PLANNING FOR STABLE GROWTH

The Pacific Power and Utah Power
Resource and Market Planning Program

Volume 1 - Summary Report

November 1989

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PREFACE

"Planning for Stable Growth" may strike some readers as either an oxymoron or a futile endeavor. After all, how can growth be stable, given the changes growth implies, and how can change be stable? Growth in the electric utility industry in the 1970's and 1980's has been anything but stable, and consumers were painfully aware of the instability in prices at various times in that period. A fundamental conclusion of the efforts reported here, however, is that growth in the demand for energy services and stability in the availability and cost of those services need not be contradictory. Our hope is that this report convinces the reader of that possibility.

Perhaps this report could more accurately be titled "Documentation of the Planning Process Intended to Position the Company to Manage Its Future and Respond to Uncertainties in Growth in Demand and Availability of New Sources, Such that the Variety of Customers' Needs Are Met at the Lowest Possible Cost and with a High Degree of Assurance that Adequate Supplies Will Be Available, at Stable Prices, to Sustain a Healthy Economy." It wasn't, for obvious reasons. Whatever the title, the report will inevitably be referred to as the Company's least cost plan.

This report represents the Company's first attempt to document a planning process that complies with regulatory planning requirements and comports to the generally accepted elements of integrated resource planning or "least cost planning". The purpose of the planning process described in the this report is to identify actions that should be taken, and that the Company intends to take, to assure that customers' demands are met at the lowest possible cost. Such a process requires an understanding of the marketplace in which the Company competes, as well as the range of resource alternatives open to the Company, hence a Resource and Market Planning Program.

Both the process and the report preparation have been challenging to all involved, but rewarding in similar measure. The sources of the planning challenge have been numerous, beyond the complexities of an electric utility system. There was the desire to recognize the broadest range of future alternatives and uncertainties, for one. Then there was the analysis as part of a public process, interacting with critical participants and regulators as the analysis proceeded. Conducting this process while two companies' managements and staff were merging into one only added to the challenge. Finally, there was the demanding task of documenting the process and communicating the results in a written report.

While this report represents a significant accomplishment by all involved in the planning process and provides valuable information to the Company, its customers, and its regulatory commissions, both the process and the report have left ample room for improvement. The planning process will be ongoing, and in the next two years the outstanding needs and inevitable new issues will be addressed, culminating in a new report. Fortunately, as in life, the journey is the reward.

INTRODUCTION

This report summarizes the status and findings of the Resource and Market Planning Program (RAMPP), for the Pacific Power and Utah Power merged system. In conjunction with supporting technical documentation in a separate volume, this report is also intended to comply with regulatory commission requirements for long range resource planning. The reader will find a description of the Company's strategies aimed at assuring that future customers' needs are met with efficient electric energy services. The assumptions and analyses that were developed in the planning process are also documented, primarily in Volume 2.

The goal of these strategies is to achieve the lowest possible cost in providing these services, while recognizing the appreciable uncertainties affecting future requirements and sources.

BACKGROUND

Electric utilities have traditionally planned for future customers' needs with a long time horizon. Often, the need for new facilities was examined ten to twenty years into the future. This long time horizon was used because generating facilities being built required many years lead time to construct. Growth in demand was steady, and seemed certain, as continued efficiencies and economies of scale kept real electricity prices dropping. This was the pattern throughout the US until the early 1970's, when inflation, increasing oil and gas prices, and environmental and safety costs caused electricity prices to escalate.

In the face of increasing electricity prices and a general economic downturn, demand growth tapered in the late 1970's and early 1980's. Many utilities, including Pacific Power and Utah Power, found themselves completing generation construction programs on time, but without the anticipated increased demand for electricity. This situation added to the price increase pressures.

One of the reasons for the slowing growth in demand was the rational response of customers to economic choices. Electricity consumers found a variety of alternatives: substitution (burning wood for space heating, for example), efficiencies (weatherizing homes), and even generating their own electricity (industrial customers with large process heat requirements). In addition, decreasing natural gas prices brought about by an oversupply of natural gas and petroleum products led to increasing competition for new customers.

These are examples of the fundamental changes taking place in the electric utility business. In a word, the trend is toward increasing competition. Pacific Power and Utah Power have responded to these competitive pressures by improving effectiveness and efficiency of operations, and by pricing competitively. The resulting increase in electricity sales has been provided out of underutilized generating capability. Making profitable sales of power to other utilities, for example, has lowered costs to retail customers. Nevertheless, a fundamental shift has occurred in the utility business, from a perceived monopolistic industry to an increasingly competitive marketplace.

The margin between existing generating resources and existing customer demand (the "surplus") has begun to diminish. Attention is turning again to the future, with such questions as: What actions should utilities undertake to maintain an efficient balance between supplies and demands for electricity? How can utilities continue to serve customer needs, respond to competitive pressures, and develop the most efficient systems in the face of an uncertain future?

To answer these questions, sometimes at the behest of regulatory commissions, many utilities have focused their long range resource planning programs in a direction that has come to be labeled least cost planning (LCP) or integrated resource planning. Pacific Power initiated a Resource and Market Planning Program (RAMPP) in 1988. After the Pacific Power and Utah Power merger, the program was expanded to address the merged system's demand and supply acquisition directions. The planning process is also intended to comply with LCP requirements of the Company's regulatory commissions.

LEAST COST PLANNING REQUIREMENTS

This document has been prepared to describe the Company's ongoing planning process that helps guide resource and market decisions. At the same time, it is intended to meet resource planning requirements of the Washington Utilities and Transportation Commission and the Oregon Public Utilities Commission. The California Public Utilities Commission and Idaho Public Utilities Commission also adopted orders or rules related to resource planning submissions.

The Oregon and Washington requirements are similar in most respects, and similar to LCP requirements that have been adopted in many other states in recent years. Each commission has required that utilities prepare and submit, every two years, a plan that includes the following elements:

> Examine a range of demand forecasts.

> Consider all feasible alternatives for balancing supply and demand, including energy efficiency programs and purchases as well as Company owned generation sources.

> Assess supply and demand alternatives in a consistent manner.

> Describe a long range plan for balancing supply and demand, and a short range set of actions consistent with the long range plan.

> Involve the public in the process of developing the plan.

> The goal of the long range plan is meeting customer needs at the "lowest cost to the utility and its customers" (Washington rules), and "consistent with the long run public interest" (Oregon rules).

In addition to the above, the Oregon Commission has specifically required that external costs, such as environmental impacts of resource alternatives, be quantified and recognized in the development of plans.

THE LEAST COST PLAN: A DOCUMENT OR A PROCESS ?

Long range planning for electric utilities is generally understood to serve as a guide to resource actions, such that the resultant system is built at the lowest possible cost. This is a deceptively simple concept, behind which are hidden many complexities. How is cost measured? What level and types of services are assumed? How can the value of different services be accounted for? How are uncertainties recognized? It is worthwhile, at the outset, to clarify what a least cost plan is, and what it can't be.

A least cost planning process typically addresses a twenty year time frame, but it can not realistically produce a "plan" in the form of a specific schedule of events over the next 20 years. The future is, of course, laden with uncertainties. Which actions are appropriate to take ten or twenty years hence depends on how the future unfolds. While a least cost planning process cannot predict the future, it can help provide an understanding of the future implications of current decisions. Although some resource actions, such as construction of a power plant, can require more than ten years lead time, most decisions needn't be made at the outset of a twenty year plan's time frame. Planning does not require premature decision making, and a "plan" can't of itself provide every answer to every question, but it can help guide ongoing decision making.

A planning process can aid decision making by providing a consistent framework of assumptions and analyses. Planning is an ongoing process. A plan document is the compilation of the most current planning information, and a statement of the strategies or principals that will guide supply and demand decisions in the future. The primary accomplishment of the planning process is in the process itself - the understanding, insights, and information it generates - rather than in any specific set of actions identified. For these reasons, we refer to this document as a planning report, rather than a least cost plan.

In the context of public participation and regulatory commission review, a distinction must be recognized between general resource strategies that are developed and and published within a planning report, and competitive business information which by its very nature must remain proprietary. While the general strategies and the underlying competitive assumptions are closely related, they are not one and the same. For this reason, the information that does receive wide dissemination may, at times, seem to lack specificity.

RAMPP PROCESS

The planning method that has been followed during the RAMPP process consists of four general steps:

- Identify issues
- Describe alternative futures
- Assess supply and demand resource alternatives
- Assess strategies and draw conclusions

The first step, **identifying issues,** helped focus the planning process by asking what information and insights are sought. It describes the current decisions that the Company is facing and the trends and uncertainties that will affect their outcomes. The issues that were identified at the outset of the process, and the findings and conclusions that came out of the process are described in the next chapter of this report.

The second step, **describing alternative futures,** was approached from two different perspectives in RAMPP. The conventional utility practice of generating demand growth forecasts was followed, using a range of economic and demographic assumptions. In addition, scenarios describing plausible futures as determined by other uncertainties were also identified, in order to examine a broader range of futures. The conventional forecasts and alternative scenarios are summarized in chapter 3 of this volume and documented in Volume 2.

The next step, **assessing resource alternatives**, consists of estimating the cost and availability of a broad range of activities that can be undertaken to keep customer demands and electricity supplies in balance. Both conventional generating resources on the supply-side and energy efficiency programs on the customer, or demand-side, of this balance were examined. In addition, the potential contributions to this balance from the other suppliers in the emerging energy marketplace were assessed. These resource and market alternatives are summarized in chapter 4 of this volume and described in further detail in Volume 2.

The fourth step, **assessing strategies and drawing conclusions**, is used to illustrate how resource and market alternatives can be used to meet plausible futures. Plans are formulated for each of the alternative futures and system costs, as measured from several perspectives, are estimated by simulating the results of following those plans. Based on those results, effective strategies are identified.

Through an ongoing part of this planning process, **public involvement**, was elicited from a technical advisory group and from customer panels. That involvement process is summarized in Volume 2.

Chapter 5 of this volume summarizes the portfolio of new sources that should be relied upon in the future. Chapter 6 describes the long-range results (extensively documented in Volume 2) when these new sources are employed under alternative future assumptions, and the strategies or time frames within which decisions should be made. Chapter 7 summarizes the actions that will be undertaken in the next two years, consistent with long-range strategies.

ISSUES AND FINDINGS

Current and prominent planning issues arise from a specific context - a substantial energy surplus for most of the 1980's, both for the Company and the Pacific Northwest region as a whole. That surplus resulted from demand growth lower than forecasts which indicated the need for generation construction programs, and was amplified by a recession in the early part of the decade that was severe and prolonged in the Company's service areas. The prominence of timber, mining and petroleum extractive industries in the Company's service areas was a major factor in this slump. Throughout this period, changes in the patterns of electricity consumption worked their way through the system, in response to price increases and stiffer competition.

The Company's response to this situation was to become more efficient in operations, to defer new resource additions, and to increase wholesale sales aimed at increasing wholesale revenues, thereby lowering costs to retail customers. In addition, efforts to broaden the base of retail customers through a more diversified economy was sought through economic development activities. The PP&L/UP&L merger helped accomplish additional operating efficiencies as well as significantly increasing the customer base. Finally, the Company has sought to broaden its services to existing customers, recognizing new energy services as a source for business growth, and a value to customers.

As these programs have delivered results, concerns have arisen that projected deficits may occur sooner than originally anticipated and that this could lead to a new round of ambitious generation construction programs. In this context, the Company has identified a specific set of issues as the appropriate focus for this stage of RAMPP. A discussion of these issues and the findings and conclusions from this phase of the planning program follows.

Issue: Magnitude and duration of merged Company surplus

One person's perspective of the regional surplus has been expressed as follows:

"The Northwest is using electricity at an unexpected pace ... Without improved conservation of energy or a new power plant, the region is faced with the prospect of purchasing energy at higher cost from outside sources." (1)

Like the Pacific Northwest region as a whole, the Company has had surplus resources throughout the 1980's. During this period, resource decisions were deferrable, given the size of the energy surplus and the relatively slow rates of growth. This issue looks for answers to the questions of how much longer might those decisions be deferrable, and is the surplus of sufficient magnitude that actions should be taken to reduce it? As the above quote illustrates, the conventional notion of "the surplus" implies that there are few choices, limited time to make them, and dire consequences once "the surplus" is gone.

Finding: Pacific Power and Utah Power have a broad range of flexible and efficient options that can be used to maintain an efficient balance between demand and supplies. The availability of these options suggests that the Company has more flexibility to meet increased demand than is implied in the quote above. The alternative new sources identified in the RAMPP process suggest that a narrow focus on "the surplus" is not the fundamental issue

1 "BPA official foresees NW electrical crunch", THE OREGONIAN, August 10, 1989.

facing the Company, and attempting to precisely define its duration is fruitless. The band of uncertainty surrounding projections of future demand is sufficiently broad that growth could surpass existing resources virtually anywhere in the twenty year planning horizon. This makes a precise answer to the magnitude and duration of the surplus question impossible and highlights the risks of assuming that there are only a few, inflexible options for meeting future demand growth. This uncertainty also underscores the value of flexible strategies and a diverse portfolio of new sources to mitigate risks.

Issue: Suitable mix and timing of supply and demand actions

What are the availability, cost and timing constraints on various supply and demand resources? Specifically, what actions short of a new generation construction program similar to the 1970's are available? What strategies can best assure low and stable costs in the face of future demand growth uncertainties?

Finding: A broad range of supply and demand alternatives have been identified that can be deployed to meet the range of possible futures, with costs lower than construction of new, large baseload generating facilities and many at costs at or below current system average costs. These sources are likely to be sufficient for future demand growth in the most probable range of economic conditions. Energy efficiency programs appear to have relatively low cost, but timing, regulatory treatment, operability, and size of the various alternatives make a balanced development strategy imperative. Energy efficiency programs emphasizing lost opportunities, pilots and demonstrations should proceed. At the same time, system efficiencies, improved planning strategies, and cost-effective supplies from the marketplace should also be pursued in the near-term.

Issue: Benefits and risks of economic development and wholesale sales

During the last decade, a large energy surplus prompted the Company to initiate economic development efforts, and to make long-term wholesale sales arrangements with other utilities. The purpose of these efforts has been to use existing resources more efficiently and thereby lower costs to customers. These activities have provided benefits, both to customers and to the Company as a business enterprise. Customers have benefited from wholesale sales by an annual revenue stream that has averaged in excess of $113 million per year over each of the past ten years. These revenues are used to directly offset retail customer costs. The Company has benefited from a broader, more vital and stable customer base, and from more competitive prices. The question is, do these efforts eventually commit customers to costly future construction programs and new large generating plants?

Finding: The future economic growth conditions examined in this process were based on a range of alternative underlying economic growth assumptions, rather than the results of specific economic development activities. Results of RAMPP studies do show, however, that the Company's portfolio of new sources can meet load growth in the high range without a major new thermal generation construction program. Moreover, the lower cost alternatives allow the Company to maintain stable or declining prices and customer costs (in real terms) over a range of future load growth assumptions. Even under high growth assumptions, real prices and customer costs are stable or declining over the 20 year horizon. The benefits of economic development are, of course, much broader than electricity price stability, and no attempt has been made in this planning process to quantify those benefits. An important conclusion, though, is that current prices are reasonable indicators of future costs, and can be used by consumers to weigh the value of services in relation to costs.

Issue: Demand-side program cost-effectiveness and price/equity implications

The customary planning approach in the Northwest has been to estimate conservation technical potential up to a cost-effectiveness limit, and then assume some rough cost of implementing programs. The price and cost impacts of programs can vary, depending on how programs are implemented and how the costs are shared. What are realistic and reliable estimates of the energy efficiency savings and cost per unit of energy saved, specific to the Company's customer base? Are there other benefits to be accounted for in energy efficiency measures, and how should they be recognized in program implementation and pricing decisions?

Finding: Programs capable of deriving approximately 400 to 600 average megawatts of energy efficiencies in the Company's customer base appear to have relatively low costs, when compared with conventional coal fired generation, on a total life cycle cost basis. Price impacts depend on how the programs are implemented and accounted for in the regulatory process. Cost estimates were based on technical assessments, plus specific program assumptions, often with innovative delivery mechanisms. The programs typically are staged such that they ramp up from pilot and demonstration phases into an acquisition phase, allowing refinements and providing flexibility and adaptability to change. Cost recovery through energy service charges have the potential to mitigate price impacts and address associated equity and lost revenue issues, but needs to be tested in pilot programs.

Issue: Reliability, availability, and price of power purchases

In the past, the Company has used a forecast of BPA's New Resource (NR) rate to represent the cost of new resources, for purposes of estimating avoided costs. The availability and reliability of purchases from BPA under the NR rate, and of other purchases from other entities, have been questioned, with the implication that future costs may be underestimated with this avoided cost measure.

Finding: Economical purchases of up to 800 average megawatts are likely to be available from BPA and from other utilities in the rocky mountain, desert southwest, and Canadian areas of the interconnected west. Significant economical cogeneration potential exists in the Company's customer base, amounting to about 400 average megawatts. Purchases from BPA under the NR rate appear to be in the middle of the cost range of economical new sources. The NR rate is not particularly sensitive to the Company's demand, in modest amounts, but wide BPA latitude in acquiring resources and setting rates raises cost stability issues and suggests that such purchases should not dominate the Company's portfolio of new sources.

Issue: Implications of bidding, by-pass, transmission access, and increasing market forces

These are prominent trends in the industry. Much attention has been devoted to increasing market forces and its implications for both supplying utilities with efficient low cost resources, on the one hand, and competing for customers and market share on the other. What are the potential risks to the Company and its customers of industrial bypass or other customer loss?

Conversely, to what degree can this marketplace be viewed as an efficient provider of new resources alternatives, at what costs, over what time period, and in what amounts?

Finding: The marketplace can be expected to provide a significant share of future resources, in the form of purchases from other utilities and cogeneration. At the same time, cogeneration potential could represent bypass risk. A loss of customers, and thus lost sales and revenues, due to increasing competition could also have the effect of a significant price shock to remaining customers and stagnant sales. Cost control, price competitiveness, and value-added services are appropriate strategies to manage this risk.

Issue: Effects of major environmental (SO2 or CO2 controls) or other constraints

Concerns over acid deposition on a national basis has focused attention on SO2 and NOx emissions from coal-fired generation. More recently, concern over the potential for long-term global climate change from CO2 emissions has called into question the cost and availability of new fossil fuel generation. Will future policies aimed at addressing these concerns affect the ability of the Company to supply future customers' needs at stable costs?

Finding: Estimates of economic costs of externalities span a wide range. The Company's portfolio of new sources is sufficiently diversified, with relatively small reliance on coal-fired generation, that accounting for acid deposition related externalities would not cause a major shift in resource choices. Alternatives without such impacts (energy efficiency and system efficiency programs) already have a higher priority for implementation based on internal costs, and the amount and timing of these alternatives is not particularly sensitive to the costs assumed for externalities. The Company's existing coal generation relies on low sulfur coal, and much already has SO2 removal. The same can be said for other coal generation in the western states that is one likely source of utility purchase alternatives.

Large uncertainties exist with respect to the environmental impact of CO2 emissions, the cost associated with speculative control technologies and mitigation measures, and possible national and international policy responses.

At the request of the RAMPP public advisory group, a scenario was developed to examine the impact of reducing the Company's CO2 emissions by 20% by the year 2005. In this scenario, the reduction is achieved by a combination of some fuel conversions (coal to gas), and heavier reliance on renewable resources. It is presumed that a large national commitment to reducing CO2 emissions will lead to a significant reduction in the cost of alternative technologies (such as solar and wind) and a increase in accessibility to prime geothermal sites. This scenario results in significant cost and price impacts. The Company's current strategy of emphasizing energy efficiency, promoting resource flexibility, and actively participating in national policy forums, appears to be a reasonable, cost effective, approach to these uncertainties.

ALTERNATIVE VIEWS OF THE FUTURE

The RAMPP process has explicitly recognized uncertainty by describing a range of possible futures, using both conventional demand growth forecasting and scenario planning methods. Conventional demand growth forecasting is sensitive primarily to long range economic growth assumptions. Economic growth is one of the major uncertainties affecting long range resource planning, but by no means the only significant source. A strict reliance on these methods could overlook the implications of change, the presence of which is otherwise obvious. Econometric and end-use methods are tied to historic technologies and energy use patterns, which are another source of uncertainty. Competition also can be a factor overlooked by conventional forecasts. To recognize the implications of these significant trends, several scenarios have been formulated and analyzed; these are discussed in the second part of this chapter.

DEMAND FORECASTS

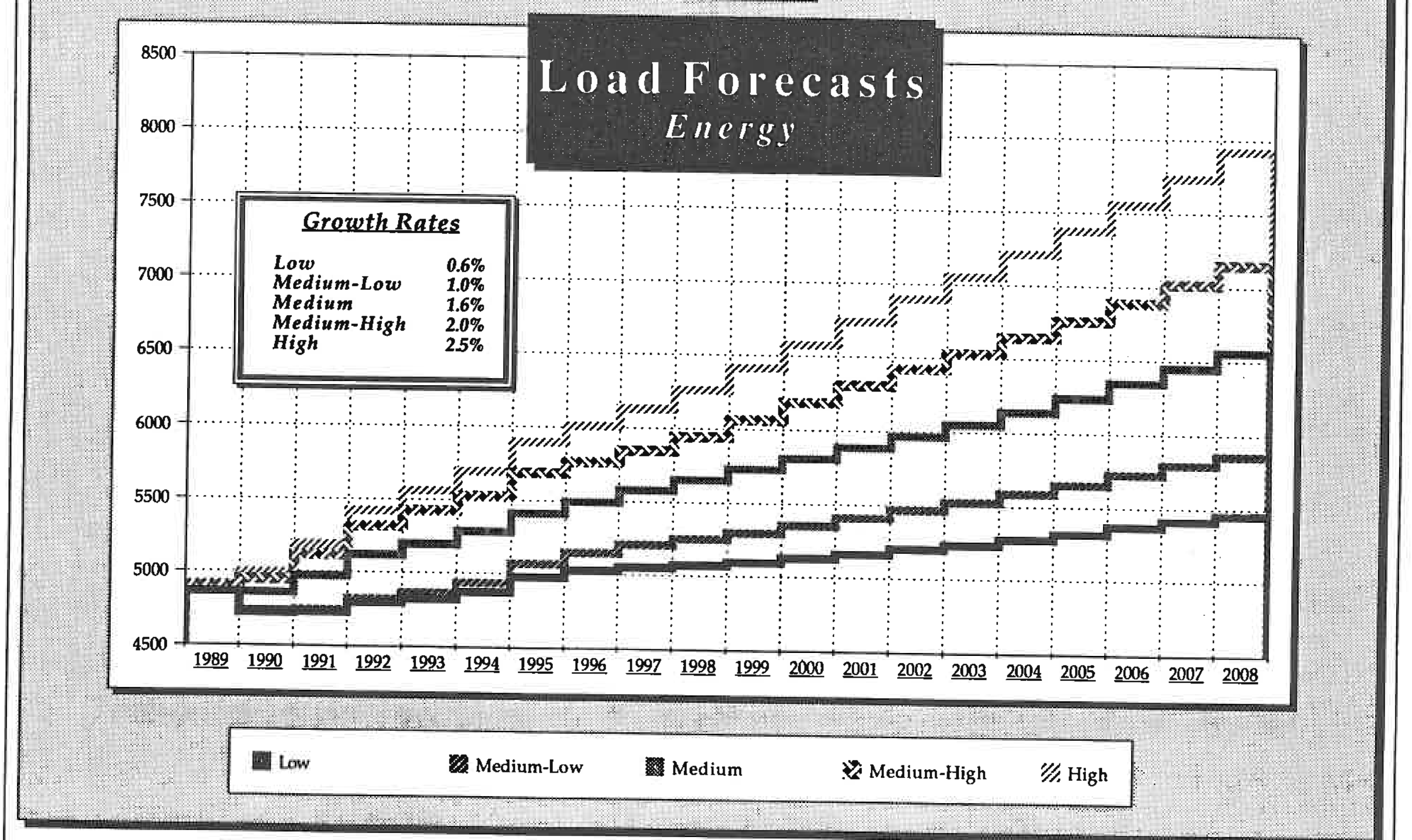
A range of possible demand growth futures has been developed. This range is defined by five economic and demand forecasts. The high and low forecasts, which are affected by high economic and population growth assumptions, are intended to bound the range of uncertainty with a high degree of confidence. Between the low and high forecasts are three discrete forecasts, medium low, medium, and medium high. This narrow range represents the more probable effect of economic and population growth assumptions. The demand growth forecast range is illustrated in Figure 1.

The five cases demonstrate the magnitude of uncertainty with regard to growth in customer demand. In the low case, demand is growing in aggregate at an annual rate of 0.7%, or between 30 and 40 average megawatts per year of energy. In the high case, demand is growing at an annual rate of 2.7%, or between 120 and 180 average megawatts per year of energy.

The range of forecasts from low to high is comparable, in concept, to the range of forecasts developed jointly by the NPPC and BPA for the Pacific Northwest Region as a whole. Merged system forecasts have been generated by combining forecasts for the PP&L and UP&L divisions, using consistent assumptions. The forecasts are produced in a manner that recognizes the unique characteristics of each division and service area.

For example, Pacific Division forecasts are built through a series of steps, starting with basic employment, population, and income growth tied to national economic growth assumptions. These basic economic drivers are building blocks for electricity sales forecasts by customer class, the primary categories being residential, commercial, and industrial customer classes. Residential and commercial customer sales forecasts are developed using econometric and end-use techniques that account for the uses of electricity. Industrial sales forecasts rely on econometric techniques that recognize the relationship between manufacturing output and electricity consumption. The final step is conversion of aggregate annual energy sales to monthly energy and capacity generation requirements, based on historic use patterns and generation:sales ratios (losses). Although different methods have been employed for the Utah Division, those forecasts were also derived from a detailed customer and service-area specific perspective.

Figure 1



Energy	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Low	4861	4721	4727	4793	4822	4869	4975	5024	5051	5071	5093	5124	5160	5199	5229	5270	5313	5367	5412	5454
Medium-Low	4865	4734	4742	4818	4864	4934	5067	5145	5205	5248	5294	5348	5406	5467	5521	5583	5650	5725	5794	5858
Medium	4861	4858	4969	5116	5192	5278	5408	5492	5575	5649	5727	5808	5886	5968	6048	6139	6235	6343	6450	6557
Medium-High	4889	4946	5116	5317	5421	5523	5686	5765	5846	5944	6063	6183	6304	6422	6529	6642	6757	6885	7015	7147
High	4914	4996	5186	5418	5557	5691	5894	6011	6128	6260	6414	6572	6733	6896	7047	7209	7372	7552	7736	7923

Although demand forecasts are the primary output of the forecasting process, there are other important uses of related information throughout the RAMPP process. For example, inflation, cost of capital, and fuel escalation rates are inputs to estimates of the cost of supply alternatives. Similarly, detailed information on customers and their energy uses are primary inputs for estimates of potential energy efficiency savings. In fact, careful coordination between demand forecasts and energy efficiency estimates has been followed to assure those estimates are as reasonable as possible and do not double count efficiency measures that customers might undertake on their own. The primary underlying assumptions for the five cases are summarized in Table 1.

While coordination with energy efficiency estimates can account for some changes in how customers might use electricity in the future, other fundamental changes are easily overlooked by the conventional demand forecasting. The scenario process described below is intended to bring some recognition of these changes into the RAMPP process.

ALTERNATIVE SCENARIOS

Through the development of alternative scenarios, the Company assessed the impact of significant changes in the underlying economic and business environment that cannot be fully captured through econometric or end use analysis. By developing and analyzing the impact of these scenarios, the Company is able to assess several important elements of its planning process. The scenario analysis helps the Company recognize the implications of possible changes that could occur in its electric service business environment. This analysis helps test the effectiveness of the resource and program flexibility that has been designed into the Company's new source portfolios. In addition, the scenario analysis tests the range of possible costs and resource options that may confront the Company and its customers in a speculative "global warming" environment.

As in most scenario planning processes, the Company considered a long list of possible trends and events that could yield different supply and demand assumptions. Through a process of refining and narrowing, a manageable number of specific scenarios were arrived at. Not all of these proved to be useful and illuminating. The three scenarios that did offer useful insights are discussed in this report. Those three examined the effect of

1) Oil and Gas Price Increase,

2) Increased Competition (Deregulation), and

3) Climate Change Initiatives.

In the first two scenarios, the underlying economic environment was stable, characterized by medium economic growth, up until the time when the significant change occurred. In the first instance the economics change virtually overnight from good to bad as three 25 percent annual increases in oil and gas prices are absorbed by the economy beginning in 1995. In the second instance the underlying economics remain good while the business environment becomes radically altered. The effect of this alteration is the loss of load associated with the Pacific Division's ten largest industrial customers to alternate energy suppliers.

In the third scenario, the flexibility of the Company's new source portfolio was examined in the context of an assumed national and international policy initiative prompted by concerns over

Table 1

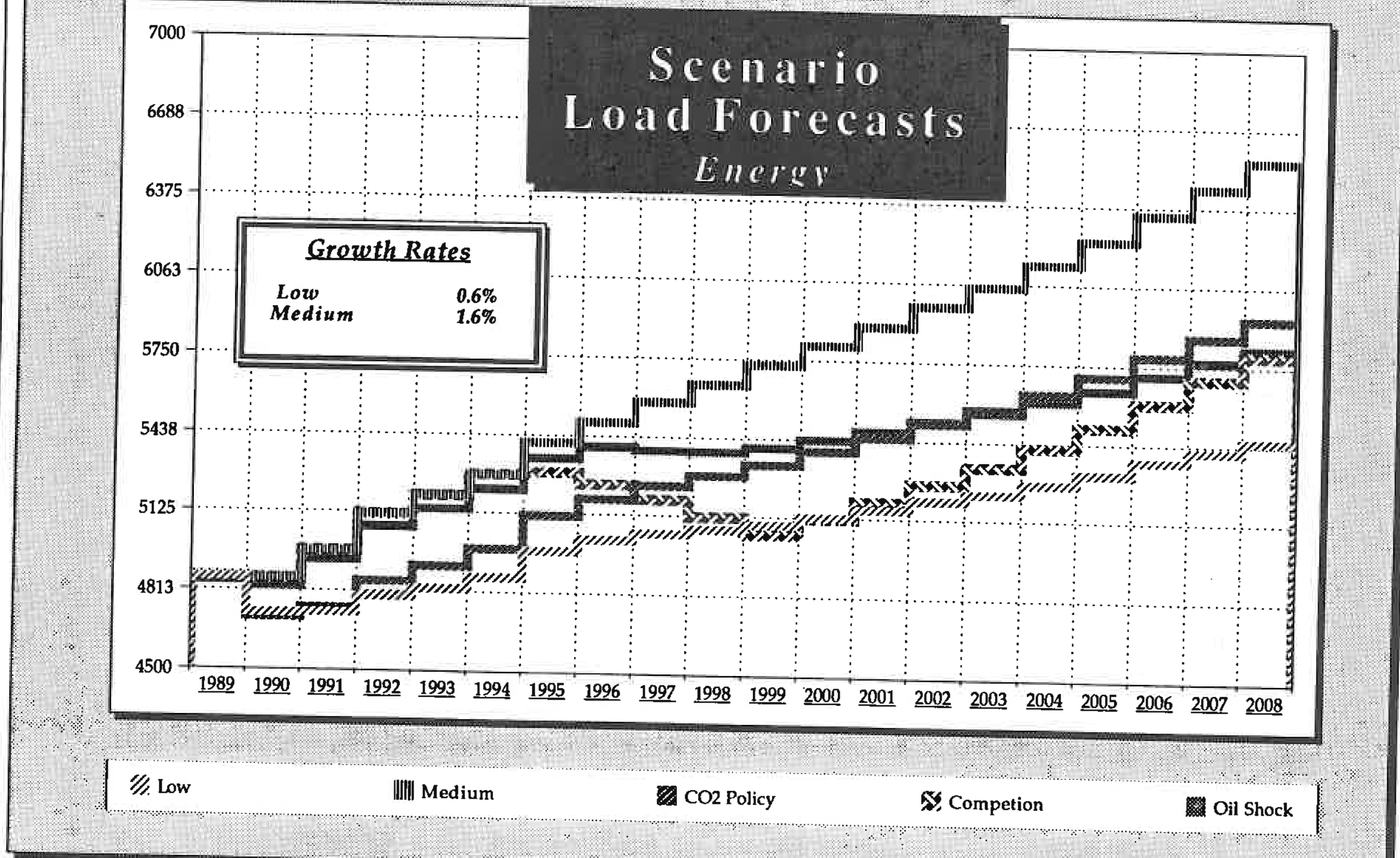
RAMPP Case Assumptions

	High	Medium High	Medium	Medium Low	Low
	ROBUST Local & National Economy				***STAGNANT Local & National Economy***
Inflation Rate *(20 year average)*	3.92%	3.92%	5.19%	7.14%	7.14%
Cost of Capital					
Debt	8.95%	8.95%	10.25%	12.15%	12.15%
Preferred	7.95%	7.95%	9.25%	11.15%	11.15%
Common	12.60%	12.60%	13.50%	14.80%	14.80%
Short Term Debt / Investment Rate	6.70%	6.70%	8.00%	9.90%	9.90%
Real Per Capita Income *(Annual 20 year Increase)*	1.60%	1.50%	1.20%	0.70%	0.60%
Natural Gas Price *(Annual 20 year Increase)*	7.90%	7.90%	8.70%	10.80%	10.80%

global warming. Although the actual risks of climate change due to human activities and the most effective actions in response to such risks are both very speculative at present, one possible policy response was hypothesized. For the purpose of this scenario, it was assumed that the Company was required to reduce its carbon dioxide emission levels by twenty percent by the year 2005. A major national effort aimed at promoting the development and diffusion of energy efficiency and alternative generation technologies was also assumed. In recognition of the implications of fundamental re-direction of the nations capital resources, and of the effects of inevitable electricity price increases under this scenario, the assumptions and growth pattern underlying the medium low forecast case were adopted for this scenario.

The demand growth patterns associated with each of these scenarios are illustrated in Figure 2, in comparison with the low and medium economic growth cases.

Figure 2



Energy	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
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Medium	4861	4858	4969	5116	5192	5278	5408	5492	5575	5649	5727	5808	5886	5968	6048	6139	6235	6343	6450	6557
CO2 Policy	4,860	4,705	4,743	4,848	4,911	4,981	5,115	5,185	5,240	5,284	5,333	5,389	5,447	5,509	5,566	5,633	5,704	5,785	5,861	5,935
Competion	4,861	4,858	4,969	5,116	5,192	5,278	5,289	5,243	5,186	5,121	5,053	5,122	5,191	5,265	5,336	5,417	5,503	5,601	5,697	5,794
Oil Shock	4,847	4,829	4,934	5,065	5,137	5,219	5,344	5,393	5,382	5,380	5,400	5,433	5,474	5,517	5,555	5,603	5,651	5,711	5,767	5,819

FUTURE SOURCES OF SUPPLY

The forecasts and scenarios described above set the stage, but they are by no means a complete description of the future. The other major piece is a description of the actions that are available to help maintain electricity supplies in balance with demands. The RAMPP process has identified potential new sources that can contribute anywhere from 1000 to 2000 average megawatts, with reasonable life-cycle costs. In this section, these alternative new supplies are described, as well as the existing power system with which they must be integrated.

EXISTING POWER SYSTEM

The existing system will continue to be the primary supplier for future customer demands. Besides its size in relation to demand, which determines the timing of new resource needs, other characteristics of the system influence how efficiently new source alternatives can be integrated into the existing system.

Current energy requirements are met by about 80% coal generation, 15% hydro, with the remaining coming from miscellaneous sources and purchases. Table 2 summarizes the energy and capacity that these existing resources will be able to supply over the twenty-year planning horizon, and also identifies contractual obligations for sales to other utilities. Energy production from thermal generation is based on historic availability of the specific units. For hydro generation, the energy is based on production under dry conditions.

Almost all of the coal fired generation is from plants located adjacent to mines and thus low in operating cost. These units, designed to run continuously at high output levels, are known as "base load". This means other resources must have the ability to respond to daily, weekly and seasonal load shapes. Hydro generation contributes heavily to meet capacity needs, as these resources have more flexibility to cycle in relation to load variations. Capacity purchases from BPA are another major source of energy shaping over a daily and weekly time frame (2). Pacific Power is also a participant in the Pacific Northwest Coordination Agreement, and coordinates the seasonal storage of its hydro resources with other major regional hydro storage, and thus sharing in the gains from coordinated operations.

The thermal and hydro relationships in the Company's resource system contrast with the Pacific Northwest's regional resource system, in which hydroelectric generation predominates. The regional hydro system, besides low operating cost, has the advantage of an abundance of capacity and flexibility in shaping energy to loads. For the Company's system, the value of new resource alternatives must be weighed in terms of their contributions of energy to the system, and also their capacity and operability. In contrast, regional planning has typically focused on the energy component, assuming that regional hydro resources provide both sufficient capacity and operating flexibility.

The Company's generating resources are expected to contribute at about current levels throughout the planning horizon. In the next twenty years, a few hydro and thermal generating units will be reaching 35 years of operation, the useful life typically assumed for economic

[2] The Company's current capacity purchase contract expires in 1991. Although negotiations with BPA for a replacement contract have been underway for some time, a final agreement has not been reached. For planning purposes, a purchase of 1000 MW has been assumed. Whether it is acquired from BPA or other generating capacity or purchases, this was assumed to represent the minimum amount of capacity required to efficiently operate the Company's baseload thermal generation.

Resource & Market Planning Program

Existing Firm Resources & Commitments

Table 2

Average Megawatts	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Firm Commitments	483	570	627	646	646	646	646	617	617	617	504	482	482	482	448	362	362	335	254	254
Resources																				
Merged System Hydro	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434	434
Firm Purchased Resources	525	600	594	587	592	603	602	540	487	468	461	457	451	451	445	444	439	388	388	388
Thermal Generation	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029	5029
Thermal Maintenance	405	394	426	421	439	359	389	433	407	402	428	393	417	417	417	404	407	380	425	403
Total Resources	5583	5670	5632	5629	5617	5708	5677	5571	5544	5530	5496	5528	5498	5497	5492	5504	5496	5472	5427	5449

Peak	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Firm Commitments	680	707	809	854	854	854	854	754	754	754	679	627	627	627	627	427	427	427	227	227
Resources																				
Merged System Hydro	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001
Firm Purchased Resources	2098	2188	2289	1142	1121	1007	996	920	779	727	721	695	676	675	673	653	653	544	544	544
Thermal Generation	5840	5845	5850	5856	5856	5856	5856	5856	5856	5856	5856	5856	5856	5856	5856	5856	5856	5856	5856	5856
Total Resources	8938	9034	9140	7998	7977	7863	7852	7776	7635	7584	7577	7551	7532	7531	7529	7509	7509	7400	7400	7400

analysis in resource planning. Current maintenance is aimed at an extended operating life, as long as maintenance expense and capital replacement costs are small relative to new resource alternatives. There is also a potential for increased generating capability from existing hydro and thermal units, and this potential is discussed in the supply alternatives section.

Geography is another important dimension of the Company's power system which imposes potential constraints on amounts and locations of new sources, but at the same time provides unique access to potential sources. Transmission capabilities between the Wyoming, Utah and Pacific Northwest load and resource centers must be recognized in planning for new sources. In spite of potential transmission constraints or costs, the geographic extent of the system has a major advantage with the interconnection it provides to rocky mountain and desert southwest utilities, besides the Pacific Northwest, with their load and resource diversities. These diversities are a potential source of operating efficiencies, over and above those already realized by the UP&L/PP&L merger. The potential for seasonal purchase and exchange transactions is discussed in the Marketplace section of this chapter.

Sales to other utilities under long-term contract (firm sales) are another important feature of the existing power system, although they represent a requirement for energy and capacity rather than a supply. Revenues from these sales are generally used to offset system costs that would otherwise be recovered from retail customers.

Besides their future energy and capacity requirements, two features of some of the firm sales must be considered in long range planning. One is flexibility or uncertainty in the amounts of power that will be required. Most of the firm contracts give the purchaser some ability to determine the energy deliveries, within a minimum to maximum range. For planning purposes, the maximum deliveries are assumed. Contractual arrangements can also provide for reductions, as determined by the Company within certain constraints. The Company's flexibility can be considered a supply alternative, and these features are discussed in the new supply sources section. A reduction in firm sales to another utility is one means of assuring that existing resources are available for future retail customer needs. Another method used in many of the Company's wholesale contracts is flexible pricing terms, such that if new, more expensive resources are required, the firm sale price is adjusted to reflect those additions. The increased revenue that results serves to insulate retail customers from price impacts, to the extent that new sources are more expensive than the current resources.

NEW SOURCE ALTERNATIVES - A WORD ON COSTS

New sources the Company can turn to in the future cover a broad range - system efficiencies, customer efficiency programs, new generation sources and supplies from the marketplace. Their diversity is an important aspect of planning strategy, but it also complicates cost comparisons. The problem is akin to comparing apples and oranges, although the differences have to do with the amounts of energy they produce (or save), the timing of costs, and how the costs are allocated. For example, investment or purchase alternatives have different useful lives or durations; capital investment and fuel expense costs are incurred over different time frames.

For comparison purposes, a life cycle cost approach is commonly used in resource planning. The cost per unit of energy is expressed in mills/kwh, on a real levelized cost basis. This measure gives an estimate of what the average unit cost of an alternative will be over it's life, relative to current dollars. Although there are limitations to this measure, as discussed in

Chapter 5, it allows a comparison between alternatives, and in relative reference to current generation costs and electricity prices.

Another issue is which costs are included. From a utility perspective, there are direct costs of any alternative, such as capital investment, fuel and operation and maintenance expense. The sum of all of these are referred to as total utility costs. Energy efficiency programs can have these types of direct costs to the utility, as well as costs paid directly by the customer such as a customer's investment in a weatherization program involving a utility's incentive payment. The sum of these two represent the total direct costs of an alternative, and are referred to as total resource cost (TRC). Both of these cost perspectives are used in this chapter.

New sources may also have indirect costs, or externalities, that society as a whole bears, although no money changes hands. Impacts of pollution on public health are an example. These are more difficult to quantify and estimate in dollars terms, but to the extent that they are incurred by someone, they are no less real than direct costs. Adding estimates of these external costs to total resource cost gives a quantity often referred to as societal cost of an alternative. Accounting for externalities is discussed in Chapter 5.

ENERGY EFFICIENCY PROGRAMS: THE DEMAND-SIDE ALTERNATIVES

For more than ten years, the Company has been an innovator in the development and evaluation of energy efficiency customer programs. In the late 1970's, a Zero Interest Program was initiated that recognized the hurdle of financing residential efficiency improvements. The Company is currently one of the sponsors of the Energy Edge program, aimed at demonstrating that commercial building energy efficiency beyond current building codes. The Company is also working to assist low-income customers gain the benefits of energy efficiency through a tailored energy education program. The Company's most widely recognized efficiency program was the Hood River Conservation Project, which demonstrated that utility, government, and customer commitment can secure high customer participation in efficiency programs.

The amount of savings available through energy efficiency programs is tied directly to the number of homes, businesses and industries that make up the Company's customer base. Therefore estimates of potential depend on detailed end-use information and economic forecasts. The cost of programs and the resulting amount of efficiency savings will depend on the cost of the efficiency measures and upon the administrative and marketing costs of the programs. RAMPP analyses considered both dimensions. The methods used and results are described below.

Detailed end use models were prepared for residential and commercial customer classes, by geographic area. Technical information on estimated costs and energy savings were developed for numerous efficiency measures. Based on detailed information derived from the Company's demand forecasts, the total potential for electricity savings from the various measures was estimated.

The next step is to describe the programs that can most efficiently offer the service provided by these efficiency measures to customers. Many considerations went into this stage of the analysis besides the actual technologies to be employed. These considerations included: marketing and development costs, customer interests and choices, administration and work force requirements, and rate of development over time. Technical potential "maps" helped to identify the measures that could be most effectively offered in cohesive programs. In developing these programs, all efficiency measures with estimated costs up to a cost effectiveness ceiling were used. The ceiling of 55 mills/kwh is based on the estimated life cycle cost of generation form a generic new coal generation plant, comparable to the value used by the Northwest Power Planning Council.

In developing efficiency program estimates, full Model Conservation Standards (MCS) were assumed to be in effect by 1993 in at least Oregon and Washington. The Company's existing Super Good Cents program promotes the development and acceptance of efficient building standards in advance of MCS code adoption, while at the same time helping to capture current "lost opportunity" resources. It is assumed that current programs will create the necessary environment for code adoption by making full MCS common practice.

The program design stage resulted in 10 programs to be used as alternatives in subsequent planning. The timing, energy savings, and costs of each program were estimated for each of the economic growth forecast cases. For purposes of planning the program's impact on utility loads, net savings were used. Net savings are those energy savings that remain after the impact of "background conservation" (that which the customer initiates independently) and "customer takeback" (the portion of a program's benefit that is realized in the form of additional consumption, rather than energy savings) have been taken into account.

Information describing the identified programs is summarized in Table 3 for the medium economic growth case. Besides the programs within the cost-effectiveness ceiling, Table 3 also shows estimates for a "Major Thermal Appliances" program, with TRC well above the ceiling. The measures included in that program represent the next major increment of savings available at costs above the cost-effectiveness ceiling. Since the amount of savings available from many of the programs is a function of demand growth, it was necessary to develop program estimates for each of the economic forecast cases. Table 4 compares program energy savings and cost for the low, medium and high economic growth cases.

Tables 3 and 4 indicate the total energy savings estimated to be available over the planning horizon. Another important dimension of these programs is their development over time. Most programs begin with a pilot phase, allowing the testing of marketing and delivery methods, cost and availability assumptions, and measurement and verification techniques. This stage allows adjustments and refinements to be made in the programs before they move into capability building and acquisition phases. In addition, the transition between these phases can be adjusted over time. This flexibility allows the programs to be sized more closely to requirements over time. An exception to this dynamic phasing is made for lost opportunity programs. Lost opportunities are those measures that are cost effective if installed at time of new construction for a home, or purchase of a long-lived energy using device,but are much more expensive to achieve at a later time. The timing of the resource acquisition is driven by a window of opportunity, rather than the specific timing of new source needs.

In addition to these programmatic savings, the efficiency effects of government regulation have been included within the demand forecasts. For example, in the medium forecast, federal appliance efficiency standards account for 109 average megawatts of savings by 2010 while residential model conservation standards account for 51 average megawatts of savings by 2010.

Besides the customer focus and perspective, energy efficiency programs differ from supply resources in that they meet new demands with reductions in electricity sales, and they provide

Table 3

Pacific Power & Utah Power
Major Resource Acquisition Programs - Based upon Medium Economic Forecast 1990 to 2010

PROGRAM	PHYSICAL GOAL	TIMING	RESOURCE YIELD MWa	TOTAL LEVELIZED RESOURCE COST Mills/Kwh	LEVELIZED UTILITY COST Mills/Kwh	GROSS UTILITY PROGRAM COST MILLIONS 1989 $'s	KEY FEATURES
UTAH COMMERCIAL MODEL CONSERVATION STANDARDS (LOST OPPORTUNITY)	18,000 Buildings	1990-2010	16	24	4	$6	Short term program. Benefits from market transformation, or MCS code adoption
NEW APPLIANCES (LOST OPPORTUNITY)	1 Million Appliances	1990-2010	22	18	24	$73	Short term program. Benefits from market transformation, or MCS code adoption
LIGHTING AND WATER HEAT RETROFIT	200,000 Homes	1995-2002	14	22	19	$27	Energy Service Charge Based Program
COMMERCIAL BUILDING RETROFIT	55,000 Buildings	1995-2002	75	25	14	$152	Cost share with participant via energy service charge
UTAH RESIDENTIAL MODEL CONSERVATION STANDARDS (LOST OPPORTUNITY)	55,000 Homes	1990-2010	23	41	4	$11	Short term program. Benefits from market transformation, or MCS code adoption
NEW COMMERCIAL BUILDING (LOST OPPORTUNITY)	60,000 Buildings	1990-2010	47	28	13	$162	On-going, utility-financed, lost opportunity acquisition program
INDUSTRIAL PROGRAM	217 Plants	1990-2010	200	18	6	$262	Expert technical assistance, and financing, provided by the utility
NEW RESIDENTIAL MCS (LOST OPPORTUNITY)	94,500 Homes	1990-2010	31	50	8	$29	Short term program. Benefits from market transformation, or MCS code adoption
NEW MOBILE HOME MODEL CONSERVATION STANDARDS (LOST OPPORTUNITY)	37,000 Homes	1995-2010	18	41	0	$0	No utility program. Benefits from market transformation, or MCS code adoption
RESIDENTIAL BUILDING RETROFIT	198,000 Homes	1995-2002	58	40	35	$462	Cost share with participant via energy service charge
NEW MAJOR THERMAL APPLIANCES	250,000 Heat Pump, Solar Water / Solar Space	2000-2010	57	80 TO 120	35	$109	Cost share with participant via energy service charge
			561 MWa			$1,293	

Table 4

DEMAND-SIDE RESOURCES

Pacific and Utah Divisions

Resources	LOW FORECAST MWa	LOW FORECAST TRC	MEDIUM FORECAST MWa	MEDIUM FORECAST TRC	HIGH FORECAST MWa	HIGH FORECAST TRC
Commercial Lost Op.- non PNW	11	15.9	16	24.0	16	18.8
New Appliances Lost Op.	26	17.9	22	18.1	39	17.6
Lights & Water Heater Appliances Retrofit	12	19.2	14	22.0	15	18.2
Commercial Retrofit	75	18.7	75	25.0	77	18.3
New Res.idential MCS Lost Op.- non PNW.	24	20.6	45	20.3	87	20.0
New Commercial Lost Op.	57	22.5	47	21.0	86	20.2
Industrial Program	70	23.8	173	19.0	115	22.4
New Residential MCS Program Lost Op.*	29	31.1	61	27.6	113	28.3
Mobile Home Lost Op.	12	34.6	24	34.3	44	34,5
Residential Retrofitr Program	66	40.9	66	40.9	66	40.9

* assumed in demand forecast

other services to the customer recipients. The programs therefore have a different revenue and price impact than supply resources. Revenue impacts were not considered in the estimates of cost-effectiveness and technical potential described here, since they are cost recovery and pricing issues. The Company is developing a mechanism to mitigate these impacts through an Energy Service Charge (ESC), which also recognizes the specific customer service benefits of programs.

RESOURCE ALTERNATIVES ON THE SUPPLY SIDE

In assessing supply-side resources, the RAMPP process attempted to consider the broadest range of new supplies that the Company could develop. Besides construction of new generating resources, these include a number of specific alternatives for deriving more from the existing resource system. Purchases for which the Company currently has contractual rights are addressed in this category. Purchase opportunities beyond these are also realistic supply alternatives. However, since the Company currently does not have contractual rights, and instead must acquire them from the marketplace, these opportunities are discussed in Marketplace section of this chapter.

Specific Supply Alternatives

Energy amounting to more than 300 average megawatts can be derived from the existing resource system through efficiency improvements, refurbishment, and planning and operating strategies. In addition, up to 375 average megawatts can be acquired through existing contractual arrangements. Estimates of costs, energy and capacity, and some of the key features of these alternatives are summarized in Table 5.

System Efficiencies and Refurbishment

System efficiencies will be developed through several ongoing Company programs. For example, transmission and distribution construction programs involve regular improvement and replacement investments. Often, improved equipment and design techniques can achieve significant economic loss reductions, based on avoided generation cost decisions. Another Company program is aimed at economical capital and O&M improvements to existing hydro facilities. Based on an initial screening that identified potential improvements and priorities, detailed engineering studies are being conducted on a systematic, project-by-project basis. Capital and O&M improvement programs are also expected to derive additional energy from existing thermal generating units. The potential for major refurbishment projects at currently operating generating plants has not been considered at this stage of RAMPP.

One refurbishment alternative specifically included is the Utah Division's Gadsby Plant. Currently on cold reserve, the plant has three units with oil, gas, and/or coal fuel capability. The cost of generation from the plant depends significantly on fuel and operating assumptions. The planning assumption used in the RAMPP process is that Gadsby will be gas fired and operated intermittently, fitting with the nonfirm strategy discussed below. Although coal fired generation would require higher capital expenditures for the refurbishment of some emission controls, the fuel cost could be substantially lower than natural gas or oil. No final decision has been made at this time as to the most economical choice.

TABLE 5

SPECIFIC SUPPLY OPTIONS

	Energy (MWa)	Capacity (MW)	Estimated Cost (mills/kwh)	Timing Constraints	Key Features
System Efficiencies and Refurbishments					
Hydro Generation Improvements	10	20	15 - 20	1990-2008 *	Refurbishments or improvements at existing facilities, may be tied to FERC relisence schedule
Transmission & Distribution Efficiencies	30	30	15 - 20	1990-2008 *	System loss savings from ongoing T&D improvement programs
Voltage Regulation	35	35	5 - 35	1990-2008 *	Estimated customer savings from distribution modifications
Thermal Generation Improvements	15	0	20 - 25	1990-2008 *	Availability improvements from ongoing O&M programs
Gadsby Generating Plant	100	224	20 - 25	1-3 year lead time	Refurbishment for gas fuel, hydro firming operation
Planning and Operating Strategies					
Thermal Maintenance Strategy	125	0	15 - 25	1-2 year lead time	Firming spring maintenance purchases
Specific Contractual Rights					
BPA NR Purchase	200	270	30 - 35	7 year notice required	Purchase under Power Sales Agreement. Renewal of contract after 2001 assumed
WNP3 Exchange	65	164	20 - 30	18 month notice 1996 deadline	Firm winter capacity and energy. Flexible provisions for return, if BPA exercises exchange provision
SCE Energy Withdrawal	108	0	30 - 40	4 year notice, 36 MWa/year no earlier than 1996	Conversion to capacity sale.

* Gradual gains from ongoing programs. Timing may be determined by lost opportunities or other constraints. 5 - 15 year implementation assumed.

Planning and Operating Strategies

Differences in precipitation from year to year cause a significant variability of energy production from hydro generation. Conventional resource planning is based on hydro capability under dry conditions, such that all demands can be met when such conditions arise. On average, under actual operations hydro energy in excess of this firm capability is available. This nonfirm or secondary energy is used instead of operating thermal generation, thus saving fuel expense. Alternatively, the additional system capability is used to make nonfirm sales to other utilities. The Company is often a purchaser of nonfirm energy in the region, as well as a seller in wholesale markets. The difference between firm and average capability of Company's hydro resources is about 150 average megawatts. For the region, this difference is about 4,000 average megawatts.

Opportunities for realizing greater benefit from nonfirm hydro capability are called nonfirm strategies. In concept, this means acquiring a contingency resource for use during critical hydro conditions, but not having to utilize it in most cases, since better hydro conditions predominate. Economics can be favorable when lower fixed cost contingency resources are available, even if their operating costs are relatively high. As discussed above, refurbishment of the Gadsby plant for operation with oil or gas fuel would provide a hydro firming resource. Gas and oil fired combustion turbines are another such resource; they are discussed in the following section on new generating resources.

A closely related strategy involves maintenance outages for existing thermal generating units. Typically, annual overhauls leave a generating unit out of service for about four weeks. In the Pacific Northwest, such outages are scheduled as frequently as possible during the spring season, because of lower loads and the availability of more hydro generation during the high runoff. Nonfirm energy is available, in part, because of water releases from Columbia and Snake River reservoir storage to aid anadromous fish passage. To the extent that normal thermal maintenance schedules result in firm energy deficits during this season, it is possible to treat nonfirm energy, both purchases and from Company's system, as firm resource. The backup resource, in this case could come from two sources. First, under contingency conditions, thermal overhauls could be postponed or foregone. Alternatively, contingency purchases could be arranged with utilities that have older or underutilized oil or gas generating resources . Such purchases would have low fixed or reservation charges, but high operating costs.

Although much of the Company's thermal generation is outside of the Pacific Northwest and not recognized directly in the Pacific Northwest Coordination Agreement, there may Coordination Agreement implications from nonfirm strategies. These are being examined by the Company, as well as other parties in the Pacific Northwest.

Specific Contractual Rights

Two of the Company's contractual alternatives involve rights to purchase from BPA. One alternative is the WNP-3 Exchange, giving the Company the right to purchase about 65 average megawatts of energy and 164 megawatts of capacity from BPA. This right must be exercised by 1996, but requires only 18 months advance notice from the Company.

The Company's other right to purchase from BPA is under a power sales agreement, as authorized by the Northwest Power Act. Purchases under this contract would be at BPA's New Resource (NR) rate. BPA is authorized under the act to acquire resources to supply such purchases, subject to the terms of the contract governing timing and amounts. Nothing in this contract constrains BPA's discretion in acquiring resources nor its latitude in setting rates. This means that there are uncertainties as to the amounts that may be made available and future prices. BPA forecasts future rates using computer models that assume the region's future supply sources are primarily new thermal generation. The current NR rate forecast assumes BPA will not be requested to supply any of the region's investor owned utility requirements. Studies indicate, however, that the NR rate would not be appreciably different from the current forecast if 200-300 average megawatts of investor owned utilities were supplied out of the NR rate pool.

One other contractual right available to the Company is the right to convert its existing firm sale to Southern California Edison to an exchange or a capacity sale, thereby reducing its net energy obligation by up to 108 average megawatts.

New Generation Sources

Besides the specific supply alternatives addressed above, the RAMPP process reviewed a broad range of generation alternatives as potential new supply sources. New generation alternatives are summarized in Table 6. As compared to the specific supply sources, a generic approach to cost estimates was required for new generation alternatives. Based on surveys from a variety of sources, and on specific Company experience, estimates were made for costs, timing and operating assumptions for a variety of generating technologies and sizes. Many factors such as: costs, impact and availability factors, licensing requirements, and transmission implications, are site specific. In addition, actual costs depend on how generating resources are actually operated as part of the power system. Cost estimates are therefore general, and aimed at providing a relative perspective.

THE ENERGY MARKETPLACE

The marketplace can be expected to provide a significant portion of the Company's future new resource needs. Resources can be acquired through the purchase of capacity and energy from western US and Canadian utilities, through power purchases from - and possible ownership of - cogeneration facilities, and through purchases from non-utility generation (NUG) sources. In addition, the Company anticipates that the marketplace will continue to provide the incentives for advancement of new energy efficiency and alternative generation technologies over the next twenty years.

Although all new sources have some associated uncertainties, the marketplace alternatives are inherently the least definable alternatives. At the same time, the diversity of sources in the marketplace tends to mitigate any potential risks of including marketplace alternatives among future sources. One effective way of verifying the availability and cost of marketplace resources is through a competitive bidding process. Although acquisition of known resources need not necessarily occur through a bidding process, bidding has the potential to uncover heretofore unknown alternatives.

TABLE 6

ESTIMATED GENERATING RESOURCE COSTS

RESOURCE	SIZE (MW)	CAP FACTOR (%)	FUEL	RANGE OF ESTIMATED POWER COST LOW (m/kWh)	EXPECTED (m/kWh)	HIGH (m/kWh)
Conventional Coal - wet cooling	50	70	Coal	48.3 a	52.3 a	56.3 a
	250	70	Coal	35.9 a	40.0 a	44.1 a
	500	50	Coal	39.0 a	43.8 a	48.6 a
Conventional Coal - dry cooling	315	70	Coal	35.9 a	40.0 a	44.1 a
Atmospheric Fluidized Bed	50	70	Coal	48.3 a	59.5 a	70.7 a
	100	70	Coal	41.2 a	48.5 a	55.8 a
	250	70	Coal	37.4 a	42.6 a	47.8 a
Pressurized Fluidized Bed	50	70	Coal	47.6 a	58.7 a	69.8 a
	100	70	Coal	40.7 a	48.0 a	55.2 a
Integrated Gasification Combined Cycle	50	70	Coal	75.9 a	86.9 a	97.9 a
	100	70	Coal	63.4 a	72.6 a	81.7 a
	250	70	Coal	50.4 a	58.3 a	66.3 a
	500	70	Coal	37.4 a	42.9 a	48.5 a
Simple Cycle Gas Turbine	50	50	Gas	57.0	59.5	62.1
	50	50	Oil	76.1	78.6	81.1
	100	50	Gas	51.1	52.7	56.0
	100	50	Oil	67.6	69.1	72.5
Combined Cycle Gas Turbine	50	50	Gas	61.5	66.0	68.2
	50	50	Oil	75.0	79.5	81.6
	250	50	Gas	45.1	47.5	49.8
	250	50	Oil	57.0	59.4	61.7
Conventional Gas/Oil	50	50	Gas	61.8	68.7	75.6
	50	50	Oil	75.8	82.8	89.6
	500	50	Gas	55.4	60.1	64.8
	500	50	Oil	69.3	74.0	78.7
Fuel Cell	10	70	Gas	42.1	76.3	91.0
	10	70	Oil	53.7	87.9	102.5
Biomass (wood)	25	70	Wood	60.9	67.7	74.5
Wind	5	50	na	38.0	48.4	58.7
Solar	50	50	na	60.6	81.8	138.5
Geothermal - binary	50	70	na	34.1	45.5	48.9
Geothermal - flash	10	70	na	48.5	57.0	64.9
	50	70	na	33.8	40.8	47.1
Nuclear	500	70	na	47.3	77.7	99.3
Hydroelectric - conventional	10	50	na	43.2	47.3	67.2
	16	50	na	32.5	42.5	52.1
Hydroelectric - pumped storage	1050	30	na	60.8	47.5	93.4

NOTES:

All costs shown in levelized 1989 $'s.

a. Exclusive of coal transportation costs.

b. Exclusive of transmission investment requirements

Purchases from Other Utilities

Substantial surplus resources currently exist in some areas of the WSCC. Even as surpluses diminish over time, the availability of these purchases in the long-term can be secured by relying on load and resource diversities between the Company and supplying utilities. Estimates of future costs of utility purchases were based on reviews of operating costs of incremental resources, and include pricing margins reflective of the current wholesale marketplace. While the availability of purchases throughout the WSCC is potentially very large, amounts of purchases included as potential new sources for the Company were limited to a reasonable fraction of load growth, in consideration of the future transfer capability of the Company's existing transmission system.

Cogeneration

Cogeneration represents another viable marketplace option. The Company can take advantage of the inherent total energy efficiency opportunities that exist at certain large industrial locations, either by power purchases or ownership. Many large industrial customers have historically invested in on-site electrical generating equipment and operating it successfully for many years. Cogeneration potential at existing customers' facilities was estimated using a typical facility analysis for all customers with demand larger than one megawatt. That analysis took into account the cost of generation facilities roughly matched to the customer's process heat requirements, the cost and availability of any incremental fuel required by the addition of electricity generation, and the customers likely internal value of capital financing.

Cogeneration potential at large industrial locations could represent a significant bypass risk to the Company. The economics of industrial cogeneration are influenced to a large degree by the price of purchased electricity relative to the price of alternate fuels and suppliers. To the extent that the Company's prices fail to remain competitive in relation to these other factors, and that sufficient action has not occurred to secure the purchase or ownership of the cogeneration facility, then the utility risks losing that industrial facility as a retail customer. The implications of substantial customer loss have been examined under one of the alternative scenarios, and are discussed in Chapter 6 of this report.

Purchases From Other Non-Utility Generation Sources

Non-utility generation refers to electrical generation by entities other than the Company's customers that could be made available for purchase through direct negotiation or through some form of bidding process. The Company views non-utility generation as a potentially viable supply option so long as system requirements are met, and the price of the output is competitive with that obtainable from other supply, or demand-side, sources.

Taken together, the Company's marketplace supply options account for over 800 average megawatts of new energy supply that can be acquired at a real levelized life cycle cost of 40 mills/kwh or less. In addition to the above mentioned supply options, technological advances are continuing in alternative generation technologies such as wind-powered electricity generation, photovoltaics, and fuel cells.

PORTFOLIO OF FUTURE SOURCES

The supply, demand and marketplace alternatives constitute a portfolio of sources that can be employed in the future. These alternatives cover a range of costs, when measured on a TRC basis. If the TRC measure were perfect, and this cost measure were the only consideration, it would be relatively straightforward to specify a plan, starting from the lowest cost alternative, and working down the list. Although this is implication of the term "least cost planning", in practice the most effective use of these alternatives depends on a complex set of characteristics. Planning their use is necessarily an art as much as a science. Assembling the desirable alternatives into a portfolio is the first step in that complex planning process.

The portfolio of alternatives is a summary of the quantities, costs, constraints and other characteristics of sources that can be relied upon in the future. Inclusion in the portfolio means that an alternative is likely to be available and cost competitive in a short, medium or long-term time frame, if needed. The Company's portfolio is summarized in Table 7. Included in this portfolio are alternatives described in Chapter 4 with life cycle costs less than or equal to conventional baseload coal generation. This table also summarizes some of the other characteristics that constrain new sources or that must be taken into account in the decisions that will initiate them.

Although no precise equation can reduce all important characteristics of any alternative into a single dimension, the cost measure used in Table 7 to describe each alternative (TRC) can serve as a legitimate, general guide to priorities. At the same time, it must be recognized as an incomplete and inexact measure of costs. A more comprehensive cost measure would take into account the total system cost, as affected by each alternative. Since the cost of an alternative depends, in part, on the manner in which it is integrated into the system, and the system operating costs depend on which alternatives are employed. Moreover, these system costs depend on the level of demand that actually emerges, and on a range of other operating assumptions such as: hydro conditions, transmission constraints, and nonfirm prices.

Inevitably, it is impossible to precisely predict the system costs of any alternative at the outset. Nevertheless, other characteristics listed in the portfolio can aid in a planning and decision making framework. Size in relation to need, lead time and ability to adjust timing are examples. Some alternatives are less risky than others, in the sense that the costs incurred if they are developed ahead of need are lower than the TRC. Combustion turbines are an example. Others are lost opportunities, meaning that they are not available after a specific time, or they are much more costly if not acquired within a certain time frame. All of these characteristics can be weighed in a decision, but they are not measured by the TRC estimate.

Consideration of External Costs

External costs are those that are borne by society but are not adequately reflected in costs for internal decision making. The Oregon Public Utility Commission has directed that the Company consider external costs in the development of its least cost plan. Although the Commission provided no specific details as to how such consideration is to be put into practice, from a power planning perspective, there are two areas where such consideration can be reflected. One is whether or not the relative priority would change between new sources included within the supply and demand-side portfolios, if external costs are included in the comparison. Second is whether new sources, such as energy efficiency programs, are lower

TABLE 7

RAMPP NEW SOURCE PORTFOLIO

	Energy Availablity over Planning Horizon (MWa)							
	Low	Med	High	Estimated Total Resource Cost	Features	Timing	Oper-ability	Potential Externalities
Energy Efficiency Programs	360	440	600	18 - 40	Pilot, lost opportunity and aquisition programs	1990-2008 *	none	Indoor air quality
System Efficiency Improvements	100	100	100	5 - 35	Improvements to existing hydro, T&D and thermal generation facilities	1990-2008 *	good	Site modifications Air emissions from thermal improvements
Planning and Operating Strategies	300	300	300	15 - 30	Thermal maintenance strategies, hydro firming with Gadsby and CTs	short notice 1-4 year lead	moderate good	Site modifications Air emissions from thermal contingencies
Purchases and Contractual Rights	350	350	700	20 - 40	Contractual rights from BPA, purchases from existing WSCC generation (potential lost opportunities) or new independent sources	varies	mod-good	Air emissions if thermal derived purchases
Cogeneraton	140	280	380	30 - 40	Potential from customer base; purchase or ownership alternatives; potential lost opportunities	1-4 year lead	low	Primarily biomass derived fuels; potential air emissions from incremental gas burned
Generating Resources - Renewables	120	120	120	40 - 50	Geothermal and wind sources.	3-6 year lead	mod-good	Site modifications
Generating Resources - Thermal	600	600	600	40 - 50	Combined cycle combustion turbines, small mine-mouth coal in rocky mountain area	5-10 year lead	good	Site modifications Air emissions from thermal generation

* Gradual gains from ongoing programs. Timing may be determined by lost opportunities or other constraints. 5 - 15 year implementation assumed for system efficiencies. Customer efficiency programs depend on program design and implementation, but can be varied according to need.

cost than existing generation sources, if external costs are included in the comparison.

The Company's approach has been to identify major environmental concerns that would have an impact upon resource acquisition decisions, quantify externalities in terms of physical units, and identify the range of possible costs that could be attributed to such externalities. Table 8 summarizes the assumptions regarding primary emissions from typical new generation sources. The broader range of externalities and their costs are discussed in greater detail in the Technical Volume of this report.

Although the sources discussed in Volume 2 suggest a broad range of uncertainty, the emissions associated with fossil fuel combustion sources appear to be the most significant. The greatest uncertainty in this area is the cost of carbon dioxide emissions from their contribution to potential global warming. External costs from combustion emissions of from a few mills/kwh to upwards of fifteen mills/kwh are possible. For the purpose of comparison, a value of 10 mills/kwh can be used to reflect the potential external costs of combustion sources. A 10 mills/kwh external cost would cause clear-cut changes in the new source portfolio in only a few instances. For example, it could cause a renewable generation resource to be favored over a fossil fuel generating resource, since the cost of these new sources are both estimated to be in the 40-50 mills/kwh life cycle cost range. On the other hand, it would not cause existing coal generating sources, whose operating costs are in the range of 10-15 mills, to be replaced by new sources identified in the portfolio. Finally, such external costs would not cause the estimates of cost-effective energy efficiency to change substantially, since the only technologies not included in the new source portfolio had costs above those in the portfolio by a margin substantially greater than the 10 mills/kwh figure.

Table 8

GENERIC GENERATING FACILITY EMISSION LEVELS

	SULFUR DIOXIDE			NITROGEN OXIDES			CARBON DIOXIDE		
	lb/MMBtu (Input)	lb/kW - hour	Tons / Year	lb/MMBtu (Input)	lb/kW - hour	Tons / Year	lb/MMBtu (Input)	lb/kW - hour	Tons / Year
Conventional Coal 500 MW	0.42	0.005	9,006	0.41	0.005	8,790	214	2.5	4,588,404
Atmospheric Fluidized Bed 100 MW	0.36	0.004	1,524	0.18	0.002	748	265	2.9	998,640
Pressurized Fluidized Bed 100 MW	0.14	0.003	1,050	0.30	0.006	2,250	89	1.9	665,000
Integrated Coal Gassification 100 MW	0.01	0.000	16	0.08	0.001	230	76	1.9	663,760
Oil Fired Turbine 100 MW	0.06	0.001	228	1.00	0.010	3,800	149	1.6	560,000
Gas Fired Turbine 100 MW	0.00	0.000	0	0.70	0.007	2,620	121	1.3	455,000
Combined Cycle Turbine (Oil) 250 MW	0.06	0.001	423	1.60	0.010	10,925	138	1.1	962,500
Combined Cycle Turbine (Gas) 250 MW	0.00	0.000	0	1.00	0.006	6,520	112	0.9	787,500
Wood Fired Power Plant 25 MW	0.00	0.000	0	0.16	0.002	354	165	2.4	219,551

SOURCES RELIED UPON UNDER RANGE OF FUTURES

Alternatives in the Company's new source portfolio can be thought of as building blocks. They can be put together, building on the existing resource and customer base, in a variety of configurations. How they will actually be used will depend, of course, on how the future unfolds, and on the decisions made in anticipation of the future or in response to actual events. While it is impossible to specify now how the portfolio would be used under every conceivable future, it is reasonable to test it under a range of futures. Such an examination sheds light on such issues as: do the alternatives provide sufficient energy and capacity for the future, are they flexible enough, are they economical, and what are the immediate decisions with regard to their use are all appropriate questions at this stage.

In this section, the use of the new source portfolio is demonstrated under a range of alternative futures. While each of the cases described can be thought of as a "resource plan", none pretend to predict the future. Neither are they the result of a cost optimizing exercise, rather they are aimed at identifying valuable strategies for managing the future, and addressing the broader planning questions posed above.

METHODS

Each of the cases was assembled and analyzed in the following fashion. For each of the economic growth cases and alternative scenarios, a "resource plan" was described, and then the results of the plan were analyzed in terms of system costs and revenue requirements on a year-by-year basis.

In assembling the plans for each case, resources were deployed such that total resources were in balance with annual capacity and energy demands. Two other primary criteria used in selecting alternatives from the portfolio were relative cost and timing constraints. Prescience was assumed at this stage, in the sense that the plans were assembled with full knowledge of which future was being tested. Other myopic cases were also examined to test the flexibility of the portfolio by simulating the effect of believing one future to be unfolding, only to discover another some years later.

Consequences of any plan were simulated using a power cost model to quantify total operating costs, considering not only fuel and other operating costs, but also nonfirm purchase, sales, and wheeling effects, over the range of possible water conditions. The resulting expected annual operating costs, together with new capital costs, were then used in calculations representing the financing, accounting, and cost recovery treatment of the resource decisions and operations, in the form of a simplified revenue requirements model. This model gives representative, year by year results as measured from various perspectives. Results include annual revenue requirements, cost per unit of energy sold, average customer's annual cost of electricity, and average customer's own energy efficiency investments. Table 9 defines the key outputs of this method.

A number of simplifying assumptions are required to arrive at these results. Among other simplifications, the revenue requirements model ignores jurisdictional allocations, customer classes, regulatory decisions on recoverability of investments or expense, and the BPA residential exchange. While not absolute predictions, the results do serve as reasonable relative indicators over the plan horizon. From this standpoint, it is not so important how many

Table 9
Definition of Key Results

1	**System Load (MWa)**	*Forecast (before Conservation)*
2	Total Conservation	*Total Conservation in resource plan*
3	System Load net of Conservation	*Line 1 minus line 2*
4	**Energy Sales after Conservation**	*Line 3 net of losses*
5	**Total Customers (000's)**	*Forecast*
6	**Net Electric Plant (M$)**	*Includes net Conservation assets*
7	**Net Conservation Assets**	
8	**General Inflation Rate**	
9	**Operating Revenues (M$)**	*From financial analysis*
	Nominal	
	Real	
	NPV (11.47% discount rate)	*Discounted at utilities cost of capital*
	Average Growth	
	Nominal	
	Real	
10	**Base Unit Cost (mills/kwh)**	*Revenue Requirements divided by energy sales net of conservation*
	Nominal	
	Real	
	Average Growth	
	Nominal	
	Real	
11	**Average Customer Bill ($)**	*Revenue Requirements divided by number of customers*
	Nominal	
	Real	
	NPV (11.47% discount rate)	
	Customer Cost (M$)	
12	**Levelized Customer Cost (M$)**	*Conservation undertaken by customer with no Company involvement*
	(30 years at a 13.47% discount rate)	
	NPV (11.47% discount rate)	
13	**Energy Services Charge (M$)**	*Charges to customer for involvement in company sponsored conservation programs*
	NPV (11.47% discount rate)	
14	**Total Resource Cost (M$)**	*Sum of Revenue Requirements, levelized Customer Costs, and Energy Service Charges*
	Nominal	
	Real	
	NPV (11.47% discount rate)	
	Average Growth	
	Nominal	
	Real	
15	Mills / KWh	*Total Resource Cost divided by energy sales net of Conservation*
	Nominal	
	Real	
	Average Growth	
	Nominal	
	Real	

millions of dollars in revenue requirements or mills/kwh costs are shown in any year, rather how those values change over time.

RESULTS

Although results of these analyses can be examined in excruciating detail, two types of broad overviews are most useful. One perspective is a comparison of the resources deployed throughout the planning horizon in each of the cases. The other is to look at how key results change through time for each case.

The results presented in this final RAMPP report are slightly different from those presented in the draft document. The only basic change was the correction of the coal price forecast that was utilized in determining the fuel cost of existing generation. Upon review of the input assumptions it was discovered that the future stream of coal prices was growing at the same rate as natural gas prices. The proper long-run rate of growth in coal prices, as projected by Data Resources, is roughly one-half the size of the rate of growth of natural gas prices.

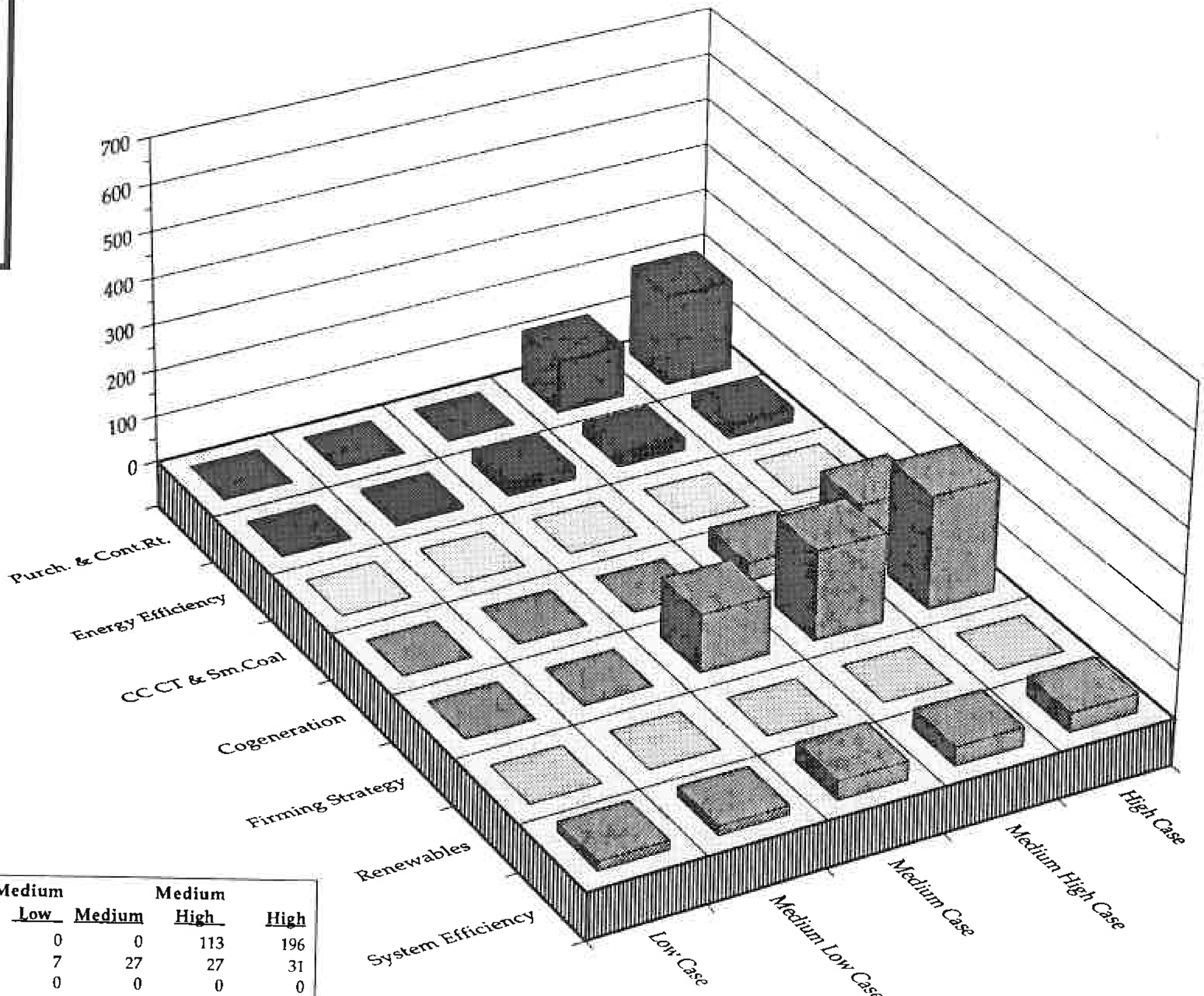
The resource perspective is depicted in Figures 3-8, showing the energy derived from new sources, as grouped into several categories, for each of the economic growth cases examined. For the key results perspective, Tables 10-14 summarize beginning and ending results. More detailed results are compiled in the Technical Documentation volume of this report.

Comparing resources added over the planning horizon in Figure 5, one can see the need for few new sources under a low economic growth case, primarily energy efficiency programs, system efficiencies and nonfirm strategies. In the high economic growth case, a variety of categories contribute, including purchases and contractual rights, energy efficiency programs, cogeneration, firming strategies, and some new generation, using combined cycle combustion turbines, a small coal unit, and renewable resources. It is also interesting to note that under medium or higher economic growth, no single category of new source alternatives is sufficient to meet all new needs over the entire planning horizon. In addition, even in a shorter time frame, it is necessary to be developing alternatives with different costs. For example, by 1993 under medium high growth, purchases and cogeneration sources are relied upon, even though all energy efficiency programs, some of which have lower costs, have not achieved their full potential. This is a result of the timing constraints of such programs, as well as the fact that some of the potential is a result of growth that has not yet occurred as of that time.

Direct comparisons of resource additions between cases is enlightening. The key economic results, on the other hand, are not directly comparable between cases in the same fashion. This is because the cases represent different economic growth conditions, not decisions by the Company to be in one case or another. With different underlying inflation assumptions, cost of capital, and discount rates, the key results are not directly comparable. (Please refer to Table 1 for the compilation of those assumptions.) What is enlightening in examining these key results, however, is the relative stability in costs, adjusted for inflation. Per unit costs are indicative of average prices, and these are flat or declining in real terms under medium growth over the planning horizon. Even the medium high and high growth conditions show only very modest real increases, in spite of the substantial resource additions.

