allowances. Given the current market price of about $150/ton of SO2, which translates to 0.236 mills/kWh, or less than $0.005/kWh, and the cost of new resources at $0.04 to 0.06/kWh, it is more cost effective for the company to use all the allowances needed for current generation.

Thank you for the letter, and we hope that a representative from the Department of Natural Resources will be able to participate in PacifiCorp's next round of IRP.

Sincerely,

Nancy Esteb

Nancy Esteb, Manager
Integrated Resource Planning

NE/ja

Written Comments on Draft Report

PP 147

LAND AND WATER FUND

Legal Aid For The Environment

March 6, 1994

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Ms. Nancy Esteb
Pacificorp
920 S.W. 6th Ave.
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Dear Nancy:

The Land and Water Fund of the Rockies would like to thank you for providing us with an opportunity to review and comment on Pacificorp's draft Resource and Market Planning Program III (RAMPP3). As a non-profit environmental group, we did not have the resources to participate in the regular RAG meetings held in Portland. As a result, this opportunity to provide written comments is particularly appreciated.

As always, we are impressed with the technical competence you have shown in the RAMPP3 IRP analysis. Indeed, PacifiCorp seems to have made significant progress in improving its modeling and scenario development capabilities.[1] Moreover, we are pleased with PacifiCorp's Action Plan commitments to acquire wind and geothermal power. We believe that these renewable resources will produce significant economic, risk diversification, and environmental benefits for PacifiCorp and its customers.

Nevertheless, we have a number of concerns about this draft report. These concerns involve (1) the treatment of new coal resources; (2) PacifiCorp's standards and plans for acquiring DSM; and (3) the consistency of the RAMPP3 document with the decision of the Utah Commission in regard to RAMPP2.

I. New Coal Resources

We have a number of concerns about PacifiCorp's treatment of coal-fired resources in the draft RAMPP3 report, particularly your result showing large amounts of coal-fired capacity in a number of the modeling runs.

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1 As a former ICF employee who used to work with the Integrated Planning Model, I wholeheartedly approve of your choice of model!

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First, it has been our understanding that the Rocky Mountain and Desert Southwest regions have substantial amounts of excess baseload capacity (due to the over-building of coal and nuclear capacity during the 1980s). Indeed, a number of utilities in this region own coal units that are currently operating at far less than full capacity. This situation -- of excess utility capacity during nights and weekends -- is likely to be exacerbated by the re-operation of the federal dams such that some generation may be shifted to off-peak periods. Given this excess baseload capacity, we were surprised to learn that the model often selected new coal-fired resources.[2]

Our analysis of the draft RAMPP3 report suggests that the model is selecting new coal plants, in large part, because of the extremely low fuel price and variable O&M cost assumptions used in the analysis. For example, the RAMPP3 analysis assumes a fuel price for Utah coal of slightly under 6 mills/kwh and a variable O&M cost of .24 mills/kwh.[3] Moreover, these numbers appear to be expressed on a levelized basis suggesting that coal costs do not increase significantly over the 20-year planning horizon.

In contrast, PacifiCorp's FERC Form 1 report shows that fuel costs in 1992 for the Hunter plant were approximately 10 mills/kwh or about 70% higher than the fuel price planning assumptions used for Utah coal in RAMPP3.[4] Similarly, this same FERC report shows that actual variable O&M expenses for PacifiCorp's large coal plants in 1992 ranged from 1-3 mills/kwh -- roughly an order of magnitude larger than the .24 mill/kwh assumption used by PacifiCorp in the RAMPP3 analysis. Moreover, the planning assumptions of other utilities in the region tend to confirm that future costs are likely to reflect PacifiCorp's historical experience with coal, rather than the planning assumptions used in RAMPP3.

Similarly, in RAMPP2 PacifiCorp assumed that variable O&M costs for both Utah and Wyoming coal were between 3-5 mills/kwh --

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[2] We recognize that, because of the capacity exchange agreement with BPA, PacifiCorp is currently using most of its excess baseload capacity. Nevertheless, other regional utilities do not have similar opportunities. As a result, we would expect that PacifiCorp would be able to purchase low-cost baseload power during off-peak periods. This access to cheap power should limit PacifiCorp's need for new coal plants.

[3] See Chapter 4, Table 4-9, at p. 17.

[4] Even the cheapest plant on the PacifiCorp system, Dave Johnson, showed a 1992 fuel cost of 7.2 mills/kwh -- about 20% higher than the costs assumed in the RAMPP3 process.

almost 20 times larger than the RAMPP3 assumptions.[5] Also, the RAMPP2 real levelized fuel costs for coal were expected to range from 11-15 mills/kwh, roughly double the RAMPP3 planning numbers. Despite this enormous change in PacifiCorp's planning assumptions, there is virtually no discussion of this change in the draft report.

We recognize that PacifiCorp may own some excess coal capacity (through an unregulated subsidiary?) that will allow coal to be sold very cheaply in the future. If this is the case, several interesting policy questions arise. First, does this access to cheap coal mean that PacifiCorp's current coal purchase contracts are imprudent since they are significantly higher than 6 mills/kwh? Or, alternatively, for future ratemaking purposes would PacifiCorp be willing to cap its cost recovery for existing coal units at 6 mills/kwh? If cheap coal is available for future coal plants, why isn't it available for the current plants? In any case, it seems a bit disingenuous to have such low cost assumptions in the planning analysis, while actual costs are substantially higher.

In any case, this result -- that the model is choosing substantial amounts of coal -- is significantly different than the conclusions reached in RAMPP2. Despite this difference, there is little explanation of the factors that may be causing it. We would urge PacifiCorp to explain these differences in far more detail in the final RAMPP3 report.

Finally, in RAMPP2 PacifiCorp found that higher load growth raised customer electricity prices. In contrast, in RAMPP3 PacifiCorp now concludes that greater load growth tends to lower electricity prices. Despite this dramatic change in conclusions, PacifiCorp does not fully explain what causes this change. Is this change being driven, in large part, by the low coal cost assumptions used by PacifiCorp?

II. PacifiCorp's Acquisition of DSR

In the Action Plan, PacifiCorp sets a number of standards -- financial and otherwise -- that guide its acquisition of DSR. We are particularly concerned about two of these standards: (1) including lost revenue recoveries in the cost-effectiveness analysis; and (2) limiting DSR acquisitions cumulative incremental price impact, over what would result from an alternative supply-side resource, to below 1 percent.

Our first comment is: where do these standards come from? There is virtually no analysis justifying either standard. Why is a DSR-related rate impact of .8 percent acceptable, but 1.1 percent unacceptable? Why wasn't 2 percent or three percent chosen? Are

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[5] See RAMPP2, at p. 46, filed May 14, 1992.

these standards consistent with what other, potentially competing utilities are doing? Although we are sensitive to the concerns that lead PacifiCorp to suggest these standards, we would urge PacifiCorp to provide some explanation of the process that led to their development.

In regard to including lost revenues in the avoided cost calculation used to determine program cost-effectiveness, we believe that this is inconsistent with the TRC test for DSM adopted by the Utah Public Service Commission. Moreover, we are uncertain as to what constitutes lost revenues: Is it the annual amounts collected in the deferral accounts consistent with the recent Joint Recommendation approved by the Utah PSC? Or, alternatively, is it the theoretical present value amount of lost revenues that would arise even subsequent to a future rate case? These are very different concepts with significant quantitative implications for DSR program implementation.

In regard to the rate cap of 1%, we are sensitive to the competitive and equity concerns that drive PacifiCorp's desire to set this standard. However, the cap seems to be extremely low. For example, Public Service Company of Colorado is suggesting a cap in the 3% range. Moreover, the RAMPP3 report has virtually no analysis of what this cap implies in regard to the TRC and other benefits associated with DSR over the long run. Accordingly, we would urge PacifiCorp to present some of the key TRC versus RIM trade-offs before adopting such a rigid standard.

Moreover, there appear to be a number of opportunities to achieve significant energy savings, while also mitigating the rate impacts associated with PacifiCorp's DSR programs. Despite these opportunities, however, PacifiCorp has not as of yet taken advantage of them. For example, the LAW Fund has suggested to PacifiCorp that there are likely to be large DSR opportunities in the industrial sector in Wyoming. Given the low industrial rates that prevail in Wyoming, the lost revenues and rate impacts associated with these DSR opportunities may be negligible. As a result of taking advantage of this opportunity, PacifiCorp could meet relatively aggressive efficiency targets without raising competitive or equity concerns.

Similarly, the LAW Fund has suggested an alternative DSR program design to PacifiCorp that could also help to mitigate adverse rate impacts. The key idea is to provide a significant upfront bonus payment to customers. In return, PacifiCorp could apply an energy service charge focused on recovering lost revenues. Unlike PacifiCorp's current DSR programs, which focus only on direct cost recovery, this alternative approach could potentially mitigate adverse rate impacts, while still maintaining high levels of participation. We urge PacifiCorp to explore these and other similar approaches.

Finally, in the RAMPP3 Action Plan PacifiCorp appears to question the cost-effectiveness of DSR. In prior plans, DSR was clearly cost-effective. Why has there been such a strong shift in PacifiCorp's attitudes about DSR? We would urge PacifiCorp to provide some more information along these lines.

III. Compliance with Earlier Commission Decisions

In 1993, the Utah Public Service Commission issued a detailed Decision on PacifiCorp's RAMPP2 report. In RAMPP3, we would urge you to include a detailed point-by-point discussion about how each recommendation was handled. Although we have not thoroughly examined this issue, it appears as if many of the Commission's concerns may not have been completely addressed.

* * * * *

Finally, since we have not had an extended period of time to analyze the report and since we did not participate in the RAG process, the LAW Fund's comments should be viewed as initial reactions and expressions of concern rather than final positions. We are still in the process of thinking through our positions on many of these issues.

In any case, we appreciate having the opportunity to comment on the draft RAMPP3 report and look forward to continuing to maintain an open dialogue with PacifiCorp.

Sincerely,

Eric Blank

Bruce Driver, Project Director
Eric Blank, Staff Attorney
LAW Fund Energy Project

PacifiCorp RAMPP-3 Draft Report
Comments from the Land and Water Fund of the Rockies:
Letter from LAW dated March 6, 1994

1) PacifiCorp's RAMPP-3 coal price estimates seem to conflict with coal cost information in PacifiCorp's FERC Form 1 Report and with estimates used in RAMPP-2, yet there is no discussion of this dramatic change in assumptions. RAMPP-3 uses a coal cost of 6 mills/kWh, FERC Form 1 shows Hunter's fuel costs at 20 mills/kWh, RAMPP-2 used 11-15 mills/kWh. PacifiCorp should explain these differences in far more detail in the final report.

<u>Answer</u>: FERC Form 1 gives average fuel prices for generating units. These average prices are a mixture of a number of coal contracts and fuels (includes start-up oil or gas) at various prices. The FERC Form 1 average fuel price for Hunter is about 10 mills; however, at the margin, the incremental cost is less. RAMPP-2 coal costs were based on average costs, either from existing contracts or the DRI Mountain 1 coal index (in real 1991 dollars). RAMPP-2 average costs were 9 mills/kWh for Hunter and 5 mills/kWh for Wyodak, found on pages 44-45 of the RAMPP-2 Supply Side Appendix. The table on page 46 in the RAMPP-2 Report inadvertently used DRI's Mountain 1 price for Wyodak 2 and Hunter 4, and were in error. However, RAMPP-2 modeling used the correct prices for Wyodak 2 and Hunter 4, as shown in the Appendix. RAMPP-2 used DRI's Mountain 1 price for new IGCC or AFB coal units. While RAMPP-2 used average coal costs, RAMPP-3 used incremental or market-based coal costs for new coal resources.

2) PacifiCorp's RAMPP-3 O&M cost estimates for coal plants seem to conflict with O&M costs reported in PacifiCorp's FERC Form 1 Report and with estimates used in RAMPP-2. RAMPP-3 uses an O&M cost of 0.24 mills/kWh, FERC Form 1 shows coal O&M at 1-3 mills/kWh, RAMPP-2 used 3-5 mills/kWh. PacifiCorp should explain these differences in far more detail in the final report.

<u>Answer</u>: O&M costs fall into two categories: fixed and variable. The split of O&M costs between these categories is subject to some uncertainty. In RAMPP-3, pulverized coal plants were allocated $28.40/kW fixed O&M and $0.24/kWh variable O&M costs in real 1994 dollars. At an 85 percent capacity factor this works out to a total O&M cost of 4 mills/kWh. The O&M values reported in FERC Form 1 of 1 to 3 mills/kWh and the RAMPP-2 values for new units at Wyodak 2 and Hunter 4 of 3 to 5 mills/kWh were total (both fixed and variable) O&M costs. Therefore, the total O&M values are consistent.

3) Why did RAMPP-2 results show that load growth caused higher customer electricity prices, but RAMPP-3 results show stable prices? Is this change being driven in part by the low coal cost assumptions?

<u>Answer</u>: It is true that coal price assumptions in RAMPP-3 are lower than they were in RAMPP-2, but the RAMPP-3 no-coal cases, also showed lower prices, and there the change cannot be driven by the low coal cost assumptions. The company believes that the lower price impacts from RAMPP-3 results occurred because of different real world assumptions and different modeling techniques. RAMPP-2 assumed an inflation rate of 5.1 percent, and a discount rate of 9.54 percent. RAMPP-3 assumed an inflation rate of 3.4 percent, and a discount rate of 8.8 percent. Modeling techniques in RAMPP-2 did not include an optimization model, so resource additions did not always exactly match the reserve margin requirement (they often exceeded it), whereas in RAMPP-3, the model only added the exact amount required to meet the reserve margin requirement. Also, the RAMPP-2 financial model was less precise than the RAMPP-3 financial model.

4) Where do the internal financial standards for DSR come from? PacifiCorp should provide some explanation of the process that led to the development of these standards. Are these standards consistent with what other, potentially competing utilities are doing?

<u>Answer</u>: A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

5) The 1 percent price cap seems to be extremely low. Why is a DSR-related price impact of 0.8 percent acceptable, but 1.1 percent unacceptable? Why wasn't 2 percent or 3 percent chosen?

<u>Answer</u>: A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

6) The RAMPP-3 report has no analysis of what the 1 percent DSR-related price cap implies in regard to the TRC and other benefits associated with DSR over the long run. PacifiCorp should present some of the key TRC versus RIM trade-offs before adopting such a rigid standard.

<u>Answer</u>: A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

7) What is included in lost revenues? Is it the annual amounts collected in the deferral accounts consistent with the recent Joint Recommendation approved by the Utah PSC? Or, is it the theoretical present value amount of lost revenues that would arise even subsequent to a future rate case?

<u>Answer</u>: The lost revenue in the DSR financial analysis is the difference between the revenue with the measure and the revenue without the measure, before any regulatory action (prices are the same with and without the program in question). This is consistent with the way the company analyzes supply-side resources and other capital projects. If the company considered revenues after regulatory action (price increases) all programs would show the same internal rate of return. Comparing the IRRs of projects, excluding regulatory recovery, gives the company a tool for allocating capital to the most cost-effective programs.

8) PacifiCorp should take advantage of low-cost DSR opportunities in the industrial class in Wyoming, where the low rates would result in low lost revenues and small rate impacts.

Answer: Although the potential exists for low cost DSR acquisition in Wyoming, the lack of impetus to undertaking more DSR in Wyoming during the short run reflects the nature of the load and resource centers of the system. The resources identified in the plan and reflected in the action plan recognizes that the westside of PacifiCorp's system is more of a load center and the eastside is more of a resource center. Given this condition, DSM makes more sense on the westside since any westside DSM achieved will have the effect of lowering transmission losses associated with moving the power to the westside. Therefore, DSR opportunities targeted at Westside industrial customers would take precedence over Eastside projects.

9) PacifiCorp should consider providing a significant up front bonus payment to customers as an alternative DSR program design to mitigate adverse rate impacts.

Answer: On an on-going basis the company evaluates different incentive mechanisms to increase DSR program participation and mitigate adverse rate impacts. Although possibly increasing penetration to a degree, the bonus payment concept does not mitigate the rate impact of a given program on non-participants. A bonus payment system would only exacerbate the rate impact issue for those who had already undertaken energy efficiency actions on their own (free drivers) or those who could not participate due to the lack of application (non-electric space and water heating customers).

10) Why has PacifiCorp shifted its attitudes about DSR from a cost effective resource in prior plans to questioning the cost effectiveness of DSR in RAMPP-3?

Answer: A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

11) PacifiCorp should include in RAMPP-3 a point-by-point discussion of how each recommendation from the Utah PSC order on RAMPP-2 was handled in RAMPP-3.

Answer: PacifiCorp responded to the modeling points from the Utah PSC order on RAMPP-2 in the RAMPP-3 Modeling Appendix. The company is also responding to 311 items from parties' comments on the draft Report. These responses addressed almost all of the issues addressed in the recommendations from the Utah PSC order.

PP 157

DEPARTMENT OF NATURAL RESOURCES AND CONSERVATION

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March 4, 1994

Nancy Esteb
Integrated Resource Planning
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Re: Comments to PacifiCorp's Draft RAMPP-3 Report

Dear Nancy:

DNRC appreciates your staff's effort that has gone into the Draft RAMMP-3 Report. The Report, however, could be improved in the following areas:

1) The Report did not include detailed supply-side resource costs that would support the unit capital cost figures presented in Table 4-9. On April 29th, PacifiCorp distributed a handout entitled "Supply-Side Resource Cost Detail" that included similar supply-side resource costs. Those costs, however, do not correspond with the cost estimates in the Report. DNRC believes that updated supply-side resource costs should be included in the Report.

2) The Report failed to document how the Action Plan was derived given the optimal resource results under the different model runs and PacifiCorp's objectives. Administrative Rules of Montana 38.5.2001(9) states "The Utility should thoroughly document the exercise of its judgment in weighing the importance of conflicting decision objectives. The utility should prepare such documentation so that it can be reasonably understood by the commission and interested parties." DNRC does not believe that PacifiCorp satisfied this rule. For example, it is not clear why the pulverized coal resources, which were optimal resources in many of the model runs, were not included in the Action Plan. The Action Plan merely states that clean coal technologies should be looked at. DNRC believes that PacifiCorp should clearly state the objective criteria that were used in making its decisions.

Sincerely,

John M. Goroski

John M. Goroski

PP 158

PP 159

PacifiCorp RAMPP-3 Draft Report
Comments from Montana Department of Natural Resources and Conservation:
Letter from DNRC dated March 4, 1994

1) Provide back-up in an Appendix for the inputs to Table 4-9 (costs for portfolio technologies) to support the unit capital cost figures and other components of supply-side resource costs.

Answer: Material has been added to the modeling technical appendix providing detailed information on derivation of costs for the supply-side resources.

2) Document how the action plan was derived given the optimal resource results under the different model runs and PacifiCorp's objectives. PacifiCorp should clearly state the objective criteria that were used in making its decisions. The Report should thoroughly document the exercise of management judgment in weighing the importance of conflicting decision objectives.

Answer: Additional text has been added to the Conclusion chapter discussing the company's decision criteria, and the decision-making process the company uses in making its resource acquisition and capital investment decisions.

PP 16(

PP 161

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March 4 1994

Nancy Esteb
Manager, Integrated Resource Planning
PacifiCorp
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Portland, Oregon 97204

Dear Nancy,

Thank you for the opportunity to comment on PacifiCorp's draft RAMPP-3 report. PacifiCorp has devoted significant resources to analyze and digest the difficult policy questions involved in RAMPP-3. The result is a coherent, well-written and thoroughly documented plan. While we would not agree with everything in the plan, it is clear that PacifiCorp put significant thought into the document. Our comments appear below by subject.

Financial Criteria Used to Evaluate Conservation

The Council is concerned about the financial criteria used to evaluate the desirability of conservation to PacifiCorp. In particular, we are concerned that a rate impact test leaves both consumer dollars and conservation resources on the table. The entire concept of least-cost planning in Oregon revolves around finding the minimum total cost -- not the least rate impact that is acceptable. Clearly, by selecting the three financial criteria, PacifiCorp is directly contradicting the intent of the least-cost planning orders in Oregon and Washington. While we would agree that the output of least-cost plans cannot be followed blindly -- for example, the actions of PacifiCorp to pursue renewables to hedge risk even though they are currently not least-cost is laudable -- differing from the least-cost path should warrant significant explanation. Such explanation is completely lacking in the case of conservation.

The criteria seem particularly stringent because they appear to guide PacifiCorp to the medium DSR case instead of either the accelerated or high DSR case. While the text indicates that the medium DSR case passes PacifiCorp's criteria, no indication is given how the accelerated or high DSR cases fare. In terms of least-cost, there is no question that PacifiCorp would have picked the accelerated or high DSR case since both result in \$100-\$200 million dollar savings over the medium case. In either case the rate impact (above what is already incurred in the medium DSR path) is quite small, on the order of

1 to 2 tenths of one mill/kWh. We urge PacifiCorp to pursue these savings instead of the medium DSR case.

As a final note to this subject, the appendices to RAMPP-3 should show the details of how the rate impact criteria was calculated.

Action Plan Targets for DSR are too Low

One direct consequence of the financial criteria and selecting the medium DSR path is the level of conservation activity targeted in the two-year action plan. While PacifiCorp is actively in the process of purchasing gas fired, base load generation, it is proposing to keep DSR acquisition efforts virtually stable, at a level that is about one-third the acquisition rate of similarly sized utilities in the Northwest. Early indications are that about 18.5 AMW were achieved by the Utah and Pacific Divisions of PacifiCorp in 1993, but targets for 1994 and 1995 remain at about 20 AMW, instead of increasing. For the Pacific Division, targets are about 10 AMW each year. This should be contrasted with Puget Power, a similar sized utility to the Pacific Division, which acquired about 28 AMW in 1992 and 30 AMW in 1993.

When the OPUC acknowledged RAMPP-2, it wanted PacifiCorp to ramp up to 8% of the 20 year industrial target by 1996. This would be about 21 AMW. Yet PacifiCorp is only proposing to acquire about 10.5 AMW in 1995, leaving too large a gap to fill to get to 21 AMW by 1996. This is particularly egregious because of the low cost nature of industrial sector savings and because of the period of 'partnership building' that needs to occur with industrial customers.

All these factors point to the need for PacifiCorp to increase the resources available to develop conservation and to increase its DSR targets in the action plan.

Industrial Sector Action Items

PacifiCorp should pursue process change improvements in industrial customer facilities that will result in both electric efficiency and product/process improvements. Process improvements require a significant commitment from the industrial customer. PacifiCorp should train its field personnel to identify industries that may be ready to review their entire process and seek efficiency/product enhancements. These types of projects will likely result in very large savings to both PacifiCorp and the industrial customer.

PacifiCorp should investigate the feasibility of motor rebate programs, to help ensure that the lost opportunity represented by the replacement motor market is not overlooked. We recommend that PacifiCorp join forces with its neighboring utilities to form a consortium similar to that formed in the Puget Sound area.

Commercial Sector Action Items

PacifiCorp should consider going further than training and educational programs for code compliance in Washington. Similar actions should cover other jurisdictions as new codes are developed. In addition, PacifiCorp should partner with local jurisdictions by providing resources for code enforcement.

Appliance Action Items

We strongly support PacifiCorp's commitment to coordinated action to move the market for appliances. You are a valuable player in national and regional efforts to move standards and change market supplies. We urge you not to limit these actions to the residential sector, but to expand your efforts to commercial and industrial equipment, such as lights and motors, as well.

Wind Activities

PacifiCorp is to be complemented on its aggressive wind energy confirmation program. The Foote Creek and Juniper Point projects will significantly contribute to the wind resource confirmation agenda advocated by the Council. In pursuing its wind projects, PacifiCorp should encourage a proactive wind site development process to facilitate economic and environmentally acceptable development of the full wind potential, of which a specific project may be only the initial part. Key to this approach is early identification and resolution of the cumulative technical, institutional and environmental issues associated with full development of the wind resource area. For example, transmission interconnection planning for the initial wind power plant should consider interconnection requirements for ultimate development of the entire wind resource.

The option approach devised for the RSEP geothermal pilot projects is intended to accomplish similar objectives for geothermal resource area development and might be used as a model for wind. In the geothermal case, the developer is encouraged to undertake environmental and resource assessment, permitting and preliminary site development planning for an additional increment of development, several times the size of the initial pilot project. Encouragingly, current wind project development activities appear to support this concept. For example, Kenetech Windpower proposes to permit 500 MW of wind development at Foote Creek and Simpson Ranch, though the initial project will be much smaller. PacifiCorp should encourage a similar approach at other wind sites in which it has interest.