Use of new sources under each of the three alternative scenarios, one of which -- global warming -- consists of two separate alternate approaches, is depicted in Figures 9-12. Figure 13 compares the total new source additions over the planning horizon for the scenarios with

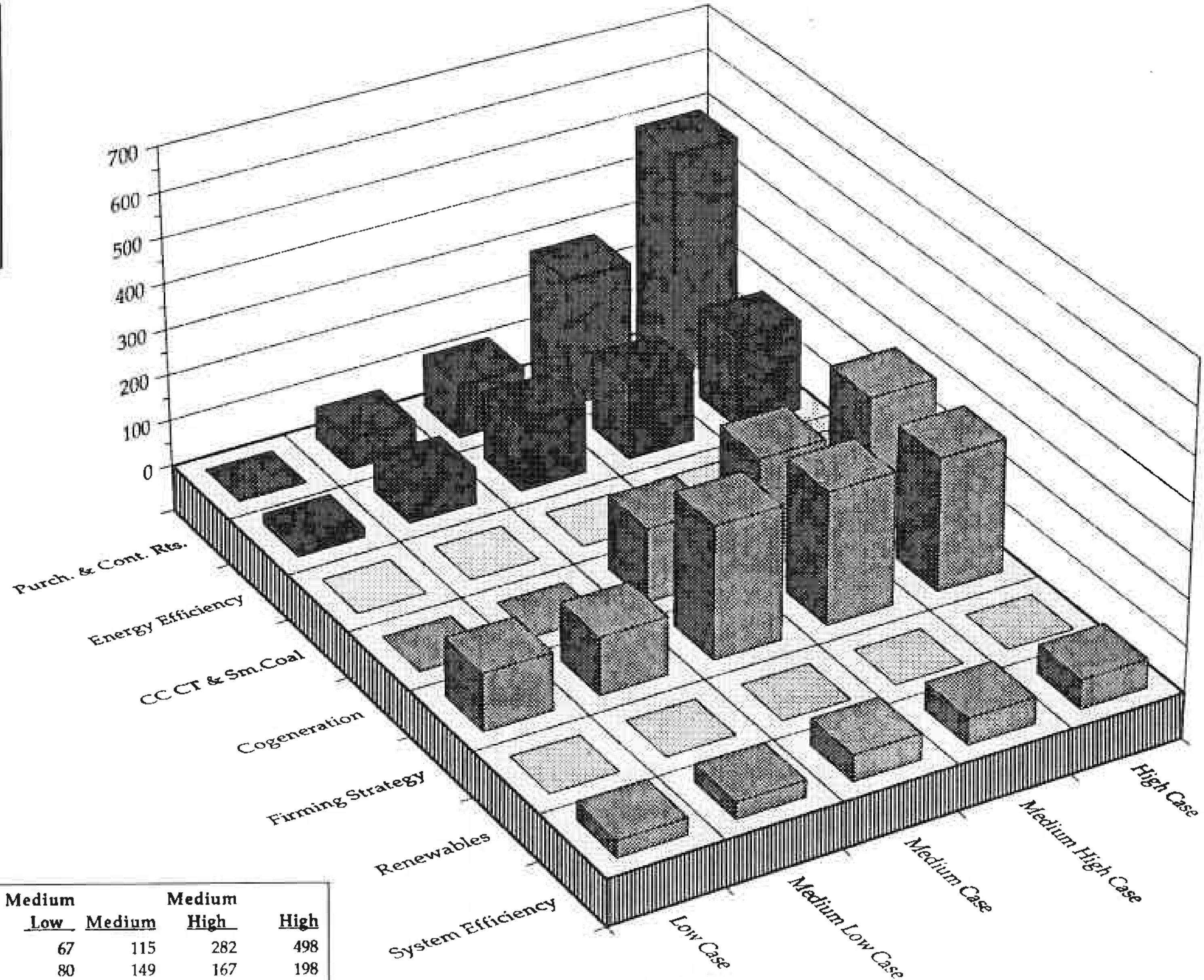
Figure 3
Resource Additions (in MWa) 1989-1993



Average MW's	Low	Medium Low	Medium	Medium High	High
Purch. & Cont.Rt.	0	0	0	113	196
Energy Efficiency	2	7	27	27	31
CC CT & Sm.Coal	0	0	0	0	0
Cogeneration	0	0	0	40	100
Firming Strategy	0	0	125	192	244
Renewables	0	0	0	0	0
System Efficiency	20	20	41	41	41
Total	**22**	**27**	**193**	**412**	**612**

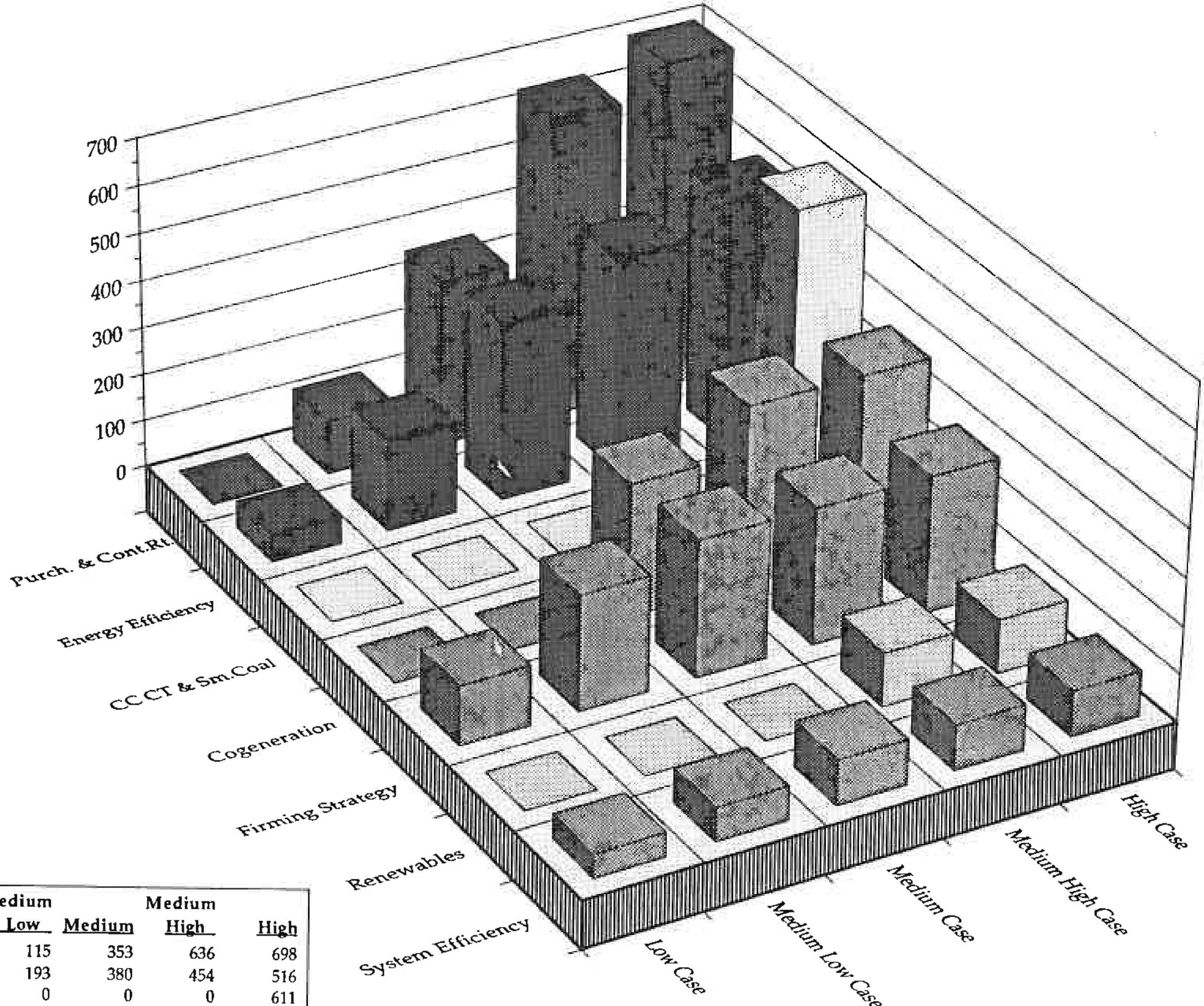
Figure 4

Resource Additions (in MWa) 1989-1998



Average MW's	Low	Medium Low	Medium	Medium High	High
Purch. & Cont. Rts	0	67	115	282	498
Energy Efficiency	22	80	149	167	198
CC CT & Sm.Coal	0	0	0	0	0
Cogeneration	0	0	160	240	300
Firming Strategy	125	125	289	289	289
Renewables	0	0	0	0	0
System Efficiency	37	37	58	58	63
Total	184	309	771	1034	1347

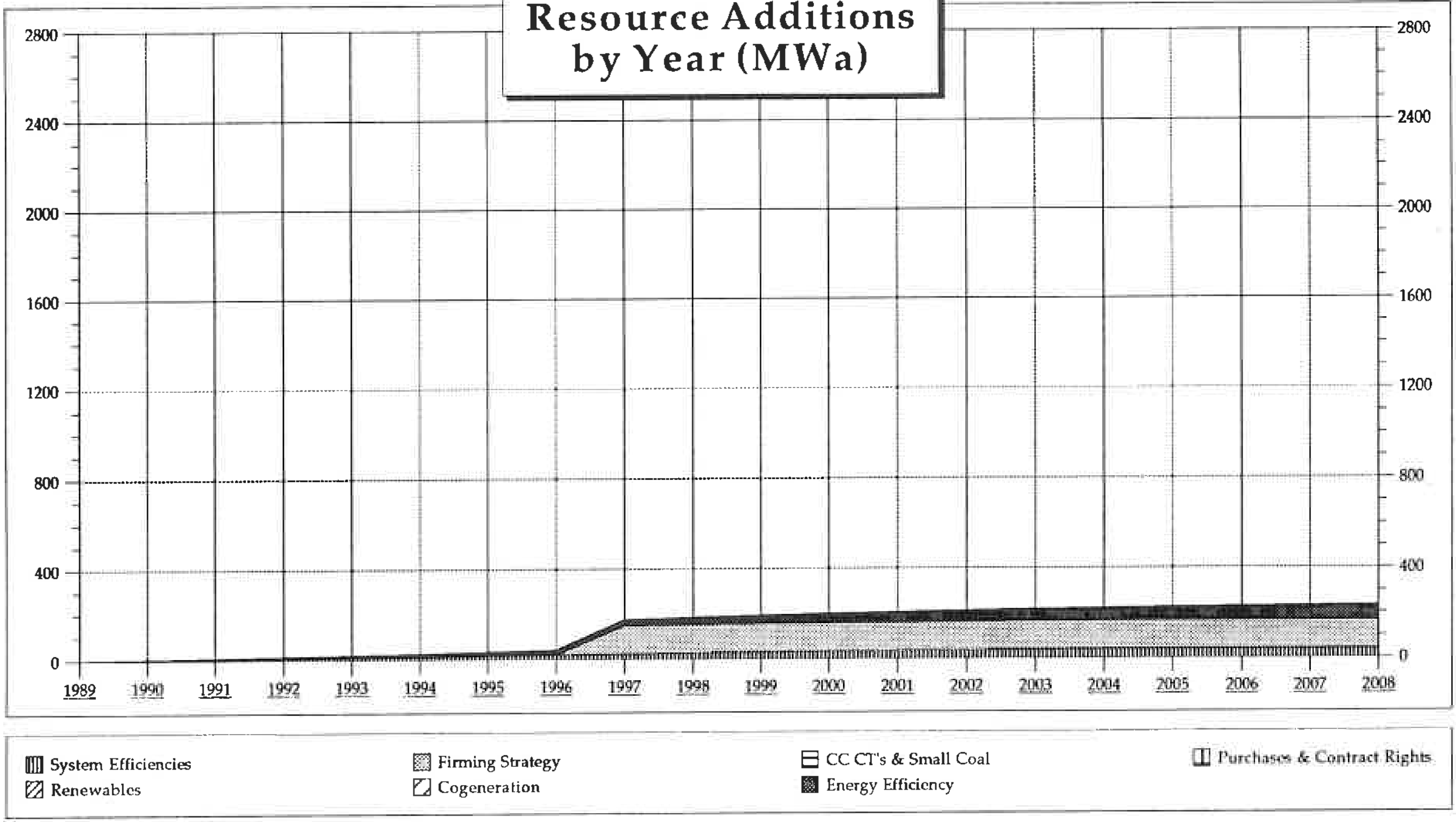
Figure 5
Resource Additions (in MWa) 1989-2008



Average MW's	Low	Medium Low	Medium	Medium High	High
Purch. & Cont.Rt.	0	115	353	636	698
Energy Efficiency	57	193	380	454	516
CC CT & Sm.Coal	0	0	0	0	611
Cogeneration	0	0	280	380	380
Firming Strategy	125	244	289	289	289
Renewables	0	0	0	114	114
System Efficiency	50	71	96	96	96
Total	232	622	1396	1969	2703

Figure 6

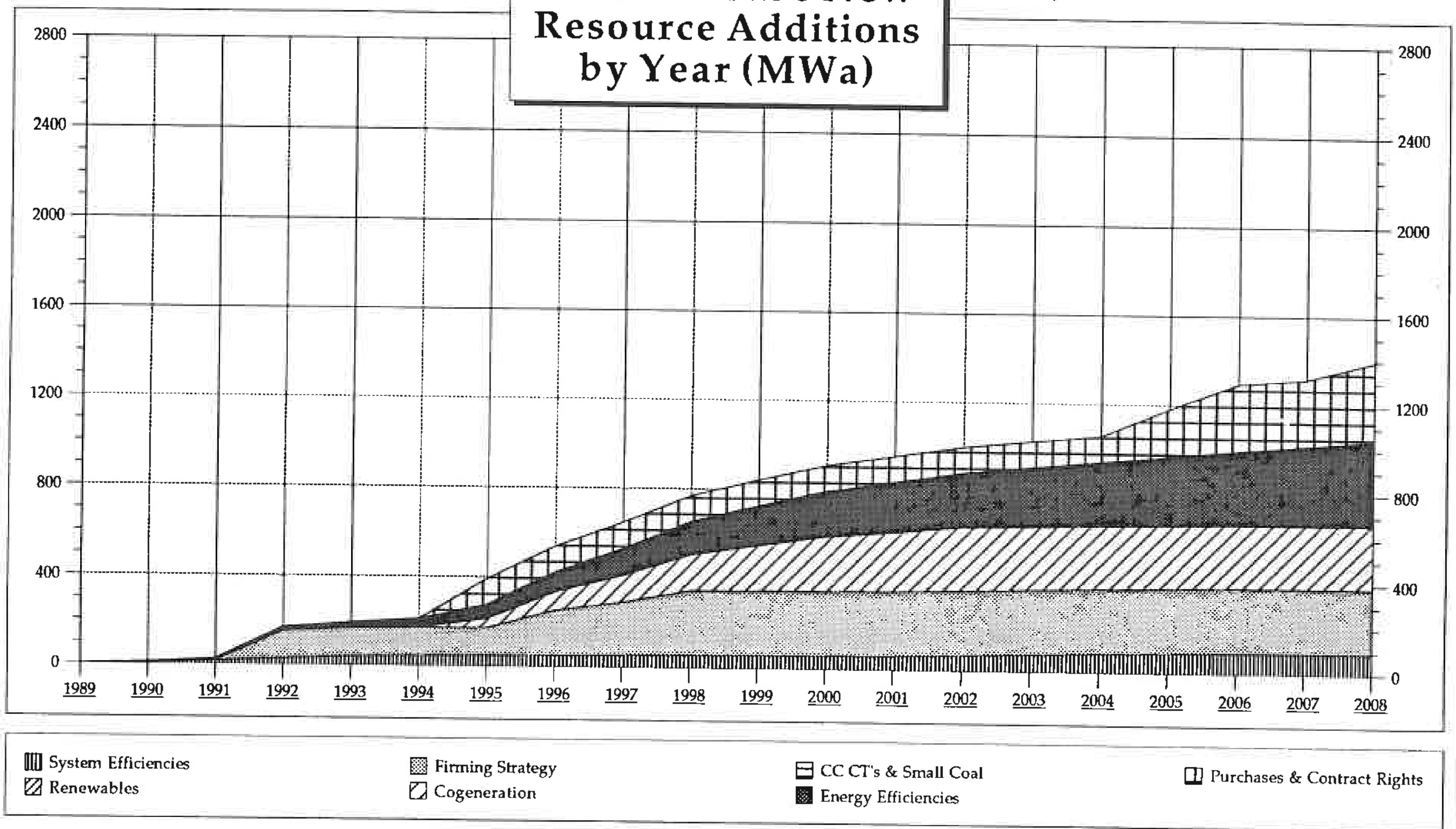
Low Case New Resource Additions by Year (MWa)



Average MW's	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiencies	0	3	6	9	12	15	18	21	24	27	30	32	34	36	38	40	40	40	40	40
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firming Strategy	0	0	0	0	0	0	0	0	125	125	125	125	125	125	125	125	125	125	125	125
Cogeneration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC CT's & Small Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	0	2	4	7	10	13	17	21	27	32	37	41	48	50	54	57	59	62	64	67
Purchases & Contract Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Totals	0	5	10	16	22	28	35	42	176	184	192	198	207	211	217	222	224	227	229	232

Figure 7

Medium Case New Resource Additions by Year (MWa)

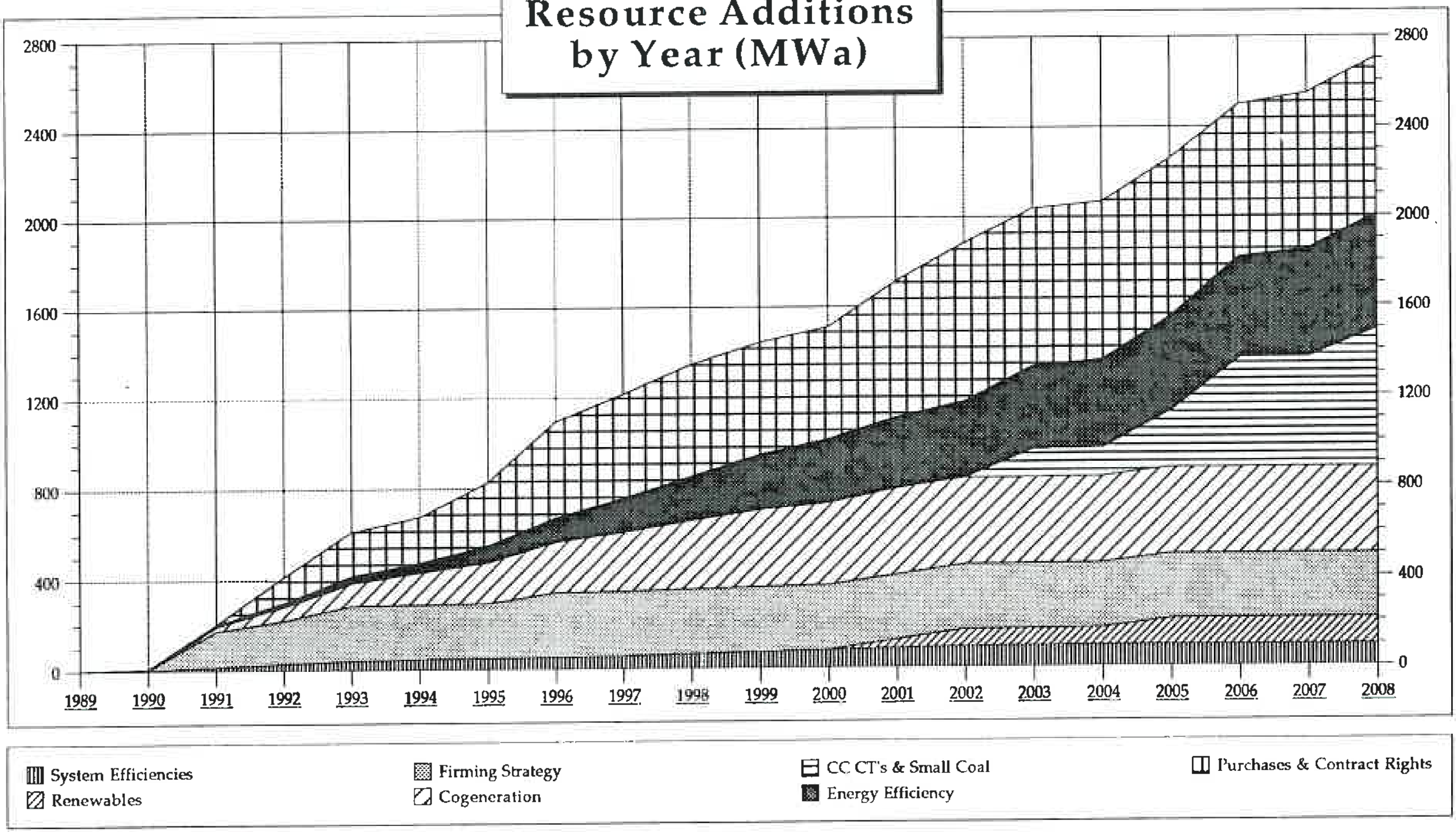


Average MW's	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
System Efficiencies	0	5	17	29	41	46	49	52	55	58
Renewables	0	0	0	0	0	0	0	0	0	0
Firming Strategy	0	0	0	125	125	125	125	203	237	289
Cogeneration	0	0	0	0	0	0	40	80	120	160
CC CT's & Small Coal	0	0	0	0	0	0	0	0	0	0
Energy Efficiencies	1	4	9	17	27	40	65	91	120	149
Purchases & Contract Rights	0	0	0	0	0	0	115	113	117	115
Totals	**1**	**9**	**26**	**171**	**193**	**211**	**393**	**539**	**648**	**771**

Average MW's	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiencies	61	63	65	72	79	86	91	96	96	96
Renewables	0	0	0	0	0	0	0	0	0	0
Firming Strategy	289	289	289	289	289	289	289	289	289	289
Cogeneration	200	240	260	280	280	280	280	280	280	280
CC CT's & Small Coal	0	0	0	0	0	0	0	0	0	0
Energy Efficiencies	180	205	227	246	266	286	308	332	356	380
Purchases & Contract Rights	115	115	115	115	115	115	215	298	298	353
Totals	**844**	**911**	**955**	**1001**	**1028**	**1055**	**1183**	**1294**	**1318**	**1396**

Figure 8

High Case New Resource Additions by Year (MWa)



Average MW's	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
System Efficiencies	0	5	17	29	41	46	49	52	55	63	71
Renewables	0	0	0	0	0	0	0	0	0	0	0
Firming Strategy	0	0	158	192	244	244	244	289	289	289	289
Cogeneration	0	0	20	60	100	140	180	220	260	300	340
CC CT's & Small Coal	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	1	4	10	19	31	46	75	109	151	198	246
Purchases & Contract Rights	0	0	0	115	196	200	282	426	462	498	498
Totals	**1**	**9**	**205**	**415**	**612**	**676**	**829**	**1096**	**1216**	**1347**	**1443**

Average MW's	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiencies	78	85	92	94	96	96	96	96	96
Renewables	0	38	76	76	76	114	114	114	114
Firming Strategy	289	289	289	289	289	289	289	289	289
Cogeneration	360	380	380	380	380	380	380	380	380
CC CT's & Small Coal	0	0	0	125	125	250	486	486	611
Energy Efficiency	285	316	340	367	394	423	453	484	516
Purchases & Contract Rights	498	606	706	706	706	706	679	698	698
Totals	**1510**	**1713**	**1882**	**2036**	**2065**	**2257**	**2496**	**2546**	**2703**

Table 10

Summary Of Results

Low Case

	1989	2008	growth rate
Total Gross Electric Plant (M$)	7228.5	15191.6	
Gross Conservation Assets	*0.1*	*359.5*	
Total Net Electric Plant (M$)	5283.6	7549.4	
Net Conservation Assets	*0.1*	*252.8*	
Operating Revenues (M$)			
Nominal	1886.0	4297.0	4.43%
Real	1886.0	1125.8	-2.68%
NPV (13.13% discount rate)	18201.4		
Base Unit Cost (mills/kwh)			
Nominal	49.2	100.9	3.85%
Real	49.2	26.4	-3.23%
Average Customer Bill ($)			
Nominal	1546.2	3051.0	3.64%
Real	1546.2	799.3	-3.41%
NPV (13.13% discount rate)	16381.8		
Levelized Customer Cost (M$)			
(30 years at a 15.13% discount rate)	0.0	24.7	
NPV (13.13% discount rate)	28.7		
Energy Services Charge (M$)	0.0	38.0	
NPV (13.13% discount rate)	55.9		
Total Resource Cost (M$)			
Nominal	1886.0	4359.7	4.51%
Real	1886.0	1142.2	-2.60%
NPV (13.13% discount rate)	18286.0		
Per Unit TRC (mills / kwh)			
Nominal	49.2	101.1	3.86%
Real	49.2	26.5	-3.21%

Emissions Data	Total Change in Emissions/MWH 1989 - 2008	Change in Total Emissions per Year 1989 - 2008
SO_2	87.8%	-0.08%
NO_x	87.8%	-0.08%
CO_2	88.6%	-0.03%

Table 11

Summary Of Results

Medium - Low Case

	1989	2008	growth rate
Total Gross Electric Plant (M$)	7230.0	16026.0	
Gross Conservation Assets	*1.1*	*964.3*	
Total Net Electric Plant (M$)	5284.6	8190.9	
Net Conservation Assets	*1.1*	*687.8*	
Operating Revenues (M$)			
Nominal	1886.9	4759.7	4.99%
Real	1886.9	1247.0	-2.16%
NPV (13.13% discount rate)	18773.8		
Base Unit Cost (mills/kwh)			
Nominal	49.2	107.1	4.18%
Real	49.2	28.1	-2.91%
Average Customer Bill ($)			
Nominal	1528.1	2975.9	3.57%
Real	1528.1	779.7	-3.48%
NPV (13.13% discount rate)	15766.1		
Levelized Customer Cost (M$)			
(30 years at a 15.13% discount rate)	0.0	50.2	
NPV (13.13% discount rate)	55.1		
Energy Services Charge (M$)	0.0	109.0	
NPV (13.13% discount rate)	131.0		
Total Resource Cost (M$)			
Nominal	1886.9	4918.9	5.17%
Real	1886.9	1288.7	-1.99%
NPV (13.13% discount rate)	21441.7		
Per Unit TRC (mills / kwh)			
Nominal	49.2	106.2	4.13%
Real	49.2	27.8	-2.97%

Emissions Data	Total Change in Emissions/MWH 1989 - 2008	Change in Total Emissions per Year 1989 - 2008
SO_2	84.1%	0.07%
NO_x	86.6%	0.22%
CO_2	85.2%	0.13%

Table 12

Summary Of Results

Medium Case

	1989	2008	growth rate
Total Gross Electric Plant (M$)	7234.9	15744.0	
Gross Conservation Assets	*6.5*	*1614.4*	
Total Net Electric Plant (M$)	5289.9	7742.5	
Net Conservation Assets	*6.5*	*1147.8*	
Operating Revenues (M$)			
Nominal	1889.9	4375.8	4.52%
Real	1889.9	1652.9	-0.70%
NPV (11.47% discount rate)	22880.2		
Base Unit Cost (mills/kwh)			
Nominal	49.3	90.1	3.23%
Real	49.3	34.0	-1.93%
Average Customer Bill ($)			
Nominal	1529.7	2735.9	3.11%
Real	1529.7	1033.4	-2.04%
NPV (11.47% discount rate)	16946.7		
Levelized Customer Cost (M$)			
(30 years at a 13.47% discount rate)	0.0	67.2	
NPV (11.47% discount rate)	81.7		
Energy Services Charge (M$)	0.1	155.4	
NPV (11.47% discount rate)	291.0		
Total Resource Cost (M$)			
Nominal	1889.0	4598.4	4.79%
Real	1889.0	1737.0	-0.44%
NPV (11.47% discount rate)	23252.9		
Per Unit TRC (mills / kwh)			
Nominal	49.3	88.7	3.14%
Real	49.3	33.5	-2.01%

Emissions Data	Total Change in Emissions/MWH 1989 - 2008	Change in Total Emissions per Year 1989 - 2008
SO_2	79.4%	0.36%
NO_x	90.5%	1.06%
CO_2	84.1%	0.66%

Table 13
Summary Of Results
Medium - High Case

	1989	2008	growth rate
Total Gross Electric Plant (M$)	7230.4	16271.0	
Gross Conservation Assets	*2.0*	*2251.2*	
Total Net Electric Plant (M$)	5285.4	8035.9	
Net Conservation Assets	*2.0*	*1544.0*	
Operating Revenues (M$)			
Nominal	1894.4	4450.7	4.60%
Real	1894.4	2143.3	0.65%
NPV (10.33% discount rate)	25312.0		
Base Unit Cost (mills/kwh)			
Nominal	49.2	84.6	2.90%
Real	49.2	40.7	-0.99%
Average Customer Bill ($)			
Nominal	1534.2	2782.7	3.18%
Real	1534.2	1340.1	-0.71%
NPV (10.33% discount rate)	16905.3		
Levelized Customer Cost (M$)			
(30 years at a 12.33% discount rate)	0.0	65.3	
NPV (10.33% discount rate)	91.6		
Energy Services Charge (M$)	0.1	212.4	
NPV (10.33% discount rate)	427.7		
Total Resource Cost (M$)			
Nominal	1894.5	4728.1	4.93%
Real	1894.5	2276.9	0.97%
NPV (10.33% discount rate)	23307.8		
Per Unit TRC (mills / kwh)			
Nominal	49.2	83.7	2.84%
Real	49.2	40.3	-1.04%

Emissions Data	Total Change in Emissions/MWH 1989 - 2008	Change in Total Emissions per Year 1989 - 2008
SO_2	76.8%	0.61%
NO_x	91.4%	1.54%
CO_2	83.0%	1.02%

Table 14

Summary Of Results

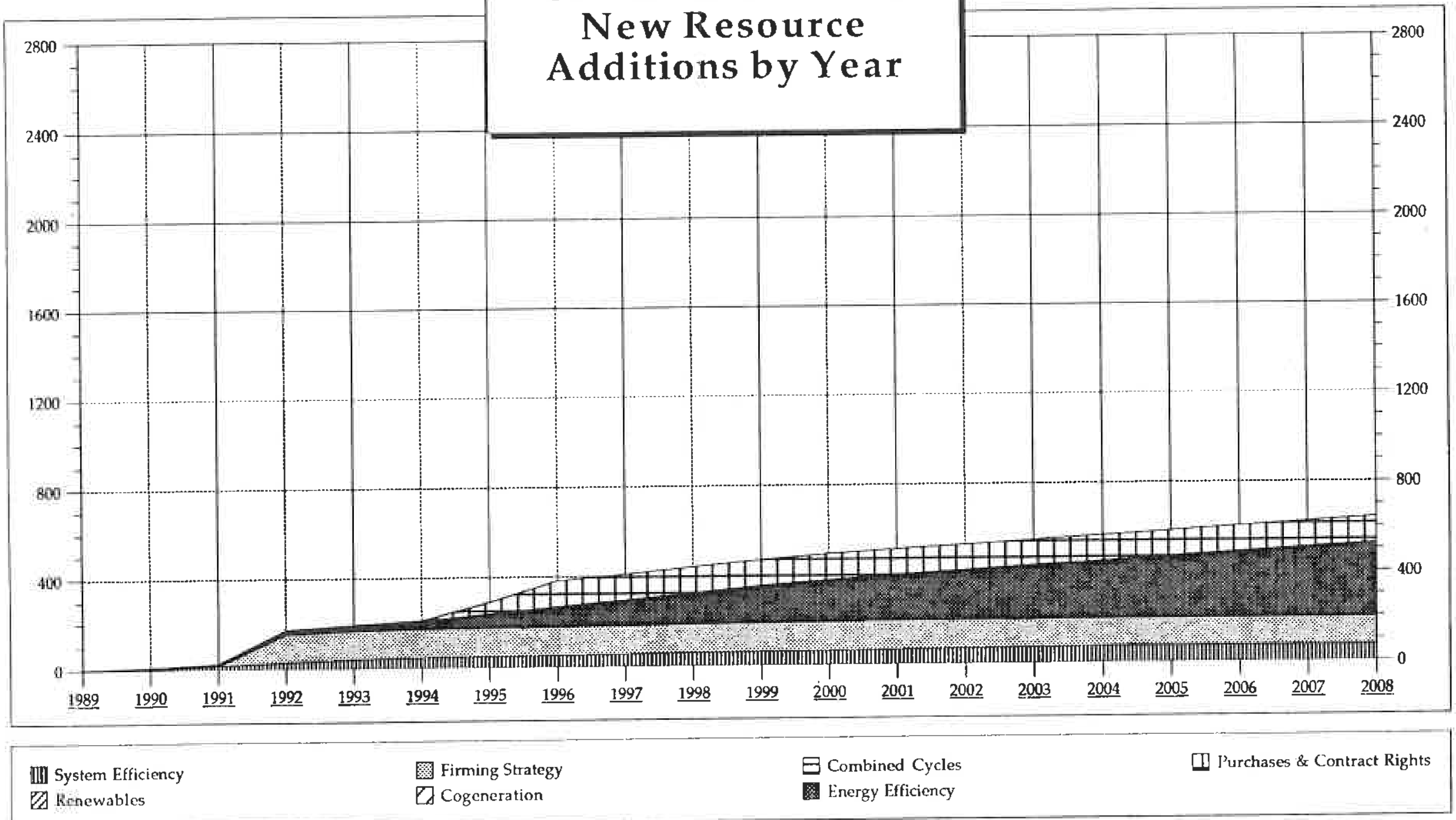
High Case

	1989	2008	growth rate
Total Gross Electric Plant (M$)	7234.8	18635.2	
Gross Conservation Assets	*6.4*	*2271.5*	
Total Net Electric Plant (M$)	5289.8	10048.2	
Net Conservation Assets	*6.4*	*1519.2*	
Operating Revenues (M$)			
Nominal	1898.7	5471.4	5.73%
Real	1898.7	2634.8	1.74%
NPV (10.33% discount rate)	24387.6		
Base Unit Cost (mills/kwh)			
Nominal	49.0	93.9	3.48%
Real	49.0	45.2	-0.42%
Average Customer Bill ($)			
Nominal	1514.4	2866.9	3.42%
Real	1514.4	1380.6	-0.49%
NPV (10.33% discount rate)	18040.6		
Levelized Customer Cost (M$)			
(30 years at a 12.33% discount rate)	0.0	106.5	
NPV (10.33% discount rate)	148.2		
Energy Services Charge (M$)	0.1	217.8	
NPV (10.33% discount rate)	457.2		
Total Resource Cost (M$)			
Nominal	1899.0	5795.7	6.05%
Real	1899.0	2791.0	2.05%
NPV (10.33% discount rate)	27530.0		
Per Unit TRC (mills / kwh)			
Nominal	49.0	92.5	3.40%
Real	49.0	44.6	-0.50%

Emissions Data	Total Change in Emissions/MWH 1989 - 2008	Change in Total Emissions per Year 1989 - 2008
SO2	71.8%	0.78%
NOx	96.9%	2.38%
CO2	80.4%	1.38%

Figure 9

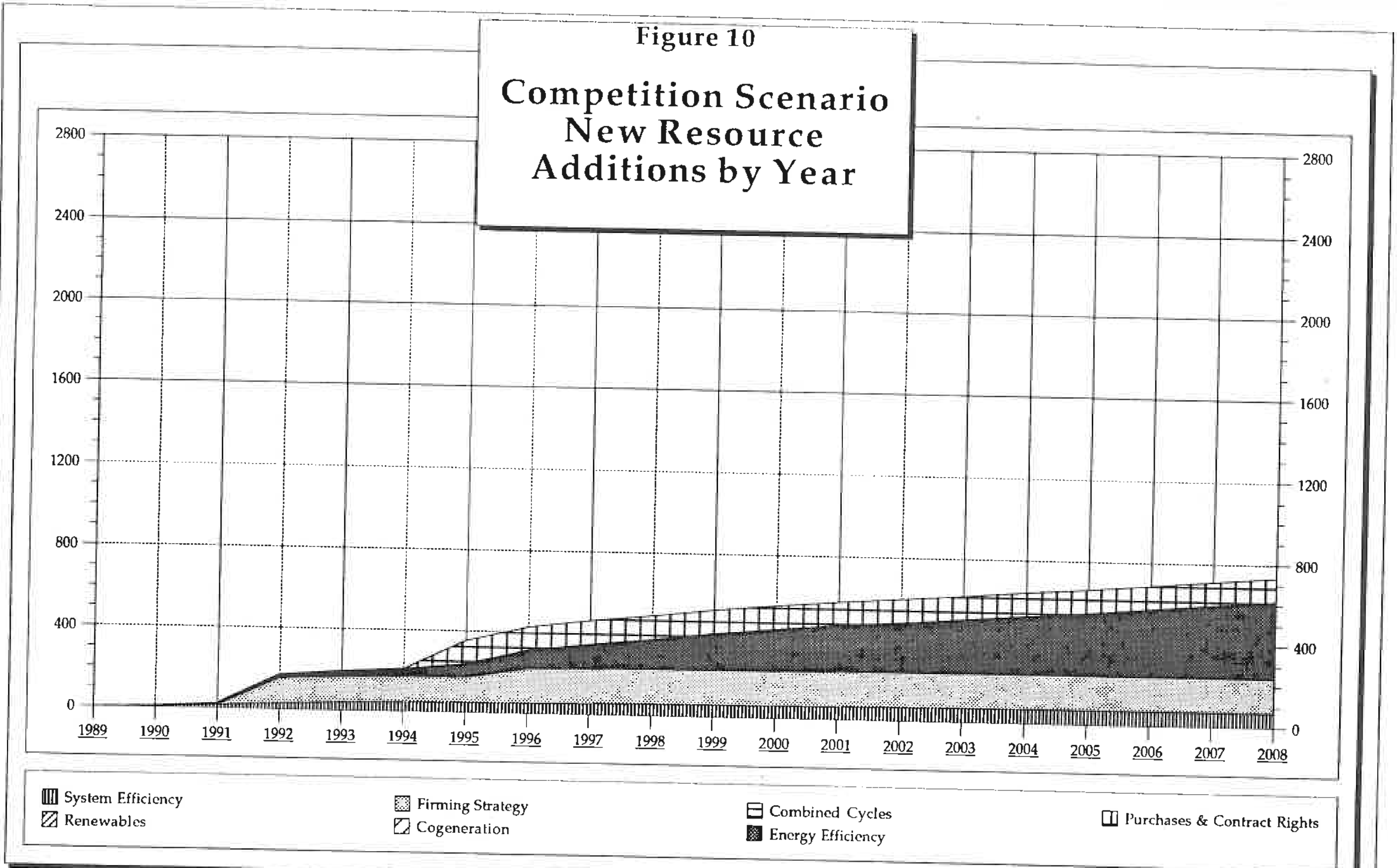
Oil Shock Scenario New Resource Additions by Year



Average MW's	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiency	0	5	17	29	41	46	49	52	55	58	61	63	65	67	69	71	71	71	71	71
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firming Strategy	0	0	0	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Cogeneration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycles	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	1	4	9	17	27	40	64	89	114	139	166	188	206	222	240	256	274	293	312	331
Purchases & Contract Rights	0	0	0	0	0	0	50	115	113	117	115	115	115	115	115	115	115	115	115	115
Totals	1	9	26	171	193	211	288	381	407	439	467	491	511	529	549	567	585	604	623	642

Figure 10

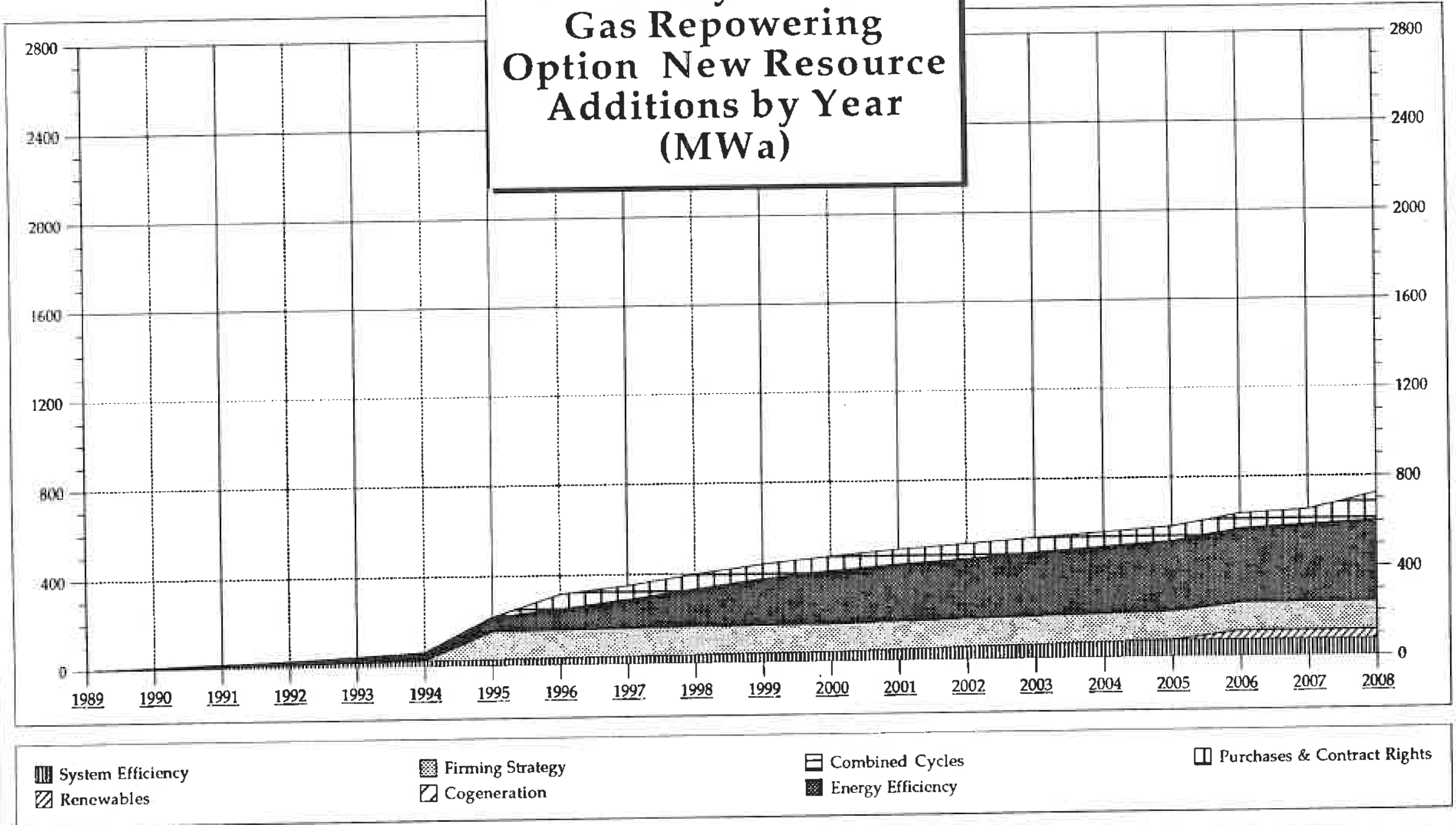
Competition Scenario New Resource Additions by Year



Average MW's	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiency	0	5	17	29	41	46	49	52	55	58	61	63	65	67	69	71	71	71	71	71
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firming Strategy	0	0	0	125	125	125	125	170	170	170	170	170	170	170	170	170	170	170	170	170
Cogeneration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycles	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	1	3	9	17	27	40	65	91	120	149	180	205	227	246	266	286	308	332	356	380
Purchases & Contract Rights	0	0	0	0	0	0	115	113	117	115	115	115	115	115	115	115	115	115	115	115
Totals	1	8	26	171	193	211	354	426	462	492	526	553	577	598	620	642	664	688	712	736

Figure 11

CO_2 Policy Scenario Gas Repowering Option New Resource Additions by Year (MWa)



Average MW's	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
System Efficiency	0	5	10	15	20	25	28	31	34	37
Renewables	0	0	0	0	0	0	0	0	0	0
Firming Strategy	0	0	0	0	0	0	125	125	125	125
Cogeneration	0	0	0	0	0	0	0	0	0	0
Combined Cycles	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	2	5	10	16	25	39	64	94	129	169
Purchases & Contract Rights	0	0	0	0	0	0	0	65	63	67
Totals	2	10	20	31	45	64	217	315	351	398

Average MW's	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiency	40	42	49	56	63	70	75	75	75	75
Renewables	0	0	0	0	0	0	0	38	38	38
Firming Strategy	125	125	125	125	125	125	125	125	125	125
Cogeneration	0	0	0	0	0	0	0	0	0	0
Combined Cycles	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	209	238	257	271	287	301	318	334	351	367
Purchases & Contract Rights	65	65	65	65	65	65	65	65	65	119
Totals	439	470	496	517	540	561	583	637	654	724

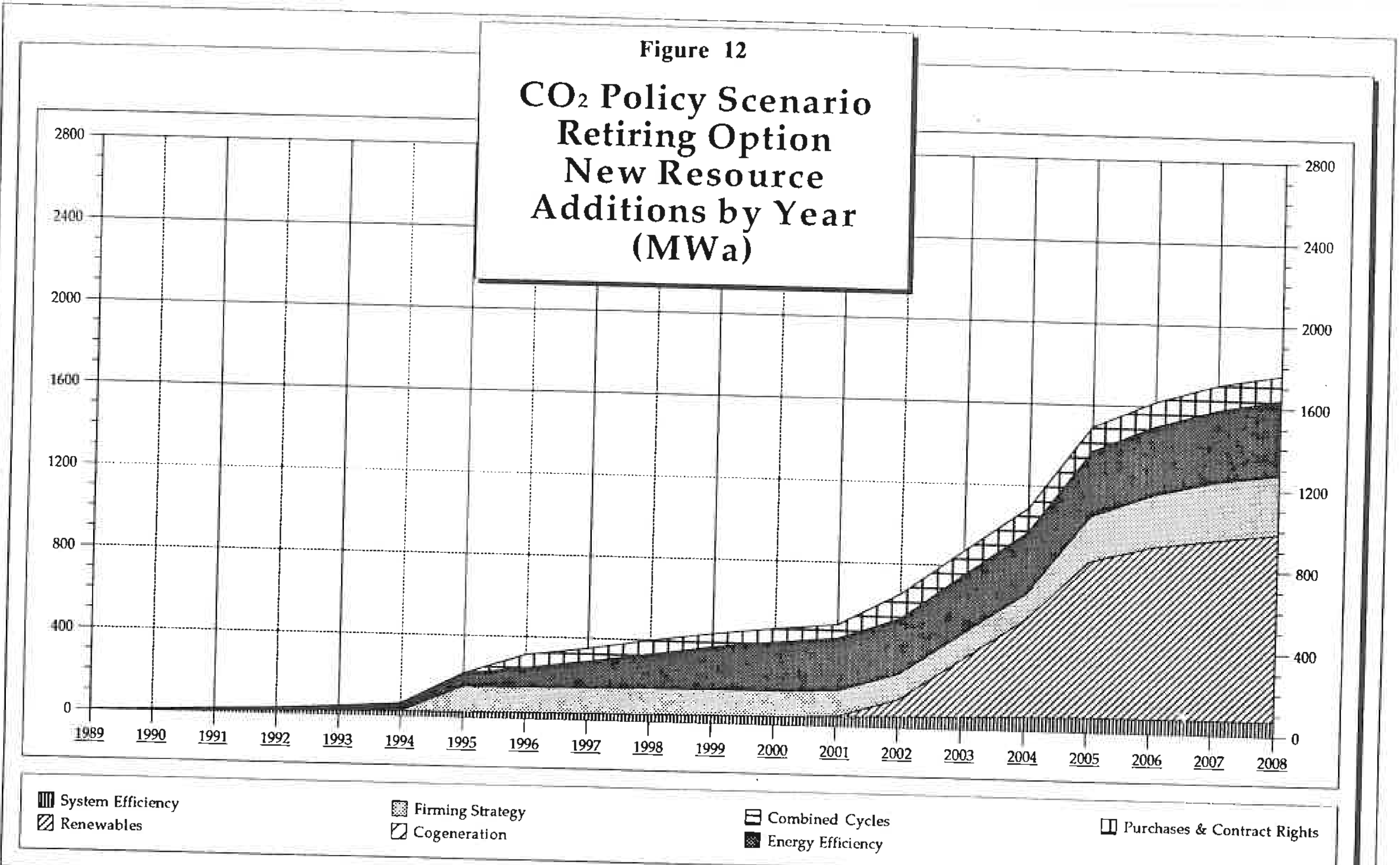


Figure 12

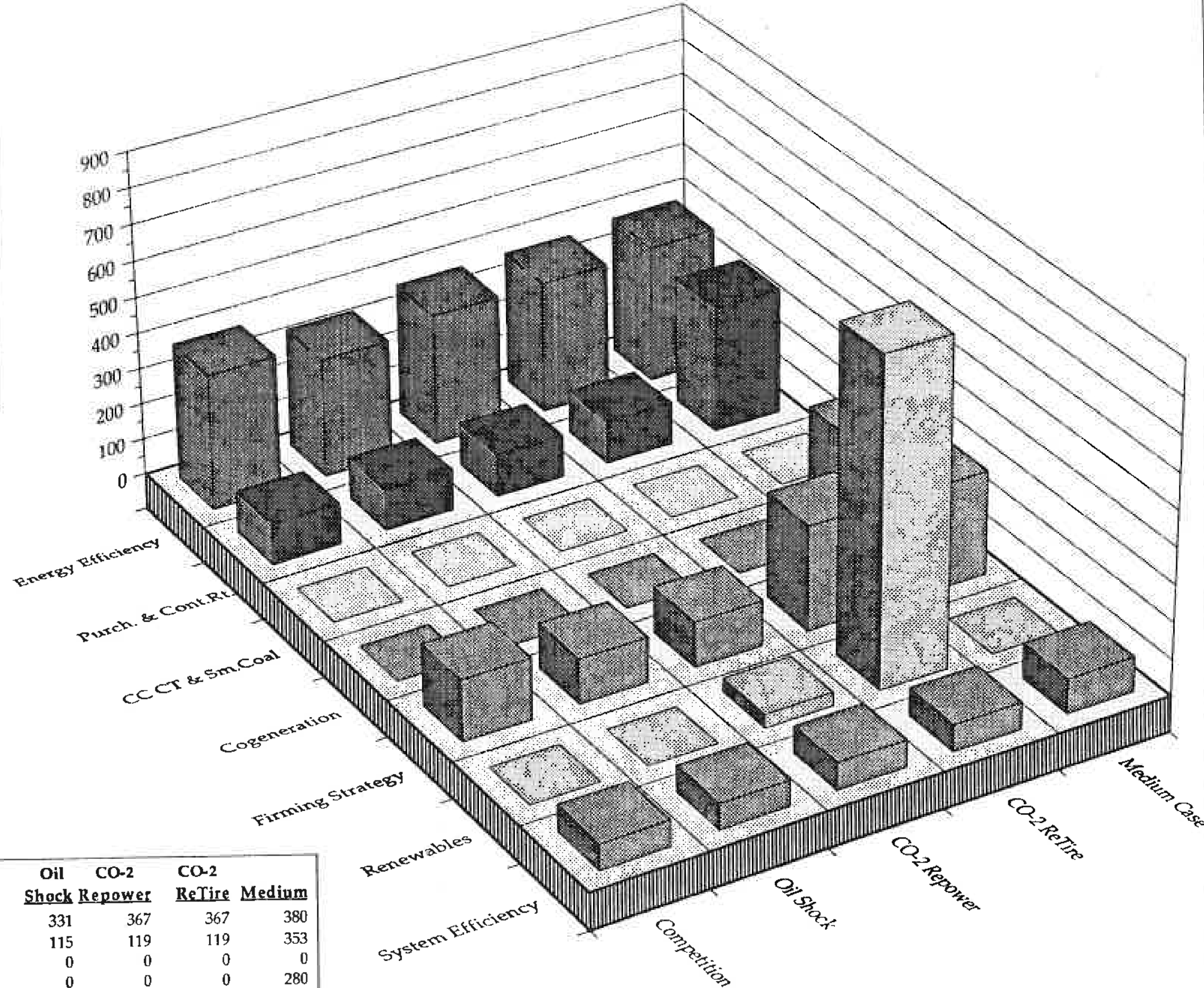
CO2 Policy Scenario Retiring Option New Resource Additions by Year (MWa)

Average MW's	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiency	0	5	10	15	20	25	28	31	34	37	40	42	49	56	63	70	75	75	75	75
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	82	279	475	760	836	874	912
Firming Strategy	0	0	0	0	0	0	125	125	125	125	125	125	125	125	125	125	222	256	288	288
Cogeneration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycles	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	2	5	10	16	25	39	64	94	129	169	209	238	257	271	287	301	318	334	351	367
Purchases & Contract Rights	0	0	0	0	0	0	0	65	63	67	65	65	65	119	119	119	119	119	119	119
Totals	2	10	20	31	45	64	217	315	351	398	439	470	496	653	873	1090	1494	1620	1707	1761

Figure 13

RAMPP Resource Additions by Senario

(in MWa) 1989-2008



Average MW's	Competition	Oil Shock	CO-2 Repower	CO-2 ReTire	Medium
Energy Efficiency	380	331	367	367	380
Energy Efficiency	115	115	119	119	353
CC CT & Sm.Coal	0	0	0	0	0
Cogeneration	0	0	0	0	280
Firming Strategy	170	125	125	288	288
Renewables	0	0	38	912	0
System Efficiency	71	71	75	75	96
Total	736	642	724	1761	1396

those used in the medium economic case. In the oil shock and competition scenarios, the new source additions were adjusted dynamically in response to the events as they were assumed to unfold, without the benefit of foreknowledge. Key results from these scenarios are summarized in Tables 15-18. The value of the flexible portfolio approach to resource planning is demonstrated by the ability to adjust resource acquisitions for these scenarios in such a manner as to reduce the impact upon average costs.

In the oil and gas price increase scenario, average cost impacts, after adjusting for inflation, are relatively minor. The portfolio of new sources is not especially sensitive to the fuel price increases assumed in this scenario. On the other hand, in the increased competition scenario increases in average unit costs and in unit total resource costs, as compared with the medium case, follow the loss of customers for a period of time. The increase depends upon the amount of load lost each year. Eventually, as supplies and demands are brought back into balance, costs return to levels similar to the medium case. This scenario illustrates that a diverse and flexible portfolio is not necessarily sufficient to insure cost stability to customers over time. In addition, a strategy employing cost control, price competitiveness, and the provision of valued customer products and services that best fit customers' energy needs is required to manage the risks of large customer loss.

Although the portfolio itself is not lacking for cost-effective new sources, these alone are not enough to avoid the major cost impacts to existing resources, under the assumptions describing the third scenario. In this case, it is assumed that utilities are required to reduce carbon dioxide emission levels by twenty percent by the year 2005 (3). This is assumed to occur as part of a larger national and international program to reduce worldwide CO2, and other emissions, and promote the development and diffusion of efficiency and alternative generation technologies.

Several strategies for achieving the required reductions have been suggested. These include installing technologies for controlling CO2 emissions, retiring some existing generation early and replacing it with non-combustion generation such as geothermal and solar thermal, repowering some existing coal-fired generation to natural gas, and tree planting to offset emissions from existing generation.

Two different approaches to reducing CO2 emissions by 20 percent were modeled. The first approach, the <u>repowering option</u>, and the <u>retiring option</u>. Under the repowering option a number of existing coal-fired units are converted to natural gas. In the retiring option, a number of older coal-fired units are retired and replaced with renewable resources, primarily geothermal and solar. Among the important assumptions underlying these two approaches are: 1) that the Company is experiencing medium-low demand growth conditions, 2) that the future price path of natural gas is no higher than the highest rate currently projected by Data Resources, and 3) that the future cost of solar generation decreases to the most optimistic level currently assumed by the solar industry and the US Department of Energy.

The range of utility and customer costs associated with this scenario are very wide, indicating the highly speculative nature of the assumptions concerning advancements in alternative generation technologies, the availability and price of low carbon dioxide emitting fuels, and the uncertainty related to the global warming effect itself. However, in each specific evaluation of this particular scenario, both utility and customer costs were higher than they were under any of the conventional demand forecasts, as well as any of the aforementioned scenarios.

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[3] This assumption is not meant to imply that such a goal is the most effective means for reducing CO2 emissions. Any rational policy aimed at reducing mankind's contributions to potential climate change would have to consider the entire gamut of human activities.

Table 15

Summary Of Results

Oil Shock Scenario

	1989	2008	growth rate
Total Gross Electric Plant (M$)	7230.4	14986.1	
Gross Conservation Assets	*2.0*	*1137.3*	
Total Net Electric Plant (M$)	5285.5	7205.6	
Net Conservation Assets	*2.0*	*795.6*	
Operating Revenues (M$)			
Nominal	1886.4	3802.3	3.76%
Real	1886.4	1436.3	-1.42%
NPV (11.47% discount rate)	19993.0		
Base Unit Cost (mills/kwh)			
Nominal	49.4	87.4	3.05%
Real	49.4	33.0	-2.09%
Average Customer Bill ($)			
Nominal	1527.7	2377.4	2.35%
Real	1527.7	898.0	-2.76%
NPV (11.47% discount rate)	14939.2		
Levelized Customer Cost (M$)			
(30 years at a 13.47% discount rate)	0.0	31.0	
NPV (11.47% discount rate)	37.7		
Energy Services Charge (M$)	0.1	124.8	
NPV (11.47% discount rate)	230.8		
Total Resource Cost (M$)			
Nominal	1886.5	3958.1	3.98%
Real	1886.5	1495.1	-1.22%
NPV (11.47% discount rate)	20261.5		
Per Unit TRC (mills / kwh)			
Nominal	49.4	86.0	2.96%
Real	49.4	32.5	-2.18%

Emissions Data	Total Change in Emissions/MWH 1989 - 2008	Change in Total Emissions per Year 1989 - 2008
SO_2	87.8%	0.28%
NO_x	88.3%	0.31%
CO_2	85.9%	0.16%

Table 16
Summary Of Results
Competition Scenario

	1989	2008	growth rate
Total Gross Electric Plant (M$)	7235.0	15404.0	
Gross Conservation Assets	*6.0*	*1499.0*	
Total Net Electric Plant (M$)	5289.9	7492.1	
Net Conservation Assets	*6.5*	*1048.2*	
Operating Revenues (M$)			
Nominal	1888.9	3832.0	3.79%
Real	1888.9	1447.2	-1.39%
NPV (11.47% discount rate)	19795.7		
Base Unit Cost (mills/kwh)			
Nominal	49.3	89.7	3.20%
Real	49.3	33.9	-1.95%
Average Customer Bill ($)			
Nominal	1529.7	2395.9	2.39%
Real	1529.7	904.8	-2.73%
NPV (11.47% discount rate)	14795.9		
Levelized Customer Cost (M$)			
(30 years at a 13.47% discount rate)	0.0	67.2	
NPV (11.47% discount rate)	81.7		
Energy Services Charge (M$)	0.1	155.4	
NPV (11.47% discount rate)	291.0		
Total Resource Cost (M$)			
Nominal	1889.0	4054.6	4.10%
Real	1889.0	1531.3	-1.10%
NPV (11.47% discount rate)	20168.5		
Per Unit TRC (mills / kwh)			
Nominal	49.3	88.5	3.13%
Real	49.3	33.4	-2.03%

Emissions Data	Total Change in Emissions/MWH 1989 - 2008	Change in Total Emissions per Year 1989 - 2008
SO_2	87.8%	0.24%
NO_x	88.6%	0.29%
CO_2	87.0%	0.19%

Table 17

Summary Of Results

CO_2 Repowering Scenario

	1989	2008	growth rate
Total Gross Electric Plant (M$)	7236.0	17367.0	
Gross Conservation Assets	*8.0*	*2106.0*	
Total Net Electric Plant (M$)	5291.4	9068.8	
Net Conservation Assets	*7.9*	*1391.7*	
Operating Revenues (M$)			
Nominal	1886.1	8232.1	8.06%
Real	1886.1	2156.5	0.71%
NPV (13.13% discount rate)	22743.6		
Base Unit Cost (mills/kwh)			
Nominal	49.2	188.2	7.32%
Real	49.2	49.3	0.01%
Average Customer Bill ($)			
Nominal	1527.4	5147.0	6.60%
Real	1527.4	1348.3	-0.65%
NPV (13.13% discount rate)	16742.1		
Levelized Customer Cost (M$)			
(30 years at a 15.13% discount rate)	0.0	50.2	
NPV (13.13% discount rate)	55.1		
Energy Services Charge (M$)	0.2	184.4	
NPV (13.13% discount rate)	308.9		
Total Resource Cost (M$)			
Nominal	1886.3	8466.7	8.22%
Real	1886.3	2218.0	0.86%
NPV (13.13% discount rate)	23026.5		
Per Unit TRC (mills / kwh)			
Nominal	49.2	180.5	7.08%
Real	49.2	47.3	-0.21%

Emissions Data	Total Change in Emissions/MWH 1989 - 2008	Change in Total Emissions per Year 1989 - 2008
SO_2	31.4%	-4.92%
NO_x	108.3%	1.48%
CO_2	64.2%	-1.27%

Table 18

Summary Of Results

CO2 Retiring Scenario

	1989	2008	growth rate
Total Gross Electric Plant (M$)	7235.0	24492.0	
Gross Conservation Assets	*7.0*	*2085.0*	
Total Net Electric Plant (M$)	5290.0	15000.5	
Net Conservation Assets	*6.6*	*1380.2*	
Operating Revenues (M$)			
Nominal	1890.6	6743.2	6.92%
Real	1890.6	1766.5	-0.36%
NPV (13.13% discount rate)	20023.2		
Base Unit Cost (mills/kwh)			
Nominal	49.4	153.8	6.16%
Real	49.4	40.3	-1.07%
Average Customer Bill ($)			
Nominal	1531.1	4216.1	5.48%
Real	1531.1	1104.5	-1.70%
NPV (13.13% discount rate)	14870.5		
Levelized Customer Cost (M$)			
(30 years at a 15.13% discount rate)	0.0	50.2	
NPV (13.13% discount rate)	55.1		
Energy Services Charge (M$)	0.1	183.4	
NPV (13.13% discount rate)	302.2		
Total Resource Cost (M$)			
Nominal	1890.7	6976.8	7.11%
Real	1890.7	1827.7	-0.18%
NPV (13.13% discount rate)	20380.5		
Per Unit TRC (mills / kwh)			
Nominal	49.3	148.7	5.98%
Real	49.2	39.0	-1.22%

Emissions Data	Total Change in Emissions/MWH 1989 - 2008	Change in Total Emissions per Year 1989 - 2008
SO_2	47.9%	-2.78%
NO_x	51.6%	-2.40%
CO_2	68.5%	-0.93%

RESOURCE STRATEGY CONCLUSIONS

Besides the adequacy and cost effectiveness of the new source portfolio, the results summarized here shed some light on the resource strategies that can help guide decisions in the future. Of course, the fundamental strategy or decision rule, when new sources are required, is to acquire lowest cost sources first, and postpone the acquisition of high cost sources as long as possible. This is the fundamental strategy that has been implemented in arriving at the results described in this chapter. The true planning challenge, however, comes in deciding when and how much of various new sources should be acquired, given the uncertainties of need and availability. In the face of substantial uncertainties, retaining flexibility is the logical general strategy. This general strategy can take on several dimensions in resource strategies. These are:

Portfolio Diversity - Maintaining a broad and diversified portfolio means that the full range of alternatives that could be used for meeting the range of plausible futures should be maintained. Alternatives should not be prematurely foreclosed, if there are low costs of carrying them but risks of not having them.

"Just-In-Time" Deployment - Just as alternatives should not be foreclosed prematurely, commitments should not be made prematurely. Alternatives with shorter lead times, or with flexibility for adjustment are valuable in this regard, and should be preserved.

Secure Options - The shorter lead time nature of alternatives should be cultivated, when the cost of optioning is relatively low. At the same time, attractive opportunities should not be foregone, if they are likely to be valuable over the planning horizon. Some early pilots, demonstrations, and testing the market are appropriate to assure the flexibility of shorter lead times, or to reduce the uncertainty of future costs or availability. Similarly, some purchases may also be lost opportunities, or may have lower costs if acquired earlier.

A fundamental conclusion of the planning program is that new source alternatives are available to allow implementation of these general strategies. The diversity of new sources in the Company's portfolio is self-evident. Moreover, several of the new sources in the portfolio have desirable flexibility characteristics. Almost 300 average megawatts of energy, with 400 megawatts of capacity, can be acquired by the Company within three years of a decision, without reliance on marketplace resources. Existing marketplace options exist with several cogeneration projects. Utility purchases also have the potential of being converted into options, by combining long-term purchases with flexible short- or medium-term wholesale sales.

A more detailed description of how individual new source alternatives can be used to implement these general resource strategies is included in Volume 2 of this report.

The Company's planning program has only begun to analyze the long range application of these strategies. The first steps have been describe in this report, namely analyses of demand growth uncertainties and supply and demand alternatives. Although there combinations in the form of plausible futures has been demonstrated, a more rigorous decisions analysis or risk analysis framework is also desirable. Such analytical work is an appropriate focus of the next stage of integrated resource planning at the Company.

EXTERNAL COST CONCLUSIONS

Two broad conclusions can be reached with regard to the consideration of external costs. First, the inclusion of external costs does not effect the most immediate new source decisions. Energy efficiency programs and system efficiencies already occupy the highest priority positions among new sources. Furthermore, the timing of energy efficiency acquisitions is motivated by the need to develop them systematically to meet long range needs. The second conclusion is that consideration of external costs would likely not cause economical purchases derived from existing fossil generating sources to be replaced by new renewable generating resources, given current costs of those renewable sources.

SHORT-TERM ACTION PLAN

The results of analyses show that a broad range of alternative sources will be relied upon to meet future requirements, but the actual amount and timing of required new sources depends on how the future unfolds. Fortunately, most decisions to acquire new sources over the entire planning horizon do not need to be made now. Nevertheless, some actions are necessary in the short-term to prepare for the long-term.

The general planning strategies identified in the previous section can help guide short-term actions, such that they are compatible with the range of future requirements. Table 19 summarizes the short-term actions indicated by these strategies, and the basis for their inclusion. They are described in more detail below.

PROCEED WITH CUSTOMER ENERGY EFFICIENCY PROGRAMS

1) Implement energy efficiency programs to capture lost opportunities.

2) Implement pilot programs to demonstrate and test program delivery mechanisms, aimed at full scale programs as early as 1995.

Under medium or higher loads, energy efficiency programs can be expected to provide 150-200 average megawatts by the late 1990's. Several activities are being undertaken in the short-term to assure that this magnitude of customer energy savings can be achieved in that time frame. At the same time, these short-term actions must be flexible enough to adjust to a lower future requirement. Program activities in 1990-91 that conform to these general needs are summarized in Table 20. These programs share the following general objectives:

> develop the capability to acquire demand-side efficiencies when needed
> capture lost opportunities when they become available
> develop the means to mitigate price and equity impacts of energy efficiency programs
> improve the base of information from which cost and savings estimates are derived
> improve the Company's ability to plan and operate programs effectively

These programs target residential, commercial and industrial customers, and include most of the program options in the new source portfolio relevant to the Pacific Northwest region. They are consistent with current program estimates included in recent filings with the OPUC and WUTC. While these programs are important first steps toward larger acquisition programs under medium or higher growth conditions, they are not irreversible commitments to major acquisition, should lower growth cause that phase to be delayed.

Table 19

ACTION PLAN SUMMARY

ELEMENT	NEAR TERM POTENTIAL	BASIS FOR INCLUSION IN 1990-91 ACTIONS
Customer Efficiency Programs	20-75 MWa by 1995 40-285 MWa by 2000	Lost opportunities required in all cases. Pilot programs to confirm cost and availability and build capability before longer term acquisition phase.
System Efficiency Programs	20-50 MWa by 1995 30-75 MWa by 2000	Ongoing operating programs. Hydro and T&D improvements have lost opportunity component.
Marketplace Opportunities		Potential lost opportunities. Cost effective and required under medium high growth
- Purchases	0-280 MWa by 1995 0-500 MWa by 2000	
- Cogeneration	0-180 MWa by 1995 0-360 MWa by 2000	
Firming Strategies	0-240 MWa by 1995 125-290 MWa by 2000	Required under medium growth. Preparations to implement improve flexibility.

Table 20

ACTION PLAN PROGRAMS - MEDIUM FORECAST 1990 - 1991
** LOST OPPORTUNITY AND PILOT PROGRAMS **

PROGRAM	PHYSICAL GOAL	RESOURCE YEILD MWA	GROSS UTILITY PROGRAM COST MILLIONS 1990 $'s	KEY OBJECTIVES
NEW RESDENTIAL	3,810 SUPER GOOD CENTS HOMES	3.0	$7.2	Capture Lost Opportunities Transform Market
NEW COMMERCIAL	360 BUILDINGS, NEW & REMODEL	1.0	$5.0	Capture Lost Opportunities Transform Market Test Shared Savings
NEW APPLIANCES	6,000 WATER HEATERS 200 LOAD CONTROLLERS	0.2	$0.2	Capture Lost Opportunities Transform Market Seek Regional Program
INDUSTRIAL PILOT	5 FACILITIES	3.8	$3.5	Transform Market Test Shared Savings
RESIDIENTIAL RETROFIT PILOT	600 HIGH-USER HOMES WEATHERIZED	0.6	$3.1	Test Shared Savings Build Capability
COMMERCIAL RETROFIT PILOT	100 BUILDINGS	0.7	$3.3	Test High Intensity Retrofit Test Shared Savings Build Capability
LOW INCOME RESIDENTIAL RETROFIT	3,000 HOMES FULLY WEATHERIZED	1.3	$3.5	Share Cost With Low Income Assistance Agencies
ALL PROGRAMS		10.6	$25.8	

PROCEED WITH SYSTEM EFFICIENCY PROGRAMS

1) Continue transmission and distribution design and investment decisions recognizing the cost of losses and opportunities for improved voltage regulation, valued at short and long range avoided resource costs.

2) Conduct detailed engineering studies to estimate potential Lewis River system improvements. Continue hydro system betterment programs to maintain or improve capacity, availability and efficiency, based on short and long range avoided resource costs

3) Continue thermal generation availability and maintainability evaluation programs, with the goal of deriving improved energy capability from existing generation at low cost.

The Company's system efficiency programs can provide up to about 100 average megawatts of new energy or energy savings over the long-term planning horizon, from existing hydro and thermal generation facilities and through transmission and distribution loss reductions. The new energy these programs provide will develop gradually over time, since the programs are closely tied to ongoing operations. Although it is difficult to develop an exact estimate of the energy they may provide over the next two years, it is nevertheless important to recognize them as ongoing elements of the Company's resource development strategy.

TEST MARKETPLACE, & SECURE COST-EFFECTIVE OPPORTUNITIES

1) Identify specific long-term firm purchase opportunities. Secure purchases with costs comparable to those in the resource portfolio, if they are at risk of becoming lost opportunities.

Under medium or higher loads, utility purchases are expected to provide a substantial fraction of future new sources in the long-term. Even in the short-term, under high growth assumptions, purchases are a cost-effective component of the new source portfolio. Given the significance of marketplace purchases as a future supply source, beginning to test the marketplace is the necessary first step in a strategy of securing future options. Besides utility purchases, the broader marketplace should be tested through a trial competitive bidding process consistent with existing Washington Commission, and potential Oregon Commission, rules.

2) Develop and test contractual arrangements with the most economical cogeneration candidates. Demonstrate the ability of the Company to own and operate electric generation facilities as part of industrial cogeneration processes.

Under medium or higher loads, cogeneration can contribute between 150 and 300 average megawatts to future requirements by the late 1990's. Pacific Power currently has contracts with three industrial customers giving the Company options to participate in and determine the timing of cogeneration developments. Details of the contractual arrangements whereby the Company could participate in the development of cogeneration, with benefits to the industrial customer, all other customers, and the Company need to be developed and tested before large scale acquisition of this resource can begin.

PREPARE TO IMPLEMENT FIRMING STRATEGIES

1) Prepare alternative thermal maintenance practices that derive more firm energy from the coordinated hydro-thermal system.

2) Address refurbishment and fuel supply issues, with the goal of being able to return the Gadsby Plant to service within one year of a decision.

Firming strategies can contribute between a fourth and a third of new source requirements over the next ten years. These strategies derive more firm energy from existing resources by providing contingencies to back up nonfirm sources. The use of more flexible thermal maintenance scheduling to implement firming strategies is one of two promising means to implement this strategy available to the Company. Details of contingency maintenance planning should be developed so that this strategy can be implemented in the short-term. Under medium or higher growth conditions, generation from Utah Power's Gadsby generating plant, currently on cold standby, will be cost-effective in a firming mode within the next five years. Preparing these units for return to service on short notice builds additional flexibility into the exercise of this strategy. Fuel supply issues and associated refurbishment requirements should be resolved.

ADDRESS FUTURE PLANNING ISSUES

1) Review the adequacy of information on potential renewable resource at sites readily incorporated into the Company's system.

Geothermal and wind resources can meet long-term requirements cost-effectively under higher growth conditions. Solar technologies have the promise of falling into this category, if long-term cost goals are met. The ability to better plan for their future contributions depends on the quality of resource potential information.

2) Improve estimates of the effects of energy efficiency programs on peak loads and capacity requirements, estimates of the potential for cost-effective load management technologies within the Company's customer base.

Information on the capacity impacts of energy oriented customer efficiency programs has proven scarce. Better ability to plan for future capacity requirements will be well served by improved information in this area. Similarly, the potential for load management in the Pacific Northwest has been largely ignored. As the Company's system becomes more capacity constrained and less hydro based, the potential for load management grows.

3) Improve capability to identify and account for externalities of new source decisions.

The OPUC's requirement that externalities be taken into account in least cost planning has been approached in a general sense in this stage of RAMPP. Initial surveys of the cost of externalities show wide variance of cost estimates, and little consensus on methods of placing these costs on a comparable basis to internal costs. The Company intends to work with the OPUC on improving the ability to estimate and incorporate external costs into its planning process.

Improve the capability to analyze new source alternatives and planning strategies, considering major planning uncertainties.

The RAMPP process has identified a range of economic and demand growth conditions that could unfold in the future. Resource plans and decisions can benefit from a more rigorous analytical approach to consideration of these and other uncertainties. A decision analytic framework should be developed that allows better comparison of alternatives and strategies, taking important uncertainties into account.

PLANNING FOR STABLE GROWTH

The Pacific Power and Utah Power Resource and Market Planning Program

Errata

January 1990

PLANNING FOR STABLE GROWTH

The Pacific Power and Utah Power
Resource and Market Planning Program

Errata

Volume 1 - Summary Report - Text and Table Changes

Page 11, Third Paragraph:	Change "annual rate of 0.7%", to "annual rate of 0.6%" Change "annual rate of 2.7%", to "annual rate of 2.5%"
Table 10, Page 44:	Change Average Customer Bill NPV from *16381.8* to *14486.3*
Table 11, Page 45:	Change Average Customer Bill NPV from *15766.1* to *14038.7* Change Total Resource Cost NPV from *21441.7* to *18960.0*
Table 12, Page 46:	Change Operating Revenues NPV from *22880.2* to *20748.4* Change Average Customer Bill NPV from *16946.7* to *15458.6* Change Total Resource Cost NPV from *23252.9* to *21121.1*
Table 13, Page 47:	Change Operating Revenues NPV from *25312.0* to *22788.6*
Table 14, Page 48:	Change Average Customer Bill NPV from *18040.6* to *16465.1* Change Total Resource Cost Nominal from *1899.0* to *1898.8* Change Total Resource Cost Real from *1899.0* to *1898.8* Change Total Resource Cost NPV from *27530.0* to *24992.9*

Volume 1 - Summary Report - Page Replacement

Please replace the following Figures and Tables:

Figure 11 - Page 51	Table 15 - Page 55
Figure 12 - Page 52	Table 17 - Page 57
Figure 13 - Page 53	Table 18 - Page 58

Volume 2 - Technical Appendix - Text and Table Changes

Table 7, Page 19:	Change Existing Residential Technical Potential from *160* to *99*
Page 27, Second Paragraph:	Change "45 average megawatts" to 23 "average megawatts" Change "20 mills" to "41 mills"

Errata (Continued)

Volume 2 - Technical Appendix - Text and Table Changes (Continued)

Page 27, Fourth Paragraph:	Change "173 average megawatts" to "200 average megawatts"
	Change "19 mills" to "18 mills"
Page 27, Fifth Paragraph:	Change "24 average megawatts" to "18 average megawatts"
	Change "34 mills" to "41 mills"
Page 27, Sixth Paragraph:	Change "66 average megawatts" to "58 average megawatts"
	Change "41 mills" to "40 mills"
Page 97, First Paragraph:	Change "1.5 %" to "1.6%"

Volume 2 - Technical Appendix - Page Replacement

Please replace the following Figures:

Figure 12 - Page 106

Appendix A - Numerical Results by Case and Scenario: Oil Shock Scenario: New Resource Additions by Year

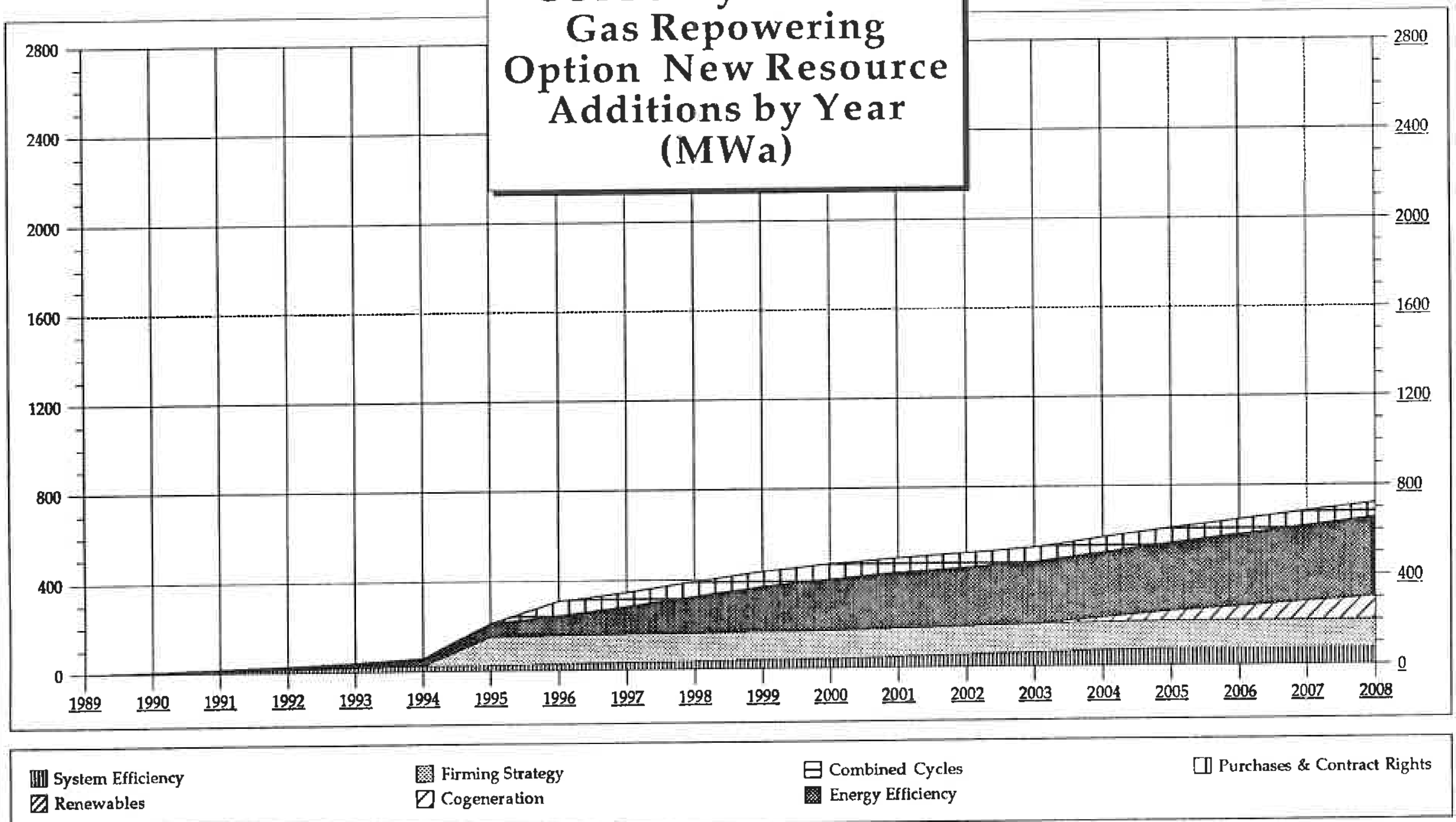
Appendix A - Numerical Results by Case and Scenario: Competition Scenario: New Resource Additions by Year

Volume 2 - Technical Appendix - Note

Each of the detailed loads and resources tables erroneously display the Company's firm sale to Black Hills Power & Light expiring in 1999. This contract is in effect throughout the entire study period. The Company has chosen not to correct this minor oversight since it does not change the results or conclusion of the report.