Geothermal Activities

PacifiCorp's stated interest in geothermal development is encouraging. PacifiCorp should initiate activities leading to the development of a geothermal pilot project with the option for further expansion at a promising geothermal resource areas. Resource confirmation, environmental assessment and other option development activities should be undertaken for the expansion option if the pilot plant proves feasible and cost-effective. Although the overall development should be cost-effective compared to alternative resources, the opportunity to confirm new geothermal resources and to secure an expansion option warrants some cost-effectiveness premium for the pilot project.

Photovoltaics

PacifiCorp should encourage the development of all cost-effective photovoltaic applications in its service territory, grid-connected as well as off-grid applications. An approach in which PacifiCorp has financial interest in the facilities seems preferable, as this should encourage neutrality to these potentially load offsetting facilities. At minimum, the action to provide information to interested customers should include system design and economic evaluation assistance. Design assistance could be provided directly, or PacifiCorp could recommend qualified design firms. Information regarding equipment availability, reliability, cost and performance should also be provided. PacifiCorp should be prepared to assess and credit distributed system benefits of remote on-grid photovoltaic applications. Finally, financing assistance to customers for whom photovoltaic service is cost-effective should be considered.

Small-scale Renewables and Cogeneration Development

With development of the James River Camas project, PacifiCorp is demonstrating that thermally-balanced congeneration of the type advocated by the Council can be successfully developed in competition with large central-station combined cycle powerplants. PacifiCorp should continue to encourage the development of small-scale cogeneration and renewable resource projects where cost-effective. Power plants using refuse or biomass residues and small-scale cogeneration development are often unique and time-dependent opportunities. This type of project can benefit from a continuously open acquisition window, clearly defined acquisition criteria and financial assistance. Regularly scheduled small-scale RFPs or open windows for unsolicited proposals can create an ongoing opportunity for prospective resource developers to bring proposals to the company. Clearly defined resource acquisition criteria will minimize spurious and non-competitive proposals and expedite proposal evaluation. A means of crediting environmental offsets, such as those associated with cogeneration projects that enable retirement of older boilers, should be developed.

Local Area Peak Management

PacifiCorp should consider distributed supply-side technologies such as engine-generator sets, storage technologies, fuel cells and photovoltaics, in addition to direct load control measures, as proposed, as a means to resolve transmission and distribution capacity constraints.

Thank you again for the opportunity to comment. Please call if you have any questions.

Sincerely,

Theresa Degg for

Margaret Gardner
Senior Conservation Analyst

Jeffery King
Senior Resource Analyst

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PacifiCorp RAMPP-3 Draft Report
Comments from Northwest Power Planning Council:
Letter from NPPC dated March 4, 1994

1) The report should explain why PacifiCorp diverted from the least-cost path in the case of DSR.

<u>Answer</u>: A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

2) How did the accelerated and high DSR strategies fare relative to the three DSR financial standards.

<u>Answer</u>: The accelerated and high DSR strategies were not run through the financial model. The model tested individual programs, not a package of programs. Also, please refer to the new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

3) The appendices should show the details of how the rate impact criteria was calculated.

<u>Answer</u>: A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

4) Explain why the company is only proposing to acquire about 10.5 MWa in 1995 of industrial DSR, when the OPUC in their RAMPP-2 acknowledgment order wanted PacifiCorp to ramp up to 8 percent of the 20-year industrial target by 1996, or about 21 MWa.

<u>Answer</u>: The company's short term action plan states that the 1994 and 1995 cumulative acquisition of industrial energy efficiency will yield 18 MWa. The 1995 level of acquisition is 11.6 MWa alone. The acquisition spelled out in RAMPP-3 combined with historic acquisition to date will yield over 22 MWa in place by the end of 1995. This would represent approximately 9% of the program technical potential identified in RAMPP-3. The company has provided a previous response to the NPPC on August 24, 1993 that the level of industrial acquisition is greater in the RAMPP-3 plan versus the RAMPP-2 plan.

5) PacifiCorp should pursue process change improvements in industrial customer facilities that will result in both electric efficiency and product/process improvements. PacifiCorp should train its field personnel to identify industries that may be ready to review their entire process and seek efficiency/product enhancements.

<u>Answer</u>: The company has been evaluating industrial process improvement areas as a mechanism to increase participation in the company's industrial energy efficiency program by large industrial customers. In June of 1993 the company released an evaluation report on the Industrial Energy FinAnswer program. The findings of the evaluation report as well as experiences in the field led to the investigation of another

approach which was piloted in Oregon during early 1994. The approach relies upon a total review of the customers' production process to determine how the process can be reconfigured. This approach goes well beyond asking the question of what incremental efficiency upgrades can be conducted at a customer facility to ask the larger question of whether a customer can skip or replace an entire process with a more efficient one. Rather than simply evaluating if a more efficient motor can be used in an existing production process, this approach focuses on how the production process can be reconfigured so that the motor isn't needed at all. The result of the process is a much more efficient use of total energy per unit of production. More important, the customer is the driving force behind the recommendation. The company's initial pilot has yielded a successful plan for future action which has the support of the customer. The concept is being targeted for application at other pilot sites. The one drawback of this approach is that it requires substantial lead times and customer commitment. Despite this drawback, the approach has tremendous potential for improvement in the use of energy at the customer facility.

6) PacifiCorp should investigate the feasibility of motor rebate programs, to help ensure that the lost opportunity represented by the replacement motor market is not overlooked. We recommend that PacifiCorp join forces with its neighboring utilities to form a consortium similar to that formed in the Puget Sound area.

<u>Answer</u>: The company has incorporated motor initiatives into its current design for the industrial FinAnswer program. At this point, the company does not believe motor rebates are necessary, although PacifiCorp is participating in a national study to determine the size of the original equipment manufacturers (OEM) market for motors. The company is not adverse to pursuing upstream activities targeted at improving motor efficiencies. The company supports efforts to transform energy efficiency markets through initiatives like the Consortium for Energy Efficiency (CEE). CEE is currently investigating a possible initiative in this area. The company will evaluate the appropriateness of the initiative for possible participation when it is circulated in final form.

7) PacifiCorp should consider going further than training and educational programs for code compliance in Washington. Similar actions should cover other jurisdictions as new codes are developed. In addition, PacifiCorp should partner with local jurisdictions by providing resources for code enforcement.

<u>Answer</u>: Additional text has been added to the discussion of residential code enforcement efforts in the RAMPP-2 performance section of the DSR Action Plan Detail chapter.

8) PacifiCorp should not limit its efforts to move appliance standards and change market supplies to the residential sector, but expand efforts to commercial and industrial equipment.

<u>Answer</u>: The company agrees that there are significant opportunities to improve efficiency standards for electric equipment in the commercial

and industrial market. the company is actively researching possibilities in these markets through collaborative participation in studies as well as efforts such as the Consortium for Energy Efficiency. The company is participating in an OEM motor drive study, and is actively evaluating a packaged air conditioning system program. Current programs include minimum efficiency standards which are constantly ratcheted up to push the technology envelope. Future DSR research efforts target the investigation of even more options. Company efforts to move HVAC appliance efficiency standards spill over into commercial applications. Efforts in the building code arena have resulted in pushing market practice. Also, see the response to NPPC question #6 above. Two new action items were added to the commercial and industrial sections of the RAMPP-3 DSR action plan.

9) In pursuing its wind projects, PacifiCorp should encourage a proactive wind site development process to facilitate economic and environmentally acceptable development of the full wind potential. Key to this approach is early identification and resolution of the cumulative technical, institutional and environmental issues, for example for transmission facilities.

Answer: PacifiCorp is open to considering transmission sizing for its part in the jointly owned wind projects to allow for the full potential of the wind resource. In fact, however, the facilities to be built must be agreed upon by all project participants. All participants' needs as well as their points of interconnection must be taken into account when planning these facilities. The owners of the Columbia Hills wind project have an option for an additional 50 MW. At Foote Creek, Kenentech Windpower is permitting the site for 500 MW. At both sites, the transmission is being designed for much greater capacity than the initial project would require.

10) For geothermal resource development, PacifiCorp should encourage the developer to undertake environmental and resource assessment, permitting and preliminary site development planning for an additional increment of development, several times the size of the initial pilot project.

Answer: The geothermal developers which PacifiCorp has considered for project development have on their own initiative planned the optimum development and permitting size of their leaseholds, in accordance with the federal requirements for geothermal leases. For example, the leaseholders at the Glass Mountain site have projected a resource capable of supporting at least 1,000 MW, and they are jointly pursuing permitting on this basis.

11) PacifiCorp should encourage the development of all cost effective photovoltaic applications in its service territory, grid connected as well as off grid applications.

Answer: See action plan item #2, f through i. Also, additional text has been added to the first page of the Renewables Analysis chapter addressing the company's activities in the photovoltaic area.

12) PacifiCorp should consider distributed supply side technologies such as engine generator sets, storage technologies, fuel cells and photovoltaics, in addition to direct load control ~~measures,~~ as proposed, as a means to resolve transmission and distribution capacity constraints.

Answer: DSR action plan item #6h has been modified.

PP 169

B R I C K F I E L D

B U R C H E T T E

R I T T S , P C

WASHINGTON D C
AUSTIN TEXAS

March 7, 1994

Via TeleFax

RECEIVED

MAR 1 1 1994

OWER PLANNING

Ms. Nancy Esteb
Manager, Integrated Resource Planning
PacifiCorp
920 S.W. Sixth Avenue
Portland, Oregon 97204-1256

Re: Comments of Nucor Steel on Draft RAMPP-3 Report

Dear Nancy:

Thank you for the opportunity to provide comments on the draft RAMPP-3 report. Due to the limited amount of time to fully analyze and review the report, and due to limitations on the level of resources Nucor can reasonably devote to the review of a draft report, Nucor is not in a position to offer detailed comments on the draft RAMPP-3 report at this time. However, Nucor would expect to offer comments after the final RAMPP-3 report is filed with the Utah Public Service Commission and to participate in any proceedings conducted by the Commission to consider RAMPP-3.

Nucor's primary concern continues to be the treatment of interruptible power in the context of integrated resource planning. Interruptible power is discussed directly only in Chapter 9 (as part of the questions and answers), and indirectly as one of the "peak management opportunities" referred to in the Action Plan in Chapter 10. While Nucor welcomes PacifiCorp's apparent recognition of more of the benefits of interruptible power than it has in the past, the lack of specificity with regard to PacifiCorp's commitment to the utilization of interruptible power as a resource continues to give Nucor cause for concern.

Sincerely,

BRICKFIELD, BURCHETTE & RITTS, P.C.

Peter J. Mattheis

Attorneys for Nucor Steel

cc: All RAG Participants

PP 17(

PacifiCorp RAMPP-3 Draft Report
Comments from Nucor Steel:
Letter from Nucor dated March 7, 1994

1) The lack of specificity with regard to PacifiCorp's commitment to the utilization of interruptible power as a resource continues to give Nucor cause for concern.

Answer: As indicated in the Action Plan chapter, the company is in the process of developing a capacity credit which would apply to additional requests for interruptible-type power and serve as a replacement for existing interruptible service upon expiration of existing contracts.

PP 172

PP 173

OAK RIDGE NATIONAL LABORATORY
MANAGED BY MARTIN MARIETTA ENERGY SYSTEMS, INC.
FOR THE U.S. DEPARTMENT OF ENERGY

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Eric Hirst
Corporate Fellow

February 22, 1994

TO: Nancy Esteb

FROM: Eric Hirst

Thanks for sending me a copy of the RAMPP-3 draft report. I did not have time to read the report carefully, so please take interpret my comments in that light.

Overall, I am impressed with the amount, quality, and relevance of the technical content of the report. It looks like the new ICF model you chose for RAMPP-3 provides you with much more analytical power (especially its ability to geographically disaggregate the results) to examine a range of IRP issues. Hopefully, for RAMPP-4 you can relax the model's constraint that only one season (either winter or summer, but not both) can be used for capacity planning.

However, I think you need to spend a lot more time making the final report easy to read, which this draft is not. The report presents summary results for about 150 cases, but far too little in the way of interpretative narrative and graphs to show what you found from all these computer runs. I suggest you add lots of figures (similar to the tradeoff graphs in chapter 7) to show the key results buried in all those complicated tables. You should also tell your readers clearly what the tradeoffs are among, as examples, more DSM and electricity price and between less carbon dioxide and more natural gas.

I would especially like to see more explanation of the DSR results shown on pages 28-30 of chapter 6. I could not tell what the tradeoff is for PacifiCorp's system between the TRC test and the RIM test. This issue is especially important given the company's very restrictive DSR acceptance criteria. What was the basis for the corporate decision to allow no more than a 1% DSM-induced price increase? I accept the need to limit price increases, but why so strictly? Also, is the 9% minimum IRR criterion for DSR investments consistent with that used for other investments?

How come the amount of DSR resources selected by the model is invariant with changes in natural-gas prices? Shouldn't more DSR be cost effective at higher gas prices?

Is the company running any load-building programs (e.g., economic development or retention efforts)? If so, the final report should analyze the effects of these programs on resource requirements, costs, and electricity prices.

I am puzzled that you print the avoided costs separately from the RAMPP report. As I recall, the final RAMPP-2 report did not include avoided costs. I suggest that the separate memo, "RAMPP-3 Avoided Cost Calculations" be included in the final RAMPP-3 report.

I am also impressed with the interactions between PacifiCorp and the Technical Advisory Group. Although I did not attend any of the meetings, it appears that PacifiCorp was responsive to many of the group's requests, both for modeling runs and for meetings with PacifiCorp executives.

I look forward to seeing the final report.

PacifiCorp RAMPP-3 Draft Report
Comments from Eric Hirst (Oak Ridge National Laboratory):
Letter from Hirst dated February 22, 1994

1) Hopefully, for RAMPP-4 you can relax the model's constraint that only one season (either winter or summer, but not both) can be used for capacity planning.

Answer: The model vendors are revising the code so that RAMPP-4 resource selections will have to meet both summer and winter peaking needs.

2) Provide more in the report in the way of interpretative narrative and graphs to show what you found from all the computer runs. I suggest you add lots of figures to show the key results buried in all those complicated tables.

Answer: The company added some year-by-year price graphs, and more narrative in areas requested by parties' comments.

3) Tell the reader clearly what the tradeoffs are among, as examples, more DSM and electricity price and between less carbon dioxide and more natural gas.

Answer: The Illustrative Plans chapter provides a discussion of the trade-offs between DSR and price. The Environmental Analysis chapter provides a discussion of the adder results, which include how the model switched from coal to gas to reduce system emissions. Also, a new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

4) Provide more explanation of the DSR results shown on pages 28-30 of Chapter 6. Indicate what the tradeoff is for PacifiCorp's system between the TRC test and the RIM test.

Answer: The modeling process used for RAMPP-3 focused around testing four levels of DSR. The results shown on pages 28-30 of Chapter 6 in the draft Report are for those four levels. Each level of DSR was forced into the model; the model did not pick the level of DSR in each model run. PacifiCorp did not calculate a tradeoff between the TRC test and the RIM test. Also, a new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

5) What was the basis for the corporate decision to allow no more than a 1% DSM-induced price increase?

Answer: The 1 percent was developed by senior management using their collective judgment. It is consistent with the company's overall goal to remain a low-cost provider. Also, a new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

6) Is the 9% minimum IRR criterion for DSR investments consistent with that used for other investments?

Answer: Yes, it is. The company uses the same 9 percent standard in analysing its capital spending programs. The threshold that any particular program has to meet depends on the riskiness of the program and the uncertainty of the assumptions. Management discretion is applied in approving projects on a program-by-program basis. The company does not use one set hurdle rate for all programs. However, most of the approved capital expendutures that are justified on the basis of economics have IRRs well in excess of 9 percent.

7) Why is the amount of DSR resources selected by the model invariant with changes in natural gas prices? Shouldn't more DSR be cost effective at higher gas prices?

Answer: The modeling process used for RAMPP-3 focused around testing four levels of DSR. This allowed for reasonable running times, versus allowing the model to select the amount and timing of 26 DSR programs. To pose more DSR cost effective at higher gas prices would require creating new programs (with more higher cost measures) for higher gas prices, which would have required months of development work by the DSR program managers and field personnel.

8) Is the company running any load-building programs (e.g., economic development or retention efforts)? If so, the final report should analyze the effects of these programs on resource requirements, costs, and electricity prices.

Answer: The Questions and Answers chapter contains a discussion of the company's economic development activities. Case #202, shown on Tables 6-22 and 6-23, and discussed in the accompanying text, provides the requested analysis.

9) The draft avoided costs should be included in the final Report.

Answer: Because avoided costs, as required by PURPA for payments to qualifying facilities, vary from state-to-state, depending on their specific requirements, the company prefers to not publish an avoided cost schedule in the RAMPP Report.

PP 177

DEPARTMENT OF ENERGY

March 7, 1994

Nancy Esteb, Manager
Integrated Resource Planning
PacifiCorp
920 SW 6th Avenue
Portland, OR 97204

Dear Nancy:

The Oregon Department of Energy appreciates the opportunity to comment on PacifiCorp's draft RAMPP 3 report. Staff is to be commended. The report is well-researched, well-documented, and well-written.

We support much of the proposed supply strategy and actions in the draft plan. Our one fundamental concern with the draft is that the proposed level of conservation acquisition is far too little. We recommend that PacifiCorp increase its planned level of conservation acquisition by an additional 80 to 100 average megawatts between now and the end of 1997. We believe that such an accelerated conservation program is consistent with state and regional policy.

We recognize your concerns about rate impacts in an increasingly competitive market. However, by your own reckoning, your proposed level of conservation acquisition would cause consumers to forego hundreds of millions of dollars of benefits. Further, accelerated conservation acquisition would have minor rate impacts over the long run.

PacifiCorp proposes to acquire a cumulative 105 average megawatts (aMW) of demand-side resource (DSR) by the end of 1997 under medium load growth, 4 aMW below the medium DSR level. The accelerated program would achieve 191 aMW by 1997. The high program would achieve 204 aMW.

The table below compares the 50-year net present value of total resource costs of achieving medium, high, and accelerated levels of demand side acquisitions under various scenarios. The medium conservation strategy shows the highest total resource cost in all cases shown. The high DSR strategy has the lowest cost under medium loads with medium or high gas prices. The accelerated DSR strategy has the lowest cost under medium loads with low gas price and under medium-high loads with medium gas prices. The projected cost savings between the high or accelerated strategies and the medium

Barbara Roberts
Governor

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DSR strategy range from $50 to $350 million depending on the scenario. The corresponding rate increase is .3 to .8 percent (50 year real levelized).

COMPARISON OF DSR STRATEGIES
(Million $ NPV)

	TOTAL RESOURCE COST by Demand Side Resource Strategy		
	Medium	Accelerated	High
SCENARIO			
Medium Load Growth			
Low Gas Price	48,467	48,315	48,333
Medium Gas Price	48,903	48,727	48,691
High Gas Price	50,039	49,992	49,827
Medium-High Load Growth			
Medium Gas Price	55,430	55,078	55,186

All cases assume no coal plants and strategic renewables

In short, accelerated or high DSR acquisitions may fail to meet your financial or rate impact test but they meet a least-cost resource test. Accordingly, we urge you to increase your planned near-term conservation acquisitions in line with the high or accelerated conservation strategies.

We will be making further comments under separate cover.

Thank you again for the opportunity to comment.

Sincerely,

John Savage

John Savage
Acting Director

PacifiCorp RAMPP-3 Draft Report
Comments from the Oregon Department of Energy: Savage:
Letter from ODOE dated March 7, 1994

1) The proposed level of conservation acquisition is far too little. We recommend that PacifiCorp increase its planned level of conservation acquisition by an additional 80 to 100 MWa by the end of 1997. Accelerated conservation acquisition would have minor rate impacts over the long run, and they meet a least cost resource test.

Answer: A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

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PP 181

DETAILED ODOE COMMENTS ON DRAFT RAMPP3
March 4, 1994

To: Nancy Esteb, Manager
Integrated Resource Planning

Via FAX (503) 275-2827

If there are questions regarding the data requests or comments,
please contact Phil Carver at (503) 378-6874

Data Requests:

1. How many aMW of DSR would PacifiCorp acquire by 2013 under it financial criteria under each of the 15 load growth/gas price futures?

2. Please provide the cost and MW of the 98 MW of upgrades of thermal plant by plant (Chapt. 10, p. 16). Please provide the average heat rate before and after the upgrade.

3. Does the 40 aMW of DSR in Action 1 (Chapt. 10, p. 10) refer to cumulative by the end of calendar 1995? Does this refer to DSR installed? Please provide year by year historical installed DSR by state.

4. Please provide your rationale for the assumption that wind's peak contribution will be 90 percent of its average level of generation (Chapt 8. p. 10). Please provide assumed lifetimes and the associated rationale for all generating units.

5. Please reconcile how "Utility costs and levelized customer prices were slightly lower for higher gas prices than under medium gas." (Chapt 7 p. 7), given the IPM model optimizes total cost and DSR was invariant. This discrepancy is also true for the TRC in the comparable high and medium gas runs with any coal (Chapt 6, p. 25). Does the model seek to minimize the 50 year result? It should.

6. Does Case #241 use the 3 percent discount rate as the utility cost of capital as well as the discount rate? If so, please provide a new run where only the discount rate is set to 3 percent.

7. In the High Load Growth Table (Table 6-9, Chapt 6, p. 14) moving from the Accelerated to the High DSR (no coal, strategic renewables: runs 97 and 101) lowers Utility Cost from 60,469 to 60,201 but raises TRC from 62,218 to 62,633. Usually more DSR lowers both Utility Cost and TRC. What is the cause for this reversal for TRC under high loads?

8. Under Medium Load Growth (Table 6-5) moving from Medium to Accelerated DSR with no coal and strategic renewables lowers utility cost by $68 million NPV under

Medium Gas prices (47,338 to 47,270, Cases 36 and 40). However, under High Gas (Table 6-13) this move raises Utility Costs by $60 million NPV (48,474 to 48,534, Cases 53 and 57). How can higher gas prices raise the utility cost of shifting to Accelerated DSR?

9. Please provide justification for choice of coal plants with different heat rate in Utah (10,300 Btu/kWh) than in Wyoming (9,058) (see Table 4-8, Chapt 4, page 16).

Supplemental Comments:

DSR
Comments being sent under separate cover.

Coal Plants
The company wisely rejects committing to coal plants in the near-term. Over the next 30 years governments may regulate carbon dioxide emissions to reduce the risk of climate change. This makes building coal plants an imprudent investment. Investigation of integrated gassification combined-cycle coal plants (IGCC) is reasonable response to the uncertainty. The company should not commit to building any type of coal plant before the conclusion of the RAMPP4 process.

Renewable Resources
ODOE supports the PacifiCorp's strategic renewable resource targets. Pacific also plans to study integration issues. The company needs to do more to get ready to acquire large amounts of renewable resources by 2000 if cost conditions change. Pacific should perform site specific resource assessments and acquire site control. This could be done in cooperation with developers. PacifiCorp should convene a renewable resource working group and acquire some resources with a green request for proposal. PacifiCorp should be fully prepared for renewable resources by 2000.

PacifiCorp RAMPP-3 Draft Report
Comments from Oregon Department of Energy: Carver:
Letter from ODOE dated March 4, 1994

1) How many MWa of DSR would PacifiCorp acquire by 2013 under its financial criteria under each of the 15 load growth/gas price futures?

Answer: The internal standards were not used to evaluate DSR for all of the load growth and gas price futures. The results of the IPM and financial models were used to provide guidance in the selection of a DSR strategy. Please see theadded section "DSR Financial Standards and Decision Making" in the DSR Action Plan Detail chapter.

2) Please provide the cost and MW of the 98 MW of upgrades of thermal plant by plant. Please provide the average heat rate before and after the upgrade.

Answer: The capital costs for the Hunter and Huntington units range from \$130 to \$170/kW, whereas the costs for Cholla are estimated at \$10/kW. There is no expected change to heat rates.

3a) Does the 40 MWa of DSR in the action plan refer to cumulative acquisition by the end of calendar 1995? Does this refer to DSR installed?

Answer: Yes on both counts. The Action Plan item #1 has been corrected.

3b) Please provide year by year historical installed DSR by state.

Answer: The company has provided historic installed DSR savings by year (back to 1978), by program and by state to the Northwest Power Planning Council as part of a regional effort to track and report DSR savings against the regional goal of 1,500 MWa. Please contact the Demand-Side Policy and Strategy Department of PacifiCorp for a copy of the report (Green Book, Vols. I and II), which includes DSR savings for all utilities within the region.

4a) Please provide your rationale for the assumption that wind's peak contribution will be 90 percent of its average level of generation.

Answer: Additional text has been added to the Renewable chapter discussion of sensitivities to explain the company's rationale.

4b) Please provide assumed lifetimes and the associated rationale for all generating units.

Answer: Table 4-8 has been revised to include plant life and tax life.

5a) Please reconcile how utility costs and levelized customer prices were slightly lower for higher gas prices than under medium gas, given that the IPM is an optimization model and DSR was invariant.

Answer: Explanatory language has been added to the report in the Illustrative Plans chapter under the discussion of gas price results. Under higher gas prices, the prices in the non-firm market also change, which alters the results.

5b) Does the model seek to minimize the 50-year result?
Answer: Yes, the model seeks to minimize the 50-year result.

6) Does case #241 use the 3 percent discount rate as the utility cost of capital as well as the discount rate? If so, please provide a new run where only the discount rate is set to 3 percent.
Answer: Case #241 uses the 3 percent discount rate only as the discount rate. The language in the report describing this case has been clarified.

7) In Table 6-9 (high load growth), moving from accelerated to high DSR (cases #97 and #101 of no-coal and strategic-renewables) lowers utility cost but raises TRC. Usually more DSR lowers both utility cost and TRC. What is the cause for this reversal for TRC under high loads?
Answer: Comparing the accelerated DSR to the high DSR, customer costs increased disporportionately to energy savings. Customer costs increased by 58 percent; energy savings increased by only 12 percent.

8) In Table 6-5 (medium load growth) moving from medium to accelerated DSR with no coal and strategic renewables lowers utility cost under medium gas prices (cases #36 and #40). However, under high gas prices (Table 6-13) this move raises utility cost (cases #53 and #57). How can higher gas prices raise the utility cost of shifting to accelerated DSR?
Answer: Moving to high gas prices causes other aspects of the modeling process to change as well. Therefore, the higher utility cost may well be due to one of these other changes. Please see the response to ODOE question 5a.

9) Please provide justification for a different heat rate for coal plants in Utah compared to Wyoming (Table 4-8).
Answer: Additional text has been added to the description of new coal units in the Portfolio chapter explaining the different heat rates.

10) The company should not commit to building any type of coal plant before the conclusion of the RAMPP-4 process.
Answer: The company is not committing to building any type of coal plant at this point, and intends to use the information to be provided in the coal study in the RAMPP-3 action plan before making any firm decisions.

11) The company needs to do more to get ready to acquire large amounts of renewable resources by 2000 if cost conditions change. Pacific should perform site specific resource assessments and acquire site control. This could be done in cooperation with developers. PacifiCorp should convene a renewable resource working group and acquire some resources with a green request for proposal.
Answer: As noted in the Action Plan chapter under RAMPP-3 action plan item 2c, PacifiCorp has an option to purchase additional windplant from

Kenentech at the SW Washington site. In addition, the active wind developers continue to study wind potential in various regions and aggressively acquire rights to site their projects on lands which have sufficient potential. These developers regularly contact the company with project ideas and proposals. The owners of the Columbia Hills wind project have an option for an additional 50 MW. At Foote Creek, Kenentech Windpower is permitting the site for 500 MW. At both sites, the transmission is being designed for much greater capacity than the initial project would require.

12) Please provide two additional DSR sensitivity cases. The details will be worked out with PacifiCorp staff after publication of the RAMPP-3 Report.

Answer: The Company will perform the requested studies after publication of the Report, and will mail the results to all of the RAG participants.

PP 18

PP 187

PUBLIC
UTILITY
COMMISSION

March 4, 1994

NANCY ESTEB, MANAGER
INTEGRATED RESOURCE PLANNING
920 SW SIXTH AVE
PORTLAND OR 97204-1256

Based on OPUC staff's review of Pacific's RAMPP-3 Draft Report, it is clear that the company has made a significant effort to produce a comprehensive least-cost plan. Generally, the report reflects a great deal of analysis and an attempt to address the concerns expressed in the RAMPP-2 filing as well as the extensive RAMPP-3 public process.

However, staff believes there are several areas where the final report needs to be strengthened and clarified to enable us to recommend that the Commission acknowledge the plan. Staff's comments and questions on the RAMPP-3 draft report are attached. Please call me at (503) 378-6137 or Ed Busch at (503) 378-6625 if you have questions regarding these comments. We look forward to working with you on the RAMPP-3 final plan.

Lee Sparling

Lee Sparling
Program Manager
Electric Rates & Planning
(503) 378-6137

\pplsteb.ltr

Attachment

Barbara Roberts
Governor

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OPUC Staff Comments on RAMPP-3 Draft Report
March 4, 1994
Page 1

General Comments

1. The report should more clearly explain how the conclusions from the model runs (currently summarized in Chapter 13) lead to the RAMPP-3 action plan items. The report describes how the RAMPP-3 model creates a resource plan for each scenario. However, there should be a detailed discussion which: (a) identifies generally how much of each type of resource is consistently selected across the most likely scenarios; (b) describes why more weight is given to certain strategies and futures; and (c) clearly links these conclusions with the 1994-95 (and beyond) action items. This detailed discussion should be included as a separate chapter in the report before, not after, the Action Plan.

2. Similarly, although the plan examines a wide range of scenarios, it does not define a path the company expects to follow. For example, the only supply side resources indicated for the future are those that are already contractually committed. Beyond these acquisitions, the document simply refers to further study and evaluation, thus retaining the maximum flexibility for future actions. We believe the plan should spell out what the company's strategy is and define the sequence of resource additions (year by year for the next 10 years, at least) under three or four most likely scenarios.

3. Please ensure that all acronyms used in the report--including OWC, WYO, UTA, etc.--are included in the glossary.

Supply-Side Resources

4. There is no documentation on how the supply-side resource costs were developed. The plan should contain, in a separate technical appendix, substantially more detail on how the supply-side resource cost estimates were developed.

5. In particular, although Pacific generally recognizes that transportation charges are a basic component of the delivered price of natural gas, the plan fails to explicitly present and discuss the pipeline transportation charges it would expect to incur in getting gas to the various probable sites for its gas-fired generating resources. Supply-side cost estimates should be broken down by all individual cost components, including transportation, storage-related, and electric transmission costs.

   The detail supporting the supply-side cost estimates should clearly show that (a) supply-side cost estimates include replacement capital costs and transmission costs, and (b) new combustion turbine units include the costs of natural gas transmission and storage capacity, electric transmission, and backup fuel facilities. *[See Order 93-206, p. 9.]*

6. Pacific's range of gas price escalation rates appears to be reasonable. The company's starting point gas price estimate of $2.11 per MMbtu, however, appears to be somewhat overstated. (For example, the average LDC gas price for 1994 is expected to be about $1.89 per MMbtu.) Pacific should expand its gas cost, transportation and storage cost analysis to include more site-specific costs. The discussion should describe site-specific costs and benefits and contrast site- or area-specific delivered gas costs with those obtained from national or U.S. average forecasts.

Renewable Resources

The RAMPP-3 Portfolio chapter (Chapter 4) discusses wind, geothermal, solar, and pumped storage technologies. What Pacific is currently doing to gain experience with renewable technologies is discussed in Chapter 8 - Renewable Analysis. The following comments are on Chapter 8.

7. In Oregon, it may not be possible to treat expenses for small renewable projects as R&D expenditures. Until a new plant is brought on-line, the OPUC is by law not allowed to approve recovery of expenses in rates (C-8, p.1).

8. The pending OPUC UM 550 order will encourage utilities, as part of the LCP process, to improve their ability to model non-price factors, such as fuel price risk and environmental impacts. In the first paragraph under **Barriers to Using Renewable Resources,** Staff recommends that Pacific note that it will make this effort in its next LCP (C-8, p.2).

9. In the **Barriers to Using Renewable Resources** section, in order to better organize and clarify the discussion, please break down the text into subsections on the specific barrier or planning issue (i.e., direct costs, siting, non-price factors, targets, etc.).

10. The text (C-8, p.7) indicates that when the model selected renewables, it always selected wind, because wind was the most cost-competitive with other supply-side options. Does the model assume an infinitely elastic supply for wind and other renewable technologies? Given that on page 4 of Chapter 8 it is stated that "Industry experts expect the costs of renewable technologies to decline in the next few years," is it reasonable to assume that wind will always win among renewables?

11. The text (C-8, p.7) states that, "customers would pay 0.38 mills/kWh more under strategic-renewables than under any-renewables." Please expand and clarify the significance of the .38 mills/kWh difference.

12. What is the logic of assuming that geothermal O&M costs will increase at the same rate as gas prices?

13. The **Conclusion** should be a separate section which interprets the model's mathematical results. *[See "General Comments", above.]* Please provide further discussion to support the first conclusion that, "the renewables industry needs to advance significantly before renewables will be cost-competitive." Do the model results indicate what is significant? Does the sensitivity analysis provide an estimate of how much more expensive renewables are?

14. Similarly, for the second conclusion: "... if the company erred in the input assumptions used for all other cases, those errors would have to be quite large to effect modeling results." Perhaps interpretation of the shadow prices on the LP model's resource constraints would provide some insight into what "quite large" is.

15. The OPUC considers the LCP analysis of renewable technologies to be of prime importance; this will become even more so after the Commission issues the final order in UM 550. A well written Conclusion section, which interprets the LP model's mathematical results and summarizes the company's overall plan for determining how renewables will best fit into its resource mix, is necessary.

Competitive Bidding

16. The Commission's competitive bidding order directs that each electric utility obtain at least a portion of its new power resources through the competitive bidding process. *[See Order No. 91-1383, p.1.]* In Chapter 9, page 4, Pacific does indicate that it plans to issue another RFP after completing the RAMPP-3 report. For the final RAMPP-3, please expand upon the company's plan for conducting a bid solicitation, including how it intends to deal with the multistate difficulty where the bidding regulations for Washington are somewhat different from those in Oregon.

Avoided Costs

17. Please elaborate on why the company considers the power purchase agreement with U.S. Generating Company to be a non-deferrable resource.

18. How do the RAMPP-3 draft avoided cost estimates compare with the price stream in the power purchase agreement with U.S. Generating Company?

19. On page 4 of Chapter 9, please clarify the meaning of "Avoided costs in the previous RAMPPs have been very similar, reflecting only evolutionary changes."

Discount Rate

20. Chapter 4, pages 32-33: The last paragraph notes that varying the discount rate changes the ranking of resources very little. To verify that conclusion, the reader must flip back and forth between Table 4-10 and Table 4-9. A separate page should be used to compare the ranking of resources (and total cost of each) under the two discount rate assumptions.

21. The plan should provide information and discussion regarding the effect on conservation supply curves of changes in the discount rate. *(See Order No. 93-206, p. 13.)*

22. Chapter 6, p. 41: Case #241 uses a social discount rate, assuming a medium DSR strategy with unconstrained coal and renewable strategies. It added slightly more coal and slightly less peaking strategies. Why did the analysis not allow high DSR as it is a capital intensive resource whose NPV cost should drop (relative to other resources) with a lower discount rate?

Fuel Switching

23. Chapter 9, p. 8-9: Pacific has provided an extremely cursory discussion of fuel switching. This does not meet the intent of *Order No. 93-206, p. 14*, that a report assessing fuel switching as a resource option should be provided to the Commission. Although staff and the company have made some progress in meetings on substantive issues, staff has not agreed that a study is unnecessary. We believe the Commission's requirement to file a report has not yet been met.

Demand-Side Resources

24. Does development of cost effectiveness for DSR programs in RAMPP-3 take into account the changes in cost effectiveness proposed in UM 551 (which will likely be adopted by the OPUC before the final RAMPP-3 report is issued)? If not, how will the company reconcile treatment of DSR in RAMPP-3 with the treatment proposed in UM 551 regarding non-energy benefits, the cost of incentive payments, the exclusion of lost revenues, etc.? If the company has based its decisions on a cost-effectiveness methodology which is significantly different than that which the OPUC has adopted,

what will be the results for the applicability of the Action Plan in Oregon?

25. Chapter 6, page 30: Why does the increase from accelerated DSR to high DSR result in a substantial decrease to both NPV Utility Cost and NPV Total Resource Cost but cause an increase in kWh customer cost?

26. In Chapter 10, page 9, the company states that it is more likely that gas prices will be in the low-to-medium range, and that it gave more weight to the model runs of medium DSR and strategic renewables. Why is a medium DSR strategy reasonable when TRC is lower under the accelerated and high DSR strategies for Pacific's most likely planning futures (see Tables 6-5, 6-7, 6-12, and 6-14)? Does this mean Pacific is departing from least-cost planning principles? Are the company's financial standards shown on page 122 of the DSR Technical Appendix the basis for developing the Action Plan and selecting the medium DSR strategy across the most likely scenarios?

27. Chapter 10, page 10, discusses how Pacific's financial standards affect resource acquisition strategy in the near term. Pacific should offer an explicit discussion of how and when the company's financial standards intersect with the UM 551 cost-effectiveness standards to be used in evaluating DSR programs. This should include a decision-tree diagram with some examples of programs which (a) might not pass the company's financial standards but would pass the UM 551 tests, (b) a program which would pass both the company's financial standards and UM 551 tests, and (c) a program which would fail both tests.

28. Chapter 11, page 2: Pacific should add its efforts in commercial code support to the code enforcement discussion.

29. Chapter 11, page 12: Please explain what an existing residential "customer response-oriented program as an alternative to a community-based Pacific-as-general-contractor approach" means.

30. Chapter 11, p. 13: A single-family showerhead blitz has occurred in Oregon. What are Pacific's plans for the multifamily showerhead market during the term of the Action Plan?

RAMPP-3 Technical Appendix: Demand Side Resources

31. Page 19: The industrial conservation load factor is noted as being closer to 100% rather than the 60% used in RAMPP-2. Was this reflected in the development of cost effectiveness for industrial measures and programs?

32. Pages 35, 48-49: Does the black part of the histograms shown reflect background or frozen efficiency? If so, it should be clearly labelled here and elsewhere.

33. Page 38: Average consumption needs to be labelled in terms of units (it is assumed to be kWh).

34. Page 56: Figure 26 does not allow the categories of lights, motors, and heat to be distinguished from one another.

35. Page 58: Regarding cost-effective fuel switching, the company states, "the marginal cost of gas should be 30% higher at the wellhead." How does this comport with the company's decision to depend on low or medium gas prices in selecting probable futures (See Chapter 10, p. 9 in the Report.)

36. Page 85: Is supplemental funding included in the computation of program cost-effectiveness? If so, how?

37. Page 87: Why are there no adjustments for free riders in the calculation of program potential for industrial, residential and appliance programs (see Table 24)?

38. Page 92: Why is there no long term administrative cost estimated for new residential?

39. Page 95: The company assumes that once measures are installed and the building is occupied, that savings will persist over the life of the measures. The company should add into its EFA TRC those costs due to periodic education and training of building operators, particularly because such savings are large in the commercial and industrial sectors and are emphasized in the company's Action Plan.

40. Page 97: Pacific states that it will decide when to schedule DSR acquisition probably around 1996 with only pilots and lost opportunity programs to begin immediately. With a high growth scenario, all programs would immediately be ramped into full-scale acquisition. If medium growth is anticipated, only relatively low cost programs will proceed, and if low growth is expected, conservation would continue to be postponed. Does this apply only to programs which are currently being planned, or does it apply to programs across the board? How does the company reconcile its arguments that it can immediately ramp-up to full acquisition if necessary with its arguments elsewhere that it takes at least three years to bring a program to maturity? Pacific has consistently argued that it takes years to bring pilots to the status of programs. Is it now reversing its stance?

41. Page 108: Penetration rates shown in Table 30 are based on total number of new homes

built between 1994 and 2013. Is this electrically-heated homes only, or does it include all new residential construction?

42. Page 112: OPUC does not consider the commercial retrofit program to be a pilot and will continue to require that it be handled as a program by Pacific within its Oregon jurisdiction.

43. Pages 128-129: Please provide an analysis which indicates how the Oregon residential retrofit program was assessed relative to its potential for trimming administrative and programmatic costs.

44. Page 134: The OPUC has recommended that Pacific establish an advisory group in Oregon (1993 Annual Conservation Review). Please include this evaluation group in the Action Plan.

45. Technical Appendix D: Why does Oregon have a residential takeback factor of 30% while Utah, Montana and Washington have a 0% residential takeback factor?

Technical Appendix: "Modeling"

46. Although page #1-5 states that most Commission recommendations regarding modeling were adopted by the RAMPP-3 modeling approach, discussion of these changes is not easily found in the appendix. Therefore, the appendix should use the "request/response" format (as used on pages #1-5 to #1-7 to describe why certain recommendations were <u>not</u> adopted in RAMPP-3) to discuss how the new model incorporates each agreed-to Commission recommendation. Alternatively, after listing each recommendation on pages #1-3 to #1-5, provide a page reference to the discussion of how the recommendation was implemented in the new model.

Corrections

- Ch. 1, p. 3, under "10)...": correct the spelling of "implement".
- Ch. 3, p. 13, next to last paragraph: insert the word "generating" before the word "resource" in the first sentence, and change the word "their" to "its".
- Ch. 3, p. 15, third paragraph: eliminate the second "of" in the third sentence.
- Ch. 4, p. 24, fourth paragraph, eighth line: remove second comma.

- Ch. 4, p. 30, second full paragraph, first line: change "and" to "an".
- Ch. 5, p. 24, third full paragraph, first line: remove period.

PacifiCorp RAMPP-3 Draft Report
Comments from Oregon Public Utilities Commission Staff:
Letter from OPUC dated March 4, 1994

General

1) The report should more clearly explain how the conclusions from the model runs lead to the RAMPP-3 action plan items. A detailed discussion should identify how much of each type of resource is consistently selected across the most likely scenarios, why more weight is given to certain strategies and futures; and link these conclusions with the action items. This should be a separate chapter before the Action Plan chapter.

Answer: The Conclusions chapter has been placed before the Action Plan chapter, and additional text added to both chapters to address how the conclusions lead to the action plan items.

2) The plan does not define a path the company expects to follow. The only supply side resources indicated for the future are those that are already contractually committed. The plan should define the sequence of resource additions (year by year for the next 10 years, at least) under three or four most likely scenarios.

Answer: The action plan calls for several resources which are not already contractually committed: more cogeneration than the Hermiston plant, more renewables if early projects are cost effective, and peaking resources. The Conclusion chapter provides a table showing the model's resource additions for five of the most likely cases.

3) Please ensure that all acronyms used in the report (including OWC, WYO, UTA) are in the glossary.

Answer: The company has made a best effort to include all acronyms in the glossary, including the three listed in this comment item.

Supply-Side Resources

4) A technical appendix should contain substantially more detail on how the supply-side resource costs were developed.

Answer: Material has been added to the modeling technical appendix providing detailed information on derivation of costs for the supply-side resources.

5) Supply-side cost estimates should be broken down by all individual cost components, including transportation costs for gas, storage related gas costs, and electric transmission costs. The detail supporting the supply-side cost estimates should clearly show that they include replacement capital costs, transmission costs, the costs of natural gas transmission and storage capacity, electric transmission, and backup fuel facilities.

Answer: Material has been added to the modeling technical appendix providing detailed information on derivation of costs for the supply-side resources.

6) The starting point gas price estimate of $2.11 per mmbtu appears too high. (The average LDC gas price for 1994 is expected to be about $1.89 per mmbtu.) Pacific should expand its gas cost, transportation and storage cost analysis to include more site-specific costs. The discussion should describe site-specific costs and benefits and contrast site- or area-specific delivered gas costs with those obtained from national or US average forecasts.

Answer: PacifiCorp developed its beginning gas price estimate using the most recent data available for the Northwest and Utah/Wyoming areas. When the company evaluates a specific acquisition, it uses site-specific costs. The RAMPP analysis, which uses generic technologies and generic sites, cannot incorporate site-specific costs for each potential site for resources over the seven-state area. By using different gas price components for the eastern and western parts of the system, the company attempted to capture the major cost variation.

Renewable Resources

7) In Oregon, it may not be possible to treat expenses for small renewable projects as R&D expenditures (see p. 1 of Chapter 8).

Answer: The language relating to this comment has been removed.

8) In the first paragraph under Barriers to Using Renewable Resources, Staff recommends a comment that it will make an effort to improve the modeling of non-price factors, such as fuel price risk and environmental impacts in RAMPP-4.

Answer: The requested comment has been added to the report in the first paragraph under barriers in this chapter.

9) Please break down the text under Barriers to Using Renewable Resources, into subsections on the specific barrier or planning issue (direct costs, siting, non-price factors, targets, etc.).

Answer: The requested sub-headings have been added.

10) Does the model assume an infinitely elastic supply for wind and other renewable technologies? Is it reasonable to assume that wind will always win among renewables?

Answer: The company did not put any limits on the model's ability to add wind or other renewable resources (no caps on total amounts added). In the highest externality adder case with high gas prices, the model added 6,461 MW of wind resources; under high load growth with high gas prices the model added 5,450 MW of wind resources. Those amounts may not be feasible in the next 20 years, but until the company gains more experience with wind plants, it is difficult to predict. The best information available indicates that wind is the least expensive of the renewable options; whether that will always remain so is an open question, but the company uses the most current information available for the RAMPP analyses.

11) Please expand and clarify the significance of the 38 mills/kWh difference between the strategic-renewables runs and the any-renewables runs.

Answer: Additional language has been added to the Renewables Chapter, discussing the cost of the strategic-renewables strategy compared to the cost of the high-DSR over the medium-DSR strategy.

12) What is the logic of assuming that geothermal O&M costs will increase at the same rate as gas prices?

Answer: Additional text has been added to the description of case #262 (the geothermal O&M sensitivity) to explain that the company believes geothermal pricing will follow the market.

13a) The Conclusion should be a separate section which interprets the model's mathematical results.

Answer: The Conclusion chapter now is placed after the study results and before the Action Plan chapter. The model's mathematical (optimization) algorithm produced certain resource selections. The mathematical results are in the form of a massive matrix (over 20,000 rows by 300,000 columns). Therefore, the company can discuss the selections, but not the mathematical results. The new conclusion chapter discusses what the company learned from the model's resource selections in the different cases.

13b) Please provide further discussion to support the conclusion that the renewables industry needs to advance significantly before renewables will be cost competitive. Do the model results indicate what is significant. Does the sensitivity analysis provide an estimate of how much more expensive renewables are?

Answer: Additional text has been added at the end of the Renewables chapter to explain the statement.

14) Please provide support for the conclusion that if the company erred in the input assumptions for renewables used for all other cases, those errors would have to be quite large to affect modeling results. Perhaps interpretation of the shadow prices on the LP model's resource constraints would provide some insight into what "quite large" is.

Answer: Additional text has been added at the end of the Renewables chapter to explain the statement.

15) The conclusion needs to interpret the LP model's mathematical results and summarize the company's overall plan for determining how renewables will best fit into its resource mix.

Answer: The model's mathematical (optimization) algorithm produced certain resource selections. The mathematical results are in the form of a massive matrix (over 20,000 rows by 300,000 columns). Therefore, the company can discuss the selections, but not the mathematical results. The Renewables chapter contains a more complete discussion of what the company learned about the strategic-renewable strategy.

Competitive Bidding

16) Please expand upon the company's plan for conducting a bid solicitation, including how it intends to deal with regulations which differ across states.

Answer: Additional explanatory material has been added to the Question and Answer item dealing with bidding.

Avoided Costs

17) Please elaborate on why the company considers the power purchase agreement with US Generating Company to be a non-deferrable resource.

Answer: The company considers the agreement non-deferrable because the company has signed a legally enforceable contract that commits the company to the power purchase.

18) How do the RAMPP-3 draft avoided cost estimates compare with the price stream in the power purchase agreement with US Generating Company?