Figure 11

CO_2 Policy Scenario Gas Repowering Option New Resource Additions by Year (MWa)



Average MW's	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
System Efficiency	0	5	10	15	20	25	28	31	34	37
Renewables	0	0	0	0	0	0	0	0	0	0
Firming Strategy	0	0	0	0	0	0	125	125	125	125
Cogeneration	0	0	0	0	0	0	0	0	0	0
Combined Cycles	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	1	3	8	14	24	36	60	89	124	163
Purchases & Contract Rights	0	0	0	0	0	0	0	65	63	67
Totals	**1**	**8**	**18**	**29**	**44**	**61**	**213**	**311**	**346**	**392**

Average MW's	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiency	40	42	49	56	63	70	75	75	75	75
Renewables	0	0	0	0	0	0	0	0	0	0
Firming Strategy	125	125	125	125	125	125	125	125	125	125
Cogeneration	0	0	0	0	0	20	40	60	80	100
Combined Cycles	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	203	231	249	262	277	291	307	323	340	356
Purchases & Contract Rights	65	65	65	65	65	65	65	65	65	65
Totals	**432**	**463**	**488**	**508**	**530**	**572**	**612**	**648**	**685**	**721**

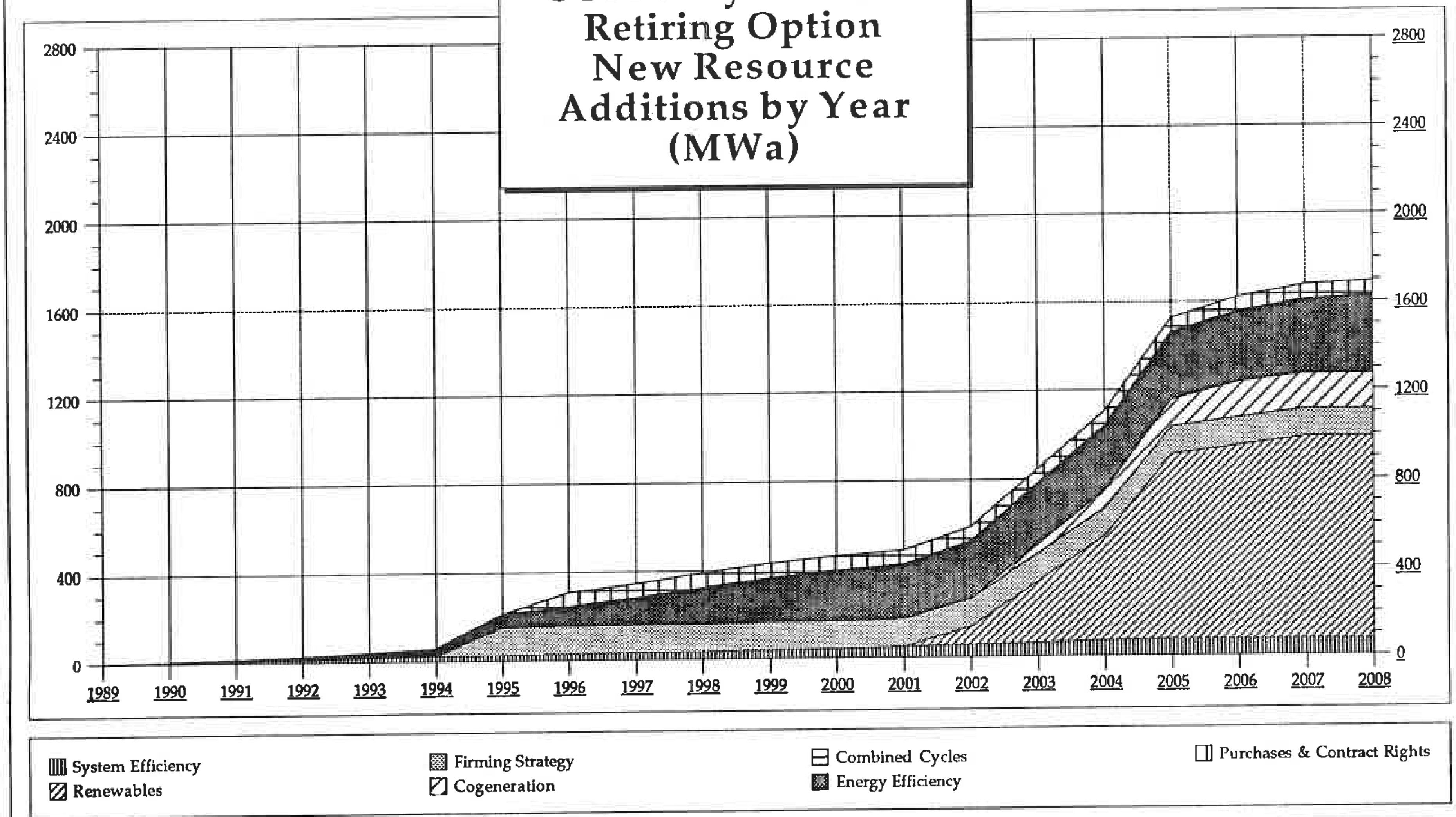


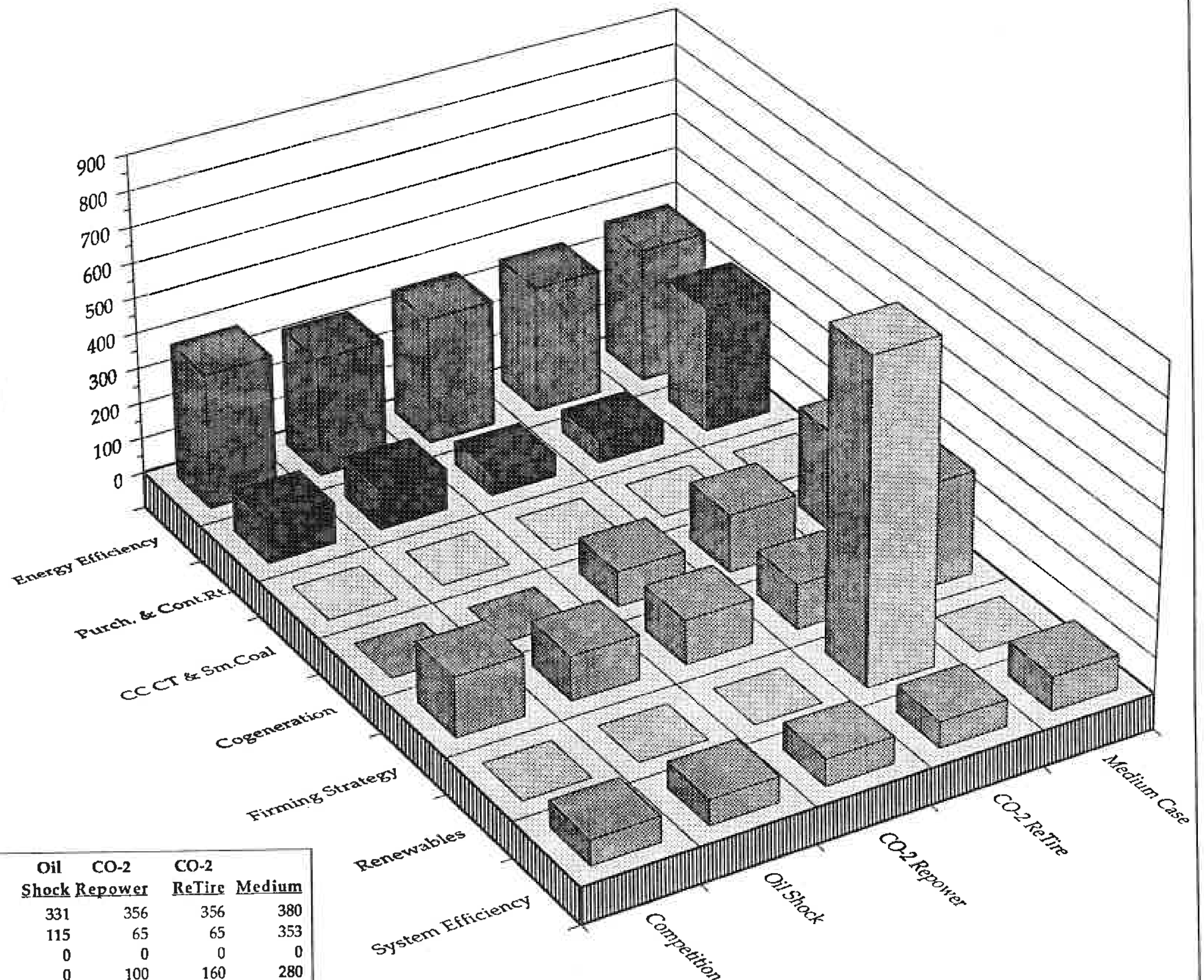
Figure 12

CO_2 Policy Scenario Retiring Option New Resource Additions by Year (MWa)

Average MW's	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiency	0	5	10	15	20	25	28	31	34	37	40	42	49	56	63	70	75	75	75	75
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	82	279	475	836	874	912	912
Firming Strategy	0	0	0	0	0	0	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Cogeneration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	40	80	120	160	160	160
Combined Cycles	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	1	3	8	14	24	36	60	89	124	163	203	231	249	262	277	291	307	323	340	356
Purchases & Contract Rights	0	0	0	0	0	0	0	65	63	67	65	65	65	65	65	65	65	65	65	65
Totals	1	8	18	29	44	61	213	311	346	392	432	463	488	590	849	1106	1528	1622	1676	1693

Figure 13
RAMPP Resource Additions by Senario

(in MWa) 1989-2008



Average MW's	Competition	Oil Shock	CO-2 Repower	CO-2 ReTire	Medium
Energy Efficiency	380	331	356	356	380
Purch. & Cont.Rt.	115	115	65	65	353
CC CT & Sm.Coal	0	0	0	0	0
Cogeneration	0	0	100	160	280
Firming Strategy	170	125	125	125	288
Renewables	0	0	0	912	0
System Efficiency	71	71	75	75	96
Total	736	642	721	1693	1396

Table 15

Summary Of Results

Oil Shock Scenario

	1989	2008	growth rate
Total Gross Electric Plant (M$)	7,235	15,617	
Gross Conservation Assets	*6*	*1,768*	
Total Net Electric Plant (M$)	5289.9	7574.8	
Net Conservation Assets	*6.5*	*1164.4*	
Operating Revenues (M$)			
Nominal	1886.7	3820.3	3.78%
Real	1886.7	1442.8	-1.40%
NPV (11.47% discount rate)	20130.4		
Base Unit Cost (mills/kwh)			
Nominal	49.4	88.8	3.14%
Real	49.4	33.5	-2.02%
Average Customer Bill ($)			
Nominal	1528.0	2388.6	2.38%
Real	1528.0	902.1	-2.74%
NPV (11.47% discount rate)	15036.2		
Levelized Customer Cost (M$)			
(30 years at a 13.47% discount rate)	0.0	31.0	
NPV (11.47% discount rate)	37.7		
Energy Services Charge (M$)	0.1	176.2	
NPV (11.47% discount rate)	344.6		
Total Resource Cost (M$)			
Nominal	1886.8	4027.5	4.07%
Real	1886.8	1521.0	-1.13%
NPV (11.47% discount rate)	20512.7		
Per Unit TRC (mills / kwh)			
Nominal	49.4	87.5	3.06%
Real	49.4	33.1	-2.08%

Emissions Data	Total Change in Emissions/MWH 1989 - 2008	Change in Total Emissions per Year 1989 - 2008
SO_2	87.8%	0.28%
NO_x	88.3%	0.31%
CO_2	85.9%	0.16%

Table 17

Summary Of Results

CO2 Repowering Scenario

	1989	2008	growth rate
Total Gross Electric Plant (M$)	7235.0	17348.0	
Gross Conservation Assets	*7.0*	*2085.0*	
Total Net Electric Plant (M$)	5290.0	9072.7	
Net Conservation Assets	*6.6*	*1380.2*	
Operating Revenues (M$)			
Nominal	1886.3	8353.4	8.15%
Real	1886.3	2188.3	0.78%
NPV (13.13% discount rate)	20563.4		
Base Unit Cost (mills/kwh)			
Nominal	49.2	190.6	7.39%
Real	49.2	49.9	0.07%
Average Customer Bill ($)			
Nominal	1527.6	5222.8	6.68%
Real	1527.6	1368.2	-0.58%
NPV (13.13% discount rate)	15216.5		
Levelized Customer Cost (M$)			
(30 years at a 15.13% discount rate)	0.0	50.2	
NPV (13.13% discount rate)	55.1		
Energy Services Charge (M$)	0.1	183.4	
NPV (13.13% discount rate)	302.2		
Total Resource Cost (M$)			
Nominal	1886.4	8587.0	8.30%
Real	1886.4	2249.5	0.93%
NPV (13.13% discount rate)	20920.6		
Per Unit TRC (mills / kwh)			
Nominal	49.2	183.0	7.16%
Real	49.2	47.9	-0.14%

Emissions Data	Total Change in Emissions/MWH 1989 - 2008	Change in Total Emissions per Year 1989 - 2008
SO2	31.0%	-4.98%
NOx	111.5%	1.64%
CO2	65.9%	-1.14%

Table 18

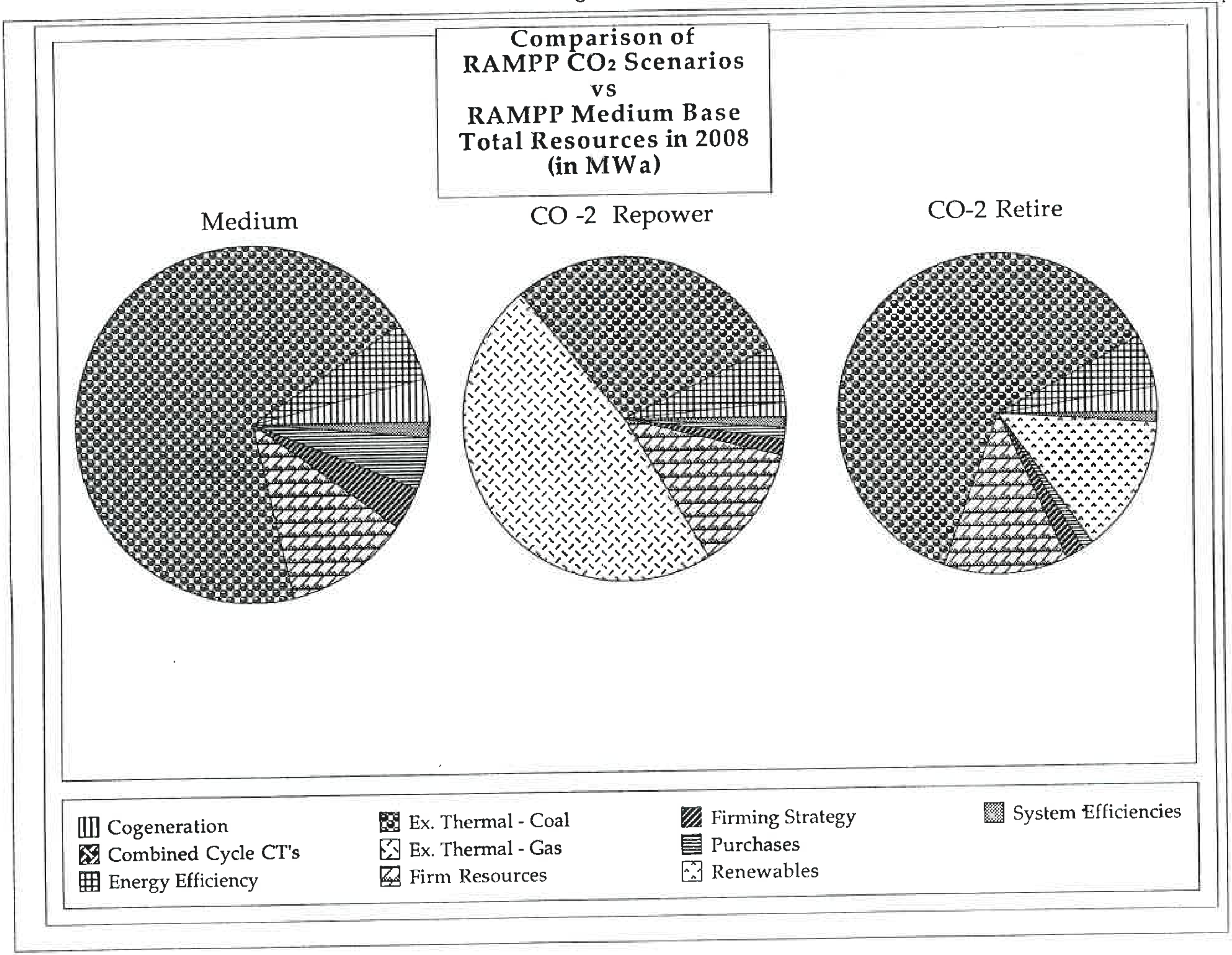
Summary Of Results

CO2 Retiring Scenario

	1989	2008	growth rate
Total Gross Electric Plant (M$)	7235.0	24657.0	
Gross Conservation Assets	*7.0*	*2085.0*	
Total Net Electric Plant (M$)	5290.0	15105.1	
Net Conservation Assets	*6.6*	*1380.2*	
Operating Revenues (M$)			
Nominal	1890.6	6535.8	6.75%
Real	1890.6	1712.1	-0.52%
NPV (13.13% discount rate)	19946.1		
Base Unit Cost (mills/kwh)			
Nominal	49.4	149.1	5.99%
Real	49.4	39.1	-1.22%
Average Customer Bill ($)			
Nominal	1531.1	4086.4	5.30%
Real	1531.1	1070.5	-1.87%
NPV (13.13% discount rate)	14818.3		
Levelized Customer Cost (M$)			
(30 years at a 15.13% discount rate)	0.0	50.2	
NPV (13.13% discount rate)	55.1		
Energy Services Charge (M$)	0.1	183.4	
NPV (13.13% discount rate)	302.2		
Total Resource Cost (M$)			
Nominal	1890.7	6769.3	6.94%
Real	1890.7	1773.3	-0.34%
NPV (13.13% discount rate)	20303.3		
Per Unit TRC (mills / kwh)			
Nominal	49.3	144.3	5.82%
Real	49.3	37.8	-1.39%

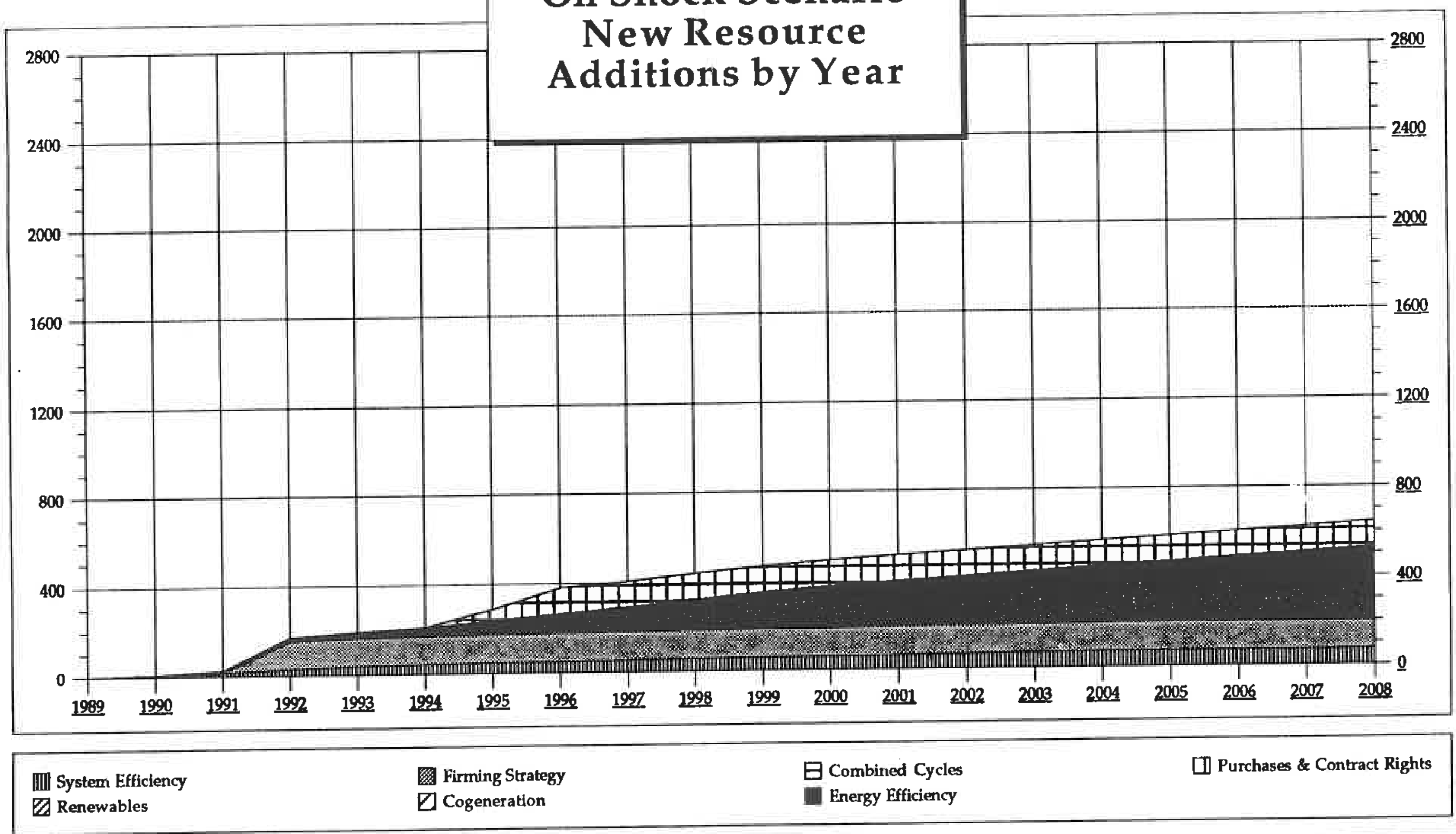
Emissions Data	Total Change in Emissions/MWH 1989 - 2008	Change in Total Emissions per Year 1989 - 2008
SO_2	47.1%	-2.87%
NO_x	49.2%	-2.65%
CO_2	68.2%	-0.96%

Figure 12



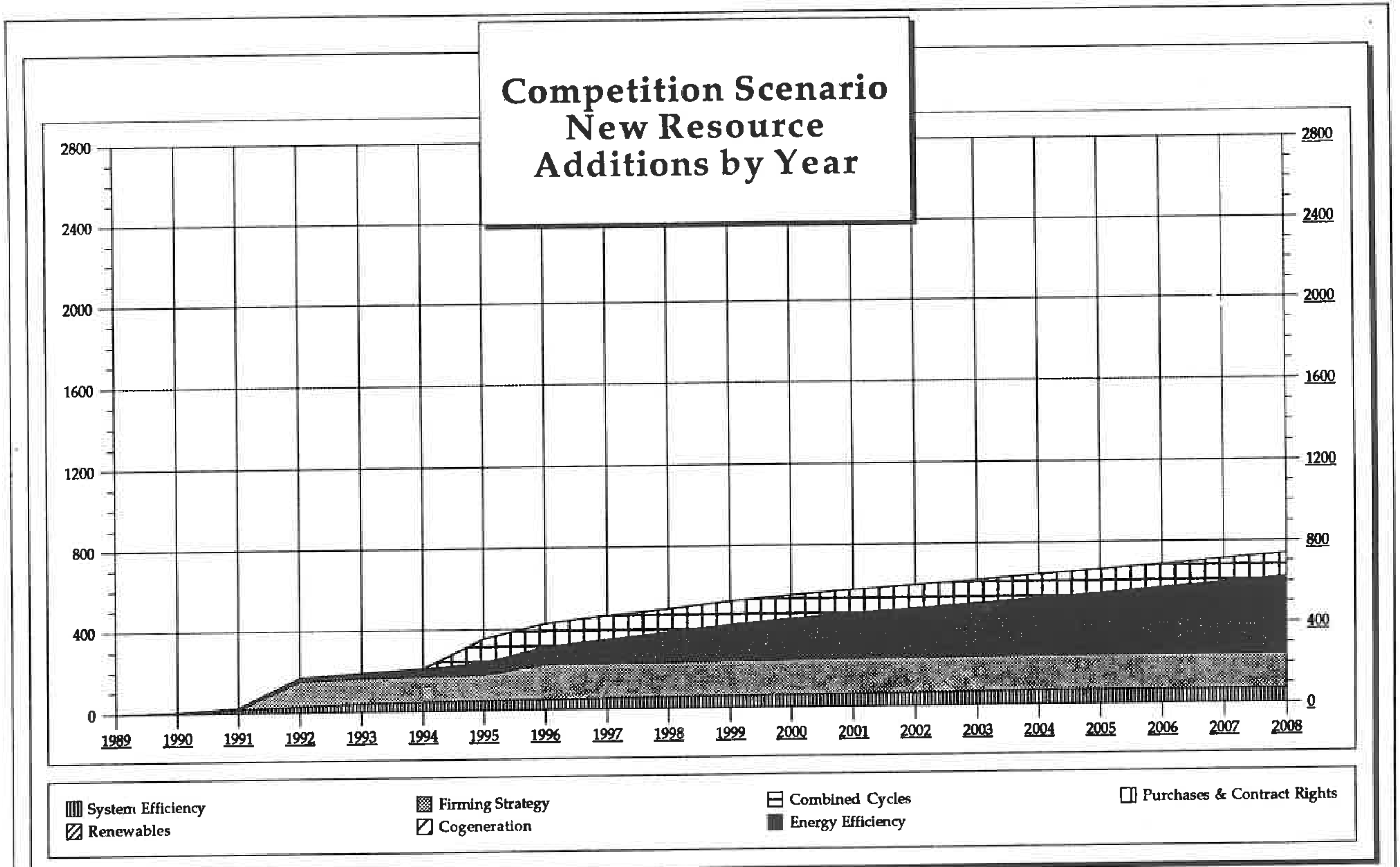
Comparison of
RAMPP CO2 Scenarios
vs
RAMPP Medium Base
Total Resources in 2008
(in MWa)
Medium
CO -2 Repower
CO-2 Retire
Cogeneration
Combined Cycle CT's
Energy Efficiency
Ex. Thermal - Coal
Ex. Thermal - Gas
Firm Resources
Firming Strategy
Purchases
Renewables
System Efficiencies

Oil Shock Scenario New Resource Additions by Year



Average MW's	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiency	0	5	17	29	41	46	49	52	55	58	61	63	65	67	69	71	71	71	71	71
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firming Strategy	0	0	0	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Cogeneration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Combined Cycles	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	1	4	9	17	27	40	64	89	114	139	166	188	206	222	240	256	274	293	312	331
Purchases & Contract Rights	0	0	0	0	0	0	50	115	113	117	115	115	115	115	115	115	115	115	115	115
Totals	1	9	26	171	193	211	288	381	407	439	467	491	511	529	549	567	585	604	623	642

Competition Scenario New Resource Additions by Year



Average MW's	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
System Efficiency	0	5	17	29	41	46	49	52	55	58
Renewables	0	0	0	0	0	0	0	0	0	0
Firming Strategy	0	0	0	125	125	125	125	170	170	170
Cogeneration	0	0	0	0	0	0	0	0	0	0
Combined Cycles	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	1	3	9	17	27	40	65	91	120	149
Purchases & Contract Rights	0	0	0	0	0	0	115	113	117	115
Totals	1	8	26	171	193	211	354	426	462	492

Average MW's	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiency	61	63	65	67	69	71	71	71	71	71
Renewables	0	0	0	0	0	0	0	0	0	0
Firming Strategy	170	170	170	170	170	170	170	170	170	170
Cogeneration	0	0	0	0	0	0	0	0	0	0
Combined Cycles	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	180	205	227	246	266	286	308	332	356	380
Purchases & Contract Rights	115	115	115	115	115	115	115	115	115	115
Totals	526	553	577	598	620	642	664	688	712	736

PLANNING FOR STABLE GROWTH

The Pacific Power and Utah Power
Resource and Market Planning Program

Volume 2 - Technical Appendix

November 1989

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The Pacific Power and Utah Power Resource and Market Planning Program

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Table of Contents

INTRODUCTION

This document is the second volume of a report on the status and findings of PacifiCorp Electric Operation's Resource and Market Planning Program (RAMPP). The material contained within this document provides supporting documentation concerning the assumptions, models, and techniques utilized during the RAMPP process. The RAMPP process culminated in the development of a resource strategy that will guide supply and demand decisions in the future.

The results of the RAMPP process demonstrate that Pacific Power and Utah Power have a broad range of flexible and efficient options that can be used to maintain an efficient balance between demand and supply. Resources can be drawn from a portfolio of demand-side, supply-side, and marketplace options. The resulting resource strategy can be summarized in the following manner: 1) maintain a diversity of resource options, 2) maintain flexibility in terms of acquiring, or choosing not to acquire, a new resource, and 3) practice "just in time" resource acquisition.

This strategy is employed in an inherently uncertain environment. A broad band of uncertainty surrounds projections of future demands. In addition, uncertainties exist with respect to the cost and availability of each of the various demand-side, supply-side, and marketplace options that comprise the resource portfolio. This uncertainty underscores the value of developing and maintaining flexible strategies, as well as a diverse portfolio of new sources, in order to mitigate future risks.

Furthermore, in developing flexible programs and resources that meet direct customer needs, external costs that are borne by the public at large, and not by the Company or its customers, were also evaluated. The conclusion of this evaluation was that the resource strategy resulted in the most efficient selection of resource and program options, in terms of minimizing the estimated impact of external effects while maintaining competitive prices, over all reasonable projections of future demand growth.

Key results of these analyses include: that the new resource portfolio is likely to be sufficient to meet future demand growth over the 20-year planning horizon; application of the flexible portfolio strategy likely would result in relatively stable costs and average customer prices; and the inherent value in a flexible resource portfolio is its ability to respond to unforeseen, dramatically changed circumstances, even if it cannot always avoid cost and price increases.

The elements that comprise this documentation are presented in the following manner. Chapter 2 discusses the various demand forecasts. Chapter 3 discusses the resource portfolio. Chapter 4 discusses the responses to possible alternate futures.

DEMAND FORECASTS

The development of a long-range demand forecast is the first step toward developing a least cost plan. The demand forecast estimates how much electricity retail customers will require over a twenty year time horizon. 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 some instances, take many years to construct or develop.

The planning process recognized the inherent difficulty in forecasting economic and demographic trends, consumer tastes and preferences, and the development and market penetration of new electricity-using technologies and applications over a period as long as twenty years. The process also recognizes that this task is too difficult to be adequately performed by a single demand forecast. Therefore, a range of forecasts were developed that reasonably bound the range of possible futures.

Five separate forecasts have been developed in order to help bound this uncertainty. These five forecasts are referred to as: low, medium-low, medium, medium-high, and high. Each forecast represents a consistent and dynamic representation of how the numerous economic, demographic, and energy utilization variables interact on both the national level, and the service area level. The high and the low forecast are designed to bound the forecast in such a way that the likelihood of the future unfolding outside of the range is highly unlikely. In this context, the term "highly unlikely" refers to a 90 percent confidence level. In other words, there is only a one in ten chance that future economic growth will transpire, in the long-term, in a manner that is outside of the high and low forecast bounds.

The high bound portion of the forecast range is based upon the assumption that strong, stable, economic growth conditions are experienced nationwide, and system-wide, over the next two decades. Employment opportunities are assumed to be plentiful, even within the high-pay, high-skill, manufacturing and mining categories. Inflation and interest rates are each assumed to be moderate. Population is expanding at a moderate pace as individuals are attracted into the service area by employment opportunities and excellent living conditions. Finally, real per capita income, the traditional measure of overall economic well being, is increasing at an annual rate of 1.6 percent per year.

The low bound portion of the forecast range is based upon the assumption that weak economic growth conditions are experienced nationwide, and system-wide, over the next two decades. In addition, a moderate recession is assumed to take place in the early 1990's Employment opportunities become scarce as both the manufacturing and agricultural employment categories experience decline. Inflation and interest rates are each assumed to be high. Population is expanding at an anemic pace as individuals move into the service area to compete for jobs in the service sector. Finally, real per capita income is increasing at an annual rate of only 0.6 percent per year, just slightly above the rate of inflation.

The forecast range technique is similar to the one developed and used by the Pacific Northwest Power Planning Council. Like the Regional Council, the Company believes that the most probable range of forecasts is bounded by the medium-low and medium high forecasts.

Summary of Methodology - Pacific Division

Pacific Division's long-range forecasts are produced in the following manner. Forecasts of economic and demographic variables, such as employment, population, and total personal income, are produced for the Company's service area. These service territory specific forecasts are based upon a twenty-year projection of total national economic activity which is provided by Data Resources (DRI). The results of the economic and demographic forecasts are used as inputs into the electricity sales forecasting models.

The electricity sales forecasting models project electricity demand through the year 2010 for each of six customer classes. These customer classes are: residential, commercial, industrial, street and highway lighting, irrigation, and "other" customer classes. These projections are made using a combination of several widely used forecasting techniques - econometric modeling, and end use analysis.

The resulting economic, demographic, and electricity sales forecasts can be easily varied by assuming different levels of critical "drivers" such as; national and regional economic activity, energy prices, and persons per household. By varying these drivers in a reasonable and consistent manner, the range of forecasts described above can be produced.

These forecasts are produced in a manner that recognizes the unique characteristics of it's service area. The portion of the six states served by Pacific Division are projected independently. The resulting state-level forecasts are then combined to produce forecasts at the regional and division level.

Economic and Demographic Forecasts

The electricity sales forecasts are driven by projections of employment, population, total personal income, and per capita income. Employment is projected on a detailed, industry specific, basis. A projection of the national economic environment is used to set the stage for the regional economy.

Employment: The overall methodology utilized is based upon "regional export base theory". This methodology assumes that the local economy is comprised of two distinct sectors: the "basic" sector, and the "non-basic" sector.

The basic sector is comprised of those businesses and industries which serve out-of-region markets. Consequently, the demand for the products produced by the basic sector, and by extension the level of employment, is determined by market forces which are by and large outside of the regions control. Employment categories which are treated as basic are: manufacturing (such as food processing, lumber & wood products, pulp and paper products, chemicals and allied products, petroleum refining, and primary metals), mining employment (such as coal mining, oil & gas extraction, and trona mining), agriculture, and federal government. A "regional share" approach is utilized to forecast many of the specific industries that make up the basic employment category. A regional share approach evaluates the historic regional growth pattern of a particular industry in relation to that industry's national growth pattern. These shares can then be varied during the forecast period in order to allow the regional component to grow faster, slower, or at the same rate as the industry as a whole.

The non-basic sector is comprised of those businesses and industries which serve in-region markets. Consequently, the demand for the products and services produced by the non-basic sector are determined by in-region market forces. Employment categories which are treated as non-basic include: commercial employment (such as transportation & public utilities, wholesale & retail trade, and finance insurance & real estate) contract construction, state and local government, and non-farm proprietors.

The relationship between basic and non-basic employment has changed over time on the basis of changes in relative productivity, real wages, consumer taste, the intensity of national and international competition. As a result, a relative shift away from basic industries toward those that are service oriented has occurred. It is expected that this trend will continue throughout the forecast interval. This expectation is reflected in each of the five forecasts.

Table 1 displays the summary results of Pacific Division's employment forecast from a 1987 base to the year 2010 for each of the five forecasts. In the medium case, total employment is expected to grow at an average rate of 1.2 percent per year between 1987 and 2010. At this rate of growth 229,000 (9,900 per year) new employees are added to total employment. The majority of these new employees (215,400) are added to the non-basic employment category, indicating a continuing trend toward commercial and service-related employment.

In the high case, over 414,000 (18,000 per year) new employees are added to total employment by 2010. As in the medium case, the majority of these new employees are added to commercial and service related employment. However, under the high case growth assumptions, each of the major employment categories exhibit positive growth over the forecast interval. Under the high growth employment forecast, employees are being added to payrolls at nearly the same pace as was recorded during the regions rapid growth period of 1960 to 1979.

In the low case, 89,400 (3,900 per year) new employees are added to total employment by 2010. As in the other cases the majority of these employees are added to commercial and service related employment. Employment declines in both the manufacturing and agriculture categories.

<u>Population:</u> Data Resources' <u>Regional Information Service</u> contains long-range forecasts of total population, and total non-agricultural employment for the states served by Pacific Division. Population per employee at the state level is calculated by dividing one series by the other. Population per non-agricultural employee at the service territory level is forecast as a function of population per non-agricultural employee at the state level. The forecast of total service territory population is arrived at by multiplying the resulting ratio by the forecast of total non-agricultural employment.

Total population grows in each of the five forecast cases. In the medium case, total population increases from 1.5 million people in 1987 to nearly 1.8 million people by 2010. In the high case total population increases to nearly 2.2 million people: in the low case total population increases to nearly 1.6 million people.

<u>Total Personal and Per Capita Income:</u> Two primary measures of income are utilized in producing the forecast of total electricity demand. Total personal income is used as a measure of "economic vitality" which impacts energy utilization in the commercial sector. Per capita

Table 1

PACIFIC DIVISION

Forecast of Employment By Category
1987 - 2010

	1987	2010 LOW	Growth Rate (87 to10)	2010 MED-LOW	Growth Rate (87 to10)	2010 MEDIUM	Growth Rate (87 to10)	2010 MED-HIGH	Growth Rate (87 to10)	2010 HIGH	Growth Rate (87 to10)
BASIC EMPLOYMENT											
Manufacturing	97,800	82,700	-0.7%	89,400	-0.4%	103,300	0.2%	110,700	0.5%	123,100	1.0%
Mining	11,500	14,300	0.9%	14,300	0.9%	16,100	1.5%	19,100	2.2%	22,900	3.0%
Agriculture	58,100	39,000	-1.7%	49,800	-0.7%	57,500	0.0%	57,900	0.0%	59,400	0.1%
Federal Government	27,600	31,600	0.6%	31,600	0.6%	31,700	0.6%	32,700	0.7%	33,300	0.8%
	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total	195,000	167,600	-0.7%	185,100	-0.2%	208,600	0.3%	220,400	0.5%	238,700	0.9%
NON-BASIC EMPLOYMENT	507,600	624,400	0.9%	650,200	1.1%	723,000	1.5%	773,500	1.8%	878,100	2.4%
TOTAL EMPLOYMENT	702,600	792,000	0.5%	835,300	0.7%	931,600	1.2%	993,900	1.5%	1,116,800	2.0%

income is used as a measure of "purchasing power" which impacts energy utilization in the residential sector. For convenience, the word "real:" has been excluded from the name of each income series even though each of these income measures are adjusted for inflation.

Pacific Division'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 diverse economic base of this service territory, the total personal income forecast is derived from the sum of eight separate components. These eight components are: manufacturing, commercial, mining ,and farm income, contributions for social insurance, transfer payments, property income, and a residence adjustment factor. The majority of these separate income streams are directly affected by changes in employment.

Once the eight components of total personal income have been forecast, they are summed together and divided by the forecast of total population. The resulting figure is the forecast of per capita income.

Per capita income grows in each of the five forecast cases. In the medium case, per capita income increases from $12,400 in 1987 to $16,400 by 2010. In the high case per capita income increases to $18,300: in the low case per capita income increases to $14,300.

Electricity Sales Forecasts

The electricity sales model produces forecasts for the period 1988 through 2010 for each of six customer classes. The forecasts are based upon a consistent set of economic, demographic, and price projections that are specific to each of the six states.

One of the 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 demand. In order to put increased demand-side efficiencies on an equal footing with other supply-side resources, the retail sales forecasts were developed using "frozen efficiencies". What this means is that crucial elements that help constitute an individual customers' total electricity consumption, such as average space heat usage for existing customers, and average appliance usage (except those where new government standards are required), are held at their 1987 levels throughout the forecast period. New dwellings which are added to the existing base over the forecast interval are assumed to be built to current codes, or to meet Model Conservation Standards.

By holding efficiencies constant within the sales forecast, the economics of various energy efficiency programs that might be developed to impact the existing customer market can be fairly evaluated. The economics of these demand-side programs for new and existing customers are evaluated on a fair and consistent basis with supply-side resources on the basis of their ability to meet future customer demand.

Electricity sales to the residential, commercial, and industrial customer classes account for over 97 percent of Pacific Division's total retail sales. For this reason, the following discussion will focus upon these three customer groups.

<u>Residential:</u> The residential sector forecasting model is a hybrid econometric/end use model in which forecasts are made for each of twelve end uses, for each of three structure types. The

twelve end uses evaluated are: space heat, water heat, electric ranges, dishwashers, electric dryers, microwave ovens, refrigerators, televisions, air conditioners, lighting, freezers, and "residual uses". The three structure types are: single family, multi-family, and mobile home.

The number of residential customers is projected as a function of households per person, at the state level, which is derived by dividing DRI's forecast of households by their forecast of total population.

Commercial: Like the residential sector, the commercial sector is modeled using a hybrid econometric / end use model. Forecasts are made at the state service territory level for seven end uses and twelve commercial activity segments. The seven end uses evaluates are: space heating, water heating, space cooling, ventilation, cooking, lighting, and "residual uses". The twelve commercial activity segments are: Communications/Utilities/& Transportation, Food Stores, Retail Stores, Restaurants, Wholesale Trade, Lodging, Schools, Hospitals, Other Health Services, Offices, Services, and "other structures".

Industrial: The industrial sector is modeled using an econometric forecasting system. The industrial sector has been disaggregated into manufacturing and mining customer segments. The following categories are included within the manufacturing category: Food Processing, Lumber and Wood Products, Paper and Allied Products, Chemicals and Allied Products, Petroleum Refining, Primary Metals, and "Residual" Manufacturing. The following categories are included within the mining category: Uranium Mining, Coal Mining, Trona Mining, Bentonite Mining, Oil and Natural Gas Exploration, Pumping, and Pipeline Transportation.

Table 2 displays the results of Pacific Division's electricity sales forecasts which are consistent with the economic and demographic forecasts presented on Table 1. Total retail electricity sales increases by 1.8 percent per year from 1987 through 2010 in the medium case forecast. In the high case forecast, total retail sales are forecast to increase at an annual rate of 2.6 percent, and in the low case by 0.7 percent per year from 1987 through 2010. In each of the five forecast cases, sales to commercial customers are the fastest growing component of total retail sales (in the medium-high case commercial sales and industrial sales increase at the same rate).

These five forecasts demonstrate the magnitude of the uncertainty that is faced with regard to future retail sales. On the one hand, under the low case total retail sales could be 17 percent higher than they are today by the year 2010. On the other hand, under the high case total retail sales could be nearly double (+84 percent) what they currently are today by the year 2010.

Summary of Methodology - Utah Division

Utah Division projects electricity sales for each major class of customer in two intervals. The first interval covers the period 1989 to 1999, the second interval covers the period 1999 to 2010. The customer groups whose retail sales are specifically evaluated include: residential, commercial, industrial, street & highway lighting, other sales to public authorities, contract sales for resale, and interruptible. The industrial customer class is disaggregated into four components: general service customers, oil customers in the "over-thrust" area, irrigation, and large, special contract customers.

Table 2

PACIFIC DIVISION

Forecast of Electricity Sales By Customer Class
1987 - 2010

	1987	2010 LOW	Growth Rate (87 to10)	2010 MED-LOW	Growth Rate (87 to10)	2010 MEDIUM	Growth Rate (87 to10)	2010 MED-HIGH	Growth Rate (87 to10)	2010 HIGH	Growth Rate (87 to10)
Residential Customers	570,000	605,900	0.3%	634,900	0.5%	689,400	0.8%	738,800	1.1%	835,300	1.6%
Residential Sales *(Thousands MWa)*	6,700	7,100	0.3%	7,600	0.5%	8,300	0.9%	9,000	1.3%	10,300	1.9%
Commercial Sales *(Thousands MWa)*	5,100	6,700	1.2%	7,800	1.8%	8,700	2.3%	9,500	2.7%	10,500	3.1%
Industrial Sales *(Thousands MWa)*	8,700	10,500	0.8%	11,900	1.4%	14,500	2.2%	16,300	2.7%	17,600	3.0%
Other Sales *(Thousands MWa)*	700	500	-1.5%	300	-3.8%	400	-2.5%	500	-1.5%	700	0.0%
	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
Total Sales *(Thousands MWH)*	21,200	24,800	0.7%	27,600	1.1%	31,900	1.8%	35,300	2.2%	39,100	2.6%

The methodology employed to project future electricity sales to each customer group is based upon the following elements: 1) a thorough understanding of local economic and demographic trends that have affected, and will continue to affect, small customers, 2) regular and detailed discussions with the 200 largest industrial and commercial customers concerning current and future economic conditions and potential changes in electric requirements, and 3) the application of experienced judgement.

The majority of retail demand is accounted for by sales to the residential, commercial, and industrial (including irrigation) customer classes. In 1987 these three major customer groups accounted for 96 percent of total retail sales. For this reason, the following discussion will focus upon these three customer groups.

<u>Residential:</u> Over the first ten years of the forecast, a significant slowing in the rate of growth of residential electricity sales compared to that experienced over the past years is expected. The rate of growth is expected to increase somewhat in the second ten years of the forecast as the "boom/bust" cycle of residential customer growth begins to enter another boom phase.

This projection is based upon the relative changes in residential customer growth, and in usage per customer. In terms of customer growth, a slowdown is expected as the "baby-boom" surge in housing demand continues to wane. This slowing is expected to continue until the mid-1990's when the children of the baby-boom generation are expected to enter the housing market. Average household electricity consumption will remain at current levels, or decrease slightly, over the forecast period.

<u>Commercial:</u> The rate of growth of electricity sales to commercial customers will also grow at a slower rate to that recorded in the recent past over the full forecast interval.

<u>Industrial:</u> The overall industrial category will grow at a different rate than that recorded in the past. This projection is based upon observations related to each of the four components that comprise the industrial class. These four components are: General Service Customers, Oil Customers, Irrigation Customers, and Special Contract Customers.

1) General Service Customers: A recurrence of the numerous economic cycles and shocks that characterized the pattern of growth experienced by these customers over the past twenty-five years is not expected. Consequently, the future growth trend of electricity sales to this industrial component will be moderate, and free of any severe positive, or negative, economic oscillations.

2) Oil Customers: While few new major oil field discoveries are expected in the over-thrust area during the forecast interval, the increased use of enhanced oil recovery techniques will require the increased use of electricity per barrel of oil extracted. Low to moderate growth is therefore expected as facilities that are already in place begin to shift to these more electricity-intensive recovery techniques.

3) Irrigation Customers: Total electricity sales to irrigation customers is expected to decline slightly from current levels, and then remain fairly constant at this lower level

throughout the forecast interval. Most of the land located within Utah Division's service area that is suited for irrigation is currently under cultivation, and many farms are being converted each year to urban and industrial use as economic development continues to advance.

4) Special Contract Customers: Anticipated major facility modifications that are expected to occur by 1996 are included in the forecast. Such modifications are discussed in advance in meetings between Utah Division's large customer representatives, and those representing special contract customers. After 1996 it is assumed that all of the major modifications have taken place, therefore no further change in electricity requirements are made after this time.

Table 3 displays the results of Utah Division's electricity sales forecasts. A forecast range, similar to the one used for Pacific Division's electricity sales, was estimated in a manner that is generally consistent with the economic and demographic forecasts presented on Table 1. Total retail electricity sales increase by 1.7 percent per year from 1987 through 2010 in the medium case forecast. In the high case forecast, total retail sales are forecast to increase at an annual rate of 2.5 percent, and in the low case by 0.8 percent per year from 1987 through 2010. In each of the five forecast cases, sales to commercial customers are the fastest growing component of total retail sales.

These five forecasts display the magnitude of the uncertainty that is face with regard to future retail sales. On the one hand, under the low case total retail sales could be 21 percent higher than they are today by the year 2010. On the other hand, under the high case total retail sales could be nearly double (+81 percent) what they currently are today by the year 2010.

Table 4 displays selected key DRI macroeconomic variables, and their variability between the high, medium and low cases.

Table 3

UTAH DIVISION

Forecast of Electricity Sales By Customer Class
1987 - 2010

	1987	2010 LOW	Growth Rate (87 to10)	2010 MED-LOW	Growth Rate (87 to10)	2010 MEDIUM	Growth Rate (87 to10)	2010 MED-HIGH	Growth Rate (87 to10)	2010 HIGH	Growth Rate (87 to10)
Residential Customers	467,313	658,000	1.5%	690,000	1.7%	749,000	2.0%	803,000	2.3%	908,000	2.8%
Residential Sales *(Thousands MWa)*	3,577	4,232	0.7%	4,246	0.7%	4,614	1.1%	4,948	1.4%	6,172	2.3%
Commercial Sales *(Thousands MWa)*	3,208	5,565	2.4%	5,662	2.4%	6,236	2.8%	6,829	3.2%	7,568	3.7%
Industrial Sales Including Irrigation *(Thousands MWa)*	7,543	7,517	0.0%	9,096	0.8%	10,630	1.5%	11,946	2.0%	12,448	2.2%
Other Sales *(Thousands MWa)*	599	766	1.1%	765	1.1%	765	1.1%	765	1.1%	766	1.1%
Total Retail Sales *(Thousands MWH)*	14,927	18,080	0.8%	19,769	1.2%	22,245	1.7%	24,488	2.1%	26,954	2.5%

Table 4

Key Macroeconomic Variables
High - Medium - Low

	HIGH	MEDIUM	LOW
Real Gross National Product *(Annual Growth -1988 to 2008)*	2.8	2.3	1.9
Consumer Price Index *(Annual Growth - 1988 to 2008)*	4.4	5.3	6.9
Housing Starts (Millions) *(Annual Average - 1988 to 2008)*	1.68	1.53	1.42
Civilian Unemployment Rate (Percent *(Annual Average - 1988 to 2008)*	5.6	5.6	5.9
Real Personal Income (1988 $) *(Annual Growth - 1988 to 2008)*	1.8	1.4	1.1
Industrial Production *(Annual Growth - 1988 to 2008)*	3.4	2.7	2.2
Non-Farm Employment *(Annual Growth - 1988 to 2008)*	1.4	1.1	0.8

RESOURCE PORTFOLIOS

A. DEMAND SIDE PORTFOLIO

Consumers do not purchase energy - such as electricity, natural gas, wood, or petroleum products - for what it is, but rather for what it does. Consumers want the benefits of using energy for specific services These energy services include ultimate end-uses such as: space conditioning (heating and cooling), water heating, lighting, cooking, refrigeration, motor drive, and transportation. If those same end-uses can be achieved using less energy (higher efficiency) then more energy will be available for use by others.

By decreasing the physical amount of energy consumed, energy efficiency improvements make additional energy available to other consumers. Improvements in energy efficiency can therefore be evaluated as a potential source of new energy. The resulting new energy resource is referred to as a"demand-side" resource.

In evaluating the amount of this potential that could become available, and at what cost, it is essential to look at specific customer end-uses of energy, as well as specific devices. The planning methodology employed to assess the cost and quantity of this demand-side resource does both.

The Total Resource Cost (TRC) concept for the planning of demand, as well as supply-side, options has been selected as a reasonable measure for determining relative cost-effectiveness between programs and options. This approach requires that cost decisions be based on the sum of all direct costs, including those paid by the utility, its customers, and other parties. Included within the estimates of TRC are all administration costs. For planning purposes, programs are ranked in order of increasing TRC.

Of equal importance is the net cost to the utility which will ultimately be passed to customers. Selection of programs based on TRC does not necessarily obligate the utility to pay all of the costs. Part of the TRC may be paid directly by customers, or by government agencies. This minimizes the financial burden on the utility. However, if on this basis the cost of a resource places an undue financial burden on customers, then its viability becomes questionable.

There are trade-offs between the total resource cost and the utility net cost. For example, consider an efficiency improvement that will be required by a change in building codes. The cost of that efficiency resource would be borne by customers and builders. The utility, which would have very little direct cost associated with the program, might be expected to promote this option. However, before the utility can adopt such a planning approach, it must check to make sure that the measure meets the TRC test. It may be that the measure is too expensive for society as a whole.

Utility cost is also influenced by the net savings produced by a program. The net energy savings may be reduced by customer takeback or "free riders". These concepts are discussed in more detail below. At this point, it is important to note that from societies perspective the TRC of any given program option is not affected by takeback of some of the energy savings.

It is important to note that the TRC methodology, which is very useful in determining the relative cost-effectiveness of various dissimilar utility options, is not by itself a totally adequate means upon which to base a resource option choice. Other considerations such as: timing, resource size, availability, lost-opportunity determination, and environmental considerations, enter into the resource selection.

Planning Methodology

The initial step in the evaluation of energy efficiency resources is to identify the total potential size of the demand-side resource at an associated cost that is lower than a predetermined ceiling. The predetermined cost effectiveness ceiling price was set at a level of 55 mills per kilowatthour, adjusted for inflation, in the year 2010. The total amount of the efficiency resource that could be forthcoming from existing customers, and those assumed to be added to the customer base is referred to as the **technical potential**.

The technical potential includes all efficiency improvements that fall beneath the price ceiling. It is based on assumptions regarding current customers and their associated patterns of energy use, and a reasonable estimate of future customers and their associated patterns of energy use.

The total technical potential within the existing stock of dwellings and energy-consuming devices, and expected addition to the stock from new construction over the next twenty years (assuming a medium economic scenario) is estimated to be 1,059 average megawatts with a cost effectiveness ceiling of 55 mills per kilowatthour. Table 5 displays the estimated technical potential and how it is divided among the individual customer sectors on the basis of existing stock and new construction.

In order to increase the value of efficiency resources as viable power planning options, it is necessary to reduce the estimate of the technical potential to an amount that is considered achievable. Achievable efficiency is the net resource that is available after taking into consideration various obstacles to full implementation such as: consumer behavior, market imperfections, program design and quality control limitations, and unforeseen technical problems. Fortunately, many of the obstacles to full implementation can be influenced to a certain degree by utilities and policy makers. Effective programs, incentives, and regulatory measures aimed at overcoming these market and institutional barriers can be developed and pursued in a manner that will increase the percentage of the total technical potential that is actually achievable within the cost effectiveness guidelines.

A portion of the technical potential could be achieved by customers acting on their own without the benefit of a utility-sponsored efficiency program. The total impact of this cost-induced efficiency improvement accounts for a relatively small proportion of the total technical potential. Table 6 displays the estimate of the amount of cost-induced efficiency included within the estimate of technical potential. In total, the cost induced component of the technical potential accounts for approximately 12 percent of the total. Cost-induced efficiency estimates were not developed for the industrial sector due to incomplete data about low-cost industrial efficiency options. These estimates of cost-induced efficiency improvements were *subtracted* from the expected outcome of efficiency programs (program development and implementation is discussed in detail below) to give the net effect of each program.

Table 7 displays the adjustments to technical potential that were made to each of the programs that have been included in the two-year action plan in order to arrive at total programmatic potential. Several initial adjustments were made to the technical potential. For example, solar access is not addressed in the MCS program, so it was removed when calculating the program

Table 5

Pacific Power & Utah Power

Efficiency Technical Potential in the Year 2010 (*)
Medium Economic Forecast - 55 mill / kWh or Less
(Average Megawatts)

Sector		Existing Stock	New Construction	Total Stock
Residential				
	Single Family	69	70	139
	Manufactured Homes	20	27	47
	Multi-Family	10	16	26
	Appliances	----	170	170
	Subtotal	100	283	382
Commercial		105	160	265
Industrial		----	----	412
Total				1059

(*) Columns and rows may not sum due to rounding.

Note: Total technical potential includes 133 MWa of efficiencies from Model Conservation Standards (58 MWa commercial, 75 MWa residential). These savings are included in the demand forecast. Thus, the potential available for new resource acquisition is 926 MWa.

Table 6

Pacific Power & Utah Power

Cost Induced Conservation Technical Potential in the Year 2010
Medium Economic Forecast - 55 mill / kWh or Less
(Average Megawatts)

Sector	Existing Stock	New Construction	Total Stock
Residential	9.2	0	9.2
Appliances	----	31.8	31.8
Commercial	28.1	37.7	65.8
Industrial	----	----	----
Total	37.3	69.5	106.8

Table 7

Adjustments to Technical Potential Required to Arrive at Programmatic Potential

SECTOR	TECHNICAL POTENTIAL (MWa)	ADJUSTMENT (MWa)	BACKGROUND CONSERVATION (MWa)	PENETRATION (Percent)	LINE LOSS (Percent)	TAKEBACK (Percent)	PROGRAM POTENTIAL (MWa)
New Single Family & Multi-Family	55	-11 (a)		76	10	-15	31
Utah New Single Family & Multi-Family	31			70	10	-15	23
New Manufactured Homes	27			61	10		18
Industrial	412	-88 (b)		59	5		200
New Appliances	170	-29 (c)		29	10		22
Existing Commercial	105		-13	73	10		74
New Commercial	160	-58 (d)	-17	63	10		47
Existing Residential	160			69	10	-23	58

(a) Solar Access
(b) 30 mill ceiling
(c) New Technologies
(d) New Building Codes

penetration rate. Some of the appliance potential represents new products not yet on the market. New commercial sector efficiency is assumed to be partly covered by a new building code to become effective in the early 1990's.

The industrial program only addressed savings below 30 mills per kilowatthour. This is based on the assumption that a shared savings program would not be attractive since the industrial rate is about 30 mills per kilowatthour. In the case where more resources are needed, the industrial program could be expanded to produce more savings, but at a higher cost.

The calculation is made as follows: an adjustment deletes a portion of the resource which is not addressed in the programs, and, background conservation, if any, is then subtracted. The result is taken times the penetration rate times (1 + the line loss) times (1 minus any takeback fraction). This gives the programmatic savings estimated for deployment.

Once the programmatic potential has been identified, the issue shifts to question of how much of that potential can be obtained at a given price. Efficiency Program Supply Curves were developed to evaluate the amount of the efficiency resource that is expected to be available at various price levels. A supply curve is an economic description of how much of a certain product will be made available by suppliers at various prices. In the case of efficiency resources, the suppliers are energy users who supply more generating resource to others by increasing the efficiency of their own energy use.

An efficiency program supply curve model was developed for all major customer classifications within the Company's service area. The efficiency program supply curve displays the amount of energy savings that is expected different prices. Figure 1 displays the estimated aggregate programmatic supply curve for the year 2010 based upon a medium economic forecast.

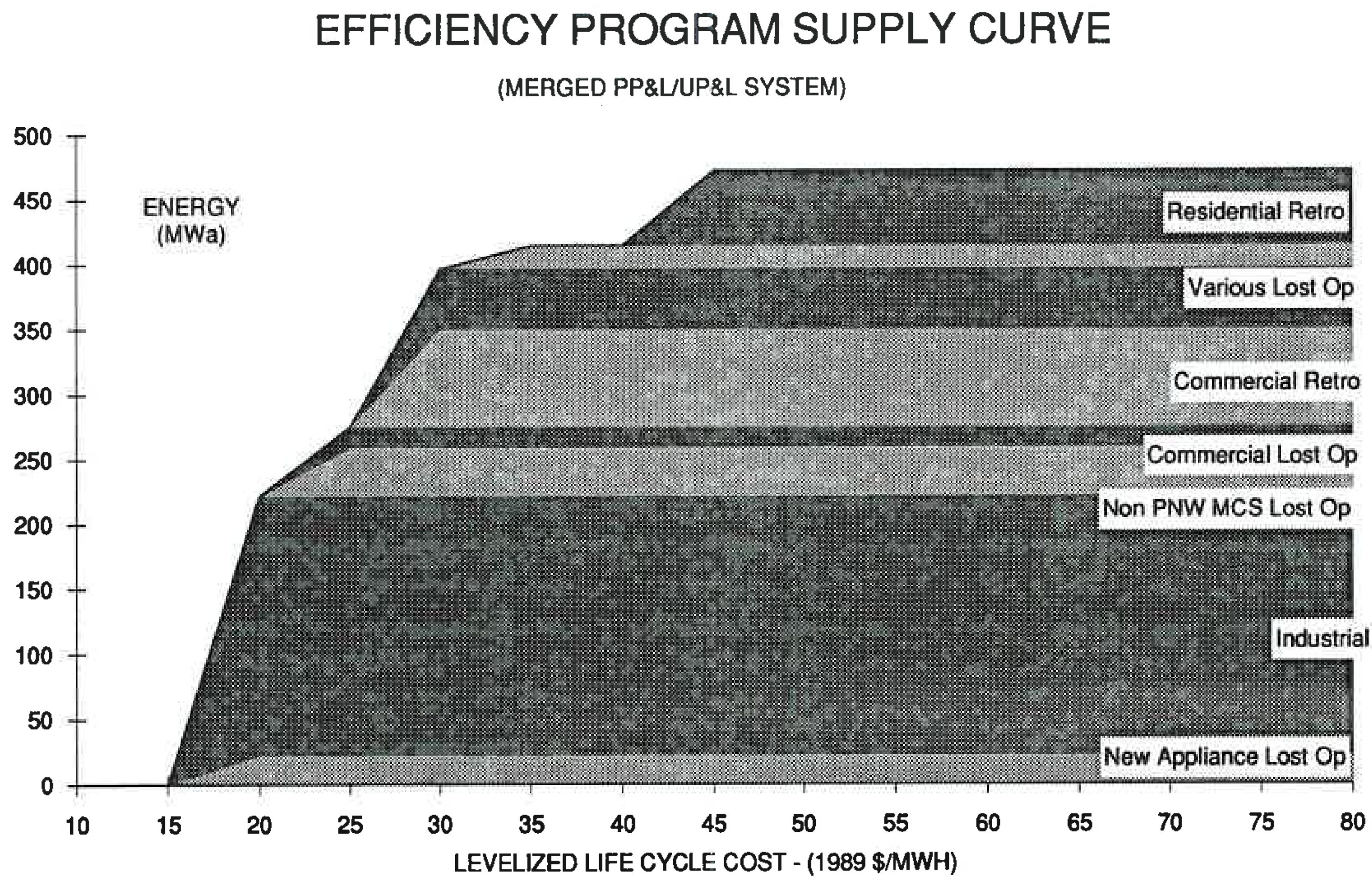
The model used to develop this supply curve is a spreadsheet-based system that evaluates major energy end-use categories, and prototypical residential dwelling, commercial building, and industrial process information for each of the three major customer classifications. The model also relies upon input data regarding real discount rates, measured both from the consumers perspective and from the utilitys perspective, as well as the overall forecast of economic activity.

On the basis of this two stage analytical process -- the determination of the technical potential, and the development of the programmatic supply curve -- specific efficiency measures can be evaluated. These measures generally fall into two categories: discretionary measures (those whose timing and implementation can be varied on the basis of resource needs), and lost opportunities.

Lost opportunity resources are efficiency resources which, while not cost effective at current marginal costs, are expected to be cost effective over their lifetime. These resource measures are referred to as "lost" opportunities due to the brief window that exists during which they can be efficiently captured. If the window is missed, the efficiency resource is lost forever or becomes prohibitively expensive to achieve.

For example, a lost opportunity resource could be created if new residential dwellings do not include all cost effective efficiency measures. Once completed, the building is prohibitively expensive to retrofit with high efficiency components. The end result is a long-lived, energy consuming, building which will never be as efficient as it could have been had it been

Figure 1



EFFICIENCY PROGRAM SUPPLY CURVE
(MERGED PP&L/UP&L SYSTEM)
ENERGY (MWa)
500
450
400
350
300
250
200
150
100
50
0
Residential Retro
Various Lost Op
Commercial Retro
Commercial Lost Op
Non PNW MCS Lost Op
Industrial
New Appliance Lost Op
10
15
20
25
30
35
40
45
50
55
60
65
70
75
80
LEVELIZED LIFE CYCLE COST - (1989 $/MWH)

constructed to efficiency standards known to be cost effective when measured over its entire lifetime.

The approach taken with regard to these two efficiency categories varies upon whether the resource is discretionary, or represents a lost opportunity. Lost opportunity resources are captured as the opportunities arise. Discretionary efficiency resources can be captured on the basis of cost and timing as the need for future resources arises.

Program Development

Programs are groupings of various efficiency measures that are targeted for significant market penetration, cost effectiveness, manageability, and maximum effect. In addition, programs are developed that avoid the creation of lost opportunities, and ensure the participation of low-income homeowners and renters.

Specific efficiency measures are grouped into programs that present an integrated package whose cost and resource deliverability can then be evaluated against other demand and supply-side resource options.

In some instances a pilot program may be developed prior to the decision of whether of not to ramp-up to a major resource acquisition program. A pilot program is a localized, high-intensity, test program that evaluates the program's marketability, the ability to cost share with customers, and "builds capability". By building capability, the Company increases its ability to significantly expand the program when, and if, acquisition is eventually needed.

Program design, monitoring and evaluation, and market transformation all become essential components of a complete resource development package. In addition, price impact and equity issues are also important.

Program Design: Each program consists of a "bundle" of individual efficiency measures subject to the constraint that no single measure has a levelized cost greater than the cost effectiveness ceiling used to determine the technical potential.

Program Timing and Ramping Rate: Efficiency programs are generally thought to have short lead times, and the ability to be easily started, or stopped, as conditions warrant. In fact, there are numerous constraints to effective efficiency deployment that impact the various programs timing and ramping rates.

Energy efficiency programs are dependent upon the perspectives of consumers, equipment suppliers and others. These programs will not succeed if they are not effectively deployed, or if they are changed too often. Critical contractors and equipment suppliers cannot stay in business if program implementation rates vary excessively. Thus, there are minimum viable levels necessary to maintain energy efficiency 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 hired and trained. Administrative costs become difficult to control as programs become larger and more complex. Thus, a maximum efficient ramp-up rate exists for each program. These various programs need to be managed so that the underlying industry stays viable during periods of surplus, and then can be effectively developed when required. Lead-times and ramp-up rates for demand-side resources are not clearly quantifiable numbers. The ramp-up rates used were developed based primarily on "expert judgement". There is considerable uncertainty with any ramping/lead-time estimate. The estimates here represent one plausible set of assumptions, but are not only possible set.

Ramp rates are an issue for deferrable conservation programs and are subject to these constraints: (1) programs start in 1989 or 1990 from essentially zero and, thus, initial efforts focus on program development versus acquisition; (2) it is estimated that programs cannot increase faster than one doubling each year. Sufficient capacity, however, should be in place by 1995 to move to full acquisition, if needed. A complete lead-time cycle works out to about 5 years. To a certain extent, programs could be operated at a lower level if the date for acquisition appears to be further into the future. However, it is doubtful they could be operated more quickly.

Program Monitoring and Evaluation: The achievement of cost and penetration targets will require an explicit and timely monitoring and evaluation component. Evaluation must be closely integrated with program planning and operations in order to perform the following essential tasks: 1) establish and update work and materials specification, 2) develop and produce periodic tracking reports, 3) establish an impact evaluation methodology for credible certification of program outputs, 4) provide expert "trouble shooting" analysis, 5) Identify other market opportunities, and 6) provide ongoing input into the power planning process.

Market Transformation: Utility programs operate within an evolving regulatory and market environment. Major demand-side programs require the direct participation of numerous parties: program participants, contractors, suppliers, designers, government agencies, and utilities. Direct action by the utility, or by government agencies, is sometimes required to overcome market barriers to efficiency investments which are not cost effective at current prices, but are cost effective over their lifetime. However, once these barriers have been overcome, and each of the parties is actively involved in the program, then the market is considered to be transformed. The utility program is no longer necessary although customers will continue to receive the benefits of efficient installations. An example of a market transformation is the development and implementation of construction codes that incorporate all energy efficiency measures that will be cost effective over the life of the dwelling.

Price Impact and Equity: Utility financed energy efficiency programs present a paradox to utilities, customers, and regulators. Although the energy efficiency measure may be less expensive in the long run than supply-side resources, its successful implementation can cause per unit electricity prices to increase. Utilities rely on customer payments to meet the fixed expenses associated with previously constructed facilities, transmission lines, distribution facilities, and customer service networks. These expenses were incurred in order to provide electric service to all customers. To the extent that some customers, by taking advantage of a utility-sponsored energy efficiency program, are successful in reducing their purchases, prices must increase across all remaining sales in order to recover the same amount of fixed costs plus cover the added program costs.

An "energy service charge" concept has been proposed in response to these equity concerns.. Through the energy service charge, customers that participate in Company-sponsored energy efficiency programs will pay a significant share of the cost of the investments made directly on their behalf while still enjoying lower overall energy costs due to kilowatthour savings. This appears to be a reasonable mechanism through which program participants, who are receiving a valuable energy service, could return a portion of their energy savings to non-participants. This program feature could substantially reduce the impact of future energy efficiency programs on overall prices.

Implementation

The manner in which the various programs are implemented will determine the extent to which they are successful in delivering the expected proportion of the technical potential of each of the individual efficiency measures. Effective implementation ensures that each of the following program goals are met. Meeting these goals helps ensure that the efficiency program not only benefits customers but also makes its targeted contribution to the resource portfolio.

A. Minimize Lost Opportunities: 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 their operation. The programs that are developed and implemented should be comprehensive, including all cost effective measures that can be put into place during the initial site visits.

B. Low Income Household Participation: In keeping with the commitment to assure that low income customers are equally represented in utility-sponsored efficiency programs, these programs will be implemented in such a manner such that the number of low income participants, relative to all participants, will be at least as great as the proportion of low income customers to all customers. In the case of programs targeted to the residential sector, this implies that at least 22 percent of the participants must be low income customers.

C. Cost Control: Multiple utility programs will involve thousands of smaller individual transactions. There is an enormous opportunity for cost savings through effective coordination and cost control, and there is an equal threat of cost overrun due to inadequate program planning and management. Anticipating a high level of program activity mandates consideration of several cost control issues early in the design phase. These cost control issues are:

1) **Selection of Eligible Measures.** The effective operation of this safeguard will prevent the inclusion of a non-cost effective measure from entering the program bundle, thereby causing the unnecessary deterioration of the programs economics.

2) **Cost Sharing.** Cost sharing between the participants and the utility helps ensure that both parties are realizing economic value from the energy efficiency investment. Presumably, the program participant is free to invest in the energy efficiency measures without the aid of the utility program. If the utility program becomes overburdened with costs it loses whatever competitive advantage - direct access to customers, access to low cost capital, technical expertise, and economies of scale - it may have had in delivering cost effective energy service improvements to the customer.

3) **Program Synergies**. The requirement for significant program delivery means that several programs will be operating simultaneously. Programs designed as a package offer opportunities for cost savings through consolidated operations, materials purchase, program marketing, and coordinated evaluation and reporting services. In addition, per unit program costs will be reduced over time as the program management and implementation teams gain more experience, and as more programs are put into operation.

4) **Market Transformations**. As mentioned earlier, successful utility efficiency programs will have the eventual effect of becoming the market standard. As this transformation to a more energy efficient environment occurs the need for individual utility programs will be reduced. Successful utility programs will be discontinued once these market transformations make them obsolete.

D. Evaluation: An explicit and timely program evaluation component can assist in the achievement of program cost and penetration targets, as well as help ensure that quality standards are met across all programs, Company-wide. In order to yield the full benefit evaluation must be closely integrated with operations and planning. Feedback and evaluation of programs are major components in the program design.

Demand-Side Resource Portfolio

Table 8 displays the current major resource acquisition program portfolio that is applicable to a medium economic forecast. The total resource yield of these ten programs by the year 2010 is 600 average megawatts. The gross utility program cost is nearly $1.3 billion in 1989 dollars.

The following is a brief description of each of the ten programs listed on Table 8.

Utah Commercial Model Conservation Standards (MCS) is a program designed to provide incentives and technical assistance to builders in the state of Utah in order to help bring commercial building practices up to MCS levels. It is anticipated that the state of Utah will eventually adopt MCS building standards for all new commercial construction. This program is designed to yield 16 average megawatts at a total levelized resource cost of 24 mills per kilowatthour.

New Appliances is a program designed to provide incentives and marketing assistance to retailers and consumers in order to increase the market penetration of energy efficient appliances in advance of tightened federal appliance usage standards. This program is designed to yield 22 average megawatts at a total levelized resource cost of 18 mills per kilowatthour.

Lighting and Water Heat Retrofit is a program designed to increase the market penetration of miscellaneous energy efficiency devices such as light bulbs. It is anticipated that the programs will utilize an energy service charge or leasing system. This program is designed to yield 14 average megawatts at a total levelized resource cost of 22 mills per kilowatthour.

Commercial Building Retrofit is a program designed to increase the energy efficiency of existing commercial buildings through energy system redesign (such as the lighting, food

Table 8

Pacific Power & Utah Power
Major Resource Acquisition Programs - Based upon Medium Economic Forecast 1990 to 2010

PROGRAM	PHYSICAL GOAL	TIMING	RESOURCE YIELD MWa	TOTAL LEVELIZED RESOURCE COST Mills/Kwh	LEVELIZED UTILITY COST Mills/Kwh	GROSS UTILITY PROGRAM COST MILLIONS 1989 $'s	KEY FEATURES
UTAH COMMERCIAL MODEL CONSERVATION STANDARDS (LOST OPPORTUNITY)	18,000 Buildings	1990-2010	16	24	4	$6	Short term program. Benefits from market transformation, or MCS code adoption
NEW APPLIANCES (LOST OPPORTUNITY)	1 Million Appliances	1990-2010	22	18	24	$73	Short term program. Benefits from market transformation, or MCS code adoption
LIGHTING AND WATER HEAT RETROFIT	200,000 Homes	1995-2002	14	22	19	$27	Energy Service Charge Based Program
COMMERCIAL BUILDING RETROFIT	55,000 Buildings	1995-2002	75	25	14	$152	Cost share with participant via energy service charge
UTAH RESIDENTIAL MODEL CONSERVATION STANDARDS (LOST OPPORTUNITY)	55,000 Homes	1990-2010	23	41	4	$11	Short term program. Benefits from market transformation, or MCS code adoption
NEW COMMERCIAL BUILDING (LOST OPPORTUNITY)	60,000 Buildings	1990-2010	47	28	13	$162	On-going, utility-financed, lost opportunity acquisition program
INDUSTRIAL PROGRAM	217 Plants	1990-2010	200	18	6	$262	Expert technical assistance, and financing, provided by the utility
NEW RESIDENTIAL MCS (LOST OPPORTUNITY)	94,500 Homes	1990-2010	31	50	8	$29	Short term program. Benefits from market transformation, or MCS code adoption
NEW MOBILE HOME MODEL CONSERVATION STANDARDS (LOST OPPORTUNITY)	37,000 Homes	1995-2010	18	41	0	$0	No utility program. Benefits from market transformation, or MCS code adoption
RESIDENTIAL BUILDING RETROFIT	198,000 Homes	1995-2002	58	40	35	$462	Cost share with participant via energy service charge
NEW MAJOR THERMAL APPLIANCES	250,000 Heat Pump, Solar Water / Solar Space	2000-2010	57	80 TO 120	35	$109	Cost share with participant via energy service charge
			561 MWa			$1,293	

preparation, and HVAC systems), shell improvements (such as window film and increased insulation), and equipment replacement. This program is designed to yield 75 average megawatts at a total levelized resource cost of 25 mills per kilowatthour.

Utah Residential Model Conservation Standards is a program designed to provide incentives and technical assistance to builders in the state of Utah in order to help bring residential building practices up to MCS levels. It is anticipated that the state of Utah will eventually adopt MCS building standards for all new residential construction. This program is designed to yield 45 average megawatts at a total levelized resource cost of 20 mills per kilowatthour.

New Commercial Building (Lost Opportunity) is a program that it designed to capture cost effective efficiency improvements in new commercial buildings that are not included within the model conservation standards. Unlike the commercial MCS program, this program will continue to operate following the adoption of MCS codes. This program is designed to yield 47 average megawatts at a total levelized resource cost of 28 mills per kilowatthour.

Industrial Program reflects an increase in the Industrial Sector Representative program. Under this program, expert technical representatives are assigned to specific industrial accounts to work closely with those facilities to ensure the timely development of cost effective, location and industry-specific, efficiency improvements. In some instances, financial assistance will be offered in order to improve the market penetration of long-term efficiency technologies. This program is designed to yield 173 average megawatts at a total levelized resource cost of 19 mills per kilowatthour.

New Mobile Home Model Conservation Standards is not strictly defined as a utility program. Rather it is a reflection of the adoption of MCS codes for mobile homes. It is expected that the adoption of mobile home MCS codes will yield 24 average megawatts at a total levelized resource cost of 34 mills per kilowatthour.

Residential Building Retrofit is a program designed to increase the energy efficiency of existing residential buildings primarily through shell improvements (such as high-efficiency windows and increased insulation), and equipment replacement. This program is designed to yield 66 average megawatts at a total levelized resource cost of 41 mills per kilowatthour.

New Major Thermal Appliances is a program designed to increase the market penetration of new, large, residential thermal appliances such as heat pumps, solar hot water systems, and solar space heating systems. This program is designed to yield 57 average megawatts at a total levelized resource cost of between 80 to 120 mills per kilowatthour. Because this program exceeds the cost effective ceiling, it was not included in any RAMPP scenario

The Customer Efficiency Component of the Near-Term Action Plan

The Action Plan describes the actions that the Company will take in the near-term toward achievement of its 20-year goals. The Plan provides a set of programs for the next two years based on assumptions about the best strategy for the future. It also provides a standard against which to measure progress toward meeting long-term goals. The plan assumes a five-year commitment to ramping and capability building.

Given the uncertainty of predicting the future, no plan can be expected to set a specific path. Instead the plan provides the general direction. Several activities are being undertaken in the short-term to assure that the magnitude of estimated customer energy savings can be achieved in within the plans time frame. At the same time, these short-term actions must be flexible enough to adjust to the possibility of lower future requirements.

Customer Energy Efficiency programs share the following general objectives:

- Develop the capability to acquire demand-side efficiencies when needed.

- Capture lost opportunities when the they become available.

- Develop the means to mitigate price and equity impacts.

- Improve the base of information from which cost and savings estimates are derived.

- Improve the ability to plan and operate programs effectively.

Figure 2 shows the customer efficiency two-year action plan as it relates to long-term strategy under different growth assumptions. Under each assumption there is an initial 5-year program of capability building, pilot tests and demonstration programs. Around the year 1995, a decision point is reached where each of the programs must be examined. Under the high growth assumption, programs would be ramped up into full-scale acquisition of demand-side efficiencies. Under medium growth, most efficiency programs would still be implemented; the exception being the Residential Retrofit Weatherization program which is relatively expensive and could be deferred until about 2010. Under low growth (medium-expected), most customer efficiency resources would not be needed. Therefore, most of the program activities would be halted. Those programs which involve a change in building codes, or other efficiency standards, would continue to supply efficiency but at a low rate.

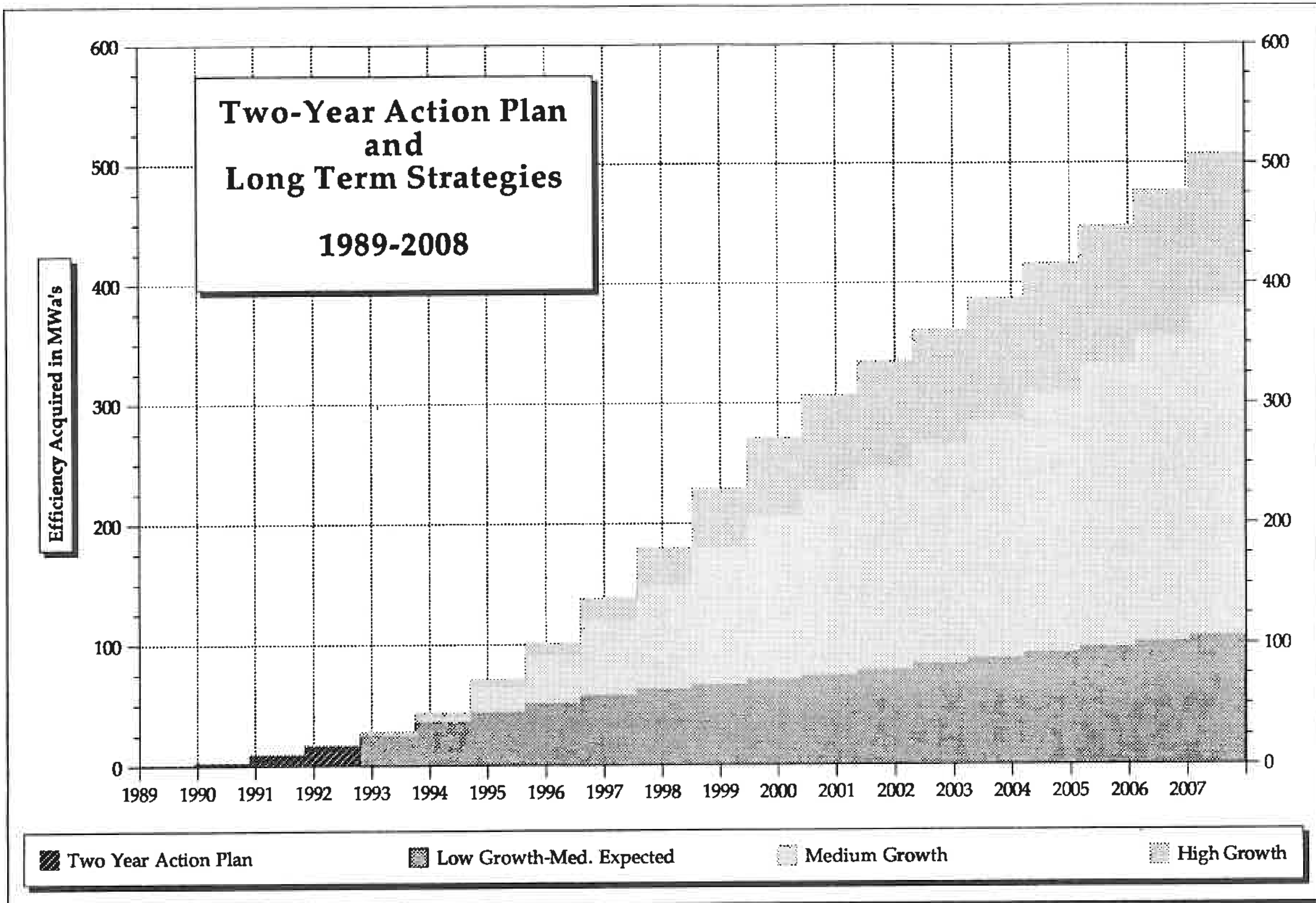
The demand-side programs are intended to build capability through a lost opportunity / pilot phase. These activities position the Company to undertake an acquisition phase when necessary to capture the major portion of the resource. At this time, the exact date upon which acquisition will start has not been determined.

For illustration, assume that resource acquisition will start in 1996. Working backward, this means that pilot programs should be completed, and the ramp-up phase should be occurring, by 1994. Pilot programs then need to start by about 1990, in order to provide useful results in time for ramp-up.

Penetration rates are an issue for lost opportunity programs targeting new construction. The company used 85% as the maximum penetration rate -- consistent with the Northwest Power Planning Council's expectations. Lost opportunity programs reach maximum by about 1995.

The lost opportunity / pilot phase, shown in Table 9, makes use of the current surplus to develop capability. The goal is to create cost-effective program options which can be applied later during the acquisition phase. The total utility expenditures for the lost opportunity / pilot phase in the Action Plan is on the order of $10-15 million per year. The impact of this level of expenditures on utility prices can be minimized by sharing some of the participants savings with non-participants through an energy service charge.

Figure 2



Efficiency Acquired in MW	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Two Year Action Plan	1	3	9	17																
Low Growth-Med. Expected	1	3	9	15	25	36	44	51	57	62	66	70	74	78	83	87	92	97	101	106
Medium Growth	1	3	9	17	27	40	65	91	120	149	180	205	227	246	266	286	308	332	356	380
High Growth	1	4	10	19	31	46	75	109	151	198	246	285	316	340	367	394	423	453	484	516

Table 9

ACTION PLAN PROGRAMS - MEDIUM FORECAST 1990 - 1991
** LOST OPPORTUNITY AND PILOT PROGRAMS **

PROGRAM	PHYSICAL GOAL	RESOURCE YEILD MWA	GROSS UTILITY PROGRAM COST MILLIONS 1990 $'s	KEY OBJECTIVES
NEW RESDENTIAL	3,810 SUPER GOOD CENTS HOMES	3.0	$7.2	Capture Lost Opportunities Transform Market
NEW COMMERCIAL	360 BUILDINGS, NEW & REMODEL	1.0	$5.0	Capture Lost Opportunities Transform Market Test Shared Savings
NEW APPLIANCES	6,000 WATER HEATERS 200 LOAD CONTROLLERS	0.2	$0.2	Capture Lost Opportunities Transform Market Seek Regional Program
INDUSTRIAL PILOT	5 FACILITIES	3.8	$3.5	Transform Market Test Shared Savings
RESIDIENTIAL RETROFIT PILOT	600 HIGH-USER HOMES WEATHERIZED	0.6	$3.1	Test Shared Savings Build Capability
COMMERCIAL RETROFIT PILOT	100 BUILDINGS	0.7	$3.3	Test High Intensity Retrofit Test Shared Savings Build Capability
LOW INCOME RESIDENTIAL RETROFIT	3,000 HOMES FULLY WEATHERIZED	1.3	$3.5	Share Cost With Low Income Assistance Agencies
ALL PROGRAMS		10.6	$25.8	

The following discussion presents a brief description, and detailed definitions, of each program included in the two-year action plan..

New Residential MCS: This program addresses lost opportunities by accelerating the efficiency transformation in new residential construction. Sixty percent penetration is expected by 1992 from the Super Good Cents program. This program includes a direct incentive payment of $1500/home to builders to assist in transition to an MCS code. The basic Super Good Cents program is enhanced to include solar orientation and daylighting. Also, for a limited period, an additional incentive ($800) is provided to qualifying customers under the Company's Pacific Plus program. This program is designed to build momentum for the Super Good Cents program. Both programs are intended to move the market toward energy efficiency goals so that efficient building practice is encouraged paving the way to code adoption.