Answer: The company believes it is inappropriate to compare Hermiston to draft RAMPP-3 avoided costs, because the draft RAMPP-3 avoided costs were developed subsequent to the decision to purchase power from Hermiston. The appropriate analysis to determine whether or not Hermiston was a cost-effective resource at the time the decision was made should compare Hermiston to the Oregon avoided cost rates that were being reviewed by the Oregon Commission on July 1, 1993, when the Hermiston contract was signed, and which were accepted by the Commission effective July 16, 1993. Hermiston is less expensive than the Oregon avoided costs, the RAMPP-3 draft avoided costs with Hermiston, and the RAMPP-3 draft avoided costs without Hermiston. The 30-year net present value, beginning in 1996, for the various comparisons were as follows: Hermiston 32.65 mills/kWh, Oregon avoided costs 47.34 mills/kWh, RAMPP-3 draft avoided costs with Hermiston 32.80 mills/kWh, and RAMPP-3 draft avoided costs without Hermiston 36.70 mills/kWh.

19) In Chapter 9, please clarify the meaning of "Avoided costs in the previous RAMPPs have been very similar, reflecting only evolutionary changes."

Answer: Additional text has been added to the answer to the question on avoided costs, to clarify the company's statement regarding evolutionary changes.

Discount Rate

20) Provide a separate page to compare the ranking of resources (and total cost of each) under the two discount rate assumptions.

Answer: The report now has a table 4-12 which ranks the resources under the two discount rate assumptions.

21) The plan should provide information and discussion regarding the effect of changes in the discount rate on the conservation supply curve.
Answer: The company has added the following discussion to the Demand-Side Appendix, Section 3, on discount rates. "Discount rate affects the conservation supply curve through changes in the calculated present value of the discounted flow of future benefits and discounted flow of future O&M costs for the measure. Everything else being equal, as the discount rate increases, fewer measures will be cost effective. The RAMPP-3 analysis used an effective real discount rate of 5.23 percent."

22) Why did the company not run the discount rate sensitivity (case #241) with high DSR, since its NPV cost should drop with a lower discount rate?

Answer: The company used the medium DSR to be consistent with the other sensitivities and with the company's preferred DSR level. An explanatory sentence has been added to the discussion of case #241 in the report.

Fuel Switching

23) The Commission's requirement to file a fuel switching report has not yet been met.

Answer: RAMPP-2 order required that company and the PUC staff hire an outside contractor and conduct fuel switching analysis. Company representatives were under the understanding from meetings with representatives from the Oregon Public Utility Commission and Oregon Department of Energy that the group decided that there was no need to select a contractor and conduct further analysis beyond the information provided to staff regarding the customers with gas space heat and electric water heat. The company thought it had met the RAMPP-2 order for the fuel switching analysis. PacifiCorp staff will follow-up with OPUC and ODOE staff to determine the status of this issue.

Demand-Side Resources

24) Does development of cost effectiveness for DSR programs in RAMPP-3 take into account the changes in cost effectiveness proposed in UM 551? If not, how will the company reconcile treatment of DSR in RAMPP-3 with the treatment proposed in UM 551 regarding non-energy benefits, the cost of incentive payments, the exclusion of lost revenues, etc.? If the company has

based its decisions on a cost effectiveness methodology which is significantly different than that which the OPUC has adopted, what will be the results for the applicability of the action plan in Oregon?

Answer: RAMPP-3 DSR analysis for program or measure screening occurred in early 1993, and thus did not take into account the proposed UM 551 cost-effectiveness changes. However, the screening criteria used in selecting programs for RAMPP-3 are largely consistent with the draft UM 551 order in that the company 1) evaluates programs based on the present value of revenue requirements, 2) includes incentive costs in the TRC, 3) includes program administration cost in the TRC, 4) treats shareholder incentives as costs, and 5) allows for supplemental measures to be incorporated into the program potential. However, the company has not evaluated the impact of inclusion of non-energy benefits. The company will need to evaluate the impact of the order on measure selection criteria and program cost-effectiveness, once the order is finalized. In addition, the company will make appropriate modifications for RAMPP-4 analysis.

25) Why does the increase from accelerated DSR to high DSR result in a substantial decrease to both NPV utility cost and NPV total resource cost, but cause an increase in kWh customer cost?

Answer: Higher levels of DSR result in fewer kWhs sold, thus the total revenue requirement is divided by a smaller number, raising the mills/kWh.

26) Why is a medium DSR strategy reasonable when TRC is lower under the accelerated and high DSR strategies for Pacific's most likely futures? Does this mean Pacific is departing from least cost planning principles? Are the company's financial standards (in the DSR technical appendix) the basis for developing the action plan and selecting the medium DSR strategy?

Answer: A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

27) Explain how and when the company's financial standards intersect with the UM 551 cost effectiveness standards to be used in evaluating DSR programs. This should include a decision tree diagram with some examples of programs which don't pass the financial standards but do pass the UM 551 tests, programs which pass both the financial standards and the UM 551 tests, and programs which fail both tests.

Answer: The company has not fully evaluated the intersection of the company financial standards with the proposed order in UM 551. The company plans on conducting further review of its DSR programs in light of UM 551, but will not be able to conduct this analysis within the scope of the current RAMPP-3 plan.

28) Pacific should add its efforts in commercial code support to the code enforcement discussion (chapter 11, p. 2)

Answer: Additional explanation of the company's activities in commercial code support has been added to the DSR Action Plan Detail chapter.

29) Please explain what an existing residential customer response oriented program as an alternative to a community-based Pacific-as-general contractor approach means.

Answer: The action item has been changed to read "Launch a Super Good Cents Home Improvement Retrofit Program in Oregon." The original statement was a poorly worded attempt to distinguish between a community-based residential retrofit initiative, Home Comfort, and a more regionalized approach which is not as targeted, Super Good Cents Home Improvement. The former is a community-based program where Pacific acts as a general contractor. This program uses the Energy Service Charge approach and offers a comprehensive audit and 100 percent up-front financing. The latter is a customer-response program where there is no community involvement and Pacific does not act as general contractor. The customer is solicited through targeted advertising and is provided a list of certified contractors. This program design is closer to the existing statutory programs which offer a choice of a loan or a small up-front cash payment option.

30) What are Pacific's plans for the multifamily showerhead market during the term of the action plan?

Answer: The company's DSR action plan includes the execution of a multi-family showerhead program in Washington and Utah, as well as potentially extending the initiative to other jurisdictions.

Demand-Side Technical Appendix

31) Was an industrial load factor closer to 100% than 60% (as in RAMPP-2) used in developing cost effectiveness for industrial measures and programs?

Answer: Yes. The conservation load factors used for industrial programs were 100 percent for Wyoming, 98 percent for Utah, and 98 percent for Oregon, Washington, and California. Additional details are in Section 3 of the Demand-Side Appendix.

32) On pages 35 and 48-49 the background and frozen efficiency portions should be clearly labeled here and elsewhere.

Answer: The amounts have been clearly labeled in the Demand-Side Appendix.

33) Page 38, average consumption needs to be labeled, is it kWh?

Answer: Yes, it is kWh/year, and has been labeled.

34) Page 56, figure 26 does not allow the categories of lights, motors, and heat to be distinguished from one another.

Answer: The text has been corrected.

35) Page 58, regarding cost-effective fuel switching, the company states, "the marginal cost of gas should be 30% higher at the wellhead." How does this comport with the company's decision to depend on low or medium gas prices in selecting probable futures?

Answer: The statement in the technical appendix relates to the sensitivity analysis that was performed as part of the fuel switching study. The break-even level of kWh consumption which would make fuel switching cost effective was calculated for various gas prices. The analysis showed that the break-even point for fuel switching would be 19,000 kWh if the price of gas goes up by 30 percent. The analysis evaluated various levels of gas price increase and was simply used to illustrate the fact that the outcome of the analysis was sensitive to the gas price assumption.

36) Page 85, is supplemental funding included in the computation of program cost effectiveness? If so, how?

Answer: This issue is addressed in Section 14 of the Demand-Side Appendix.

37) Page 87, why are there no adjustments for free riders in the calculation of program potential for industrial, residential and appliance programs?

Answer: In the industrial sector the estimates of free riders are implicitly embedded into the specification of the econometric equations used to forecast energy consumption. Based upon short payback required for free riders and the high discount rate implicitly used among residential customers, the company estimated that there would be very few measures that customers would do on their own. For further discussion, see Section 13 of the Demand-Side Appendix.

38) Page 92, why is there no long term administrative cost estimated for new residential?

Answer: The figure reported on table 25, page 92 of the draft DSR technical appendix was incorrect. This table was corrected.

39) Page 95, the company should add to its EFA TRC those costs due to periodic education and training of building operators.

Answer: The costs associated with training and education of the building operator are included within the program costs associated with commissioning and verification. On-going costs associated with retraining were not included. This issue will be addressed in RAMPP-4. See Section 14 of the Demand-Side Appendix.

40) Page 97, does the company's plan to pursue only relatively low cost programs under medium load growth apply only to programs which are currently being planned, or does it apply to all programs? How does the company reconcile its arguments that it can immediately ramp up to full

acquisition if necessary with its arguments elsewhere that it takes at least three years to bring a program to maturity?

Answer: The company is committed to pursuing the most cost-effective DSR options as compared to other resource options. In order to be prepared to deliver large scale acquisition when needed, the company recognizes the need to build capability. During 1993-1996 the company is actively building capability in all sectors to position the company for full deployment when the resource is required or to delay if the need does not arise. Additional information has been added to Section 15 of the Demand-Side Appendix.

41) Page 108, does Table 30 include in new homes built between 1994 and 2013 only electrically heated homes, or does it include all new residential construction?

Answer: The number shown in the table presents all new homes built between 1994 and 2013. This information has been added to Section 16 of the Demand-Side Appendix.

42) Page 112, the OPUC considers the commercial retrofit a program, not a pilot.

Answer: The company also believes this to be a program and not a pilot. The document has been corrected.

43) Pages 128-129, please provide an analysis which indicates how the Oregon residential retrofit program was assessed relative to its potential for trimming administrative and programmatic costs.

Answer: The residential retrofit program cost was assumed to be 75 percent lower than the administrative cost of the Home Comfort program. Additional information has been added to Section 14 of the Demand-Side Appendix.

44) Page 134, please include in the action plan the evaluation group that the OPUC has recommended Pacific establish.

Answer: The evaluation related item in the action plan, presented in page 134, has been changed to read " Continue participation in Evaluation and other Advisory Groups as recommended by regulatory agencies to obtain external review and input into improvement of program evaluation and process. (NW Evaluation Group, Utah Evaluation Collaborative, and Regional Evaluation Network).

45) Appendix D, why does Oregon have a residential takeback factor of 30% while Utah, Montana and Washington have a 0% takeback factor?

Answer: A takeback adjustment factor of 30% is applied to space heating for existing residential units, in all states. The takeback adjustment factor for new residential space heating is zero for all states. The tables in Appendix D show the takeback adjustment for both new and existing residential units. Residential takeback factor for Oregon is same as other states. The tables on pages D-1, D-3, D-5 and D-7 show the takeback assumption for existing units. The tables on pages D-2, D-4, D-6, and D-8 show our assumptions for the new units. The vintage of the units is documented on the top right hand corner of each table, in the cell labeled "Vintage of Housing"

Modeling Appendix

46) The text should use the request/response format to describe how the new model incorporates each agreed-to Commission recommendation, or provide a page reference after listing each recommendation on pages 1-3 to 1-5.

Answer: Additional text has been added to the Modeling Appendix to respond to the modeling items in the Commission's acknowledgment order on RAMPP-2.

PP 207

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working for a sustainable energy future

Solar Energy Association of Oregon
027 SW Arthur Street
Portland, OR 97201
March 7, 1994

Nancy Esteb
PacifiCorp
920 SW 6th Avenue
Portland, OR 97204

Re: SEAO COMMENTS ON RAMPP-3 PLAN

Dear Ms. Esteb:

The Solar Energy Association of Oregon (SEA of O) has participated in the Advisory Group for Pacific's Least Cost Plan. We have often been impressed with the dedication of individual staff members in developing this complex planning process. However, it appears that corporate management has determined to ignore the planning results. Unless there is a complete change in the development of the Action Plan and implementation, we will recommend to the Oregon Public Utility Commission that the plan should not be acknowledged.

Our major concern is the company's announced deviation from Total Resource Cost (TRC) planning. The company's process directly violates the Oregon Public Utilities Commission (the Commission) order.

The critical points are :

- The plan is not Least Cost. The company's own analysis shows that the accelerated DSM provides benefits, both on a TRC and a Utility Cost perspective.

- The company has rejected TRC as the planning criterion. The Commission has ordered that Least Cost Plans are to minimize TRC cost. PacifiCorp management has substituted their own business planning criteria in direct opposition to the Commission order. Lost revenue is included in at teast two of three criteria, making the analysis one of rate impact rather than TRC.

In the past, we have agreed with the company that program design options, such as the Energy Service Charge, can be implemented as a secondary objective to reduce rate impact for programs which have been determined to meet TRC criteria. At the time, the company has stated that the policy is to obtain all the Demand Side Management (DSM) resource. If the Energy Service Charge prevents full realization, the company has promised to provide another program offering. Now the company is rescinding that policy. The new policy seeks to drop programs even though they meet TRC criteria if the company feels like it.

- The "financial analysis" which the company uses to justify cutting back on DSM has not been presented to the Advisory Group in complete detail. The company presented a worksheet to document the methodology. However the sheet is incomplete. It does not provide all the information used by the company to assess rate impacts.

- There is no connection between the results of the planning study and the Two Year Action Plan. PacifiCorp should be able to demonstrate that the level of DSM is the optimal one and that program activity levels proceed from resource development. Instead, PacifiCorp has adjusted program level to meet management priorities that are not related to the planning process.

- The planning process fails to consider risk, externality cost, fuel switching and pricing policy in developing the Action Plan. This is in direct contradiction to the Commission order.

The following points are specific objections to the "financial analysis":

- The planning process settled on a 50-year financial analysis in order to include end effects of resource choices, particularly escalation of fuel costs. All the financial calculations were done for a 50-year period. Yet the "financial analysis" for the management decision was done using only a 30-year analysis. PacifiCorp has already demonstrated that this short period is inadequate to capture end effects. Please use consistent economic analysis. The "financial analysis" changed other variables as well. Avoided cost is not based on any filed values but is instead an artificial number created by management. Please use the same economic parameters as the RAMPP-3 financial analysis.

- Annual cash flows are computed by a method that includes the annual cost of taxes but discounts by a post-tax discount rate. These assumptions are incompatible. This procedure violates the Commission order on discount rates. Please correct the cash flow parameters.

- PacifiCorp shows no explanation of the comparison of rate impacts. Where are the comparable prices for the case with no DSM? Please show the rate impact.

- The company assumption of a 1% ceiling on rate impact is without justification. There is no explanation of how this figure was derived. How does the company know that 2% is not equally acceptable? If the analysis is based on elasticity of the customers, then provide the data demonstrating elasticity.

- The "financial analysis" appears to be merely justification to do less conservation. There was no analysis of the accelerated DSM case to see if the benefits justify more DSM. In the draft plan, the company admits that the economic development programs raise rates. If so, why have they not been subjected to the same financial analysis? Please demonstrate the same analysis applied to the economic development programs and the accelerated DSM scenarios..

- The "financial analysis" does not include any assessment of rewards or penalties that might be imposed on the company for failure to meet DSM goals. We propose that the company goal should be based on the accelerated DSM case, since that case demonstrates TRC benefits. The company should then pay a penalty for any deviation from that goal. Please show how this consideration would affect the analysis.

- The comparison case of no DSM is not shown, although rate impacts are judged against that case. Staff informs us that a no DSM case was run thorough the planning model. Please present all results including the no DSM case.

- The company has dropped 9 MWa from program plans without showing where the decrease occurs or what the analysis would look like if the 9 MWa were retained. The example analysis shows a 14% IRR so even with the 9 MWa the programs probably still pass that criterion. It is hard to believe that the rate impact was significant. What is the criterion which the 9 MWa failed and why were they removed from the programs? In the meeting of December 17, 1993, Dan Spalding stated that the programs were viewed together as a combined DSM package. What are the results for the combined package including the 9 MWa? How different are they from the package without the 9 MWa? Please show the comparison of plan results against the criteria and demonstrate why the programs were removed.

- The company suggests that dropping 9 MWa is a small change and that the programs essentially conform to the MD case. However, the results show that the accelerated cases provide benefits and should be the Least Cost plan. Why then did the company drop the 84 MWa represented by the accelerated case by the year 1998? Where is the analysis to justify that decision? Please show the results for the accelerated scenarios. ODOE staff have indicated that PacifiCorp is running additional accelerated scenarios through the RAMPP-3 models for sensitivity review. We would also like to see those results. Please present all results to the public.

- Previous statements from Dennis Steinberg were that the company faced a problem raising capital. The new criteria appear to be a rationale to justify the company's decision to devote capital to acquisitions and mergers rather than DSM. The reason for an IRR criterion appears to be priority decisions for capital investment. Why doesn't the company discuss capital problems? Have they consider canceling recent coal plant acquisitions if capital is scarce?

Consideration of risk is required by the Commission order. PacifiCorp included scenarios with higher gas prices. However, the avoided cost calculation should be based on an expected value for fuel that takes into account the probabilities of gas price increases. Similarly, the risk analysis should include an expected value for the risk of CO2 externality cost being imposed on generation. We expect that PacifiCorp should include the cost of an "insurance premium" to hedge against the possibility that CO2 adders will be applied in the future. If PacifiCorp does not include such a premium in their analysis, then we expect that the shareholders will absorb any unanticipated fuel cost or future externality tax. It is incorrect to pass any unanticipated costs to ratepayers when PacifiCorp has refused to include their analysis in the decision making process.

The Commission order requires PacifiCorp to consider price policy as a potential DSM program option. Yet PacifiCorp refused requests from the Advisory Group to do so. We have requested that PacifiCorp quantify the reduction in load growth that would result from increased rate spread in tiered prices. Pricing policies of this sort should be explicitly considered in the DSM program portfolio. PacifiCorp has been reluctant to do so, arguing that there is little information on price elasticity. Yet, PacifiCorp has adopted a criterion of a 1% ceiling on rates without providing any supporting justification. If this criterion is based on customer's price elasticity, then PacifiCorp should present that information. Furthermore, the same elasticity data should be used to design tiered pricing as DSM programs. If the data do not exist, then what is the justification for the 1% ceiling?

We have also requested that PacifiCorp consider other pricing policies such as a revenue-neutral hookup fee for new construction. We think the later approach could be a low-cost program alternative for new residential construction. It is noteworthy that PacifiCorp has refused to consider this idea even though they profess to want low-cost program alternatives.

In summary, we believe that company management has incorrectly interfered in the planning process. We recommend that PacifiCorp return to the planning objective as originally stated in the Advisory Group one year ago -- that objective is to minimize total societal cost, not to minimize rates.

Sincerely Yours,

Robin Christle

Robin Christle, Representative
Solar Energy Association of Oregon

PacifiCorp RAMPP-3 Draft Report
Comments from Solar Energy Association of Oregon:
Letter from SEAofO dated March 7, 1994

1) The plan is not least cost. The company's own analysis shows that the accelerated DSM provides benefits, both on a TRC and utility cost perspective.

Answer: PacifiCorp does not believe there is one least cost plan. The company prepared 156 least cost plans, for 156 possible futures. Although a higher level of DSR provides benefits on a TRC and total utility cost basis, it also causes customer prices to increase. The company attempts to balance costs and risks to customers, society, and the company's shareholders. Also, a new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

2) The company has rejected TRC as the planning criterion. PacifiCorp management has substituted their own business planning criteria, which uses rate impact, instead of minimizing TRC.

Answer: The company has not rejected TRC. The company tries to balance multiple goals in its IRP process: TRC, retail prices, risks to customers and shareholders, and environmental concerns. Also, A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

3) The company earlier promised to modify programs if the ESc prevented full realization, but now the company is rescinding that policy.

Answer: The company does not believe that the ESc has in any way prevented the full realization of DSR resources. To the contrary, the approach has proved to be quite successful and is now being copied by other utilities around the country. Results to date indicate that over $50 million has been invested through the ESc approach. Over 159 commercial buildings have signed ESc agreements, 31 industrial customers, and 1,049 residential customers. The Energy FinAnswer program has resulted in acquiring 76 percent of the potential square footage in Oregon and 36 percent company-wide (Oregon has had the program longer). Actual program savings have exceeded RAMPP 2 planning technical estimates by 32 percent. These results would indicate that the approach has been quite successful.

4) There is no connection between the results of the planning study and the two year action plan. PacifiCorp should demonstrate that DSR program activity levels are optimal, rather than adjusting program levels to meet management priorities.

Answer: A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

5) The planning process fails to consider risk, externality cost, fuel switching and pricing policy in developing the action plan.

Answer: The company considered risk and externality costs in developing the action plan. Each resource and each resource strategy carries risk, which the company tried to balance with the anticipated benefits of each resource and each resource strategy. The company provided 23 runs which included externality costs or limits, and used those results in developing the coal action plan item. Fuel switching and pricing policy are issues which were addressed through case #201, reduced load.

Financial Analysis for DSR

6) The financial analysis uses only a 30-year analysis, when RAMPP-3 used a 50-year analysis.

Answer: The DSR measures being analyzed typically have a life of 15 years or less. Thus, the financial analysis model used to calculate the IRR's of the various DSR programs does not go out more than 30 years.

7) Avoided cost is not based on any filed values but is instead an artificial number created by management.

Answer: The draft avoided costs distributed with the Draft RAMPP-3 Report were developed using the same basic methodology as the avoided costs currently approved in the States of Oregon, Washington, Wyoming, and Utah. They incorporate the most recent data updates and are therefore relevant for use at this time. These avoided costs will be filed in each of these states during this year either as part of the formal competitive bidding process or as separate filings.

8) Annual cash flows for the financial analysis include the annual cost of taxes but discount by a post-tax discount rate. These assumptions are incompatible.

Answer: Including tax effects produces after-tax, unlevered, economic cash flows to which an after-tax discount rate is applied to derive the net present value of a program. This is the common methodology used in financial analysis text books. the OPUC white paper on the discount rate for least cost planning takes the same appoach.

9) We understand that a no DSR case was run through the planning model What are the price impacts for a case with no DSR? Please present all results including the no DSR case.

Answer: At the beginning of the RAMPP-3 process, a no-DSR case using RAMPP-2 inputs and modeling was presented to the RAG group to illustrate the impact of alternative levels of DSR on customer prices. The company has not performed a no-DSR case with RAMPP-3 inputs and modeling.

10) How was the 1% rate impact ceiling derived? How does the company know that 2% is not equally acceptable to customers? If the analysis is based on customers' price elasticity, then provide the data demonstrating elasticity.

Answer: A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

11) There was no analysis of the accelerated DSR case to see if the benefits justify more DSR. Please provide the financial analysis for the accelerated DSR level.

Answer: A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue. Additionally, the modeling results included the TRC and price impacts for the accelerated case, so it could be compared to the other three DSR strategies.

12) The company admits that economic development programs raise rates. If so, why have they not been subjected to the same financial analysis as DSR? Please demonstrate the same analysis applied to the economic development programs.

Answer: The corrected analysis, shown in the final plan, indicates that economic development programs can cause retail prices to be lower.

13) The financial analysis does not include any assessment of rewards or penalties that might be imposed on the company for failure to meet DSR goals. Please show how consideration of a reward or penalty for performance on DSR would affect the analysis.

Answer: The financial analysis model looks at the cash flow of the project before considering the impact of regulatory rewards or penalties. Also, see the answer to Land and Water question #7.

14) The company has dropped 9 MWa from program plans without showing where the decrease occurs or what the analysis would look like if the 9 MWa were retained. The example analysis shows a 14% IRR, so even with the 9 MWa the programs probably still pass that criterion. What is the criterion which the 9 MWa failed? What are the results for the combined package including the 9 MWa. How different are they from the package without the 9 MWa?

Answer: The 9 percent IRR test is applied to each individual program. The 9 MWa reduction represents programs that failed the IRR test. Also, a new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

15) Why did the company drop the 84 MWa by the year 1998 represented by the accelerated case? Where is the analysis to justify that decision. Please show the results for the accelerated scenarios. ODOE staff indicate that PacifiCorp is running additional accelerated cases. Please present all results to the public.

Answer: A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue. The results for the cases with the accelerated DSR strategy were in the draft report, and are in the final report, along with the results for the cases with the other three DSR strategies.

16) Why doesn't the company discuss capital problems. Dennis Steinberg said that the company faced a problem raising sufficient capital. Has the company considered canceling recent coal plant acquisitions if capital is scarce?

Answer: Scarcity of capital is nothing new. It is common for companies to have more potential capital spending projects than they can afford to do. This leads to a prioritization process which involves quite a lot of senior management time. It is not as simple as just selecting the programs that have an IRR greater than a certain amount. Management must factor in the riskiness of the projects and must take into account non-economic factors. For example, safety programs are not justified on the basis of economics alone. PacifiCorp has not acquired any coal plants since 1991 and 1992. At that time, the company had different tools to evaluate potential projects and did not compute the IRR. The economics of the coal plant purchases, however, were very good and the cost was calculated to be much lower than the company's avoided cost at the time. Therefore, the coal plants were prioritized at a high enough level to be funded.

Other Issues

17) Avoided cost should be based on an expected value for fuel that takes into account the probabilities of gas price increases. The risk analysis should include an expected value for a CO2 tax.

Answer: The draft avoided costs do take into account the likelihood of natural gas price increases. The gas price escalation assumption is in fact somewhat above the current market expectations as reflected in the energy price escalation rate built into the Hermiston power purchase agreement. The Company does not believe that its customers should be required to pay a premium for QF power based on the speculative possibility that some as yet unspecified CO2 emissions tax might be imposed sometime in the future.

18) PacifiCorp should include the cost of an insurance premium to hedge against the possibility that CO2 adders will be applied in the future.

Answer: PacifiCorp included in the Environmental Analysis chapter an insurance premium analysis.

20) PacifiCorp refused requests from the advisory group to consider price policy as a potential DSR program option. PacifiCorp should quantify the reduction in load growth that would result from increased rate spread in tiered prices.

Answer: The company has considered pricing policy as a potential demand-side program option. As indicated in the Action Plan chapter, the company developed a number of pricing proposals for promoting energy efficiency and acquiring demand-side resources. These include more time-of-day pricing options and the use of a capacity credit to acquire DSR. PacifiCorp is currently meeting with customers to discuss these options and their impact on energy use.

21) PacifiCorp should consider other pricing policies such as a revenue-neutral hookup fee for new construction.

Answer: From November 1993 through January 1994, the company participated in a collaborative task force with other utilities in Washington, as ordered by the Washington Utilities and Transportation Commission, to examine proposed state-wide hook-up fees for new construction. Participants included representatives from the Washington State Energy Office, the Public Counsel's office, Puget Power, Washington Water Power, Washington Natural Gas, WICFUR (representing industrial customers), and PacifiCorp. The collaborative agreed that consensus could not be reached on the appropriateness of hook-up fees for new construction. There was no agreement on the criteria that should be used in determining appropriate hook-up fees. In addition, hook-up fees force the selection of alternative fuel sources by parties other than the end user and result in market distortions. In a survey conducted by PacifiCorp in January 1994 for the Washington collaborative, the company found no electric utilities west of the Mississippi that use hook-up fees. Nationally, the company was able to identify only three utilities that have used hook-up fees in the past, but none of these utilities use them at the current time.

22) We believe that company management has incorrectly interfered in the planning process. PacifiCorp should return to the planning objective to minimize total societal cost, not to minimize rates.

Answer: The least cost planning process involves balancing multiple objectives. Management makes its decisions to balance those objectives. In the RAMPP process, the company attempts to balance costs and risks to customers, society, and the company's shareholders.

PP 21

PP 217

Memorandum

To: Nancy Esteb, PacifiCorp

From: Utah CCS
Dan Gimble

Re: Comments on the Draft RAMPP 3 Report

Date: March 3, 1994

A. **Background**

1. On page #9 the actual load growth figure for year-end 1993 should be given. Further, it should be indicated that the load growth figure relates to energy and not capacity.

2. On page #11 the Company discusses RAMPP 3 improvements. This list of principal improvements should include a fifth area pertaining to the cost analysis of the refurbishment of existing plant.

3. At the bottom of page #12 the Company states, "The results of this analysis indicated a change in the electricity price through the 20-year planning horizon of less than expected inflation. These levels would have had an insignificant effect on the load forecast." My question is this: what price elasticity assumptions did the Company rely on in their demand forecast modelling that support this conclusion.

B. **Futures**

1. From Table 3-1 on page #4, it appears that demand requirements are growing faster than energy requirements. If this is so, why is there no capacity component in the total avoided cost price until 1999? This is especially disturbing when the Company has publicly stated that it plans to acquire resources in the near-term to meet summer peak needs.

2. In referring once again to Table 3-1, why do the demand load growth rates closely match the energy load growth rates in all five load growth scenarios? Is this because the Company does not independently forecast demand (i.e.,., the demand forecast is basically

derived from the energy forecast)? Since the merger what have been the actual annual load growth figures for both energy and peak demand?

3. What load growth forecast(s) is the Company's two-year action plan premised on? The **medium** energy and peak demand forecast or some other combination of energy and peak demand? Since summer peaking requirements are driving the Company's short run acquisition strategy, the CCS believes that the above questions are relevant to understanding the action plan.

4. Referring to the "financial hedge" discussion on page #15, does the Company intend to pursue a hedging strategy in its procurement of gas supplies? Please discuss in detail.

C. **Portfolio**

1. Regarding the information detailed on the existing power system (pg. #1), how does the existing power system compare with the supply portfolio back in January 1989, when PPL and UPL first merged. In other words, how has the portfolio evolved over the past 5 years.

2. At the top of page #12, the Company indicates that 720 Mw of Company-owned hydro units needs to be relicensed during the 20-year planning horizon. What are the expected costs associated with each hydro unit and how are they treated/reflected in the RAMPP 3 analysis.

3. Referring to the plant refurbishment discussion on page 13, are there physical limitations to this refurbishment strategy? Do utilities in the country typically operate thermal generation that is over 45-50 years old?

4. Table 4-7 on page #14 should be updated to reflect Dec '93 availability figures.

5. On page 7-29 of Energy Ventures Analysis's ("EVA") 1991 Coal Study, EVA states that PacifiCorp uses an inappropriately low incremental cost when evaluating capital projects. EVA recommends an incremental cost level of $15/ton. With this in mind, what specific cost assumptions did the Company make in determining a 1993 beginning coal price of $12/ton for new coal-fired plant sited in Utah (i.e., Carbon or Emery County)? Is the Company assuming that a new pulverized bed coal plant could be supplied coal from existing mines that presently provide coal to Hunter and Huntington? Would a new

coal mine need to be developed? What is the incremental cost of the new Trail Mt. Mine? Does a change from $12/ton to $15/ton impact the ranking of resource options? This should be discussed in both the overview and the technical appendix on supply-side resources.

D. **Analysis Plan**

1. On page #7 the Company indicates that the IPM model cannot select between a generation resource and a transmission upgrade. Does the Company plan to modify the model to remedy this apparent shortcoming? How much would such a modelling enhancement cost? Do other Company models (i.e., GE maps or Multisym) have the modelling capability to evaluate transmission versus generation options from an economic and operational standpoint? This should be discussed at the appropriate place in the RAMPP 3 Report.

2. Regarding the social discount rate discussion on page #8, the Company should indicate the level of the social discount rate used, whether it is real or nominal, and how it compares to the discount rate actually used to assess supply- and demand-side resources in RAMPP 3. In RAMPP 4 the Company should also perform a discount rate sensitivity that is at least 3% higher than the "base case" discount rate.

3. On page #20, the Company used <u>three</u> non-firm markets--PNW, Desert SW and California--to account for P-Corp's purchase and sales transactions in the non-firm market. Two questions: (a) why was the Nevada Market excluded, or is it treated as part of the Desert SW market; and (2) is the Colorado Market presumed to be part of the Desert SW Market?

4. On page #22 and #23 the Company conveys that summer capacity requirements are driving the short-term resource acquisition strategies. However, the Company continues to use winter peak demand in its modelling endeavors. During its RAMPP-3 presentation in Utah, the Company indicated that this problem will be resolved in RAMPP-4 by enhancing the model so that it can simultaneously consider both summer and winter peak demand requirements. This information should be briefly discussed in this section and in the action plan under "action step" #10 (b).

5. In its discussion of "critical versus average water planning," the Company should note on page #24 that the move to average water planning exemplifies a significant change in the Company's planning

philosophy.

E. **Illustrative Plans**

1. Now that the Company has an IRP model that fully integrates the planning module with the plant dispatch module, and additionally considers spatial transmission constraints, the Company should perform "backcast" runs to see if and when the IPM model chooses the Cholla, Hayden and Craig units.

2. On page #19 the Company needs to provide a clear explanation of why the model selects fewer SCCTs under the low gas price escalation scenario vis-a-vis the medium gas price escalation scenario.

3. Two additional gas price escalation rate scenarios should be performed: (a) the first scenario should set the gas escalation rate at the <u>low</u> (1.71%) level through the year 2000 and at the <u>high</u> (5.56%) escalation rate level thereafter; (b) the second scenario should set the gas escalation rate at the high level through the year 2000 and at the low level thereafter. The CCS believes that these are reasonable sensitivities to run because of conflicting short term gas price forecasts among DRI, WEFA and NERA.

4. On page #36 the Company indicates that a load growth scenario (case #202) between medium and medium-high results in a lower NPV of utility cost and TRC, but a higher customer price vis-a-vis the medium high case. Can the Company shed any light on why this result was obtained?

F. **Questions and Answers**

1. On page #2 the Company asserts that RAMPP provides the basis for avoided costs. Please fully explain what the Company means by this statement?

2. On page #10 the Company states that load forecasts include the energy requirements of interruptible customers, but not the capacity requirements. The reasons undergirding this dichotomous approach for treating interruptible loads needs to be fully articulated in the "answer."

G. **Action Plan**

- <u>Performance on RAMPP-2 Action Plan</u>

1. Under action step #2 which relates to the Calpine Geothermal project, what is the anticipated TRC associated with this purchase and at what Mw level?

2. With regard to meeting action step #5, the Company states, " RAMPP-2 identified a need for additional peaking resources by the mid-1990s and this contract provides those resources at a lower cost than other alternatives." What is the cost comparison? RAMPP-3 should present this kind of information, especially if the Company finds it cost-effective to deviate from its prior action plan.

3. Regarding action step #9, the Company says that it obtained additional south-to-north AC intertie rights from BPA. How much additional intertie rights did the Company obtain and at what price? Further, how has the recent earthquake affected the Company's capacity on the PNW-Cal. intertie?

- <u>RAMPP-3 Action Plan</u>

1. Realizing that there are limitations to increasing DSR programs in the short run, which one of the 200 or so RAMPP-3 "cases" results in the lowest total resource cost. In other words, what is the "benchmark" cost-minimizing plan that the action plan is evaluated against? Finally, what is the monetary difference between this particular case and the case that reflects the "strategic" resources that the Company deems reasonable to pursue at this juncture?

2. Action Step #5 conveys that other models or studies indicated summer peaking needs as early as 1997. What models have been used in preparing these peak demand studies and how does the Company plan to share these modelling results with regulators? Will it be in a RAMPP-3 appendix?

PP 222

PacifiCorp RAMPP-3 Draft Report
Comments from Utah Committee of Consumer Services:
Letter from UCCS dated March 3, 1994

Background Chapter

1) On page 9, the actual load growth figure for year-end 1993 should be given. Further, it should be indicated that the load growth figure relates to energy and not capacity.

Answer: The added information has been added, and a clarification that it is an energy number.

2) On page 11, the company discusses RAMPP-3 improvements. This list of principal improvements should include a fifth area pertaining to the cost analysis of the refurbishment of existing plant.

Answer: The company determined that this change is not of the same magnitude of the other changes discussed in this chapter. The information on refurbishment is provided in the Portfolio chapter.

3) At the bottom of page 12, the company states, "The results of this analysis indicated a change in the electricity price through the 20-year planning horizon of less than expected inflation. These levels would have had an insignificant effect on the load forecast." My question is this: what price elasticity assumptions did the company rely on in their demand forecast modeling that support this conclusion.

Answer: The explanation of this point in the Futures chapter clarifies that when fed into the model, the actual price forecast changed the results of the model less than one percent. A more detailed discussion of elasticity is included in the Load Forecasting Appendix.

Futures Chapter

4) From Table 3-1 on page 4, it appears that demand requirements are growing faster than energy requirements. If this is so, why is there no capacity component in the total avoided cost price until 1999? This is especially disturbing when the company has publicly stated that it plans to acquire resources in the near term to meet summer peak needs.

Answer: As indicated in the RAMPP-3 Avoided Cost Calculations report distributed with the Draft RAMPP-3 Report, a capacity cost component is incorporated in the avoided cost beginning in 1994 and continuing for each year of the analysis. In the years 1994 through 1998, inclusive, the capacity resource is a summer capacity purchase matching the one-season capacity shortage in the load and resource balance in that period. Beginning in 1999, the capacity resource is a simple cycle combustion turbine matching the additional winter and summer capacity requirement which begins in 1999.

5) From Table 3-1, why do the demand load growth rates closely match the energy load growth rates in all five load growth scenarios? Is this because the company does not independently forecast demand (i.e., the demand forecast is basically derived from the energy forecast)? Since the merger what have been the actual load growth figures for both energy and peak demand?

Answer: A detailed discussion of the methodology used to forecast demand is included in the Load Forecasting Appendix. Growth rates on energy demand may be found in the Background chapter of the report. Since the merger, winter peak and summer peak load has increased by 3.0 percent and 2.3 percent annually, respectively.

6) What load growth forecast(s) is the company's two-year action plan premised on? The medium energy and peak demand forecast or some other combination of energy and peak demand? Since summer peaking requirements are driving the company's short run acquisition strategy, the CCS believes that the above questions are relevant to understanding the action plan.

Answer: The company believes that any load growth between the medium-low and the medium-high forecast is equally likely, so the company primarily relied on results from the medium-low, medium, and medium-high load forecasts in developing the action plan, and of those three, the most important results were those from the medium load forecast cases. Summer peaking requirements are only driving the peaking acquisition strategy, not the strategy to acquire DSR, renewables, cogeneration, or other baseload resources.

7) Referring to the financial hedge discussion on page 15, does the company intend to pursue a hedging strategy in its procurement of gas supplies? Please discuss in detail.

Answer: PacifiCorp does not currently hold a direct natural gas futures position and at this time it does not anticipate moving towards one. However, as a part of PacifiCorp's overall strategy of maintaining its position as a low-cost provider of electricity, a portfolio of natural gas supply contracts for generation is being developed by the company. This portfolio will contain a mixture of supply arrangements with varying terms, quantities, load factors and pricing arrangements. Because NYMEX-based hedging products are central to many natural gas production and marketing arrangements, it is likely that some of PacifiCorp's term purchases are now and will in the future be hedged by the seller. These contracts will benefit PacifiCorp by making the term purchase portion of the company's gas supply more predictable and reliable.

Portfolio Chapter

8) How does the existing power system compare with the supply portfolio back in January 1989, when PP&L and UP&L first merged. How has the portfolio evolved over the past 5 years.

Answer: Gadsby #3 began production (100 MW), Cholla #4 added (380 MW), Craig #1 and #2 added (166 MW), Hayden #1 and #2 added (78 MW), improved availability at existing plants added 36 MW, SCE winter purchase (322 MW), and additional modifications of plant ratings.

9) At the top of page 12, the company indicates that 720 MW of company's owned hydro units need to be relicensed during the 20-year planning horizon. What are the expected costs associated with each hydro unit, and how are they treated/reflected in the RAMPP-3 analysis.

Answer: Additional text has been added to the discussion of hydro relicensing to provide more detail regarding cost estimates, and to indicate that the RAMPP-3 financial model includes the projected relicensing costs.

10) Are there physical limitations to the coal plant refurbishment strategy? Do utilities in the country typically operate thermal generation that is over 45-50 years old?

Answer: The limitations of coal plant refurbishments are unknown. A plant's 35-year expected life was, in large part, based on expected construction cost decreases and expected major increments in plant efficiencies. In fact new plants are expensive to build and have similar running costs to the older plants. Nationally many utilities are refurbishing and/or repowering older fossil units. However, PacifiCorp has not conducted a survey of other utilities' coal plants and their ages.

11) Table 4-7 on page 14 should be updated to reflect December 1993 availability figures.

Answer: An additional column has been added to the table to reflect 1993 availability. The 1992 column remains, to show the data that was used in the RAMPP-3 modeling.

12) On page 7-29 of Energy Ventures Analysis' (EVA) 1991 Coal Study, EVA states that PacifiCorp uses an inappropriately low incremental cost when evaluating capital projects. EVA recommends an incremental cost level of $15/ton. With this in mind, what specific cost assumptions did the company make in determining a 1993 beginning coal price of $12/ton for new coal-fired plant sited in Utah (i.e., Carbon or Emery County)? Is the company assuming that a new pulverized bed coal plant could be supplied coal from existing mines that presently provide coal to Hunter and Huntington? Would a new coal mine need to be developed? What is the incremental cost of the new Trail Mt. Mine? Does a change from $12/ton to $15/ton impact the ranking of resource options? This should be discussed in both the overview and the technical appendix on supply-side resources.

Answer: After reviewing the coal price assumptions used in RAMPP-3, the company confirmed the validity of the Wyoming price, but believes there is more uncertainty about the Utah price, especially as it relates to the number of coal units added. Five coal price sensitivities have been added to the analysis (described in the Analysis Plan chapter and the results discussed in the Illustrative Plans chapter). They used a Utah coal price which doubled that used in the rest of the studies, or $24/ton with a 1.5 percent real escalation rate, which is higher than the $15/ton as recommended in the 1991 EVA report.

Analysis Plan Chapter

13) On page 7 the company indicates that the IPM model cannot select between a generation resource and a transmission upgrade. Does the company plan to modify the model to remedy this apparent shortcoming? How much would such a modeling enhancement cost? Do other company models (i.e., GE maps or Multisym) have the modeling capability to evaluate transmission versus generation options from an economic and operational standpoint? This should be discussed at the appropriate place in the RAMPP-3 Report.

Answer: PacifiCorp is exploring the costs (in dollars and modeling difficulty) compared to the benefits (useful information) of adding such an enhancement. Other company models do not have the ability to select between a capacity expansion and a transmission upgrade. Text in the Analysis Plan chapter and in the Illustrative Plans chapter explains the model's inability to choose between generation and transmission, and that the company is exploring this with the model vendor.

14) Regarding the social discount rate discussion on page 8, the company should indicate the level of the social discount rate used, whether it is real or nominal, and how it compares to the discount rate actually used to assess supply- and demand-side resources in RAMPP-3. In RAMPP-4 the company should also perform a discount rate sensitivity that is at least 3 percent higher than the base case discount rate.

Answer: The text has been modified to include the requested information. RAMPP-4 will provide ample opportunity to discuss sensitivities to include in the analysis plan.

15) On page 20, the company used three non-firm markets -- PNW, Desert SW and California -- to account for PacifiCorp's purchase and sales transactions in the non-firm market. Two questions: (a) why was the Nevada market excluded, or is it treated as part of the Desert SW market; and (b) is the Colorado market presumed to be part of the Desert SW market?

Answer: The Nevada market is part of the California area; the Colorado market is part of the Desert SW area. Text clarifying this information has been added to the description of the geographic areas in the Analysis Plan chapter.

16) On pages 22 and 23, the company conveys that summer capacity requirements are driving the short-term resource acquisition strategies. However, the company continues to use winter peak demand in its modeling endeavors. During its RAMPP-3 presentation in Utah, the company indicated that this problem will be resolved in RAMPP-4 by enhancing the model so that it can simultaneously consider both summer and winter peak demand requirements. This information should be briefly discussed in this section and in the action plan under action step #10.

Answer: The requested language has been added to the Analysis Plan chapter and to the Action Plan chapter, action step #10.

17) In its discussion of critical versus average water planning, the company should note on page 24 that the move to average water planning exemplifies a significant change in the company's planning philosophy.

Answer: The use of average water planning for RAMPP-3 was in large part a consequence of the requirement to use either average or critical water planning for the study, which meant using one water assumption for both planning and calculating the financial results for each case. Using critical water planning would have distorted all of the financial results. The company decided to use average water planning so as to minimize the financial distortion.

Illustrative Plans Chapter

UCCS 18) Now that the company has an IRP model that fully integrates the planning module with the plant dispatch module, and additionally considers spatial transmission constraints, the company should perform backcast runs to see if and when the IPM model chooses the Cholla, Hayden and Craig units.

Answer: The IPM model includes information that is now available, rather than information that was available when the Cholla, Hayden and Craig decisions were made. Therefore, determining whether the IPM model would select those plants would not provide an accurate test of those decisions. Additionally, the IPM model and IRP in general evaluate relatively simple generic resources. The agreements for the APS and Colorado Ute acquisitions are complex, and include pricing that incorporates the asset acquisition, sales, transmission, and other exchange agreements. Neither IPM nor any other IRP model is capable of evalulating such complex transactions. Rather, IRP provides a framework within which real-world resource acquisitions can be evaluated.

19) On page 19 the company needs to provide a clear explanation of why the model selects fewer SCCTs under the low gas price escalation level compared to the medium gas price escalation level.

Answer: Additional text has been added to the description of the results of the low gas cases, explaining why the model selected fewer SCCTs under low gas.

20) Two additional gas price escalation cases should be performed: (a) the first should set the gas escalation rate at the low (1.71%) level through the year 2000 and at the high (5.56%) escalation rate thereafter; (b) the second should set the gas escalation rate at the high level through the year 2000 and at the low level thereafter. The CCS believes that these are reasonable sensitivities to run because of conflicting short term gas price forecasts among DRI, WEFA, and NERA.

Answer: The company does not have the time now to perform additional model runs. RAG participants and other interested parties had ample time to request additional runs earlier in the process. The company would be happy to add this request to its list of analyses for consideration under RAMPP-4.

21) On page 36, the company indicates that a load growth scenario (case #202) between medium and medium-high results in a lower NPV of utility cost and TRC, but a higher customer price compared to the medium-high case. Can the company shed any light on why this results was obtained?

Answer: The company discovered an error in the total sales figure that was used in the financial model. That error was correct, and the financial model re-run. The new results indicate that the customer price is lower than the medium-high case.

Questions and Answers Chapter

22) On page 2, the company asserts that RAMPP provides the basis for avoided costs. Please fully explain what the company means by this statement.

Answer: A new Q&A has been added to the Questions and Answers chapter. The new Q&A deals with how avoided costs are derived from the RAMPP results.

23) On page 10 the company states that load forecasts include the energy requirements of interruptible customers, but not the capacity requirements. The reasons under girding this dichotomous approach for treating interruptible loads needs to be fully articulated in the answer.

Answer: The energy forecast includes the company's contractual obligations to provide energy to interruptible customers. However, the capacity forecasts do not include the capacity for these customers since they can be interrupted during peak periods. These customers have the option of not being interrupted if they are willing to pay current market prices at the time of interruption.

Action Plan Chapter
Performance on RAMPP-2 Action Plan

24) Under action step #2 which relates to the Calpine geothermal project, what is the anticipated TRC associated with this purchase and at what MW level?

Answer: The price is subject to ongoing discussions with Calpine. The company anticipates that it could purchase up to 100 MW of power from the project, at the right price.

25) For action step #5, the company states, "RAMPP-2 identified a need for additional peaking resources by the mid-1990s and this contract provides those resources at a lower cost than other alternatives." What is the cost comparison? RAMPP-3 should present this kind of information, especially if the company finds it cost effective to deviate from its prior action plan.

Answer: Additional text has been added to the paragraph explaining the SCE purchase in performance on the RAMPP-2 action plan, including a cost comparison between the SCE purchase and a SCCT.

26) For action step #9, the company says that it obtained additional south-to-north AC intertie rights from BPA. How much additional intertie rights did the company obtain and at what price? Further, how has the recent earthquake affected the company's capacity on the PNW-Cal intertie?

Answer: Additional text has been added to the discussion of the RAMPP-2 action step #9 in the Action Plan chapter explaining the company's additional intertie rights. As a result of the January 17, 1994, Los Angeles earthquake, the Pacific DC intertie's southern terminal facilities in Los Angeles were severely damaged. The present schedule of repairs will provide the following transfer capability for the Pacific DC intertie: 600 MW by mid-April, 1994; 900 MW by May, 1994; 1,638 MW by December, 1994; and back to full operational capability (2,950 MW) by December, 1995. PacifiCorp's south-to-north Pacific DC intertie rights at any hour are its percentage share of rights on a fully operational line. So if PacifiCorp's normal share is 200 MW of a 2,950 MW line (7 percent), its share of the 600 MW until mid-April 1994 is 40 MW (7 percent of 600 MW).