If the codes achieve 80% of the savings identified in the MCS, as assumed, remaining savings are not cost effective enough to pursue with programs. Hence, the site-built portion of the residential MCS is phased out in 1993. The manufactured home component is addressed by supporting the Residential Conservation Demonstration Program of MCS mobile homes and advocating strong HUD standards be implemented in 1990. If the HUD standards achieve 75% of the MCS potential, then remaining energy savings are too small to be a cost effective program target. If the event that the HUD standards fall far short of MCS, a contingency program involving a manufacturer's incentive applied regionally is the preferred approach. A strong demonstration program drives the code and standards process minimizing utility costs in the long-term. Figure 3 displays the long-term penetration potential for this program in the medium forecast. Figure 4 displays the potential long-term residential MCS construction growth under the medium growth case.

New Commercial: This program addresses lost opportunities by accelerating the energy efficiency transformation in new commercial construction. New commercial construction includes remodels and major equipment replacement, a level of activity at least as large as actual new construction. A design incentive of approximately $.15 per square foot and an installation incentive of approximately $.90 per square foot are offered to qualifying new commercial construction. The incentives are reduced by 30% after three years if warranted by successful penetration.

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 market transformation, the commercial MCS code upgrade scheduled for 1992 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 1995-2010 time period, with the utility's role and incentive levels to be defined on the basis of the actual realized code. Figure 5 displays the long-term penetration potential for this program in all scenarios. Figure 6 displays potential long-tern new commercial construction under the medium growth case.

Figure 3

NEW RESIDENTIAL ANNUAL PENETRATION
MEDIUM FORECAST

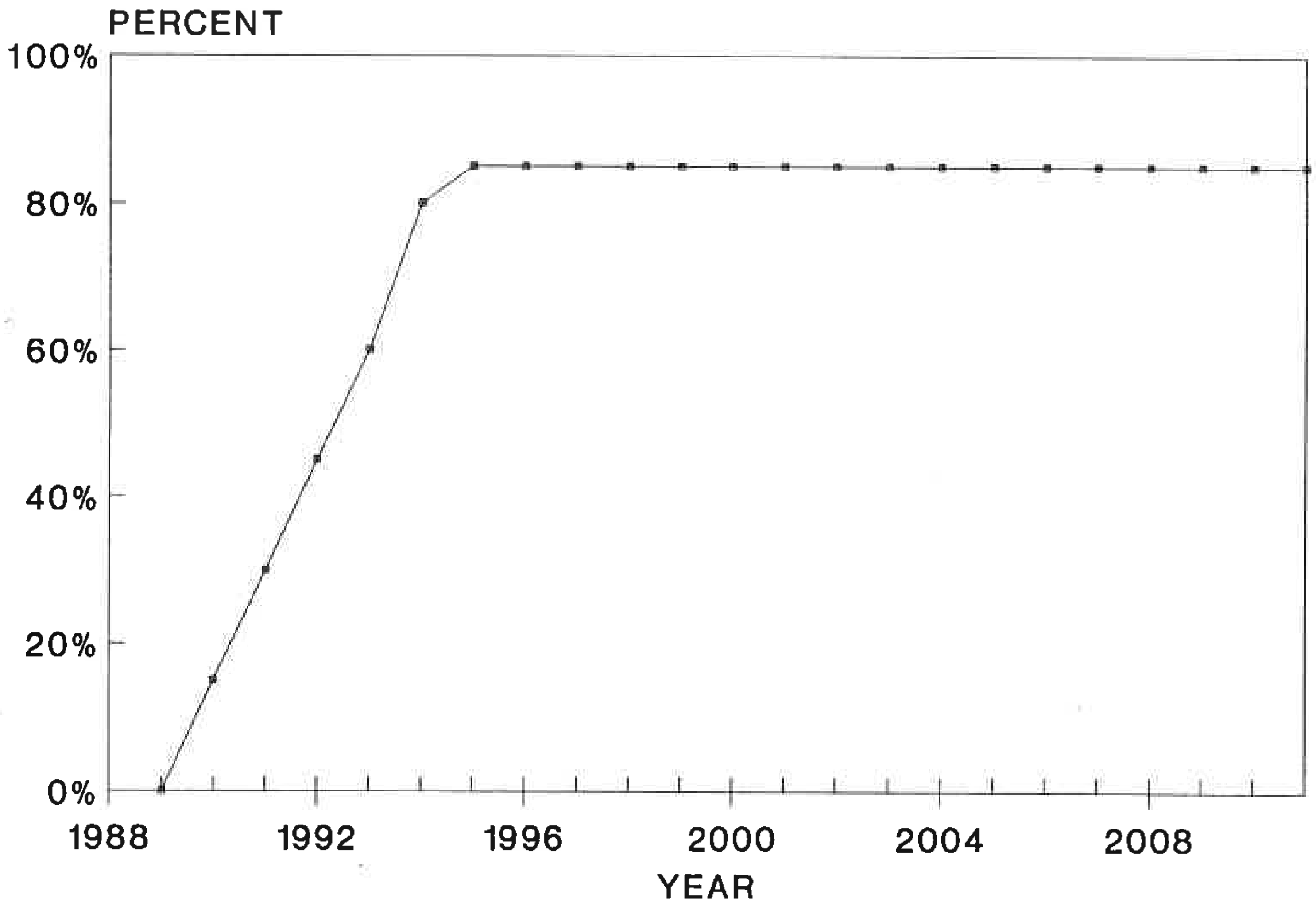
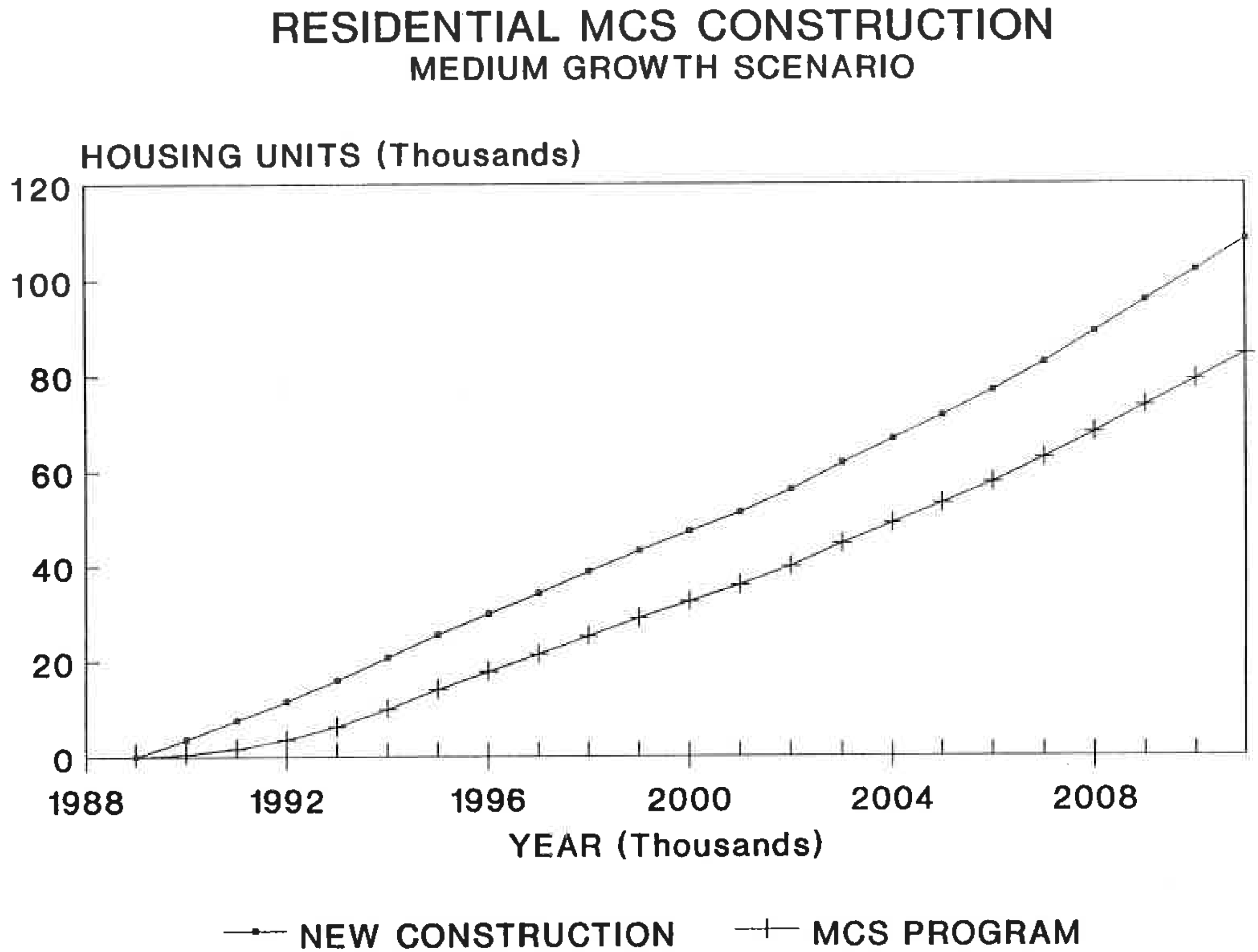
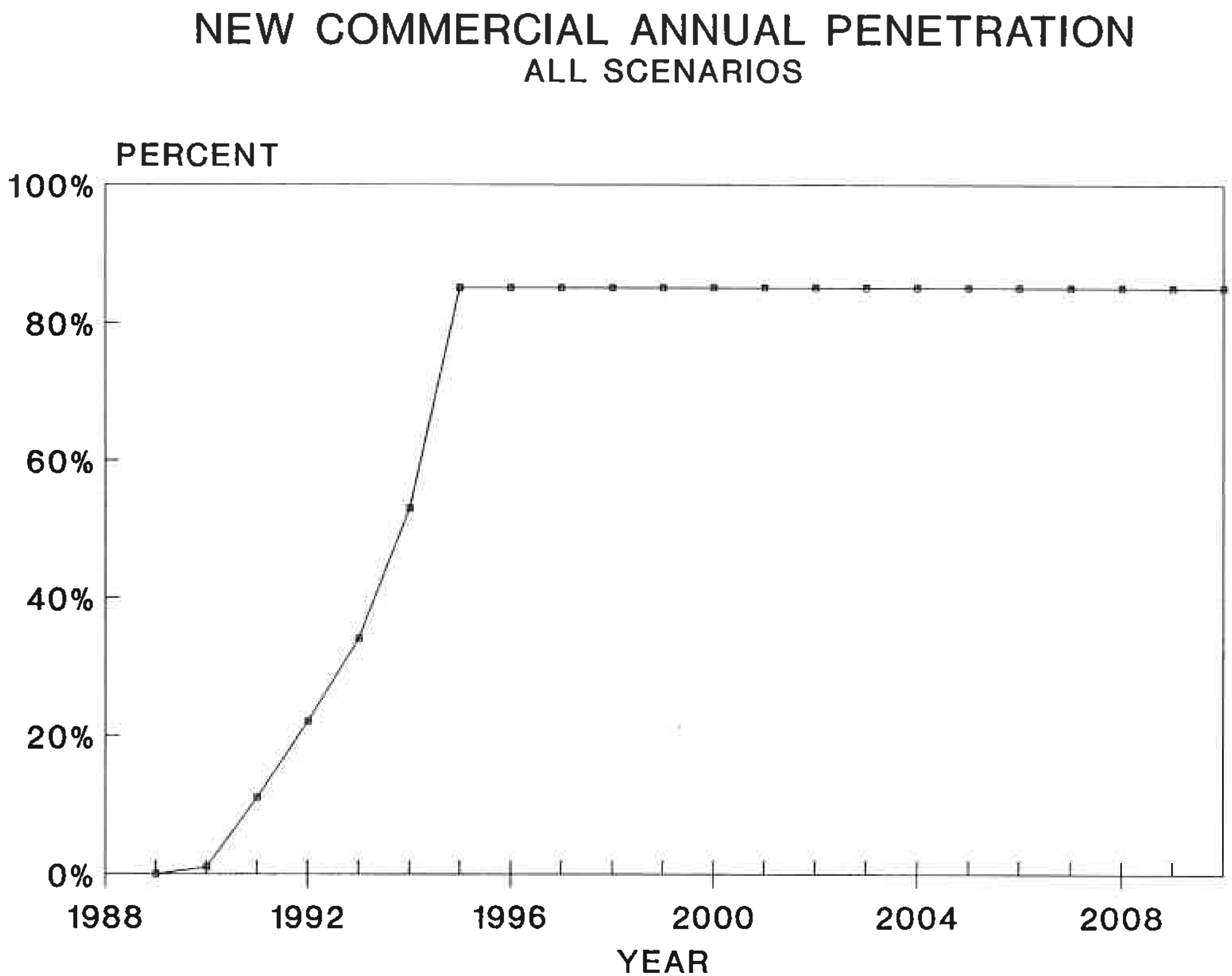


Figure 4



RESIDENTIAL MCS CONSTRUCTION
MEDIUM GROWTH SCENARIO
HOUSING UNITS (Thousands)
120
100
80
60
40
20
0
1988
1992
1996
2000
2004
2008
YEAR (Thousands)
NEW CONSTRUCTION
MCS PROGRAM

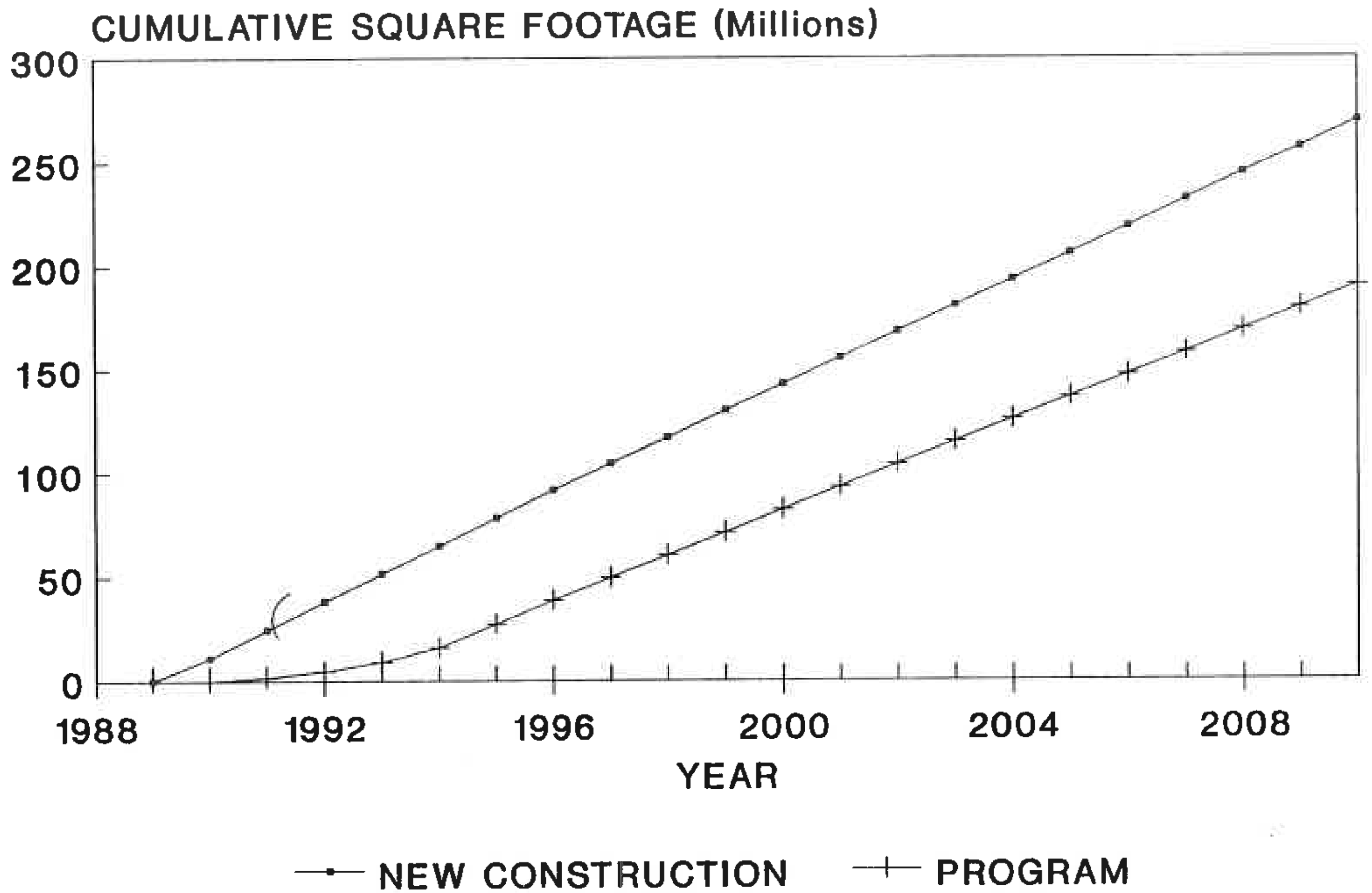
Figure 5



NEW COMMERCIAL ANNUAL PENETRATION
ALL SCENARIOS
PERCENT
100%
80%
60%
40%
20%
0%
1988
1992
1996
2000
2004
2008
YEAR

Figure 6

NEW COMMERCIAL CONSTRUCTION
MEDIUM GROWTH SCENARIO



New Residential Appliances: This program addresses lost opportunities by accelerating efficiency increases in new water heaters, refrigerators, and freezers. In the first two years, two pilots are targeted:

1) an incentive of the order of $25 is applied at the wholesale level to remove the price differential of "Blue Clue" designated appliances on the showroom floor. Application of the incentive at the wholesale level is intended to leverage the incentive by approximately 2 to 1.

2) an incentive check of the order of $50 is mailed to residential customers, redeemable only upon purchase of qualifying appliances.

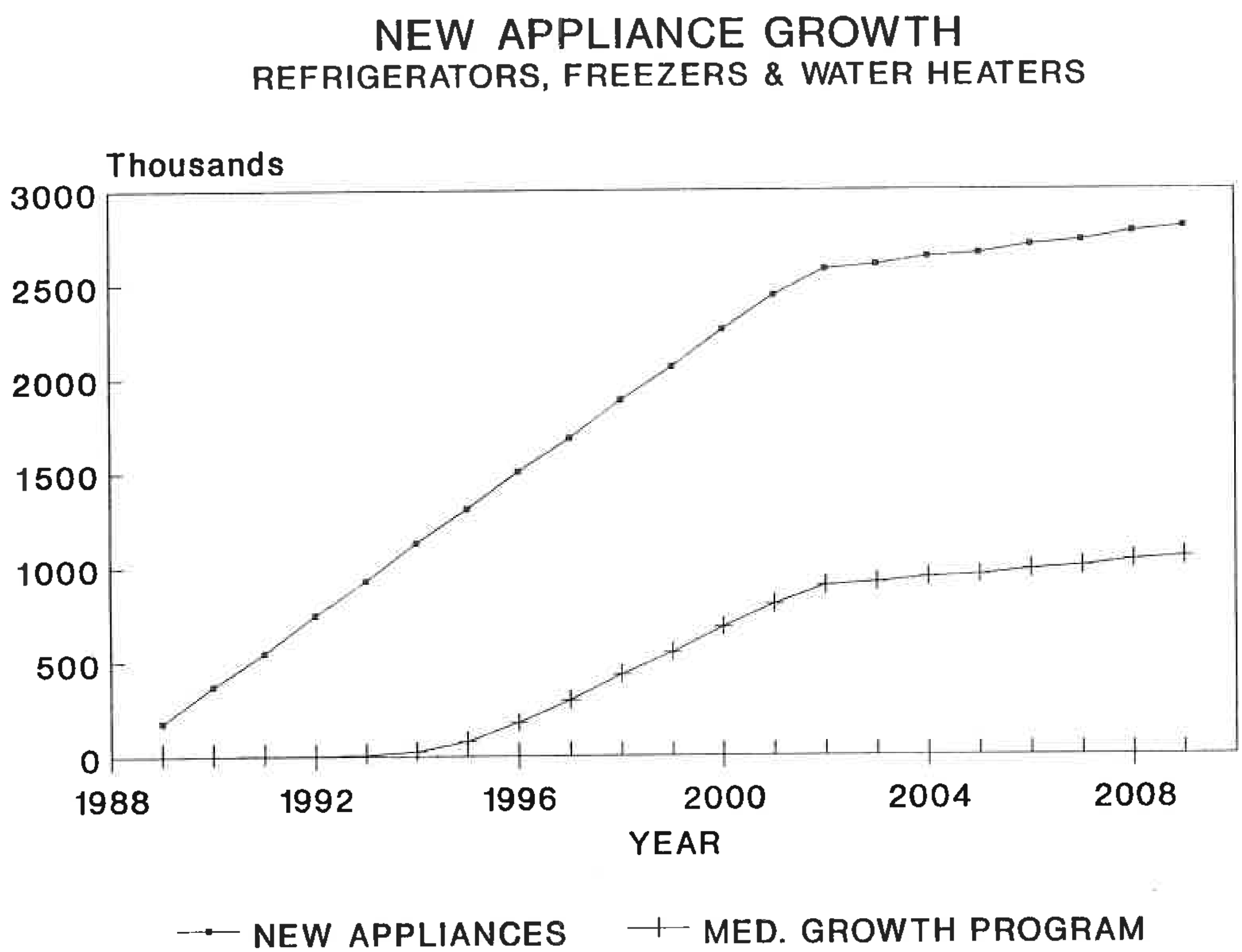
Application of the incentive in this manner may hasten the purchase of efficient appliances enough to influence retailers. The acquisition phase of the program is executed only if the California appliance standards fail to influence the efficiency of Northwest appliance stock and in the absence of Northwest appliance standards. To operate effectively, similar programs would need to be offered on a regional basis, through BPA and other utilities. To reinforce the market transformation, this program includes cooperative support for R&D on efficient refrigerators surpassing California standards and support for regional appliance standards. Figure 7 displays the new appliance growth potential, in units. Figure 8 displays the potential long-term new appliance market penetration under the medium growth case.

New Industrial Pilot: This program, run in 1989-1995, is seeks a strong liaison between Pacific and new industrial customers. The Company's current economic development role in new industrial is augmented to include the financing and a 25% cost share of electrical efficiency measures cost-effective at up to 30 mills/KWh. The program tests and refines the "energy service charge" mechanism to implement a cost share relationship with no upfront cost for the customer. The program also develops an industrial sector information base. This will assist with apportionment of 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. This transformation effect and an assessment of the industrial markets natural response to forecast energy prices, will be the basis for establishing the utility's role/cost share in a long-term schedulable resource acquisition program.

Residential Retrofit Pilot: There are two components of this program. The low-income program would operate immediately (1989 - 1993) and take advantage of potential cost-sharing opportunities. The pilot program component would commence 5 years prior to the estimated date that acquisition would be required. This component is assumed to start in late 1989. 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.

The low income component would produce low income participation substantially higher than other customers by offering $1200 toward the costs of full weatherizations to be matched by other funding sources. The non-low income pilot would test a utility cost share of 50% and the use of an "energy service charge" 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. Under a "HiSaver" program, those customers with a high savings potential would be identified and

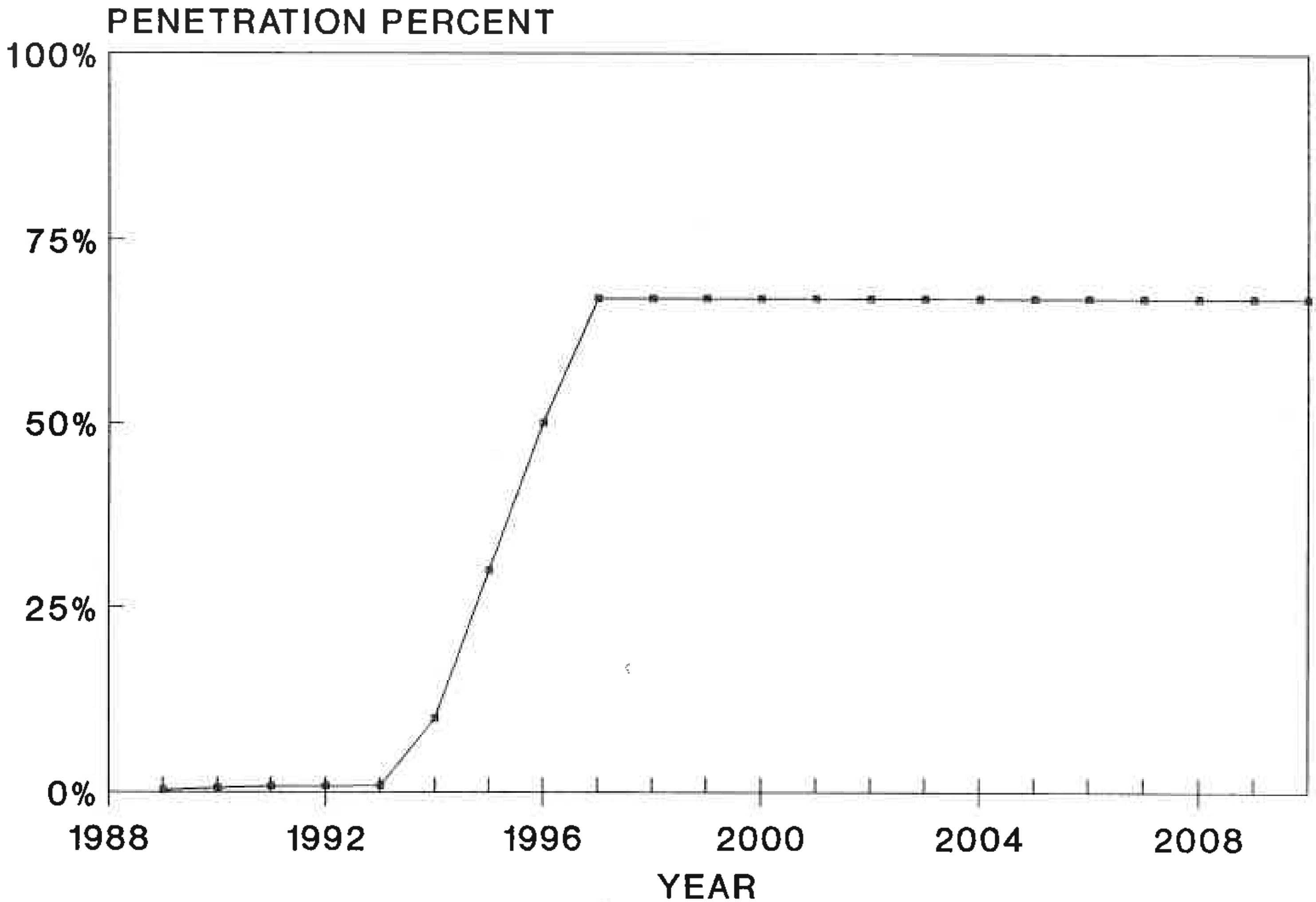
Figure 7



NEW APPLIANCE GROWTH
REFRIGERATORS, FREEZERS & WATER HEATERS
Thousands
3000
2500
2000
1500
1000
500
0
1988
1992
1996
2000
2004
2008
YEAR
NEW APPLIANCES
MED. GROWTH PROGRAM

Figure 8

NEW APPLIANCE ANNUAL MARKET PENETRATION
MEDIUM GROWTH SCENARIO



marketed through a screening of billing histories. Figure 9 displays the potential long-term residential retrofit program saturation rate under the medium, and high growth, forecast cases.

Commercial Retrofit Pilot: This program would run 5 years prior to the estimated need for acquisition, starting in 1990. It is operated as a high profile event in a medium-sized city typical of Pacific's territory and, thus, is similar to a commercial sector version of the Hood River Project. The program objective, a comprehensive retrofit of a major portion of the commercial space, tests the viability of accessing a broad spectrum of commercial customers.

This pilot also will help in validating or refining Pacific's least cost planning model for the commercial sector. The retrofits will be on the basis of a 50% utility cost share with the customer portion 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. A associated objective of this pilot will be to assure that retrofit lighting is superior to original in terms of quality and function. Figure 10 displays the potential long-term commercial retrofit program saturation rate under the medium forecast case.

Water Heater Wrap: This program, run as an acquisition program, shows minor energy savings but a high community profile. As a retrofit measure, it addresses an estimated 150,000 to 250,000 customers who can benefit from a water heater wrap and/or improved shower fixtures. This program develops or purchases in bulk high quality efficient showerheads and a durable 10 year wrap. These products are attractively and competently packaged to facilitate marketing by including choice of design motifs on the wraps (Snoopy, Garfield, Beethoven, Chinook salmon, etc.). Ideally, the products would be marketed locally by civic groups (Boy/Girl scouts, FFA, 4-H etc) who would receive about $10 per placement. The customer's 50% cost share (about $30) would be recovered through a two year energy service charge of the order of $1.35 per month, approximately equal to the energy savings.

Residential Retrofit Acquisition: This program, operated when resources are needed, is a major retrofit resource acquisition executed on a city by city basis. It operates in concert with the commercial retrofit program to maximize project visibility and penetration. In smaller urban areas, the program would be run through a temporary project office (two years) in the manner of the Hood River project. In larger urban areas, a permanent office would serve the whole district for the entire project duration.

This program relies on the evolution of an efficient retrofit capability in the pilot phase. The customer cost share of the weatherization costs will be recovered through an "energy service charge" based on the pilot experience, prevailing energy costs, and regional contractual arrangements.

Commercial Retrofit Acquisition: This program, also will operate when resources are needed. This comprehensive commercial retrofit may include a specially packaged lighting service component which has been identified and developed in the pilot. The customer cost share will be determined based on prevailing energy prices and other contractual circumstances.

Figure 9

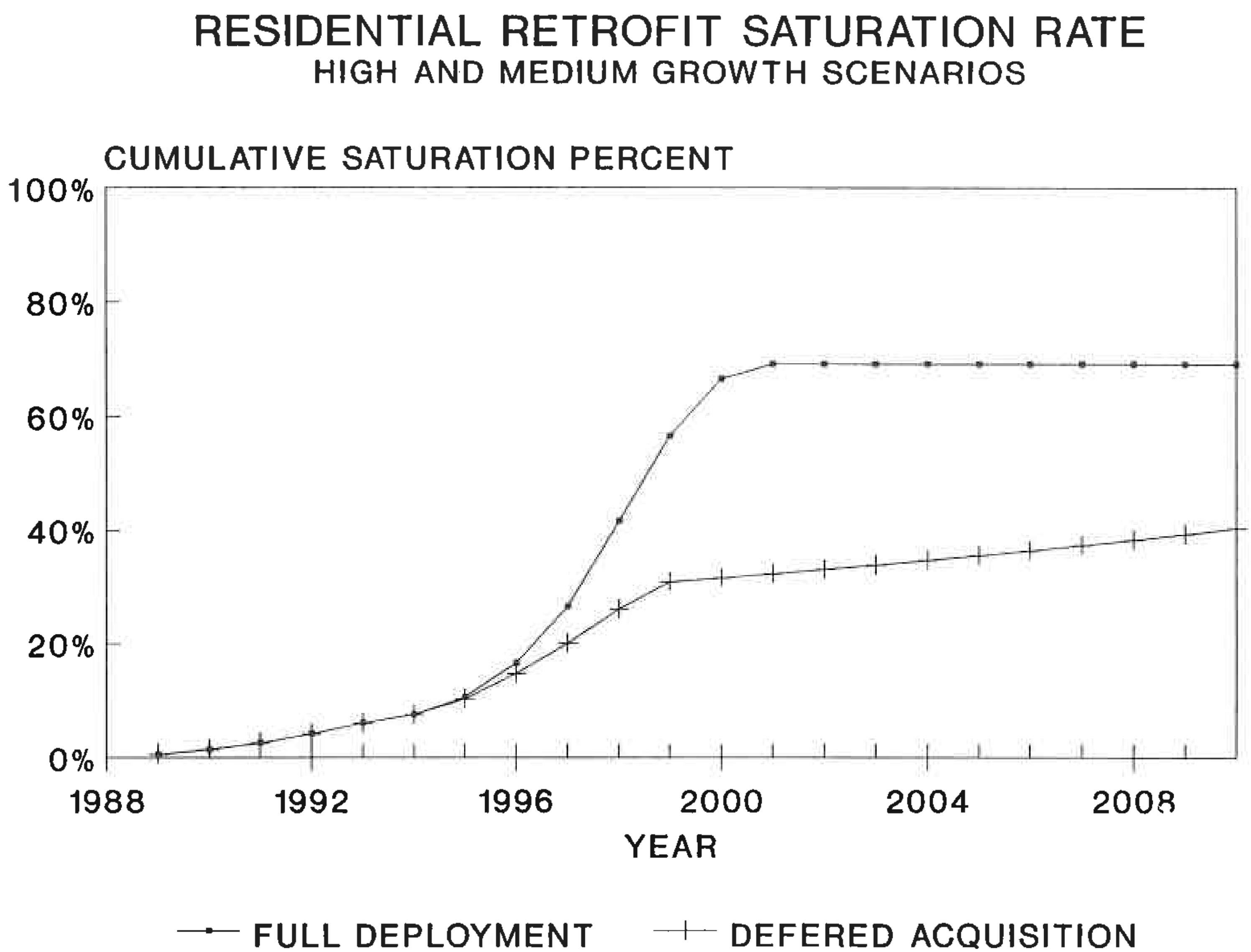
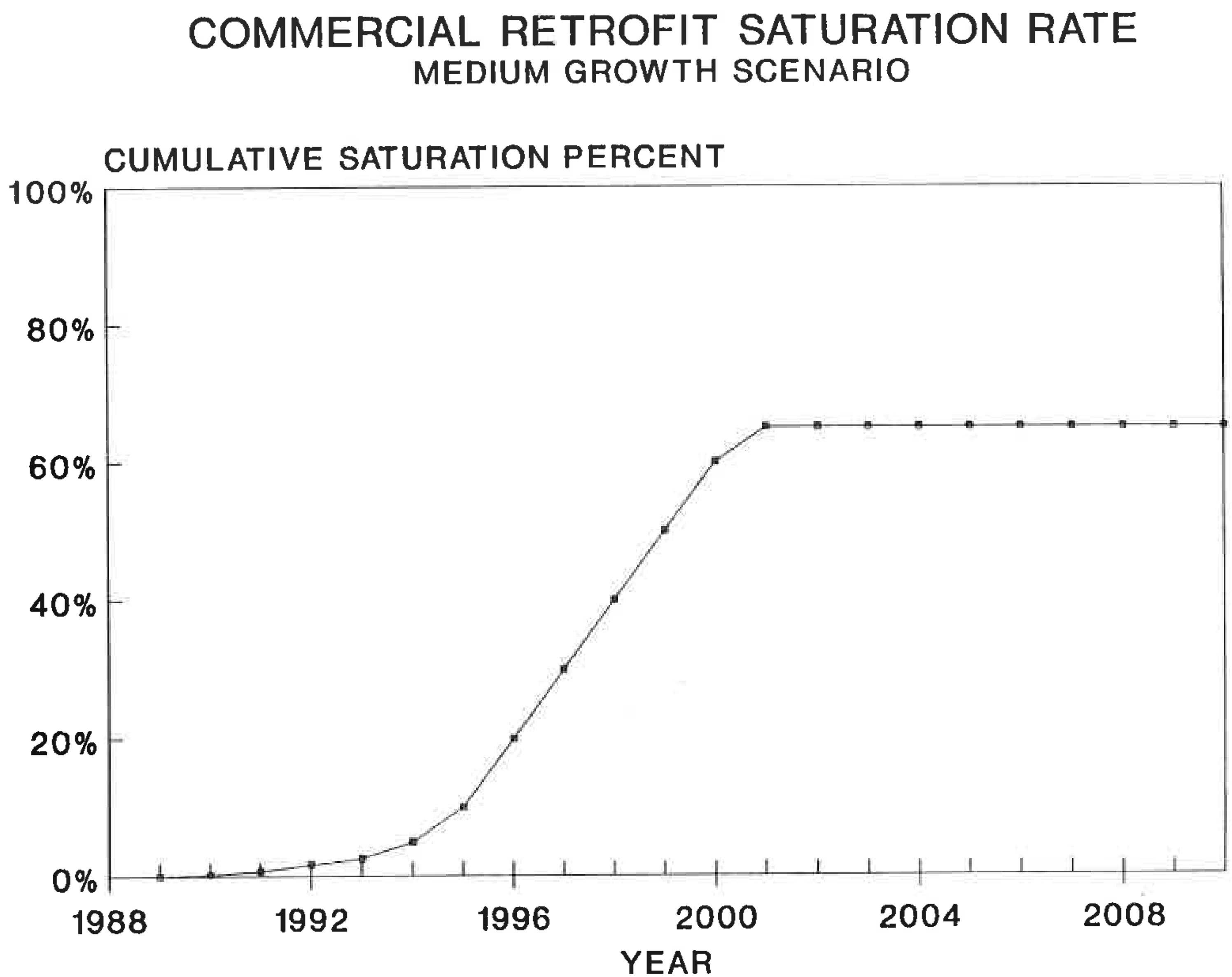

RESIDENTIAL RETROFIT SATURATION RATE
HIGH AND MEDIUM GROWTH SCENARIOS
CUMULATIVE SATURATION PERCENT
100%
80%
60%
40%
20%
0%
1988
1992
1996
2000
2004
2008
YEAR
FULL DEPLOYMENT
DEFERED ACQUISITION

Figure 10



COMMERCIAL RETROFIT SATURATION RATE
MEDIUM GROWTH SCENARIO
CUMULATIVE SATURATION PERCENT
100%
80%
60%
40%
20%
0%
1988
1992
1996
2000
2004
2008
YEAR

Large Users Retrofit: In this program, run in 1995-2002, large industrial users are offered custom designed programs involving combinations of incentives and energy service fees. Included in the incentive would be technical assistance provided by engineering contractors in the various industries. New industrial is included in this program and offered a "hook up conservation purchase" based on the efficiency of the proposed load compared to a baseline efficiency determined on a case by case basis. The program would be managed by an "account executive" assigned to service each large user.

Further technical information concerning the measures and programs contained in the demand-side portfolio is contained in the following documents:

Conservation Supply Curve Technical Documentation
October 26, 1989

Demand-Side Program Options Technical Appendix
October 26, 1989

B. SUPPLY SIDE PORTFOLIO

Tables 10 and 11 illustrate the existing firm resources and commitments for both peak and energy over the entire forecast interval. In addition, Tables 12 through 15 present detailed descriptions of the RAMPP Loads & Resources Base Requirement and Resource Assumptions, as well as the production factors associated with the Company's thermal units. These tables, which assume a medium case load forecast, demonstrate the operation of the existing system, and commitments, prior the exercising any of future demand-side, supply-side, and marketplace resource options.

The analysis of supply resource alternatives addressed new generating resources, as well as a number of existing specific resource alternatives, that do not require construction of new large central-station generating plant. The latter alternatives include existing contractual options, efficiency improvements to the existing generation and transmission/distribution system, alternative planning and operating strategies, and refurbishment of existing generating resources currently held in cold reserve. This section presents information on the cost, availability, and constraints affecting these supply resource alternatives.

Existing Supply Side Alternatives

System Efficiencies Improvements in existing hydro and thermal units offer the opportunity to increase the energy and capacity produced by those resources over current performance, and over the output described in the Existing Resource System section of this report. Improvements to the transmission and distribution system aimed at reducing losses also have the effect of deriving more capacity and energy from the existing resource system.

The energy derived from existing thermal generating units is a function of numerous factors. Although the average availability from the Company's thermal generation has steadily improved throughout the 1980's, there are still opportunities for further improvement. Capital

Table 10

Existing Firm Resources and Commitments

Resource & Market Planning
Medium Case Load Forecast

Average Megawatts	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements																				
Merged System Load	4861	4858	4969	5116	5192	5278	5408	5492	5575	5649	5727	5808	5886	5966	6048	6139	6235	6343	6450	6557
Black Hills	38	45	53	53	53	53	53	53	53	53	0	0	0	0	0	0	0	0	0	0
P G & E	29	29	29	29	29	29	29	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power	28	28	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power II	60	60	85	120	120	120	120	120	120	120	120	120	120	120	86	0	0	0	0	0
So Cal Edison	161	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	81	0	0
SMUD	0	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Nevada	0	61	83	82	83	83	83	82	83	83	21	0	0	0	0	0	0	0	0	0
Sierra Pacific	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Sierra Pacific II	10	38	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
IPP Layoff to LA	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
IPP Banked Recall	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
South Idaho Exchange - UPL	30	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41
Total	5337	5421	5589	5755	5831	5917	6047	6103	6186	6260	6224	6284	6362	6444	6489	6495	6591	6671	6698	6805

Average Megawatts	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Resources																				
Pacific System Hydro	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389
Utah System Hydro	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
Black Hills Energy Purchase	6	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Canadian Entitlement	-8	-8	-7	-6	-6	-6	-5	-5	-5	-4	-3	-2	-2	-2	-1	0	0	0	0	0
CSPE	34	32	31	30	29	28	27	25	24	22	13	10	9	9	2	0	0	0	0	0
Hanford WNP #1	68	68	68	68	68	68	68	31	0	0	0	0	0	0	0	0	0	0	0	0
Mid Columbia	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	178	127	127	127
Miscellaneous Purchases	6	6	3	-4	7	19	19	16	16	18	16	15	9	9	9	9	9	9	9	9
Pelton Rereg	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Q.F. Contracts - PP&L	67	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
QF Contracts - UP&L	34	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
Gem State	7	6	6	6	6	6	6	8	6	6	6	6	6	6	6	6	6	6	6	6
GSLM	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
IPP	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
WAPA Capacity Exchange	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
MPC Purchase	0	15	15	15	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0
WWP Purchase	44	50	50	50	50	50	50	38	17	0	0	0	0	0	0	0	0	0	0	0
South Idaho Exchange - PPL	30	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41
South Idaho Exchange Storag	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Centralia	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573
Dave Johnston	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675
Jim Bridger	1193	1204	1212	1221	1221	1221	1221	1221	1221	1221	1221	1221	1221	1221	1221	1221	1221	1221	1221	1221
Wyodak	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239
Colstrip	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103	103
Carbon	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136
Naughton	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541
Huntington	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681
Hunter	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846
Blundell	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Trojan	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Total	5994	6081	6083	6084	6089	6100	6099	6036	5984	5965	5958	5954	5948	5948	5942	5940	5936	5885	5885	5885
Thermal Maintenance	405	400	425	420	439	357	388	433	404	400	428	390	420	417	415	401	407	378	422	403
Balance	252	259	68	-92	-181	-174	-336	-499	-606	-694	-695	-720	-834	-913	-962	-955	-1061	-1164	-1235	-1323

Table 11

Existing Firm Resources and Commitments

Resource & Market Planning
Medium Case Load Forecast

January Peak	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements																				
Merged System Load	6440	6551	6665	6777	6891	7000	7081	7188	7299	7394	7497	7604	7707	7819	7923	8045	8174	8322	8467	8610
Black Hills	75	75	75	75	75	75	75	75	75	75	0	0	0	0	0	0	0	0	0	0
P G & E	100	100	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power	55	55	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power II	100	100	100	200	200	200	200	200	200	200	200	200	200	200	200	0	0	0	0	0
So Cal Edison	298	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	0	0
SMUD	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Nevada	0	0	52	52	52	52	52	52	52	52	52	0	0	0	0	0	0	0	0	0
Sierra Pacific	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Sierra Pacific II	0	25	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Total	7120	7258	7474	7631	7745	7854	7935	7942	8053	8148	8176	8231	8334	8446	8550	8472	8601	8749	8694	8837
Resources																				
Pacific System Hydro	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881
Utah System Hydro	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Black Hills Capacity	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BPA Entitlement Capacity	29	29	29	26	23	21	18	16	13	12	11	5	5	5	4	0	0	0	0	0
BPA Peak Purchase	1127	1127	1127	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BPA Supplemental Capacity	27	27	27	25	22	20	17	15	12	12	10	5	5	4	4	0	0	0	0	0
Canadian Entitlement	-29	-29	-29	-26	-23	-21	-18	-16	-13	-12	-11	-5	-5	-5	-4	0	0	0	0	0
CSPE	96	96	97	93	80	71	63	54	46	45	39	19	18	18	16	0	0	0	0	0
Hanford WNP #1	80	80	80	80	80	80	80	80	0	0	0	0	0	0	0	0	0	0	0	0
Mid Columbia	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	242	242	242
Miscellaneous Purchases	143	143	143	129	129	26	26	21	21	21	21	21	3	3	3	3	3	3	3	3
Pelton Rereg	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Q.F. Contracts - PP&L	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
QF Contracts - UP&L	38	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Gem State	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GSLM	0	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
MPC Purchase	0	15	15	15	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0
WWP Purchase	50	50	150	150	150	150	150	100	50	0	0	0	0	0	0	0	0	0	0	0
Centralia	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608
Dave Johnston	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750
Jim Bridger	1361	1366	1371	1377	1377	1377	1377	1377	1377	1377	1377	1377	1377	1377	1377	1377	1377	1377	1377	1377
Wyodak	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252
Colstrip	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140
Carbon	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Naughton	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700
Huntington	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815
Hunter	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001	1001
Blundell	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Trojan	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Total	8938	9034	9140	7998	7977	7863	7852	7776	7635	7584	7577	7551	7532	7531	7529	7509	7509	7400	7400	7400
Reserve Requirement																				
Reserve	1013	1013	1013	1013	1013	1013	1013	1013	1013	1013	1013	1013	1013	1013	1013	1013	1013	1013	1013	1013
Balance	805	763	653	-646	-781	-1004	-1096	-1179	-1431	-1578	-1612	-1693	-1815	-1928	-2034	-1976	-2105	-2362	-2307	-2450

Table 12

RAMPP L&R Base Requirement and Resource Assumptions.

Requirements:

Merged System Loads

Forecasts prepared specifically for RAMPP studies.

Includes Utah Interruptible loads.

Black Hills P&L

Contract ends in on 12/31/2003.

52.5 MWa energy and 75 MW Peak.

70% Load Factor.

P G & E

Contract ends in on 12/31/2003.

28.5 MWa Energy.

Capacity distribution: April-October 80 MW, and November-March 100 MW.

Puget Power

8/1/1986-7/31/1991 27.5 MWa energy, and 55 MW Peak.

50% Load Factor.

Puget Power II

11/1/1988 - 7/31/1991: 60 MWa Energy, and 100 MW Peak.

8/1/1991 - 10/31/2003: 120 MWa Energy, and 200 MW Peak.

60% Load Factor.

Southern California Edison

18/1987 - 12/31/1989: 161 MWa Energy, and 298 MW Peak.

1/1/1990 - 9/2006: 108 MWa Energy, and 200 MW Peak.

54% Load Factor.

SMUD

1/1/1990-12/31/2014: 40 MWa Energy and 100 MW Peak.

40% Load Factor.

Nevada

6/1/1990-5/31/1999: 145.6 MW June-September, 52 MW October-May

Table 13

Sierra Pacific

Contract for 71.8 MWa Energy and 52 MW Peak in 1989-2008.

Sierra Pacific II

6/1/1989-5/31/1990: 17.5 MWa Energy and 25 MW Peak.

6/1/1990-12/31/2008: 52.5 MWa Energy and 75 MW Peak.

70% Load Factor.

IPP Layoff to LA

Layoff Sale of UP&L's IPP share 1989-2008.

IPP Banked Recall

7.5 MWa in 1989.

South Idaho Exchange

41 MWa starting 3/1/89.

Resources:

Pacific System Hydro

Based on Critical water (1928-1929).

Derated Lewis River peak - Based on 8 hrs/day, 5 days/week.

Winter Peak.

Utah System Hydro

Based on Utah Critical water (1961).

Black Hills Energy Purchase

6.2 MWa from 7/1/88 to 6/31/1990.

Canadian Entitlement - (8.2) MWa in 1989, increasing to 0 MWa in 2004.

CSPE - 34.1 MWa in 1989, decreasing to 0 MWa in 2004.

Hanford WNP #1

Until 7/1/96: 68 MWa energy and 80 MW Peak.

Mid Columbia

Based on Critical water.

Including a 10% capacity reduction.

Winter Peak

Table 14

Misc. Purchases - 5.7 MWa in 1989-1990, 3 MWa in 1991, (4.3) MWa in 1992, 7.1 MWa in 1993, 18.5 MWa in 1994-1995, 16.2 MWa in 1996-1999, and 9 MWa in 2000-2008.

Pelton Regulation

10 MWa energy and 19 MW capacity in 1989-2008.

Based on 10/4/88 analysis by R. Lindley.

QF Contracts - PP&L

67.1 MWa in 1989, 74.8 MWa in 1990, 74.9 MWa in 1991, and 75.3 MWa in 1992-2008. Based on R. Lindley's 10/21/88 estimate.

QF Contracts - Utah

34.2 MWa in 1989, and 73.5 MWa in 1990-2008.

From 1989 Idaho L&R.

Gem State - 6.6 MWa in 1989, and 5.6 MWa in 1990-2008.

Gem State - Little Mountain - 2 MWa in 1989, and 3.5 MWa in 1990-2008.

IPP

UP&L's Share of the IPP Project: 42.2 MWa in 1989-2008.

WAPA Capacity Exchange

5.9 MWa in 1989-2008.

MPC Purchase

15 MWa in 1990-1992, and 10 MWa in 1993-1995.

WWP Purchase

50 MWa in 2/13/1989-12/31/1995, 38 MWa in 1996, and 17 MWa in 1997.

50 MW Peak in 1989-1990, 150 MW in 1991-1995, 100 MW in 1996, and 50 MW in 1997.

South Idaho Exchange - 42.2 MWa starting 3/1/1989-2008.

South Idaho Exchange Storage - 0 MWa in 1989-2008.

Thermal Plants:

Production factor based on 48 month history 1/85-12/89.

Thermal Maintenance:

Based on schedules effective in May 1989.

Table 15

Utah Plants — Base on 48-month EEI data as of 12/31/88 (except Blundell & Gadsby)

Plant	Unit	Production Factor
Carbon	Unit 1	0.8376
	Unit 2	0.8108
Gadsby	Unit 1	0.6500
	Unit 2	0.6500
	Unit 3	0.6500
Hunter	Unit 1	0.8529
	Unit 2	0.8122
	Unit 3	0.8579
Huntington	Unit 1	0.8579
	Unit 2	0.8140
Naughton	Unit 1	0.8495
	Unit 2	0.7690
	Unit 3	0.7368
Blundell	Unit 1	1.0240

Pacific Plants — Base on 48-month EEI data as of 12/31/88 (except Colstrip & Trojan)

Plant	Unit	Production Factor
Centralia	Unit 1	0.8886
	Unit 2	0.9253
Dave Johnston	Unit 1	0.9163
	Unit 2	0.9028
	Unit 3	0.8444
	Unit 4	0.8372
Jim Bridger	Unit 1	0.8548
	Unit 2	0.8584
	Unit 3	0.8558
	Unit 4	0.8848
Wyodak	Unit 1	0.8649
Colstrip	Unit 3	0.7321
	Unit 4	0.7321
Trojan	Unit 1	0.8405

improvements and operation and maintenance practices can be exercised to capture these opportunities. Ongoing thermal plant programs are aimed at retaining current operating levels, which are currently at the high end of industry-wide experience, and at improving performance where such levels are not currently attained. To reflect this potential, an improvement program has been assumed that develops a total of fifteen average megawatts of energy, over a five year period. This figure was arrived at based on current availability at the Naughton generating plant and is considered to be a conservative estimate of the energy that can be developed from the entire base of resources. Over time, refinements will be made to this estimate as new information is gained with ongoing thermal maintenance and preservation programs. Turbine modifications at several generating units are also being considered, and can increase capacity and availability above the improvements assumed in the supply portfolio, if they prove to be feasible.

Hydro resources, which are a much smaller portion of the existing resource base also offer the opportunity for additional energy and capacity production. An evaluation of the entire hydro system has been initiated to determine its rehabilitation needs and uprating potential. The incentive for this program has been the desire to identify cost-effective generating capability, as well as the need to address questions related to resource utilization which are part of the federal hydro re-licensing process.

A screening of existing hydro facilities has been conducted using a newly developed EPRI model which evaluates projects on the basis of age, license expiration, condition, water utilization, and downtime. Essentially the same components included in the NPPC portfolio were also considered in screening potential efficiency improvements. In addition, this evaluation has also included modification of civil works to gain energy or capacity. Evaluation of the screening process is ongoing. Detailed engineering studies are being conducted on a project-by-project basis. The priorities for this work are dictated by a number of factors, including the rating system contained within the screening model, economic feasibility, environmental impact, and considerations related to re-licensing of the projects by the Federal Energy Regulatory Commission.

The increase in hydro system capability, based on the initial screening, is expected to range between 10 and 40 megawatts of capacity, of which 5 to 15 megawatts is anticipated to be derived from civil works improvements. For purposes of resource planning, this potential is represented by a program to gain 10 average megawatts of energy and 20 megawatts of capacity over a ten year period.

A range of activities and practices are being employed to reduce losses in the transmission and distribution system. These include a distribution planning program, circuit re-configuration and load balancing studies, re-conductoring existing circuits, installation of line capacitors, conversions of primary voltages, and installation of low-loss transformers. While these practices are, in many cases not new, they can be expected to continue to gain energy and capacity capability. For the purposes of planning new resources needs, they have been assumed to provide a net increase of 30 megawatts of capacity and average energy, over a 15 year time frame.

<u>Contractual Rights</u> Contractual rights exist under two different arrangements with the Bonneville Power Administration for the purchase of energy and capacity. One of these is under the exchange agreement covering the Company's original participation in WNP-3. Under this agreement, the Company has the right to about 68 average megawatts of energy and

164 megawatts of capacity annually for a period of twenty years. This option must be exercised by 1996, and requires that BPA be notified by June for purchases to begin in November of the following calendar year. Prices are based on the performance of surrogate units unless and until WNP-3 operates, in which case prices are based on actual WNP-3 operating costs. Based on the first three years of performance at the surrogate units, purchases under this contract would be in the 27 mills/kwh range.

The second contractual option is through the Power Sales Contract, as authorized by the Regional Act, that allows the Company to purchase power from BPA at the NR rate. The amount that may be purchased is limited to the load growth within the region, in excess of the amount of regional resources dedicated to regional loads. Seven years notice is required for changes in requirements, although shorter notice can be exercised under defined conditions. While BPA is authorized to acquire resources to serve such loads a situation could arise, if BPA is unable to acquire sufficient resources, where less than the total requirement placed on BPA is met.

There are two sources of uncertainty with regard to the BPA-NR alternative: availability and cost. While the certainty of a requirement placed on BPA actually being met can be questioned, BPA's ability to acquire resources appears sufficient to make the availability of this purchase alternative a reasonable assumption. The uncertainty with regard to cost is reflected in BPA's forecast of future NR rates. BPA performs this forecast using it's Supply Pricing Model, and has periodically published a forecast. The most recent forecast (*Wholesale Power Rate Projections, 1989-2010*, BPA, January 1989) was used as the basis for future NR prices. BPA's NR rate escalation under three different assumptions of regional growth were used for the comparable RAMPP load forecast cases. While BPA's forecasts assume no new requirement is placed on BPA by any investor owned utility (IOU), BPA has performed several sensitivities at the request of the Company. The sensitivities indicate that a ten percent IOU load placed on BPA (about 220 average megawatts) has the effect of lowering the NR rate very slightly over most of the planning horizon, under a medium growth assumption. Assuming fifty percent IOU load growth is place on BPA causes the NR rate to be about 7% higher than the base forecast by the year 2010.

One other contractual option exists under the wholesale sale contract to the Southern California Edison (SCE). Under this contract, the Company sells 200 megawatts of power to SCE at a 54% annual load factor. The contract allows the sale to be converted to a sale of capacity only, or to a seasonal exchange. No more than one third of the original contract energy may be withdrawn in any one year, and 1996 is the first year that the contract can be converted to a sale of capacity only. The revenue from this sale is a direct reduction in retail revenue requirements. For purposes of power planning, the cost of this option as an energy resource is the loss of revenue and the increase in retail revenue requirement.

Refurbishment Cost of returning the Gadsby Plant to service is based on preliminary estimates of capital investment required to operate each unit with natural gas. Operating cost estimates are based on assumed hydro firming operation.

New Supply Side Alternatives

Various resource types, and various sizes within each resource type, have been reviewed. Efforts have been made to identify all supply-side resources on a generic basis with two exceptions: Wyodak Unit 2 and Shady Cove Hydroelectric. A building block concept has been developed to estimate the future cost of a resource using different assumptions about the location, and different types available for use. Other inputs to the cost matrix would include licensing costs and transmissions costs. These individual inputs are then combined to estimate the total cost of the resource.

The capital cost estimate matrix is contained in Table 16. The ranges of capital costs are estimated on a dollars per kilowatt basis by technology and by size of facility. The assumptions used in establishing all the cost estimates are contained in Table 17. The matrix for estimating the time required to license each type of facility, by size, is shown in Table 18 and the estimates of the cost to license each facility are contained in Table 19. The generic transmission cost matrix is shown as Table 20, with transmission licensing periods contained in Table 21.

As indicated earlier a number of different resource types have been investigated for possible use in the supply-side resource portfolio. Each of the major resource categories are discussed in the following sections.

Conventional Pulverized Coal Plants The existing system has a total of twenty-eight conventional coal units of various ages and sizes. The estimates of cost in this plan are for a sub-critical steam boiler burning subbituminous coal. Particulate removal and flue gas de-sulfurization equipment are designed on the Best Available Control Technology (BACT) and the costs of such controls are included in the plant estimates.

This technology is considered mature and is in common commercial use today. There are concerns about the impacts the combustion of coal may have on the environment both from an acid rain aspect as well as global warming. These concerns have been taken into consideration in the future resource selection process.

The cost estimates for three different facilities are shown in Table 22. Given uncertainties associated with future rates of demand growth, and the financial risks associated with the construction of large central station generating facilities, there will be a tendency to develop smaller plants, in the range of 250 megawatts, should the requirement for such facilities ever arise.

Atmospheric Fluidized Bed Combustion Limestone and pulverized coal are fed by a pneumatic or spreader stoker system onto an air distribution grid. Forced draft fans introduce combustion air at the bottom of the steam generator. Air flows upward through a distribution grid, suspending and fluidizing the solid particles. The calcium in the limestone captures most of the sulfur released from the coal during combustion forming anhydrous calcium sulfate. The calcium sulfate and the bottom ash are removed from the fluidized bed through drain pipes located in the air distribution grid. Particulates are captured in a series of cyclones followed by an electrostatic precipitator. Additional flue gas de-sulfurization equipment is not required.

Table 16

Capital Cost Matrix
1989 Dollars per Installed Kilowatt

SIZE, MEGAWATTS

TECHNOLOGY	5	10	25	50	100	250	500
FOSSIL							
Coal							
Conventional PV , wet cooling				$1,670 - 2,270		$1,760 - 2,380	$1,490 - 2,010
Conventional PV, dry cooling						$1,780 - 2,400	
Atmospheric Fluidized Bed				$1,968 - 3,656	$1,654 - 2,756	$1,576 - 2,364	
Pressurised Fluidized Bed				$1,947 - 3,616	$1,648 - 2,747		
Integrated Gasification CC				$3,300 - 4,960	$2,780 - 4,160	$2,400 - 3,600	$1,670 - 2,510
Gas/Oil							
Simple Cycle Combustion Turb				$310 - 570	$340 - 590		
Combined Cycle				$910 - 1,250		$650 - 880	
Conventional, wet cooling				$1,066 - 1,777			$964 - 1,446
FUEL CELL		$1,050 - 4,550					
RENEWABLES							
Hydroelectric		$1,881 - 3,134	$1,538 - 2,563				
Pumped Storage							$769 - 1,795
Biomass		$1,467 - 2,444					
Wind	$1,588 - 2,647						
Solar				$2.537 - 6,525			
Geothermal, Binary				$3,540 - 6,580			
Geothermal, Flash		$2,480 - 5,800		$3,420 - 6,340			

Table 17

SUPPLY SIDE RESOURCES ESTIMATING ASSUMPTIONS

CAPITAL

- All estimates include AFUDC at 11%
- All estimates include Owner's costs and G & A
- All estimates include initial spare parts, chemical and start-up costs
- Switchyard and Transmission costs are excluded. Estimated using separate matrix.
- Costs associated with licensing a facility are indicated separately.
- All costs are in January 1, 1989 dollars (instantaneous construction basis.)
- Income from sale of start-up power is excluded.
- A nominal cost for land is included in all estimates.
- A three month fuel inventory is included for coal and wood fuel plants.

Operation & Maintenance

- Plant capacity factor is expressed in terms of "net" plant capacity.
- Operating costs are estimated for a year of normal operation
- Company G&A allocations to the operation of these facilities are not included in the O&M figures provided.
- Replacement capital is not included in O&M.

Fuel

- Cost of rolling stock is included in capital cost of facilities.
- Oil pricing assumes use of residual (no. 6) fuel oil.
- A 14 day inventory of distillate oil is included as backup for natural gas fired plants to accommodate gas supply interruptions.

Table 18

Plant Licensing Period (Months)

TECHNOLOGY	5	10	25	50	100	250	500
				SIZE, MEGAWATTS			
FOSSIL							
Coal							
Conventional PV , wet cooling					24 - 48	24 - 48	24 - 48
Conventional PV, dry cooling					24 - 48	24 - 48	
Atmospheric Fluidized Bed				24 - 48	24 - 48	24 - 48	
Pressurised Fluidized Bed				24 - 48	24 - 48		
Integrated Gasification CC				24 - 48	24 - 48	24 - 48	24 - 48
Gas/Oil							
Simple Cycle Combustion Turb		18	18	24 - 48	24 - 48		
Combined Cycle				24 - 48	24 - 48	24 - 48	
Conventional, wet cooling				24 - 48	24 - 48	24 - 48	24 - 48
FUEL CELL		18	18	24 - 48			
RENEWABLES							
Hydroelectric	36 - 48	36 -48	36 - 48	36 - 48	36 - 48		
Pumped Storage							36 - 48
Biomass		18 - 48	18 - 48	18 - 48			
Wind	12 - 24						
Solar				12 - 24			
Geothermal, Binary				18 - 48			
Geothermal, Flash		18 - 48		18 - 48			

Table 19

Plant Licensing Cost

LICENSING COST AS A PERCENT OF CAPITAL COST

Size	LOW	EXPECTED	HIGH
>50 MW	1%	1.50%	2%
<50 MW	2%	2.50%	3%

Assumption: 1. No strident opposition

Table 20

Transmission Line Costs

SINGLE UNIT ADDITIONS — UNIT SIZE (MW)

LINE MILES	10	25	50	100	250	500
1	$750	$1,000	$2,500	$2,600	$4,700	$11,800
10	$2,350	$2,600	$5,600	$6,000	$9,100	$24,800
50	$9,300	$9,300	$19,100	$21,000	$28,300	$82,800
100	$17,800	$17,800	$36,000	$39,800	$52,400	$155,300
200	$34,700	$34,700	$69,800	$77,400	$107,000	$306,700
MULTIPLE UNIT ADDITIONS						
1				$4,700	$11,800	$18,900
10				$9,100	$24,800	$35,000
50		SAME AS ABOVE		$28,300	$82,800	$106,500
100				$52,400	$155,300	$195,800
200				$107,000	$306,700	$387,500

NOTES ON USE:

1. Determine whether transmission is to be sized for single addition or first of multiple units. Use appropriate tabl
2. Given unit size, estimate distance from bulk transmission grid. The table will give total transmission plan cost. Interpolate between values for mileages not given on the table.
3. If a major resource is constructed on PacifiCorp's East side to serve West side load, an additional $703,700,000 must be added to the cost in the table above. Whether this transmission is actually needed should consider use o facilities and the energy shape being transmitted.
4. If a major resource is constructed on PacifiCorp's West side to serve East side load, an additional $61,800,000 must be added to the costs in the table above.
5. Appropriate wheeling costs depending on unit location should be added for transferring power through BPA's syste

Table 21

Transmission Licensing Period (Months)

Distance (miles)	One State	Multi-State
<10	12 - 18	18 - 24
10 - 100	12 - 24	18 - 36
>100	12 - 36	18 - 48

Assumptions:
1. Federal land involved
2. NEPA is schedule critical item
3. No strident opposition

Table 22

Pulverized Coal

	250 mW w/ Wet Cooling	500 mW w/Wet Cooling	315 mW w/Dry Cooling
Heat Rate, Net (BTU/kWh)	10,100	10,100	11,900
Capital Cost Data (1-1-89 $)			
Expected Plant Cost	$518,679,000	$875,489,000	$658,350,000
Expected Licensing Cost	$7,780,000	$13,132,000	$9,875,000
Expected Total Cost	$526,459,000	$888,621,000	$668,225,000
$/kW - Low (-15%)	$1,781	$1,503	$1,794
$/kW - Expected	$2,106	$1,777	$2,121
$/kW - High (+15%)	$2,433	$2,054	$2,452
Estimated Construction Time (mos)	45	60	60
Estimated Licensing Time (mos)	24-48	24-48	24-48
Primary Fuel	Coal	Coal	Coal
Fuel Cost (FOB Mine)	$.25/mmBTU	$.25/mmBTU	$.25/mmBTU
Estimated Capacity Factor	70%	70%	70%
Estimated O & M			
Total - Excluding Fuel (Mills/kWh	6	4	5
Estimated Economic Life (Yrs)	35	35	35

This technology is in the pilot / demonstration phase with several plants under construction and operation nationwide. Commercial availability is expected in the 1990-1995 period. Examples of cost estimates are in Table 23.

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. No additional particulate or de-sulfurization systems are included. Costs for the gasifier are included in the total plant costs.

This technology is in the pilot stage. An estimate of what costs might be available in the future is shown in Table 24.

Gas/Oil Simple Cycle Combustion Turbine The simple cycle combustion turbine represents a relatively inexpensive power resource to construct. Typically low sulfur distillate/gas or residual fuel is fired in a combustion turbine/electric generator. There are various options for using such facilities such as peaking units, firming nonfirm energy from the hydroelectric system or as base load facilities. Due to the anticipated expense of natural gas or fuel oil, one would anticipate that the units would not be used as a base load firm resource. With relatively low capital cost, however, they are candidates for use in a non firm hydro strategy.

The estimates used in this study assume use of conventional 50 and 100 megawatt combustion turbines and as "advanced technology" combustion turbine for the 130 megawatt facility. These units are considered stand alone units and do not include any provisions for eventual conversion into a combined cycle facility. The cost estimates are contained in Table 25.

Gas/Oil Combined Cycle Turbine Low sulfur distillate/gas or residual fuel is fired in a combustion turbine/electric generator. The hot exhaust gases from the turbine pass through a heat recovery steam generator that produces steam for a conventional steam turbine/electric generator.

This is considered a mature technology and provides the option of being constructed in stages, initially as a simple cycle facility with the later addition of the combined feature. A sample cost estimate is included as Table 26.

Hydroelectric Hydroelectric generation is an existing commercially available resource which has recently received strong environmental review. Most environmentally acceptable large-scale hydropower sites have been developed. The adoption of the Northwest Power Planning Council's Protected Areas concept, the passage of HB-2990 in Oregon and the extension of the Wild and Scenic Rivers list in Oregon have defined guidelines for future development of both large and small scale facilities. Small scale development has attractive characteristics, including short construction lead time and small increments of capacity.

Table 23

Atmospheric Fluidized Bed

	100 mw	250 mw
Heat Rate, Net (BTU/kWh)	11,670	10,045
Capital Cost Data (1-1-89 $)		
Expected Plant Cost	$220,503,000	$492,406,000
Expected Licensing Cost	$3,308,000	$7,386,000
Expected Total Cost	$223,811,000	$499,792,000
$/kW - Low (-25%)	$1,670	$1,592
$/kW - Expected	$2,238	$1,999
$/kW - High (+25%)	$2,811	$2,411
Estimated Construction Time (mos	48	54
Estimated Licensing Time (mos)	24 - 48	24 - 48
Primary Fuel	Coal	Coal
Fuel Cost (FOB Mine)	$.25/mmBTU	$.25/mmBTU
Estimated Capacity Factor	80	80
Estimated O & M		
Total - Excluding Fuel(Mills/	11.2	9.1
Estimated Economic Life (Yrs)	35	35

Table 24

Integrated Gasification Combined Cycle

	250 mw IGCC	500 mw IGCC
Heat Rate, Net (BTU/kWh)	10,130	9,470
Capital Cost Data (1-1-89 $)		
Expected Plant Cost	$692,328,000	$1,044,000,000
Expected Licensing Cost	$10,385,000	$15,660,000
Expected Total Cost	$702,713,000	$1,059,660,000
$/kW - Low (-20%)	$2,237	$1,687
$/kW - Expected	$2,811	$2,119
$/kW - High (+20%)	$3,390	$2,555
Estimated Construction Time (mos)	48	48
Estimated Licensing Time (mos)	24 - 48	24 - 48
Primary Fuel	Coal	Coal
Fuel Cost (FOB Mine)	$0.25/mmBTU	$0.25/mmBTU
Estimated Capacity Factor	80%	80%
Estimated O & M		
Total - Excluding Fuel(Mills/kWh	11	8
Estimated Economic Life (Yrs)	35	35

The majority of the hydroelectric facilities are located within the Pacific Division. Hydroelectric makes up 11.3% of Pacific Division's existing resource portfolio while contributing 1.5% of the total on Utah Division's system. Estimates of hydroelectric costs are outlined in Table 27.

Fuel Cells Fuel cell power plants convert the energy of hydrocarbon based fuel 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 currently making steady progress. Incentives for fuel cell application are: quiet and relatively pollution-free operation, ease of siting, modularity, high efficiency, cogeneration potential and rapid installation time. For utility planning purposes and allowing for the technology to develop a proven and reliable track record, fuel cells of one type or another may become a viable resource option in about ten years. Cost estimates of a fuel cell application are contained in Table 28

Biomass (Wood Waste) Wood wastes are fired in a boiler producing steam that is sent to a conventional turbine/generator. Steam is condensed and recycled. No cogeneration features are included. The cost of particulate removal equipment has been included in the cost estimates. This is a mature and available technology, but development will largely depend on fuel availability and cost. Cost estimates of a biomass facility are contained in Table 29.

Wind Power Intermediate sized wind energy conversion systems (i.e. 50 to 500 kw wind turbines) have evolved into a fairly proven generation technology. Wind power generation has minimum environmental impacts, long-term fuel availability (no fuel cost) and a short lead time compared to conventional power plants. Problems associated with wind generation are related to: high cost, low capacity factor, unreliable (nonfirm) characteristic of the wind resource, the site specific nature of wind energy, and esthetics.

Wind energy has been developed on a large scale in California primarily due to favorable utility "buy-back" arrangements, significant tax incentives, and a conducive wind environment. Smaller demonstration projects have been developed in the Pacific Northwest with minimum success. A major detriment in this area has been the relative high cost of energy. Cost estimate for wind energy is contained in Table 30.

Solar Power Recent breakthroughs in solar cell efficiencies have greatly improved the competitiveness of photovoltaic (PV) systems when compared to conventional generation technologies.

Advantages of PV systems include: direct energy conversion (sunlight into electricity) with no moving parts, long-term fuel availability (no fuel cost), modular design, siting flexibility, no air or water pollutants and short construction time. Disadvantages include: high capital/construction costs, intermittent (nonfirm) availability, long-term reliability uncertainties, short component life, minimal commercial track record, and restricted siting opportunities. Cost estimate for a solar facility is contained in Table 31.

Table 25

Combustion Turbines

	50 mw Simple Cycle GT	130 mw Simple Cycle GT
Heat Rate, Net (BTU/kWh)	13,800	13,100
Capital Cost Data (1-1-89 $)		
Expected Plant Cost	$23,555,000	$45,800,000
Expected Licensing Cost	$589,000	$687,000
Expected Total Cost	$24,144,000	$46,487,000
$/kW - Low (-20%)	$384	(-30%) $253
$/kW - Expected	$483	$358
$/kW - High (+20%)	$576	(+30%) $467
Estimated Construction Time (mos)	24	30
Estimated Licensing Time (mos)	24 - 48	24 - 48
Primary Fuel	Gas	Gas
Fuel Cost N.G. Interruptible	$2.42/mmBTU	$2.42/mmBTU
N.G. Firm	$3.27/mmBTU	$3.27/mmBTU
N.G. Hybrid	$2.85/mmBTU	$2.85/mmBTU
Estimated Capacity Factor	20	20
Estimated O & M		
Total - Excluding Fuel (Mills/kWh)	5	5
Estimated Economic Life (Yrs)	30	30

Table 26

Combined Cycle

	250 mw Combined Cycle
Heat Rate, Net (BTU/kWh)	8,310
Capital Cost Data (1-1-89 $)	
Expected Plant Cost	$188,913,000
Expected Licensing Cost	$2,834,000
Expected Total Cost	$191,747,000
$/kW - Low (-15%)	$649
$/kW - Expected	$767
$/kW - High (+15%)	$886
Estimated Construction Time (mos)	42
Estimated Licensing Time (mos)	24 - 48
Primary Fuel	Gas
Fuel Cost N.G. Interruptible	$2.42/mmBTU
N.G. Firm	$3.27/mmBTU
N.G. Hybrid	$2.85/mmBTU
Estimated Capacity Factor	80%
Estimated O & M	
Total - Excluding Fuel (Mills/kWh)	3
Estimated Economic Life (Yrs)	35

Table 27

Hydroelectric Facilities

	16 mw Hydro - Shady Cove	10 mw Generic
Heat Rate, Net (BTU/kWh)	N.A.	N.A.
Capital Cost Data (1-1-89 $)		
Expected Plant Cost	$32,806,000	$20,896,000
Expected Licensing Cost	$820,000	$522,000
Expected Total Cost	$33,626,000	$21,418,000
$/kW - Low (-25%)	$1,569	(-10%) $1,919
$/kW - Expected	$2,100	$2,142
$/kW - High (+25%)	$2,640	(+50%) $3,228
Estimated Construction Time (mos)	36	36
Estimated Licensing Time (mos)	36 - 48	36 - 48
Primary Fuel	Water	Water
Fuel Cost	N.A.	N.A.
Estimated Capacity Factor	40%	40%
Estimated O & M		
Total - Excluding Fuel (Mills/kWh	2	6
Estimated Economic Life (Yrs)	35	35

Table 28

Fuel Cell

	10 mw Fuel Cell
Heat Rate, Net (BTU/kWh)	8,050
Capital Cost Data (1-1-89 $)	
Expected Plant Cost	$35,000,000
Expected Licensing Cost	$875,000
Expected Total Cost	$35,875,000
$/kW - Low (-70%)	$1,071
$/kW - Expected	$3,588
$/kW - High (+30%)	$4,686
Estimated Construction Time (mos)	42
Estimated Licensing Time (mos)	18
Primary Fuel	Natural Gas
Fuel Cost N.G. Interruptible	$2.42/mmBTU
N.G. Firm	$3.27/mmBTU
Estimated Capacity Factor	60
Estimated O & M	
Total - Excluding Fuel (Mills/kWh	3
Estimated Economic Life (Yrs)	30

Table 29

Biomass

	25 mw Full Condensing
Heat Rate, Net (BTU/kWh)	14,750
Capital Cost Data (1-1-89 $)	
Expected Plant Cost	$48,885,000
Expected Licensing Cost	$1,222,000
Expected Total Cost	$50,107,000
$/kW - Low (-25%)	$1,496
$/kW - Expected	$2,004
$/kW - High (+25%)	$2,517
Estimated Construction Time (mos)	36
Estimated Licensing Time (mos)	36 - 48
Primary Fuel	Wood Waste
Fuel Cost	$1.12/mmBTU
Estimated Capacity Factor	70%
Estimated O & M	
Total - Excluding Fuel (Mills/kWh)	19
Estimated Economic Life (Yrs)	35

Table 30

Wind

	5 mw Windfarm
Heat Rate, Net (BTU/kWh)	N. A.
Capital Cost Data (1-1-89 $)	
Expected Plant Cost	$10,586,000
Expected Licensing Cost	$265,000
Expected Total Cost	$10,851,000
$/kW - Low (-25%)	$1,620
$/kW - Expected	$2,170
$/kW - High (+25%)	$2,726
Estimated Construction Time (mos)	30
Estimated Licensing Time (mos)	12 - 24
Primary Fuel	Wind
Fuel Cost	N. A.
Estimated Capacity Factor	20%
Estimated O & M	
Total - Excluding Fuel (Mills/kWh)	10
Estimated Economic Life (Yrs)	

Table 31

Solar

	(Present Cost) 10 MW Concentrating PV	(Potential Future Cost) 10 MW Concentrating PV
Heat Rate, Net (BTU/kWh)	N.A.	N.A.
Capital Cost Data (1-1-89 $)		
Expected Plant Cost	$41,271,000	$10,826,000
Expected Licensing Cost	$565,000	$565,000
Expected Total Cost	$41,836,000	$11,391,000
$/kW - Low	$2,927	$951
$/kW - Expected	$4,182	$1,138
$/kW - High	$7,527	$1,324
Estimated Construction Time (mos)	12	12
Estimated Licensing Time (mos)	12 - 24	12 - 24
Primary Fuel	Solar	Solar
Fuel Cost	N.A.	N.A.
Estimated Capacity Factor	27%	27%
Estimated O & M Total - Excluding Fuel(Mills/kWh)	8 - 9	6 - 7
Estimated Economic Life (Yrs)	30	30
Levelized Cost (Mills/kWh)	165	43

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 earth's surface and partially de-pressurized. This steam is used to drive a steam turbine generator.

Binary cycle plants are used for geothermal fluids too cool to produce useful amounts of steam when de-pressurized. In these plants the geothermal fluid is used to vaporize a secondary working fluid having a low boiling point. The secondary working fluid is then used to drive a turbine-generator.

Both flashed steam and binary cycle units have been demonstrated and are commercially available. There are estimates of vast amounts of geothermal resources in the Pacific Northwest. To date many of the potential sites have not been developed to the point of proving the existence of sufficient resource for electrical production. Exploratory drilling is continuing at a number of sites. Cost estimates for various geothermal facilities are contained in Table 32.

Future Coal Prices

The price of coal contained in the fuel cost estimates for coal-fired facilities are based on Powder River Basin mine-month estimates. FOB mine estimates were utilized due to the unknown location of potential coal burning facilities. To obtain total delivered fuel cost a transportation adder need to be applied. Figure 11 presents a graphical representation of estimated transportation costs.

The base price of $.25 / mmBTU is based on recent experience. It is further substantiated by the Autumn 1988 issue of the DRI Energy Review which lists a price of $0.20 / mmBTU for mine mouth coal in the Rocky Mountain area. In June 1988 a staff paper of the Northwest Power Planning Council recommended a fuel price of $1.50 / mmBTU for Powder River Basin coal delivered to the Boardman, Oregon area. Removing the transportation component results in a mine mouth price of $0.26 / mmBTU.

Data Resources estimates the "Average Mine Mouth Price by Utilities" for coal in the Rocky Mountain Area to be $0.57 / mmBTU in 1989 dollars. This cost is based on existing contracts and price structures. The average transportation adder applied by DRI to deliver coal to the Washington/Oregon area was $1.11 / mmBTU. This brings the total cost of Powder River Basin coal delivered to the Pacific Northwest to approximately $1.66 / mmBTU. The 1988 Supplement to the 1986 Power Plan indicates delivered Powder River Basin coal pricing starting at $1.49 / mmBTU in 1988 dollars. This represents a reduction from the $2.15 / mmBTU (1988 dollars) used in the 1986 Power Plan.

At the current time there is little cost difference between long-term contract versus short-term, or spot prices, in the coal market. The 1988 DRI Autumn Energy Review states that new contract prices are currently at or near the spot price due to the level of demand being far below the level of productive capacity.

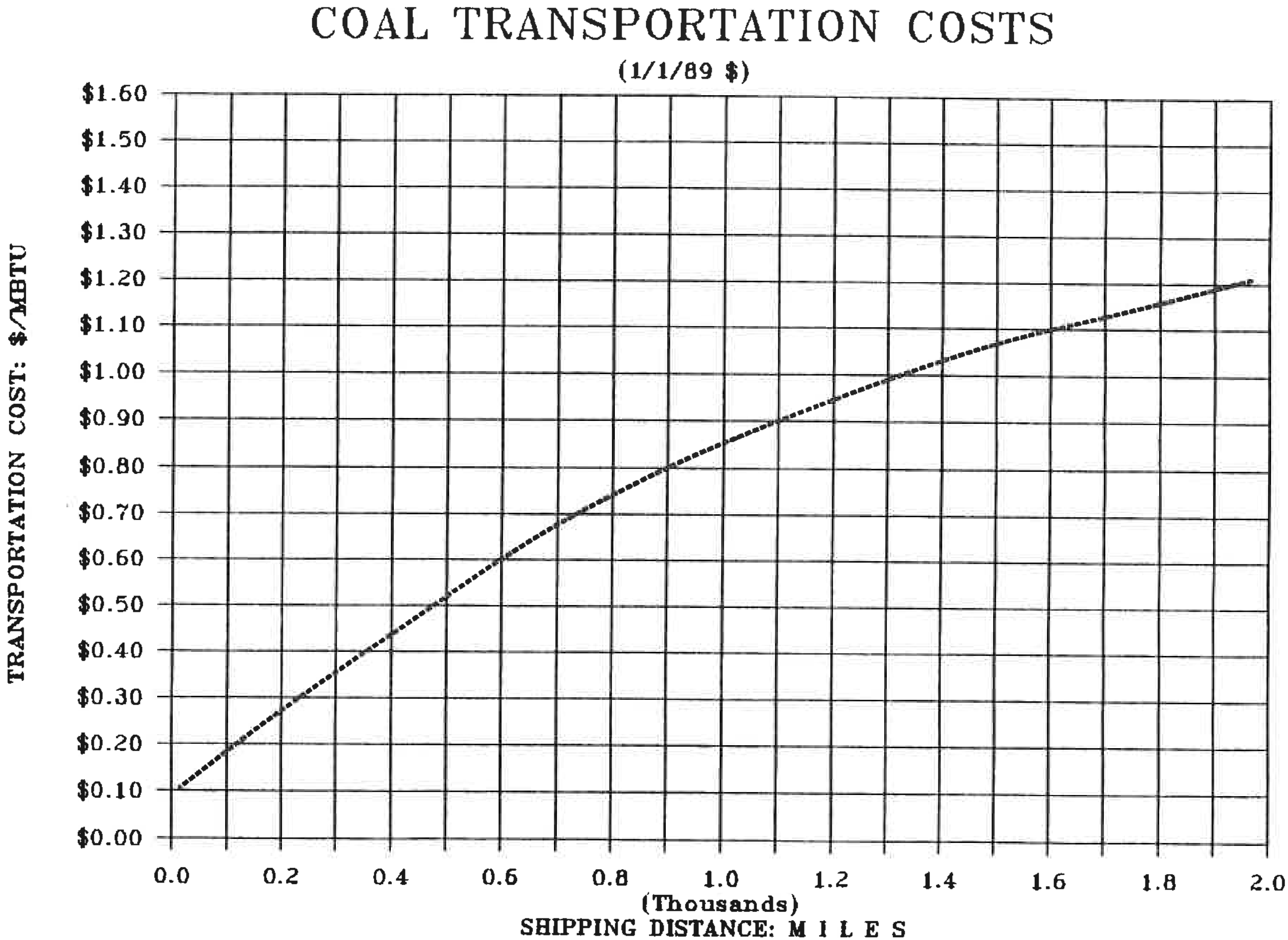
A long-term contract would most likely be structured with "reopeners" scheduled to occur at periodic intervals over the duration of the contract. During the "reopener" the price would be renegotiated based upon then current market conditions.