Action Plan Chapter
RAMPP-3 Action Plan

27) Realizing that there are limitations to increasing DSR programs in the short run, which one of the 200 or so RAMPP-3 cases results in the lowest total resource cost. What is the benchmark cost-minimizing plan that the action plan is evaluated against? What is the monetary difference between this particular case and the case that reflects the strategic resources that the company deems reasonable to pursue at this juncture?

Answer: The case with the lowest total resource cost is low load growth, medium gas prices (the low load growth was only done with medium gas prices), medium DSR (financial results for the low load growth were only done with medium DSR), any-renewables under either any-coal or no-coal. However, the company did not rely on these cases, nor any particular case, as a benchmark cost-minimizing plan. The purpose of the action plan is to pursue those actions which best position the company for an uncertain future. The Renewables Chapter has added text discussing the costs of the strategic-renewables strategy.

28) Action step #5 conveys that other models or studies indicated summer peaking needs as early as 1997. What models have been used in preparing these peak demand studies and how does the company plan to share these modeling results with regulators? Will it be in a RAMPP-3 appendix?

Answer: The company uses other models for various analysis tasks, including a very detailed hourly simulation model. When the company files for recovery of peak-related costs in a rate case, it will provide documentation justifying the costs.

Demand-Side Appendix

29) Why is the conservation load factor so much higher for new residential space heat in Utah? Does the reference to 51 percent and 26 percent include appliances?

Answer: The 51 and 26 percent represent the fraction of savings from appliances. This information is included in Section 3 of the the Demand-Side Appendix.

30) Explain how the capital recovery factor converts the up-front costs of the measure into equal payments over time, and that it varies, depending on the life of the measure. (Page 21)

Answer: The capital recovery factor is multiplied by the first cost of the measure, to convert it into an annual flow. The CRF decreases as measure life increases. For further discussion, see Section 3 of the Demand-Side Appendix.

31) On page 25, are you assuming that homes with no wall insulation are being replaced with new homes?

Answer: The process described on page 25 is a stock adjustment process. As new homes are added to the existing stock, the percentage of homes with no insulation is reduced. The company does not assume that for every new home built there is a one-to-one reduction in the number of homes with no insulation. For further discussion, see Section 4 of the Demand-Side Appendix.

32) Table 6, page 27, how do the results of the conditional demand study and the base load study translate into the average kWh per customer, and average space heat kWh? When were these studies conducted?

Answer: The 1992 space heating consumption figures shown in table 8 are based on conditional demand analysis. The figures shown for 2014 space heat consumption are based on the engineering estimates shown in table 7, and adjustment factors for that residence type. The conditional demand study was finalized in December 1990. For further discussion, see Section 4 of the Demand-Side Technical Appendix.

33) Table 8, page 29, why didn't the use of wood heat decrease in Utah?
Answer: The 1990 and 1992 Energy Decisions surveys conducted by the Company indicate that wood usage in Utah is not decreasing. Additional detail can be found in Section 4 of the Demand-Side Appendix.

34) Table 8, page 29, how was the down rating adjustment applied to the various categories (i.e., single family dwellings, multi-family and mobile homes)?
Answer: The down rating was applied to all categories of residences. The down rating was applied to engineering estimates of the space heating consumption, to estimate space heating energy consumption in the year 2013. A detailed discussion of this topic was added to the residential space heating section of the Demand-Side Appendix, Section 4.

35) Do the adjustment factors in Table 7 include the 30% derate for economic takeback?
Answer: Yes.

36) Table 11, page 38, What is the source of appliance saturation data? What is the basis for vacancy rates? What is the basis for average consumption?
Answer: The source for appliance saturation data is the company's Energy Decision Survey for 1992. The vacancy rates were based on 1980 US Census, and refined using the Energy Decision survey data. The average consumption data presented on table 11 were based on a conditional demand analysis study in 1990. Further discussion of this issue can be found in Section 5 of the Demand-Side Appendix.

37) Page 69, did the implicit discount rate of 60 percent apply to both residential and commercial?
Answer: Yes.

38) Page 78 definition of lost opportunity resources differs from the definition in the Executive Summary.
Answer: The correct definition of lost opportunity is presented in the executive summary section. Lost opportunities are conservation measures that will be cost effective during their lifetime if installed now, but not if installed later as part of a more expensive retrofit. The two definitions have been corrected to read the same.

39) Page 83, what is the basis for the conservation load factor? Would a change in the load factor impact the ceiling for cost effectiveness?
Answer: The discussion in Section 3 of the the Demand-Side Appendix has been amended to include a discussion of the basis for the conservation load factor. A change in the load factor would alter the ceiling for cost

effectiveness. This is also now explained in the same section of the Appendix.

40) Is supplemental funding included in determining the program cost effectiveness level? Please explain. Does the company plan on evaluating the impact of supplemental funding on participation rates? What is the basis for the 30 percent and 20 percent assumption on page 85?

Answer: Supplemental funding of measures above the cost-effectiveness threshold is included in the program cost-effectiveness level. According to an August, 1993, evaluation report for the Energy FinAnswer, supplemental funding represented 25 percent of total funding. Additional information can be found in Section 14 of the Demand-Side Appendix.

41) Does the company assume a fixed administrative cost for all programs, or do these costs differ by program? Please explain. In actual experience, have these costs been higher or lower? Again, please explain.

Answer: The RAMPP-3 DSR model did not assume a fixed administrative cost for all programs. The administrative cost percentage varies across the programs. Administrative cost was calculated as a percentage of measure cost, excluding supplemental funding costs. The relevant table has been updated in Section 14 of the Demand-Side Appendix. Additional information on this topic can be found in that section of the Appendix.

42) Please provide a detailed calculation of the total resource cost test, utility cost test, and company's economic criteria for each of the Utah demand-side programs.

Answer: Total Resource Cost and total utility cost are provided for each program in the Summary report for each program, appendix H of the Technical Appendix Demand Side Resources. The total resource cost test is performed for each program at state level, at the program filing for each state. The company's internal financial criteria were not applied at the state level for the planning process.

State of Utah
DEPARTMENT OF NATURAL RESOURCES

Michael O. Leavitt
Governor
Ted Stewart
Executive Director
Richard Anderson, Ph.D.
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PP 233

March 7, 1994

Dr. Nancy Esteb, Manager
Integrated Resource Planning
PacifiCorp
920 S.W., Sixth Avenue
Portland, Oregon 97204-1256

RE: Comments to PacifiCorp on the Draft RAMPP-3 Report and Appendices

Dear Dr. Esteb:

The following memo provides comments, suggestions and requests on the RAMPP-3 report and technical appendices on behalf of the Utah Department of Natural Resources, Office of Energy and Resource Planning. We appreciate the opportunity to comment.

RAMPP-3 DRAFT REPORT

Portfolio Chapter

Coal-Fired Resources

The total resource cost estimates for conventional coal-fired resources appear very low relative to the discussion of long-range incremental coal costs for PacifiCorp discussed on pages 7-29 through 7-33 in the January 1991 report, "Evaluation of the Coal Procurement Policies and Coal Management Practices of PacifiCorp," prepared by Energy Ventures Analysis, Inc. We request that coal costs be explained in greater detail either in this section or that you direct us to the section where a more thorough discussion of coal costs can be found. Specifically, please discuss in greater detail the derivation of the total resource cost of coal in Utah and Wyoming and discuss the choice and impact of the assumptions employed in the TRC derivation. For instance, PacifiCorp presented total resource costs for the resource stack to the RAMPP-3 advisory group in July and again in September, and each time total resource costs for coal were slightly different based on changes in the assumptions (transmission cost, expected utilization rate, fuel cost). The final numbers employed in the IRP model were slightly different than previously presented in the RAG meetings. Since the selection of coal resources provide a least total resource cost strategy according to the economic results of RAMPP-3, it would be useful to have a better understanding of how coal costs have been developed. The narrative in the "Portfolio" section, page 22, mentions analysis of spot market prices, and verbally PacifiCorp states the fuel costs reflect the incremental cost of coal from PacifiCorp-owned mines. However, the above noted study on PacifiCorp coal procurement policies indicates that PacifiCorp may be in shortfall to supply *current* plants with PacifiCorp coal.

Secondly, because coal resources are found by the IRP to be least (total resource) cost, a discussion of the potential barriers to conventional coal development should be discussed. Again, if this discussion is found elsewhere in the document or appendices, please direct us to that discussion.

Illustrative Plan Chapter

The quantification of the impact of the DSR strategies on NPV of total resource cost, page 30, does not look right. If you compare like strategies and futures, changing only the level of DSR, NPV of TRC decreases as DSR is increased. Please explain in greater detail how the analysis was conducted on this page. If you averaged all the costs over all scenarios, you would pick up cost impacts due to the coal or renewable strategies which would not be a valid reflection of the impact of alternative DSR levels on TRC. The results of this analysis also conflict with the statement in the conclusion (section 13, page 2, paragraph 2), but is supported in the Modeling technical appendix, page 5-124.

How is it that the strategic renewables strategy when coupled with the any coal strategy, reduces total resource cost as gas price increases? If strategic renewables provide a lower total resource cost than gas resources in the low gas price future, why doesn't the model pick them in order to optimize? If we missed your discussion of this occurrence, please direct us to the discussion.

The last paragraph on page 9 and third paragraph on page 19 could be reiterated and expanded upon in your conclusions section or as an introduction to your action plan. You also mentioned somewhere that 10 year model results received greater attention than the 20 year model results in developing the action plan; this could also be brought out to help explain the action plan.

Action Plan

We suggest you target the accelerated DSR level in the action plan and drop all discussion of the financial standards. The financial standards are applied to acquisition costs which are based on broad DSR planning assumptions rather than actual state by state resource acquisition estimates which are developed for each state when a program is proposed and implemented and the issues raised by the financial standards really should be addressed by each jurisdiction. For a least cost plan, least cost resources to meet growth should be identified and an attempt made to acquire the resources. If regulatory treatment becomes a barrier in a given jurisdiction which causes less acquisition than planned, that will provide an explanation of failure to meet targets.

Please include the expected dollar budget for DSR in addition to DSR kWh targets, by state.

Load Forecasting Technical Appendix

Please include 1993 actual electricity sales by class, by state in each table of forecasts, as well as the growth rate from 1992. Please also include forecasted customers by class, by state.

Demand Side Technical Appendix

Please include expected cost to acquire targeted DSR energy in each state. If this is already in the technical appendix, please direct us to the page.

Modeling Technical Appendix

We request that you either provide the average annual customer bill for the 20 year period with end-effects in section 5 or include all 103 model runs in section 6 so that your reader has the information to derive this value.

Sincerely,

Richard Anderson

Richard Anderson, Director
Department of Natural Resources
Office of Energy and Resource Planning

Rebecca

Rebecca L. Wilson, Utility Economist
Department of Commerce
Division of Public Utilities

mc

cc: Kathleen Clarke, DNR
Rich Collins, PSC
George Compton, DPU
Frank Johnson, DPU
Ken Powell, DPU
Ted Stewart, DNR
Connie White, DOC

PP 23(

PacifiCorp RAMPP-3 Draft Report
Comments from Utah Department of Natural Resources:
Letter from UDNR dated March 7, 1994

1) Please explain coal costs for new coal plants in Wyoming or Utah in greater detail. The costs appear low compared to long-range incremental coal costs in the January 1991 report "Evaluation of the Coal Procurement Policies and Coal Management Practices of PacifiCorp" prepared by Energy Ventures Analysis, Inc.

Answer: After reviewing the coal price assumptions used in RAMPP-3, the company confirmed the validity of the Wyoming price, but believes there is more uncertainty about the Utah price, especially as it relates to the number of coal units added. Five coal price sensitivities have been added to the analysis (described in the Analysis Plan chapter and the results discussed in the Illustrative Plans chapter). They used a Utah coal price which doubled that used in the rest of the studies, or $24/ton with a 1.5 percent real escalation rate, which is higher than the $15/ton as recommended in the 1991 EVA report.

2) Please discuss the potential barriers to conventional coal development.

Answer: These are addressed in the Portfolio chapter's discussion of new coal resources. There is potential coal price uncertainty, uncertainty of the clean coal technologies, and uncertainty over a future environmental tax or emission limit.

3) Please explain how the DSR analysis on page 30 of chapter 6 was conducted. Why does the table indicate that the NPV of TRC increases with higher DSR, when the table 6-5 shows the opposite.

Answer: The worksheet used to calculate this section is included in the Modeling Appendix, Chapter 5, page 124. The section of the table in the text which appears in error has been corrected.

4) Why does the strategic renewables strategy when coupled with the any coal strategy reduce TRC as gas price increases. If strategic renewables provide a lower TRC than gas resources in the low gas price future, why doesn't the model pick them in order to optimize?

Answer: This question is similar to ODOE Question #5a, which addresses why NPV goes down when gas price goes up. The reader should review the response to ODOE 5a.

5) Reiterate your conclusions from the Illustrative plans chapter (examples last paragraph page 9, third paragraph page 19, reliance on 10-year results for action plan) in the action plan chapter to help link the analysis to the action plan.

Answer: The Conclusion chapter has been moved, it is now after the results and before the Action Plan chapter. The Conclusion chapter has also been expanded to better link the analysis to the action plan.

6) We suggest the company target the accelerated DSR level in the action plan and drop all discussion of the financial standards. The financial standards address resource acquisition and are an issue for each jurisdiction to address. For a least cost plan, the resource should be identified and attempt made to acquire the resource.

Answer: A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

7) Please include the expected dollar budget for DSR in addition to DSR kWh targets.

Answer: Components of the expected dollar budgets for DSR is provided in Appendix I of the Demand-Side Appendix for the short-term action plan and assumptions regarding utlity cost for the planning horizon are contained within Appendix H. Both sections have program summary tables for each program. In addition, Appendix I has the results for each state for the two-year action plan.

8) Please include 1993 actual electricity sales by class, by state, in each table of forecasts in the Load Forecasting Appendix.

Answer: The data have been added to the Load Forecasting Appendix.

9) Please include expected cost to acquire targeted DSR in each state in the Demand-Side Appendix.

Answer: The expected cost to acquire DSR potential is presented in the Demand-Side Appendix, Appendix H, by program for the entire planning horizon and in Appendix I for the two-year action plan.

10) Please either provide the average annual customer bill for the 20-year period with end effects in section 5 of the Modeling Appendix, or include all 103 model runs in section 6.

Answer: A table showing the average annual customer bill in real dollars for each of the model run years has been added to the Modeling Appendix.

PP 239

UTAH DIVISION OF PUBLIC UTILITIES
COMMENTS ON RAMPP-3 DRAFT REPORT

Note: We are making a distinction between comments herein on the draft report and comments on the RAMPP-3 study overall, which we will make after the final report comes out. Silence here on a particular approach, assumption, model run, conclusion or etc., does not imply approval.

1. The summary tables which were handed out to RAG participants (copy attached), do not show up in this explicit form anywhere in the draft report. This is a useful summary and should be included in this form in the report.

2. These summary tables can also be expanded to be more useful by showing the deviation from least cost in each load growth case, similar to what I have done on the attached sheet. This should be done for prices and for the total resource cost as well.

3. The Conclusions section of the report seems to be out of place. Logically, I would expect to find the study results, then the conclusions drawn from those results, and finally the action plan developed from those conclusions.

4. The report has some missing links between the results and the conclusions. No conclusions are drawn about the cost penalties of various choices. For example the stragegic renewable strategy costs nearly a half a billion dollars, over the any renewable strategy.

5. The report has some missing links between the conclusions and the action plan. In spite of coal being the lowest cost resource, the Company has, de facto, decided not to include any coal in its action plan. If this decision is based on the environmental results or some other factors, that should be explained. Also the explanation for why the Company has elected to go to strategic renewables needs to be explained more fully.

6. The report needs additional discussion on what PC is using for a decision criteria. Are they using price or revenue requirement, for the utility or for total resource? Why?

7. Some discussion on the impact of the action plan on DSM non-participants is desirable.

8. I am somewhat troubled by calling mills/kwh "price." It actually represents a system average cost. I realize that average price has to equal average cost, but there are other factors that go into rate design in addition to average cost.

9. An action plan needs to very specific in order to be acted on. Unfortunately, in many areas the PC Action Plan is not specific. It needs to have greater specificity with regard to achievements in MW, dates by which studies are to be completed, the standards that will be used for evaluation, etc. I have in mind comments like "evaluate clean coal technologies," and "if cost effective." Either RAMPP-3 shows renewables are cost effective, or it doesn't.

Ken Powell
March 7, 1994

PacifiCorp RAMPP-3

PP 240

Utility Cost
Financial Results after 50 Years (2043)

Future		DSR	50 Year Real Levelized mills/kWh				Utility Cost 50 Year NPV ($M)			
Load	Gas Price	Strategy	AC.AR	AC.SR	NC.AR	NC.SR	AC.AR	AC.SR	NC.AR	NC.
Low	Medium	Medium	50.1	51.1	50.1	51.1	38,040	38,791	38,040	38,7
Medium Low	Medium	Medium	47.0	47.6	47.2	47.7	41,419	41,939	41,582	41,9
Medium	Low	Low	45.7	46.2	45.7	46.2	47,167	47,664	47,188	47,6
Medium	Low	Medium	46.2	46.7	46.2	46.7	46,379	46,878	46,406	46,9
Medium	Low	Accelerated	46.4	46.9	46.5	47.0	46,334	46,837	46,361	46,8
Medium	Low	High	46.5	47.0	46.6	47.1	46,096	46,598	46,112	46,6
Medium	Medium	Low	45.7	46.2	46.3	46.7	47,196	47,681	47,742	48,
Medium	Medium	Medium	46.1	46.6	46.7	47.1	46,337	46,802	46,894	47,
Medium	Medium	Accelerated	46.4	46.9	46.9	47.4	46,327	46,809	46,836	47,
Medium	Medium	High	46.5	47.0	47.0	47.4	46,067	46,549	46,563	46,
Medium	High	Low	45.7	46.2	48.5	48.4	47,153	47,652	50,053	49,
Medium	High	Medium	46.2	46.4	48.3	48.3	46,403	46,607	48,841	48,
Medium	High	Accelerated	46.4	46.8	48.6	48.6	46,305	46,687	48,469	48,
Medium	High	High	46.4	46.8	48.5	48.6	45,945	46,381	48,015	48,
Medium H	Low	Medium		45.8		46.0		52,410		52,
Medium H	Medium	Low	45.3	45.7	46.4	46.6	53,278	53,767	54,588	54,
Medium H	Medium	Medium	45.7	46.1	46.7	46.9	52,290	52,786	53,440	53,
Medium H	Medium	Accelerated	45.8	46.2	46.7	47.0	52,137	52,627	53,125	53,
Medium H	Medium	High	45.9	46.3	46.7	47.1	51,930	52,423	52,886	53,
Medium H	High	Medium		46.3		49.3		53,085		56,
High	Low	Medium		45.0		45.4		58,639		59,
High	Medium	Low	44.9	45.2	46.3	46.4	59,980	60,428	61,809	62,
High	Medium	Medium	45.2	45.5	46.5	46.6	58,788	59,243	60,508	60,
High	Medium	Accelerated	45.2	45.6	46.6	46.7	58,519	58,982	60,250	60,
High	Medium	High	45.2	45.6	46.6	46.7	58,258	58,722	59,984	60,
High	High	Medium		46.0		50.0		59,903		65,

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UTILITY COST ANALYSIS
PC-RAMPP-3

			RevReq ACAR	RevReq ACSR	RevReq NCAR	RevReq NCSR	Diff from lowest cost ACAR	Diff from lowest cost ACSR	Diff from lowest cost NCAR	Diff from lowest cost NCSR
low	medium	medium	38040	38791	38040	38791	0	751	0	751
med-low	medium	medium	41419	41939	41582	41984	0	520	163	565
medium	low	low	47167	47664	47188	47692	1071	1568	1092	1596
medium	low	medium	46739	46878	46406	46901	643	782	310	805
medium	low	accel	46334	46837	46361	46857	238	741	265	761
medium	low	high	46096	46598	46112	46612	0	502	16	516
medium	medium	low	47195	47681	47742	48224	1128	1614	1675	2157
medium	medium	medium	46337	46802	46894	47338	270	735	827	1271
medium	medium	accel	46327	46809	46834	47270	260	742	767	1203
medium	medium	high	46067	46549	46563	46970	0	482	496	903
medium	high	low	47153	47652	50053	49925	1208	1707	4108	3980
medium	high	medium	46403	46607	48541	48474	458	662	2596	2529
medium	high	accel	46305	46687	48469	48534	360	742	2524	2589
medium	high	high	45945	46381	48015	48106	0	436	2070	2161
med-high	low	medium		52410		52682		0		272
med-high	medium	low	53278	53767	54588	54811	1348	1837	2658	2881
med-high	medium	medium	52290	52785	53449	53664	360	855	1519	1734
med-high	medium	accel	52137	52627	53125	53504	207	697	1195	1574
med-high	medium	high	51930	52423	52886	53257	0	493	956	1327
med-high	high	medium		53043		56461		0		3418
high	low	medium		58639		59049		0		410
high	medium	low	59980	60428	61809	62024	1725	2173	3554	3769
high	medium	medium	58788	59243	60580	60733	533	988	2325	2478
high	medium	accel	58519	58982	60250	60469	264	727	1995	2214
high	medium	high	58255	58722	59984	60201	0	467	1729	1946
high	high	medium		59903		65092		0		5189

PP 242

PacifiCorp RAMPP-3 Draft Report
Comments from Utah Division of Public Utilities:
Letter from UDPU dated March 8, 1994

1) The summary tables showing TRC and total utility cost for each model run do not show up in the draft report. This is a useful summary and should be included in the report.

Answer: Tables 7-5 through 7-8 contain that information. They have been revised to be more succinct, while containing the TRC and total utility cost information for each model run in the base study plan and the environmental adder cases.

2) These summary tables should also show the deviation of each case from least cost for each load growth case. This should be done for prices and for TRC.

Answer: The company does not believe that the lowest cost case for each load growth level is necessarily the wisest plan for each load growth level. Therefore, the company chose not to present the results in a format which compared each case to one particular case which does not have a special significance.

3) The conclusions section of the report should be placed after the study results and before the action plan.

Answer: The Conclusions chapter has been placed after the study results and before the Action Plan chapter.

4) The report has some missing links between the results and the conclusions. No conclusions are drawn about the cost penalties of various choices, such as the strategic renewables strategy.

Answer: Additional discussion in the Conclusions chapter addresses the lessons learned from the analysis. The Renewables chapter includes additional discussion about the costs of the strategic-renewables strategy.

5) The report has some missing links between the conclusions and the action plan. The company has not explained why it did not include any coal in its action plan, since it is the lowest cost resource. The company has not explained why it chose the strategic renewables path.

Answer: The company believes it is too early to begin siting a coal plant. Given the potential benefits of the IGCC technology, the company wants to better understand the trade-offs between pulverized coal and IGCC coal, and examine site-specific costs before proceeding further. The company hopes that the study to be performed will shorted the lead time of coal and provide more flexibility in the future. The Renewables chapter contains additional text explaining the company's rationale for the strategic-renewables path.

6) What is PacifiCorp using for a decision criteria? Is it price, revenue requirement, is it for the utility or for the total resource cost? Why?

Answer: As stated in the Introduction chapter, the company attempts to balance multiple goals: minimizing costs and risks to customers, society, and the company's shareholders. The Conclusion chapter contains an added discussion of the company's decision criteria.

7) The report should include a discussion of the impact of the action plan on DSR non-participants.

Answer: The modeling does not recognize participants versus non-participants in terms of treatment of the impact of increasing average prices. The company does evaluate the trade-off between prices and utility costs to determine appropriate levels of DSR rather than relying on any simple rate impact measure or total resource cost test. This issue is discussed in a separate section of the DSR Action Plan Detail chapter.

8) Mills/kWh from the analysis is not price. Mills/kWh from the analysis represents a system average cost.

Answer: The text explaining Table 6-3 has been modified to clarify how the company is using the term "price" and what it means.

9) In many areas the PacifiCorp action plan is not specific. It should have greater specificity such as goals in MW, dates by which studies are to be completed, standards for evaluation, etc.