Table 32

Geothermal

	50 mw Binary	10 mw Flash	50 mw Flash
Heat Rate, Net (BTU/kWh)			
Capital Cost Data (1-1-89 $)			
Expected Plant Cost	$88,480,000	$15,291,000	$82,881,000
Expected Licensing Cost	$2,212,000	$382,000	$2,072,000
Expected Total Cost	$90,692,000	$15,673,000	$84,953,000
$/kW - Low (-30%)	$1,252	(-40%) $936	(-30%) $1,172
$/kW - Expected	$1,814	$1,567	$1,699
$/kW - High (+30%)	$2,346	(+40%) $2,205	(+30%) $2,203
Estimated Construction Time (mos)	36	36	36
Estimated Licensing Time (mos)	18 - 48	18 - 48	18 - 48
Primary Fuel	Geothermal Fluid	Geothermal Fluid	Geothermal Fluid
Fuel Cost			
Estimated Capacity Factor	80%	80%	80%
Estimated O & M			
Total - Excluding Fuel(Mills/kWh)	10	42	10
Estimated Economic Life (Yrs)	35	35	35

Figure 11


COAL TRANSPORTATION COSTS
(1/1/89 $)
TRANSPORTATION COST: $/MBTU
$1.60
$1.50
$1.40
$1.30
$1.20
$1.10
$1.00
$0.90
$0.80
$0.70
$0.60
$0.50
$0.40
$0.30
$0.20
$0.10
$0.00
0.0
0.2
0.4
0.6
0.8
1.0
1.2
1.4
1.6
1.8
2.0
(Thousands)
SHIPPING DISTANCE: M I L E S

The transportation cost curve was based upon recently received coal-hauling price quotes. The 1988 NPPC study on Cost and Availability of New Generating Resources uses an average cost of \$0.02 / ton mile (\$0.0012 / mmBTU mile) for transportation which is more conservative than the Company's cost figures. This figure could be used in lieu of the Company's cost history to arrive at a more conservative total delivered cost. For example, the transportation adder for shipment of Powder River Basin coal to Boardman, Oregon, is \$0.88 / mmBTU based upon the Company's experience versus \$1.25 / mmBTU using the NPPC.

C. THE ENERGY MARKETPLACE

Purchases From Other Utilities

In addition to purchases under BPA NR, and other specific purchase / exchange alternatives, the Company will have the opportunity to make additional power purchases from other western US and Canadian utilities on the open wholesale power market.

Purchases and exchanges with other utilities have historically been an important component of the total resource portfolio. These purchases will be utilized to meet system requirements and provide low cost, reliable, service to customers. Power purchases are an important component of a flexible resource strategy which maximizes the total benefits available from integrated utility systems. RAMPP analysis demonstrates that surplus energy, and capacity and firm energy purchases, as well as various forms of capacity / energy exchange, will continue to be a viable supply option throughout the forecast period.

A significant amount of surplus generating capability currently exists within the WSCC region. The majority of this surplus capability is located in areas which exhibit characteristics of: a predominance of thermal generation, reduced load growth, capacity additions which have come on line ahead of need, and large seasonal load differences. In addition, utility systems which are predominantly hydro-based typically have significant amounts of surplus energy available for sale over the course of a year. These characteristics result in significant amounts of available generating capability in excess of local needs.

The Company has numerous power supply arrangements with neighboring utilities located throughout the Western Systems Coordinating Council (WSCC). Among the services required are: baseload energy, winter peaking, seasonal capacity exchange, and capacity / energy exchange. Utilities in neighboring regions of the WSCC are currently providing many of these services. In the future, this surplus generating capability of neighboring systems could be relied upon to provide a portion of new resources acquired to meet increasing customer demand. An analysis was performed to estimate the amount of surplus capability that could be made available for purchase, assuming adequate transmission capability exists. The result of this analysis is discussed for the Rocky Mountain Power Area, and the Arizona - New Mexico Power Areas.

<u>Rocky Mountain Power Area</u>: The Rocky Mountain area contains a significant amount of underutilized, base-load, coal-fired generating capability which can be utilized at levels substantially in excess of those required to serve local load requirements. It is estimated that 500 to 1,200 average megawatts of energy is available in the Rocky Mountain area that is in excess of that usable for local requirements.

While the price of surplus energy from Rocky Mountain coal facilities will be determined by negotiations, it is reasonable to assume that energy not usable for local area needs, and not otherwise utilized, would be available for a reasonable markup over actual production costs. Assuming a 20 percent markup and using generally available information reflecting fuel cost and O&M expense for Rocky Mountain facilities, such energy is estimated to be available in a range of $20 to $25 per megawatthour in 1989, and using projected Data Resources escalators applicable to the region, in the range of $30 to 35 per megawatthour by the year 2000. All price projections are presented in nominal terms.

Arizona - New Mexico Power Area: The Arizona - New Mexico area also contains a significant amount of underutilized base load coal and natural gas-fired generating capability which can be utilized at levels substantially in excess of those required to serve local load requirements. It is estimated that 500 to 2,000 average megawatts of energy is available in the Arizona - New Mexico area that is in excess of that useable for local requirements.

While the price of surplus energy from Arizona - New Mexico coal facilities will also be determined by negotiations, it is reasonable to assume that energy not usable for local area needs, and not otherwise utilized, would be available for a reasonable markup over actual production costs. Assuming a 20 percent markup and using generally available information reflecting fuel cost and O&M expense for Arizona - New Mexico facilities, we believe such coal-fired energy is estimated to be available in a range of $25 to 30 per megawatthour in 1989, and using projected DRI escalators applicable to the region, in the range of $40 to 45 per megawatthour in the year 2000.

Assuming a 10 percent markup over production costs for natural gas-fired facilities, this energy will be available in a range of $30 to 35 per megawatthour in 1989, and in the range of $55 to 60 per megawatthour in the year 1997. All price projections are presented in nominal terms.

Approximately 400 megawatts of capacity and 170 average megawatts of energy have been included in the resource portfolio to reflect potential future purchases as described above.

Cogeneration Potential At Customer Locations

Many current large industrial customers have significant amounts of cogeneration potential. Several customers have already invested in on-site electrical generating equipment and have been successfully operating it for many years. Others have signed special cogeneration deferral contracts, or are purchasing large amounts of interruptible power, in order to maximize the total economic benefits that are available for both the potential cogenerator, the utility, and all other remaining customers. Cogeneration at customer facilities will be an important component of the Company's new resource portfolio.

Studies were conducted that assessed the cogeneration potential that currently exists on Pacific Division's system, and on Utah Division's system. Detailed models were developed independently for each of the two divisions. Each model evaluated the cogeneration potential at specific large industrial locations, and for smaller customers that are aggregated into more general market classifications. Pacific Division's model evaluated customers whose load exceeded one megawatt on an individual basis, while customers whose load was under one megawatt were evaluated on a generic basis. Utah Division's model evaluated all customers whose load exceeded 100 kilowatts on an individual basis.

Each model incorporated a set of input variables such as; system size, heat rate, capital cost, non-fuel operation and maintenance cost, fuel price, life of project, discount rate, and reliability rate; to arrive at a project's levelized cost. Facility sizes were summed at various energy price levels to arrive at the total cogeneration potential available at each price. These various summations produced the cogeneration resource supply curves.

As part of the least cost planning process, cogeneration supply curves were generated for the high, medium, and low growth scenarios. Within each of these scenarios, the assumptions regarding fuel prices, discount rates, and future economic activity were varied. The resulting high, medium, and low cogeneration supply curves were considered as components of the aggregate resource portfolio.

The following brief description of the results of the analysis indicates the magnitude of the estimated cogeneration potential that currently exists on the Company's systems.

Pacific Division: The amount of cogeneration potential currently existing at Pacific Division's industrial locations is estimated to be around 175 to 200 average megawatts at a levelized cost of between \$30 and \$40 per megawatthour. The majority of this potential is comprised of pulp and paper, lumber and wood products, and chemical facilities. An additional 100 average megawatts of cogeneration potential is added between \$40 and \$80 per megawatthour. The majority of this additional potential is located at lumber and wood product, food processing facilities, and at petroleum refineries. Total industrial cogeneration potential is approximately 300 average megawatts at levelized costs ranging up to \$80 per megawatthour.

The estimate of industrial cogeneration potential varies over the forecast interval on the basis of changing levels of economic activity. Table 33 presents a summary of Pacific Division's cogeneration potential scenario analysis. The results are presented for the high, base, and low economic forecasts in five year intervals beginning in 1990 and continuing through 2010. In addition, the results are displayed over four levelized cost categories ranging from \$40 or less to \$100 per megawatthour. Taking the levelized cost category of \$40.00 per megawatthour as an example, high case cogeneration potential increases from 240 average megawatts in 1990 to 410 average megawatts by 2010, base case cogeneration potential increases from 200 average megawatts in 1990 to 205 average megawatts by 2010, and low case cogeneration potential increases from 105 average megawatts in 1990 to 200 average megawatts by 2010.

The amount of cogeneration potential currently existing at commercial locations is estimated to be around five average megawatts at a levelized cost of \$80 per megawatthour. The majority of this potential is located at several large hospitals. An additional 35 average megawatts is added to commercial cogeneration potential between \$80 and \$90 per megawatthour. The majority of this additional potential is accounted for by several large education facilities. Total commercial cogeneration potential is approximately 40 average megawatts at levelized costs ranging up to \$90 per megawatthour.

Utah Division: The amount of cogeneration potential currently existing at Utah Division's industrial locations is estimated to be around 160 average megawatts at a levelized cost of \$60 per megawatthour. The estimate of cogeneration potential increases sharply at higher cost levels. It is estimated that 418 average megawatts of cogeneration potential exists at a levelized cost of \$80 per megawatthour.

Table 33

Pacific Division

INDUSTRIAL COGENERATION POTENTIAL
1990 to 2010 - High / Base / Low Economic Scenarios
(Dollar Figures = Levelized Cost Energy Figures = Average Megawatts)

	$40.00 / MWa			$60.00 / MWa			$80.00 / MWa			$100.00 / MWa		
	High	Base	Low	High	Base	Low	High	Base	Low	High	Base	Low
1990	240	200	105	275	240	220	340	300	280	340	310	295
1995	300	260	185	350	310	240	410	365	290	415	370	315
2000	360	295	195	415	345	240	480	415	300	490	420	320
2005	385	300	200	450	360	240	520	435	315	525	440	330
2010	410	305	200	490	370	250	560	440	315	575	450	330

Currently, a significant amount of low-cost cogeneration exists at several large industrial locations. The fixed costs associated with these facilities are low, they are well maintained, and can be fueled by a variety of sources. It is anticipated that in the future these facilities will operate solely for the benefit of their owners. Consequently, these technologies are not considered as part of the overall cogeneration potential.

The estimates of Utah Division's industrial cogeneration potential vary over the forecast interval on the basis of changing levels of economic activity. Table 34 presents a summary of the cogeneration potential scenario analysis. The results are presented for the high, base, and low economic forecasts in five year intervals beginning in 1990 and continuing through 2010. In addition, the results are displayed over four levelized cost categories ranging from $40.00 to $100.00 per megawatthour. Taking the levelized cost category of $60.00 per megawatthour as an example, high case cogeneration potential increases from 320 average megawatts in 1990 to 489 average megawatts by 2010, base case cogeneration potential increases from 169 average megawatts in 1990 to 206 average megawatts by 2010, and low case cogeneration potential increases from 92 average megawatts in 1990 to 80 average megawatts by 2010.

By comparing Table 33 with Table 34 some of the major structural differences between the Divisions' cogeneration potential can be highlighted. In total, Utah Division has a larger cogeneration potential than Pacific Division, but at a much higher cost. The relative cost differential is caused by Utah's lack of abundant, low-cost, biomass fuels as well as a large base of pulp and paper manufacturing facilities, both of which exist within the Pacific Northwest. Consequently, the majority of Utah's cogeneration potential consists of natural gas-fired combustion turbines and combined cycle units, or coal-fired steam units.

The amount of cogeneration potential currently existing at Utah's commercial locations is estimated to be around 19 average megawatts at a levelized cost of $80 per megawatthour.

<u>Total Company:</u> Taken together, the cogeneration potential located at existing customer facilities is nearly 250 average megawatts at a levelized life cycle cost of $40.00 or less per megawatthour. At a levelized life cycle cost of $60.00 per megawatthour the cogeneration potential of existing customers jumps to over 400 average megawatts.

These models will continue to be developed and refined as part of the ongoing planning process. In addition, contractual arrangements with the most economical cogeneration candidates will be developed and tested; and the ability to own and operate cogeneration facilities as part of industrial processes will be demonstrated.

Non-Utility Generation

Non-utility generation (NUG) refers to electrical generation that could be made available for purchase through direct negotiation or through some form of bidding process. Utilities in many parts of the country are beginning to rely upon off-system sources to supply a portion of their new capacity and energy requirements. The recent non-utility resource acquisition activity of utilities such as Virginia Power, the Northern California Power Agency, and POWEREX (BC Hydro's new power marketing subsidiary) indicate that the non-utility generation industry is becoming a viable alternative to new generation facilities for some applications. Non-utility generation will be a viable supply option so long as system requirements are met, and the price of the output is competitive with that obtainable from other supply, or efficiency sources.

Table 34

Utah Division

INDUSTRIAL COGENERATION POTENTIAL
1990 to 2010 - High / Base / Low Economic Scenarios
(Dollar Figures = Levelized Cost   Energy Figures = Average Megawatts)

	$40.00 / MWa			$60.00 / MWa			$80.00 / MWa			$100.00 / MWa		
	High	Base	Low	High	Base	Low	High	Base	Low	High	Base	Low
1990	62	63	62	320	169	92	577	436	393	653	571	543
1995	71	65	56	365	176	83	659	453	355	746	594	490
2000	76	68	56	391	185	82	707	477	352	800	625	486
2005	86	72	55	443	195	81	800	503	348	905	659	481
2010	95	76	54	489	206	80	883	532	343	1000	697	474

An evaluation of this evolving industry was performed in order to begin placing reasonable bounds around the expected future quantity, and price, of its product. Lack of sufficient regional experience and operating history limits the ability to produce precise forecasts of the industries potential size, availability, operating characteristics, and costs. However, it can be stated that the current national trends appear to be very favorable to the development of a robust independent power generation market that will be capable of delivering significant quantities of reliable, cost-effective, electricity as well as other energy services.
The enactment of Sections 201 and 210 of the Public Utilities Regulatory Policies Act of 1978, and the development of the FERC rules that implemented them, encouraged the development of an independent cogeneration and small power production industry. This development was further encouraged by the deregulation of the natural gas industry, the repeal of the Fuels Use Act, and the deceleration of electric utility generation construction programs. These institutional changes have brought about the advancement and evolution of a number of independent power supply companies and a related network of consultants, manufacturers, engineering companies, and financial institutions.

Significant industry development is occurring on a national basis as developers (such as Applied Energy Services and Bonneville Pacific), equipment manufacturers (such as Westinghouse, General Electric, and Babcock and Wilcox), design & engineering consulting firms (such as Fluor and Bechtel), electric and natural gas utility subsidiaries (such as Mission Energy and Dominion Energy), and financial institutions (such as Prudential and John Hancock) enter the market independently or on a joint venture basis.

Currently, the NUG market is highly fragmented. The major suppliers, and the various combination of suppliers, are concentrating in different sections of the total energy market. The type of customer that each of these suppliers attempts to acquire differs with the particular section of the market that they are attempting to compete in. The customers that these suppliers compete for include:

- utilities that might require additional resources,

- large industrial facilities that might require process heat and/or electricity,

- large commercial customers that might require space conditioning, electricity, and/or energy management services, and

- municipalities that might require waste management, electrical generation, or a new source of revenue.

Suppliers in the NUG industry compete with one another to provide one or more types of service to their customers. Some suppliers are attempting to become "full-service" energy providers; making available to the customer the full package of planning, design, financing, procurement, construction, and operation. Among the specific services that these NUG suppliers are providing to the market are: design and engineering, feasibility analysis, site preparation, permitting, hardware manufacture and/or procurement, construction and/or installation, operation and/or management, and maintenance.

It is important to keep in mind that the NUG industry is a total energy service industry; providing non-electric services such as: process heat, space conditioning, and waste management. What sets this new industry apart from the traditional energy hardware design and construction business is it's ability to generate vast amounts of reliable, off-system, electricity. Consequently, it becomes convenient to categorize the markets that these suppliers are competing in by the installed capacity of the generation devices they bring into being.

On this basis, the NUG suppliers appear to be competing in one or more of three distinct markets: 1) the "utility grade" market where unit sizes range from 100 to 250 megawatts, 2) the "industrial grade" market where unit sizes vary from 1 to 100 megawatts, and 3) the "small scale" market where unit sizes vary from 20 to 1000 kilowatts.
Utility grade suppliers are developing combustion turbines, combined-cycle stations, fluidized-bed and pulverized coal stations, and hydroelectic sites. The fuels used by these facilities are mainly coal, natural gas, petroleum waste coal, and hydropower. The units being constructed by these suppliers are not significantly different from standard utility-owned facilities.

Industrial grade suppliers are developing waste to energy stations, biomass stations, and reciprocating engines, in addition to the utility-grade technologies listed above. Fuel sources for these stations include coal, natural gas, petroleum waste coal, hydropower, municipal waste, and biomass (including wood waste and black liquor).

Small scale suppliers are developing modular, ready-to-install, cogeneration systems that are based on reciprocating engines. The two premier manufacturers of these devices are Tecogen Inc. (a subsidiary of Thermo Electron) , and Ultrasystems Inc. These devices typically produce electricity and hot water. Some of the latest designs also produce refrigeration. These devices are typically installed in locations such as: hospitals, hotels, schools, restaurants, and health clubs. The main fuel source for these devices is typically natural gas, although many have a dual-fuel capability that utilizes diesel fuel.

The direction that the NUG industry will take in the future is highly uncertain. The safest conclusion that can be reached is that the industry will continue to grow both in terms of its size, and in its relative importance to the total US energy picture. The uncertainty arises over the eventual organization of the industry, what role the electric utilities will play, and which regions of the country will be the most affected.

One vision of the organization of the future NUG industry is one where the industry is comprised of five or six multi-billion dollar, multi-state, generation companies each with a large portfolio of diverse facilities totaling several thousand megawatts of installed capacity. A constraint upon this vision is its requirement for a large number of qualified management teams which can successfully operate within an environment inhabited by federal regulators, planning and regulatory agencies from several states, numerous utilities and other basic energy providers, numerous diverse facility types /technologies / and sizes, and many large individual customers.

Another vision of future NUG industry organization is one where NUG suppliers continue to concentrate, and consolidate, within relatively narrow market segments such as utility grade CT's, municipal waste management facilities, industrial boiler and generator sets, and small-scale generator networks.

The role to be played by the electric utilities in the industries evolution is also an element of uncertainty. While many utilities have ventured into segments of the NUG industry, others are holding back until issues relating to the Public Utilities Holding Company Act, and transmission access are resolved. The potential impact that changes to either the Holding Company Act, or to transmission access, could have on the NUG industry is enormous.

A further uncertainty regards which areas of the country will be most affected by the NUG industry once the larger organization and political questions have been resolved. Suppliers in the NUG industry have the ability to do business virtually anywhere in the country, in fact many suppliers are currently moving into overseas markets.

The current direction in which the industry appears to be heading is toward areas of the country that exhibit one or more of the following characteristics:

1) rapid, and sustained, energy and demand growth,

2) current, or impending, shortages of generating capacity,

3) relatively high commercial and industrial electricity prices (high in relation to the price of natural gas, and petroleum),

4) a large number of aging, high-cost, utility facilities.

Currently, the majority of NUG activity, including earlier investments that qualified under PURPA, is concentrated in California, the Gulf Coast states, and in a band that runs from the mid-Atlantic coast states into New England. While these areas host the majority of the NUG investment, isolated pockets of activity are scattered throughout the country wherever large industrial customers that are well suited for cogeneration have access to sufficient quantities of low-cost fuel.

Industry analysts are predicting that in the next twenty years the NUG industry will experience rapid growth. These analysts further expect that the majority of this growth will be in the areas of the country that are already experiencing significant NUG activity. Growth is expected in each of the three general market areas identified earlier. Utility grade investments will be made primarily in response to utility requests for new capacity to meet increased demand, or to replace aging facilities. Industrial grade investments will be made in response to utility requests for new facilities, and large customer demands for lower-cost total energy service. Small scale investments will be made in response to high utility demand charges in order to lower the total energy service cost of small customers.

The NUG markets that are expected to have the greatest impact on the areas served by Pacific Division and Utah Division are the utility grade market, and the industrial grade market. Currently, the NUG industry derives most of its potential within the Pacific Northwest from low cost, indigenous, fuel sources such as; wood waste, black liquor, hydro, and geothermal; and from pre-existing process steam systems which can accommodate the addition of cogeneration without extensive facility modification.

The amount of non-utility generation that is actually constructed will vary over time on the basis of numerous economic and regulatory variables. Among these variables are; the level of economic activity, relative fuel prices, utility retail and buy-back prices, and various regulatory and financial incentives.

Small-scale generation is currently having, and is expected to continue to have, difficulty gaining a foothold in the regions commercial market. Numerous factors account for the expected difficulty that small-scale generation is having in gaining widespread penetration. Among these difficulties are: high initial capital investment and facility modification costs, relatively low purchased electricity prices and customer demand charges, relatively high natural gas prices, vibration and noise, and recurring maintenance requirements. Small scale generation will be useful in specific applications at some customer sites as part of an overall total energy management system. However, at this time the ability of small-scale generation to achieve widespread penetration within the region appears to be limited.

As previously mentioned, the lack of significant regional experience and operating history limits the ability to produce precise forecasts of the non-utility generation industries potential size, availability, operating characteristics, and costs. Without sufficient local experience to draw upon, any projection of NUG penetration within this area is speculative.

It is estimated that the current, cost effective, regional non-utility generation potential could be as large as 2,000 to 3,000 average megawatts. Included in this total is non-utility generation potential located within British Columbia. The cost-effectiveness criteria is based upon a total levelized cost of four cents per kilowatthour. This assessment of regional NUG potential appears to be consistent with estimates recently published by the Bonneville Power Administration (which estimated a region-wide cogeneration potential of 1,560 average megawatts at four cents per kilowatthour) and with the initial response to a recent RFP initiated by POWEREX (which reportedly received proposals for 3,600 average megawatts at four cents per kilowatthour - a number which given Virginia Power's experience will be revised downward).

The methods of assessing the regions non-utility generation potential, and the means by which it can be acquired in a manner which benefits all customers, will continue to be developed and refined as part of the evolving planning process.

Competitive Bidding

Voluntary competitive bidding processes will be an important element in assuring that marketplace-based resources, as well as other demand-side and supply-side resources, are acquired at the least cost subject to several crucial non-price criteria. These non-price criteria, such as dispatchability, fuel diversity, and the financial stability of the potential developer, are important elements in assuring that power, or efficiency savings, that are acquired through a bidding process actually produce the promised energy service.

Adequately documenting the extent to which competitive bidding may be utilized to acquire new resources, and the associated terms and conditions, is extremely difficult in the face of insufficient regional experience in calling for, and acquiring, new power sources through bidding. However, the planning process indicates that the range of prices identified for potential marketplace-based resources, and the costs associated with new energy efficiency and demand-side management programs, are representative of the range of prices that will be forthcoming through a bidding process. The potential size, and range of costs, associated with resources that could be offered through a bidding system have been evaluated as part of the resource portfolio analysis. The remaining issues are: 1) the extent to which these resources would be developed and provided by outside developers, 2) the security and deliverability of the power or service, and 3) the timing of the resource. These answers to these remaining issues will be forthcoming once the region has begun gaining experience in competitive bidding.

Competitive bidding systems will be utilized to acquire a portion of new resource requirements, consistent with rules developed by the various state regulatory agencies, in proportion to the magnitude of expected demand. For instance under low demand conditions, where the total 20-year resource requirement around 230 average megawatts is met by demand-side & system efficiencies and hydro-firming resources, competitive bidding would play a very minor role. Under high demand conditions, where the total 20-year resource requirement is in excess of 2,700 average megawatts, competitive bidding would play a much larger role.

Technological Change in Production and Consumption

Among the trends that characterize the increasingly competitive energy marketplace is the development and market diffusion of new energy-related technologies. The advancement of several new technologies - those that alter the way energy is produced, delivered, and utilized - will continue over the next twenty years.

Advancements are anticipated in two general categories of new technologies. These categories are: 1) demand-side technologies, those that improve a customer's end-use application of energy, and 2) supply-side technologies, those that improve the efficiency of the production of electricity.

Many of these anticipated new technologies have been discussed elsewhere in the plan document. These include:

- the increased diffusion of currently known, though not widely distributed, energy efficiency technologies, such as improved commercial lighting systems that have already been incorporated within the demand-side program evaluation.

- small-scale cogeneration devices that have been evaluated as a potential source of non-utility generation.

- the increased diffusion of currently known, though not widely distributed, industrial process electro-technologies that have already been incorporated into the load forecasts.

Among the remaining new technologies that are being monitored and evaluated on an ongoing basis are: 1) geothermal electricity generation, 2) wind-powered electricity generation, 3) solar electricity generation, 4) fusion, 5) superconductive materials, 6) fuel cells and 7) electrified transportation.

Geothermal: Generation of electricity from geothermal resources is a proven, commercially viable, technology. Two general categories of geothermal resources are under investigation: **flashed steam plants**, and **binary cycle plants**. Flashed steam plants are used when geothermal fluids are of sufficient temperature to flash to steam when brought to the surface. That steam in used to turn a turbine generator Binary cycle plants utilize a secondary, low boiling point, working fluid which is contained within a closed cycle. The steam from the secondary fluid is utilized to turn a turbine generator. Both systems are commercially viable. Portions of the Pacific Northwest are ideally suited to geothermal generation from an engineering standpoint. However, numerous environmental and institutional factors, such as: water quality, accessibility, transmission corridor siting, and noise, significantly complicate the estimate of viable geothermal resource potential.

Given the large technical potential of the geothermal resources within the Pacific Northwest, and the successful geothermal operating experience of utilities such as Pacific Gas & Electric, several moderate-sized geothermal installations have been included within the supply-side resource portfolio. These units, which are sized at 50 megawatts capacity, with 38 average megawatts of energy, are estimated to have levelized life cycle costs that range between 45 and 50 mills per kilowatthour.

Wind: Intermediate-sized wind energy conversion systems, those sized between 50 and 500 kW, have evolved into a proven, though relatively high-cost, generation technology in certain areas of the country. While recent wind electric experiments in the Pacific Northwest have not proved to be successful, due primarily to mechanical difficulties, a large potential wind resource still exists at certain locations. Blade-related mechanical problems that recently emerged within the large wind farms of California have apparently been brought under control.

It is anticipated that the cost of wind-electric generation will decline over the forecast period as technological improvements are made in blade and turbine technology, and as operators gain additional experience with the facilities that are already in place. A moderate-size wind resource, 38 average megawatts of energy and 20 megawatts of capacity, has been included in the supply-side resource portfolio. It is assumed that the output from this wind farm will be available at a total levelized cost between 45 and 50 mills per kilowatthour.

Developments in the technology and economics of wind-energy will be monitored in order to better evaluate the cost and availability of this potential resource.

Solar: Several solar technologies are of interest. Generally, these technologies can be categorized within two groups; **photovoltaic cells** which convert sunlight directly into electricity, and **solar thermal resources** which convert sunlight into heat which in turn is used to generate electricity. Examples of solar thermal resources include: parabolic dishes, parabolic troughs, central receivers, and solar ponds.

Cost projections for these various solar technologies continue to decline as advancements are made in materials, and as operating experience is gained at existing facilities. Over the past decade, average photovoltaic cell efficiency, the percentage of solar radiation that is converted to electricity, has increased by over 50 percent. Researchers are hoping to develop photovoltaics that achieve a sunlight-to-electricity conversion efficiency of 15 percent, and production costs of $100 per square meter. Currently, average fixed photovoltaic module efficiencies are around 13 percent, while production costs are in excess of $300 per square meter.

At current rates of improvement, photovoltaic technologies will gain widespread acceptance in many areas of the US. Initially, solar technologies will be utilized as a cost-competitive source of peaking capacity, and as an essential component of demand-side management programs. By the end of the century it is expected that larger scale facilities will be in operation that will provide a more continuous flow of power into utility grids, through the use of thermal storage systems or "shoulder-filling" fossil fuel combustion.

It is anticipated that significant cost reductions will occur in solar electric generation technologies over the next twenty years. Some estimates of future solar generation costs range as low as 40 to 45 mills per kilowatthour on a levelized cost basis. Assuming that these low-end cost estimates become reality during the next twenty years, and that several operations-related obstacles such as timing and transmission design, solar electric generation would become a larger proportion of the new resource portfolio. As a result, the evolution of these technologies will be monitored in order to better quantify the size and timing of this potential resource.

Fusion: Theoretical and laboratory developments in the area of low-temperature fusion will also be monitored as part of the ongoing planning process. The successful development of fusion technology would represent an enormous energy breakthrough. However, there appears to be virtually no possibility of the development, and widespread diffusion, of low-temperature fusion technology during the next twenty years.

Superconductivity: High-temperature superconductivity (HTSC) holds great promise for significant improvements in energy efficiency and storage. However, not enough is known about the fundamental nature of the technology to warrant large-scale commercial commitments. Most likely, years of laboratory research lie ahead before large-scale applications of superconductive materials and processes can be relied upon to provide a significant proportion of the nation's total energy service requirement.

Basic and applied research continues in many areas that could lead to significant future breakthroughs. For instance, Allied-Signal is currently producing a 3 kW, 140,000 rpm HTSC motor. Another US company is developing a 75 kW HTSC motor. Finally, a group of 14 Japanese companies are attempting to develop a 200 megawatt generator for low-temperature superconductive materials that contain design characteristics such that modification can be made to incorporate HTSC materials.

The Company currently does not produce cost estimates for future supply and demand-side applications that incorporate HTSC technologies. However, future HTSC research and development will be monitored and evaluated.

Fuel Cells: Fuel cells are devices that convert the chemical energy of a hydrocarbon fuel directly into electrical energy and heat. Neither combustion or moving parts are required in the conversion process. Fuel cell power plants are expected to generate electrical power very efficiently, and with modest environmental impacts relative to conventional combustion technologies. Fuel cells vary in size from small cogeneration units to large central power stations. In addition, the thermal energy generated by fuel cells can be utilized for non-electric energy purposes, such as: water heating, space heating, and industrial process heat.

The American Gas Association, in cooperation with several large manufacturing concerns, is currently developing a new generation of modular fuel cells that can provide multiple energy services directly to end use customers. The first generation phosphoric acid fuel cell (PAFC) are on the verge of commercialization according to the Electric Power Research Institute. A 4.5 megawatt demonstration unit has been built and tested in Japan, and 40 kW systems have been field tested in the United States.

Fuel cell cost estimates vary across a wide range. Current capital cost estimates for 10 megawatt PAFC systems range from a low of $1,100 per kW to a high of $4,500 per kW. Estimates of non-fuel operation and maintenance costs are also quite wide -- estimates vary between 2 and 17 mills per kilowatthour. Assuming that technological advancements, and increased operating experience, result in a cost structure that approaches the low end of the estimated range, then the total life cycle cost of a 10 megawatt PAFC system would be around 60 mills per kilowatthour.Fuel cell research and development activities both from the resource perspective, and from the new products / customer service perspective, will continue to be monitored and evaluated as part of the evolving planning process.

Electric Transportation: Advances in electric transportation technologies are being monitored in anticipation of the development of a competitively-priced, dependable, and acceptable alternative to oil-based transportation. Unlike the other new technologies discussed so far which could potentially add to the resource portfolio, advancements in electrified transportation represents a potentially large source of new load.

Developments in the research and development of electrical transportation vehicles will continue to be monitored and evaluated as part of the evolving planning process. The widespread diffusion of electric vehicles would have a significant impact on the amount of load, and upon the mix of resources utilized to serve that load.

The Evaluation of External Costs

Introduction: The Oregon Public Utility Commission, as part of its least cost planning order, instructed the Company to evaluate to the fullest extent practical and quantifiable, the costs and benefits external to any resource transaction. External costs are defined as those that may be imposed on society at large, and not borne directly by the Company or its customers. Although the Commission provided no specific details as to how such consideration is to be put into practice, from a power planning perspective, the issue appears to be whether or not the relative priority would change between new resources included within the supply and demand-side portfolios.

The basic analytical approach that was taken by the Company to account for external costs was to estimate the range of costs associated with controlling and/or reducing major emissions, such as SO2, NOX, and CO2, at the powerplant. The Company received comments during the technical advisory group process, and through written comments following the issuance of the draft RAMPP report, that indicated a desire on the part of many reviewers for a more complete determination of the costs associated with the effects of these, and other potential environmental hazards and risks.

While a more complete assessment of environmental risks and hazards, and their relative contribution to the total cost of new resources would add to the planning knowledge base, it would not have an immediate effect on short-term resource decisions as discussed in Volume 1. In addition, to be effective, this assessment must go beyond the environmental effects that are uniquely associated with electricity, and incorporate the interrelationships among other energy sources and uses.

For example, in order to reduce world carbon dioxide levels utilities might convert existing coal-fired facilities to natural gas. The resulting increase in natural gas demand could have several important ramifications, such as: increased natural gas exploration and transportation in environmentally sensitive areas, increased requirements for natural gas end end use efficiency programs, and energy price increases that could induce some customers to burn more wood or oil for space heat.

Another example would be where global warming concerns lead to the widespread diffusion of electric vehicles. A situation can be envisioned where electric utilities might be required to operate natural gas-fired generation in order to facilitate the carbon dioxide reduction of the personal transportation industry. However, it is possible that the transportation industry could provide offsets to the electric and natural gas industries in order to facilitate a process that would result in a net reduction in carbon dioxide emissions. A variation of this example is where the utility utilizes the cash value of these offsets to fund increased end use efficiency programs and/or renewable resource development in order to make sufficient capacity available to meet the needs of the transportation industry.

These two examples, which indicate the interrelationship among all energy sources and uses, point to the necessity of evaluating environmental costs on a total energy basis.

The Company will work to improve its method of quantifying the costs associated with various environmental effects, and incorporate these costs into its new resource selection process over the next two years. The Company is confident that the ultimate results of this "effects-based" environmental cost methodology will not appreciably alter the long-term resource planning results contained in this report. The Company bases this confidence on the fact that in nearly all forecast cases and scenarios the majority of identified, cost effective, end-use efficiency-based options are employed prior to the exercising of thermal-based resource options. In addition, the timing and sequence of new resource options generally follows a graduated, low-to-high, environmental effects scale. Typically, energy and system efficiency programs are the first options selected, followed by hydro firming, cogeneration, purchases, combustion turbines, renewable resources, and coal facilities. It is possible that under some demand forecast assumptions the timing and/or sequence of acquisition of a resource such as a gas-fired combustion turbine may be altered relative to a coal-based power purchase. However, if the demand assumption is high enough to require the acquisition of both resources, and if the environmental effects "adder" is not large enough to alter the relative economics of the next highest cost efficiency program or renewable resource, then both the combustion turbine and the power purchase will be acquired during the forecast period.

Method: As part of the RAMPP process, an evaluation of the effect that certain external costs may have on the determination of the cost-effectiveness of various resource options was undertaken. Resource costs were evaluated that could be internalized at some time in the future, as well as some external costs whose potential internalization is more speculative. This process consisted of the following steps: 1) an identification and appraisal of externalities, 2) a decision phase where, for each major type of external cost, the value of proceeding with further evaluation was balanced against the ability of that factor to influence the relative priority of a given resource decision in relation of other supply and demand-side options and 3) the incorporation of various analyses and speculations into the resource choice process.

Step 1: Appraisal of Externalities An appraisal of externalities that could have an impact upon the cost-effectiveness of a resource option was undertaken. The resulting list of possible externalities was long and diverse. Table 35 presents a partial list of potential externalities that could affect a particular resource decision. This list is not an exhaustive list of possible externalities A review of this table reveals list of possible externalities that could impact any

Table 35

POSSIBLE EXTERNALITIES

Acid Deposition Impacts	Ground Water Impact	Recreation Impact
Aesthetic Impact	Heat Pollution Effects	Resource Depletion
Agricultural Impact	Magnetic Field Effects	Runoff from Mines
Carbon Dioxide Emissions	Noise Effects	Sulfur Dioxide
Crop Yield Effects	Nitrous Oxides	Surface Water Impacts
Displacement of People	Ozone Effects	Technology Advancement
Displacement of Wildlife	Particulate Emission	Toxic Emissions
Effect of Property Values	PCB's	Waste Water Discharge
Effects on Visibility	Proximity to Population	Water Flow/Distribution Effect
Endangered Species Impact	Public Acceptance	Wetlands Impact
Fish Impact	Public Lands Encroachment	Radon

one of a number of resource options. Notably missing from this list are economic development and job creation, or job loss effects that were included, in compliance with the Oregon Commission's least cost planning order.

A number of the possible externalities listed on Table 35 can be considered as already internalized within the resource, and program, cost estimates. Externalities within this group include: fish and wildlife, ground and surface water, PCB's, mine runoff, radon, toxic emissions, waste water discharge, and wetlands impact.

Another group of possible externalities proved to be difficult to evaluate in terms of their relative impact upon the various resource options under evaluation. Externalities within this group include: aesthetic impact, agricultural impact, effect on property values, effects of visibility, magnetic field effects, public lands encroachment, resource depletion, and technology advancement.

A further group of potential externalities emerged as having the capability to influence the cost-effectiveness of a resource option over the plans 20-year horizon, and therefore influence the choice decision. Not surprisingly, these potential externalities are those currently receiving a significant amount of media, research, and political attention. Externalities within this group include: carbon dioxide emissions, nitrous oxide emissions, and sulfur dioxide emissions.

<u>Step 2: Decision Phase</u> A literature review of the estimated range of effects associated with each major externality was performed. A judgmental weight was then applied to each resource option in proportion to this range. A further decision was made to focus on the direct impact of a possible externality, and not to attempt to model a speculative chain of events that could be associated with each externality. For instance, while a range of costs associated with increased emissions were assumed for the purchase of coal-fired electricity from the desert southwest, the effects related to possible future resource or program decisions made by the selling utility were not incorporated - the external effects associated with large scale production of fiberglass (building insulation) and gallium arsenide (photovoltaic cells) were also not specifically evaluated.

It was determined that little useful power planning information would be gained by evaluating the relative cost-effectiveness of one resource option versus another through the quantification of minor externalities which affect all options to varying degrees. This proposition was tested by applying modest (1 to 3 mills per kilowatthour) additions to different program and option costs. This test resulted in no appreciable change in the resource choice and timing decision, under each load growth case, when compared to a situation where the external cost additions were not included. The only tangible effect was that each resource become slightly more expensive as these additional costs were applied.

As a result it was decided to concentrate analytical efforts in the area of quantifying the potential external costs of the externalities that could have the capability to greatly influence the cost-effectiveness of one resource option versus another, and therefore influence the resource choice decision. The potential external costs that the Company decided to evaluate more fully were those attributable to: carbon dioxide emissions, nitrous oxide emissions, and sulfur dioxide emissions.

Step 3: Incorporation into the Resource Choice Process Evaluations were made of the costs associated with additional emission control and mitigation technologies and techniques at existing, facilities. In addition, the costs associated with these technologies and techniques were included as part of the evaluation of those new resources which emitted these gases. Included in the category of new resources were potential sources of purchased power. Each source of purchased power was evaluated in order to arrive at a rough approximation of the proportion of each primary fuel-type used to generate that purchased power. The emission control standards included within President Bush's proposed Clean Air Act of 1989 were used as benchmarks in determining the range of costs associated with any control or mitigation process that might be required during the next twenty years.
The results of this portion of the external costs process helped verify the effectiveness of the portfolio approach to resource planning in terms of its ability to acquire new resources at least cost. The external costs process helped lead toward the selection of low-cost energy efficiency, and system efficiency, programs as the least cost resource option exercised in its initial two-year action plan.

In addition to the above analysis, a speculative "global warming" scenario was developed that encompassed a broader array of options that might consider exercising that would alter the costs and types of any future resources that might be required, and alter the fuel choice and operation of some existing resources, in order to arrive at a substantial reduction in overall carbon dioxide emissions. (This scenario is discussed more fully in the section dealing with Alternate Futures.) The purpose of this scenario, in addition to incorporating the risks associated with this situation within the two-year action plan, was to test the flexibility in dealing with a hypothetical situation where global warming is internationally recognized as a serious environmental problem, and that significant steps are taken worldwide to reduce the release of man-made carbon dioxide into the atmosphere. The operating goal of this scenario is that the Company acts to reduce its total carbon dioxide emissions by 20 percent by the year 2005.

The approach that was taken by the Company in the global warming scenario was very comprehensive. In exercising the options required to reduce its total carbon dioxide emissions by 20 percent the Company modeled significant alterations its existing resource base. In one variation, a significant proportion of existing coal-fired generation was repowered to natural gas. In the other variation a significant amount of existing coal-fired generation was removed from service and replaced with renewable resources whose costs had declined to levels associated with the most optimistic future estimates currently available.

The results of this portion of the external costs process helped verify the effectiveness of the portfolio approach to resource planning as well as the Company's ability to effectively meet the energy service needs of customers while at the same time reducing its carbon dioxide emissions. Unfortunately, the response to this situation, either with repowering coal facilities to natural; gas, engaging in a significant tree planting program, or relying upon large amounts of as-yet undeveloped low-cost renewable resources, carries a heavy price tag. In each run of the "global warming" scenario utility costs rise significantly in the latter years of the forecast. The resulting increase in the price of all energy forms, and the possibility that as-yet unknown or untested energy efficiency devices will be developed, leads to the conclusion that the demand for electric energy in this hypothetical environment will tend to be in the low, to medium-low, forecast range.

Table 36 displays the estimated range of costs associated with some emission control technologies for sulfur dioxide, nitrous oxide, and carbon dioxide. The costs associated with

Table 36

Estimated Range of Costs Associated With Emissions Control

Technique	Total Capital Cost ($ Per KW)	O&M Cost (Mills per KWH)	O&M Cost ($ Per Ton Removed)
SO2			
Conventional Limestone FGD	$100 to $120	2 to 3	$500 to $700
NOX			
Low NOX Burner	$2.00	-	-
Urea Injection	$2.00	6 to 8	$1800 to $2,000
CO2			
CO2 Scrubber inc. FGD (Hypothetical) (1)	$300 to $400 *plus* $100 to $200 for Disposal	10 to 12	$10 to $12
Gas Co-Firing (2)	$20	6 to 12	$5 to $10
Tree Planting (3)	$75 to $150	1 to 7	1 to 6

Notes:

1. Technology effectiveness unknown for large-scale power plant applications. In addition, prior FGD installation is required. Disposal method assumes deep ocean storage.
2. O&M costs assume "Low-Case" fossil fuel prices. No allowance made for fuel shortage.
3. 750,000 acres of trees are required to capture the carbon output of a 300 MWa coal facility

Further Reading:

1. Michael Shepard, "The Politics of Climate", EPRI Journal, Volume 13, Number 4: June 1988.

2. John Douglas, "Quickening the Pace in Clean Coal Technology", EPRI Journal, Volume 14/ Number 1: January/February 1989.

3. Mark Casper, "The Greenhouse Effect, A Utility Perspective", Presentation at EEI Conference: Electric Utilities in the Year 2000, November 18, 1988.

4. John Kinsman & Gregg Marland, "Contribution of Deforestation to Atmospheric CO2 and Reforestation as an Option to Control CO2", Presentation to Air & Waste Management Association, June 25-30, 1989.

emissions control was utilized as a surrogate for the external costs associated with the uncertain effects of these emissions. This range of costs highlights the difficulty associated with assigning, with any level of assurance, a range of costs to any particular emission control technology. These technologies display a tremendous variability both in terms of total capital cost, and in estimated O&M costs. With regard to carbon dioxide, there are additional uncertainties associated with each of the three control techniques listed. The hypothetical scrubber technology is not only untested in terms of its applicability for large-scale stack gas collection, but has an additional difficulty associated with CO2 disposal. The economics of co-firing with natural gas depends to a large extent upon the fuel's price and availability. The economics of large-scale, plantation style, tree planting techniques are dependent upon the price of available land, the cost of ongoing maintenance, and the willingness of society, particularly third-world societies, to allow the plantation to stand undisturbed for several generations (80 to 100 years).

RESPONSES TO POSSIBLE FUTURES

Description of Resource Response to Various Forecasts

For each of the five economic growth cases, a sequence of new sources was identified which balanced system loads and resources. This plan integration stage of the RAMPP process tied together potential supply and demand side resources and the Company's existing firm resources and commitments with the range of possible future system requirements.

To accomplish this integration of loads and resources, a spreadsheet based tool was developed with which the planner could make resource deployment decisions and evaluate the impact on the relative balance of energy and capacity loads and resources. In this fashion, resource plans were created by deploying one resource after another, until load and resource balance was achieved for the 20 year planning horizon. The tool does not produce plans automatically. It merely provides a framework for the planner to create alternative plans for subsequent evaluation.

The spreadsheet tool requires data describing existing firm commitments and resources, new resource options, and demand growth assumptions for each case. New resource options are defined in terms of annual energy and capacity, capital costs, and expense. For demand side resources, customer cost, and energy services revenue are also supplied. Customer cost is the expense, beyond normal electricity costs, paid by the customer, to entities other than the electric Company, for energy services. Energy services revenue is the additional cost paid by the customer to the utility for energy services associated with these demand side programs.

Economic growth assumptions include a forecast of system requirements in terms of capacity and energy, a forecast of the number of customers within the system, general inflation rates, cost of the elements of capital for the Company, and short-term debt and investment rates. Elements of capital cost are the cost of long-term debt, and common and preferred stock.

In creating resource plans, resources were deployed such that total resources remained in approximate balance with annual system capacity and energy demands. The order of resource deployment was based primarily on levelized life cycle cost, timing constraints (such as lead time and ability to adjust timing of delivery) , and goodness of fit to annual system requirements. In addition, resources that are potential "lost opportunities", meaning that they are not available or are much more costly after a specific time, were given special consideration.

It must be emphasized that levelized life cycle cost is an incomplete and inexact measure of resource costs. A more accurate cost measure would take into account the total system cost, as affected by each alternative. These system costs depend on how each resource is integrated into the system, and on a range of operating assumptions such as hydro conditions, transmission constraints, and nonfirm prices. Other characteristics considered were seasonality of energy and capacity delivered, point of delivery on the power system, and external costs and benefits.

Initially, plans were assembled assuming perfect knowledge of future requirements. Subsequent iterations were used to test the flexibility of the resource portfolio without perfect foresight. For example, cases which acquired resources to satisfy medium growth were tested under low and high growth assumptions, with recourse and adjustment made in recognition of actual growth conditions after five years.

Once a resource plan is finalized, the spreadsheet tool generates summary resource availability and cost data for use in determining the system costs of the plan. Financial data are escalated to the year of resource deployment using general inflation assumptions.

System costs for the resource plan were evaluated using the Company's production cost model and a simple revenue requirements model. The production cost model uses the resource plan and the system load forecast to quantify the power cost impacts of the plan. The production cost model averages the power cost results from multiple simulations assuming different hydrologic conditions. The model considers major transmission constraints such as: nonfirm market economics, and the intertie access policy. Consequently it requires a monthly distribution of energy availability for each resource, as well as a divisional breakdown. In this model demand side resources are represented as power purchases, or direct offsets to system load.

The model produces a detailed load and resource balance summary and quantifies total operating costs. These costs include fuel, firm purchase expense, and firm sales revenue, as well as wheeling and purchased power expense and non firm sales revenue.

These expenses and revenues are passed to a revenue requirements model, which simulates the financing, accounting, and cost recovery treatment of the resource decisions embodied in the resource plan, as well as planned resource and operational decisions for the existing system. The model determines revenue requirements based on an assumption of perfect regulatory treatment. All investments and expenses are fully recovered. Using these assumptions, the Company's annual return on investment is calculated by multiplying net assets (rate base) by the current cost of capital (rate of return). There is no consideration of regulatory ratemaking lag in the calculation of revenues. Further, there is no consideration of jurisdictional allocations, customer classes, or the BPA residential exchange.

The revenue requirements model is based on a simplified model developed by the Washington Utilities and Transportation Commission staff, but modified to better reflect specific characteristics of the Company and the resources available to it. It does a basic financial analysis: calculates CWIP and AFUDC for planned and new construction programs, calculates book and tax depreciation of assets and resulting deferred taxes, and it issues and retires long-term debt and stock to finance construction programs.

Results are derived from the simplified financial simulations. These include: average prices, customer bills, and total resource costs. Results are expressed in nominal and real terms, and expressed as total dollars, dollars per unit of system load, and 20 year net present values. See Table 37 for a description and explanation of the key outputs of the financial analysis model. In addition, emissions of SO_2, CO_2, and NO_x were estimated for each resource plan. These results were expressed in tons per megawatthour, and as a percentage of base 1989 emissions levels

Key Outputs and summary load and resource balances for each of the cases examined are contained in Appendix A. An overview of these results is provided below.

Table 37

Definition of Key Results

1	**System Load (MWa)**	*Forecast (before Conservation)*
2	Total Conservation	*Total Conservation in resource plan*
3	System Load net of Conservation	*Line 1 minus line 2*
4	**Energy Sales after Conservation**	*Line 3 net of losses*
5	**Total Customers (000's)**	*Forecast*
6	**Net Electric Plant (M$)**	*Includes net Conservation assets*
7	**Net Conservation Assets**	
8	**General Inflation Rate**	
9	**Operating Revenues (M$)**	*From financial analysis*
	Nominal	
	Real	
	NPV (11.47% discount rate)	*Discounted at utilities cost of capital*
	Average Growth	
	Nominal	
	Real	
10	**Base Unit Cost (mills/kwh)**	*Revenue Requirements divided by energy sales net of conservation*
	Nominal	
	Real	
	Average Growth	
	Nominal	
	Real	
11	**Average Customer Bill ($)**	*Revenue Requirements divided by number of customers*
	Nominal	
	Real	
	NPV (11.47% discount rate)	
	Customer Cost (M$)	
12	**Levelized Customer Cost (M$)**	*Conservation undertaken by customer with no Company involvement*
	(30 years at a 13.47% discount rate)	
	NPV (11.47% discount rate)	
13	**Energy Services Charge (M$)**	*Charges to customer for involvement in company sponsored conservation programs*
	NPV (11.47% discount rate)	
14	**Total Resource Cost (M$)**	*Sum of Revenue Requirements, levelized Customer Costs, and Energy Service Charges*
	Nominal	
	Real	
	NPV (11.47% discount rate)	
	Average Growth	
	Nominal	
	Real	
15	Mills / KWh	*Total Resource Cost divided by energy sales net of Conservation*
	Nominal	
	Real	
	Average Growth	
	Nominal	
	Real	

Low Case: The low economic growth case assumptions result in growth in energy requirements at an average annual rate of just 0.6%. The increase in system energy demand is less than 600 average megawatts by 2008. Since several firm wholesale transactions expire over this period, the result is a net requirement for new resources of only about 230 average megawatts over the planning horizon.

New requirements in this case can be met through a balance of customer energy efficiency programs, system efficiency improvements, and planning and operating strategies. System efficiency improvements of about 40 average megawatts are developed gradually over the planning horizon. Customer energy efficiency programs also develop gradually, contributing about 70 average megawatts by 2008. These consist primarily of lost opportunity programs, including commercial and mobile home codes. Replacement peak capacity purchase begins in 1992. After 1997, additional energy requirements can be met with thermal maintenance firming strategies.

Key results of this case indicate increasing nominal revenue requirements and average unit costs, in spite of the modest new source requirements. This is primarily a reflection of the high underlying inflation environment of this case. After adjusting for inflation, revenue requirements and average costs are declining.

Even though energy efficiency programs provide a small contribution to new requirements in this case, they represent significant capital investment by the Company of up to $25 million per year in the 1995-2000 period.

Medium - Low Case: System energy demand grows at an average annual rate of about 1% in the medium low case, or a total growth of almost 1000 average megawatts over the planning horizon. As in the low case, new requirements are met through a balance of customer energy efficiency programs, system efficiency improvements, and planning and operating strategies. System efficiency improvements of about 71 average megawatts and customer energy efficiency programs contributing 193 average megawatts are developed gradually over the planning horizon. The customer efficiency programs include not only lost opportunity programs, but also substantial commercial retrofit. By 2008, virtually all of the estimated potential from customer efficiency programs are fully implemented, with the exception of customer efficiency programs associated with industrial customers and residential retrofit programs. Between 1996 and 2005, firming strategies are implemented, including the staged return of Gadsby generation beginning in 2002. Purchases include the WNP-3 exchange rights beginning in 1996 and 50 average megawatts from off-system in the last three years of the plan.

Of the 622 average megawatts of total new energy sources developed under this case, purchases contribute about 20%, system efficiencies about 10%, customer efficiency programs about 30%, and firming strategies about 40%.

As in the low case, revenue requirements, average unit costs, and average customer costs grow at less than the underlying inflation rate, on average. Annual investments in customer efficiency programs reach about $50 million in 1995, and range between $40 and $70 million thereafter.

Medium Case: The medium case reflects expected load growth averaging about 1.5% per year. To meet this level of growth, system efficiencies and customer efficiency programs are again the initial new source additions. All demand side programs save Residential Retrofit go into acquisition in the mid-90's; the residential retrofit acquisition extends more gradually, being the most expensive customer efficiency program on a total resource cost basis. On the supply side, firming strategies are employed beginning in 1992 and the WNP-3 exchange is invoked in 1993, with deliveries beginning in late 1994. Acquisition of cogeneration also begins in 1994, developing about 200 average megawatts in the next five years. Gadsby repowering begins in 1995. A BPA NR purchase is requested in 1997, with delivery of 100 average megawatts beginning in 2005. Power purchases of 50 average megawatts beginning in 1995, increasing to 130 average megawatts in 2006 round out the new sources in this case.

Of the nearly 1,400 average megawatts of total new energy sources developed under this case, purchases contribute about 25%, system efficiencies about 10%, customer efficiency programs about 25%, cogeneration about 20%, and firming strategies about 20%.

Again, average unit costs and average customer costs grow at less than the underlying inflation rate, on average. Annual investments in customer efficiency programs reach about $70 million in 1995, and range up to $125 million thereafter.

Medium-High Case: The medium high case yields an average annual growth rate of 2.0% in system energy demand. As in the medium case, system efficiencies and demand side pilot programs are the earliest resource additions. After the pilot stage, all demand side pilot programs ramp up to acquisition in the mid-90's. Other early plan responses include invoking the WNP-3 exchange in 1990 (delivery in late 1991), firming strategies and Gadsby repowering beginning in 1991. Off-system purchases begin in 1992, starting at 50 average megawatts, increasing in several steps to about 370 average megawatts by 2008. Cogeneration acquisition begins in 1993. BPA NR purchase begins in 2002, requiring notice of BPA in 1995. A Hydro firming CT is activated in 1995, as well as a seasonal purchases. Other new generation is required in this case, with geothermal and wind resources shortly after the year 2000.

Of the 1,969 average megawatts of total new energy sources developed under this case, purchases contribute about 30%, system efficiencies about 5%, customer efficiency programs about 25%, cogeneration about 20%, firming strategies about 15%, and new generation from renewable sources about 5%. With this resource plan, average unit costs grow at at a rate below the underlying inflation rate, about -1.0 percent in real terms, on average. In the latter part of the planning horizon, investments in energy efficiency represent almost 20% of net electric plant assets of the Company.

High Case: The high case is based on a robust 20 year growth rate averaging 2.5% per year. As in the medium-high case, system efficiencies, BPA peak, full acquisition of demand side programs, the WNP-3 exchange, Gadsby repowering, off peak purchase, and cogeneration acquisition are the initial resource additions in the 1989 to 1992 time period. Hydro firming CT generation, and additional off-system purchases are employed by 1995. BPA NR purchase are required by 2002. Construction of new generation resources is postponed until the late 1990's. Combined cycle combustion turbines, geothermal and wind resources, and a small coal unit all begin generating in the final six years of the planning horizon, requiring decisions on their construction in the 1995 - 2000 time period.

Of the 2,703 average megawatts of total new energy sources developed under this case, purchases contribute about 25%, system efficiencies about 5%, customer efficiency programs about 20%, cogeneration about 15%, firming strategies about 10%, new generation from renewable sources about 5%, and new small thermal generation about 20%. Even with these substantial resource requirements, average unit costs and average customer costs grow at a rate below the underlying inflation rate. Near the end of the planning horizon, investments in energy efficiency represent about 17% of net electric plant assets of the Company.

Discussion Concerning The Comparison of Various Plans

By comparing the resource plans for each case, three distinct sets of resource options emerge. These are summarized in Tables 38 through 40 in the categories of Baseline Actions, Flexible Resource Options, and Long-Term Options. In addition, the elements of an overall resource deployment strategy can be defined.

The Baseline Actions consist of short-term actions common to all cases. In each case system efficiencies, energy efficiency pilot programs, and firming strategies are employed in the first few years. In the low growth case, these resources are sufficient to meet requirements, without the ramp up of customer efficiency programs other than lost opportunity programs.

The next group of resource alternatives, Flexible Resource Options, are those alternatives for which the primary decision focus is the timing of their acquisition, since they are generally required in all but the low growth cases. The alternatives in this group are distinguished by their relatively low cost, as compared with long-term options, but also by their very attractive timing and flexibility. The WNP-3 exchange and return of the Gadsby generators from cold standby condition are especially valuable in this regard because of their high certainty of availability. Options on certain cogeneration alternatives exist, but with somewhat greater associated uncertainty. Utility purchases have the potential to be acquired in a short time frame, and can be combined with shorter term wholesale sales to give them greater option flexibility. The decision parameters affecting the timing of these various Flexible Resource Options are identified in Table 39.

The final set of resource options include higher cost, longer lead time alternatives, including BPA NR purchases, renewable generating alternatives (geothermal, wind), and thermal generation (CC CT's and small mine-mouth coal). These longer lead time, more expensive, resource deployment decisions are postponed as much as possible into the future. Even in the high growth case, these resources decisions are not required until the late 1990's.

The final element of strategy emphasizes the benefit of resource portfolio diversity. In each of the medium or higher growth cases, no more than a 30 percent reliance on any of the seven resource categories is required. This diversity protects against unforeseeable risks associated with any one new source, even though each of the elements of the new source portfolio is expected to be available over the planning horizon.

In conclusion, a diversified portfolio of resources is available to respond to a variety of load growth scenarios with a balanced resource plan. Longer lead time decisions, such as major construction programs, are postponed as long as possible, maximizing the ability to respond to changes in the business environment and minimizing impacts on customer costs and prices.

Table 38

Resource and Market Planning Strategy

Short Term Plan - Baseline Actions

Resource	TRC* (mills/kwh)	Energy / Capacity	Category
• Demand Side Programs	17-23		Customer Efficiency
Begin pilot, demonstration, and lost opportunity programs in 1989 and 1990, contributing 10.6 mwa by 1991. Prepare to ramp to acquisition levels in 1993-95 period. Pilot programs provide knowledge about program costs, expected energy / capacity savings achievable. These programs are crucial for meeting higher growth cases, and can be held at minimum viable levels in lower growth conditions. Very flexible.			
• T&D Efficiency Improvements	18.6	30 / 30	System Efficiency
Hydro Efficiency Improvements	18.6	10 / 20	
Voltage Regulation	2.0	10 / 20	
Thermal Efficiency Improvements	21.9	15 / 0	System Efficiency
Ongoing system improvements contribute about 10 mwa by 1991.			
• Maintenance/Firming Strategies	15.3	125 / 0	Firming Strategy
Purchase of available hydro energy associated with spring runoff, as well as off-peak thermal generation, to cover maintenance outages. This energy can be acquired as needed.			
• Capacity Purchase		0 / 1000	Contractual Rights
Continue / replace existing capacity contract services.			

* *Total Levelized Resource Cost*

Table 39

Resource and Market Planning Strategy

Short Term Plan - Flexible Resource Options

Resource	TRLC* (mills)	Energy / Capacity	Category
• WNP-3 Exchange	26.8 mills	65 / 164	Contractual Rights
Option must be exercised by 1/1/96,. minimum 1 1/2 year notice required in advance of deliveries. Energy required by 1992-93 if Med-high / High growth expected, which implies notice by May of 1991 Option should be exercised at that time if high growth conditions prevail and comperable marketplace alternatives have not been identified. If growth is Medium / Med-low, notice is not required until May 1993 or 1994.			
• Gadsby (gas peaking)	23.4	100 / 224	Firming Strategy
The three units are capable of gas firing, with only minor refurbishment expense. The time required to begin generation is estimated to be within a 1-3 year time frame. Unit 3 (108 MW) is likely available within a six month time frame.			
• Utility Purchases	22-33	50 to 220 / 0 to 200	Purchase
Purchases of energy from surplus coal generation in DSW and Rocky Mountain areas. Potential lost opportunity in the future. Off-peak energy and winter season capacity and energy purchases likely to be available, and could be acquired in 1990-92 period. Additional flexibility can be built in by combining with shorter term wholesale sales. Energy required as early as 1991-92, under Med-high / High growth, 1995 if Medium, 2006 if Med-low.			
• Cogeneration	30-35	160 / 160	Cogeneration
Current contracts give the Company options on a portion of the total potential. This potential is needed in 1991 - 93 time frame under High / Med-high growth. Option should begin to be exercised in that time frame if high growth conditions prevail and comperable marketplace alternatives have not been identified. A demonstration or test case is desirable in the short term.			

* *Total Levelized Resource Cost*

Table 40

Resource and Market Planning Strategy

Long Term Options

Resource	TRLC* (mills)	Energy / Capacity	Category
• Hydro Firming (Single Cycle Combustion Turbine)	29.5	45/100	Firming Strategy
3 year lead time. Acquisition decision as early as 1992, under high growth. Contingency purchases could substitute.			
• BPA NR Purchase	30.6	200 / 270	Contractual Rights
Sign up in 1990 if we expect High growth, 1994 if Medium-high. 7 year lead time. Some untested ability to ramp up or down our requirements during the 7 year lead period. Flexibility is an unknown.			
• Voltage Regulation 2	35.0	25/50	System Efficiency
Prospective higher cost CVR program could be instituted, based on experience with pilot baseline program, and more rigorous estimates of potential.			
• Small Coal	47.5	235 / 315	Coal
5 year lead time. Begin building in 1999 if we achieve High growth.			
• SCE Energy Withdrawal	31.0	108/0	Contractual Rights
Required in 1996 if we expect high growth. Notice required in 1992 for use beginning in 1996. Available thru 2005-06. Not as flexible as other potential marketplace options.			
• Combined Cycle Combustion Turbine	44.6	125/250	Gas
4 year lead time. Begin construction in 1996 if we achieve high growth.			
• Geothermal	45.7	38/50	Renewables
3 year lead time. Begin construction in 1994 if we achieve high growth.			
• Wind Farm	45.7	38/50	Renewables
3 year lead time. Begin construction in 1997 if we achieve high growth.			

* *Total Levelized Resource Cost*

Alternate Futures - Resource Responses to Various Scenarios

In addition to evaluating the five high-to-low forecast cases, an extensive scenario evaluation exercise was performed. The purpose of the scenario exercise was two-fold.

First, the scenario exercise tested the flexibility and adaptability of the resource portfolio to significant external events that would be capable of having a profound influence upon the Company's business environment. This "profound impact" can be thought of in several ways. One manner of viewing this impact is a situation in which the Company finds future load growth shifting from one extreme to the other, such as: loads grow at a high-case rate for several years, then deteriorate to a much lower growth rate. Another situation is were the underlying one-to-one relationship between the rate of overall economic activity and electric load growth is altered, such as: loads deteriorate significantly due to changing industry structure, or improved technologies, while economic activity remains robust.

Second, through the "global warming" scenario a significant national, and international, push to reduce overall carbon dioxide emissions could be evaluated both in terms of its effect on the selection of future resources, and also upon the costs and operation of the existing system. Through this scenario certain external costs associated with global warming could be incorporated into the planning process.

Three alternative scenarios were evaluated as part of the RAMPP process. These three scenarios were: 1) Oil Shock in the mid-1990's, 2) Increased Competition, and 3) Global Warming. These scenarios emerged following a lengthy and involved scenario development process that was undertaken with the assistance of the Regional Research Advisory Group. Numerous alternative scenarios were evaluated for inclusion within RAMPP as part of this scenario development process. These scenarios ranged from the three mentioned above to: prolonged economic recession, increased economic instability, prolonged economic boom, technological breakthroughs in energy efficiency technologies, and technological breakthroughs in electrification technologies. On the basis of the input received during the internal, and external, scenario evaluation process, these three scenarios were included within the current RAMPP analysis. Additional scenarios will be evaluated as part of ongoing planning activities including one that evaluates the impact of high near-term load increases.

These scenarios adequately tests the capability of the RAMPP models to respond to changing economic and business conditions in a way the minimizes cost impact to the Company, and price impacts to customers. Also the scenarios, in conjunction with the five demand forecast cases, yield an accurate portrayal of the future risks and uncertainties that confront the Company as it evaluates various resource and program options.

These alternative scenarios are not directly comparable with one another. They were developed solely as a means of testing the ability to "shift gears", in terms of resource acquisition programs, as major unforeseen economic or business environment changes occur. Each scenario is based upon significantly different underlying economic and/or business environment assumptions. Consequently, no conclusions can be drawn concerning the relative merits of one scenario, or its resulting configuration of future resources, and another scenario. Similarly, no conclusions are drawn from comparing the output from the various scenarios to the output of any of the five forecast cases.

Oil Price Shock: This scenario is based upon the assumption that a major oil and natural gas price increase, a virtual doubling in nominal terms within three years, occurs in the mid-1990's. As a result the national economy is thrown into an economic recession that is characterized by high inflation and interest rates, and several years of prolonged economic stagnation. From a power planning perspective, a significant slowing in the rate of demand growth is experienced in the mid-1990's which effectively causes a shift from a medium-growth path to a low / medium-low growth path. (Demand growth doesn't slow to zero due to an increase in economic activity within the mining industry that is in turn associated with high fossil fuel commodity prices.) Several potential new resource options, those that are based upon firing with fossil fuels, become more expensive.

The flexibility inherent in the total resource portfolio provides the ability to modify the resource acquisition programs immediately following the economic crash. Programs and options that were exercised when loads were growing along a medium economic path are sufficient to meet capacity and energy demands throughout the remainder of the forecast period.

Increased Competition: This scenario is based upon the assumption that a significant change in the business environment (deregulation) occurs in the mid to late-1990's that leads to the loss of the Pacific Division's ten largest industrial customers to alternative suppliers. This scenario is unique in that the underlying economic assumptions are the same as the medium forecast case, but the relationship between economic growth and electricity purchased from Pacific Division is drastically altered downwards. A significant decrease in demand is experienced in the mid-1990's as two industrial customers per year leave the system over a five year period under the assumptions of this scenario. This situation effectively causes a shift from a medium-growth path to a level of demand that is below the low growth path. Following this demand collapse, load growth returns to the medium growth path as residential and commercial customer classes grow. From a power planning perspective, a significant increase in the amount of surplus capacity and energy capability is experienced that extends for nearly a decade. A portion of the fixed costs associated with the operation of the system are passed on to remaining customers. Power cost simulations for this scenario indicate that the price impacts of this shift can be moderated by increases in secondary sales. The secondary sales cushion rests on secondary market prices that are assumed to have increased as compared to current market conditions. Eventually, increases in residential and commercial load absorb the surplus, requiring the acquisition of an off-peak power purchase arrangement at the end of the forecast interval.

As with the oil price shock scenario, the flexibility inherent in the total resource portfolio provides the ability to modify the resource acquisition programs soon after the loss of the industrial customers. Programs and options that were exercised when loads were growing along a medium economic path become surplus to the needs following the loss of service to the ten largest industrial customers. However, as loads gradually grow over the remainder of the forecast interval, these resources become a cost-effective source of supply.

Global Warming: This scenario is based upon the assumption that a major national and international commitment is made to reducing atmospheric carbon dioxide emissions.

The issue of global warming is highly speculative in many areas. For example:

A consensus has not been reached within the scientific community regarding the possibility of a human-activity induced change in global climate.

Several of the leading experts who do expect a human-induced change in climate cannot speculate with any accuracy as to the timing or magnitude of such an occurrence, nor to the relative effectiveness of any particular emissions reduction program in altering the timing or magnitude of the effect.

Disagreements exist among the experts as to the reliability of global warming estimates that are being produced by contemporary computer models. Among the sources of this disagreement is the extent to which other earth-bound and cosmic factors such as ocean absorption, cloud cover, and sunspots, impact global climate conditions.

However, it is also recognized that the national and international debate has grown over this issue, and that a significant amount of politicalization that has occurred. Consequently the Company considered it necessary to evaluate the potential impact that a national and international carbon dioxide reduction program could have on future resource choices, and existing system operation. Additionally, the resulting range of costs associated with this speculative, though politically viable, scenario adequately captures the majority of the potential costs associated with a variety of other fossil fuel combustion-based external costs. From a power planning perspective the issue of the consideration of external costs appears to be whether of not the relative priority would change between new sources included within the supply and demand-side portfolios.

This scenario presumes that a large-scale national and international program is embarked upon to reduce global carbon dioxide emissions in the mid-1990's. The goal of the scenario is to evaluate the costs associated with several methods of achieving a 20 percent reduction in Company-produced carbon dioxide emissions, as measured from a 1989 base, while at the same meeting a medium-low level of load increase. Medium-low economic conditions were assumed in consideration of the notion that an international approach to global carbon dioxide reductions will lead to a relative economic slowdown in the industrialized nations as they grapple with prematurely altering their domestic stock of energy-using devices, while at the same time transferring wealth to third-world nations to fund programs aimed at goals such as: reducing de-forestation, encouraging re-forestation, and altering traditional patterns of energy use.

Two different approaches to reducing CO2 emissions by 20 percent were modeled. The first approach, the repowering option, and the retiring option. Under the repowering option a number of existing coal-fired units are converted to natural gas. In the retiring option, a number of older coal-fired units are retired and replaced with renewable resources, primarily geothermal and solar. Among the important assumptions underlying these two approaches are: 1) that the Company is experiencing medium-low demand growth conditions, 2) that the future price path of natural gas is no higher than the highest rate currently projected by Data Resources, and 3) that the future cost of solar generation decreases to the most optimistic level currently assumed by the solar industry and the US Department of Energy.

Other potential carbon-reducing measures were studied as part of the RAMPP process. These measures included: the range of cost estimates for tree-planting activities that are aimed at removing and storing carbon from the atmosphere, and the potential overall carbon reduction possibilities inherent in increased electrification - particularly in the area of electrified transportation.

In each of the two cases modeled as part of the global warming scenario the following pattern emerged. Demand-side and system efficiency resource options were exercised in the early and mid 1990's as customer demand levels followed the medium-low economic case. As the repowering, and alternative resource / unit retirement programs are instituted during the later years of the forecast interval real electricity prices began to increase as compared to the medium case.

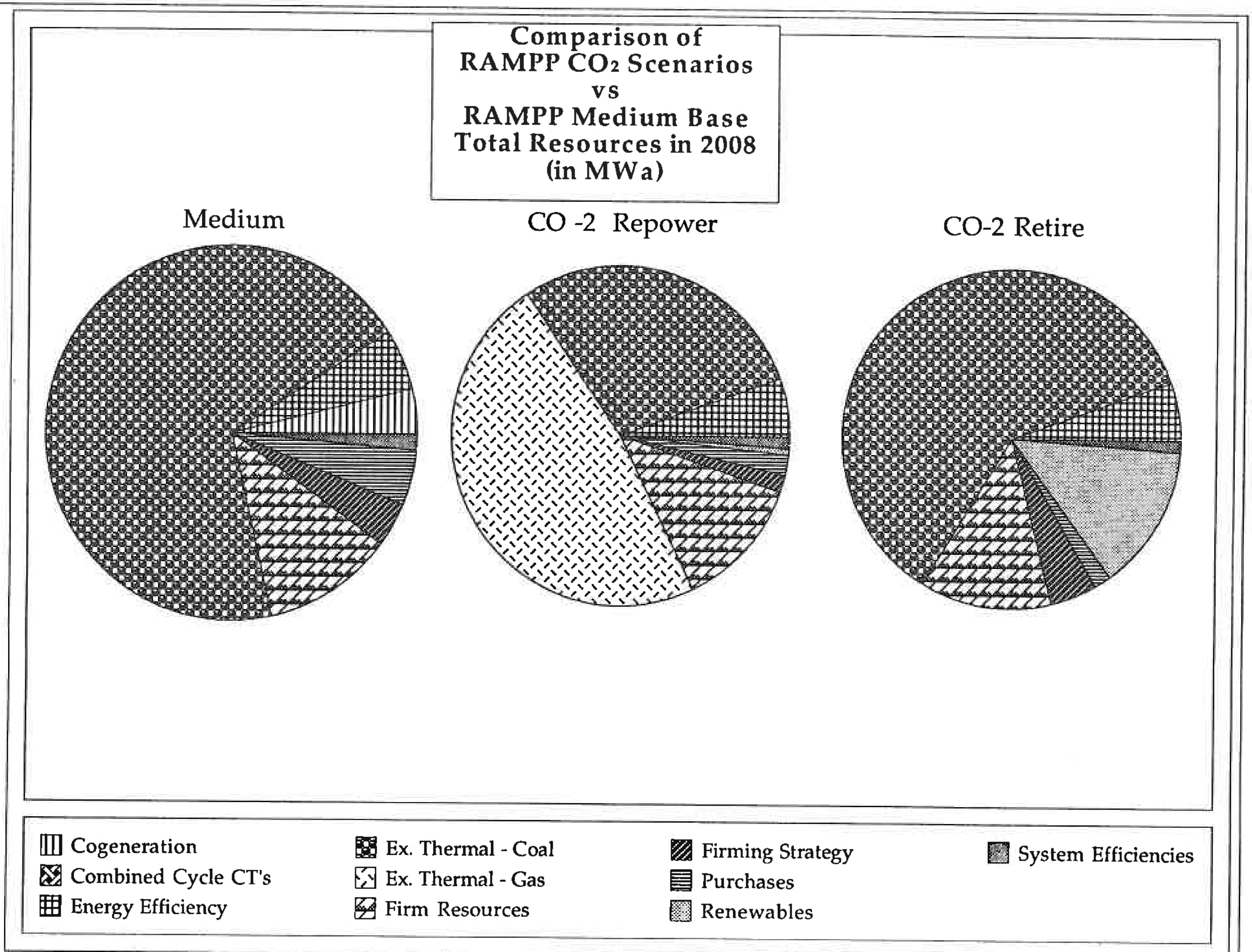
In the gas repowering case, for example, real electricity prices fall at an annual rate of 3.6 percent per year between 1989 and 1998. However, real price increases average a 3.5 percent per year increase between 1998 and 2008, with most of the increase coming in the last six years.

In the retirement case, real electricity prices fall at an annual rate of 3.6 percent per year between 1989 and 1998 and rise at an average increase of 1.0 percent per year between 1998 and 2008.

Figure 12 presents a comparison of the proportions of all fuel, renewable energy, and efficiency sources needed to serve customer demands in the year 2008 for the CO2 repower case, the retire case, and the medium projection. In the repower case, more than half of the Company's existing coal-fired generation has been converted to natural gas. In the retire case, a number of older coal-fired facilities have been retired and replaced with renewable resources.

The range of utility and customer costs associated with various responses to this scenario are very wide, indicating the highly speculative nature of the assumptions dealing with the advancement in alternative technologies, the availability and price of low carbon dioxide emitting fuels, and the uncertainty related to the global warming effect itself. However, in each specific evaluation of this scenario, both utility and customer costs were significantly higher that they were under any of the conventional demand forecasts, as well as any of the aforementioned alternative scenarios. The global warming scenario, while highly simplified, again illustrate the desirability of maintaining a flexible portfolio of supply and demand-side options.

Figure 12


Comparison of
RAMPP CO_2 Scenarios
vs
RAMPP Medium Base
Total Resources in 2008
(in MWa)
Medium
CO -2 Repower
CO-2 Retire
Cogeneration
Combined Cycle CT's
Energy Efficiency
Ex. Thermal - Coal
Ex. Thermal - Gas
Firm Resources
Firming Strategy
Purchases
Renewables
System Efficiencies

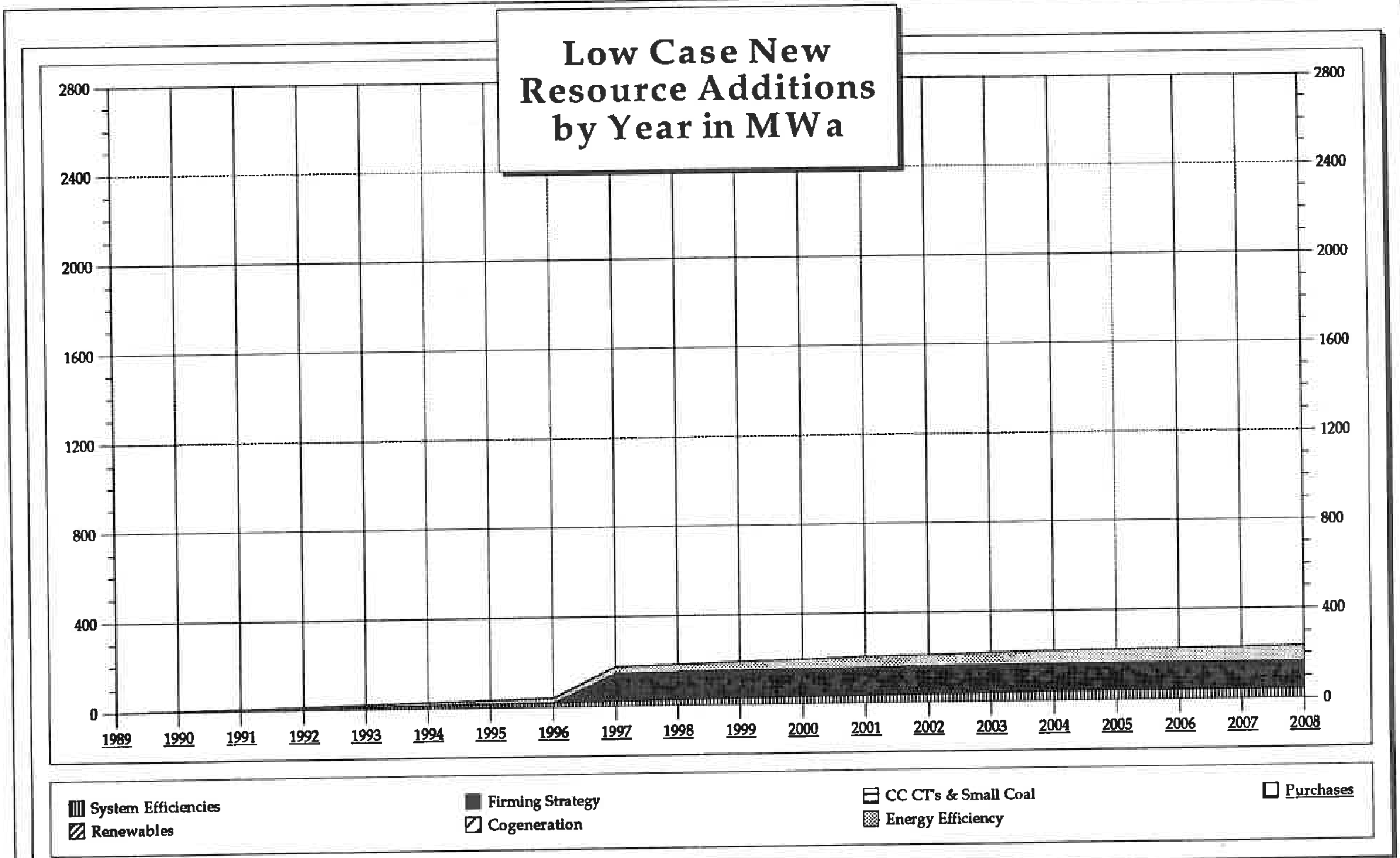
PLANNING FOR STABLE GROWTH

Volume 2 - Technical Appendix

Appendix A - Numerical Results by Case and Scenario

Low Case Study

Low Case New Resource Additions by Year in MWa



	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiencies	0	3	6	9	12	15	18	21	24	27	30	32	34	36	38	40	40	40	40	40
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firming Strategy	0	0	0	0	0	0	0	0	125	125	125	125	125	125	125	125	125	125	125	125
Cogeneration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC CT's & Small Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	0	2	4	7	10	13	17	21	27	32	37	41	48	50	54	57	59	62	64	67
Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Totals	0	5	10	16	22	28	35	42	176	184	192	198	207	211	217	222	224	227	229	232

KEY OUTPUTS - Revised

Low Case/TRC

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Load (MWa)	4861.0	4721.0	4727.0	4793.0	4822.0	4869.0	4975.0	5024.0	5051.0	5071.0	5093.0	5124.0	5160.0	5199.0	5229.0	5270.0	5313.0	5367.0	5412.0	5454.0
Total Energy Efficiency	0.0	2.1	4.3	6.8	9.7	13.0	17.2	21.4	27.1	31.9	37.0	41.3	47.7	50.1	54.3	56.5	59.3	61.6	64.4	66.7
System Load net of Energy Efficiency	4861.0	4718.9	4722.7	4786.2	4812.3	4856.0	4957.8	5002.6	5023.9	5039.1	5056.0	5082.7	5112.3	5148.9	5174.7	5213.5	5253.7	5305.4	5347.6	5387.3
Energy Sales after Energy Efficiency	4374.9	4247.0	4250.4	4307.6	4331.1	4370.4	4462.0	4502.3	4521.5	4535.2	4550.4	4574.4	4601.1	4634.0	4657.2	4692.2	4728.3	4774.9	4812.8	4848.6
Total Customers (000's)	1,220	1,216	1,214	1,218	1,228	1,239	1,247	1,255	1,260	1,264	1,267	1,274	1,279	1,299	1,314	1,328	1,346	1,365	1,387	1,408
Net Electric Plant (M$)	5283.6	5464.6	5583.7	5658.8	5697.4	5680.7	5692.1	5719.6	5761.3	5823.3	5900.2	5996.3	6111.3	6246.0	6395.6	6572.3	6766.4	6996.2	7255.1	7549.4
Net Energy Efficiency Assets	0.1	0.7	3.7	9.2	17.5	32.2	48.6	69.7	91.3	114.0	134.7	157.9	179.7	197.9	207.5	217.0	224.2	234.4	242.3	252.8
General Inflation Rate	3.90%	7.00%	6.20%	6.50%	6.70%	6.60%	7.20%	7.40%	7.60%	7.70%	7.70%	7.80%	7.70%	7.60%	7.50%	7.50%	7.60%	7.60%	7.50%	7.40%
Operating Revenues (M$)																				
Nominal	1886.0	1863.8	1911.0	2010.3	2075.9	2131.9	2235.9	2310.3	2385.1	2475.7	2610.7	2737.9	2870.7	3015.2	3160.8	3338.7	3555.0	3784.3	4061.9	4297.0
Real	1886.0	1741.9	1681.7	1661.1	1607.6	1548.8	1515.2	1457.8	1398.7	1348.0	1319.9	1284.0	1250.1	1220.3	1189.9	1169.2	1157.0	1144.7	1142.9	1125.8
NPV (13.13% discount rate)	18201.4																			
Average Growth																				
Nominal	4.43%																			
Real	-2.68%																			
Base Unit Cost (mills/kwh)																				
Nominal	49.2	50.1	51.3	53.1	54.7	55.7	57.2	58.4	60.2	62.3	65.5	68.1	71.2	74.3	77.5	81.0	85.8	90.5	96.3	100.9
Real	49.2	46.8	45.2	43.9	42.4	40.5	38.8	36.9	35.3	33.9	33.1	32.0	31.0	30.1	29.2	28.4	27.9	27.4	27.1	26.4
Average Growth																				
Nominal	3.85%																			
Real	-3.22%																			
Average Customer Bill ($)																				
Nominal	1546.2	1533.4	1573.8	1649.9	1690.9	1720.8	1793.2	1841.5	1892.9	1959.2	2061.0	2149.2	2244.0	2321.2	2405.7	2514.7	2641.2	2771.6	2929.0	3051.0
Real	1546.2	1433.1	1384.9	1363.4	1309.5	1250.1	1215.2	1162.0	1110.0	1066.8	1042.0	1008.0	977.1	939.4	905.6	880.6	859.6	838.3	824.1	799.3
NPV (13.13% discount rate)	14486.3																			
Customer Cost (M$)	0.0	0.0	0.0	0.0	0.0	0.0	10.1	11.1	10.1	8.5	7.0	5.8	7.4	11.8	14.9	13.3	11.3	14.0	17.4	18.3
Levelized Customer Cost (M$)																				
(30 years at a 15.13% discount rate)	0.0	0.0	0.0	0.0	0.0	0.0	1.6	3.3	4.8	6.1	7.2	8.1	9.2	11.0	13.3	15.4	17.1	19.2	21.9	24.7
NPV (13.13% discount rate)	28.7																			
Energy Services Charge (M$)	0.0	0.0	0.2	0.5	1.1	2.2	3.6	5.6	7.9	10.6	13.4	16.7	20.2	23.6	26.2	29.0	31.6	34.6	36.6	38.0
NPV (13.13% discount rate)	55.9																			
Total Resource Cost (M$)																				
Nominal	1886.0	1863.8	1911.2	2010.8	2077.0	2134.1	2241.1	2319.2	2397.8	2492.4	2631.3	2762.7	2900.1	3049.9	3200.3	3383.1	3603.7	3838.2	4120.4	4359.7
Real	1886.0	1741.9	1681.9	1661.5	1608.5	1550.4	1518.7	1463.4	1406.1	1357.1	1330.3	1295.7	1262.9	1234.3	1204.8	1184.7	1172.9	1161.0	1159.4	1142.2
NPV (13.13% discount rate)	18286.0																			
Average Growth																				
Nominal	4.51%																			
Real	-2.61%																			
Mills / KWh																				
Nominal	49.2	50.1	51.3	53.1	54.6	55.6	57.1	58.4	60.2	62.3	65.5	68.2	71.3	74.4	77.6	81.2	86.0	90.7	96.6	101.1
Real	49.2	46.8	45.1	43.8	42.3	40.4	38.7	36.8	35.3	33.9	33.1	32.0	31.0	30.1	29.2	28.4	28.0	27.4	27.2	26.5
Average Growth																				
Nominal	3.86%																			
Real	-3.21%																			

Study
Merged System
Resource & Market Planning
Low Case/TRC

Average Megawatts	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Requirements										
Merged System Load	4,860.6	4,721.4	4,726.7	4,793.4	4,821.6	4,868.6	4,975.4	5,023.5	5,050.7	5,070.7
Black Hills	37.5	45.0	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5
P G & E	28.5	28.5	28.5	28.5	28.5	28.5	28.5	0.0	0.0	0.0
Puget Power	27.5	27.5	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power II	60.0	60.0	85.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1
So Cal Edison	161.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0
SMUD	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
WIDCO Sale	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9	6.8	6.8
Nevada	0.0	61.2	82.5	82.4	82.5	82.5	82.5	82.4	82.5	82.5
Sierra Pacific	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8
Seirra Pacific II	10.3	38.0	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5
IPP Layoff to LA	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2
IPP Banked Recall	7.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Idaho Exchange - UPL	30.1	41.0	41.0	41.1	41.0	41.0	41.0	41.1	41.0	41.0
Total	5,343.9	5,291.4	5,353.6	5,439.2	5,467.4	5,514.4	5,621.2	5,640.8	5,668.0	5,688.1
Resources										
Pacific System Hydro	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8
Utah System Hydro	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5
Black Hills Energy Purchase	6.2	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Canadian Entitlement	-8.2	-7.6	-6.9	-6.4	-6.0	-5.5	-5.2	-5.0	-4.8	-4.2
CSPE	34.1	32.3	31.4	30.1	28.9	27.6	26.5	25.2	24.2	21.8
Hanford WNP #1	68.0	68.0	68.0	68.0	68.0	68.0	68.0	30.8	0.0	0.0
Mid Columbia	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6
Miscellaneous Purchases	5.7	5.7	3.0	-4.3	7.1	18.5	18.5	16.2	16.2	16.2
Pelton Rereg	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Q.F. Contracts - PP&L	67.1	74.8	74.9	75.3	75.3	75.3	75.3	75.3	75.3	75.3
Widco Purchase	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3
QF Contracts - UP&L	34.2	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5
Gem State	6.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
GSLM	2.0	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
IPP	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2
WAPA Capacity Exchange	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8	5.9	5.9
MPC Purchase	0.0	15.0	15.0	15.0	10.0	10.0	10.0	0.0	0.0	0.0
WWP Purchase	44.1	50.0	50.0	50.0	50.0	50.0	50.0	38.0	17.0	0.0
South Idaho Exchange - PPL	31.0	42.2	42.2	42.3	42.2	42.2	42.2	42.3	42.2	42.2
South Idaho Exchange Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flush Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	125.0	125.0
Hydro Efficiency	0.0	1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0
Transmission and Distribution Improvement	0.0	1.4	2.8	4.2	5.6	7.0	8.4	9.8	11.2	12.6
Transmission and Distribution Improvement	0.0	0.6	1.2	1.8	2.4	3.0	3.6	4.2	4.8	5.4
New Peak Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Voltage Regulation 1	0.0	2.0	4.0	6.0	8.0	10.0	10.0	10.0	10.0	10.0
New Appliances Lost Opp	0.0	0.1	0.1	0.2	0.3	0.4	0.8	1.3	3.1	4.5
New Appliances Lost Opp-utah	0.0	0.0	0.1	0.1	0.1	0.2	0.4	0.7	1.7	2.4
Commercial Lost Opp	0.0	0.0	0.1	0.4	0.9	1.8	3.4	5.1	6.6	7.9
Commercial Lost Opp-utah	0.0	0.0	0.0	0.2	0.4	0.7	1.4	2.1	2.8	3.3
Mobile Home MCS Lost Opp	0.0	0.0	0.0	0.0	0.0	0.0	0.9	1.8	2.5	3.1
Mobile Home MCS Lost Opp-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.5	0.6
Centralia	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0
Dave Johnston	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8
Jim Bridger	1,193.0	1,204.4	1,212.1	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0
Wyodak	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7
Colstrip	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5
Carbon	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4
Naughton	540.6	540.6	540.6	540.6	540.6	540.6	540.6	540.6	540.6	540.6
Huntington	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0
Hunter	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2
Blundell	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trojan	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7
Total	5,988.7	6,080.6	6,087.6	6,094.3	6,105.7	6,122.6	6,129.0	6,073.6	6,154.8	6,143.7
Thermal Maintenance										
Centralia	58.1	46.8	47.1	63.9	47.1	36.1	47.1	62.8	47.1	64.1

Average Megawatts	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements										
Merged System Load	5,093.3	5,123.6	5,159.9	5,199.2	5,229.3	5,270.1	5,313.3	5,367.0	5,412.4	5,453.5
Black Hills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
P G & E	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power II	120.1	120.1	120.1	120.1	85.6	0.0	0.0	0.0	0.0	0.0
So Cal Edison	108.0	108.0	108.0	108.0	108.0	108.0	108.0	80.8	40.0	40.0
SMUD	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
WIDCO Sale	6.8	6.9	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9
Nevada	21.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra Pacific	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8
Seirra Pacific II	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5
IPP Layoff to LA	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1
IPP Banked Recall	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Idaho Exchange - UPL	41.0	41.1	41.0	41.0	41.0	41.1	41.0	41.0	41.0	41.1
Total	5,597.0	5,606.1	5,642.2	5,681.6	5,677.3	5,632.4	5,675.6	5,702.1	5,666.7	5,707.8
Resources										
Pacific System Hydro	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8
Utah System Hydro	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5
Black Hills Energy Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Canadian Entitlement	-2.5	-2.0	-1.9	-1.9	-0.5	0.0	0.0	0.0	0.0	0.0
CSPE	12.8	9.8	9.4	9.1	2.3	0.0	0.0	0.0	0.0	0.0
Hanford WNP #1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid Columbia	182.6	182.6	182.6	182.6	182.6	182.6	178.3	127.3	127.3	127.4
Miscellaneous Purchases	16.2	15.1	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Pelton Rereg	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Q.F. Contracts - PP&L	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3
Widco Purchase	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3
QF Contracts - UP&L	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5
Gem State	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
GSLM	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
IPP	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1
WAPA Capacity Exchange	5.9	5.8	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8
MPC Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WWP Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Idaho Exchange - PPL	42.2	42.3	42.2	42.2	42.2	42.3	42.2	42.2	42.2	42.3
South Idaho Exchange Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flush Purchase	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Hydro Efficiency	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Transmission and Distribution Improvement	14.0	15.4	16.8	18.2	19.6	21.0	21.0	21.0	21.0	21.0
Transmission and Distribution Improvement	6.0	6.6	7.2	7.8	8.4	9.0	9.0	9.0	9.0	9.0
New Peak Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Voltage Regulation 1	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
New Appliances Lost Opp	6.3	7.6	10.3	10.1	11.1	10.9	11.2	11.0	11.3	11.2
New Appliances Lost Opp-utah	3.4	4.1	5.5	5.5	6.0	5.9	6.0	5.9	6.1	6.0
Commercial Lost Opp	9.2	10.5	11.8	13.1	14.4	15.6	16.8	18.1	19.2	20.4
Commercial Lost Opp-utah	3.9	4.4	4.9	5.5	6.0	6.6	7.1	7.6	8.1	8.6
Mobile Home MCS Lost Opp	3.6	4.0	4.4	5.0	5.7	6.3	6.9	7.5	8.2	8.9
Mobile Home MCS Lost Opp-utah	0.7	0.7	0.8	0.9	1.1	1.2	1.3	1.4	1.5	1.6
Centralia	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0
Dave Johnston	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8
Jim Bridger	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0
Wyodak	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7
Colstrip	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5
Carbon	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4
Naughton	540.6	540.6	540.6	540.6	540.6	540.6	540.6	540.6	540.6	540.6
Huntington	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0
Hunter	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2
Blundell	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trojan	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7
Total	6,144.5	6,147.2	6,149.2	6,153.4	6,154.1	6,156.5	6,155.1	6,106.3	6,109.2	6,111.4
Thermal Maintenance										
Centralia	47.1	57.9	46.8	47.1	64.1	46.9	36.1	47.1	63.0	46.9

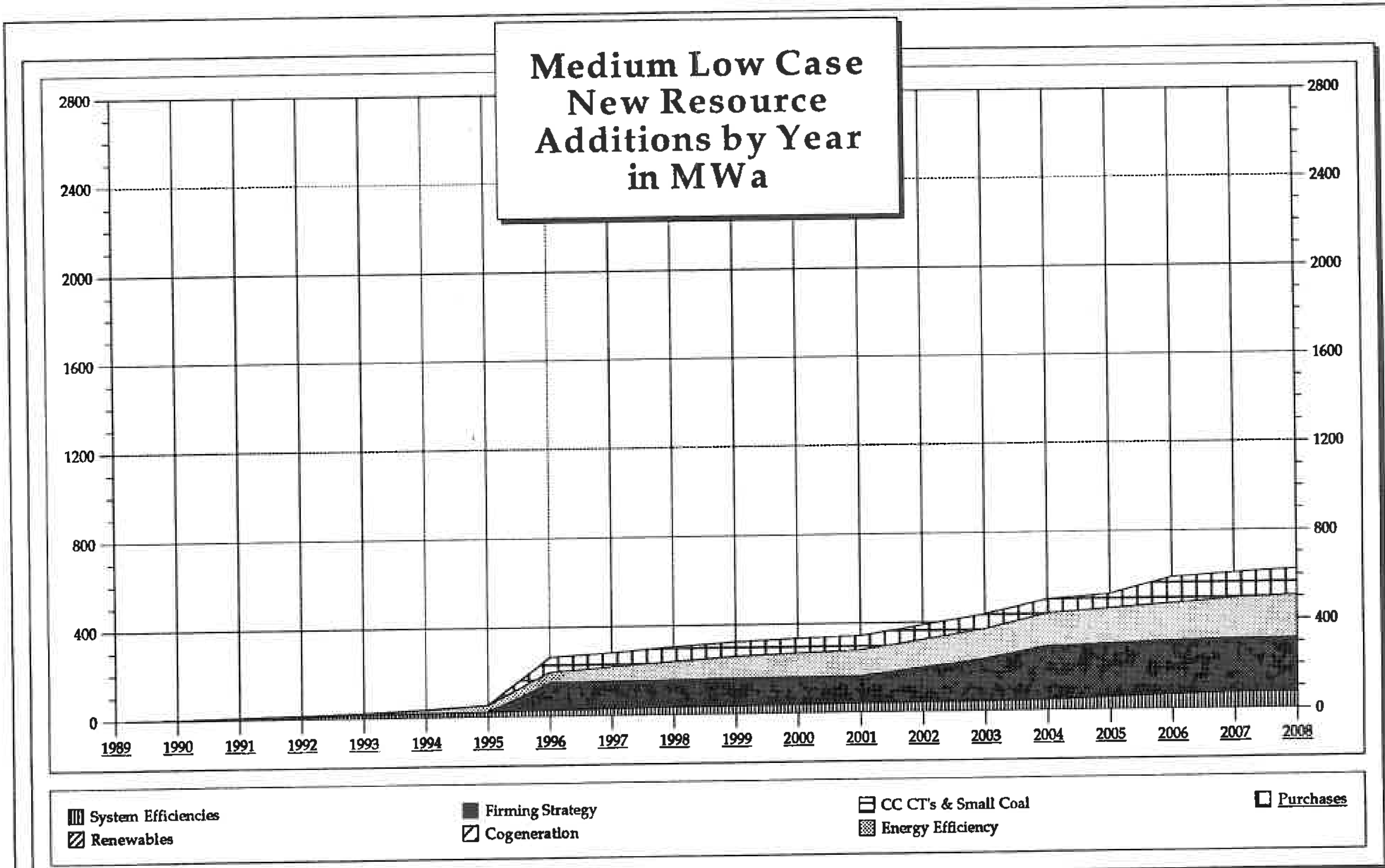
Dave Johnston	40.0	47.8	59.2	47.7	75.0	53.5	53.6	47.7	59.2	47.8	58.4	52.4	59.2	47.8	47.8	74.8	53.5	53.6	59.2	47.7
Jim Bridger	106.3	121.5	122.4	97.6	111.7	106.3	111.1	117.4	111.5	105.3	116.9	109.2	123.5	124.3	97.9	111.4	106.3	111.1	117.7	111.2
Wyodak	19.6	19.6	15.0	33.3	15.0	19.6	15.0	19.6	15.0	28.8	15.0	19.6	19.6	15.0	33.4	15.0	19.6	15.0	19.6	15.0
Colstrip	8.7	8.4	8.4	8.4	8.4	8.4	8.4	6.2	8.4	8.4	8.4	8.7	8.4	8.4	8.4	8.4	8.4	8.4	6.2	8.4
Carbon	8.8	5.3	16.7	6.2	4.2	6.2	14.7	4.2	12.4	10.5	4.2	6.2	14.7	4.2	12.4	10.4	4.2	6.2	14.7	4.2
Naughton	43.6	22.8	40.4	29.0	29.0	31.0	34.3	28.0	40.4	38.4	22.8	40.2	38.4	22.8	40.4	38.3	22.8	40.4	38.4	22.8
Huntington	27.3	52.2	38.9	39.3	78.4	25.9	26.3	52.1	25.9	26.3	78.4	25.9	26.3	52.2	25.9	26.2	78.4	25.9	26.3	52.1
Hunter	87.6	64.9	72.2	89.8	64.9	64.9	72.2	89.8	79.5	64.9	72.2	64.7	72.2	90.1	79.5	64.7	72.2	64.9	72.2	89.8
Blundell	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trojan	4.4	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	4.3	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Total	405.4	394.4	425.3	420.2	438.8	357.1	387.8	432.7	404.5	399.5	428.4	390.1	414.2	417.0	414.8	401.2	406.6	377.7	422.4	403.1
Balance	239.4	394.8	308.6	234.9	199.5	251.1	120.0	0.0	82.3	56.1	119.1	151.0	92.7	54.8	62.0	122.9	72.9	26.5	20.1	0.5

Study
Merged System
Resource & Market Planning
Low Case/TRC

January Peak	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements																				
Merged System Load	6,436.0	6,391.0	6,302.0	6,309.0	6,357.0	6,418.0	6,486.0	6,550.0	6,583.0	6,606.0	6,636.0	6,672.0	6,723.0	6,773.0	6,813.0	6,867.0	6,925.0	7,000.0	7,059.0	7,115.0
Black Hills	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
P G & E	100.0	100.0	100.0	100.0	100.0	100.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power	55.0	55.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power II	100.0	100.0	100.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	0.0	0.0	0.0	0.0	0.0
So Cal Edison	298.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	0.0	0.0
SMUD	0.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Nevada	0.0	0.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra Pacific	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Seirra Pacific II	0.0	25.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Total	7,116.0	7,098.0	7,111.0	7,163.0	7,211.0	7,272.0	7,340.0	7,304.0	7,337.0	7,360.0	7,315.0	7,299.0	7,350.0	7,400.0	7,440.0	7,294.0	7,352.0	7,427.0	7,286.0	7,342.0
Resources																				
Pacific System Hydro	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5
Utah System Hydro	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
Black Hills Capacity	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
BPA Entitlement Capacity	28.7	28.6	28.7	26.0	23.4	20.9	18.3	15.5	12.9	12.4	10.8	5.1	4.8	4.7	4.1	0.0	0.0	0.0	0.0	0.0
BPA Peak Purchase	1,127.3	1,127.3	1,127.3	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	0.0
BPA Supplemental Capacity	27.0	27.0	27.1	24.5	22.0	19.7	17.2	14.7	12.1	11.7	10.2	4.8	4.5	4.4	3.8	0.0	0.0	0.0	0.0	0.0
Canadian Entitlement	-28.7	-28.6	-28.7	-26.0	-23.4	-20.9	-18.3	-15.5	-12.9	-12.4	-10.8	-5.1	-4.8	-4.7	-4.1	0.0	0.0	0.0	0.0	0.0
CSPE	95.6	96.1	96.5	93.2	79.7	71.3	62.9	54.4	45.9	44.5	39.3	18.9	18.1	17.7	15.8	0.0	0.0	0.0	0.0	0.0
Hanford WNP #1	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid Columbia	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	242.3	242.3	242.3
Miscellaneous Purchases	142.7	142.7	142.7	128.7	128.7	26.0	26.0	21.0	21.0	21.0	21.0	21.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Pelton Rereg	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6
Q.F. Contracts - PP&L	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0
QF Contracts - UP&L	38.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
Gem State	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GSLM	0.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
MPC Purchase	0.0	15.0	15.0	15.0	10.0	10.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WWP Purchase	50.0	50.0	150.0	150.0	150.0	150.0	150.0	100.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flush Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro Efficiency	0.0	2.0	4.0	6.0	8.0	10.0	12.0	14.0	16.0	18.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Transmission and Distribution Improvement	0.0	1.4	2.8	4.2	5.6	7.0	8.4	9.8	11.2	12.6	14.0	15.4	16.8	18.2	19.6	21.0	21.0	21.0	21.0	21.0
Transmission and Distribution Improvement	0.0	0.6	1.2	1.8	2.4	3.0	3.6	4.2	4.8	5.4	6.0	6.6	7.2	7.8	8.4	9.0	9.0	9.0	9.0	9.0
New Peak Purchase	0.0	0.0	0.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
Voltage Regulation 1	0.0	4.0	8.0	12.0	16.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
New Appliances Lost Opp	0.0	0.1	0.1	0.2	0.3	0.4	0.8	1.3	3.1	4.5	6.3	7.6	10.3	10.2	11.1	10.9	11.2	11.0	11.3	11.2
New Appliances Lost Opp-utah	0.0	0.0	0.1	0.1	0.1	0.2	0.4	0.7	1.7	2.4	3.4	4.1	5.5	5.5	6.0	5.9	6.0	5.9	6.1	6.0
Commercial Lost Opp	0.0	0.0	0.7	2.0	4.0	7.1	12.4	17.7	22.6	27.1	31.6	36.2	40.8	45.3	49.8	54.2	58.6	63.0	67.3	71.6
Commercial Lost Opp-utah	0.0	0.0	0.3	0.9	1.7	3.0	5.2	7.5	9.5	11.4	13.3	15.2	17.1	19.0	20.9	22.8	24.6	26.5	28.3	30.1
Mobile Home MCS Lost Opp	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.8	0.7	0.4	0.3	0.3	0.4	0.6	0.7	0.6	0.4	0.5	0.6	0.6
Mobile Home MCS Lost Opp-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Centralia	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0
Dave Johnston	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0
Jim Bridger	1,360.7	1,366.0	1,371.4	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7
Wyodak	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0
Colstrip	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Carbon	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0
Naughton	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0
Huntington	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0
Hunter	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0
Blundell	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trojan	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
Total	8,937.9	9,041.9	9,156.8	9,024.9	9,014.8	8,913.9	8,916.2	8,852.4	8,725.0	8,685.5	8,691.8	8,676.4	8,670.0	8,678.1	8,685.5	8,673.7	8,680.1	8,577.1	8,583.7	8,589.6
Thermal Maintenance																				
Centralia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dave Johnston	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jim Bridger	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyodak	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Colstrip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Carbon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Naughton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Huntington	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hunter	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Blundell	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trojan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reserve Requirement																				
Reserve	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0
(Reserve+Balance)/Requirements	26%	27%	29%	26%	25%	23%	21%	21%	19%	18%	19%	19%	18%	17%	17%	19%	18%	15%	18%	17%
Balance	808.9	930.9	1,032.8	848.9	790.8	628.9	563.2	535.4	375.0	312.5	363.8	364.4	307.0	265.1	232.5	366.7	315.1	137.1	284.7	234.6

Medium-Low Case Study



	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiencies	0	3	6	11	16	21	24	27	30	33	36	38	40	42	44	46	55	64	71	71
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firming Strategy	0	0	0	0	0	0	0	125	125	125	125	125	125	158	192	244	244	244	244	244
Cogeneration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC CT's & Small Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	0	1	2	4	7	15	31	47	64	80	97	107	114	123	133	144	156	168	180	193
Purchases	0	0	0	0	0	0	0	65	63	67	65	65	65	65	65	65	65	115	115	115
Totals	**0**	**4**	**8**	**15**	**23**	**36**	**55**	**264**	**282**	**305**	**323**	**335**	**344**	**388**	**434**	**499**	**519**	**590**	**609**	**622**

KEY OUTPUTS - Revised
Medium Low Case/TRC

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Load (MWa)	4865.0	4734.0	4742.0	4818.0	4864.0	4934.0	5067.0	5145.0	5205.0	5248.0	5294.0	5348.0	5406.0	5467.0	5521.0	5583.0	5650.0	5725.0	5794.0	5858.0
Total Energy Efficiency	0.3	3.1	6.6	10.5	16.7	27.2	44.5	62.7	83.3	102.7	122.3	135.9	148.0	158.3	171.1	182.9	196.5	210.1	224.3	238.5
System Load net of Energy Efficiency	4864.7	4730.9	4735.4	4807.5	4847.3	4906.8	5022.5	5082.3	5121.7	5145.3	5171.7	5212.1	5258.0	5308.7	5349.9	5400.1	5453.5	5514.9	5569.7	5619.5
Energy Sales after Energy Efficiency	4378.2	4257.8	4261.9	4326.8	4362.6	4416.1	4520.3	4574.1	4609.5	4630.8	4654.5	4690.9	4732.2	4777.8	4814.9	4860.1	4908.2	4963.4	5012.7	5057.6
Total Customers (000's)	1,235	1,248	1,263	1,279	1,295	1,312	1,323	1,335	1,347	1,359	1,370	1,385	1,403	1,425	1,449	1,472	1,501	1,531	1,564	1,599
Net Electric Plant (M$)	5284.6	5463.6	5581.7	5661.0	5710.4	5716.1	5764.2	5832.7	5919.7	6028.5	6154.1	6279.5	6416.4	6581.8	6768.1	6982.3	7233.5	7526.7	7839.8	8190.9
Net Energy Efficiency Assets	1.1	4.4	11.7	21.5	40.6	75.6	126.3	185.8	249.5	314.9	379.1	424.6	451.2	481.2	508.2	540.0	572.9	611.5	647.0	687.8
General Inflation Rate	3.90%	7.00%	6.20%	6.50%	6.70%	6.60%	7.20%	7.40%	7.60%	7.70%	7.70%	7.80%	7.70%	7.60%	7.50%	7.50%	7.60%	7.60%	7.50%	7.40%
Operating Revenues (M$)																				
Nominal	1886.9	1866.6	1914.5	2015.5	2092.8	2158.3	2275.5	2368.7	2467.9	2577.3	2734.0	2889.6	3044.6	3220.3	3412.9	3645.9	3894.5	4154.4	4471.9	4759.7
Real	1886.9	1744.5	1684.8	1665.4	1620.7	1567.9	1542.1	1494.6	1447.2	1403.3	1382.2	1355.2	1325.8	1303.3	1284.8	1276.8	1267.5	1256.6	1258.3	1247.0
NPV (13.13% discount rate)	18773.8																			
Average Growth																				
Nominal	4.99%																			
Real	-2.16%																			
Base Unit Cost (mills/kwh)																				
Nominal	49.2	50.0	51.3	53.0	54.8	55.8	57.5	59.0	61.1	63.5	67.1	70.1	73.4	76.9	80.9	85.4	90.6	95.5	101.8	107.1
Real	49.2	46.8	45.1	43.8	42.4	40.5	38.9	37.2	35.8	34.6	33.9	32.9	32.0	31.1	30.5	29.9	29.5	28.9	28.7	28.1
Average Growth																				
Nominal	4.18%																			
Real	-2.91%																			
Average Customer Bill ($)																				
Nominal	1528.1	1495.8	1516.1	1575.9	1615.6	1645.4	1720.0	1775.0	1832.7	1897.0	1995.5	2086.5	2169.7	2259.7	2356.1	2476.8	2595.5	2713.8	2858.6	2975.9
Real	1528.1	1397.9	1334.2	1302.2	1251.1	1195.4	1165.6	1120.0	1074.7	1032.9	1008.8	978.6	944.8	914.5	887.0	867.4	844.7	820.9	804.3	779.7
NPV (13.13% discount rate)	14038.7																			
Customer Cost (M$)	0.0	0.2	0.3	0.3	0.7	1.6	16.8	17.3	15.9	14.2	12.7	15.3	21.2	26.0	26.0	24.3	28.5	32.7	35.6	37.3
Levelized Customer Cost (M$)																				
(30 years at a 15.13% discount rate)	0.0	0.0	0.1	0.1	0.2	0.5	3.1	5.7	8.2	10.3	12.3	14.6	17.9	21.9	25.9	29.6	34.0	39.0	44.5	50.2
NPV (13.13% discount rate)	55.1																			
Energy Services Charge (M$)	0.0	0.1	0.5	1.0	2.1	4.3	7.9	12.6	18.2	24.5	31.3	37.7	43.7	50.6	57.8	66.7	76.7	87.9	98.8	109.0
NPV (13.13% discount rate)	131.0																			
Total Resource Cost (M$)																				
Nominal	1886.9	1866.7	1915.1	2016.6	2095.2	2163.1	2286.5	2387.1	2494.3	2612.1	2777.6	2942.0	3106.1	3292.8	3496.6	3742.2	4005.2	4281.3	4615.2	4918.9
Real	1886.9	1744.6	1685.3	1666.3	1622.5	1571.4	1549.5	1506.2	1462.7	1422.3	1404.3	1379.7	1352.6	1332.6	1316.3	1310.5	1303.5	1295.0	1298.6	1288.7
NPV (13.13% discount rate)	18960.0																			
Average Growth																				
Nominal	5.17%																			
Real	-1.99%																			
Mills / KWh																				
Nominal	49.2	50.0	51.2	52.9	54.6	55.6	57.2	58.7	60.8	63.1	66.5	69.6	72.9	76.4	80.3	84.8	89.9	94.9	101.0	106.2
Real	49.2	46.7	45.1	43.7	42.3	40.4	38.8	37.0	35.6	34.4	33.6	32.6	31.7	30.9	30.2	29.7	29.3	28.7	28.4	27.8
Average Growth																				
Nominal	4.13%																			
Real	-2.95%																			

Study
Merged System
Resource & Market Planning
Medium Low Case/TRC

Average Megawatts	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements																				
Merged System Load	4,864.9	4,733.6	4,741.8	4,817.9	4,864.2	4,933.6	5,067.3	5,145.3	5,205.0	5,247.8	5,294.1	5,347.7	5,405.7	5,468.9	5,521.0	5,583.1	5,649.5	5,725.3	5,794.3	5,858.1
Black Hills	37.5	45.0	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
P G & E	28.5	28.5	28.5	28.5	28.5	28.5	28.5	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
Puget Power	27.5	27.5	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power II	60.0	60.0	85.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	85.6	0.0	0.0	0.0	0.0	0.0
So Cal Edison	161.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	80.8	0.0	0.0
SMUD	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
WIDCO Sale	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9
Nevada	0.0	61.2	82.5	82.4	82.5	82.5	82.5	82.4	82.5	82.5	21.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra Pacific	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8
Seirra Pacific II	10.3	38.0	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5
IPP Layoff to LA	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1
IPP Banked Recall	7.5	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	0.0	0.0	0.0	0.0	0.0
South Idaho Exchange - UPL	30.1	41.0	41.0	41.1	41.0	41.0	41.0	41.1	41.0	41.0	41.0	41.1	41.0	41.0	41.0	41.1	41.0	41.0	41.0	41.1
Total	5,348.1	5,303.7	5,368.8	5,463.7	5,510.1	5,579.5	5,713.2	5,762.6	5,822.4	5,865.2	5,797.8	5,830.1	5,888.1	5,949.3	5,968.9	5,945.5	6,011.8	6,060.4	6,048.6	6,112.4
Resources																				
Pacific System Hydro	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8
Utah System Hydro	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5
Black Hills Energy Purchase	6.2	3.1	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
Canadian Entitlement	-8.2	-7.6	-6.9	-6.4	-6.0	-5.5	-5.2	-5.0	-4.8	-4.2	-2.5	-2.0	-1.9	-1.9	-0.5	0.0	0.0	0.0	0.0	0.0
CSPE	34.1	32.3	31.4	30.1	28.9	27.6	26.5	25.2	24.2	21.8	12.8	9.8	9.4	9.1	2.3	0.0	0.0	0.0	0.0	0.0
Hanford WNP #1	68.0	68.0	68.0	68.0	68.0	68.0	68.0	30.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid Columbia	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	178.3	127.3	127.3	127.4
Miscellaneous Purchases	5.7	5.7	3.0	-4.3	7.1	18.5	18.5	16.2	16.2	16.2	16.2	15.1	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Pelton Rereg	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Q.F. Contracts - PP&L	67.1	74.8	74.9	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3
Widco Purchase	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3
QF Contracts - UP&L	34.2	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5
Gem State	6.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
GSLM	2.0	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
IPP	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1
WAPA Capacity Exchange	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8
MPC Purchase	0.0	15.0	15.0	15.0	10.0	10.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WWP Purchase	44.1	50.0	50.0	50.0	50.0	50.0	50.0	38.0	17.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Idaho Exchange - PPL	31.0	42.2	42.2	42.3	42.2	42.2	42.2	42.3	42.2	42.2	42.2	42.3	42.2	42.2	42.2	42.3	42.2	42.2	42.2	42.3
South Idaho Exchange 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	0.0	0.0	0.0
Flush Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
BPA Settlement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	65.2	62.9	66.9	64.9	65.2	64.9	64.9	64.9	65.2	64.9	64.9	64.9	65.2
Hydro Efficiency	0.0	1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
New Peak Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Off Peak Purchase 1-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0
Voltage Regulation 1	0.0	2.0	4.0	6.0	8.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
New Appliances Lost Opp	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.2	2.1	2.9	3.8	5.5	7.6	10.1	13.1	16.5	20.2	24.4	29.1
New Appliances Lost Opp-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.9	1.5	2.2	2.8	4.1	5.7	7.5	9.7	12.2	15.0	18.1	21.6
Commercial Retrofit	0.2	0.5	1.1	1.7	3.4	7.0	14.1	21.2	28.3	35.5	42.6	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1
Commercial Retrofit-utah	0.1	0.3	0.7	1.1	2.1	4.3	8.7	13.1	17.4	21.8	26.2	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4
Light and Water Heater Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	1.5	2.9	4.4	6.0	7.4	8.3	9.0
Light and Water Heater Appliance-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.6	1.2	1.8	2.5	3.0	3.4	3.7
Utah MCS Lost Opp-utah	0.0	0.1	0.2	0.3	0.6	1.0	1.5	2.1	2.6	3.1	3.6	4.2	4.7	5.2	5.8	6.3	6.9	7.5	8.1	8.6
Commercial Lost Opp	0.0	0.0	0.1	0.4	1.0	2.0	3.8	5.6	7.2	8.7	10.1	11.6	13.1	14.6	16.1	17.5	19.0	20.4	21.8	23.1
Commercial Lost Opp-utah	0.0	0.0	0.0	0.1	0.3	0.7	1.3	1.9	2.4	2.9	3.4	3.9	4.4	4.9	5.4	5.9	6.4	6.8	7.3	7.8
Mobile Home MCS Lost Opp	0.0	0.0	0.0	0.0	0.0	0.0	1.3	2.6	3.6	4.5	5.2	6.0	7.0	8.4	9.4	10.3	11.2	12.4	13.5	14.6
Mobile Home MCS Lost Opp-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.8
Transmission and Distribution Improvement	0.0	0.0	0.0	1.4	2.8	4.2	5.6	7.0	8.4	9.8	11.2	12.6	14.0	15.4	16.8	18.2	19.6	21.0	21.0	21.0
Transmission and Distribution Improvement	0.0	0.0	0.0	0.6	1.2	1.8	2.4	3.0	3.6	4.2	4.8	5.4	6.0	6.6	7.2	7.8	8.4	9.0	9.0	9.0
Centralia	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0
Dave Johnston	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8
Jim Bridger	1,193.0	1,204.4	1,212.1	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0
Wyodak	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7
Colstrip	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5
Carbon	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4
Naughton	540.6	540.6	540.6	540.6	540.6	540.6	540.6	540.6	540.6	540.6	540.6	540.6	540.6	540.6	540.6	540.6	547.5	554.4	561.4	561.4
Huntington	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0
Hunter	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2
Blundell	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.8	66.7	118.5	118.5	118.5	118.5	118.5
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trojan	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7
Total	5,989.0	6,079.4	6,085.4	6,093.2	6,107.5	6,130.5	6,148.5	6,295.5	6,260.6	6,265.1	6,275.1	6,284.3	6,286.7	6,330.4	6,370.8	6,433.8	6,449.8	6,470.0	6,489.1	6,502.1
Thermal Maintenance																				
Centralia	56.1	46.8	47.1	63.9	47.1	36.1	47.1	62.8	47.1	64.1	47.1	57.9	46.8	47.1	64.1	46.9	36.1	47.1	63.0	46.9
Dave Johnston	40.0	47.8	59.2	47.7	75.0	53.5	53.6	47.7	59.2	47.8	58.4	52.4	59.2	47.8	47.8	74.8	53.5	53.6	59.2	47.7
Jim Bridger	106.3	121.5	122.4	97.8	111.7	106.3	111.1	117.4	111.5	105.3	116.9	109.2	123.5	124.3	97.9	111.4	106.3	111.1	117.7	111.2
Wyodak	19.6	19.6	15.0	33.3	15.0	19.6	15.0	19.6	15.0	28.8	15.0	19.6	19.6	15.0	33.4	15.0	19.6	15.0	19.6	15.0
Colstrip	8.7	8.4	8.4	8.4	8.4	8.4	8.4	6.2	8.4	8.4	8.4	8.7	8.4	8.4	8.4	8.4	8.4	8.4	6.2	8.4
Carbon	8.8	5.3	16.7	6.2	4.2	6.2	14.7	4.2	12.4	10.5	4.2	6.2	14.7	4.2	12.4	10.4	4.2	6.2	14.7	4.2
Naughton	43.6	22.8	40.4	29.0	29.0	31.0	34.3	28.0	40.4	38.4	22.8	40.2	38.4	22.8	40.4	38.3	22.8	41.9	40.8	22.8
Huntington	27.3	52.2	38.9	39.3	78.4	25.9	26.3	52.1	25.9	26.3	78.4	25.9	26.3	52.2	25.9	26.2	78.4	25.9	26.3	52.1
Hunter	87.6	64.9	72.2	89.8	64.9	64.9	72.2	89.8	79.5	64.9	72.2	64.7	72.2	90.1	79.5	64.7	72.2	64.9	72.2	89.8
Blundell	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trojan	4.4	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	4.3	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Total	405.4	394.4	425.3	420.2	438.8	357.1	387.8	432.7	404.5	399.5	428.4	390.1	414.2	417.0	414.8	401.2	406.6	379.3	424.8	403.1
Balance	235.5	381.4	291.3	209.3	158.6	193.9	47.5	100.2	33.7	0.4	48.8	64.0	-15.6	-35.9	-12.9	87.2	31.4	30.4	15.7	-13.4

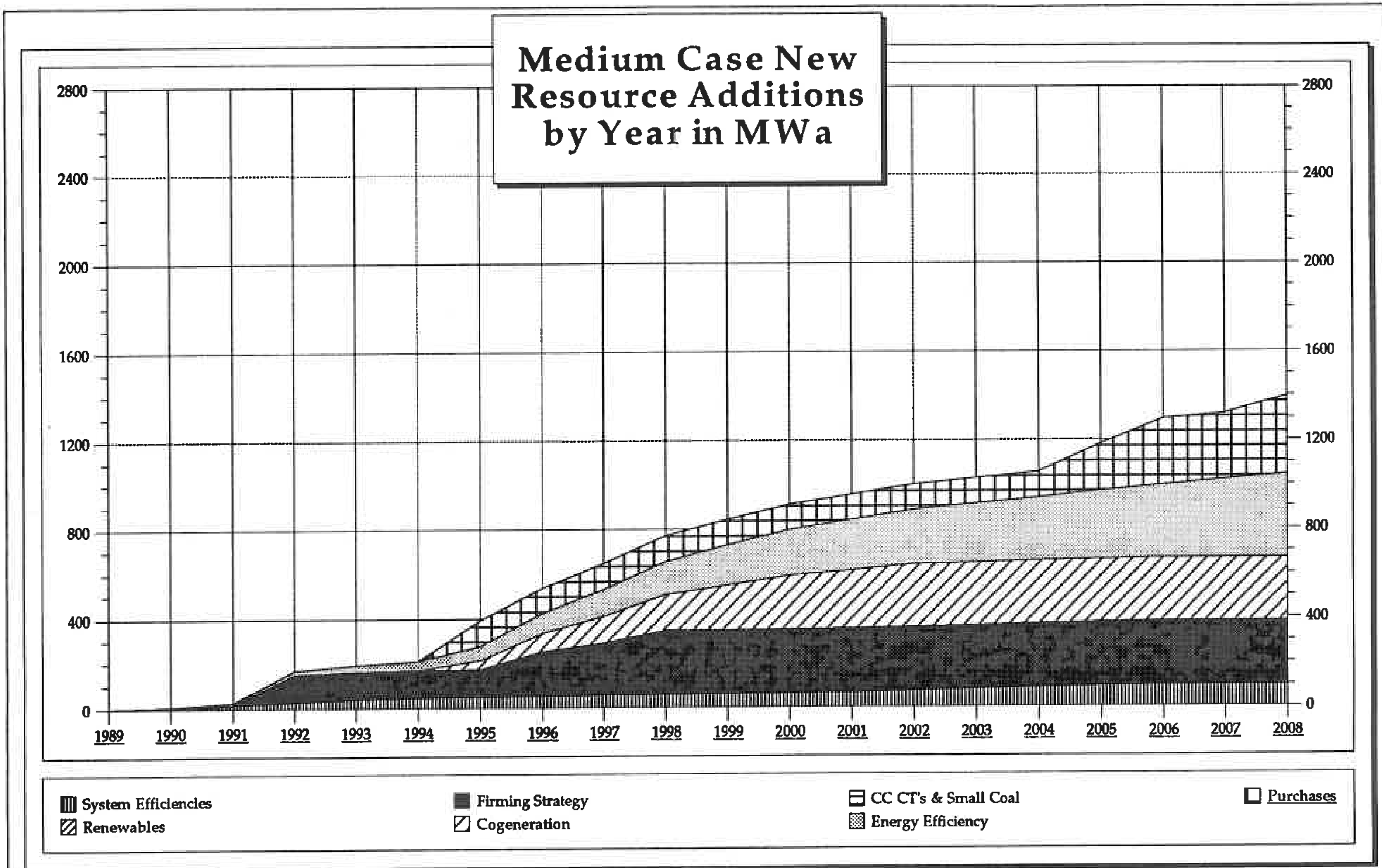
Study
Merged System
Resource & Market Planning
Medium Low Case/TRC

January Peak	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Requirements										
Merged System Load	6,442.0	6,411.0	6,326.0	6,340.0	6,413.0	6,500.0	6,601.0	6,702.0	6,776.0	6,829.0
Black Hills	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
P G & E	100.0	100.0	100.0	100.0	100.0	100.0	100.0	0.0	0.0	0.0
Puget Power	55.0	55.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power II	100.0	100.0	100.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
So Cal Edison	298.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
SMUD	0.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Nevada	0.0	0.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Sierra Pacific	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Seirra Pacific II	0.0	25.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Total	7,122.0	7,118.0	7,135.0	7,194.0	7,267.0	7,354.0	7,455.0	7,456.0	7,530.0	7,583.0
Resources										
Pacific System Hydro	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5
Utah System Hydro	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
Black Hills Capacity	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
BPA Entitlement Capacity	28.7	28.6	28.7	26.0	23.4	20.9	18.3	15.5	12.9	12.4
BPA Peak Purchase	1,127.3	1,127.3	1,127.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BPA Supplemental Capacity	27.0	27.0	27.1	24.5	22.0	19.7	17.2	14.7	12.1	11.7
Canadian Entitlement	-28.7	-28.6	-28.7	-26.0	-23.4	-20.9	-18.3	-15.5	-12.9	-12.4
CSPE	95.6	96.1	96.5	93.2	79.7	71.3	62.9	54.4	45.9	44.5
Hanford WNP #1	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	0.0	0.0
Mid Columbia	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5
Miscellaneous Purchases	142.7	142.7	142.7	128.7	128.7	26.0	26.0	21.0	21.0	21.0
Pelton Rereg	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6
Q.F. Contracts - PP&L	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0
QF Contracts - UP&L	38.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
Gem State	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GSLM	0.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
MPC Purchase	0.0	15.0	15.0	15.0	10.0	10.0	10.0	0.0	0.0	0.0
WWP Purchase	50.0	50.0	150.0	150.0	150.0	150.0	150.0	100.0	50.0	0.0
Flush Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BPA Settlement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	164.0	164.0	164.0
Hydro Efficiency	0.0	2.0	4.0	6.0	8.0	10.0	12.0	14.0	16.0	18.0
New Peak Purchase	0.0	0.0	0.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
Off Peak Purchase 1-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Voltage Regulation 1	0.0	4.0	8.0	12.0	16.0	20.0	20.0	20.0	20.0	20.0
New Appliances Lost Opp	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	1.2	2.1
New Appliances Lost Opp-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.9	1.5
Commercial Retrofit	0.3	1.0	2.2	3.5	6.9	14.1	28.5	42.8	57.2	71.6
Commercial Retrofit-utah	0.2	0.6	1.4	2.1	4.2	8.7	17.5	26.4	35.2	44.1
Light and Water Heater Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Light and Water Heater Appliance-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Utah MCS Lost Opp-utah	0.0	0.2	0.3	0.6	1.2	2.0	3.0	4.1	5.2	6.3
Commercial Lost Opp	0.0	0.0	0.8	2.2	4.3	7.6	13.3	19.1	24.3	29.2
Commercial Lost Opp-utah	0.0	0.0	0.3	0.7	1.4	2.5	4.5	6.4	8.2	9.8
Mobile Home MCS Lost Opp	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.9	0.8	0.7
Mobile Home MCS Lost Opp-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Transmission and Distribution Improvement	0.0	0.0	0.0	1.4	2.8	4.2	5.6	7.0	8.4	9.8
Transmission and Distribution Improvement	0.0	0.0	0.0	0.6	1.2	1.8	2.4	3.0	3.6	4.2
Centralia	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0
Dave Johnston	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0
Jim Bridger	1,360.7	1,366.0	1,371.4	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7
Wyodak	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0
Colstrip	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Carbon	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0
Naughton	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0
Huntington	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0
Hunter	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0
Blundell	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trojan	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
Total	8,938.5	9,041.6	9,156.5	9,026.8	9,022.7	8,934.1	8,960.2	9,084.5	8,980.3	8,964.8

January Peak	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements										
Merged System Load	6,886.0	6,955.0	7,031.0	7,110.0	7,178.0	7,260.0	7,348.0	7,450.0	7,542.0	7,625.0
Black Hills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
P G & E	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power II	200.0	200.0	200.0	200.0	200.0	0.0	0.0	0.0	0.0	0.0
So Cal Edison	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	0.0	0.0
SMUD	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Nevada	52.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra Pacific	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Seirra Pacific II	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Total	7,565.0	7,582.0	7,658.0	7,737.0	7,805.0	7,687.0	7,775.0	7,877.0	7,769.0	7,852.0
Resources										
Pacific System Hydro	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5
Utah System Hydro	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
Black Hills Capacity	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
BPA Entitlement Capacity	10.8	5.1	4.8	4.7	4.1	0.0	0.0	0.0	0.0	0.0
BPA Peak Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BPA Supplemental Capacity	10.2	4.8	4.5	4.4	3.8	0.0	0.0	0.0	0.0	0.0
Canadian Entitlement	-10.8	-5.1	-4.8	-4.7	-4.1	0.0	0.0	0.0	0.0	0.0
CSPE	39.3	18.9	18.1	17.7	15.8	0.0	0.0	0.0	0.0	0.0
Hanford WNP #1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid Columbia	351.5	351.5	351.5	351.5	351.5	351.5	351.5	242.3	242.3	242.3
Miscellaneous Purchases	21.0	21.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Pelton Rereg	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6
Q.F. Contracts - PP&L	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0
QF Contracts - UP&L	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
Gem State	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GSLM	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
MPC Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WWP Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flush Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BPA Settlement	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0
Hydro Efficiency	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
New Peak Purchase	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
Off Peak Purchase 1-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Voltage Regulation 1	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
New Appliances Lost Opp	2.9	3.8	5.5	7.6	10.1	13.1	16.5	20.2	24.4	29.1
New Appliances Lost Opp-utah	2.2	2.8	4.1	5.7	7.5	9.7	12.2	15.0	18.1	21.6
Commercial Retrofit	86.0	93.2	93.2	93.2	93.2	93.2	93.2	93.2	93.2	93.2
Commercial Retrofit-utah	52.9	57.4	57.4	57.4	57.4	57.4	57.4	57.4	57.4	57.4
Light and Water Heater Appliance	0.0	0.0	0.2	0.5	1.2	2.1	2.9	3.6	3.8	3.8
Light and Water Heater Appliance-utah	0.0	0.0	0.1	0.2	0.5	0.9	1.2	1.5	1.6	1.6
Utah MCS Lost Opp-utah	7.3	8.3	9.4	10.5	11.6	12.7	13.8	14.9	16.1	17.3
Commercial Lost Opp	34.2	39.2	44.3	49.4	54.3	59.2	64.2	69.1	74.0	78.8
Commercial Lost Opp-utah	11.5	13.1	14.9	16.6	18.2	19.9	21.5	23.2	24.8	26.4
Mobile Home MCS Lost Opp	0.6	0.6	0.8	1.0	0.8	0.7	0.8	0.9	0.9	0.9
Mobile Home MCS Lost Opp-utah	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Transmission and Distribution Improvement	11.2	12.6	14.0	15.4	16.8	18.2	19.6	21.0	21.0	21.0
Transmission and Distribution Improvement	4.8	5.4	6.0	6.6	7.2	7.8	8.4	9.0	9.0	9.0
Centralia	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0
Dave Johnston	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0
Jim Bridger	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7
Wyodak	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0
Colstrip	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Carbon	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0
Naughton	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0
Huntington	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0
Hunter	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0
Blundell	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Gadsby	0.0	0.0	0.0	62.0	126.0	224.0	224.0	224.0	224.0	224.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trojan	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
Total	8,994.4	8,991.4	8,985.5	9,061.3	9,137.7	9,232.0	9,248.9	9,157.1	9,172.3	9,188.0

Centralia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dave Johnston	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jim Bridger	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyodak	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Colstrip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Carbon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Naughton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Huntington	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hunter	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Blundell	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trojan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reserve Requirement																				
Reserve	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0
(Reserve+Balance)/Requirements	26%	27%	28%	25%	24%	21%	20%	22%	19%	16%	19%	19%	17%	17%	17%	20%	19%	16%	18%	17%
Balance	803.5	910.5	1,008.5	819.8	742.7	567.1	492.2	615.5	437.3	368.8	416.4	396.4	314.5	311.3	319.7	532.0	460.9	267.1	390.3	323.0

Medium Case Study



	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiencies	0	5	17	29	41	46	49	52	55	58	61	63	65	72	79	86	91	96	96	96
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firming Strategy	0	0	0	125	125	125	125	203	237	289	289	289	289	289	289	289	289	289	289	289
Cogeneration	0	0	0	0	0	0	40	80	120	160	200	240	260	280	280	280	280	280	280	280
CC CT's & Small Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	1	4	9	17	27	40	65	91	120	149	180	205	227	246	266	286	308	332	356	380
Purchases	0	0	0	0	0	0	115	113	117	115	115	115	115	115	115	115	215	298	298	353
Totals	1	9	26	171	193	211	393	539	648	771	844	911	955	1001	1028	1055	1183	1294	1318	1396

KEY OUTPUTS - Revised
Base Medium Case

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Load (MWa)	4861.0	4858.0	4969.0	5116.0	5192.0	5278.0	5408.0	5492.0	5575.0	5649.0	5727.0	5808.0	5886.0	5968.0	6048.0	6139.0	6235.0	6343.0	6450.0	6557.0
Total Energy Efficiency	1.0	5.5	13.4	22.6	35.3	50.4	74.7	100.7	129.9	159.4	189.9	214.9	237.2	260.6	285.8	310.9	338.4	366.6	390.8	414.6
System Load net of Energy Efficiency	4860.0	4852.5	4955.6	5093.4	5156.7	5227.6	5333.3	5391.3	5445.1	5489.6	5537.1	5593.1	5648.8	5707.4	5762.2	5828.1	5896.6	5976.4	6059.2	6142.4
Energy Sales after Energy Efficiency	4374.0	4367.3	4460.0	4584.1	4641.0	4704.8	4800.0	4852.2	4900.6	4940.6	4983.4	5033.8	5083.9	5136.7	5186.0	5245.3	5306.9	5378.8	5453.3	5528.2
Total Customers (000's)	1,235	1,248	1,263	1,279	1,295	1,312	1,323	1,335	1,347	1,359	1,370	1,385	1,403	1,425	1,449	1,472	1,501	1,531	1,564	1,599
Net Electric Plant (M$)	5289.9	5482.6	5622.4	5723.0	5803.0	5858.0	5967.2	6068.2	6181.4	6307.6	6444.2	6572.3	6686.8	6818.1	6928.3	7066.2	7216.2	7400.2	7557.5	7742.5
Net Energy Efficiency Assets	6.5	17.7	40.6	70.9	115.0	174.5	245.5	325.6	411.0	501.5	593.2	666.7	715.9	767.6	819.9	885.3	959.7	1048.5	1095.9	1147.8
General Inflation Rate	3.90%	4.60%	4.80%	4.80%	5.00%	5.20%	5.40%	5.50%	5.50%	5.60%	5.50%	5.60%	5.40%	5.40%	5.30%	5.30%	5.20%	5.30%	5.20%	5.30%
Operating Revenues (M$)																				
Nominal	1888.9	1883.2	1939.8	2046.1	2120.6	2198.0	2298.4	2392.7	2488.3	2599.2	2738.6	2872.8	2995.9	3136.4	3279.9	3442.8	3616.6	3826.8	4092.7	4375.8
Real	1888.9	1800.4	1769.5	1781.1	1758.0	1732.1	1718.4	1695.7	1671.5	1653.4	1651.2	1640.3	1622.9	1612.0	1600.9	1595.9	1593.5	1601.3	1627.9	1652.9
NPV (11.47% discount rate)	20748.4																			
Average Growth																				
Nominal	4.52%																			
Real	-0.70%																			
Base Unit Cost (mills/kwh)																				
Nominal	49.3	49.2	49.6	50.8	52.2	53.3	54.7	56.1	58.0	60.1	62.7	65.0	67.3	69.7	72.2	74.7	77.8	81.2	85.7	90.1
Real	49.3	47.1	45.3	44.2	43.2	42.0	40.9	39.8	38.9	38.2	37.8	37.1	36.4	35.8	35.2	34.6	34.3	34.0	34.1	34.0
Average Growth																				
Nominal	3.23%																			
Real	-1.93%																			
Average Customer Bill ($)																				
Nominal	1529.7	1509.1	1536.1	1599.9	1637.0	1675.7	1737.3	1793.0	1847.8	1913.2	1998.8	2074.4	2135.1	2200.8	2264.4	2338.9	2410.3	2499.9	2616.2	2735.9
Real	1529.7	1442.7	1401.3	1392.7	1357.1	1320.5	1298.9	1270.6	1241.3	1217.0	1205.2	1184.4	1156.6	1131.1	1105.2	1084.1	1062.0	1046.0	1040.6	1033.4
NPV (11.47% discount rate)	15458.6																			
Customer Cost (M$)	0.0	0.2	0.6	0.9	1.2	1.9	17.4	18.4	19.8	21.0	20.8	24.0	29.7	35.8	37.7	38.5	46.0	51.8	58.4	63.6
Levelized Customer Cost (M$)																				
(30 years at a 13.47% discount rate)	0.0	0.0	0.1	0.2	0.4	0.7	3.1	5.6	8.3	11.2	14.1	17.4	21.5	26.4	31.6	36.9	43.3	50.4	58.4	67.2
NPV (11.47% discount rate)	81.7																			
Energy Services Charge (M$)	0.1	0.7	2.2	4.6	8.3	12.2	18.0	25.4	34.4	45.1	57.2	69.7	81.9	94.6	107.0	120.3	133.0	144.1	151.6	155.4
NPV (11.47% discount rate)	291.0																			
Total Resource Cost (M$)																				
Nominal	1889.0	1883.9	1942.1	2051.0	2129.3	2210.9	2319.5	2423.7	2531.0	2655.6	2809.9	2959.9	3099.3	3257.4	3418.5	3600.1	3792.9	4021.3	4302.8	4598.4
Real	1889.0	1801.1	1771.6	1785.3	1765.2	1742.2	1734.2	1717.6	1700.2	1689.2	1694.2	1690.0	1679.0	1674.2	1668.6	1668.7	1671.2	1682.7	1711.4	1737.0
NPV (11.47% discount rate)	21121.1																			
Average Growth																				
Nominal	4.79%																			
Real	-0.44%																			
Mills / KWh																				
Nominal	49.3	49.2	49.6	50.7	52.0	53.1	54.4	55.8	57.6	59.6	62.2	64.5	66.8	69.2	71.7	74.2	77.2	80.4	84.6	88.7
Real	49.3	47.0	45.2	44.1	43.1	41.9	40.7	39.6	38.7	37.9	37.5	36.8	36.2	35.6	35.0	34.4	34.0	33.6	33.7	33.5
Average Growth																				
Nominal	3.14%																			
Real	-2.01%																			

Study
Merged System
Resource & Market Planning
Medium Case - TRC

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Average Megawatts	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements																				
Merged System Load	4,861.3	4,858.4	4,968.9	5,115.9	5,191.5	5,278.3	5,408.3	5,492.5	5,575.1	5,648.8	5,726.6	5,807.6	5,885.6	5,968.0	6,048.2	6,139.4	6,234.9	6,342.8	6,450.2	6,556.6
Black Hills	37.5	45.0	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
P G & E	28.5	28.5	28.5	28.5	28.5	28.5	28.5	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
Puget Power	27.5	27.5	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power II	60.0	60.0	85.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	85.6	0.0	0.0	0.0	0.0	0.0
So Cal Edison	161.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	80.8	0.0	0.0
SMUD	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
WIDCO Sale	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9
Nevada	0.0	61.2	82.5	82.4	82.5	82.5	82.5	82.4	82.5	82.5	21.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra Pacific	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8
Seirra Pacific II	10.3	38.0	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5
IPP Layoff to LA	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1
IPP Banked Recall	7.5	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	0.0	0.0	0.0	0.0	0.0
South Idaho Exchange - UPL	30.1	41.0	41.0	41.1	41.0	41.0	41.0	41.1	41.0	41.0	41.0	41.1	41.0	41.0	41.0	41.1	41.0	41.0	41.0	41.1
Total	5,344.6	5,428.5	5,595.8	5,761.7	5,837.4	5,924.1	6,054.2	6,109.8	6,192.4	6,266.1	6,230.3	6,290.0	6,368.0	6,450.4	6,496.2	6,501.7	6,597.2	6,677.9	6,704.5	6,810.9
Resources																				
Pacific System Hydro	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.6	388.8	388.8	388.6	388.8	388.8	388.8	388.8	388.8	388.8	388.8
Utah System Hydro	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5
Black Hills Energy Purchase	6.2	3.1	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
Canadian Entitlement	-8.2	-7.6	-6.9	-6.4	-6.0	-5.5	-5.2	-5.0	-4.8	-4.2	-2.5	-2.0	-1.9	-1.9	-0.5	0.0	0.0	0.0	0.0	0.0
CSPE	34.1	32.3	31.4	30.1	28.9	27.6	26.5	25.2	24.2	21.8	12.8	9.8	9.4	9.1	2.3	0.0	0.0	0.0	0.0	0.0
Hanford WNP #1	68.0	68.0	68.0	68.0	68.0	68.0	68.0	30.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid Columbia	182.8	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.8	182.6	182.6	182.8	182.6	182.6	182.6	182.6	178.3	127.3	127.3	127.4
Miscellaneous Purchases	5.7	5.7	3.0	-4.3	7.1	18.5	18.5	16.2	16.2	16.2	16.2	15.1	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Pelton Rereg	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Q.F. Contracts - PP&L	67.1	74.8	74.9	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3
Widco Purchase	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3
QF Contracts - UP&L	34.2	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5
Gem State	6.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
GSLM	2.0	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
IPP	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1
WAPA Capacity Exchange	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8
MPC Purchase	0.0	15.0	15.0	15.0	10.0	10.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WWP Purchase	44.1	50.0	50.0	50.0	50.0	50.0	50.0	38.0	17.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Idaho Exchange - PPL	31.0	42.2	42.2	42.3	42.2	42.2	42.2	42.3	42.2	42.2	42.2	42.3	42.2	42.2	42.2	42.3	42.2	42.2	42.2	42.3
South Idaho Exchange 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	0.0	0.0	0.0
Flush Purchase	0.0	0.0	0.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
BPA Settlement	0.0	0.0	0.0	0.0	0.0	0.0	64.9	63.2	66.9	64.9	64.9	65.2	64.9	64.9	64.9	65.2	64.9	64.9	64.9	65.2
Hydro Efficiency	0.0	1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
BPA NR Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	100.0	100.0	100.0
Off Peak Purchase 1-utah	0.0	0.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Seasonal Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.7	41.7	41.7
Seasonal Purchase-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.7	41.7	41.7
Cogen Ownership	0.0	0.0	0.0	0.0	0.0	0.0	20.0	40.0	60.0	80.0	100.0	120.0	140.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
Cogeneration Purchase	0.0	0.0	0.0	0.0	0.0	0.0	10.0	20.0	30.0	40.0	50.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Cogeneration Purchase-utah	0.0	0.0	0.0	0.0	0.0	0.0	10.0	20.0	30.0	40.0	50.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Canadian Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.0
Voltage Regulation 1	0.0	2.0	4.0	6.0	8.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Voltage Regulation 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	2.5	5.0	7.5	10.0	12.5	12.5	12.5
Voltage Regulation 2-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	5.0	7.5	10.0	12.5	12.5	12.5
New Appliances Lost Opp	0.0	0.1	0.1	0.2	0.3	0.4	0.9	1.5	3.4	5.0	7.0	8.5	11.4	11.5	12.1	12.2	12.7	12.8	13.3	13.5
New Appliances Lost Opp-utah	0.0	0.0	0.1	0.1	0.1	0.2	0.5	0.8	1.9	2.8	3.9	4.7	6.3	6.4	6.7	6.8	7.0	7.1	7.4	7.5
Light and Water Heater Appliance	0.0	0.0	0.0	0.0	0.0	0.5	1.7	3.2	5.0	6.7	8.2	9.2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Light and Water Heater Appliance-utah	0.0	0.0	0.0	0.0	0.0	0.2	0.8	1.2	1.8	2.5	3.0	3.4	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Commercial Retrofit	0.2	0.5	1.1	1.7	3.4	7.0	14.1	21.2	28.3	35.5	42.6	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1
Commercial Retrofit-utah	0.1	0.3	0.7	1.1	2.1	4.3	8.7	13.1	17.4	21.8	26.2	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4
Utah MCS Lost Opp-utah	0.0	0.2	1.0	2.0	3.3	4.9	6.1	7.4	8.7	10.0	11.3	13.1	15.2	17.6	20.3	23.0	26.3	29.7	33.4	37.2
Commercial Lost Opp	0.0	0.0	0.2	0.6	1.2	2.1	4.0	5.9	7.7	9.5	11.4	13.3	15.1	17.0	18.9	20.8	22.8	24.7	26.6	28.6
Commercial Lost Opp-utah	0.0	0.0	0.1	0.3	0.5	0.9	1.8	2.7	3.5	4.3	5.1	6.0	6.8	7.7	8.5	9.4	10.2	11.1	12.0	12.9
Industrial Lost Opp	0.0	0.3	1.2	2.1	3.0	3.8	5.9	8.4	11.5	15.0	19.0	23.6	28.7	34.3	40.3	46.9	54.0	61.6	69.2	76.8
Industrial Lost Opp-utah	0.0	0.2	0.9	1.5	2.2	2.8	4.3	6.2	8.4	11.0	13.9	17.3	21.0	25.1	29.6	34.4	39.6	45.2	50.7	56.3
Utah Code Lost Opp-utah	0.0	0.1	0.4	0.7	1.2	1.9	2.6	3.4	4.1	4.9	5.7	6.6	7.4	8.2	9.1	10.0	10.8	11.7	12.7	13.6
Mobile Home MCS Lost Opp	0.0	0.0	0.0	0.0	0.0	0.0	1.3	2.4	3.6	4.8	5.9	7.0	8.2	9.6	10.9	12.1	13.4	14.9	16.5	18.1
Mobile Home MCS Lost Opp-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.6	0.8	0.9	1.1	1.3	1.5	1.8	2.0	2.2	2.4	2.7	2.9
Residential Retro	0.6	1.5	3.2	5.6	8.9	10.1	10.8	11.6	12.4	13.2	14.1	14.9	15.7	16.5	17.3	18.1	18.9	19.7	20.5	21.3
Residential Retro-utah	0.1	0.2	0.4	0.7	1.1	1.2	1.3	1.4	1.5	1.6	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.4	2.5
New Peak Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transmission and Distribution Improvement	0.0	1.4	2.8	4.2	5.6	7.0	8.4	9.8	11.2	12.6	14.0	15.4	16.8	18.2	19.6	21.0	21.0	21.0	21.0	21.0
Transmission and Distribution Improvement	0.0	0.6	1.2	1.8	2.4	3.0	3.6	4.2	4.8	5.4	6.0	6.6	7.2	7.8	8.4	9.0	9.0	9.0	9.0	9.0
Centralia	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0

Dave Johnston	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8
Jim Bridger	1,193.0	1,204.4	1,212.1	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0
Wyodak	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7
Colstrip	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5
Carbon	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4
Naughton	540.6	540.6	547.5	554.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4
Huntington	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0
Hunter	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2
Blundell	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.8	66.7	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trojan	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7
Total	5,989.7	6,084.0	6,103.6	6,249.0	6,277.2	6,305.8	6,487.3	6,569.7	6,627.0	6,730.5	6,796.7	6,860.3	6,897.9	6,943.1	6,964.9	6,990.5	7,113.4	7,173.9	7,198.2	7,276.3
Thermal Maintenance																				
Centralia	58.1	46.8	47.1	63.9	47.1	36.1	47.1	62.8	47.1	64.1	47.1	57.9	46.8	47.1	64.1	46.9	36.1	47.1	63.0	46.9
Dave Johnston	40.0	47.8	59.2	47.7	75.0	53.5	53.6	47.7	59.2	47.8	58.4	52.4	59.2	47.8	47.8	74.8	53.5	53.6	59.2	47.7
Jim Bridger	106.3	121.5	122.4	97.6	111.7	106.3	111.1	117.4	111.5	105.3	116.9	109.2	123.5	124.3	97.9	111.4	106.3	111.1	117.7	111.2
Wyodak	19.6	19.6	15.0	33.3	15.0	19.6	15.0	19.6	15.0	28.8	15.0	19.6	19.6	15.0	33.4	15.0	19.6	15.0	19.6	15.0
Colstrip	8.7	8.4	8.4	8.4	8.4	8.4	8.4	6.2	8.4	8.4	6.4	8.7	8.4	8.4	8.4	8.4	8.4	8.4	6.2	8.4
Carbon	8.8	5.3	16.7	6.2	4.2	6.2	14.7	4.2	12.4	10.5	4.2	6.2	14.7	4.2	12.4	10.4	4.2	6.2	14.7	4.2
Naughton	43.6	22.6	41.2	30.1	29.0	32.6	35.9	28.0	42.7	40.8	22.8	42.6	40.8	22.8	42.7	40.7	22.8	42.7	40.8	22.8
Huntington	27.3	52.2	38.9	39.3	78.4	25.9	26.3	52.1	25.9	26.3	78.4	25.9	26.3	52.2	25.9	26.2	78.4	25.9	26.3	52.1
Hunter	87.6	64.9	72.2	89.8	64.9	64.9	72.2	89.8	79.5	64.9	72.2	64.7	72.2	90.1	79.5	64.7	72.2	64.9	72.2	89.8
Blundell	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trojan	4.4	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	4.3	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Total	405.4	394.4	426.1	421.3	438.8	358.7	389.4	432.7	406.9	401.9	428.4	392.5	416.6	417.0	417.2	403.6	406.6	380.1	424.8	403.1
Balance	239.8	261.1	81.6	66.0	1.1	23.0	43.7	27.2	27.7	62.5	138.0	177.8	113.3	75.7	51.5	85.2	109.7	115.9	68.9	62.3

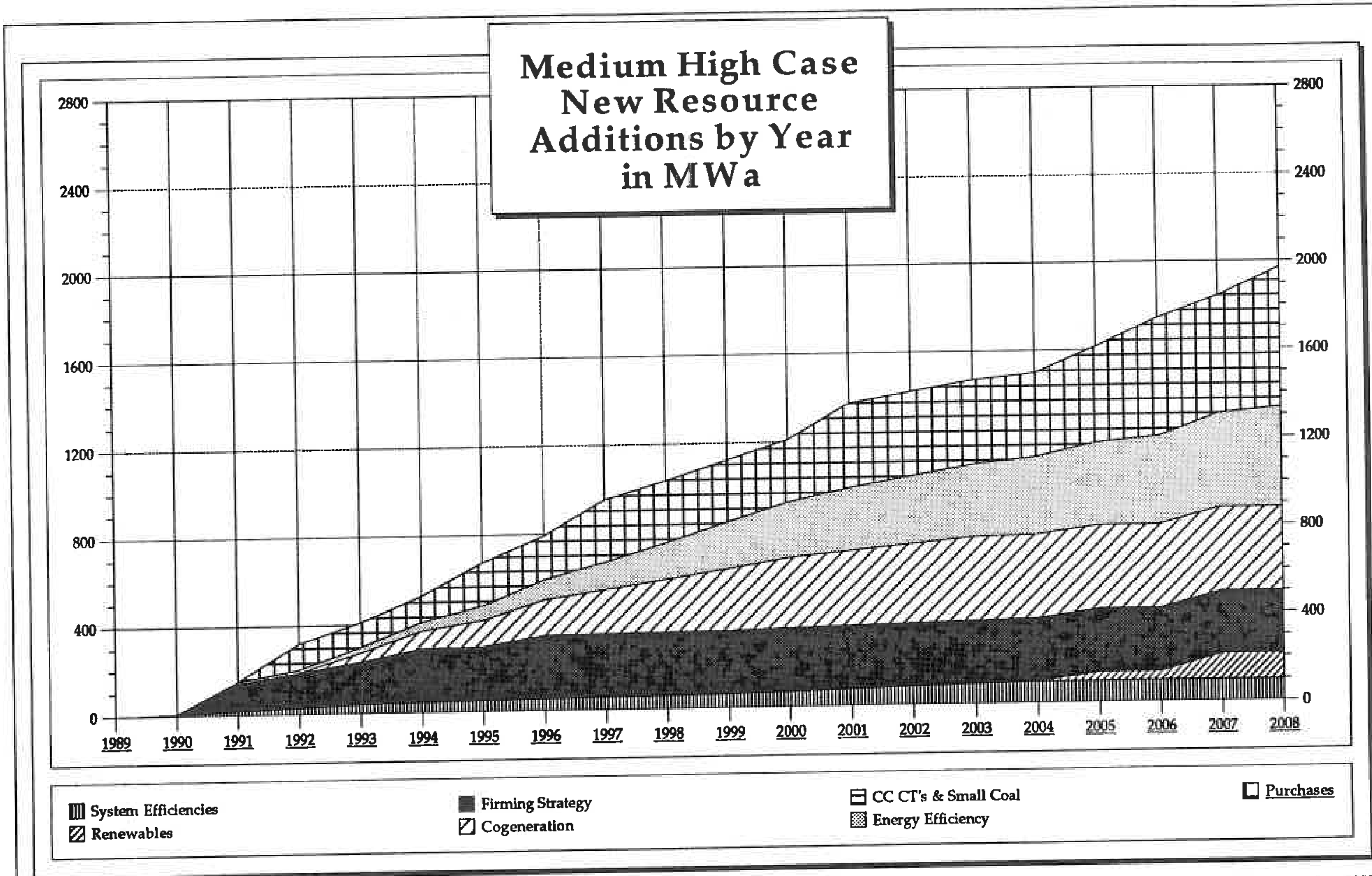
Study
Merged System
Resource & Market Planning
Medium Case - TRC

January Peak	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Requirements										
Merged System Load	6,440.0	6,551.0	6,665.0	6,777.0	6,891.0	7,000.0	7,081.0	7,188.0	7,299.0	7,394.0
Black Hills	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
P G & E	100.0	100.0	100.0	100.0	100.0	100.0	100.0	0.0	0.0	0.0
Puget Power	55.0	55.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power II	100.0	100.0	100.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
So Cal Edison	298.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
SMUD	0.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Nevada	0.0	0.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Sierra Pacific	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Seirra Pacific II	0.0	25.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Total	7,120.0	7,258.0	7,474.0	7,631.0	7,745.0	7,854.0	7,935.0	7,942.0	8,053.0	8,148.0
Resources										
Pacific System Hydro	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5
Utah System Hydro	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
Black Hills Capacity	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
BPA Entitlement Capacity	28.7	28.6	28.7	26.0	23.4	20.9	18.3	15.5	12.9	12.4
BPA Peak Purchase	1,127.3	1,127.3	1,127.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BPA Supplemental Capacity	27.0	27.0	27.1	24.5	22.0	19.7	17.2	14.7	12.1	11.7
Canadian Entitlement	-28.7	-28.6	-28.7	-26.0	-23.4	-20.9	-18.3	-15.5	-12.9	-12.4
CSPE	95.6	96.1	96.5	93.2	79.7	71.3	62.9	54.4	45.9	44.5
Hanford WNP #1	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	0.0	0.0
Mid Columbia	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5
Miscellaneous Purchases	142.7	142.7	142.7	128.7	128.7	26.0	26.0	21.0	21.0	21.0
Pelton Rereg	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6
Q.F. Contracts - PP&L	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0
QF Contracts - UP&L	38.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
Gem State	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GSLM	0.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
MPC Purchase	0.0	15.0	15.0	15.0	10.0	10.0	10.0	0.0	0.0	0.0
WWP Purchase	50.0	50.0	150.0	150.0	150.0	150.0	150.0	100.0	50.0	0.0
Flush Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BPA Settlement	0.0	0.0	0.0	0.0	0.0	0.0	164.0	164.0	164.0	164.0
Hydro Efficiency	0.0	2.0	4.0	6.0	8.0	10.0	12.0	14.0	16.0	18.0
BPA NR Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Off Peak Purchase 1-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Seasonal Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Seasonal Purchase-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cogen Ownership	0.0	0.0	0.0	0.0	0.0	0.0	20.0	40.0	60.0	80.0
Cogeneration Purchase	0.0	0.0	0.0	0.0	0.0	0.0	10.0	20.0	30.0	40.0
Cogeneration Purchase-utah	0.0	0.0	0.0	0.0	0.0	0.0	10.0	20.0	30.0	40.0
Canadian Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Voltage Regulation 1	0.0	4.0	8.0	12.0	16.0	20.0	20.0	20.0	20.0	20.0
Voltage Regulation 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Voltage Regulation 2-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Appliances Lost Opp	0.0	0.1	0.1	0.2	0.3	0.4	0.9	1.5	3.4	5.0
New Appliances Lost Opp-utah	0.0	0.0	0.1	0.1	0.1	0.2	0.5	0.8	1.9	2.8
Light and Water Heater Appliance	0.0	0.0	0.0	0.0	0.0	0.2	0.6	1.3	2.2	3.2
Light and Water Heater Appliance-utah	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.5	0.8	1.2
Commercial Retrofit	0.3	1.0	2.2	3.5	6.9	14.1	28.5	42.8	57.2	71.6
Commercial Retrofit-utah	0.2	0.6	1.4	2.1	4.2	8.7	17.5	26.4	35.2	44.1
Utah MCS Lost Opp-utah	0.0	0.2	0.9	1.8	3.0	4.5	5.6	6.8	8.0	9.2
Commercial Lost Opp	0.0	0.0	0.7	2.0	3.9	7.0	12.7	18.4	24.0	29.5
Commercial Lost Opp-utah	0.0	0.0	0.3	0.9	1.8	3.1	5.7	8.3	10.8	13.3
Industrial Lost Opp	0.0	0.3	1.2	2.1	3.0	3.9	5.9	8.4	11.5	15.0
Industrial Lost Opp-utah	0.0	0.2	0.9	1.5	2.2	2.8	4.3	6.2	8.4	11.0
Utah Code Lost Opp-utah	0.0	0.2	0.7	1.5	2.5	3.8	5.2	8.7	8.3	9.9
Mobile Home MCS Lost Opp	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0
Mobile Home MCS Lost Opp-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2
Residential Retro	1.1	2.4	4.5	7.3	10.7	14.2	15.8	17.4	19.0	20.6
Residential Retro-utah	0.1	0.3	0.5	0.9	1.3	1.7	1.9	2.0	2.2	2.4
New Peak Purchase	0.0	0.0	0.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
Transmission and Distribution Improvement	0.0	1.4	2.8	4.2	5.6	7.0	8.4	9.8	11.2	12.6
Transmission and Distribution Improvement	0.0	0.6	1.2	1.8	2.4	3.0	3.6	4.2	4.8	5.4
Centralia	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0
Dave Johnston	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0
Jim Bridger	1,360.7	1,366.0	1,371.4	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7
Wyodak	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0
Colstrip	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Carbon	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0
Naughton	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0

January Peak	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements										
Merged System Load	7,497.0	7,604.0	7,707.0	7,819.0	7,923.0	8,045.0	8,174.0	8,322.0	8,467.0	8,610.0
Black Hills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
P G & E	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power II	200.0	200.0	200.0	200.0	200.0	0.0	0.0	0.0	0.0	0.0
So Cal Edison	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	0.0	0.0
SMUD	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Nevada	52.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra Pacific	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Seirra Pacific II	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Total	8,176.0	8,231.0	8,334.0	8,446.0	8,550.0	8,472.0	8,601.0	8,749.0	8,694.0	8,837.0
Resources										
Pacific System Hydro	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5
Utah System Hydro	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
Black Hills Capacity	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
BPA Entitlement Capacity	10.8	5.1	4.8	4.7	4.1	0.0	0.0	0.0	0.0	0.0
BPA Peak Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BPA Supplemental Capacity	10.2	4.8	4.5	4.4	3.8	0.0	0.0	0.0	0.0	0.0
Canadian Entitlement	-10.8	-5.1	-4.8	-4.7	-4.1	0.0	0.0	0.0	0.0	0.0
CSPE	39.3	18.9	18.1	17.7	15.8	0.0	0.0	0.0	0.0	0.0
Hanford WNP #1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid Columbia	351.5	351.5	351.5	351.5	351.5	351.5	351.5	242.3	242.3	242.3
Miscellaneous Purchases	21.0	21.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Pelton Rereg	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6
Q.F. Contracts - PP&L	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0
QF Contracts - UP&L	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
Gem State	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GSLM	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
MPC Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WWP Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flush Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BPA Settlement	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0
Hydro Efficiency	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
BPA NR Purchase	0.0	0.0	0.0	0.0	0.0	0.0	135.0	135.0	135.0	135.0
Off Peak Purchase 1-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Seasonal Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	100.0	100.0
Seasonal Purchase-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	100.0	100.0
Cogen Ownership	100.0	120.0	140.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
Cogeneration Purchase	50.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Cogeneration Purchase-utah	50.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
Canadian Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0
Voltage Regulation 1	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Voltage Regulation 2	0.0	0.0	0.0	5.0	10.0	15.0	20.0	25.0	25.0	25.0
Voltage Regulation 2-utah	0.0	0.0	0.0	5.0	10.0	15.0	20.0	25.0	25.0	25.0
New Appliances Lost Opp	7.0	8.5	11.4	11.5	12.1	12.2	12.7	12.8	13.4	13.5
New Appliances Lost Opp-utah	3.9	4.7	6.3	6.4	6.7	6.8	7.0	7.1	7.4	7.5
Light and Water Heater Appliance	3.9	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Light and Water Heater Appliance-utah	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Commercial Retrofit	86.0	93.2	93.2	93.2	93.2	93.2	93.2	93.2	93.2	93.2
Commercial Retrofit-utah	52.9	57.4	57.4	57.4	57.4	57.4	57.4	57.4	57.4	57.4
Utah MCS Lost Opp-utah	10.5	12.2	14.2	16.4	18.9	21.5	24.6	27.7	31.2	34.8
Commercial Lost Opp	35.1	40.7	46.4	52.1	57.7	63.4	69.1	74.9	80.8	86.7
Commercial Lost Opp-utah	15.8	18.3	20.9	23.5	26.0	28.5	31.1	33.8	36.4	39.0
Industrial Lost Opp	19.0	23.6	28.7	34.3	40.3	46.9	54.0	61.6	69.2	76.8
Industrial Lost Opp-utah	14.0	17.3	21.0	25.1	29.6	34.4	39.6	45.2	50.8	56.3
Utah Code Lost Opp-utah	11.5	13.1	14.8	16.4	18.2	19.9	21.7	23.5	25.4	27.3
Mobile Home MCS Lost Opp	0.9	0.9	1.0	1.1	1.0	1.0	1.1	1.3	1.4	1.4
Mobile Home MCS Lost Opp-utah	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Residential Retro	22.2	23.8	25.4	27.0	28.6	30.3	31.9	33.5	35.1	36.7
Residential Retro-utah	2.6	2.8	3.0	3.2	3.4	3.6	3.7	3.9	4.1	4.3
New Peak Purchase	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
Transmission and Distribution Improvement	14.0	15.4	16.8	18.2	19.6	21.0	21.0	21.0	21.0	21.0
Transmission and Distribution Improvement	6.0	6.6	7.2	7.8	8.4	9.0	9.0	9.0	9.0	9.0
Centralia	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0
Dave Johnston	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0
Jim Bridger	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7
Wyodak	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0
Colstrip	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Carbon	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0
Naughton	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0

Huntington	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0
Hunter	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0
Blundell	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	62.0	126.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trojan	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
Total	8,939.7	9,047.1	9,169.0	9,045.5	9,048.5	8,967.7	9,206.6	9,363.9	9,376.3	9,512.2	9,596.5	9,648.2	9,678.1	9,733.7	9,768.7	9,786.9	9,960.1	10,089.7	10,119.4	10,248.8
Thermal Maintenance																				
Centralia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dave Johnston	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jim Bridger	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyodak	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Colstrip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Carbon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Naughton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Huntington	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hunter	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Blundell	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trojan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reserve Requirement																				
Reserve	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0
(Reserve+Balance)/Requirements	26%	25%	23%	19%	17%	14%	16%	18%	16%	17%	17%	17%	16%	15%	14%	16%	16%	15%	16%	16%
Balance	806.7	776.1	682.0	401.5	290.5	100.7	258.6	408.9	310.3	351.2	407.5	404.2	331.1	274.7	205.7	301.9	346.1	327.7	412.4	398.8