Answer: The company tries to balance specificity with the need for flexibility to respond to an uncertain and increasingly competitive future. The DSR actions are provided in great detail in the DSR Action Plan Detail chapter. At this time, the company anticipates that the coal study will be completed by January, 1995.

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PP 245

MEMO:
TO: NANCY ESTEB
FROM: RICH COLLINS RSC
RE: COMMENTS ON RAMPP-3 REPORT
DATE: MARCH 7, 1994

This memo represents the initial comments of the Utah Public Service Commission on PacifiCorp's Draft RAMPP-3 Report. The comments are intended to help revise and improve this document before it is submitted in final form to the Commission in accordance with our IRP guidelines. The final IRP will be subjected to another round of comments by interested parties. After proper analysis of these comments the Commission will either acknowledge the IRP with comments or call for further hearings on acknowledgement.

OVERALL COMMENTS

Title: Will this IRP have a title?

Organization of the Report: The general format of the report is well laid out, but it might be helpful to have more of a more rigid outline format.

Public Process: The Company should be commended for its efforts at eliciting public input into their planning process. You made substantial efforts to include more top management in this process and their presentations were helpful. You have done a good job in trying to incorporate the suggestions of various RAG members into your study. Overall you have done a good job.

Writing: The writing style is generally clear and understandable.

Content: This report is a good overall review of the process, analysis and its conclusions.

SPECIFIC COMMENTS

CHAPTER 1 - INTRODUCTION:

Page 1 - First paragraph should be either a footnote or put later in the chapter.

Second paragraph - change electricity to electric energy service.

Third paragraph - I have a problem with PacifiCorp's RAMPP aim of minimizing prices (it should be bills with some price increase constraint). This goal to minimize price can be a corporate goal but it should not be a planning goal.

RAMPP-3 Action Plan Summary:

Page 2 -
You should mention that the action plan is for four years with specific recommendations for the first two years. Also the more general recommendation for the last two years should be stated.

For DSR -

Page 3 - Is the commitment for 40 MWa by the end of 1995 based on a particular growth scenario? If so what is it? and how will your action change under different growth outcomes?

For Renewable Resources -

2) What about the 50 MWs that were pledged to come on line by 1997?

For Baseload Resources -

4) clean coal technologies- what is the impact on C02 emissions? Maybe specify somewhere which emissions are expected to be avoided by this technology. Gasification does not change the molecular structure of the coal gas, how does this process result in lower carbon emissions, through higher efficiency?

For Peaking -

5) Meet 150-200 MW of peaking needs by 2001. This action is unclear. Is this going to occur in the next two years, please clarify. If the acquisition will take place in the next two year, it should be justified as least-cost somewhere in the report.

CHAPTER 2 - BACKGROUND:

Page 4- Milestones-

RAMPP-2 Action Plan Implementation - This could be the place where you are more specific about the 170 MWa of DSR that is to be acquired.

Decisions Since RAMPP-2 - I would put Hermiston Cogen back further on the list because it is still uncertain. Also state that it is contingent on a long-term gas contract that has not been finalized yet. What about James River wasn't this in between Rampp-2 and 3?

Page 12 - Was the analysis that "closed the loop" between the assumed increase in price embedded in the load forecast and the resultant impact on the "cost of electricity of the planned expansion" done on a class cost of service or state basis? Can this level of detail be done in this round of planning or should it be done in the next round?

CHAPTER 3 - FUTURES:

Page 6 - availability of wood stoves - was income factored into their use? I view wood stoves as an inferior good in that as income rises the use of wood will decline.

Page 11 - Has any thought been given to different growth paths ie., like RAMPP-2 scenarios where growth rates of load could vary?

Page 11 - There should be some analysis of rescurce selection by the model under different assumptions regarding the cost of the potential resources. Is the choice of resources very sensitive to variances in cost estimates? I know one such analysis was done for DSR and renewables but what about coal? It would be interesting to know at what price coal is no longer selected by the model.

Gas Price Projections -

Page 14 - A brief description of the hedge strategy is in order.

CHAPTER 4 - PORTFOLIO:

Existing Power System -

Page 1 - State why the Company plans to pursue system efficiency improvements regardless of electricity sales growth. Has any analysis been done to justify the cost-effectiveness of such actions under low growth scenarios?

Page 5 - Explain why reserve requirements will increase by over 400 MWs? Is this due to growth on the system or due to new resources providing less reliability to the system over 20 years, as explained in the next few paragraphs?

Page 17 - The estimate for levelized energy costs for Utah coal needs to be explained. The estimate appears to be low, especially when compared to the estimates of costs contained in the report by EVA consultants in 1991. I am not convinced that incremental coal costs of existing mines is a realistic assumption for future coal costs. The EVA report intimates that new coal reserves will be needed just to keep existing thermal resources supplied in Utah. The EVA report estimates Utah coal prices at $15 per ton. You should elaborate on your estimate in the section on page 22.

Page 17 - The wind resources have an energy cost and an O&M cost? I thought the text indicated that the energy cost was part of O&M? Please explain the apparent contradiction.

Page 30 - typo - second full paragraph - 1st sentence: replace and with an.

Discount Rate -

Page 32 - How was the expected cost of capital for the utility over the 20-year planning horizon determined? Is it different than the 8.8% used earlier? Do you assume that the capital structure stays the same over that period as well as return on equity and the yield on bonds? Please clarify.

Page 32 - The differential between the real incremental after-tax cost of capital and the real social discount rate is only 2.3 percentage points. Wouldn't it be prudent to investigate a larger differential say 3 or 4 percentage points and see if such a social discount rate leads to a different resource selections.

CHAPTER 5 - ANALYSIS PLAN:

Page 2 - Your statement that "The Company evaluates the trade-off between prices and utility costs to determine appropriate levels of DSR rather than relying on any simple rate impact measure or total resource cost test" appears to violate the Utah Commission guideline that the Company to evaluate all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at **the lowest total cost to the utility and its customers.** i.e., Total Resource Cost. Please clarify.

Page 3 - Definition of any-renewable strategy - Does this strategy include any of the MWs of renewable that you have indicated would be acquired in your 1992 action plan?

Sensitivities -

Page 6 - Is it possible to do a price of electricity sensitivity? That is, increase the assumed price of electricity by 25 to 35% and see how that will impact loads and the demand for DSR? This might be more appropriate for RAMPP-4.

Reduced Cost of Wind -

Page 9 -Please put the $600 in percentage terms, i.e., the $600 lowered the assumed capital cost by X%

Page 9 - typo - last paragraph - 3rd line: change out to how.

Page 20 - typo - first line: eliminate are before includes.

CHAPTER 6 - ILLUSTRATIVE PLANS:

Page 12 - Price impact of different load growth assumptions- In the 3rd paragraph you mention that utility costs are higher under a medium-high load growth but that real prices are slightly lower. This needs an explanation. Is the system currently under-utilized?

Or has the industry changed to become a declining cost industry where new resource additions are lower than system average costs? This decline in real levelized prices also occurs under the high growth scenario. Check results from Table 6-7 with 6-9 with real levelized mills/kwh utility cost. Again this needs explanation.

Gas Prices

Page 16 - There appears to be some modelling anomaly that produces counter-intuitive results. How can scenarios with higher assumed gas prices produce utility cost that are lower than scenarios with lower gas cost?

Page 19 - Table - MW of Demand-Side resources Added
Why were some of the columns left blank? Are they zeroes? If so please put zeroes in.

Page 20 - Table on average cost differences resulting from DSR strategy - I suggest you include the percentage increase in prices that result and include what time frame you are referring to. Is it 20 years or 10 years or what? Also it is unclear on how you obtained your averages; is over all futures and strategies or a subset or what? Please clarify.

Coal Strategies

Page 30 - Is this right? By the end of 20 years, resource plans under any-coal included from 1000 to 1,930 MWs of coal; but in the following sentence MH load scenario produced 2600 MWs. Is the 1000 to 1,930 just for medium load growth? Please clarify.

Baseload Gas-fired Resources

Page 32 - Most of the model runs select cogeneration over CCCTs because they are cheaper, however, Company-owned and operated CCCTs provide a greater control over dispatch and provide greater assurances of reliability. How are these non-cost components evaluated by the Company. What is the cost differential between cogen and CCCTs? Under what circumstances would the Company would select CCCTs over cogen?

Peaking Resources

Page 32-33 - This section discusses the results of the model which indicate a need for peaking resources. It also discusses some of the weaknesses of the model and the Company's need for additional summer-peaking resources. This section should be expanded to describe how the Company plans to deal with this resource deficiency or indicate the section in this report where you will deal with the issue in greater detail.

Sensitivities:

Load Levels

Page 33 - Why does the reduced load sensitivity result in such a dramatic decrease in prices for kwh as compared to the ML case?

Page 36 - Explain why the economic development sensitivity and the electrification sensitivity results in such dramatic price increases. What policy implications can be drawn from these results? This should be included in the report.

Page 40 - typo - 2nd full paragraph - fourth line: change "This caused to model" to "caused the model"

Case#222 appears to give an important policy result. That conversion of CCCT's to coal gasification lowers price and gives lower TRC and Utility costs. Is this reflected in your action plan?

Case #231 and #232 indicate that more analysis in needed in studying the impact of reducing the transmission constraints between the regions as it has an impact on the choice of resources. Is the generic $300/kw realistic? What future studies do you recommend?

Case#241 - Social Discount Rate Sensitivity. It appears that DSR is fixed and thus the resource that would be most affected by the discount rate was not allowed to vary. If this is true, it should be stated and the results of this sensitivity should be discounted.

Non-Firm Markets

Page 41 - Case #253 produced interesting results: higher non-firm prices lead to lower costs and prices for PacifiCorp. It would be useful to discuss the variables that affect non-firm prices and give the Company's estimation of how these variable will change in the future.

Regional Patterns

Page 44 - 3rd paragraph - Why is more DSR selected in Oregon than in Utah? Are there cost differences or transmission constraints or different load growths?

CHAPTER 7 - ENVIRONMENTAL ANALYSIS:

External Cost Adder Cases

Page 1 - It would be useful to run the financial model using the adders as real costs, i.e., the adders were collected as a tax. A comparison of the price impacts of the different cases would be interesting.

Page 2- One weakness of these sensitivities is that DSR is not allowed to vary. You did perform two model runs with varying levels of DSR and these produced interesting results. (Case # 323 and Case #322). I think the results should be highlighted (figuratively) in the text. In particular, higher levels of DSR under the high-adder scenarios lead to lower utility costs and lower prices. Policy implications should be outlined from these results. (Discuss in section on Sensitivities with CO2 Limits page 7 and page 12)

Trade-Off Graphs

It is difficult to make comparisons with these graphs; it might be useful to label each point with a case number. For example, on graph 7-9, what is the differences in the no-coal and renewable cases? What is changing, not load growth or gas prices.

Table 7-15 is very useful I suggest adding a column that includes the ratio of emission reduction relative to price increase, sort of an elasticity number.

Include an additional section on the environmental insurance concept, as suggested in the RAG meeting, however also do an analysis that assumes that these adders are actually collected in rates. Is the insurance premium then "worth" it?

CHAPTER 8 - RENEWABLE ANALYSIS:

Model Analysis Results

Page 6 - Is there any way to allow the model to select more renewables under the strategic scenarios? That is, place a floor but not a ceiling on the model's selection of renewables?

Page 7 - The discussion of **average** price impact is not very useful, I suggest you add the range of price impacts under the different cases. Also it would be useful to put the .38 mills into a percentage increase in prices. The sensitivity with a 20% reduction in wind costs should also be put in percentage terms.

CHAPTER 10 - ACTION PLAN:

Page 1 - 3rd paragraph 1st line: Insert supply-side between acquire and resources.

1. What about the 170 MWa by the end of 1996? Is this goal discussed anywhere?

Page 2 - Table at the top of page should distinguish between signed and installed DSR, is "actual" installed or signed?

3. The PacifiCorp Calpine deal - Can an estimated price of such power be stated at this time?

7. James River Deal - Who owns the resource after 20 years?

RAMPP-3 Action Plan

1. DSR acquisition - A more detailed discussion of the three financial criteria for DSR is in order. First the 1% price impact criteria should be clarified. Over what time frame does this price impact criteria apply? 5 years? Why was 1% chosen rather than 2%. You should elaborate on why the high DSR was not chosen and discuss the price impact between the medium and the high DSR cases. I calculate a less than 1% increase over 50 years. To decide not to pursue a high DSR strategy does not appear to be justified based on the marginal impact this decision has on prices. A 2% price increase cap would have substantially different policy implications. In addition, the stated difference in DSR resource acquisitions between Medium DSR and the Company's action plan does not highlight the actual deviations between lowest Total Resource Cost criteria and the Company's selected DSR strategy.

2. Renewables - Define what is meant by if cost-effective. What are the price impacts of the strategic renewable strategy in percentage terms. Are these consistent with the price impact criteria imposed on DSR?

8. This action to increase system efficiency should reference a section of the report that found these to be cost effective.

CHAPTER 11 - DSR ACTION PLAN DETAIL:

Performance on RAMPP-2 Action Plan

Somewhere in the report RAMPP-2 DSR goals should be stated and whether their implementation is consistent with the RAMPP-3 action plans. For example: RAMPP-2 DSR acquisition goals were 170 MWa by the end of 1996; does this comport with the RAMPP-3 action plans that will acquire 40 MWa in 1994-5 and 37 MWa in 1996. This appears to fall short of RAMPP-2 goals. Please explain the discrepancy.

Existing Commercial Buildings

Page 6 - Why did the Pacific Environments program fail. What was learned from the experience.

Page 6 - Break out remodeling DSR results for Salt Lake City and Portland.

Existing Residential

Add the following action item - Work with Mountain Fuel to educate builders on new Utah Model Energy Codes that are currently in effect. Work with MFS to help insure higher enforcement of the State MEC.

New Commercial

h) Why is the penetration goal for Utah so low? Justify or change.

CHAPTER 13 - CONCLUSION:

Load Growth -

The impact of load growth on prices should be discussed either in this section or somewhere in the report. There are some interesting results i.e., higher growth leads to lower prices that should be pointed out and policy implication made clear.

Demand-Side Strategy -

There should be an explanation why the high DSR strategy is not being pursued. The conclusion should explicitly deal with the added price impact of the higher DSR strategy.

Renewable Strategy -

The cost and price impact of this strategy should be made explicit.

Baseload Resources -

The action plan should be more explicit on actions needed to get coal in place by 2001, or why such actions are not needed.

PP 254

PacifiCorp RAMPP-3 Draft Report
Comments from Utah Public Service Commission Staff:
Letter from UPSC dated March 8, 1994

Introduction Chapter

1) Move the first paragraph of the Introduction chapter to later in the chapter or as a footnote.

Answer: The paragraph was moved to the end of the chapter.

2) Change electricity to electric energy service in the second paragraph of the Introduction chapter.

Answer: The wording change was made.

3) The aim of RAMPP should be minimizing bills with some price increase constraint, rather than minimizing prices. This goal to minimize price can be a corporate goal but it should not be a planning goal.

Answer: PacifiCorp attempts to balance multiple goals in RAMPP: minimizing bills, prices, and risks for the company, its customers, its stockholders, and society. The company also believes, and previously understood the Commission to believe, that corporate goals should be consistent with planning goals.

4) In the Introduction chapter, mention that the action plan is for four years with specific recommendations for the first two years. The more general recommendations for the second two years should be stated.

Answer: The Introduction Chapter now contains a statement that the action plan includes specific actions for 1994 and 1995, and more geneal actions for 1996 and 1997, and directs the reader to the Action Plan chapter.

5) Is the commitment for 40 MWa of DSR by the end of 1995 based on a particular growth scenario? If so, what is it? And how will the action plan change under different growth outcomes?

Answer: Additional explanation has been provided to explain the RAMPP-3 DSR action plan item in the Action Plan chapter.

6) What about the 50 MWs of renewables that were pledged to come on line by 1997?

Answer: The company anticipates that the Columbia Hills and Foote Creek wind projects will provide more than 50 MW of renewables by 1997.

7) What is the impact on CO2 emissions of clean coal technologies? Please specify which emissions are expected to be avoided by this technology. How does gasification lower carbon emissions?

Answer: Additional text has been added to the description of IGCC plants in the Portfolio chapter, explaining the lower emissions.

8) The action item to meet 150-200 MW of peaking needs by 2001 is unclear. Is this going to occur in the next two years? If the acquisition will take place in the next two years, it should be justified as least cost somewhere in the report.

Answer: Additional text has been added to the action plan item. The company does not believe it can or should justify that adding generic peaking resources is a least cost action; the model can identify when peaking resources are needed. The company needs to demonstrate that the particular choice to meet peaking needs is least cost, whether it is a SCCT, pumped storage, purchased power, or other means. That will be done through a rate case showing based on the specific project.

9) Please explain how the 170 MWa of DSR is to be acquired.

Answer: The strategic goal of 170 MWa was an outgrowth of the strategic planning process that was conducted nearly simultaneously with the RAMPP-2 planning effort. The 170 MWa goal most closely reflects the medium-high load growth forecast from RAMPP-2 and an additional acquisition of DSR from an accounting of all conservation that would be captured by 1996. For example, it included 40 MWa of background conservation. There was an additional assumed acquisiton of 13 MWa from a competitive bidding initiative above and beyond the program activity included in RAMPP-2. Once adjusted for the background conservation and the additional bidding initiative, the net resource delivered under the strategic goal (170 less 40, less 13, equals 117 MWa) roughly equaled the program activity in the RAMPP-2 medium-high load growth case. The RAMPP-3 medium load growth at 2.1 percent is lower than the RAMPP-2 medium-high load growth at 2.9 percent. This change reduced the program activity by 17 MWa (to 100 MWa). In addition, improvements in state building codes and appliance efficiency standards and already-installed DSR reduced the amount of program activity for RAMPP-3. These changes reduced the program activity by 25 MWa (to 75 MWa). This 75 MWa can be compared to the 69 MWa goal in the RAMPP-3 action plan DSR for 1994-1996, for a reduction of 6 MWa in program variance from the 170 MWa strategic goal.

Background Chapter

10) In the Background chapter, state that Hermiston is contingent on a long-term gas contract that has not been finalized. What about James River?

Answer: Additional text has been added to the discussion of James River and Hermiston in the Background chapter, clarifying these points.

11) Was the analysis that closed the loop between the assumed increase in price embedded in the load forecast and the resulting impact on the cost of electricity of the planned expansion done on a class cost of service or state basis? Can this level of detail be done in this round of planning or should it be done in the next round?

Answer: Yes, the price changes were applied to each state and for each customer class in that state. This is also noted in the Background chapter discussion of this issue.

Futures Chapter

12) Was income factored in the use of wood stoves?
Answer: Yes. This is now noted in the chapter's discussion of wood stoves usage.

13) Has any thought been given to different growth paths, like the RAMPP-2 cases where the growth rates varied over time?
Answer: Yes. In the public advisory group meetings, the company discussed the trade-offs between a simulation model, which could include cases where the growth rates varied over time (fooling the model), and an optimization model, which would not have this capability. The company understood that parties wanted an optimization model used for RAMPP-3 analyses.

14) There should be some analysis of resource selection by the model under different assumptions about the cost of the potential resources. Is the choice of resources very sensitive to variances in cost estimates? At what price would coal no longer be selected by the model?
Answer: Additional text has been added at the end of the Portfolio chapter which discusses the use of Table 4-7 to compare resources.

15) Please provide a brief description of the gas hedge strategy.
Answer: PacifiCorp does not currently hold a direct natural gas futures position and at this time it does not anticipate moving towards one. However, as a part of PacifiCorp's overall strategy of maintaining its position as a low-cost provider of electricity, a portfolio of natural gas supply contracts for generation is being developed by the company. This portfolio will contain a mixture of supply arrangements with varying terms, quantities, load factors and pricing arrangements. Because NYMEX-based hedging products are central to many natural gas production and marketing arrangements, it is likely that some of PacifiCorp's term purchases are now and will in the future be hedged by the seller. These contracts will benefit PacifiCorp by making the term purchase portion of the company's gas supply more predictable and reliable.

Portfolio Chapter

16) State why the company plans to pursue system efficiency improvements regardless of electricity sales growth. Has any analysis been done to justify the cost effectiveness of such actions under low growth scenarios?

<u>Answer</u>: If load growth were to suddenly slow dramatically, the company would re-evaluate its investments in a variety of areas, including efficiency improvements. Additional text has been added to this area of the Portfolio chapter.

17) Explain why reserve requirements will increase by over 400 MW. Is this due to growth on the system or due to new resources providing less reliability to the system over 20 years?

<u>Answer</u>: This sentence was removed to avoid confusion. The 400 MW increase in reserve requirement is due to resource additions to meet load growth.

18) The estimate for levelized energy costs for Utah coal needs to be explained. The estimate appears to be low, especially when compared to the estimates of costs in the report by EVA consultants in 1991.

<u>Answer</u>: After reviewing the coal price assumptions used in RAMPP-3, the company confirmed the validity of the Wyoming price, but believes there is more uncertainty about the Utah price, especially as it relates to the number of coal units added. Five coal price sensitivities have been added to the analysis (described in the Analysis Plan chapter and the results discussed in the Illustrative Plans chapter). They used a Utah coal price which doubled that used in the rest of the studies, or $24/ton with a 1.5 percent real escalation rate, which is higher than the $15/ton as recommended in the 1991 EVA report.

19) Do wind resources have an energy cost and an O&M cost? The text indicates that the energy cost was part of O&M. Please explain the apparent contradiction.

<u>Answer</u>: No, wind resources do not have an energy cost and an O&M cost. In order to model variable O&M costs which escalate faster than inflation, a portion of the variable O&M expense was modeled as a fuel cost. It was merely a modeling necessity. Text explaining this has been added to the description of the wind sensitivities.

20) How was the expected cost of capital for the utility over the 20-year planning horizon determined? Is it different than the 8.8% used earlier? Does the company assume that the capital structure and the return on equity and the yield on bonds stays the same over that period?

<u>Answer</u>: Additional text has been added to the last page of the Portfolio chapter providing explanation of the points raised in this question.

21) Wouldn't it be prudent to investigate a larger differential between the real incremental after-tax cost of capital and the real social discount rate?

<u>Answer</u>: It is possible that a larger differential would have a greater impact. A 3 percent real social discount rate was used because that was the level requested by the advisory group. RAMPP-4 could include more sensitivities of discount rate variation. When the advisory group discusses the RAMPP-4 analysis plan, this issue can be included.

Analysis Plan Chapter

22) The company's statement that it evaluates the trade-off between prices and utility costs to determine appropriate levels of DSR rather than relying on any simple rate impact measure or total resource cost test appears to violate the Utah Commission guideline that the company meet customer electric energy service needs at the lowest total cost to the utility and its customers, i.e., total resource cost.

Answer: A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

23) Does the any-renewables strategy include any of the MW of renewables that the company indicated would be acquired in the 1992 action plan?

Answer: The two wind projects in Washington and Wyoming are in the existing system. Therefore, the financial model includes their costs in all the cases. Text clarifying this information has been added to the discussion of the renewables strategies in the Renewables chapter.

24) Is it possible to do a price of electricity sensitivity, to increase the assumed price of electricity by 25-35%, to see its impact on loads and the demand for DSR? Or should this be in RAMPP-4?

Answer: This should be discussed when the company and the public advisory group address the analysis plan for RAMPP-4.

25) Please put the $600 lower cost of wind for that sensitivity in percentage terms, indicating by what percentage the cost of wind was lowered for this sensitivity.

Answer: $600/kW is 62% of the original capital cost of $962 for wind. Text clarifying this information has been added to the description of wind resource costs in the Portfolio chapter.

Illustrative Plans Chapter

26) Please explain why utility costs are higher under a medium-high load growth but that real prices are slightly lower (compared to a medium load growth case). Is the system currently under-utilized? Or are new resources less expensive than system average costs?

Answer: Additional text has been added to the description of the medium-high load growth cases to explain why the prices were lower than under medium load growth.

27) How can cases with higher gas prices produce utility costs that are lower than cases with lower gas prices?

Answer: Explanatory language has been added to the report in the Illustrative Plans chapter under the discussion of gas price results. Under higher gas prices, the prices in the non-firm market also change, which alters the results.

28) Why were some of the columns left blank on the table on page 19 of MW of Demand-Side Resource Added? If they should be zero, please put zero's in.

Answer: There is no such table on page 19. However, on page 28 there is a table of MW of Demand-Side Resource Added. The reason some columns were left blank is that those cases were not run. It would not make sense to put zero's in.