Medium-High
Case Study



	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
System Efficiencies	0	5	17	29	41	46	49	52	55	58
Renewables	0	0	0	0	0	0	0	0	0	0
Firming Strategy	0	0	125	158	192	244	244	289	289	289
Cogeneration	0	0	0	0	40	80	120	160	200	240
CC CT's & Small Coal	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	0	3	8	15	25	40	65	93	127	167
Purchases	0	0	0	115	113	117	198	199	282	282
Totals	0	8	150	316	410	526	676	792	952	1034

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiencies	61	68	75	82	89	96	96	96	96	96
Renewables	0	0	0	0	0	0	38	38	114	114
Firming Strategy	289	289	289	289	289	289	289	289	289	289
Cogeneration	280	320	340	360	380	380	380	380	380	380
CC CT's & Small Coal	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	213	253	287	309	331	353	377	402	428	454
Purchases	282	282	382	382	382	382	436	536	536	636
Totals	1124	1212	1371	1420	1470	1499	1615	1740	1842	1969

KEY OUTPUTS

Medium High Case - TRC New

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
System Load (MWa)	4889.0	4946.0	5116.0	5317.0	5421.0	5523.0	5686.0	5765.0	5846.0	5944.0
Total Energy Efficiency	0.3	4.5	11.7	20.5	32.7	50.2	75.1	103.1	137.3	176.5
System Load net of Energy Efficiency	4888.7	4941.5	5104.3	5296.5	5388.3	5472.8	5610.9	5661.9	5708.7	5767.5
Energy Sales after Energy Efficiency	4399.8	4447.4	4593.9	4766.9	4849.5	4925.5	5049.8	5095.7	5137.8	5190.8
Total Customers (000's)	1,235	1,248	1,263	1,279	1,295	1,312	1,323	1,335	1,347	1,359
Net Electric Plant (M$)	5285.4	5476.2	5616.0	5717.3	5815.2	5887.8	5992.7	6098.2	6243.1	6448.0
Net Energy Efficiency Assets	2.0	11.3	30.9	58.0	99.0	161.3	242.0	344.9	486.9	682.2
General Inflation Rate	3.90%	3.40%	4.00%	3.90%	4.10%	4.00%	4.00%	3.90%	3.60%	3.70%
Operating Revenues (M$)										
Nominal	1894.4	1895.4	1956.2	2077.1	2162.4	2255.5	2367.2	2440.5	2509.9	2599.7
Real	1894.4	1833.1	1819.1	1859.1	1859.2	1864.6	1881.7	1867.2	1853.5	1851.3
NPV (10.33% discount rate)	22788.6									
Average Growth										
Nominal	4.60%									
Real	0.65%									
Base Unit Cost (mills/kwh)										
Nominal	49.2	48.7	48.6	49.6	50.9	52.3	53.5	54.5	55.8	57.2
Real	49.2	47.1	45.2	44.4	43.8	43.2	42.5	41.7	41.2	40.7
Average Growth										
Nominal	2.90%									
Real	-0.99%									
Average Customer Bill ($)										
Nominal	1534.2	1518.9	1549.1	1624.2	1669.3	1719.5	1789.3	1828.8	1863.9	1913.5
Real	1534.2	1468.9	1440.5	1453.6	1435.2	1421.5	1422.3	1399.2	1376.4	1362.7
NPV (10.33% discount rate)	16905.3									
Customer Cost (M$)	0.0	0.3	1.1	1.6	2.1	2.6	14.7	14.5	17.0	21.4
Levelized Customer Cost (M$)										
(30 years at a 12.33% discount rate)	0.0	0.0	0.2	0.4	0.6	1.0	2.8	4.7	6.9	9.6
NPV (10.33% discount rate)	91.6									
Energy Services Charge (M$)	0.1	0.4	1.4	3.2	6.3	11.3	17.5	26.0	37.8	53.7
NPV (10.33% discount rate)	427.7									
Total Resource Cost (M$)										
Nominal	1894.5	1895.8	1957.8	2080.7	2169.4	2267.8	2387.6	2471.2	2554.6	2663.0
Real	1894.5	1833.5	1820.6	1862.3	1865.1	1874.8	1897.9	1890.7	1886.5	1896.4
NPV (10.33% discount rate)	23307.8									
Average Growth										
Nominal	4.93%									
Real	0.97%									
Mills / KWh										
Nominal	49.2	48.6	48.5	49.5	50.8	52.1	53.3	54.2	55.4	56.8
Real	49.2	47.0	45.1	44.3	43.6	43.1	42.3	41.5	40.9	40.5
Average Growth										
Nominal	2.84%									
Real	-1.04%									

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Load (MWa)	6063.0	6183.0	6304.0	6422.0	6529.0	6642.0	6757.0	6885.0	7015.0	7147.0
Total Energy Efficiency	222.7	268.3	306.5	333.5	361.1	388.1	412.3	437.4	463.3	489.4
System Load net of Energy Efficiency	5840.3	5914.7	5997.5	6088.5	6167.9	6253.9	6344.7	6447.6	6551.7	6657.6
Energy Sales after Energy Efficiency	5256.3	5323.2	5397.8	5479.7	5551.1	5628.5	5710.2	5802.8	5896.5	5991.8
Total Customers (000's)	1,370	1,385	1,403	1,425	1,449	1,472	1,501	1,531	1,564	1,599
Net Electric Plant (M$)	6720.7	6987.3	7178.3	7291.7	7429.7	7592.0	7799.2	7962.6	7992.9	8035.9
Net Energy Efficiency Assets	943.0	1195.1	1364.4	1430.0	1457.3	1495.9	1501.0	1514.4	1526.6	1544.0
General Inflation Rate	3.60%	3.70%	3.80%	4.00%	4.10%	4.20%	4.20%	4.20%	4.10%	4.00%
Operating Revenues (M$)										
Nominal	2744.8	2885.8	3042.5	3204.2	3366.0	3548.1	3746.0	3966.5	4239.0	4450.7
Real	1886.7	1912.9	1942.9	1967.5	1985.4	2008.5	2035.0	2068.0	2123.0	2143.3
Base Unit Cost (mills/kwh)										
Nominal	59.6	61.7	64.3	66.8	69.2	71.8	74.9	78.0	82.1	84.6
Real	41.0	40.9	41.1	41.0	40.8	40.6	40.7	40.7	41.1	40.7
Average Customer Bill ($)										
Nominal	2003.4	2083.8	2168.2	2248.4	2323.8	2410.4	2496.5	2591.1	2709.7	2782.7
Real	1377.1	1381.2	1384.6	1380.6	1370.7	1364.4	1356.2	1350.9	1357.1	1340.1
Customer Cost (M$)	25.3	32.3	37.7	41.0	39.9	38.8	46.0	51.1	58.6	65.3
Levelized Customer Cost (M$)										
(30 years at a 12.33% discount rate)	12.8	16.9	21.7	26.9	32.0	36.9	42.8	49.3	56.7	65.0
Energy Services Charge (M$)	74.7	96.9	117.0	133.5	148.6	164.5	179.9	193.5	203.7	212.4
Total Resource Cost (M$)										
Nominal	2832.3	2999.6	3181.2	3364.6	3546.6	3749.5	3968.7	4209.3	4499.4	4728.1
Real	1946.9	1988.3	2031.5	2066.0	2092.0	2122.5	2156.0	2194.5	2253.4	2276.9
Mills / KWh										
Nominal	59.3	61.4	64.0	66.5	68.9	71.4	74.5	77.5	81.4	83.7
Real	40.7	40.7	40.9	40.8	40.6	40.4	40.5	40.4	40.7	40.3

Study
Merged System
Resource & Market Planning
Medium High Case - TRC New

Average Megawatts	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements																				
Merged System Load	4,888.6	4,945.8	5,115.7	5,316.5	5,421.2	5,523.0	5,685.7	5,765.3	5,846.5	5,944.5	6,062.5	6,183.4	6,304.3	6,422.3	6,528.8	6,641.8	6,757.0	6,884.8	7,014.8	7,146.6
Black Hills	37.5	45.0	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
P G & E	28.5	28.5	28.5	28.5	28.5	28.5	28.5	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
Puget Power	27.5	27.5	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power II	60.0	60.0	85.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	85.6	0.0	0.0	0.0	0.0	0.0
So Cal Edison	161.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	80.8	0.0	0.0
SMUD	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
WIDCO Sale	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9
Nevada	0.0	61.2	82.5	82.4	82.5	82.5	82.5	82.4	82.5	82.5	21.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra Pacific	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8
Seirra Pacific II	10.3	38.0	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5
IPP Layoff to LA	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1
IPP Banked Recall	7.5	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	0.0	0.0	0.0	0.0	0.0
South Idaho Exchange - UPL	30.1	41.0	41.0	41.1	41.0	41.0	41.0	41.1	41.0	41.0	41.0	41.1	41.0	41.0	41.0	41.1	41.0	41.0	41.0	41.1
Total	5,371.9	5,515.9	5,742.6	5,962.4	6,067.0	6,168.9	6,331.6	6,382.6	6,463.8	6,561.8	6,566.2	6,665.8	6,786.7	6,904.7	6,976.7	7,004.1	7,119.3	7,219.9	7,269.1	7,400.9
Resources																				
Pacific System Hydro	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8
Utah System Hydro	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5
Black Hills Energy Purchase	6.2	3.1	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
Canadian Entitlement	-8.2	-7.6	-6.9	-6.4	-6.0	-5.5	-5.2	-5.0	-4.8	-4.2	-2.5	-2.0	-1.9	-1.9	-0.5	0.0	0.0	0.0	0.0	0.0
CSPE	34.1	32.3	31.4	30.1	28.9	27.6	26.5	25.2	24.2	21.8	12.8	9.8	9.4	9.1	2.3	0.0	0.0	0.0	0.0	0.0
Hanford WNP #1	68.0	68.0	68.0	68.0	68.0	68.0	68.0	30.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid Columbia	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	178.3	127.3	127.3	127.4
Miscellaneous Purchases	5.7	5.7	3.0	-4.3	7.1	18.5	18.5	16.2	16.2	16.2	16.2	15.1	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Pelton Rereg	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Q.F. Contracts - PP&L	67.1	74.8	74.9	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3
Widco Purchase	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3
QF Contracts - UP&L	34.2	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5
Gem State	6.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
GSLM	2.0	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
IPP	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1
WAPA Capacity Exchange	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8
MPC Purchase	0.0	15.0	15.0	15.0	10.0	10.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WWP Purchase	44.1	50.0	50.0	50.0	50.0	50.0	50.0	38.0	17.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Idaho Exchange - PPL	31.0	42.2	42.2	42.3	42.2	42.2	42.2	42.3	42.2	42.2	42.2	42.3	42.2	42.2	42.2	42.3	42.2	42.2	42.2	42.3
South Idaho Exchange 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	0.0	0.0	0.0
Flush Purchase	0.0	0.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
BPA Settlement	0.0	0.0	0.0	65.2	62.9	66.9	64.9	65.2	64.9	64.9	64.9	65.2	64.9	64.9	64.9	65.2	64.9	64.9	64.9	65.2
Hydro Efficiency	0.0	1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
BPA NR Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	100.0	100.0	100.0	100.0	200.0	200.0	200.0
Off Peak Purchase 1-utah	0.0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	150.0
Seasonal Purchase	0.0	0.0	0.0	0.0	0.0	0.0	41.7	41.7	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3
Seasonal Purchase-utah	0.0	0.0	0.0	0.0	0.0	0.0	41.7	41.7	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3
Cogen Ownership	0.0	0.0	0.0	0.0	20.0	40.0	60.0	80.0	100.0	120.0	140.0	160.0	180.0	200.0	220.0	220.0	220.0	220.0	220.0	220.0
Cogeneration Purchase	0.0	0.0	0.0	0.0	10.0	20.0	30.0	40.0	50.0	60.0	70.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Cogeneration Purchase-utah	0.0	0.0	0.0	0.0	10.0	20.0	30.0	40.0	50.0	60.0	70.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Canadian Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.0	54.0	54.0	54.0
Voltage Regulation 1	0.0	2.0	4.0	6.0	8.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Voltage Regulation 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	5.0	7.5	10.0	12.5	12.5	12.5	12.5	12.5
Voltage Regulation 2-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	5.0	7.5	10.0	12.5	12.5	12.5	12.5	12.5
New Appliances Lost Opp	0.0	0.1	0.1	0.2	0.3	0.4	1.0	1.5	3.5	5.1	7.1	8.9	11.9	12.2	13.4	13.6	14.2	14.3	14.9	15.1
New Appliances Lost Opp-utah	0.0	0.0	0.1	0.1	0.1	0.2	0.5	0.8	1.9	2.7	3.8	4.8	6.4	6.6	7.2	7.3	7.6	7.7	8.0	8.2
Commercial Retrofit	0.2	0.5	1.1	1.7	3.4	7.0	14.1	21.2	28.3	35.5	42.6	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1	46.1
Commercial Retrofit-utah	0.1	0.3	0.7	1.1	2.1	4.3	8.7	13.1	17.4	21.8	26.2	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4
Light and Water Heater Appliance	0.0	0.0	0.0	0.0	0.0	0.5	1.7	3.3	5.1	6.8	8.4	9.4	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Light and Water Heater Appliance-utah	0.0	0.0	0.0	0.0	0.0	0.2	0.6	1.2	1.8	2.5	3.0	3.4	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Utah Code Lost Opp-utah	0.0	0.1	0.3	0.6	1.1	1.6	2.1	2.7	3.2	3.8	4.4	5.1	5.8	6.6	7.3	8.0	8.7	9.4	10.2	10.9
Commercial Lost Opp	0.0	0.0	0.2	0.7	1.4	2.4	4.3	6.2	8.0	10.0	12.2	14.5	16.8	19.0	21.1	23.2	25.4	27.5	29.6	31.9
Commercial Lost Opp-utah	0.0	0.0	0.1	0.2	0.5	0.8	1.4	2.1	2.7	3.3	4.1	4.9	5.6	6.4	7.1	7.8	8.5	9.2	9.9	10.7
Utah MCS Lost Opp-utah	0.0	0.2	1.2	2.6	4.4	6.2	7.0	7.9	8.7	9.7	11.0	13.0	15.5	18.1	20.8	23.4	26.4	29.5	32.8	36.3
Mobile Home MCS Lost Opp	0.0	0.0	0.0	0.0	0.0	0.0	1.2	2.2	3.4	4.9	6.6	8.2	10.0	11.7	13.2	14.5	15.9	17.5	19.1	20.9
Mobile Home MCS Lost Opp-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.6	0.8	1.0	1.3	1.6	1.9	2.1	2.3	2.6	2.8	3.1	3.4
Wind Farm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.0	38.0
Industrial Lost Opp	0.0	0.3	1.1	1.9	2.7	3.5	5.7	8.5	11.9	15.8	20.3	25.4	31.0	37.2	43.9	51.3	59.2	67.6	76.1	84.5
Industrial Lost Opp-utah	0.0	0.2	1.0	1.7	2.5	3.2	5.3	7.9	11.0	14.7	18.8	23.6	28.8	34.5	40.7	47.5	54.8	62.7	70.5	78.3
Residential Retro	0.0	0.6	1.5	3.2	5.6	8.9	10.1	12.6	17.7	26.0	38.5	50.4	57.8	59.1	58.8	58.8	58.8	58.8	58.8	58.8
Residential Retro-utah	0.0	0.1	0.2	0.4	0.7	1.1	1.2	1.5	2.1	3.1	4.5	5.9	6.8	6.9	6.9	6.9	6.9	6.9	6.9	6.9
New Peak Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transmission and Distribution Improvement	0.0	1.4	2.8	4.2	5.6	7.0	8.4	9.8	11.2	12.6	14.0	15.4	16.8	18.2	19.6	21.0	21.0	21.0	21.0	21.0
Transmission and Distribution Improvement	0.0	0.6	1.2	1.8	2.4	3.0	3.6	4.2	4.8	5.4	6.0	6.6	7.2	7.8	8.4	9.0	9.0	9.0	9.0	9.0

Centralia	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0
Dave Johnston	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8
Jim Bridger	1,193.0	1,204.4	1,212.1	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0
Wyodak	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7
Colstrip	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5
Carbon	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4
Naughton	540.6	540.6	547.5	554.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4
Huntington	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0
Hunter	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2
Blundell	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Gadsby	0.0	0.0	0.0	32.8	66.7	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.0	38.0	38.0	38.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.0	38.0
Trojan	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7
Total	5,989.0	6,083.0	6,226.9	6,394.8	6,494.1	6,621.1	6,769.5	6,823.1	6,931.0	6,994.3	7,076.1	7,160.3	7,313.9	7,362.7	7,406.9	7,434.4	7,546.1	7,620.1	7,722.0	7,848.4
Thermal Maintenance																				
Centralia	58.1	46.8	47.1	63.9	47.1	36.1	47.1	62.8	47.1	64.1	47.1	57.9	46.8	47.1	64.1	46.9	36.1	47.1	63.0	46.9
Dave Johnston	40.0	47.8	59.2	47.7	75.0	53.5	53.6	47.7	59.2	47.8	58.4	52.4	59.2	47.8	47.8	74.8	53.5	53.6	59.2	47.7
Jim Bridger	106.3	121.5	122.4	97.6	111.7	106.3	111.1	117.4	111.5	105.3	116.9	109.2	123.5	124.3	97.9	111.4	106.3	111.1	117.7	111.2
Wyodak	19.6	19.6	15.0	33.3	15.0	19.6	15.0	19.6	15.0	28.8	15.0	19.6	19.6	15.0	33.4	15.0	19.6	15.0	19.6	15.0
Colstrip	8.7	8.4	8.4	8.4	8.4	8.4	8.4	6.2	8.4	8.4	8.4	8.7	8.4	8.4	8.4	8.4	8.4	8.4	6.2	8.4
Carbon	8.8	5.3	16.7	6.2	4.2	6.2	14.7	4.2	12.4	10.5	4.2	6.2	14.7	4.2	12.4	10.4	4.2	6.2	14.7	4.2
Naughton	43.6	22.8	41.2	30.1	29.0	32.6	35.9	28.0	42.7	40.8	22.8	42.6	40.8	22.8	42.7	40.7	22.8	42.7	40.8	22.8
Huntington	27.3	52.2	38.9	39.3	78.4	25.9	26.3	52.1	25.9	26.3	78.4	25.9	26.3	52.2	25.9	26.2	78.4	25.9	26.3	52.1
Hunter	87.6	64.9	72.2	89.8	64.9	64.9	72.2	89.8	79.5	64.9	72.2	64.7	72.2	90.1	79.5	64.7	72.2	64.9	72.2	89.8
Blundell	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	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	2.2	2.2	2.2
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	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	2.2
Trojan	4.4	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	4.3	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Total	405.4	394.4	426.1	421.3	438.8	358.7	389.4	432.7	406.9	401.9	428.4	392.5	416.6	417.0	417.2	403.6	408.8	382.3	429.2	407.4
Balance	211.8	172.7	58.1	11.2	-11.6	93.6	48.6	7.8	60.2	30.5	81.5	102.0	110.6	41.0	13.0	26.6	18.0	18.0	23.8	40.0

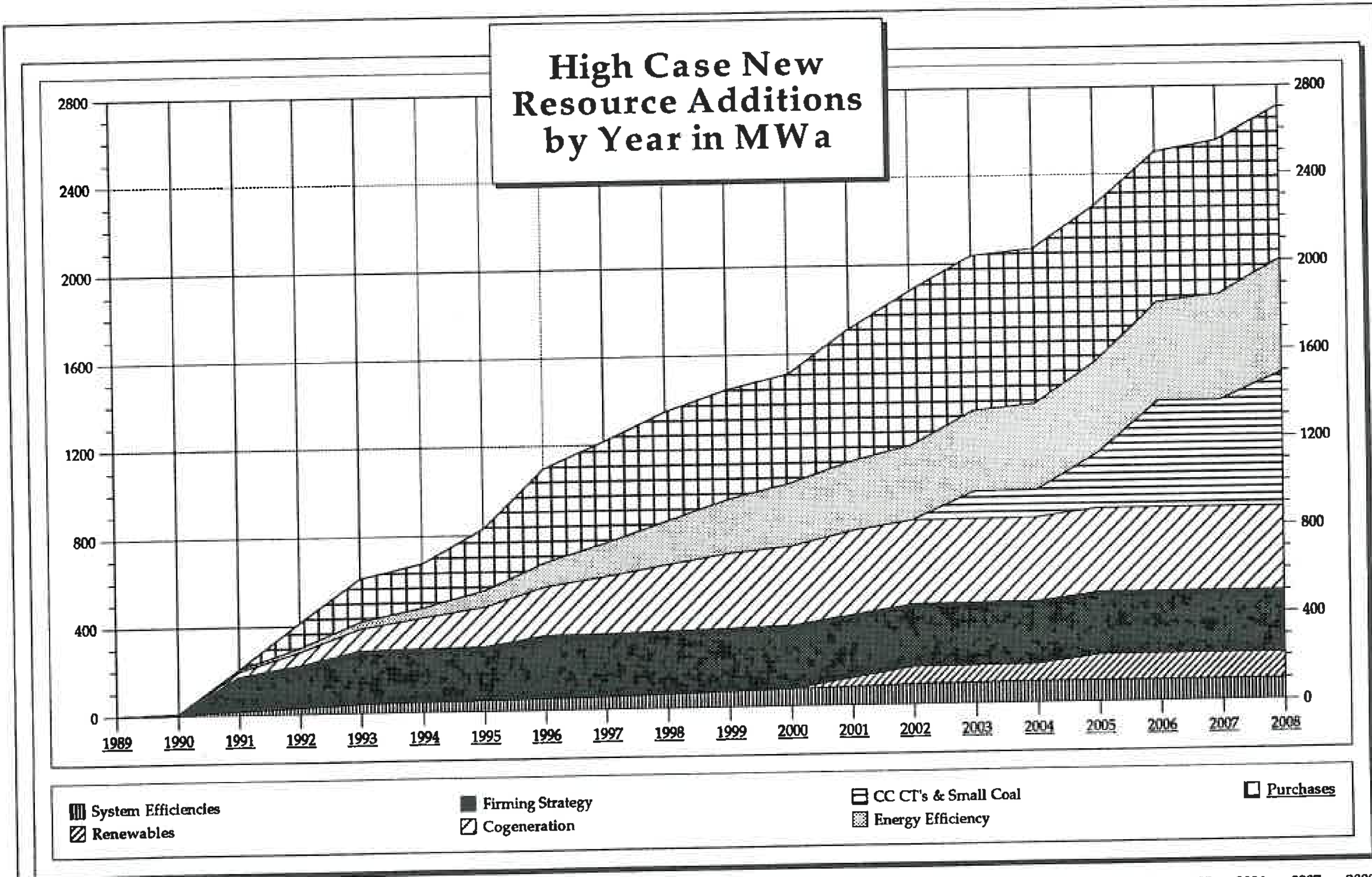
Study
Merged System
Resource & Market Planning
Medium High Case - TRC New

January Peak	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Requirements										
Merged System Load	6,479.0	6,679.0	6,878.0	7,065.0	7,222.0	7,351.0	7,481.0	7,583.0	7,686.0	7,815.0
Black Hills	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
P G & E	100.0	100.0	100.0	100.0	100.0	100.0	100.0	0.0	0.0	0.0
Puget Power	55.0	55.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power II	100.0	100.0	100.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
So Cal Edison	298.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
SMUD	0.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Nevada	0.0	0.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Sierra Pacific	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Seirra Pacific II	0.0	25.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Total	7,159.0	7,386.0	7,687.0	7,919.0	8,076.0	8,205.0	8,335.0	8,337.0	8,440.0	8,569.0
Resources										
Pacific System Hydro	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5
Utah System Hydro	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
Black Hills Capacity	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
BPA Entitlement Capacity	28.7	28.6	28.7	26.0	23.4	20.9	18.3	15.5	12.9	12.4
BPA Peak Purchase	1,127.3	1,127.3	1,127.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BPA Supplemental Capacity	27.0	27.0	27.1	24.5	22.0	19.7	17.2	14.7	12.1	11.7
Canadian Entitlement	-28.7	-28.6	-28.7	-26.0	-23.4	-20.9	-18.3	-15.5	-12.9	-12.4
CSPE	95.6	96.1	96.5	93.2	79.7	71.3	62.9	54.4	45.9	44.5
Hanford WNP #1	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	0.0	0.0
Mid Columbia	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5
Miscellaneous Purchases	142.7	142.7	142.7	128.7	128.7	26.0	26.0	21.0	21.0	21.0
Pelton Rereg	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6
Q.F. Contracts - PP&L	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0
QF Contracts - UP&L	38.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
Gem State	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GSLM	0.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
MPC Purchase	0.0	15.0	15.0	15.0	10.0	10.0	10.0	0.0	0.0	0.0
WWP Purchase	50.0	50.0	150.0	150.0	150.0	150.0	150.0	100.0	50.0	0.0
Flush Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BPA Settlement	0.0	0.0	0.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0
Hydro Efficiency	0.0	2.0	4.0	6.0	8.0	10.0	12.0	14.0	16.0	18.0
BPA NR Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Off Peak Purchase 1-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Seasonal Purchase	0.0	0.0	0.0	0.0	0.0	0.0	100.0	100.0	200.0	200.0
Seasonal Purchase-utah	0.0	0.0	0.0	0.0	0.0	0.0	100.0	100.0	200.0	200.0
Cogen Ownership	0.0	0.0	0.0	0.0	20.0	40.0	60.0	80.0	100.0	120.0
Cogeneration Purchase	0.0	0.0	0.0	0.0	10.0	20.0	30.0	40.0	50.0	60.0
Cogeneration Purchase-utah	0.0	0.0	0.0	0.0	10.0	20.0	30.0	40.0	50.0	60.0
Canadian Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Voltage Regulation 1	0.0	4.0	8.0	12.0	16.0	20.0	20.0	20.0	20.0	20.0
Voltage Regulation 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Voltage Regulation 2-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Appliances Lost Opp	0.0	0.1	0.1	0.2	0.3	0.4	1.0	1.5	3.5	5.1
New Appliances Lost Opp-utah	0.0	0.0	0.1	0.1	0.1	0.2	0.5	0.8	1.9	2.7
Commercial Retrofit	0.3	1.0	2.2	3.5	6.9	14.1	28.5	42.8	57.2	71.6
Commercial Retrofit-utah	0.2	0.6	1.4	2.1	4.2	8.7	17.5	26.4	35.2	44.1
Light and Water Heater Appliance	0.0	0.0	0.0	0.0	0.0	0.2	0.6	1.3	2.3	3.3
Light and Water Heater Appliance-utah	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.5	0.8	1.2
Utah Code Lost Opp-utah	0.0	0.2	0.6	1.3	2.1	3.1	4.3	5.4	6.5	7.6
Commercial Lost Opp	0.0	0.0	0.8	2.2	4.3	7.6	13.6	19.4	25.1	31.0
Commercial Lost Opp-utah	0.0	0.0	0.3	0.7	1.4	2.5	4.5	6.5	8.4	10.4
Utah MCS Lost Opp-utah	0.0	0.2	1.2	2.5	4.2	5.9	6.6	7.4	8.2	9.1
Mobile Home MCS Lost Opp	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.9	1.0	1.1
Mobile Home MCS Lost Opp-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.1	0.2	0.2
Wind Farm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Industrial Lost Opp	0.0	0.3	1.1	1.9	2.7	3.5	5.7	8.5	11.9	15.8
Industrial Lost Opp-utah	0.0	0.3	1.0	1.7	2.5	3.2	5.3	7.9	11.0	14.7
Residential Retro	0.0	1.1	2.4	4.5	7.3	10.7	14.2	19.8	30.7	48.6
Residential Retro-utah	0.0	0.1	0.3	0.5	0.9	1.3	1.7	2.3	3.6	5.7
New Peak Purchase	0.0	0.0	0.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
Transmission and Distribution Improvement	0.0	1.4	2.8	4.2	5.6	7.0	8.4	9.8	11.2	12.6
Transmission and Distribution Improvement	0.0	0.6	1.2	1.8	2.4	3.0	3.6	4.2	4.8	5.4
Centralia	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0
Dave Johnston	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0
Jim Bridger	1,360.7	1,366.0	1,371.4	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7
Wyodak	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0
Colstrip	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Carbon	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0

January Peak	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements										
Merged System Load	7,973.0	8,133.0	8,296.0	8,453.0	8,593.0	8,743.0	8,898.0	9,073.0	9,248.0	9,426.0
Black Hills	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
P G & E	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power II	200.0	200.0	200.0	200.0	200.0	0.0	0.0	0.0	0.0	0.0
So Cal Edison	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	0.0	0.0
SMUD	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Nevada	52.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra Pacific	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Seirra Pacific II	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Total	8,652.0	8,760.0	8,923.0	9,080.0	9,220.0	9,170.0	9,325.0	9,500.0	9,475.0	9,653.0
Resources										
Pacific System Hydro	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5
Utah System Hydro	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
Black Hills Capacity	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
BPA Entitlement Capacity	10.8	5.1	4.8	4.7	4.1	0.0	0.0	0.0	0.0	0.0
BPA Peak Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BPA Supplemental Capacity	10.2	4.8	4.5	4.4	3.8	0.0	0.0	0.0	0.0	0.0
Canadian Entitlement	-10.8	-5.1	-4.8	-4.7	-4.1	0.0	0.0	0.0	0.0	0.0
CSPE	39.3	18.9	18.1	17.7	15.8	0.0	0.0	0.0	0.0	0.0
Hanford WNP #1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid Columbia	351.5	351.5	351.5	351.5	351.5	351.5	351.5	242.3	242.3	242.3
Miscellaneous Purchases	21.0	21.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Pelton Rereg	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6
Q.F. Contracts - PP&L	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0
QF Contracts - UP&L	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
Gem State	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GSLM	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
MPC Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WWP Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flush Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BPA Settlement	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0
Hydro Efficiency	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
BPA NR Purchase	0.0	0.0	135.0	135.0	135.0	135.0	135.0	270.0	270.0	270.0
Off Peak Purchase 1-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Seasonal Purchase	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Seasonal Purchase-utah	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Cogen Ownership	140.0	160.0	180.0	200.0	220.0	220.0	220.0	220.0	220.0	220.0
Cogeneration Purchase	70.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Cogeneration Purchase-utah	70.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Canadian Purchase	0.0	0.0	0.0	0.0	0.0	0.0	100.0	100.0	100.0	100.0
Voltage Regulation 1	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Voltage Regulation 2	0.0	5.0	10.0	15.0	20.0	25.0	25.0	25.0	25.0	25.0
Voltage Regulation 2-utah	0.0	5.0	10.0	15.0	20.0	25.0	25.0	25.0	25.0	25.0
New Appliances Lost Opp	7.1	8.9	11.9	12.2	13.4	13.6	14.2	14.3	14.9	15.2
New Appliances Lost Opp-utah	3.8	4.8	6.4	6.6	7.2	7.3	7.6	7.7	8.0	8.2
Commercial Retrofit	86.0	93.2	93.2	93.2	93.2	93.2	93.2	93.2	93.2	92.3
Commercial Retrofit-utah	52.9	57.4	57.4	57.4	57.4	57.4	57.4	57.4	57.4	56.8
Light and Water Heater Appliance	4.0	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Light and Water Heater Appliance-utah	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Utah Code Lost Opp-utah	8.9	10.2	11.7	13.1	14.5	16.0	17.4	18.8	20.3	21.9
Commercial Lost Opp	37.4	44.1	50.8	57.3	63.7	69.9	76.2	82.5	88.9	95.5
Commercial Lost Opp-utah	12.5	14.8	17.0	19.2	21.3	23.4	25.5	27.7	29.8	32.0
Utah MCS Lost Opp-utah	10.3	12.2	14.5	16.9	19.4	21.8	24.6	27.5	30.6	33.9
Mobile Home MCS Lost Opp	1.2	1.3	1.5	1.5	1.3	1.1	1.2	1.4	1.5	1.6
Mobile Home MCS Lost Opp-utah	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
Wind Farm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	20.0
Industrial Lost Opp	20.3	25.4	31.0	37.2	43.9	51.3	59.2	67.6	76.1	84.5
Industrial Lost Opp-utah	18.8	23.6	28.8	34.5	40.7	47.5	54.8	62.7	70.5	78.3
Residential Retro	75.2	100.2	115.2	117.0	116.2	116.2	116.2	116.2	116.2	116.2
Residential Retro-utah	8.8	11.8	13.5	13.7	13.6	13.6	13.6	13.6	13.6	13.6
New Peak Purchase	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
Transmission and Distribution Improvement	14.0	15.4	16.8	18.2	19.6	21.0	21.0	21.0	21.0	21.0
Transmission and Distribution Improvement	6.0	6.6	7.2	7.8	8.4	9.0	9.0	9.0	9.0	9.0
Centralia	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0
Dave Johnston	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0
Jim Bridger	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7
Wyodak	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0
Colstrip	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Carbon	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0

Naughton	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0
Huntington	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0
Hunter	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0
Blundell	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Gadsby	0.0	0.0	0.0	62.0	126.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	50.0
Trojan	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
Total	8,938.5	9,045.6	9,166.9	9,268.9	9,375.5	9,432.7	9,709.5	9,808.9	9,967.7	10,024.7	10,138.9	10,229.7	10,422.7	10,481.1	10,536.8	10,555.5	10,734.2	10,789.6	10,890.0	10,918.9
Thermal Maintenance																				
Centralia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dave Johnston	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jim Bridger	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyodak	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Colstrip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Carbon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Naughton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Huntington	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hunter	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Blundell	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trojan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reserve Requirement																				
Reserve	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0
(Reserve+Balance)/Requirements	25%	22%	19%	17%	16%	15%	16%	18%	18%	17%	17%	17%	17%	15%	14%	15%	15%	14%	15%	13%
Balance	766.5	646.6	466.9	336.9	286.5	214.7	361.5	458.9	514.7	442.7	473.9	456.7	486.7	388.1	303.8	372.5	396.2	276.6	402.0	252.9

High Case Study



	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiencies	0	5	17	29	41	46	49	52	55	63	71	78	85	92	94	96	96	96	96	96
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	38	76	76	76	114	114	114	114
Firming Strategy	0	0	158	192	244	244	244	289	289	289	289	289	289	289	289	289	289	289	289	289
Cogeneration	0	0	20	60	100	140	180	220	260	300	340	360	380	380	380	380	380	380	380	380
CC CT's & Small Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	125	125	250	486	486	611
Energy Efficiency	1	4	10	19	31	46	75	109	151	198	246	285	316	340	367	394	423	453	484	516
Purchases	0	0	0	115	196	200	282	426	462	498	498	498	606	706	706	706	706	679	698	698
Totals	**1**	**9**	**205**	**415**	**612**	**676**	**829**	**1096**	**1216**	**1347**	**1443**	**1510**	**1713**	**1882**	**2036**	**2065**	**2257**	**2496**	**2546**	**2703**

KEY OUTPUTS - Revised

High Case/First Run

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Load (MWa)	4914.0	4996.0	5186.0	5418.0	5557.0	5691.0	5894.0	6011.0	6128.0	6260.0	6414.0	6572.0	6733.0	6896.0	7047.0	7209.0	7372.0	7552.0	7736.0	7923.0
Total Energy Efficiency	1.0	5.7	14.4	24.9	39.4	56.1	85.3	119.4	160.6	212.6	265.9	310.4	345.6	375.3	402.4	428.9	457.9	488.0	519.2	550.9
System Load net of Energy Efficiency	4913.0	4990.3	5171.6	5393.1	5517.6	5634.9	5808.7	5891.6	5967.4	6047.4	6148.1	6261.6	6387.4	6520.7	6644.6	6780.1	6914.1	7064.0	7216.8	7372.1
Energy Sales after Energy Efficiency	4421.7	4491.3	4654.4	4853.8	4965.8	5071.4	5227.8	5302.4	5370.7	5442.7	5533.3	5635.4	5748.7	5868.6	5980.1	6102.1	6222.7	6357.6	6495.1	6634.9
Total Customers (000's)	1,254	1,286	1,320	1,357	1,389	1,416	1,436	1,454	1,476	1,500	1,533	1,561	1,597	1,636	1,674	1,712	1,756	1,803	1,854	1,909
Net Electric Plant (M$)	5289.8	5486.4	5648.1	5771.6	5871.8	5947.9	6070.7	6214.9	6410.7	6700.6	7098.1	7558.9	7940.0	8420.9	8952.3	9470.6	9800.3	9947.2	10034.7	10048.2
Net Energy Efficiency Assets	6.4	17.8	42.4	75.3	123.0	185.8	280.7	417.9	605.6	865.7	1134.6	1330.6	1406.7	1447.5	1449.3	1456.7	1464.3	1481.9	1496.8	1519.2
General Inflation Rate	3.90%	3.40%	4.00%	3.90%	4.10%	4.00%	4.00%	3.90%	3.60%	3.70%	3.60%	3.70%	3.80%	4.00%	4.10%	4.20%	4.20%	4.20%	4.10%	4.00%
Operating Revenues (M$)																				
Nominal	1898.7	1904.5	1978.1	2107.4	2205.9	2315.9	2446.1	2566.0	2661.7	2781.1	2960.4	3146.5	3372.5	3590.1	3854.1	4093.3	4434.6	4781.3	5113.4	5471.4
Real	1898.7	1841.9	1839.5	1886.2	1896.6	1914.5	1944.4	1963.1	1965.6	1980.5	2034.9	2085.7	2153.7	2204.4	2273.3	2317.1	2409.1	2492.8	2560.9	2634.8
NPV (10.33% discount rate)	24387.6																			
Average Growth																				
Nominal	5.73%																			
Real	1.74%																			
Base Unit Cost (mills/kwh)																				
Nominal	49.0	48.4	48.5	49.4	50.7	52.1	53.4	55.1	56.6	58.3	61.1	63.6	67.0	69.8	73.6	76.4	81.4	85.9	89.9	93.9
Real	49.0	46.8	45.1	44.2	43.6	43.1	42.5	42.1	41.8	41.5	42.0	42.1	42.8	42.9	43.4	43.2	44.2	44.8	45.0	45.2
Average Growth																				
Nominal	3.48%																			
Real	-0.42%																			
Average Customer Bill ($)																				
Nominal	1514.4	1481.3	1498.4	1553.2	1587.9	1635.7	1704.0	1764.3	1803.6	1853.8	1930.6	2015.7	2111.7	2195.1	2301.9	2390.7	2525.0	2652.6	2757.4	2866.9
Real	1514.4	1432.6	1393.4	1390.2	1365.2	1352.3	1354.5	1349.8	1331.9	1320.1	1327.1	1336.1	1348.5	1347.8	1357.8	1353.3	1371.7	1383.0	1381.0	1380.6
NPV (10.33% discount rate)	16465.1																			
Customer Cost (M$)	0.0	0.3	1.1	1.6	2.2	2.8	24.9	26.6	30.3	35.4	40.6	50.8	59.1	64.3	64.8	66.0	78.2	85.7	96.7	106.2
Levelized Customer Cost (M$)																				
(30 years at a 12.33% discount rate)	0.0	0.0	0.2	0.4	0.7	1.0	4.2	7.6	11.4	15.9	21.1	27.5	35.1	43.2	51.5	59.9	69.8	80.7	93.0	106.5
NPV (10.33% discount rate)	148.2																			
Energy Services Charge (M$)	0.1	0.7	2.2	4.6	8.3	12.2	19.2	29.6	43.9	63.4	85.2	105.5	121.7	137.4	153.0	169.7	185.6	200.0	210.5	217.8
NPV (10.33% discount rate)	457.2																			
Total Resource Cost (M$)																				
Nominal	1898.8	1905.3	1980.5	2112.4	2214.9	2329.1	2469.5	2603.1	2717.0	2860.4	3066.7	3279.6	3529.3	3770.7	4058.6	4322.9	4690.1	5062.1	5416.9	5795.7
Real	1898.8	1842.6	1841.7	1890.6	1904.3	1925.5	1963.0	1991.6	2006.5	2037.0	2108.0	2173.9	2253.8	2315.3	2394.0	2447.1	2547.9	2639.1	2712.9	2791.0
NPV (10.33% discount rate)	24992.9																			
Average Growth																				
Nominal	6.05%																			
Real	2.05%																			
Mills / KWh																				
Nominal	49.0	48.4	48.4	49.3	50.6	51.9	53.1	54.8	56.2	58.0	60.6	63.1	66.5	69.4	73.1	75.9	80.7	85.0	88.8	92.5
Real	49.0	46.8	45.0	44.1	43.5	42.9	42.2	41.9	41.5	41.3	41.7	41.8	42.5	42.6	43.1	42.9	43.8	44.3	44.5	44.6
Average Growth																				
Nominal	3.40%																			
Real	-0.50%																			

Study
Merged System
Resource & Market Planning
High Case/First Run

Average Megawatts	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements																				
Merged System Load	4,913.9	4,996.4	5,185.6	5,418.3	5,556.9	5,691.4	5,893.9	6,011.0	6,127.5	6,259.8	6,414.0	6,572.1	6,732.7	6,895.6	7,047.4	7,208.6	7,371.9	7,551.7	7,736.2	7,923.3
Black Hills	37.5	45.0	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
P G & E	28.5	28.5	28.5	28.5	28.5	28.5	28.5	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
Puget Power	27.5	27.5	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power II	60.0	60.0	85.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	120.1	85.6	0.0	0.0	0.0	0.0	0.0
So Cal Edison	161.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	80.8	0.0	0.0
SMUD	0.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
WIDCO Sale	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9	6.8	6.8	6.8	6.9
Nevada	0.0	61.2	82.5	82.4	82.5	82.5	82.5	82.4	82.5	82.5	21.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra Pacific	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8
Seirra Pacific II	10.3	38.0	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5
IPP Layoff to LA	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1
IPP Banked Recall	7.5	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	0.0	0.0	0.0	0.0	0.0
South Idaho Exchange - UPL	30.1	41.0	41.0	41.1	41.0	41.0	41.0	41.1	41.0	41.0	41.0	41.1	41.0	41.0	41.0	41.1	41.0	41.0	41.0	41.1
Total	5,397.1	5,566.5	5,812.5	6,064.1	6,202.8	6,337.3	6,539.8	6,628.3	6,744.8	6,877.1	6,917.7	7,054.5	7,215.0	7,378.0	7,495.3	7,570.9	7,734.2	7,886.8	7,990.5	8,177.7
Resources																				
Pacific System Hydro	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8	388.8
Utah System Hydro	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5	45.5
Black Hills Energy Purchase	6.2	3.1	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
Canadian Entitlement	-8.2	-7.6	-6.9	-6.4	-6.0	-5.5	-5.2	-5.0	-4.8	-4.2	-2.5	-2.0	-1.9	-1.9	-0.5	0.0	0.0	0.0	0.0	0.0
CSPE	34.1	32.3	31.4	30.1	28.9	27.6	26.5	25.2	24.2	21.8	12.8	9.8	9.4	9.1	2.3	0.0	0.0	0.0	0.0	0.0
Hanford WNP #1	68.0	68.0	68.0	68.0	68.0	68.0	68.0	30.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid Columbia	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	182.6	178.3	127.3	127.3	127.4
Miscellaneous Purchases	5.7	5.7	3.0	-4.3	7.1	18.5	18.5	16.2	16.2	16.2	16.2	15.1	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Pelton Rereg	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Q.F. Contracts - PP&L	67.1	74.8	74.9	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3	75.3
Widco Purchase	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3	-6.3
QF Contracts - UP&L	34.2	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5	73.5
Gem State	6.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
GSLM	2.0	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
IPP	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1	42.2	42.2	42.2	42.1
WAPA Capacity Exchange	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8	5.9	5.9	5.9	5.8
MPC Purchase	0.0	15.0	15.0	15.0	10.0	10.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WWP Purchase	44.1	50.0	50.0	50.0	50.0	50.0	50.0	38.0	17.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Idaho Exchange - PPL	31.0	42.2	42.2	42.3	42.2	42.2	42.2	42.3	42.2	42.2	42.2	42.3	42.2	42.2	42.2	42.3	42.2	42.2	42.2	42.3
South Idaho Exchange 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	0.0	0.0	0.0
BPA Settlement	0.0	0.0	0.0	65.2	62.9	66.9	64.9	65.2	64.9	64.9	64.9	65.2	64.9	64.9	64.9	65.2	64.9	64.9	64.9	65.2
Flush Purchase	0.0	0.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Hydro Efficiency	0.0	1.0	2.0	3.0	4.0	5.0	6.0	7.0	8.0	9.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
BPA NR Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	100.0	100.0	100.0	100.0	200.0	200.0
SCE Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.0	72.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	81.0	0.0	0.0
Off Peak Purchase 1-utah	0.0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Seasonal Purchase	0.0	0.0	0.0	0.0	41.7	41.7	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3
Seasonal Purchase-utah	0.0	0.0	0.0	0.0	41.7	41.7	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3	83.3
Cogen Ownership	0.0	0.0	20.0	40.0	60.0	80.0	100.0	120.0	140.0	160.0	180.0	200.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0
Cogeneration Purchase	0.0	0.0	0.0	10.0	20.0	30.0	40.0	50.0	60.0	70.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Cogeneration Purchase-utah	0.0	0.0	0.0	10.0	20.0	30.0	40.0	50.0	60.0	70.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Canadian Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	108.0	108.0	108.0	108.0	108.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0	216.0
Voltage Regulation 1	0.0	2.0	4.0	6.0	8.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Voltage Regulation 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	5.0	7.5	10.0	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Voltage Regulation 2-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	5.0	7.5	10.0	12.5	12.5	12.5	12.5	12.5	12.5	12.5
New Appliances Lost Opp	0.0	0.1	0.1	0.2	0.3	0.5	1.1	1.9	4.1	6.1	8.4	10.5	13.9	14.4	15.9	16.4	17.2	17.7	18.5	19.1
New Appliances Lost Opp-utah	0.0	0.0	0.1	0.1	0.1	0.2	0.5	0.9	1.9	2.8	3.9	4.9	6.4	6.7	7.4	7.6	8.0	8.2	8.6	8.9
Light and Water Heater Appliance	0.0	0.0	0.0	0.0	0.0	0.6	1.9	3.7	5.6	7.6	9.4	10.5	11.4	11.4	11.4	11.4	11.4	11.4	11.4	11.4
Light and Water Heater Appliance-utah	0.0	0.0	0.0	0.0	0.0	0.2	0.6	1.2	1.8	2.5	3.0	3.4	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Commercial Retrofit	0.2	0.5	1.1	1.8	3.5	7.2	14.5	21.9	29.3	36.6	44.0	47.7	47.7	47.7	47.7	47.7	47.7	47.7	47.7	47.7
Commercial Retrofit-utah	0.1	0.3	0.7	1.0	2.1	4.3	8.7	13.0	17.4	21.8	26.2	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4
Utah MCS Lost Opp-utah	0.0	0.4	2.0	4.2	7.1	10.1	11.8	13.8	15.9	18.1	20.7	24.6	29.4	34.4	39.6	44.9	51.2	57.5	64.3	71.4
Commercial Lost Opp	0.0	0.0	0.3	0.7	1.4	2.5	4.9	7.3	9.6	11.9	14.4	17.1	19.9	22.8	25.7	28.4	31.2	33.9	36.7	39.7
Commercial Lost Opp-utah	0.0	0.0	0.1	0.3	0.5	0.9	1.7	2.6	3.4	4.3	5.2	6.1	7.1	8.2	9.2	10.2	11.2	12.2	13.2	14.2
Industrial Lost Opp	0.0	0.3	1.2	2.1	2.9	3.8	6.2	9.2	12.7	16.9	21.6	26.9	32.8	39.3	46.4	54.1	62.4	71.3	80.2	89.1
Industrial Lost Opp-utah	0.0	0.2	0.9	1.5	2.2	2.8	4.6	6.8	9.4	12.5	16.0	20.0	24.4	29.2	34.5	40.2	46.3	52.9	59.5	66.1
Utah Code Lost Opp-utah	0.0	0.1	0.3	0.7	1.1	1.7	2.4	3.0	3.7	4.3	5.1	5.9	6.7	7.6	8.4	9.3	10.1	11.0	12.0	12.9
Wind Farm	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Mobile Home MCS Lost Opp	0.0	0.0	0.0	0.0	0.0	0.0	2.1	3.8	5.8	8.0	10.3	13.0	15.5	18.1	20.5	22.5	24.9	27.3	29.8	32.5
Mobile Home MCS Lost Opp-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.6	0.9	1.3	1.7	2.1	2.5	3.0	3.3	3.7	4.0	4.4	4.9	5.3
Residential Retro	0.6	1.5	3.2	5.6	8.9	10.1	12.6	17.6	25.9	38.2	50.0	57.4	58.6	58.3	58.3	58.3	58.3	58.3	58.3	58.3
Residential Retro-utah	0.1	0.2	0.4	0.7	1.1	1.2	1.5	2.2	3.2	4.7	6.1	7.0	7.2	7.1	7.1	7.1	7.1	7.1	7.1	7.1
New Peak Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transmission and Distribution Improvement	0.0	1.4	2.8	4.2	5.6	7.0	8.4	9.8	11.2	12.6	14.0	15.4	16.8	18.2	19.6	21.0	21.0	21.0	21.0	21.0

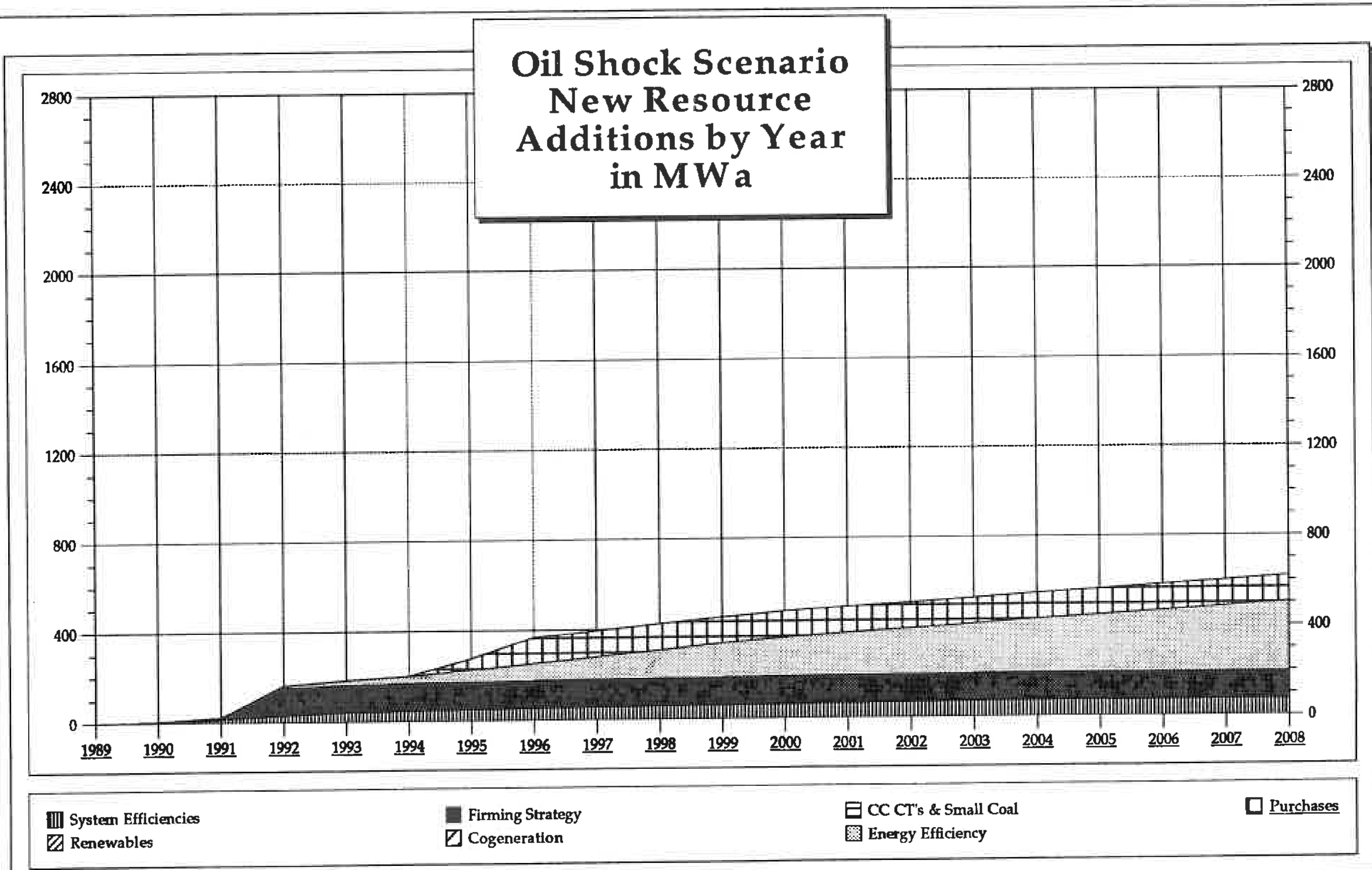
Transmission and Distribution Improvement	0.0	0.6	1.2	1.8	2.4	3.0	3.6	4.2	4.8	5.4	6.0	6.6	7.2	7.8	8.4	9.0	9.0	9.0	9.0	9.0
Centralia	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0	573.0
Dave Johnston	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8	674.8
Jim Bridger	1,193.0	1,204.4	1,212.1	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0	1,221.0
Wyodak	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	238.7	474.9	474.9	474.9
Colstrip	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5	102.5
Carbon	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4	136.4
Naughton	540.6	540.6	547.5	554.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4	561.4
Huntington	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0	681.0
Hunter	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2	846.2
Blundell	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Gadsby	0.0	0.0	32.8	66.7	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5	118.5
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0	45.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	125.0	125.0	125.0	125.0	125.0	125.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	125.0	125.0	125.0	125.0	125.0
CT Three	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	125.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0	38.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.0	38.0	38.0	38.0
Trojan	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7	22.7
Total	5,989.7	6,084.2	6,282.4	6,493.1	6,696.0	6,770.3	6,923.1	7,126.8	7,194.3	7,306.3	7,395.4	7,458.5	7,655.0	7,824.5	7,973.2	8,000.1	8,187.7	8,375.9	8,426.1	8,583.0
Thermal Maintenance																				
Centralia	58.1	46.8	47.1	63.9	47.1	36.1	47.1	62.8	47.1	64.1	47.1	57.9	46.8	47.1	64.1	46.9	36.1	47.1	63.0	46.9
Dave Johnston	40.0	47.8	59.2	47.7	75.0	53.5	53.6	47.7	59.2	47.8	58.4	52.4	59.2	47.8	47.8	74.8	53.5	53.6	59.2	47.7
Jim Bridger	106.3	121.5	122.4	97.6	111.7	106.3	111.1	117.4	111.5	105.3	116.9	109.2	123.5	124.3	97.9	111.4	106.3	111.1	117.7	111.2
Wyodak	19.6	19.6	15.0	33.3	15.0	19.6	15.0	19.6	15.0	28.8	15.0	19.6	19.6	15.0	33.4	15.0	19.6	29.9	39.0	29.8
Colstrip	8.7	8.4	8.4	8.4	8.4	8.4	8.4	6.2	8.4	8.4	8.4	8.7	8.4	8.4	8.4	8.4	8.4	8.4	6.2	8.4
Carbon	8.8	5.3	16.7	8.2	4.2	6.2	14.7	4.2	12.4	10.5	4.2	6.2	14.7	4.2	12.4	10.4	4.2	6.2	14.7	4.2
Naughton	43.6	22.8	41.2	30.1	29.0	32.6	35.9	28.0	42.7	40.8	22.8	42.6	40.8	22.8	42.7	40.7	22.8	42.7	40.8	22.8
Huntington	27.3	52.2	38.9	39.3	78.4	25.9	26.3	52.1	25.9	26.3	78.4	25.9	26.3	52.2	25.9	26.2	78.4	25.9	26.3	52.1
Hunter	87.6	64.9	72.2	89.8	64.9	64.9	72.2	89.8	79.5	64.9	72.2	64.7	72.2	90.1	79.5	64.7	72.2	64.9	72.2	89.8
Blundell	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Three	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	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	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Geothermal Two	0.0	0.0	0.0	0.0	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	2.2	2.2	2.2
Trojan	4.4	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	4.3	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Total	405.4	394.4	426.1	421.3	438.8	358.7	389.4	432.7	406.9	401.9	428.4	392.5	418.8	419.2	419.4	405.8	411.0	399.3	448.6	422.3
Balance	187.2	123.3	43.7	7.7	54.5	74.3	-6.1	65.8	42.5	27.3	49.3	11.5	21.1	27.3	58.5	23.4	42.5	89.8	-13.0	-16.9

Study
Merged System
Resource & Market Planning
High Case/First Run

January Peak	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements																				
Merged System Load	6,518.0	6,752.0	6,982.0	7,217.0	7,419.0	7,598.0	7,778.0	7,932.0	8,087.0	8,266.0	8,475.0	8,693.0	8,913.0	9,132.0	9,337.0	9,553.0	9,778.0	10,024.0	10,277.0	10,534.0
Black Hills	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
P G & E	100.0	100.0	100.0	100.0	100.0	100.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power	55.0	55.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Puget Power II	100.0	100.0	100.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	0.0	0.0	0.0	0.0	0.0
So Cal Edison	298.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	0.0	0.0
SMUD	0.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Nevada	0.0	0.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sierra Pacific	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Seirra Pacific II	0.0	25.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Total	7,198.0	7,459.0	7,791.0	8,071.0	8,273.0	8,452.0	8,632.0	8,686.0	8,841.0	9,020.0	9,154.0	9,320.0	9,540.0	9,759.0	9,964.0	9,980.0	10,205.0	10,451.0	10,504.0	10,761.0
Resources																				
Pacific System Hydro	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5	880.5
Utah System Hydro	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
Black Hills Capacity	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
BPA Entitlement Capacity	28.7	28.6	28.7	26.0	23.4	20.9	18.3	15.5	12.9	12.4	10.8	5.1	4.8	4.7	4.1	0.0	0.0	0.0	0.0	0.0
BPA Peak Purchase	1,127.3	1,127.3	1,127.3	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	0.0
BPA Supplemental Capacity	27.0	27.0	27.1	24.5	22.0	19.7	17.2	14.7	12.1	11.7	10.2	4.8	4.5	4.4	3.8	0.0	0.0	0.0	0.0	0.0
Canadian Entitlement	-28.7	-28.6	-28.7	-26.0	-23.4	-20.9	-18.3	-15.5	-12.9	-12.4	-10.8	-5.1	-4.8	-4.7	-4.1	0.0	0.0	0.0	0.0	0.0
CSPE	95.6	96.1	96.5	93.2	79.7	71.3	62.9	54.4	45.9	44.5	39.3	18.9	18.1	17.7	15.8	0.0	0.0	0.0	0.0	0.0
Hanford WNP #1	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid Columbia	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	351.5	242.3	242.3	242.3
Miscellaneous Purchases	142.7	142.7	142.7	128.7	128.7	26.0	26.0	21.0	21.0	21.0	21.0	21.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Pelton Rereg	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6	19.6
Q.F. Contracts - PP&L	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0
QF Contracts - UP&L	38.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0	98.0
Gem State	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GSLM	0.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
MPC Purchase	0.0	15.0	15.0	15.0	10.0	10.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WWP Purchase	50.0	50.0	150.0	150.0	150.0	150.0	150.0	100.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BPA Settlement	0.0	0.0	0.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0	164.0
Flush Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro Efficiency	0.0	2.0	4.0	6.0	8.0	10.0	12.0	14.0	16.0	18.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
BPA NR Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	135.0	135.0	135.0	135.0	135.0	270.0	270.0
SCE Energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Off Peak Purchase 1-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Seasonal Purchase	0.0	0.0	0.0	0.0	100.0	100.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Seasonal Purchase-utah	0.0	0.0	0.0	0.0	100.0	100.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Cogen Ownership	0.0	0.0	20.0	40.0	60.0	80.0	100.0	120.0	140.0	160.0	180.0	200.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0	220.0
Cogeneration Purchase	0.0	0.0	0.0	10.0	20.0	30.0	40.0	50.0	60.0	70.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Cogeneration Purchase-utah	0.0	0.0	0.0	10.0	20.0	30.0	40.0	50.0	60.0	70.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Canadian Purchase	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0	200.0	200.0	200.0	200.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0	400.0
Voltage Regulation 1	0.0	4.0	8.0	12.0	16.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Voltage Regulation 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0	10.0	15.0	20.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Voltage Regulation 2-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0	10.0	15.0	20.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
New Appliances Lost Opp	0.0	0.1	0.1	0.2	0.3	0.5	1.1	1.9	4.1	6.1	8.4	10.5	13.9	14.4	15.9	16.4	17.2	17.7	18.5	19.1
New Appliances Lost Opp-utah	0.0	0.0	0.1	0.1	0.1	0.2	0.5	0.9	1.9	2.8	3.9	4.9	6.4	6.7	7.4	7.6	8.0	8.2	8.6	8.9
Light and Water Heater Appliance	0.0	0.0	0.0	0.0	0.0	0.2	0.6	1.5	2.6	3.7	4.5	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Light and Water Heater Appliance-utah	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.5	0.8	1.2	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Commercial Retrofit	0.3	1.0	2.3	3.5	7.0	14.5	29.3	44.2	59.1	74.0	88.8	96.3	96.3	96.3	96.3	96.3	96.3	96.3	96.3	96.3
Commercial Retrofit-utah	0.2	0.6	1.3	2.1	4.2	8.6	17.5	26.3	35.2	44.0	52.9	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3	57.3
Utah MCS Lost Opp-utah	0.0	0.4	1.9	3.9	6.6	9.4	11.0	12.9	14.9	17.0	19.5	23.1	27.6	32.3	37.2	42.2	48.1	54.1	60.5	67.1
Commercial Lost Opp	0.0	0.0	0.7	2.1	4.2	7.4	14.3	21.0	27.7	34.3	41.3	48.7	56.5	64.3	72.0	79.5	86.9	94.5	102.2	110.2
Commercial Lost Opp-utah	0.0	0.0	0.3	0.8	1.5	2.7	5.1	7.5	9.9	12.3	14.8	17.5	20.3	23.1	25.8	28.5	31.2	33.9	36.7	39.5
Industrial Lost Opp	0.0	0.3	1.2	2.1	2.9	3.8	6.2	9.2	12.7	16.9	21.8	26.9	32.8	39.3	46.4	54.1	62.4	71.3	80.2	89.1
Industrial Lost Opp-utah	0.0	0.2	0.9	1.5	2.2	2.8	4.6	6.8	9.4	12.5	16.0	20.0	24.4	29.2	34.5	40.2	46.3	52.9	59.5	66.1
Utah Code Lost Opp-utah	0.0	0.2	0.7	1.4	2.3	3.5	4.7	6.0	7.3	8.7	10.2	11.7	13.4	15.1	16.8	18.5	20.3	22.1	23.9	25.8
Wind Farm	0.0	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	20.0	20.0	20.0	20.0	20.0	20.0
Mobile Home MCS Lost Opp	0.0	0.0	0.0	0.0	0.0	0.0	1.5	1.4	1.6	1.7	1.8	2.1	2.2	2.2	2.0	1.9	2.0	2.1	2.3	2.4
Mobile Home MCS Lost Opp-utah	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.3	0.3	0.3	0.3	0.4	0.4
Residential Retro	1.1	2.4	4.5	7.2	10.7	14.2	19.7	30.6	48.4	74.8	99.7	114.7	116.5	115.7	115.7	115.7	115.7	115.7	115.7	115.7
Residential Retro-utah	0.1	0.3	0.6	0.9	1.3	1.7	2.4	3.7	5.9	9.2	12.2	14.0	14.3	14.2	14.2	14.2	14.2	14.2	14.2	14.2
New Peak Purchase	0.0	0.0	0.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0	1,000.0
Transmission and Distribution Improvement	0.0	1.4	2.8	4.2	5.6	7.0	8.4	9.8	11.2	12.6	14.0	15.4	16.8	18.2	19.6	21.0	21.0	21.0	21.0	21.0
Transmission and Distribution Improvement	0.0	0.6	1.2	1.8	2.4	3.0	3.6	4.2	4.8	5.4	6.0	6.6	7.2	7.8	8.4	9.0	9.0	9.0	9.0	9.0
Centralia	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0	608.0
Dave Johnston	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0	750.0
Jim Bridger	1,360.7	1,366.0	1,371.4	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7	1,376.7
Wyodak	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	252.0	567.2	567.2	567.2
Colstrip	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0

Carbon	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0	166.0
Naughton	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0	700.0
Huntington	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0	815.0
Hunter	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0	1,001.0
Blundell	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Gadsby	0.0	0.0	62.0	126.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0	224.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	250.0	250.0	250.0	250.0	250.0	250.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	250.0	250.0	250.0	250.0
CT Three	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	250.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0	50.0
Trojan	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0	27.0
Total	8,939.7	9,047.3	9,252.0	9,397.5	9,740.1	9,700.8	9,983.3	10,292.0	10,262.1	10,341.9	10,467.0	10,530.2	10,827.1	11,021.9	11,302.7	11,316.1	11,649.4	11,889.9	12,060.6	12,346.5
Thermal Maintenance																				
Centralia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dave Johnston	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Jim Bridger	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wyodak	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Colstrip	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Carbon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Naughton	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Huntington	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hunter	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Blundell	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gadsby	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro Firming	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CT Three	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal One	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Geothermal Two	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Trojan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reserve Requirement																				
Reserve	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0	1,013.0
(Reserve+Balance)/Requirements	24%	21%	19%	16%	18%	15%	16%	18%	16%	15%	14%	13%	13%	13%	13%	13%	14%	14%	15%	15%
Balance	728.7	575.3	448.0	313.5	454.1	235.8	338.3	593.0	408.1	308.9	300.0	197.2	274.1	249.9	325.7	323.1	431.4	425.9	543.6	572.5

Oil Shock Scenario



	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiencies	0	5	17	29	41	46	49	52	55	58	61	63	65	67	69	71	71	71	71	71
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firming Strategy	0	0	0	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Cogeneration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC CT's & Small Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	0	2	6	10	17	29	52	76	101	124	150	171	189	204	221	236	253	271	289	307
Purchases	0	0	0	0	0	0	50	115	113	117	115	115	115	115	115	115	115	115	115	115
Totals	0	7	23	164	183	200	276	368	393	424	451	474	494	510	530	547	564	582	600	618

KEY OUTPUTS

Oil Shock Scenario

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Load (MWa)	4847.0	4829.0	4934.0	5065.0	5137.0	5219.0	5344.0	5393.0	5382.0	5380.0	5400.0	5433.0	5474.0	5517.0	5555.0	5603.0	5651.0	5711.0	5767.0	5819.0
Total Conservation	1.0	5.4	13.3	22.4	34.9	49.9	75.5	104.0	136.1	171.5	209.0	237.3	257.0	271.9	289.0	304.5	321.6	339.3	357.6	375.6
System Load net of Conservation	4846.0	4823.6	4920.7	5042.6	5102.1	5169.1	5268.5	5289.0	5245.9	5208.5	5191.0	5195.7	5217.0	5245.1	5266.0	5298.5	5329.4	5371.7	5409.4	5443.4
Energy Sales after Conservation	4361.4	4341.2	4428.6	4538.3	4591.9	4652.2	4741.7	4760.1	4721.3	4687.7	4671.9	4676.1	4695.3	4720.6	4739.4	4768.7	4796.5	4834.5	4868.5	4899.1
Total Customers (000's)	1,235	1,248	1,263	1,279	1,295	1,312	1,323	1,335	1,347	1,359	1,370	1,385	1,403	1,425	1,449	1,472	1,501	1,531	1,564	1,599
Net Electric Plant (M$)	5289.9	5482.6	5622.3	5722.9	5797.9	5820.1	5894.7	6009.2	6165.1	6380.8	6608.4	6780.1	6861.6	6924.8	6995.1	7080.8	7171.9	7287.8	7418.8	7574.8
Net Conservation Assets	6.5	17.7	40.5	70.8	115.0	168.7	253.6	372.3	525.7	726.6	931.3	1070.5	1109.2	1116.7	1118.7	1122.7	1127.4	1139.7	1150.0	1164.4
General Inflation Rate	3.90%	4.58%	4.82%	4.77%	5.04%	5.19%	5.37%	5.52%	5.49%	5.58%	5.47%	5.63%	5.44%	5.41%	5.33%	5.28%	5.24%	5.26%	5.23%	5.27%
Operating Revenues (M$)																				
Nominal	1886.7	1882.1	1941.2	2048.9	2127.0	2205.9	2303.2	2366.4	2418.2	2487.6	2608.9	2732.3	2836.1	2937.5	3038.2	3152.7	3277.5	3430.1	3636.6	3820.3
Real	1886.7	1799.7	1770.8	1784.0	1763.2	1738.3	1722.5	1677.2	1624.7	1583.0	1574.1	1560.7	1536.4	1509.6	1482.4	1461.1	1443.3	1435.0	1445.8	1442.8
NPV (11.47% discount rate)	20130.4																			
Average Growth																				
Nominal	3.78%																			
Real	-1.40%																			
Base Unit Cost (mills/kwh)																				
Nominal	49.4	49.5	50.0	51.4	52.9	54.1	55.4	56.6	58.5	60.6	63.7	66.5	69.0	71.0	73.2	75.3	78.0	81.0	85.3	88.8
Real	49.4	47.3	45.6	44.8	43.8	42.7	41.5	40.1	39.3	38.5	38.5	38.0	37.4	36.5	35.7	34.9	34.4	33.9	33.9	33.5
Average Growth																				
Nominal	3.13%																			
Real	-2.02%																			
Average Customer Bill ($)																				
Nominal	1528.0	1508.3	1537.2	1602.1	1642.0	1681.7	1740.9	1773.3	1795.8	1831.0	1904.2	1973.0	2021.1	2061.2	2097.5	2141.8	2184.3	2240.7	2324.6	2388.6
Real	1528.0	1442.2	1402.3	1394.9	1361.1	1325.2	1301.9	1256.8	1206.5	1165.1	1148.9	1126.9	1094.9	1059.3	1023.4	992.6	961.9	937.4	924.2	902.1
NPV (11.47% discount rate)	15036.2																			
Customer Cost (M$)	0.0	0.2	0.6	0.8	1.1	1.8	17.1	7.5	1.1	2.4	5.0	9.8	15.7	19.6	19.4	17.5	21.5	25.4	28.4	29.9
Levelized Customer Cost (M$)																				
(30 years at a 13.47% discount rate)	0.0	0.0	0.1	0.2	0.4	0.6	3.0	4.0	4.2	4.5	5.2	6.5	8.7	11.4	14.1	16.5	19.4	22.9	26.9	31.0
NPV (11.47% discount rate)	37.7																			
Energy Services Charge (M$)	0.1	0.7	2.2	4.6	8.3	11.9	18.3	27.4	39.5	55.6	73.7	90.5	104.1	117.2	130.3	143.7	156.2	166.9	173.6	176.2
NPV (11.47% discount rate)	344.6																			
Total Resource Cost (M$)																				
Nominal	1886.8	1882.9	1943.5	2053.7	2135.7	2218.4	2324.5	2397.8	2461.9	2547.6	2687.8	2829.4	2948.9	3066.1	3182.5	3312.9	3453.2	3619.9	3837.0	4027.5
Real	1886.8	1800.4	1772.9	1788.2	1770.4	1748.2	1738.4	1699.4	1654.0	1621.2	1621.7	1616.1	1597.5	1575.7	1552.8	1535.3	1520.7	1514.4	1525.5	1521.0
NPV (11.47% discount rate)	20512.7																			
Average Growth																				
Nominal	4.07%																			
Real	-1.13%																			
Mills / KWh																				
Nominal	49.4	49.5	50.0	51.3	52.7	53.9	55.2	56.2	58.0	60.1	63.1	65.9	68.3	70.5	72.7	74.8	77.5	80.4	84.4	87.5
Real	49.4	47.3	45.6	44.7	43.7	42.5	41.3	39.9	39.0	38.2	38.1	37.6	37.0	36.2	35.5	34.7	34.1	33.6	33.6	33.1
Average Growth																				
Nominal	3.06%																			
Real	-2.09%																			

Merged System
Resource & Market Planning
Oil Shock Scenario

Average Megawatts	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements																				
Merged System Load	4,847	4,829	4,934	5,065	5,137	5,219	5,344	5,393	5,382	5,380	5,400	5,433	5,474	5,517	5,555	5,603	5,651	5,711	5,767	5,819
Black Hills	38	45	53	53	53	53	53	53	53	53	0	0	0	0	0	0	0	0	0	0
P G & E	29	29	29	29	29	29	29	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power	28	28	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power II	60	60	85	120	120	120	120	120	120	120	120	120	120	120	86	0	0	0	0	0
So Cal Edison	161	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	81	0	0
SMUD	0	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
WIDCO Sale	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Nevada	0	61	82	82	82	82	82	82	82	82	21	0	0	0	0	0	0	0	0	0
Sierra Pacific	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Seirra Pacific II	10	38	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
IPP Layoff to LA	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
IPP Banked Recall	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
South Idaho Exchange - UPL	30	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41
Total	5,331	5,399	5,561	5,710	5,783	5,865	5,990	6,010	6,000	5,997	5,904	5,915	5,956	5,999	6,003	5,965	6,013	6,046	6,021	6,073
Resources																				
Pacific System Hydro	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389
Utah System Hydro	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
Black Hills Energy Purchase	6	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Canadian Entitlement	-8	-8	-7	-6	-6	-6	-5	-5	-5	-4	-2	-2	-2	-2	0	0	0	0	0	0
CSPE	34	32	31	30	29	28	26	25	24	22	13	10	9	9	2	0	0	0	0	0
Hanford WNP #1	68	68	68	68	68	68	68	31	0	0	0	0	0	0	0	0	0	0	0	0
Mid Columbia	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	178	127	127	127
Miscellaneous Purchases	6	6	3	-4	7	19	19	16	16	16	16	15	9	9	9	9	9	9	9	9
Pelton Rereg	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Q.F. Contracts - PP&L	67	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Widco Purchase	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6
QF Contracts - UP&L	34	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
Gem State	7	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
GSLM	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
IPP	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
WAPA Capacity Exchange	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
MPC Purchase	0	15	15	15	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0
WWP Purchase	44	50	50	50	50	50	50	38	17	0	0	0	0	0	0	0	0	0	0	0
South Idaho Exchange - PPL	31	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
South Idaho Exchange Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flush Purchase	0	0	0	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
BPA Settlement	0	0	0	0	0	0	0	65	63	67	65	65	65	65	65	65	65	65	65	65
Hydro Efficiency	0	1	2	3	4	5	6	7	8	9	10	10	10	10	10	10	10	10	10	10
Transmission and Distribution Improvement	0	1	3	4	6	7	8	10	11	13	14	15	17	18	20	21	21	21	21	21
New Peak Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Off Peak Purchase 1-utah	0	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Voltage Regulation 1	0	2	4	6	8	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
New Appliances Lost Opp	0	0	0	0	0	0	1	2	3	5	6	8	10	11	12	12	12	12	12	12
New Appliances Lost Opp-utah	0	0	0	0	0	0	1	1	2	3	5	6	8	8	9	9	9	9	9	9
Light and Water Heater Appliance	0	0	0	0	0	1	2	4	6	8	10	11	12	12	12	12	12	12	12	12
Light and Water Heater Appliance-utah	0	0	0	0	0	0	0	1	1	2	2	2	2	2	2	2	2	2	2	2
Commercial Retrofit	0	1	1	2	4	7	15	22	29	37	44	48	48	48	48	48	48	48	48	48
Commercial Retrofit-utah	0	0	1	1	2	4	9	13	17	22	26	28	28	28	28	28	28	28	28	28
Utah MCS Lost Opp-utah	0	0	1	2	3	5	6	7	7	7	8	8	10	11	13	14	16	18	20	22
Commercial Lost Opp	0	0	0	1	1	2	4	6	7	7	8	9	10	11	13	14	15	16	17	18
Commercial Lost Opp-utah	0	0	0	0	0	1	1	2	2	3	3	3	4	4	4	5	5	6	6	6
Industrial Lost Opp	0	0	1	2	2	3	5	7	9	12	16	19	24	28	33	39	45	51	57	64
Industrial Lost Opp-utah	0	0	1	2	3	4	5	8	11	14	18	22	27	32	37	43	50	57	64	71

Utah Code Lost Opp-utah	0	0	0	1	1	1	2	2	3	3	4	4	4	5	5	6	6	7	7	8
Mobile Home MCS Lost Opp	0	0	0	0	0	0	1	1	1	2	2	2	3	3	4	4	5	6	6	7
Mobile Home MCS Lost Opp-utah	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1
Residential Retro	1	2	3	6	9	10	11	12	12	13	14	15	16	16	17	18	19	20	20	21
Residential Retro-utah	0	0	0	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	3
Transmission and Distribution Improvement	0	1	1	2	2	3	4	4	5	5	6	7	7	8	8	9	9	9	9	9
Centralia	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573
Dave Johnston	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675
Jim Bridger	1,193	1,204	1,212	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221
Wyodak	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239
Colstrip	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102
Carbon	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136
Naughton	541	541	548	554	561	561	561	561	561	561	561	561	561	561	561	561	561	561	561	561
Huntington	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681
Hunter	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846
Blundell	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Gadsby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Firming	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trojan	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Total	5,990	6,084	6,104	6,249	6,277	6,306	6,382	6,412	6,386	6,399	6,419	6,440	6,454	6,471	6,486	6,503	6,516	6,484	6,503	6,522
Net before maintenance	659	685	543	538	494	441	392	402	386	402	515	524	497	472	483	537	503	437	482	449
Thermal Maintenance																				
Centralia	58	47	47	64	47	36	47	63	47	64	47	58	47	47	64	47	36	47	63	47
Dave Johnston	40	48	59	48	75	54	54	48	59	48	58	52	59	48	48	75	54	54	59	48
Jim Bridger	106	121	122	98	112	106	111	117	111	105	117	109	124	124	98	111	106	111	118	111
Wyodak	20	20	15	33	15	20	15	20	15	29	15	20	20	15	33	15	20	15	20	15
Colstrip	9	8	8	8	8	8	8	6	8	8	8	9	8	8	8	8	8	8	6	8
Carbon	9	5	17	6	4	6	15	4	12	10	4	6	15	4	12	10	4	6	15	4
Naughton	44	23	41	30	29	33	36	28	43	41	23	43	41	23	43	41	23	43	41	23
Huntington	27	52	39	39	78	26	26	52	26	26	78	26	26	52	26	26	78	26	26	52
Hunter	88	65	72	90	65	65	72	90	80	65	72	65	72	90	80	65	72	65	72	90
Blundell	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Gadsby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Firming	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trojan	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Total	405	394	426	421	439	359	389	433	407	402	428	393	417	417	417	404	407	380	425	403
Balance	254	290	117	117	55	82	3	-30	-21	0	87	132	81	55	66	134	96	57	57	46

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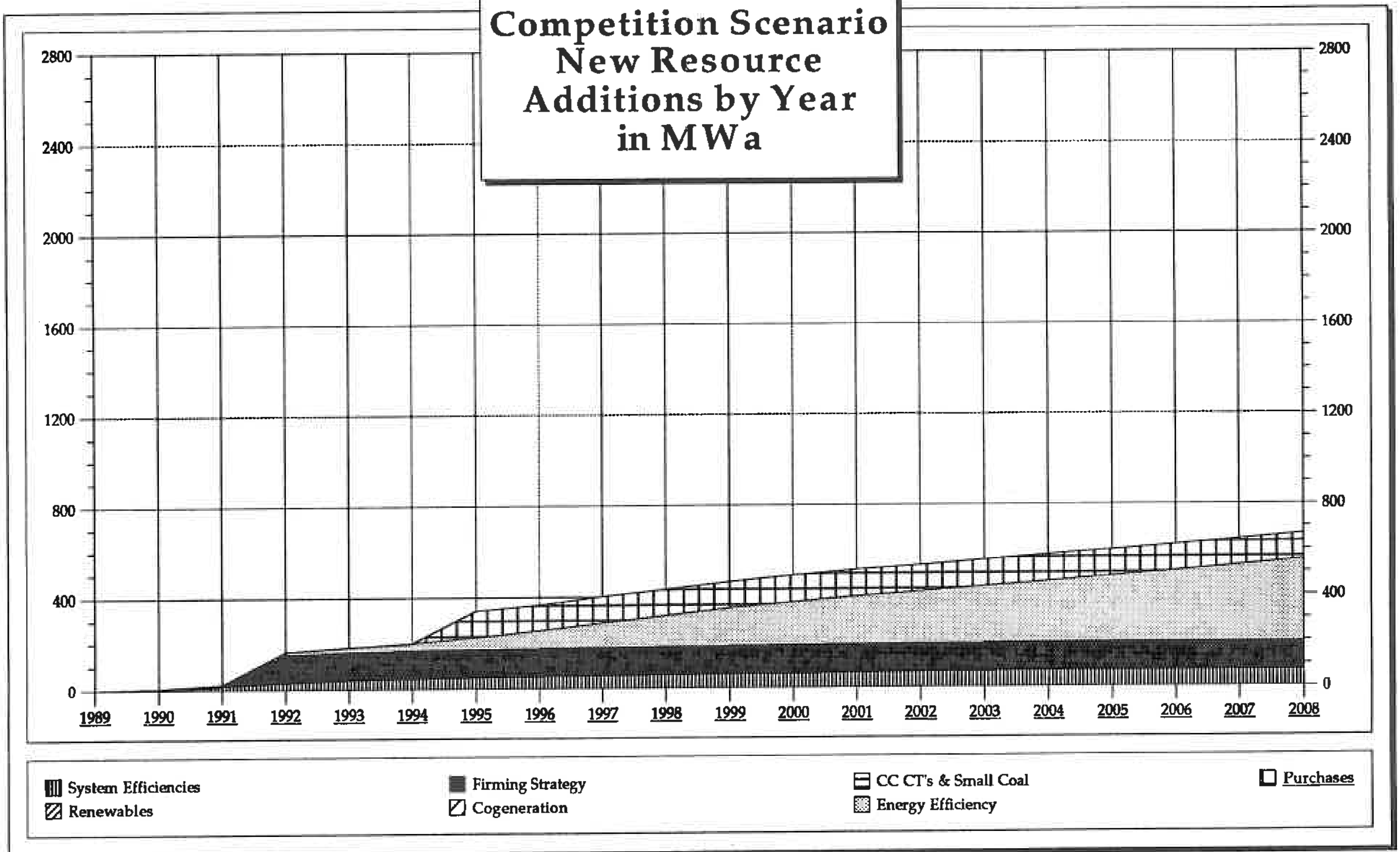
Merged System
Resource & Market Planning
Oil Shock Scenario