29) For the table on page 20 on average cost differences resulting from the different DSR strategies, please include the percentage increase in prices that results over x years. It is unclear how the averages were calculated.

Answer: The original table has been corrected, and an additional one added showing the percentage changes.

30) On page 30 the text says that by the end of 20 years, resource plans under the any-coal strategy included from 1,000 to 1,930 MW of coal, but the following sentence says that MH load produced 2,600 MW. Please clarify.

Answer: The text has been corrected to clarify that under medium load growth the model added 1,000-1,930, and under MH it added 2,600.

31) How are the non-cost advantages of company-owned CCCTs over cogeneration (control over dispatch and reliability) evaluated by the company? What is the cost differential between cogeneration and CCCTs? Under what circumstances would the company select CCCTs over cogeneration?

Answer: Additional language has been added to the end of the cogeneration section of the Portfolio chapter. The company evaluates the non-price factors on a case-by-case basis when considering any particular opportunity.

32) The discussion of peaking results should be expanded to describe how the company plans to deal with this resource deficiency, or refer to such a discussion elsewhere in the report.

Answer: Additional language has been added to the discussion of peaking results in the Illustrative Plans chapter. In addition, the action plan contains a discussion of the company's plans to meet peaking needs. The Company will carefully examine summer capacity needs and options (exchanges, purchases, new resources, or transmission) to find cost effective solutions to summer capacity problems. The company will use multiple information formats and models, including simple load and resource tables, hourly power cost simulations, the IPM model and detailed examination of required summer reserves. If actions are required the results will certainly be shared.

33) Why does the reduced load sensitivity result in such a dramatic decrease in prices compared to the medium-low case?

Answer: In examining the modeling results to respond to these comments, the company discovered an error in the load sensitivities. The sales number was not being transferred to the financial model correctly. That has been corrected, and the reduced load sensitivity now results in an increase in prices (no longer dramatic) compared to the medium-low and medium cases. The corrected text can be found in discussion of the load sensitivities in the Illustrative Plans chapter.

34) Explain why the economic development sensitivity and the electrification sensitivity result in such dramatic price increases. What policy implications can be drawn from these results?

<u>Answer</u>: In examining the modeling results to respond to these comments, the company discovered an error in the load sensitivities. The sales number was not being transferred to the financial model correctly. That has been corrected, and the economic development sensitivity and the electrification sensitivity result in price decreases. Text in the Illustrative Plans chapter discussing these cases addresses the reasons for the patterns seen.

35) Case #222 allowing conversion of CCCTs to coal gasification, which lowers price, TRC and utility costs, appears to give an important policy result. Is this reflected in the action plan?

<u>Answer</u>: Yes, this result contributed to the company's decision to begin a study of the trade-offs between pulverized coal and coal gasification (action plan item #4). That study will include related technologies, such as conversion of CCCTs to coal gasification.

36) Cases #231 and #232 indicate that more analysis is needed on the impact of transmission constraints on resource choices. Is the generic $300/kw realistic? What future studies do you recommend?

<u>Answer</u>: $300/kW equates to about $150 million for a 500 MW project, which is in line with current transmission estimates. Future transmission work will include possible IPM code changes and greater integration between the work of the transmission planning group and the work of the Integrated Resource Planning group.

37) Case #241 (discount rate) did not allow DSR to vary. This should be stated and the results of this sensitivity should be discounted.

<u>Answer</u>: The text describing this case now acknowledges that a higher level of DSR could become more cost effective under a lower discount rate.

38) Case #253, which raised non-firm prices, lowered costs and prices for PacifiCorp. Please discuss the variables that affect non-firm prices. Provide the company's estimation of how these variables will change in the future.

<u>Answer</u>: The introductory material discussing the non-firm sensitivities in the Illustrative Plans chapter addresses the variables that affect non-firm prices. PacifiCorp cannot predict how these variables will change in the future.

39) Why is more DSR selected in Oregon than in Utah? Are there cost differences or transmission constraints or different load growths?

Answer: The impetus to undertaking more DSR in Oregon versus Utah reflects the nature of the load and resource centers of the system. The resources identified in the analyses and reflected in the action plan recognize that the westside of PacifiCorp's system is more of a load center and the eastside is more of a resource center. Given this condition, it makes more sense to prioritize DSM on the westside since any westside DSM achieved will have the effect of lowering transmission losses associated with moving the power to the westside. In addition, there is more residential space and water heating in Oregon, providing more technical potential than in Utah.

Environmental Analysis Chapter

40) It would be useful to run the financial model using the adders as real costs (as taxes). A comparison of the price impacts of the different cases would be interesting.

Answer: This approach to environmental adders should be discussed when the analysis plan for RAMPP-4 is addressed.

41) The environmental adder cases are weakened because DSR is not allowed to vary. Cases #323 and #322, with different DSR levels, should be highlighted in the text. Policy implications should be outlined from these results.

Answer: Because the model did not have capability to "select" each DSR program without causing run times to be excessive, the environmental adder cases were run with different levels of DSR, for a total of 21 sensitivities. Additional text has been added to the discussion of cases #323 and #322, the carbon limit cases.

42) It is difficult to make comparisons with the trade-off graphs. It might be useful to label each point with a case number. On graph 7-9, what is the difference in the no-coal and renewable cases? What is changing, not load growth or gas prices.

Answer: The software used to prepare the graphs cannot label each point with a case number. For each combination of coal and renewable strategy, four points on the graph represent the four DSR strategies.

43) Please add a column to table 7-15 that includes the ratio of emission reduction relative to price increase.

Answer: The table has been modified to include the ratio information.

44) Please include a section in the report on the environmental insurance concept. Also do an analysis that assumes that these adders are actually collected in rates. Is the insurance premium then worth it?

Answer: The environmental insurance analysis that was presented at the February 18 RAG meeting has been added to the end of the Environmental

Analysis chapter. An additional analysis that assumes that the adders are collected in rates should be discussed when the analysis plan for RAMPP-4 is addressed.

Renewable Analysis Chapter

45) Can the model be allowed to select more renewables under the strategic renewables cases, so there is a floor but not a ceiling?
Answer: Yes, it could, but the company decided that it should proceed with renewables in a step-by-step process, allowing time to evaluate results from the first set of pilot projects before proceeding with additional acquisitions. The strategic-renewables cases used the company's best estimate of the measured progress it believes should be used to achieve its strategic renewable goals.

46) The discussion of average price impact on page 7 is not very useful. Please add the range of price impacts under the different cases. It would be useful to put the .38 mills into a percentage increase in prices. The sensitivity with a 20% reduction in wind costs should also be put in percentage terms.
Answer: This distinction has been explained in the DSR Action Plan Detail chapter at the beginning of the RAMPP-2 performance section. Similar information has been added in the Renewable Analysis chapter.

Action Plan Chapter

47) What about the 170 MWa by the end of 1996? Is this goal discussed anywhere?
Answer: A paragraph has been added to the Action Plan chapter's discussion of RAMPP-2 performance which addresses the 170 MWa. Also see the answer to UPSC question #9.

48) Please distinguish between signed and installed DSR in the table at the top of page 2.
Answer: Signed DSR represents the annual kWh savings for all projects which have signed an Energy Service charge (ESc) contract in the reporting year or signed and completed the project in that reporting year. For non-ESc programs it represents the installed savings; thus for non-ESc programs, signed and installed are the same thing.

49) Can the company estimate the price of power from the Calpine project?
Answer: The price is subject to ongoing discussions with Calpine.

50) Who owns the James River resource after 20 years?
Answer: PacifiCorp will own the generation facilities from the beginning and after 20 years.

51) A more detailed discussion of the three financial criteria for DSR is in order. The 1% price impact criteria should be clarified. Over what time frame does it apply? Why was 1% chosen rather than 2%. Why was the high DSR not chosen? What is the price impact between the medium and the high DSR cases? Why is that price impact too high?

Answer: A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

52) Define what is meant by "if renewables are cost effective." What are the price impacts of the strategic renewables strategy in percentage terms. Are these consistent with the price impact criteria imposed on DSR?

Answer: Additional text has been added to the RAMPP-3 action plan item #2, explaining how the company will evaluate the cost effectiveness of the pilot renewable projects.

53) Actions to increase system efficiency should reference a section of the report that found these to be cost effective.

Answer: Each department which has potential efficiency measures (thermal generation, hydro generation, transmission, distribution, etc.) determines which are cost effective by using the most recent avoided costs. These are then provided to the IRP group for including in the existing system tables and IPM model inputs.

DSR Action Plan Detail Chapter

54) Somewhere in the report RAMPP-2 DSR goals should be stated and whether their implementation is consistent with the RAMPP-3 action plans. RAMPP-2 DSR goals were 170 MWa by the end of 1996, and does this comport with the RAMPP-3 action plans for 40 MWa in 1994-95 and 37 MWa in 1996. Please explain this discrepancy.

Answer: See the answer to your question #9 above. Additional text has been added to the Action Plan chapter under RAMPP-2 performance.

55) Why did the Pacific Environments program fail? What was learned from the experience?

Answer: The Pacific Environments program was a pilot commercial retrofit program tariffed for the city of Albany, Oregon. An evaluation report prepared in September of 1992 provides a comprehensive evaluation of the program with specific conclusions and recommendations. Copies of this evaluation are available upon request. The lessons learned from this pilot have been used to develop and implement the Oregon state-wide commercial retrofit program which was tariffed in November of 1993. The Pacific Environmental program evaluation showed that: 1) the "shared savings" based energy service charge was difficult for customers to understand and is a barrier to higher penetration rates, 2) every commercial building audited and completed through the program was unique, 3) the largest savings opportunities occur in the largest buildings, and 4) the most appealing measure for customers is new lighting.

56) Break out remodeling DSR results for Salt Lake City and Portland.

Answer: Based on the program year end data for 1993 there were nine remodeling projects in Portland and four in Salt Lake city. Five of the nine buildings in Portland and one out of four projects in Salt Lake city were complete by year end 1993.

57) Add the following action item: work with Mountain Fuel to educate builders on new Utah Model Energy Codes that are currently in effect. Work with MFS to help ensure higher enforcement of the state MEC.

Answer: The following item has been added to the DSR Action Plan Detail chapter: Work with other interested parties to educate builders on new Utah Model Energy codes and other energy efficient construction practices.

58) Why is the penetration goal for new commercial in Utah so low? Justify or change.

Answer: The penetration goal for all new commercial programs is set at 75 percent market penetration within 5 years. Program summary tables on pages H-14, and H-24 in the Demand-Side Appendix presents the penetration rates for the new commercial construction programs in each state. Planned penetration rates for Utah are consistent with assumed penetration rates in other states.

Conclusion Chapter

59) The impact of load growth on prices should be discussed either in this section or somewhere in the report. Policy implications should be addressed.

Answer: The conclusion chapter contains a discussion of the price implications of the results of the studies.

60) Why is the high DSR strategy not being pursued. The conclusion should explicitly deal with the added price impact of the higher DSR strategy.

Answer: A new section in the DSR Action Plan Detail chapter (chapter 13), DSR Financial Standards and Decison Making, addresses this issue.

61) The cost and price impact of the strategic renewables strategy should be made explicit.

Answer: Additional language has been added to the Renewables Chapter, discussing the cost of the strategic-renewables strategy compared to the cost of the high-DSR over the medium-DSR strategy.

62) The action plan should be more explicit on actions needed to get coal in place by 2001, or why such actions are not needed.

Answer: The company believes the best first step is a study to evaluate potential sites and technologies. The study should be completed by January 1995. The study should also enable the company to reduce the normal 7-year lead time for coal.

PacifiCorp RAMPP-3 Draft Report
Comments from RAG Sub-Group and Full Group:
February 17 and 18, 1994

General

1) Say more about the uncertainties we face, especially the ones that are now most pertinent (gas prices, deregulation and restructuring)
Answer: Additional language has been added to the RAMPP-3 section of the Action Plan chapter.

2) Add a cross reference to the appendices. Direct the reader to where in each appendix are items that appear in the report.
Answer: This request would require extensive staff time. We decided that limited staff time would be better spent on other requests.

3) Add a summary of key acronyms used, as a fold-out from the back cover perhaps, so the reader can refer to it for the meaning of abbreviations used in the text.
Answer: The back cover includes such a fold-out.

4) Wherever the company drew a conclusion from its analysis, highlight that section in the text.
Answer: The conclusion chapter includes the conclusions the company drew from its analysis. The company decided that highlighting them in the text of each chapter would interrupt the flow of the text.

Background Chapter:

5) Discuss how the growth goal relates to the rest of the report, and to the DSR financial standards.
Answer: Additional language has been added to the description of the growth goal. However, it is difficult to relate the growth goal to the entire report, without developing another chapter, which would make this report much longer than it already is.

6) Clarify that the growth goal isn't sales growth, but financial growth.
Answer: Language to that effect has been added.

7) State that Goal 4 includes the effort to be positioned to acquire more renewables after 2001
Answer: Language to that effect has been added.

8) Add the information regarding selling of our northern Idaho service territory, and the anticipated impact on resource planning
Answer: Language providing that information has been added.

9) Under DSR cost recovery, add that the Utah order came out the week of 2/8, and it includes recovery of net lost revenues, and that the Oregon order also includes lost revenue for 1993 and 1994

Answer: Additional detail has been added to the discussion of DSR cost recovery.

10) Divide the Major Events section into two parts (events and company response to issues)

Answer: The company is happy with the organization of the chapter as it is.

11) Last paragraph of the chapter (close the loop between price and forecast), expand it to include more detailed information.

Answer: The information has been ·dded to the last page of the Background Chapter.

Futures Chapter:

12) Say that gas prices are not fed back to the load forecast in any of the cases

Answer: Language to that effect has been added.

13) Add what the merged company growth rate has been for the last 2 years and for the last 5 years.

Answer: The information has been added to the first page of the Futures Chapter.

14) Say in the beginning discussion of the load forecasts how the company evaluated the price impact of RAMPP-3 relative to the price forecast used in creating the load forecasts.

Answer: The information has been added to mhe first page of the Futures Chapter.

Portfolio Chapter:

15) Say that gas prices vary by gas price forecast for all gas-fired resources.

Answer: Language to that effect has been added.

16) Investigate the heat rates and capital costs for pulverized vs IGCC coal. There seems to be an inconsistency across geographic areas.

Answer: The section on new coal resources in the Portfolio Chapter now includes additional explanation of how costs for new coal resources were calculated.

17) Add a table of system efficiencies for G, T, and D, by year.

Answer: The information is provided in the second paragraph of the "Existing Power System" section of the chapter. All of the thermal improvements occur in 1994 and 1995. Table 4-2 shows the year-by-year T&D improvements.

18) Under transmission efficiencies, the sentence saying limited capital is available needs some explanation. How do we decide which projects to do and which to not do. Are there cost effective projects we aren't doing?
Answer: The language has been changed to clarify that it is personnel constraints that limit the number of projects identified each year, more than financial constraints.

19) Explain how the $7-$11/kW for refurbishments was calculated.
Answer: The numbers used in the calculation are provided now in the section on refurbishment in the Portfolio chapter.

20) Add a paragraph discussing costs required to relicense hydro plants.
Answer: The requested information has been added to that section of the chapter discussing the company's hydro system.

21) Page 30, paragraph 2, say that the new long-range transmission plan will be included in RAMPP-4.
Answer: Language to that effect has been added.

22) Provide the detail of how gas transportation costs vary by area.
Answer: Detailed information is now included in the new resource section of the Portfolio chapter under gas-fired resources.

23) Page 32, explain why we didn't do any cost of capital sensitivities. Discuss the large change in cost of capital that is required to influence the relative cost of resources. Discuss why our capital structure won't change through different resource futures. Say that we aren't asking for a premium for purchased power at this time.
Answer: Language to that effect has been added.

24) Say that the capital costs that are input into the model are total resource costs.
Answer: The appropriate language has been added in a third paragraph in the "Supply Side Resource Alternatives" section of the chapter.

25) Fix the wind O&M on tables 4-9 and 4-10 from 16.40 to 4.20.
Answer: The numbers on the tables have been corrected.

26) Remove footnote from table 4-9 and 4-10 and put in text.
Answer: The information is now in the text (regarding SO2 allowance costs being included in the capital costs for all coal-fired resources).

27) Define the Wyoming and Utah geographic areas the first time they are used (at the beginning of the "Supply Side Resource Alternatives" section.
Answer: The definition has been added.

28) Add the plant life information to the portfolio tables, either in the report or an appendix.

Answer: Two columns have been added to table 4-8: depreciation life and tax life for each resource.

Analysis Plan Chapter

29) Explain more about the tension between the needs of a production cost model and the needs of a capacity expansion model. Discuss the constraints we input into the model.

Answer: Additional explanatory language has been added to the section "IPM's Representation of the PacifiCorp System."

30) Explain more about using 90% of average for the capacity factor for wind, defend the assumption.

Answer: More explanation of the company's logic is provided in the description of the sensitivity which tests this assumption.

31) Page 7, the DSR more commercial and industrial sensitivity, this should have only included an acceleration of C&I DSR, whereas it also added more DSR.

Answer: The company misunderstood the initial request, and is willing to work with the requesting party after the completion of RAMPP-3 to provide the analysis requested.

32) Explain more how some resources require more load following service.

Answer: Additional language was added to the section "Peak Versus Energy Planning."

33) Define load following service.

Answer: The term and its definition were added to the glossary.

34) Indicate that the model doesn't select new resources to meet summer peaking needs. Discuss how we know that our summer peaking needs are more immediate.

Answer: Additional language was added to the section "Peak Versus Energy Planning."

35) Say that the IPM is minimizing total resource cost, and when the financial model calculates total utility cost, it backs out customer costs and benefits.

Answer: Appropriate language has been added to the "IPM's representation of the PacifiCorp System" section of the chapter.

36) When describing the load growth sensitivities, indicate that the load reduction level is between the medium and medium-low, and that the increased sales level is between the medium and medium-high.

Answer: The additional language was added.

Illustrative Plans Chapter

37) Investigate how the model runs with a higher gas price had a lower total utility cost and lower total resource cost than runs with a lower gas price. Since this is an optimization model, that shouldn't have happened.
Answer: The higher gas prices also raised the price of power in the non-firm market. The full explanation is provided at the end of the gas price discussion in the Illustrative Plans Chapter.

38) Say that the financial results include the existing system as well as all new resources.
Answer: Additional language was added to the first paragraph of the chapter.

39) Define price, as used in the report, in the text and glossary as the average cost/kWh of total utility cost, averaged over all customer classes.
Answer: Explanatory language has been added to the explanation of table 6-3.

40) Say when the Hermiston plant gets selected, and how much is selected in which years.
Answer: A table has been added in the text, showing the year-by-year amounts selected by the model.

41) Fix case #251 (critical water), which has an error.
Answer: The input assumptions were corrected (initial modeling used capacity available from hydro which was too high), and the accompanying text was corrected.

42) Indicate when the conversion occurs in the IGCC conversion sensitivity (case #222).
Answer: The conversion occurs in 2001. The information has been added to the text in the paragraph describing the results of case #222.

43) For case #222, say that the model selected the CCCT/IGCC as coal.
Answer: Language in the discussion of the results of case #222 has been added to indicate that the model selected the CCCT/IGCC conversion option as coal.

44) Say whether the information in the regional discussion was used for any decisions.
Answer: Additional language was added to the first paragraph in the "Regional Patterns" section.

Environmental Analysis Chapter

45) Add case numbers to tables 7-5 through 7-8.
Answer: The case numbers have been added.

46) Try to eliminate duplication of utility cost on tables 7-5 and 7-6, and on tables 7-7 and 7-8.
Answer: The table formats have been revised to more efficiently display the information.

47) Graphs 7-9 through 7-14: can we indicate that each scale does not start at zero? Can we make each increment on each scale represent the same percentage change?
Answer: A footnote on each graph indicates that the scale does not begin at zero. Each increment on each scale represents about a 1 percent change.

48) In the discussion of the CO2 limit sensitivities, say what the percentage change would be for the price impact, or delete.
Answer: The sentence was deleted.

49) Rank cases within each box on table 7-15 by price increase level.
Answer: The cases are now ranked within each box.

Questions and Answers Chapter

50) Add at beginning, before any questions, that these questions were asked by specific state commissions, and the answers may not apply to all states, because the regulatory process may differ in each state.
Answer: Language to that effect has been added.

51) Add more detail and update the answer on fuel switching.
Answer: Please refer to the ODOE written comments, question #23, in which the company addresses this issue.

52) Modify the language in the rate design answer to avoid using the term "value of service".
Answer: The language has been modified.

53) Provide an explanation of each of the bullet items in the rate design answer.
Answer: Additional text has been added to better define each of the bullet items.

54) The rate design answer is unsupported by any analysis.
Answer: Rate cases are the time to provide analysis to support a specific rate design proposal.

55) Page 5-6, say that $150/ton for SO_2 emissions was added to the cost of all new coal resources.

Answer: Language to that effect has been added.

56) Page 4, the avoided cost increment or decrement is an issue, because Washington methods require an increment.

Answer: Addressed by language at the beginning of the chapter, added per comment #1 for this chapter.

Action Plan

57) The items contain too many modifiers (for example, if cost effective), the items should be more specific, and we should state the number of what a cost effective standard is.

Answer: For example, because the renewable action items involve an incompletely tested technology (new wind turbines), until the company determines that the technology will perform as expected and prove to be cost-effective (have no more than a 1 percent price impact over five years compared to an alternative supply-side strategy), it will not commit to more wind resources.

58) For the coal action plan item, include when (in what year) we will make a decision.

Answer: The company does not know now when it will make a decision, since it cannot predict when it will have sufficient information for decision-making.

59) Say whether the RAMPP-2 DSR performance numbers are on a signed or completed basis.

Answer: All RAMPP-2 DSR performance numbers are on a completed basis.

60) Say at the beginning of the RAMPP-3 plan discussion that the load growth we expect is between the medium-low and the medium-high.

Answer: Language to that effect has been added.

61) Discuss the cost and justify the strategic-renewables strategy.

Answer: Additional language has been added to the Renewables Chapter, discussing the cost of the strategic-renewables strategy compared to the cost of the high-DSR over the medium-DSR strategy.

62) Discuss the cost and justify the medium DSR strategy (adjusted by internal financial standards).

Answer: As discussed in the Action Plan Chapter, the company's management is comfortable with a 1 percent price impact over a five-year period for demand-side resource acquisitions. The amount of DSR in the action plan is consistent with a 1 percent price impact.

63) Provide more explanation of how the action plan items were developed from the analysis. How did management make each decision? What analysis did they rely on for each action plan item?

Answer: Additional explanation has been added to the beginning discussion of the RAMPP-3 action plan.

64) Explain how the action plan is consistent with least cost principles.

Answer: Least cost principles involve minimizing both costs and risks. Some of the action items, such as for renewable resources, may increase costs, but also can reduce future risks.

65) Identify what the least cost plan is, and then why the company deviated from that in its decisions on DSR, renewables, and coal.

Answer: The company cannot identify what the one least cost plan is. The company created 151 least cost plans. Under different load growth assumptions, gas price assumptions, demand-side strategies, renewable strategies, coal strategies, and other input assumptions, the model can and did create unique least cost plans.

66) Calculate what the cost of the action plan is.

Answer: The company does not see a simple way to calculate the cost of the action plan, and it would be meaningless unless the company also calculated the cost of other potential action plans to provide a basis for comparison. This activity seems less important than evaluating whether the action plan positions the company for the flexibility it will need to respond to an uncertain future.

67) Clarify that the goal for peaking resources is 350 MW total.

Answer: The language for action item #5 on peaking needs has been modified to clarify that the goal is to acquire 300-350 MW total peaking resources, or more if operational uncertainties require it.

68) Clarify that the RAMPP-3 goals are an update of the RAMPP-2 goals, that the RAMPP-3 goals are not in addition to the RAMPP-2 goals.

Answer: Clarifying language has been added at the end of the RAMPP-2 performance section, just before the "RAMPP-3 Action Plan" section.

69) Explain why we are concerned about cost recovery, given that we have 7 jurisdictions, and each one has different ideas about what is a least cost path, and about what is a reasonable prudency demonstration.

Answer: An explanation has been added to the Action Plan chapter, in the introductory material to the RAMPP-3 action plan.

Appendices

70) Provide back-up for table 8-1.

Answer: The requested information has been added to the Modeling Appendix.

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