January Peak	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements																				
Merged System Load	6,440	6,502	6,609	6,695	6,802	6,906	6,985	7,047	7,021	7,013	7,036	7,077	7,127	7,182	7,230	7,289	7,355	7,434	7,506	7,574
Black Hills	75	75	75	75	75	75	75	75	75	75	0	0	0	0	0	0	0	0	0	0
P G & E	100	100	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power	55	55	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power II	100	100	100	200	200	200	200	200	200	200	200	200	200	200	200	0	0	0	0	0
So Cal Edison	298	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	0	0
SMUD	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Nevada	0	0	52	52	52	52	52	52	52	52	52	0	0	0	0	0	0	0	0	0
Sierra Pacific	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Seirra Pacific II	0	25	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Total	7,120	7,209	7,418	7,549	7,656	7,760	7,839	7,801	7,775	7,767	7,715	7,704	7,754	7,809	7,857	7,716	7,782	7,861	7,733	7,801
Resources																				
Pacific System Hydro	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881
Utah System Hydro	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Black Hills Capacity	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BPA Entitlement Capacity	29	29	29	26	23	21	18	16	13	12	11	5	5	5	4	0	0	0	0	0
BPA Peak Purchase	1,127	1,127	1,127	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BPA Supplemental Capacity	27	27	27	25	22	20	17	15	12	12	10	5	4	4	4	0	0	0	0	0
Canadian Entitlement	-29	-29	-29	-26	-23	-21	-18	-16	-13	-12	-11	-5	-5	-5	-4	0	0	0	0	0
CSPE	96	96	97	93	80	71	63	54	46	45	39	19	18	18	16	0	0	0	0	0
Hanford WNP #1	80	80	80	80	80	80	80	80	0	0	0	0	0	0	0	0	0	0	0	0
Mid Columbia	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	242	242	242
Miscellaneous Purchases	143	143	143	129	129	26	26	21	21	21	21	21	3	3	3	3	3	3	3	3
Pelton Rereg	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Q.F. Contracts - PP&L	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
QF Contracts - UP&L	38	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Gem State	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GSLM	0	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
MPC Purchase	0	15	15	15	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0
WWP Purchase	50	50	150	150	150	150	150	100	50	0	0	0	0	0	0	0	0	0	0	0
Flush Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BPA Settlement	0	0	0	0	0	0	0	164	164	164	164	164	164	164	164	164	164	164	164	164
Hydro Efficiency	0	2	4	6	8	10	12	14	16	18	20	20	20	20	20	20	20	20	20	20
Transmission and Distribution Improvement	0	1	3	4	6	7	8	10	11	13	14	15	17	18	20	21	21	21	21	21
New Peak Purchase	0	0	0	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Off Peak Purchase 1-utah	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Voltage Regulation 1	0	4	8	12	16	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
New Appliances Lost Opp	0	0	0	0	0	0	1	2	3	5	6	8	10	11	12	12	12	12	12	12
New Appliances Lost Opp-utah	0	0	0	0	0	0	1	1	2	3	5	6	8	8	9	9	9	9	9	9
Light and Water Heater Appliance	0	0	0	0	0	0	1	2	4	5	6	7	7	7	7	7	7	7	7	7
Light and Water Heater Appliance-utah	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1
Commercial Retrofit	0	1	2	4	7	14	29	44	59	74	89	96	96	96	96	96	96	96	96	96
Commercial Retrofit-utah	0	1	1	2	4	9	17	26	35	44	53	57	57	57	57	57	57	57	57	57
Utah MCS Lost Opp-utah	0	0	1	2	3	5	6	7	7	7	7	8	9	10	12	13	15	17	19	20
Commercial Lost Opp	0	0	1	2	4	7	13	19	23	26	30	34	38	42	46	51	55	59	63	68
Commercial Lost Opp-utah	0	0	0	1	1	3	5	7	8	9	10	12	13	15	16	18	19	21	22	24
Industrial Lost Opp	0	0	1	2	2	3	5	7	9	12	16	19	24	28	33	39	45	51	57	64
Industrial Lost Opp-utah	0	0	1	2	3	4	5	8	11	14	18	22	27	32	37	43	50	57	64	71
Utah Code Lost Opp-utah	0	0	1	1	2	3	4	5	6	6	7	8	9	10	11	12	13	14	15	16
Mobile Home MCS Lost Opp	0	0	0	0	0	0	1	0	0	0	0	0	1	1	1	0	1	1	1	1
Mobile Home MCS Lost Opp-utah	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Retro	1	2	4	7	11	14	16	17	19	21	22	24	25	27	29	30	32	33	35	37
Residential Retro-utah	0	0	1	1	1	2	2	2	2	2	3	3	3	3	3	4	4	4	4	4
Transmission and Distribution Improvement	0	1	1	2	2	3	4	4	5	5	6	7	7	8	8	9	9	9	9	9

Centralia	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608
Dave Johnston	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750
Jim Bridger	1,361	1,366	1,371	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377
Wyodak	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252
Colstrip	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140
Carbon	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Naughton	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700
Huntington	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815
Hunter	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001
Blundell	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Gadsby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Firming	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trojan	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Total	8,940	9,047	9,169	9,045	9,048	8,967	9,002	9,136	9,040	9,033	9,073	9,081	9,087	9,109	9,131	9,135	9,158	9,072	9,096	9,120
Thermal Maintenance																				
Centralia	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dave Johnston	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jim Bridger	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wyodak	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Colstrip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carbon	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Naughton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Huntington	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hunter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Blundell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gadsby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Firming	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trojan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reserve Requirement																				
Reserve	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013
(Reserve+Balance)/Requirements	26%	25%	24%	20%	18%	16%	15%	17%	16%	16%	18%	18%	17%	17%	16%	18%	18%	15%	18%	17%
Balance	807	825	738	483	379	194	150	322	252	253	345	364	320	287	261	406	363	198	350	306

Competition Scenario

Competition Scenario New Resource Additions by Year in MWa



	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiencies	0	5	17	29	41	46	49	52	55	58	61	63	65	67	69	71	71	71	71	71
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firming Strategy	0	0	0	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Cogeneration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC CT's & Small Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	0	2	6	10	17	29	53	78	106	135	164	188	210	227	247	266	287	310	333	356
Purchases	0	0	0	0	0	0	115	113	117	115	115	115	115	115	115	115	115	115	115	115
Totals	**0**	**7**	**23**	**164**	**183**	**200**	**341**	**368**	**403**	**432**	**465**	**491**	**514**	**534**	**555**	**577**	**598**	**620**	**644**	**667**

KEY OUTPUTS

Competition Scenario

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Load (MWa)	4861.0	4858.0	4969.0	5116.0	5192.0	5278.0	5289.0	5243.0	5186.0	5121.0	5053.0	5122.0	5191.0	5265.0	5336.0	5417.0	5503.0	5601.0	5697.0	5794.0
Total Conservation	1.0	5.5	13.4	22.6	35.3	50.4	74.7	100.7	129.9	159.4	189.9	214.9	237.2	255.6	275.8	295.9	318.4	341.6	365.8	389.6
System Load net of Conservation	4860.0	4852.5	4955.6	5093.4	5156.7	5227.6	5214.3	5142.3	5056.1	4961.6	4863.1	4907.1	4953.8	5009.4	5060.2	5121.1	5184.6	5259.4	5331.2	5404.4
Energy Sales after Conservation	4374.0	4367.3	4460.0	4584.1	4641.0	4704.8	4692.9	4628.1	4550.5	4465.4	4376.8	4416.4	4458.4	4508.5	4554.2	4609.0	4666.1	4733.5	4798.1	4864.0
Total Customers (000's)	1,235	1,248	1,263	1,279	1,295	1,312	1,323	1,335	1,347	1,359	1,370	1,385	1,403	1,425	1,449	1,472	1,501	1,531	1,564	1,599
Net Electric Plant (M$)	5289.9	5482.6	5622.4	5723.0	5803.0	5858.0	5941.8	6016.0	6102.2	6205.8	6318.8	6423.2	6513.5	6611.7	6715.6	6839.1	6969.4	7124.6	7295.6	7492.1
Net Conservation Assets	6.5	17.7	40.6	70.9	115.0	174.5	245.5	325.6	411.0	501.5	593.2	666.7	715.9	760.0	797.4	840.8	886.3	939.7	991.6	1048.2
General Inflation Rate	3.90%	4.58%	4.82%	4.77%	5.04%	5.19%	5.37%	5.52%	5.49%	5.58%	5.47%	5.63%	5.44%	5.41%	5.33%	5.28%	5.24%	5.26%	5.23%	5.27%
Operating Revenues (M$)																				
Nominal	1888.9	1883.2	1939.8	2046.1	2121.2	2199.7	2271.3	2318.8	2354.5	2399.9	2483.1	2591.2	2686.5	2797.1	2913.2	3061.1	3194.3	3384.3	3615.7	3832.0
Real	1888.9	1800.7	1769.5	1781.6	1758.4	1733.4	1698.6	1643.4	1581.9	1527.2	1498.2	1480.1	1455.4	1437.5	1421.4	1418.7	1406.6	1415.8	1437.5	1447.2
NPV (11.47% discount rate)	19795.7																			
Average Growth																				
Nominal	3.79%																			
Real	-1.39%																			
Base Unit Cost (mills/kwh)																				
Nominal	49.3	49.2	49.6	50.8	52.2	53.4	55.3	57.0	59.1	61.4	64.8	66.8	68.8	70.8	73.0	75.6	78.1	81.6	86.0	89.7
Real	49.3	47.1	45.3	44.2	43.3	42.1	41.3	40.4	39.7	39.0	39.1	38.2	37.3	36.4	35.6	35.0	34.4	34.1	34.2	33.9
Average Growth																				
Nominal	3.20%																			
Real	-1.96%																			
Average Customer Bill ($)																				
Nominal	1529.7	1509.1	1536.1	1599.9	1637.5	1677.0	1716.8	1737.5	1748.5	1766.4	1812.4	1871.0	1914.6	1962.8	2011.2	2079.6	2128.8	2210.8	2311.2	2395.9
Real	1529.7	1443.0	1401.3	1393.1	1357.4	1321.5	1283.9	1231.5	1174.8	1124.1	1093.5	1068.7	1037.2	1008.7	981.3	963.8	937.4	924.9	918.9	904.8
NPV (11.47% discount rate)	14795.9																			
Customer Cost (M$)	0.0	0.2	0.6	0.9	1.2	1.9	17.4	18.4	19.8	21.0	20.8	24.0	29.7	35.8	37.7	38.5	46.0	51.8	58.4	63.6
Levelized Customer Cost (M$)																				
(30 years at a 13.47% discount rate)	0.0	0.0	0.1	0.2	0.4	0.7	3.1	5.6	8.3	11.2	14.1	17.4	21.5	26.4	31.6	36.9	43.3	50.4	58.4	67.2
NPV (11.47% discount rate)	81.7																			
Energy Services Charge (M$)	0.1	0.7	2.2	4.6	8.3	12.2	18.0	25.4	34.4	45.1	57.2	69.7	81.9	94.6	107.0	120.3	133.0	144.1	151.6	155.4
NPV (11.47% discount rate)	291.0																			
Total Resource Cost (M$)																				
Nominal	1889.0	1883.9	1942.1	2051.0	2129.9	2212.6	2292.4	2349.7	2397.3	2456.2	2554.4	2678.3	2789.9	2918.1	3051.8	3218.4	3370.5	3578.8	3825.7	4054.6
Real	1889.0	1801.4	1771.6	1785.8	1765.6	1743.6	1714.4	1665.4	1610.6	1563.0	1541.2	1529.8	1511.4	1499.7	1489.0	1491.5	1484.3	1497.2	1521.0	1531.3
NPV (11.47% discount rate)	20168.5																			
Average Growth																				
Nominal	4.10%																			
Real	-1.10%																			
Mills / KWh																				
Nominal	49.3	49.2	49.6	50.7	52.0	53.2	55.0	56.7	58.6	60.8	64.1	66.1	68.2	70.3	72.5	75.2	77.7	81.0	85.2	88.5
Real	49.3	47.0	45.2	44.2	43.1	41.9	41.1	40.2	39.4	38.7	38.7	37.8	36.9	36.1	35.4	34.8	34.2	33.9	33.9	33.4
Average Growth																				
Nominal	3.13%																			
Real	-2.02%																			

Merged System
Resource & Market Planning
Competition Scenario

Average Megawatts	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements																				
Merged System Load	4,861	4,858	4,969	5,116	5,192	5,278	5,289	5,243	5,186	5,121	5,053	5,122	5,191	5,265	5,336	5,417	5,503	5,601	5,697	5,794
Black Hills	38	45	53	53	53	53	53	53	53	53	0	0	0	0	0	0	0	0	0	0
P G & E	29	29	29	29	29	29	29	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power	28	28	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power II	60	60	85	120	120	120	120	120	120	120	120	120	120	120	86	0	0	0	0	0
So Cal Edison	161	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	81	0	0
SMUD	0	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
WIDCO Sale	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Nevada	0	61	82	82	82	82	82	82	82	82	21	0	0	0	0	0	0	0	0	0
Sierra Pacific	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Seirra Pacific II	10	38	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
IPP Layoff to LA	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
IPP Banked Recall	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
South Idaho Exchange - UPL	30	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41
Total	5,345	5,428	5,596	5,762	5,837	5,924	5,934	5,860	5,804	5,739	5,557	5,604	5,673	5,747	5,784	5,780	5,865	5,936	5,952	6,048
Resources																				
Pacific System Hydro	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389
Utah System Hydro	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
Black Hills Energy Purchase	6	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Canadian Entitlement	-8	-8	-7	-6	-6	-6	-5	-5	-5	-4	-2	-2	-2	-2	0	0	0	0	0	0
CSPE	34	32	31	30	29	28	26	25	24	22	13	10	9	9	2	0	0	0	0	0
Hanford WNP #1	68	68	68	68	68	68	68	31	0	0	0	0	0	0	0	0	0	0	0	0
Mid Columbia	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	178	127	127	127
Miscellaneous Purchases	6	6	3	-4	7	19	19	16	16	16	16	15	9	9	9	9	9	9	9	9
Pelton Rereg	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Q.F. Contracts - PP&L	67	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Widco Purchase	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6
QF Contracts - UP&L	34	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
Gem State	7	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
GSLM	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
IPP	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
WAPA Capacity Exchange	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
MPC Purchase	0	15	15	15	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0
WWP Purchase	44	50	50	50	50	50	50	38	17	0	0	0	0	0	0	0	0	0	0	0
South Idaho Exchange - PPL	31	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
South Idaho Exchange Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flush Purchase	0	0	0	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125	125
BPA Settlement	0	0	0	0	0	0	65	63	67	65	65	65	65	65	65	65	65	65	65	65
Hydro Efficiency	0	1	2	3	4	5	6	7	8	9	10	10	10	10	10	10	10	10	10	10
Off Peak Purchase 1-utah	0	0	0	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Voltage Regulation 1	0	2	4	6	8	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
New Appliances Lost Opp	0	0	0	0	0	0	1	1	3	5	7	9	11	12	12	12	13	13	13	14
New Appliances Lost Opp-utah	0	0	0	0	0	0	0	1	2	3	4	5	6	6	7	7	7	7	7	8
Light and Water Heater Appliance	0	0	0	0	0	1	2	3	5	7	8	9	10	10	10	10	10	10	10	10
Light and Water Heater Appliance-utah	0	0	0	0	0	0	1	1	2	2	3	3	4	4	4	4	4	4	4	4
Commercial Retrofit	0	0	1	2	3	7	14	21	28	35	43	46	46	46	46	46	46	46	46	46
Commercial Retrofit-utah	0	0	1	1	2	4	9	13	17	22	26	28	28	28	28	28	28	28	28	28
Utah MCS Lost Opp-utah	0	0	1	2	3	5	6	7	9	10	11	13	15	18	20	23	26	30	33	37
Commercial Lost Opp	0	0	0	1	1	2	4	6	8	10	11	13	15	17	19	21	23	25	27	29
Commercial Lost Opp-utah	0	0	0	0	1	1	2	3	3	4	5	6	7	8	9	9	10	11	12	13
Industrial Lost Opp	0	0	1	2	3	4	6	8	11	15	19	24	29	34	40	47	54	62	69	77
Industrial Lost Opp-utah	0	0	1	2	2	3	4	6	8	11	14	17	21	25	30	34	40	45	51	56
Utah Code Lost Opp-utah	0	0	0	1	1	2	3	3	4	5	6	7	7	8	9	10	11	12	13	14
Mobile Home MCS Lost Opp	0	0	0	0	0	0	1	2	4	5	6	7	8	10	11	12	13	15	17	18

Mobile Home MCS Lost Opp-utah	0	0	0	0	0	0	0	0	1	1	1	1	1	2	2	2	2	2	3	3
Residential Retro	1	2	3	6	9	10	11	12	12	13	14	15	16	16	17	18	19	20	20	21
Residential Retro-utah	0	0	0	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	3
New Peak Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution Improvement	0	1	3	4	6	7	8	10	11	13	14	15	17	18	20	21	21	21	21	21
Transmission and Distribution Improvement	0	1	1	2	2	3	4	4	5	5	6	7	7	8	8	9	9	9	9	9
Centralia	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573
Dave Johnston	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675
Jim Bridger	1,193	1,204	1,212	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221
Wyodak	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239
Colstrip	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102
Carbon	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136
Naughton	541	541	548	554	561	561	561	561	561	561	561	561	561	561	561	561	561	561	561	561
Huntington	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681
Hunter	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846
Blundell	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Gadsby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Firming	0	0	0	0	0	0	0	45	45	45	45	45	45	45	45	45	45	45	45	45
CT One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trojan	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Total	5,990	6,084	6,104	6,249	6,277	6,306	6,447	6,457	6,440	6,452	6,478	6,502	6,519	6,540	6,556	6,577	6,595	6,567	6,591	6,615
Net before maintenance	645	656	508	487	440	382	513	597	637	713	921	898	846	792	772	797	730	631	640	567
Thermal Maintenance																				
Centralia	58	47	47	64	47	36	47	63	47	64	47	58	47	47	64	47	36	47	63	47
Dave Johnston	40	48	59	48	75	54	54	48	59	48	58	52	59	48	48	75	54	54	59	48
Jim Bridger	106	121	122	98	112	106	111	117	111	105	117	109	124	124	98	111	106	111	118	111
Wyodak	20	20	15	33	15	20	15	20	15	29	15	20	20	15	33	15	20	15	20	15
Colstrip	9	8	8	8	8	8	8	6	8	8	8	9	8	8	8	8	8	8	6	8
Carbon	9	5	17	6	4	6	15	4	12	10	4	6	15	4	12	10	4	6	15	4
Naughton	44	23	41	30	29	33	36	28	43	41	23	43	41	23	43	41	23	43	41	23
Huntington	27	52	39	39	78	26	26	52	26	26	78	26	26	52	26	26	78	26	26	52
Hunter	88	65	72	90	65	65	72	90	80	65	72	65	72	90	80	65	72	65	72	90
Blundell	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Gadsby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Firming	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trojan	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Total	405	394	426	421	439	359	389	433	407	402	428	393	417	417	417	404	407	380	425	403
Balance	240	261	82	66	1	23	123	164	230	311	493	505	430	375	355	394	323	251	215	164

Merged System
Resource & Market Planning
Competition Scenario

January Peak	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements																				
Merged System Load	6,440	6,551	6,665	6,777	6,891	7,000	6,918	6,849	6,770	6,676	6,581	6,670	6,762	6,861	6,954	7,064	7,180	7,314	7,445	7,574
Black Hills	75	75	75	75	75	75	75	75	75	75	0	0	0	0	0	0	0	0	0	0
P G & E	100	100	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power	55	55	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power II	100	100	100	200	200	200	200	200	200	200	200	200	200	200	200	0	0	0	0	0
So Cal Edison	298	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	0	0
SMUD	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Nevada	0	0	52	52	52	52	52	52	52	52	52	0	0	0	0	0	0	0	0	0
Sierra Pacific	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Seirra Pacific II	0	25	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Total	7,120	7,258	7,474	7,631	7,745	7,854	7,772	7,603	7,524	7,430	7,260	7,297	7,389	7,488	7,581	7,491	7,607	7,741	7,672	7,801
Resources																				
Pacific System Hydro	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881
Utah System Hydro	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Black Hills Capacity	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BPA Entitlement Capacity	29	29	29	26	23	21	18	16	13	12	11	5	5	5	4	0	0	0	0	0
BPA Peak Purchase	1,127	1,127	1,127	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BPA Supplemental Capacity	27	27	27	25	22	20	17	15	12	12	10	5	4	4	4	0	0	0	0	0
Canadian Entitlement	-29	-29	-29	-26	-23	-21	-18	-16	-13	-12	-11	-5	-5	-5	-4	0	0	0	0	0
CSPE	96	96	97	93	80	71	63	54	46	45	39	19	18	18	16	0	0	0	0	0
Hanford WNP #1	80	80	80	80	80	80	80	80	0	0	0	0	0	0	0	0	0	0	0	0
Mid Columbia	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	242	242	242
Miscellaneous Purchases	143	143	143	129	129	26	26	21	21	21	21	21	3	3	3	3	3	3	3	3
Pelton Rereg	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Q.F. Contracts - PP&L	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
QF Contracts - UP&L	38	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Gem State	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GSLM	0	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
MPC Purchase	0	15	15	15	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0
WWP Purchase	50	50	150	150	150	150	150	100	50	0	0	0	0	0	0	0	0	0	0	0
Flush Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BPA Settlement	0	0	0	0	0	0	164	164	164	164	164	164	164	164	164	164	164	164	164	164
Hydro Efficiency	0	2	4	6	8	10	12	14	16	18	20	20	20	20	20	20	20	20	20	20
Off Peak Purchase 1-utah	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Voltage Regulation 1	0	4	8	12	16	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
New Appliances Lost Opp	0	0	0	0	0	0	1	1	3	5	7	9	11	12	12	12	13	13	13	14
New Appliances Lost Opp-utah	0	0	0	0	0	0	0	1	2	3	4	5	6	6	7	7	7	7	7	8
Light and Water Heater Appliance	0	0	0	0	0	0	1	1	2	3	4	4	4	4	4	4	4	4	4	4
Light and Water Heater Appliance-utah	0	0	0	0	0	0	0	0	1	1	1	2	2	2	2	2	2	2	2	2
Commercial Retrofit	0	1	2	3	7	14	28	43	57	72	86	93	93	93	93	93	93	93	93	93
Commercial Retrofit-utah	0	1	1	2	4	9	18	26	35	44	53	57	57	57	57	57	57	57	57	57
Utah MCS Lost Opp-utah	0	0	1	2	3	5	6	7	8	9	11	12	14	16	19	22	25	28	31	35
Commercial Lost Opp	0	0	1	2	4	7	13	18	24	29	35	41	46	52	58	63	69	75	81	87
Commercial Lost Opp-utah	0	0	0	1	2	3	6	8	11	13	16	18	21	23	26	29	31	34	36	39
Industrial Lost Opp	0	0	1	2	3	4	6	8	11	15	19	24	29	34	40	47	54	62	69	77
Industrial Lost Opp-utah	0	0	1	2	2	3	4	6	8	11	14	17	21	25	30	34	40	45	51	56
Utah Code Lost Opp-utah	0	0	1	1	2	4	5	7	8	10	11	13	15	16	18	20	22	24	25	27
Mobile Home MCS Lost Opp	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mobile Home MCS Lost Opp-utah	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Retro	1	2	4	7	11	14	16	17	19	21	22	24	25	27	29	30	32	33	35	37
Residential Retro-utah	0	0	1	1	1	2	2	2	2	2	3	3	3	3	3	4	4	4	4	4
New Peak Purchase	0	0	0	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Transmission and Distribution Improvement	0	1	3	4	6	7	8	10	11	13	14	15	17	18	20	21	21	21	21	21
Transmission and Distribution Improvement	0	1	1	2	2	3	4	4	5	5	6	7	7	8	8	9	9	9	9	9

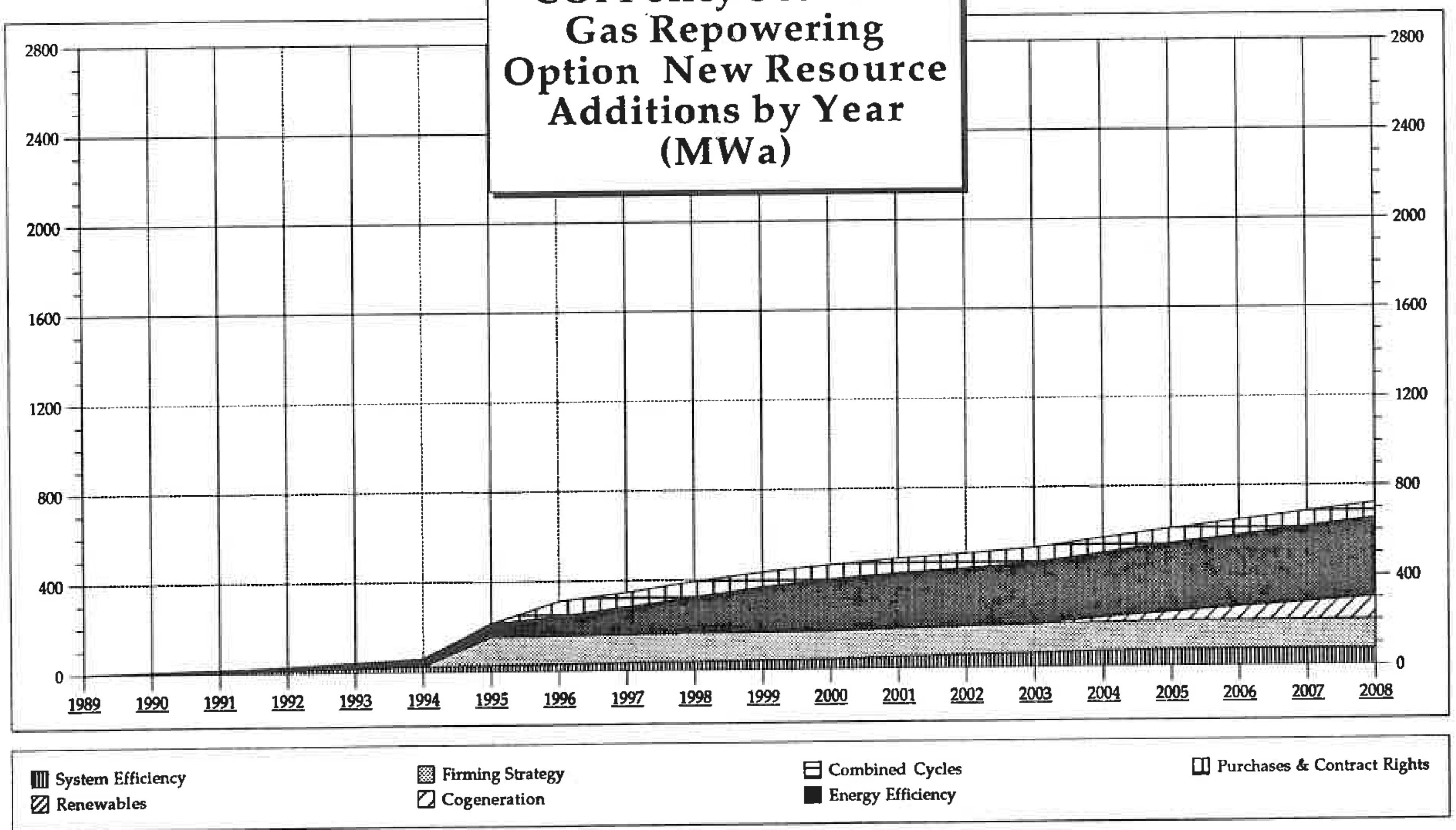
Centralia	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608
Dave Johnston	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750
Jim Bridger	1,361	1,366	1,371	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377
Wyodak	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252
Colstrip	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140
Carbon	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Naughton	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700
Huntington	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815
Hunter	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001
Blundell	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Gadsby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Firming	0	0	0	0	0	0	0	85	85	85	85	85	85	85	85	85	85	85	85	85
CT One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trojan	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Total	8,940	9,047	9,169	9,045	9,049	8,968	9,167	9,222	9,130	9,128	9,172	9,184	9,194	9,220	9,245	9,253	9,281	9,201	9,230	9,260
Thermal Maintenance																				
Centralia	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dave Johnston	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jim Bridger	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wyodak	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Colstrip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carbon	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Naughton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Huntington	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hunter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Blundell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gadsby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Firming	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trojan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reserve Requirement																				
Reserve	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013
(Reserve+Balance)/Requirements	26%	25%	23%	19%	17%	14%	18%	21%	21%	23%	26%	26%	24%	23%	22%	24%	22%	19%	20%	19%
Balance	807	776	682	401	291	101	382	606	593	685	899	874	792	719	651	749	661	447	545	446

CO_2 Policy Scenario

- Repowering Option -

Figure 11

CO_2 Policy Scenario Gas Repowering Option New Resource Additions by Year (MWa)



Average MW's	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiency	0	5	10	15	20	25	28	31	34	37	40	42	49	56	63	70	75	75	75	75
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Firming Strategy	0	0	0	0	0	0	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Cogeneration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	40	60	80	100
Combined Cycles	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	1	3	8	14	24	36	60	89	124	163	203	231	249	262	277	291	307	323	340	356
Purchases & Contract Rights	0	0	0	0	0	0	0	65	63	67	65	65	65	65	65	65	65	65	65	65
Totals	1	8	18	29	44	61	213	311	346	392	432	463	488	508	530	572	612	648	685	721

KEY OUTPUTS

CO-2 Policy Scenario: Repowering Option

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Load (MWa)	4860.0	4705.0	4743.0	4848.0	4911.0	4981.0	5115.0	5185.0	5240.0	5284.0	5333.0	5389.0	5447.0	5509.0	5566.0	5633.0	5704.0	5785.0	5861.0	5935.0
Total Conservation	1.0	5.4	12.3	20.4	31.9	45.7	70.3	99.3	134.3	173.3	212.5	240.7	264.1	282.0	302.2	321.3	341.9	357.9	374.6	390.7
System Load net of Conservation	4859.0	4699.6	4730.7	4827.6	4879.1	4935.3	5044.7	5085.7	5105.7	5110.7	5120.5	5148.3	5182.9	5227.0	5263.8	5311.7	5362.1	5427.1	5486.4	5544.3
Energy Sales after Conservation	4373.1	4229.6	4257.6	4344.8	4391.2	4441.8	4540.2	4577.1	4595.1	4599.6	4608.5	4633.5	4664.6	4704.3	4737.4	4780.5	4825.9	4884.4	4937.8	4989.9
Total Customers (000's)	1,235	1,248	1,263	1,279	1,295	1,312	1,323	1,335	1,347	1,359	1,370	1,385	1,403	1,425	1,449	1,472	1,501	1,531	1,564	1,599
Net Electric Plant (M$)	5290.0	5481.7	5619.4	5717.5	5790.0	5818.8	5907.8	6050.6	6258.6	6552.4	6866.9	7115.5	7266.7	7404.8	7572.0	7824.0	8113.5	8395.4	8712.8	9072.7
Net Conservation Assets	6.6	17.7	39.6	68.4	111.1	169.5	261.8	396.0	581.0	831.5	1084.5	1253.8	1303.0	1316.5	1332.5	1360.2	1396.8	1391.6	1384.2	1380.2
General Inflation Rate	3.90%	6.98%	6.19%	6.46%	6.73%	6.58%	7.15%	7.40%	7.63%	7.72%	7.75%	7.78%	7.72%	7.56%	7.53%	7.54%	7.64%	7.56%	7.49%	7.40%
Operating Revenues (M$)																				
Nominal	1886.3	1862.6	1916.3	2025.1	2107.3	2180.5	2299.3	2390.0	2492.8	2611.4	2790.7	2968.2	3137.9	3286.9	3866.8	4759.2	6410.6	7040.1	7680.4	8353.4
Real	1886.3	1741.1	1686.9	1674.5	1632.5	1585.0	1559.8	1509.6	1462.9	1422.7	1411.0	1392.4	1366.6	1330.8	1456.0	1666.4	2085.3	2129.1	2160.9	2188.3
NPV (13.13% discount rate)	20563.4																			
Average Growth																				
Nominal	8.15%																			
Real	0.78%																			
Base Unit Cost (mills/kwh)																				
Nominal	49.2	50.3	51.4	53.1	54.8	56.0	57.8	59.4	61.9	64.8	69.1	72.9	76.8	79.8	93.2	113.3	151.6	164.5	177.6	190.6
Real	49.2	47.0	45.2	43.9	42.4	40.7	39.2	37.5	36.3	35.3	35.0	34.2	33.4	32.3	35.1	39.7	49.3	49.8	50.0	49.9
Average Growth																				
Nominal	7.38%																			
Real	0.07%																			
Average Customer Bill ($)																				
Nominal	1527.6	1492.6	1517.5	1583.5	1626.7	1662.4	1738.0	1791.0	1851.1	1922.1	2036.9	2143.2	2236.3	2306.4	2669.5	3233.2	4272.3	4599.0	4909.5	5222.8
Real	1527.6	1395.2	1335.8	1309.3	1260.2	1208.4	1179.0	1131.2	1086.4	1047.2	1029.9	1005.4	973.9	933.9	1005.2	1132.1	1389.7	1390.8	1381.3	1368.2
NPV (13.13% discount rate)	15216.5																			
Customer Cost (M$)	0.0	0.2	0.3	0.3	0.7	1.6	16.8	17.3	15.9	14.2	12.7	15.3	21.2	26.0	26.0	24.3	28.5	32.7	35.6	37.3
Levelized Customer Cost (M$)																				
(30 years at a 15.13% discount rate)	0.0	0.0	0.1	0.1	0.2	0.5	3.1	5.7	8.2	10.3	12.3	14.6	17.9	21.9	25.9	29.6	34.0	39.0	44.5	50.2
NPV (13.13% discount rate)	55.1																			
Energy Services Charge (M$)	0.1	0.7	2.2	4.6	8.4	12.2	18.7	28.4	41.8	60.0	80.1	98.4	112.2	125.0	137.5	150.6	163.0	173.6	180.5	183.4
NPV (13.13% discount rate)	302.2																			
Total Resource Cost (M$)																				
Nominal	1886.4	1863.3	1918.6	2029.8	2115.9	2193.2	2321.1	2424.1	2542.7	2681.7	2883.1	3081.2	3268.0	3433.8	4030.1	4939.4	6607.6	7252.7	7905.3	8587.0
Real	1886.4	1741.7	1688.9	1678.4	1639.2	1594.2	1574.6	1531.2	1492.2	1461.0	1457.7	1445.4	1423.2	1390.3	1517.5	1729.5	2149.4	2193.4	2224.2	2249.5
NPV (13.13% discount rate)	20920.6																			
Average Growth																				
Nominal	8.30%																			
Real	0.93%																			
Mills / KWh																				
Nominal	49.2	50.2	51.3	53.0	54.6	55.8	57.6	59.1	61.5	64.4	68.6	72.3	76.1	79.1	91.8	110.9	146.9	159.0	171.1	183.0
Real	49.2	47.0	45.2	43.8	42.3	40.6	39.0	37.4	36.1	35.1	34.7	33.9	33.1	32.0	34.6	38.8	47.8	48.1	48.1	47.9
Average Growth																				
Nominal	7.16%																			
Real	-0.14%																			

Merged System
Resource & Market Planning
CO-2 Policy Scenario: Repowering Option

Average Megawatts	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements																				
Merged System Load	4,860	4,705	4,743	4,848	4,911	4,981	5,115	5,185	5,240	5,284	5,333	5,389	5,447	5,509	5,566	5,633	5,704	5,785	5,861	5,935
Black Hills	38	45	53	53	53	53	53	53	53	53	0	0	0	0	0	0	0	0	0	0
P G & E	29	29	29	29	29	29	29	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power	28	28	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power II	60	60	85	120	120	120	120	120	120	120	120	120	120	120	86	0	0	0	0	0
So Cal Edison	161	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	81	0	0
SMUD	0	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
WIDCO Sale	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Nevada	0	61	82	82	82	82	82	82	82	82	21	0	0	0	0	0	0	0	0	0
Sierra Pacific	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Seirra Pacific II	10	38	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
IPP Layoff to LA	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
IPP Banked Recall	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
South Idaho Exchange - UPL	30	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41
Total	5,343	5,275	5,370	5,493	5,557	5,627	5,761	5,802	5,858	5,901	5,837	5,871	5,930	5,992	6,014	5,995	6,066	6,120	6,115	6,189
Resources																				
Pacific System Hydro	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389
Utah System Hydro	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
Black Hills Energy Purchase	6	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Canadian Entitlement	-8	-8	-7	-6	-6	-6	-5	-5	-5	-4	-2	-2	-2	-2	0	0	0	0	0	0
CSPE	34	32	31	30	29	28	26	25	24	22	13	10	9	9	2	0	0	0	0	0
Hanford WNP #1	68	68	68	68	68	68	68	31	0	0	0	0	0	0	0	0	0	0	0	0
Mid Columbia	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	178	127	127	127
Miscellaneous Purchases	6	6	3	-4	7	19	19	16	16	16	16	15	9	9	9	9	9	9	9	9
Pelton Rereg	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Q.F. Contracts - PP&L	67	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Widco Purchase	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6
QF Contracts - UP&L	34	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
Gem State	7	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
GSLM	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
IPP	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
WAPA Capacity Exchange	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
MPC Purchase	0	15	15	15	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0
WWP Purchase	44	50	50	50	50	50	50	38	17	0	0	0	0	0	0	0	0	0	0	0
South Idaho Exchange - PPL	31	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
South Idaho Exchange Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Appliances Lost Opp	0	0	0	0	0	0	1	1	3	5	7	8	11	11	12	12	12	12	13	13
New Appliances Lost Opp-utah	0	0	0	0	0	0	0	1	2	3	4	4	6	6	6	6	7	7	7	7
Commercial Retrofit	0	0	1	2	3	7	14	21	28	35	43	46	46	46	46	46	46	46	46	46
Commercial Retrofit-utah	0	0	1	1	2	4	9	13	17	22	26	28	28	28	28	28	28	28	28	28
Light and Water Heater Appliance	0	0	0	0	0	0	1	3	4	6	7	8	9	9	9	9	9	9	9	9
Light and Water Heater Appliance-utah	0	0	0	0	0	0	1	1	2	2	3	3	4	4	4	4	4	4	4	4
Utah Code Lost Opp-utah	0	0	0	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	9
Commercial Lost Opp	0	0	0	0	1	2	4	6	7	9	10	12	13	15	16	18	19	20	22	23
Commercial Lost Opp-utah	0	0	0	0	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8
Flush Purchase	0	0	0	0	0	0	125	125	125	125	125	125	125	125	125	125	125	125	125	125
BPA Settlement	0	0	0	0	0	0	0	65	63	67	65	65	65	65	65	65	65	65	65	65
Hydro Efficiency	0	1	2	3	4	5	6	7	8	9	10	10	10	10	10	10	10	10	10	10
Transmission and Distribution Improvement	0	1	3	4	6	7	8	10	11	13	14	15	17	18	20	21	21	21	21	21
Transmission and Distribution Improvement	0	1	1	2	2	3	4	4	5	5	6	7	7	8	8	9	9	9	9	9
New Peak Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cogen Ownership	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	40	60	80	100
Voltage Regulation 1	0	2	4	6	8	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Voltage Regulation 2	0	0	0	0	0	0	0	0	0	0	0	0	2	5	8	10	13	13	12	12

Voltage Regulation 2-utah	0	0	0	0	0	0	0	0	0	0	0	0	2	5	8	10	13	13	12	12
Utah MCS Lost Opp-utah	0	0	0	1	1	2	2	3	4	5	5	6	7	8	9	10	12	13	15	16
Mobile Home MCS Lost Opp	0	0	0	0	0	0	1	3	4	4	5	6	7	8	9	10	11	12	14	15
Mobile Home MCS Lost Opp-utah	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1
Residential Retro	1	2	3	6	9	10	13	18	26	38	50	58	59	59	59	59	59	59	59	59
Residential Retro-utah	0	0	0	1	1	1	1	2	3	5	6	7	7	7	7	7	7	7	7	7
Industrial Lost Opp	0	0	1	2	3	4	5	8	10	13	16	20	24	29	34	40	45	52	58	64
Industrial Lost Opp-utah	0	0	1	2	2	3	4	6	8	10	12	15	18	22	25	29	34	38	43	48
Centralia	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573
Dave Johnston	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675
Jim Bridger	1,193	1,204	1,212	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221
Wyodak	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239
Colstrip	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102
Carbon	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136	136
Naughton	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541
Huntington	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681
Hunter	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846
Blundell	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Gadsby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Firming	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trojan	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Total	5,990	6,084	6,096	6,108	6,128	6,155	6,307	6,342	6,325	6,352	6,385	6,412	6,431	6,450	6,467	6,506	6,543	6,528	6,564	6,601
Net before maintenance	647	809	725	614	571	528	546	540	467	451	548	540	501	458	453	512	477	408	449	412
Thermal Maintenance																				
Centralia	58	47	47	64	47	36	47	63	47	64	47	58	47	47	64	47	36	47	63	47
Dave Johnston	40	48	59	48	75	54	54	48	59	48	58	52	59	48	48	75	54	54	59	48
Jim Bridger	106	121	122	98	112	106	111	117	111	105	117	109	124	124	98	111	106	111	118	111
Wyodak	20	20	15	33	15	20	15	20	15	29	15	20	20	15	33	15	20	15	20	15
Colstrip	9	8	8	8	8	8	8	6	8	8	8	9	8	8	8	8	8	8	6	8
Carbon	9	5	17	6	4	6	15	4	12	10	4	6	15	4	12	10	4	6	15	4
Naughton	44	23	40	29	29	31	34	28	40	38	23	40	38	23	40	38	23	40	38	23
Huntington	27	52	39	39	78	26	26	52	26	26	78	26	26	52	26	26	78	26	26	52
Hunter	88	65	72	90	65	65	72	90	80	65	72	65	72	90	80	65	72	65	72	90
Blundell	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Gadsby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Firming	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trojan	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Total	405	394	425	420	439	357	388	433	405	399	428	390	414	417	415	401	407	378	422	403
Balance	241	415	300	194	133	171	158	107	63	51	120	150	86	41	38	110	70	30	27	9

Merged System
Resource & Market Planning
CO-2 Policy Scenario: Repowering Option

January Peak	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements																				
Merged System Load	6,440	6,314	6,323	6,370	6,462	6,549	6,641	6,729	6,795	6,846	6,908	6,976	7,052	7,132	7,202	7,286	7,380	7,486	7,587	7,684
Black Hills	75	75	75	75	75	75	75	75	75	75	0	0	0	0	0	0	0	0	0	0
P G & E	100	100	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power	55	55	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power II	100	100	100	200	200	200	200	200	200	200	200	200	200	200	200	0	0	0	0	0
So Cal Edison	298	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	0	0
SMUD	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Nevada	0	0	52	52	52	52	52	52	52	52	52	0	0	0	0	0	0	0	0	0
Sierra Pacific	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Seirra Pacific II	0	25	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Total	7,120	7,021	7,132	7,224	7,316	7,403	7,495	7,483	7,549	7,600	7,587	7,603	7,679	7,759	7,829	7,713	7,807	7,913	7,814	7,911
Resources																				
Pacific System Hydro	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881
Utah System Hydro	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Black Hills Capacity	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BPA Entitlement Capacity	29	29	29	26	23	21	18	16	13	12	11	5	5	5	4	0	0	0	0	0
BPA Peak Purchase	1,127	1,127	1,127	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BPA Supplemental Capacity	27	27	27	25	22	20	17	15	12	12	10	5	4	4	4	0	0	0	0	0
Canadian Entitlement	-29	-29	-29	-26	-23	-21	-18	-16	-13	-12	-11	-5	-5	-5	-4	0	0	0	0	0
CSPE	96	96	97	93	80	71	63	54	46	45	39	19	18	18	16	0	0	0	0	0
Hanford WNP #1	80	80	80	80	80	80	80	80	0	0	0	0	0	0	0	0	0	0	0	0
Mid Columbia	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	242	242	242
Miscellaneous Purchases	143	143	143	129	129	26	26	21	21	21	21	21	3	3	3	3	3	3	3	3
Pelton Rereg	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Q.F. Contracts - PP&L	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
QF Contracts - UP&L	38	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Gem State	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GSLM	0	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
MPC Purchase	0	15	15	15	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0
WWP Purchase	50	50	150	150	150	150	150	100	50	0	0	0	0	0	0	0	0	0	0	0
New Appliances Lost Opp	0	0	0	0	0	0	1	1	3	5	7	8	11	11	12	12	12	12	13	13
New Appliances Lost Opp-utah	0	0	0	0	0	0	0	1	2	3	4	4	6	6	6	6	7	7	7	7
Commercial Retrofit	0	1	2	3	7	14	28	43	57	72	86	93	93	93	93	93	93	93	93	93
Commercial Retrofit-utah	0	1	1	2	4	9	18	26	35	44	53	57	57	57	57	57	57	57	57	57
Light and Water Heater Appliance	0	0	0	0	0	0	1	1	2	3	4	4	4	4	4	4	4	4	4	4
Light and Water Heater Appliance-utah	0	0	0	0	0	0	0	0	1	1	1	2	2	2	2	2	2	2	2	2
Utah Code Lost Opp-utah	0	0	0	1	1	2	3	4	5	6	7	8	9	10	12	13	14	15	16	17
Commercial Lost Opp	0	0	1	2	4	8	13	19	24	29	34	39	44	49	54	59	64	69	74	79
Commercial Lost Opp-utah	0	0	0	1	1	3	4	6	8	10	11	13	15	17	18	20	22	23	25	26
Flush Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BPA Settlement	0	0	0	0	0	0	0	164	164	164	164	164	164	164	164	164	164	164	164	164
Hydro Efficiency	0	2	4	6	8	10	12	14	16	18	20	20	20	20	20	20	20	20	20	20
Transmission and Distribution Improvement	0	1	3	4	6	7	8	10	11	13	14	15	17	18	20	21	21	21	21	21
Transmission and Distribution Improvement	0	1	1	2	2	3	4	4	5	5	6	7	7	8	8	9	9	9	9	9
New Peak Purchase	0	0	0	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Cogen Ownership	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	40	60	80	100
Voltage Regulation 1	0	4	8	12	16	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Voltage Regulation 2	0	0	0	0	0	0	0	0	0	0	0	0	5	10	15	20	25	25	25	25
Voltage Regulation 2-utah	0	0	0	0	0	0	0	0	0	0	0	0	5	10	15	20	25	25	25	25
Utah MCS Lost Opp-utah	0	0	0	1	1	2	2	3	4	5	5	6	7	8	9	10	11	13	14	16
Mobile Home MCS Lost Opp	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mobile Home MCS Lost Opp-utah	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Retro	1	2	4	7	11	14	20	31	49	75	100	115	117	116	116	116	116	116	116	116
Residential Retro-utah	0	0	1	1	1	2	2	4	6	9	12	14	14	14	14	14	14	14	14	14

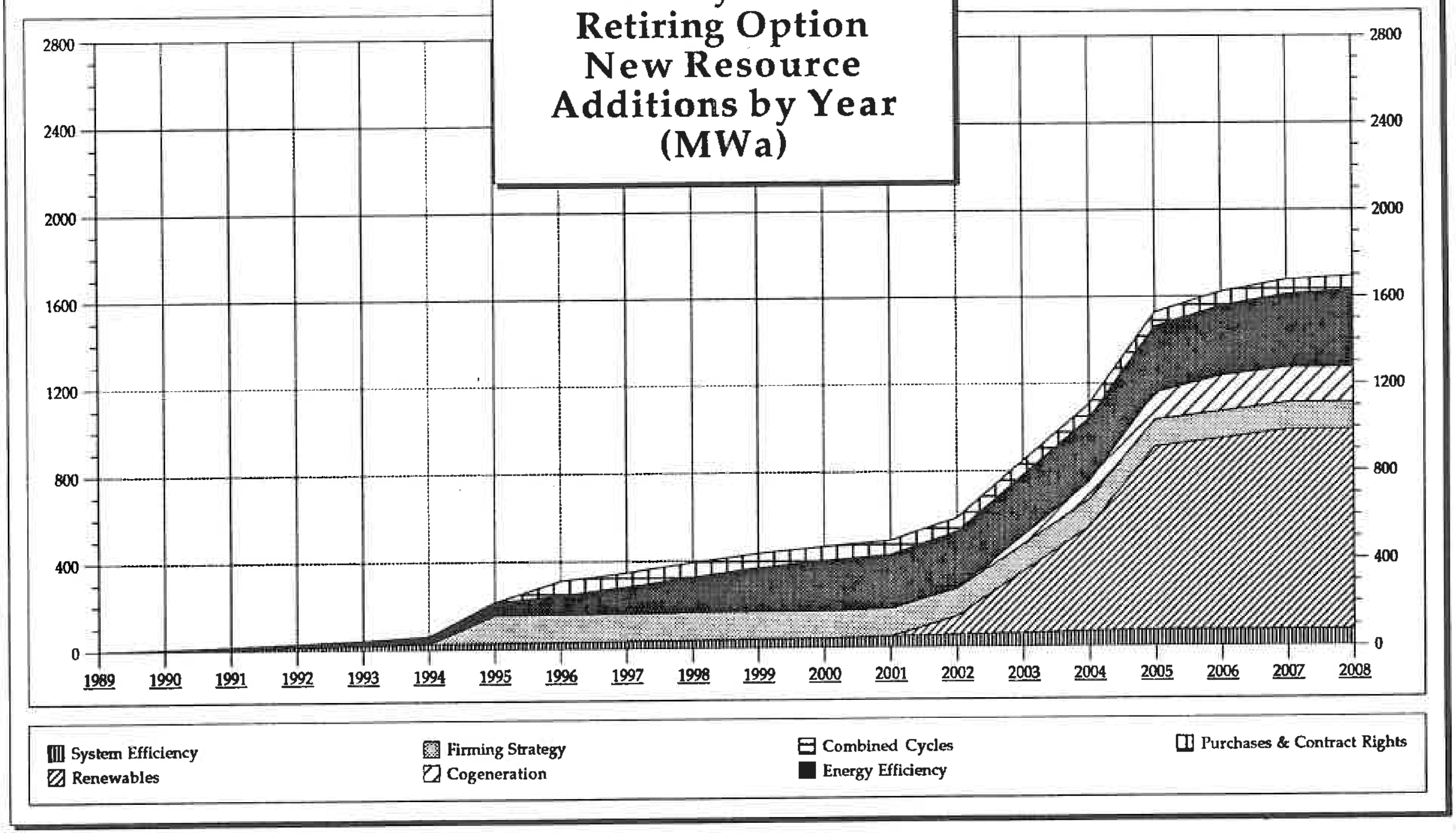
Industrial Lost Opp	0	0	1	2	3	4	5	8	10	13	16	20	24	29	34	40	45	52	58	64
Industrial Lost Opp-utah	0	0	1	2	2	3	4	6	8	10	12	15	18	22	25	29	34	38	43	48
Centralia	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608
Dave Johnston	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750
Jim Bridger	1,361	1,366	1,371	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377
Wyodak	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252
Colstrip	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140
Carbon	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Naughton	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700
Huntington	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815
Hunter	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001
Blundell	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Gadsby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Firming	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trojan	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Total	8,940	9,047	9,168	9,043	9,045	8,963	9,000	9,143	9,066	9,088	9,154	9,177	9,192	9,220	9,248	9,279	9,329	9,260	9,300	9,340
Thermal Maintenance																				
Centralia	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dave Johnston	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jim Bridger	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wyodak	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Colstrip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carbon	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Naughton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Huntington	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hunter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Blundell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gadsby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Firming	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trojan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reserve Requirement																				
Reserve	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013
(Reserve+Balance)/Requirements	26%	29%	29%	25%	24%	21%	20%	22%	20%	20%	21%	21%	20%	19%	18%	20%	19%	17%	19%	18%
Balance	807	1,013	1,023	806	716	547	492	647	504	475	554	561	500	448	406	553	509	334	473	416

CO_2 Policy Scenario

- Retiring Option -

Figure 11

CO_2 Policy Scenario Retiring Option New Resource Additions by Year (MWa)



Average MW's	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Efficiency	0	5	10	15	20	25	28	31	34	37	40	42	49	56	63	70	75	75	75	75
Renewables	0	0	0	0	0	0	0	0	0	0	0	0	0	82	279	475	836	874	912	912
Firming Strategy	0	0	0	0	0	0	125	125	125	125	125	125	125	125	125	125	125	125	125	125
Cogeneration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	40	80	120	160	160	160
Combined Cycles	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	1	3	8	14	24	36	60	89	124	163	203	231	249	262	277	291	307	323	340	356
Purchases & Contract Rights	0	0	0	0	0	0	0	65	63	67	65	65	65	65	65	65	65	65	65	65
Totals	1	8	18	29	44	61	213	311	346	392	432	463	488	590	849	1106	1528	1622	1676	1693

KEY OUTPUTS

CO-2 Policy Scenario - Retiring Option

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
System Load (MWa)	4860.0	4705.0	4743.0	4848.0	4911.0	4981.0	5115.0	5185.0	5240.0	5284.0
Total Conservation	1.0	5.4	12.3	20.4	31.9	45.7	70.3	99.3	134.3	173.3
System Load net of Conservation	4859.0	4699.6	4730.7	4827.6	4879.1	4935.3	5044.7	5085.7	5105.7	5110.7
Energy Sales after Conservation	4373.1	4229.6	4257.6	4344.8	4391.2	4441.8	4540.2	4577.1	4595.1	4599.6
Total Customers (000's)	1,235	1,248	1,263	1,279	1,295	1,312	1,323	1,335	1,347	1,359
Net Electric Plant (M$)	5290.0	5481.7	5619.4	5717.5	5790.0	5818.8	5907.8	6050.6	6258.6	6552.4
Net Conservation Assets	6.6	17.7	39.6	68.4	111.1	169.5	261.8	396.0	581.0	831.5
General Inflation Rate	3.90%	6.98%	6.19%	6.46%	6.73%	6.58%	7.15%	7.40%	7.63%	7.72%
Operating Revenues (M$)										
Nominal	1890.6	1860.6	1910.6	2026.2	2099.8	2183.2	2305.5	2386.7	2493.3	2618.6
Real	1890.6	1739.2	1681.9	1675.4	1626.7	1586.9	1564.0	1507.5	1463.2	1426.6
NPV (13.13% discount rate)	19946.1									
Average Growth										
Nominal	6.75%									
Real	-0.52%									
Base Unit Cost (mills/kwh)										
Nominal	49.4	50.2	51.2	53.1	54.6	56.1	58.0	59.4	61.9	65.0
Real	49.4	46.9	45.1	43.9	42.3	40.8	39.3	37.5	36.3	35.4
Average Growth										
Nominal	5.99%									
Real	-1.22%									
Average Customer Bill ($)										
Nominal	1531.1	1491.0	1513.0	1584.3	1621.0	1664.4	1742.6	1788.5	1851.5	1927.4
Real	1531.1	1393.7	1331.9	1310.0	1255.8	1209.8	1182.2	1129.7	1086.6	1050.0
NPV (13.13% discount rate)	14818.3									
Customer Cost (M$)	0.0	0.2	0.3	0.3	0.7	1.6	16.8	17.3	15.9	14.2
Levelized Customer Cost (M$)										
(30 years at a 15.13% discount rate)	0.0	0.0	0.1	0.1	0.2	0.5	3.1	5.7	8.2	10.3
NPV (13.13% discount rate)	55.1									
Energy Services Charge (M$)	0.1	0.7	2.2	4.6	8.4	12.2	18.7	28.4	41.8	60.0
NPV (13.13% discount rate)	302.2									
Total Resource Cost (M$)										
Nominal	1890.7	1861.4	1912.9	2030.9	2108.4	2195.9	2327.3	2420.8	2543.2	2688.9
Real	1890.7	1739.9	1683.9	1679.3	1633.4	1596.1	1578.8	1529.1	1492.5	1464.9
NPV (13.13% discount rate)	20303.3									
Average Growth										
Nominal	6.94%									
Real	-0.34%									
Mills / KWh										
Nominal	49.3	50.2	51.2	53.0	54.5	55.9	57.7	59.1	61.6	64.5
Real	49.3	46.9	45.0	43.8	42.2	40.6	39.1	37.3	36.1	35.2
Average Growth										
Nominal	5.81%									
Real	-1.39%									

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
System Load (MWa)	5333.0	5389.0	5447.0	5509.0	5566.0	5633.0	5704.0	5785.0	5861.0	5935.0
Total Conservation	212.5	240.7	264.1	282.0	302.2	321.3	341.9	357.9	374.6	390.7
System Load net of Conservation	5120.5	5148.3	5182.9	5227.0	5263.8	5311.7	5362.1	5427.1	5486.4	5544.3
Energy Sales after Conservation	4608.5	4633.5	4664.6	4704.3	4737.4	4780.5	4825.9	4884.4	4937.8	4989.9
Total Customers (000's)	1,370	1,385	1,403	1,425	1,449	1,472	1,501	1,531	1,564	1,599
Net Electric Plant (M$)	6887.6	7340.3	8176.0	9782.5	11588.8	12982.0	14977.0	15131.4	15098.0	15105.1
Net Conservation Assets	1084.5	1253.8	1303.0	1316.5	1332.5	1360.2	1396.8	1391.6	1384.2	1380.2
General Inflation Rate	7.75%	7.78%	7.72%	7.56%	7.53%	7.54%	7.64%	7.56%	7.49%	7.40%
Operating Revenues (M$)										
Nominal	2784.5	2962.2	3162.7	3373.0	3885.7	4557.6	5302.1	5967.8	6313.2	6535.8
Real	1407.9	1389.6	1377.3	1365.7	1463.1	1595.8	1724.7	1804.8	1776.2	1712.1
Base Unit Cost (mills/kwh)										
Nominal	69.0	72.8	77.4	81.9	93.6	108.5	125.4	139.5	146.0	149.1
Real	34.9	34.1	33.7	33.1	35.3	38.0	40.8	42.2	41.1	39.1
Average Customer Bill ($)										
Nominal	2032.3	2138.9	2253.9	2366.9	2682.6	3096.2	3533.6	3898.5	4035.6	4086.4
Real	1027.6	1003.4	981.6	958.3	1010.1	1084.1	1149.4	1179.0	1135.4	1070.5
Customer Cost (M$)	12.7	15.3	21.2	26.0	26.0	24.3	28.5	32.7	35.6	37.3
Levelized Customer Cost (M$)										
(30 years at a 15.13% discount rate)	12.3	14.6	17.9	21.9	25.9	29.6	34.0	39.0	44.5	50.2
Energy Services Charge (M$)	80.1	98.4	112.2	125.0	137.5	150.6	163.0	173.6	180.5	183.4
Total Resource Cost (M$)										
Nominal	2876.9	3075.2	3292.7	3519.9	4049.0	4737.8	5499.1	6180.4	6538.2	6769.3
Real	1454.6	1442.7	1434.0	1425.2	1524.6	1658.9	1788.8	1869.1	1839.5	1773.3
Mills / KWh										
Nominal	68.4	72.2	76.7	81.0	92.3	106.4	122.3	135.5	141.5	144.3
Real	34.6	33.9	33.4	32.8	34.7	37.3	39.8	41.0	39.8	37.8

Merged System
Resource & Market Planning
CO-2 Policy Scenario - Retiring Option

Average Megawatts	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements																				
Merged System Load	4,860	4,705	4,743	4,848	4,911	4,981	5,115	5,185	5,240	5,284	5,333	5,389	5,447	5,509	5,566	5,633	5,704	5,785	5,861	5,935
Black Hills	38	45	53	53	53	53	53	53	53	53	0	0	0	0	0	0	0	0	0	0
P G & E	29	29	29	29	29	29	29	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power	28	28	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power II	60	60	85	120	120	120	120	120	120	120	120	120	120	120	86	0	0	0	0	0
So Cal Edison	161	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	81	0	0
SMUD	0	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
WIDCO Sale	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Nevada	0	61	82	82	82	82	82	82	82	82	21	0	0	0	0	0	0	0	0	0
Sierra Pacific	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
Seirra Pacific II	10	38	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
IPP Layoff to LA	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
IPP Banked Recall	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
South Idaho Exchange - UPL	30	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41
Total	5,343	5,275	5,370	5,493	5,557	5,627	5,761	5,802	5,858	5,901	5,837	5,871	5,930	5,992	6,014	5,995	6,066	6,120	6,115	6,189
Resources																				
Pacific System Hydro	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389	389
Utah System Hydro	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
Black Hills Energy Purchase	6	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Canadian Entitlement	-8	-8	-7	-6	-6	-6	-5	-5	-5	-4	-2	-2	-2	-2	0	0	0	0	0	0
CSPE	34	32	31	30	29	28	26	25	24	22	13	10	9	9	2	0	0	0	0	0
Hanford WNP #1	68	68	68	68	68	68	68	31	0	0	0	0	0	0	0	0	0	0	0	0
Mid Columbia	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	183	178	127	127	127
Miscellaneous Purchases	6	6	3	-4	7	19	19	16	16	16	16	15	9	9	9	9	9	9	9	9
Pelton Rereg	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Q.F. Contracts - PP&L	67	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Widco Purchase	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6
QF Contracts - UP&L	34	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
Gem State	7	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
GSLM	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
IPP	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
WAPA Capacity Exchange	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
MPC Purchase	0	15	15	15	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0
WWP Purchase	44	50	50	50	50	50	50	38	17	0	0	0	0	0	0	0	0	0	0	0
South Idaho Exchange - PPL	31	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
South Idaho Exchange Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Flush Purchase	0	0	0	0	0	0	125	125	125	125	125	125	125	125	125	125	125	125	125	125
BPA Settlement	0	0	0	0	0	0	0	65	63	67	65	65	65	65	65	65	65	65	65	65
Hydro Efficiency	0	1	2	3	4	5	6	7	8	9	10	10	10	10	10	10	10	10	10	10
Transmission and Distribution Improvement	0	1	3	4	6	7	8	10	11	13	14	15	17	18	20	21	21	21	21	21
Cogen Ownership	0	0	0	0	0	0	0	0	0	0	0	0	0	0	40	80	120	160	160	160
Voltage Regulation 1	0	2	4	6	8	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Voltage Regulation 2	0	0	0	0	0	0	0	0	0	0	0	0	2	5	8	10	13	13	12	12
Voltage Regulation 2-utah	0	0	0	0	0	0	0	0	0	0	0	0	2	5	8	10	13	13	12	12
New Appliances Lost Opp	0	0	0	0	0	0	1	1	3	5	7	8	11	11	12	12	12	12	13	13
New Appliances Lost Opp-utah	0	0	0	0	0	0	0	1	2	3	4	4	6	6	6	6	7	7	7	7
Commercial Retrofit	0	0	1	2	3	7	14	21	28	35	43	46	46	46	46	46	46	46	46	46
Commercial Retrofit-utah	0	0	1	1	2	4	9	13	17	22	26	28	28	28	28	28	28	28	28	28
Light and Water Heater Appliance	0	0	0	0	0	0	1	3	4	6	7	8	9	9	9	9	9	9	9	9
Light and Water Heater Appliance-utah	0	0	0	0	0	0	1	1	2	2	3	3	4	4	4	4	4	4	4	4
Utah Code Lost Opp-utah	0	0	0	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8	9
Commercial Lost Opp	0	0	0	0	1	2	4	6	7	9	10	12	13	15	16	18	19	20	22	23
Commercial Lost Opp-utah	0	0	0	0	0	1	1	2	2	3	3	4	4	5	5	6	6	7	7	8
Utah MCS Lost Opp-utah	0	0	0	1	1	2	2	3	4	5	5	6	7	8	9	10	12	13	15	16

Mobile Home MCS Lost Opp	0	0	0	0	0	0	1	3	4	4	5	6	7	8	9	10	11	12	14	15
Mobile Home MCS Lost Opp-utah	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1
Residential Retro	1	2	3	6	9	10	13	18	26	38	50	58	59	59	59	59	59	59	59	59
Residential Retro-utah	0	0	0	1	1	1	1	2	3	5	6	7	7	7	7	7	7	7	7	7
Wind Farm	0	0	0	0	0	0	0	0	0	0	0	0	0	0	76	152	228	228	228	228
Sun Farm	0	0	0	0	0	0	0	0	0	0	0	0	0	44	89	133	266	266	266	266
Industrial Lost Opp	0	0	1	2	3	4	5	8	10	13	16	20	24	29	34	40	45	52	58	64
Industrial Lost Opp-utah	0	0	1	2	2	3	4	6	8	10	12	15	18	22	25	29	34	38	43	48
New Peak Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission and Distribution Improvement	0	1	1	2	2	3	4	4	5	5	6	7	7	8	8	9	9	9	9	9
Centralia	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	573	0	0	0	0
Dave Johnston	675	675	675	675	675	675	675	675	675	675	675	675	675	675	675	475	475	475	475	475
Jim Bridger	1,193	1,204	1,212	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221	1,221
Wyodak	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239
Colstrip	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102
Carbon	136	136	136	136	136	136	136	136	136	136	136	136	136	136	0	0	0	0	0	0
Naughton	541	541	541	541	541	541	541	541	541	541	541	541	541	541	541	405	405	405	405	405
Huntington	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681	681
Hunter	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846	846
Blundell	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Gadsby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Firming	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal One	0	0	0	0	0	0	0	0	0	0	0	0	0	38	76	114	190	190	190	190
Geothermal Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	38	76	152	190	228	228
Trojan	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Total	5,990	6,084	6,096	6,108	6,128	6,155	6,307	6,342	6,325	6,352	6,385	6,412	6,431	6,532	6,649	6,569	6,413	6,456	6,511	6,527
Net before maintenance	647	809	725	614	571	528	546	540	467	451	548	540	501	541	635	574	347	336	396	338
Thermal Maintenance																				
Centralia	47	36	47	63	47	64	47	47	64	47	36	47	63	47	64	47	0	0	0	0
Dave Johnston	75	54	54	48	59	48	58	59	48	75	54	53	48	59	48	46	47	35	46	35
Jim Bridger	109	105	110	117	111	105	117	124	98	112	106	111	118	111	105	117	124	98	112	106
Wyodak	15	20	15	20	15	29	15	15	33	15	20	15	20	15	29	15	15	33	15	20
Colstrip	8	8	8	6	8	8	8	4	12	4	12	2	12	4	12	4	8	8	8	6
Carbon	4	6	15	4	12	10	4	6	15	4	12	10	4	6	0	0	0	0	0	0
Naughton	29	31	34	28	40	38	23	40	38	23	40	38	23	40	38	12	40	28	12	40
Huntington	78	26	26	52	26	26	78	26	26	52	26	26	78	26	26	52	26	26	78	26
Hunter	65	65	72	90	80	65	72	65	72	90	80	65	72	65	72	90	80	65	72	65
Blundell	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Gadsby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Firming	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal One	0	0	0	0	0	0	0	0	0	0	0	0	0	2	4	7	11	11	11	11
Geothermal Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	4	9	11	13	13
Trojan	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Total	436	356	387	433	405	399	428	391	412	428	391	373	443	382	407	399	365	321	373	327
Balance	211	453	338	182	167	129	117	148	55	23	157	167	57	159	228	175	-18	15	23	11

Merged System
Resource & Market Planning
CO-2 Policy Scenario - Retiring Option

January Peak	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Requirements																				
Merged System Load	6,440	6,314	6,323	6,370	6,462	6,549	6,641	6,729	6,795	6,846	6,908	6,976	7,052	7,132	7,202	7,286	7,380	7,486	7,587	7,684
Black Hills	75	75	75	75	75	75	75	75	75	75	0	0	0	0	0	0	0	0	0	0
P G & E	100	100	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power	55	55	55	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Puget Power II	100	100	100	200	200	200	200	200	200	200	200	200	200	200	200	0	0	0	0	0
So Cal Edison	298	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	0	0
SMUD	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Nevada	0	0	52	52	52	52	52	52	52	52	52	0	0	0	0	0	0	0	0	0
Sierra Pacific	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
Seirra Pacific II	0	25	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Total	7,120	7,021	7,132	7,224	7,316	7,403	7,495	7,483	7,549	7,600	7,587	7,603	7,679	7,759	7,829	7,713	7,807	7,913	7,814	7,911
Resources																				
Pacific System Hydro	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881	881
Utah System Hydro	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Black Hills Capacity	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
BPA Entitlement Capacity	29	29	29	26	23	21	18	16	13	12	11	5	5	5	4	0	0	0	0	0
BPA Peak Purchase	1,127	1,127	1,127	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BPA Supplemental Capacity	27	27	27	25	22	20	17	15	12	12	10	5	4	4	4	0	0	0	0	0
Canadian Entitlement	-29	-29	-29	-26	-23	-21	-18	-16	-13	-12	-11	-5	-5	-5	-4	0	0	0	0	0
CSPE	96	96	97	93	80	71	63	54	46	45	39	19	18	18	16	0	0	0	0	0
Hanford WNP #1	80	80	80	80	80	80	80	80	0	0	0	0	0	0	0	0	0	0	0	0
Mid Columbia	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	352	242	242	242
Miscellaneous Purchases	143	143	143	129	129	26	26	21	21	21	21	21	3	3	3	3	3	3	3	3
Pelton Rereg	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Q.F. Contracts - PP&L	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
QF Contracts - UP&L	38	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98	98
Gem State	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GSLM	0	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
MPC Purchase	0	15	15	15	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0
WWP Purchase	50	50	150	150	150	150	150	100	50	0	0	0	0	0	0	0	0	0	0	0
Flush Purchase	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BPA Settlement	0	0	0	0	0	0	0	164	164	164	164	164	164	164	164	164	164	164	164	164
Hydro Efficiency	0	2	4	6	8	10	12	14	16	18	20	20	20	20	20	20	20	20	20	20
Transmission and Distribution Improvement	0	1	3	4	6	7	8	10	11	13	14	15	17	18	20	21	21	21	21	21
Cogen Ownership	0	0	0	0	0	0	0	0	0	0	0	0	0	0	40	80	120	160	160	160
Voltage Regulation 1	0	4	8	12	16	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Voltage Regulation 2	0	0	0	0	0	0	0	0	0	0	0	0	5	10	15	20	25	25	25	25
Voltage Regulation 2-utah	0	0	0	0	0	0	0	0	0	0	0	0	5	10	15	20	25	25	25	25
New Appliances Lost Opp	0	0	0	0	0	0	1	1	3	5	7	8	11	11	12	12	12	12	13	13
New Appliances Lost Opp-utah	0	0	0	0	0	0	0	1	2	3	4	4	6	6	6	6	7	7	7	7
Commercial Retrofit	0	1	2	3	7	14	28	43	57	72	86	93	93	93	93	93	93	93	93	93
Commercial Retrofit-utah	0	1	1	2	4	9	18	26	35	44	53	57	57	57	57	57	57	57	57	57
Light and Water Heater Appliance	0	0	0	0	0	0	1	1	2	3	4	4	4	4	4	4	4	4	4	4
Light and Water Heater Appliance-utah	0	0	0	0	0	0	0	0	1	1	1	2	2	2	2	2	2	2	2	2
Utah Code Lost Opp-utah	0	0	0	1	1	2	3	4	5	6	7	8	9	10	12	13	14	15	16	17
Commercial Lost Opp	0	0	1	2	4	8	13	19	24	29	34	39	44	49	54	59	64	69	74	79
Commercial Lost Opp-utah	0	0	0	1	1	3	4	6	8	10	11	13	15	17	18	20	22	23	25	26
Utah MCS Lost Opp-utah	0	0	0	1	1	2	2	3	4	5	5	6	7	8	9	10	11	13	14	16
Mobile Home MCS Lost Opp	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mobile Home MCS Lost Opp-utah	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Retro	1	2	4	7	11	14	20	31	49	75	100	115	117	116	116	116	116	116	116	116
Residential Retro-utah	0	0	1	1	1	2	2	4	6	9	12	14	14	14	14	14	14	14	14	14
Wind Farm	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	15	23	23	23	23
Sun Farm	0	0	0	0	0	0	0	0	0	0	0	0	0	10	20	30	60	60	60	60

Industrial Lost Opp	0	0	1	2	3	4	5	8	10	13	16	20	24	29	34	40	45	52	58	64
Industrial Lost Opp-utah	0	0	1	2	2	3	4	6	8	10	12	15	18	22	25	29	34	38	43	48
New Peak Purchase	0	0	0	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,200	1,200	1,200	1,200
Transmission and Distribution Improvement	0	1	1	2	2	3	4	4	5	5	6	7	7	8	8	9	9	9	9	9
Centralia	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	608	0	0	0	0
Dave Johnston	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	540	540	540	540	540
Jim Bridger	1,361	1,366	1,371	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377	1,377
Wyodak	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252	252
Colstrip	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140	140
Carbon	166	166	166	166	166	166	166	166	166	166	166	166	166	166	0	0	0	0	0	0
Naughton	700	700	700	700	700	700	700	700	700	700	700	700	700	700	700	540	540	540	540	540
Huntington	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815	815
Hunter	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001	1,001
Blundell	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
Gadsby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Firming	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal One	0	0	0	0	0	0	0	0	0	0	0	0	0	50	100	150	250	250	250	250
Geothermal Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	100	200	250	300	300
Trojan	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Total	8,940	9,047	9,168	9,043	9,045	8,963	9,000	9,143	9,066	9,088	9,154	9,177	9,192	9,280	9,300	9,098	8,998	8,999	9,069	9,089
Thermal Maintenance																				
Centralia	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dave Johnston	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jim Bridger	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wyodak	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Colstrip	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carbon	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Naughton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Huntington	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hunter	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Blundell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gadsby	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro Firming	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal One	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal Two	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trojan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reserve Requirement																				
Reserve	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013	1,013
(Reserve+Balance)/Requirements	26%	29%	29%	25%	24%	21%	20%	22%	20%	20%	21%	21%	20%	20%	19%	18%	15%	14%	16%	15%
Balance	807	1,013	1,023	806	716	547	492	647	504	475	554	561	500	508	458	372	178	73	242	165

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Appendix B - Public Participation

PUBLIC PARTICIPATION

In keeping with regulatory commission requirements for long range resource planning, the company's RAMPP process involved a significant amount of public involvement. The company took two approaches to fulfilling this requirement. The first approach was to utilize the expertise of an expert advisory group in an ongoing technical review function. The second approach was to involve customer advisory groups in discussions on important least cost planning topics. The following discussion describes each of these two approaches.

TECHNICAL ADVISORY GROUP

The RAMPP technical review process utilized the expertise of the company's Regional Research Advisory Group (advisory \group). The advisory group is a task force of regional energy and consumer interest experts that met on a regular basis over a period of 12 months to review and comment on the ongoing development of the the planning program. During these meetings the members of the advisory group engaged in frank, two-way, discussions with company personnel over all phases of the planning process. These discussions proved to be an extremely valuable piece of the entire RAMPP process. Many of the suggestions and recommendations of the advisory group members were incorporated directly into the evolving planning process.

Table B-1 displays the groups that were invited to participate in the RAMPP advisory group process. Table B-2 displays the dates, and discussion topics, of the nine day-long meetings that were held between August 1988 and August 1989. Nearly every organization listed on Table B-1, and several others that are not listed, were represented at each of the none advisory group meetings. Many organizations sent more than one participant.

The company found the advisory group process to be a very successful and worthwhile exercise. And while unanimity was not reached among all participants on many of the major issues and topics that were discussed, the company feels confident that consensus was reached on the majority of planning issues that were incorporated into this report.

CUSTOMER FOCUS GROUP

The company utilized Pacific Division's WIM Region (Washington, Idaho, Mid-Oregon) customer focus group program as the forum for customer participation in the RAMPP process. A twenty-three member focus group was divided into several sub-groups and given the assignment to study, and make recommendations, the full committee. The committee in turn made their final recommendations to Pacific on a number of important RAMPP topics concerning future power resources. The company, as well as the customer / participants, found the focus group process to be of great value. The participants gained a greater appreciation of the challenges that utilities face when making resource decisions, and of the increasingly complex competitive forces that are affecting the electric utility industry. The company, in turn, gained valuable insights into the way customers view the end the end results of utility resource decisions, and a better appreciation of the way customers view the role of their energy service suppliers.

While there was general agreement among the participants on most of the major issue areas, there was considerable variation in the sub-group recommendations. One sub-group focused on renewable resources and energy efficiency as major new resource options, while another group called for consideration of nuclear power. "Start-up" electricity prices were favored by a sub-group for attracting new businesses to the area. Another sub-group felt that funding of efficiency programs should continue even during periods of surplus and should be paid for by all customers, and not just those that benefit from the program (in order to "maintain a consistent message and signal about the importance of efficiency".) Another group countered that rigorous cost effectiveness tests should be applied to all programs offered in periods of surplus.

The company was very pleased with the interest taken in the RAMPP process by the WIM focus group. Many of the group's recommendations have been directly accounted for, and addressed, within this report. In keeping with the full committee's recommendations, the company has developed a planning process that will help achieve the best possible balance between energy supply and demand at the lowest possible price. In addition, the company will insure that its options are consistent with its obligation to provide good, reliable service with minimal impact on the environment.

Table B-1

Resource and Market Planning Program
Regional Research Advisory Group - Participation

Invited Participation

Conservation / Environmental:	Natural Resources Defense Council Northwest Conservation Act Coalition Solar Energy Association of Oregon
States:	Oregon Public Utilities Commission Oregon Department of Energy Washington Utilities and Trans. Commission Washington State Energy Office Washington Legislative Committees
Customer Groups:	Citizen Utility Board Industrial Customers of Northwest Utilities Oregon Committee for Fair Utility Rates Oregon League of Women Voters
Utilities & Power Planning Agencies:	Bonneville Power Administration Idaho Power Northwest Power Planning Council Portland General Electric Puget Sound Power & Light

Table B-2

Resource and Market Planning Program
Regional Research Advisory Group - Meeting Dates and Topics

Meeting Dates	Topics
8/4/88	Review Planning Process and Schedule Present End Use Models Discussion of Planning Issues
10/7/88	Conservation Supply Curves Demand Side Program Concepts Preview Supply Alternatives
11/4/88	Financial Assumptions Discussion of Cost Perspectives Conservation Estimate Progress Reports
12/6/88	Review Selective Supply Alternatives Present Demand Side Program Alternatives Discussion of Planning Methods and Externalities
1/24/89	Preliminary Forecast Range Supply Resource Assessments Marketplace Discussion
3/9/89	Levelized Costs for Supply Resources Overview of Summary Model and Methodology Discussion of Scenarios
5/25/89	Marketplace Findings Resource Portfolios Merged Demand Estimates and Forecasts Addressing Externalities
6/27/89	Review of Key Outputs and Preliminary Results Comparison of Demand Side Programs with Portfolio Resource Portfolio Sensitivities Scenario Specifications
8/22/89	Plan Format RAMPP Model Results / Evaluation RAMPP Scenarios and Externalities Evaluation Preliminary Two-Year Action Plan

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Appendix C - Draft Report Review Process

DRAFT REPORT REVIEW PROCESS

A draft version of this report was circulated for review during September and October, 1989. As part of the Oregon Public Utility Commission's formal review process (Docket LC 1), written comments were received from the Commission staff, the Oregon Department of Energy, and the Solar Energy Association of Oregon. Written comments were also received from the City of Portland Energy Office and the Natural Resources Defense Council, although these were not submitted by those parties as part of the LC 1 record.

The Draft version of this report was also presented to each of the Company's state regulatory commissions, and discussed with the commissions during quarterly information meetings. In addition, a presentation was made on the contents of the report to the Power Committee of the Northwest Power Planning Council.

Comments received during this process provided a number of constructive criticisms. Several changes and improvements have been made in this final version of the report, as a result of comments received. Moreover, many of the comments help define important issues and valuable directions that should be addressed in the ongoing planning process.

The paragraphs below briefly summarize the comments received during the draft report review process, presented in five broad areas, indicating where changes have been made in the final report and where issues and suggestions will be addressed in the ongoing planning process.

Purpose or goal of the report

Several comments were directed at a clarification of the report, its title, its relationship to the goals of least cost planning as defined by the Oregon Commission, and the Company's commitment to those goals and their implementation in the plan. Several changes in the text were made to help clarify these questions, including a more explicit statement in the Preface.

To a degree, the draft report failed to state the obvious: the purpose of the planning process described in the this report is to identify actions that should be taken, and that the Company intends to take, to assure that customers' demands are met at the lowest possible cost to the utility and its customers. As clear as that goal is, the planning process has also attempted to recognize the many inherent complexities and ambiguities, including the variety and diversity of customer demands, the uncertainties affecting those future demands, and the uncertainties affecting the alternatives that may be relied upon in the future.

Treatment of uncertainties

A number of comments requested that the report provide a better description of the timing constraints, decision rules, and contingency actions that will guide resource decisions as the future unfolds. In addition, more thorough documentation was requested of the analyses that were conducted in the development of the long term strategies and short range action plans.

Some additional discussion and tables have been included in this final version of the report, but they are just first steps in the worthwhile direction suggested by these comments. An action plan item on improving planning methods has been included to help focus improvements in the planning process. Although additional analyses have not been included within the final report itself, they can be made available in the ongoing process.

Consideration of externalities

Several comments were aimed at clarifying and improving the methods and results related to the consideration of external costs in the preparation of the plan, as required by the Oregon Commission's Order 89-507. While some additional explanation was added to the report, this is clearly an important direction that will be addressed in the ongoing planning process, as indicated in the Future Planning Issues section of the report's Action Plan.

More detailed descriptions of alternatives and short range actions

Comments in this area tended to be motivated primarily by concerns as to how actions identified in the action plan will be implemented. Also, a variety of suggestions were received on additional programs or considerations for energy efficiency activities and renewable resources. Finally, a number of comments were actually questions aimed at clarifying assumptions and details of the alternatives and short range actions.

Some additional specificity has been added in the technical documentation volume of the report, in response to some suggestions. In other areas, the Company will endeavor to improve the descriptions and documentation in future planning efforts. There is, however, a basic philosophical issue underlying some of the suggestions received. As described in the report, the purpose of long range planning is to provide the overall framework within which more immediate decisions should be analyzed. There is an inevitable trade-off between a broad, long-range scope and more specific, detailed descriptions of short-range actions. The Company has endeavored to respect the long-range scope at this stage of its planning process. Detailed workplans, schedules, or budgets for each action plan item would require an inappropriate shift in plan emphasis.

Relationship to marketing and economic development

Additional discussion and clarification of the Company's economic development and wholesale marketing activities were requested. In addition, concerns were expressed that some efficiency programs undertaken by the Company would tend to increase electrical load.

Marketing, energy efficiency, and economic development activities that respond to customer needs and provide growth opportunities for the Company will continue to be a key element of the Company's long-term business strategy. While the report does not explicitly address specific marketing and economic development programs, it does provide the framework and information necessary for such analysis. The Company's marketing efforts will continue to emphasize economic efficiencies, consistent with broad energy policies and commission orders. Specifically, the Company will endeavor to provide "reliable and affordable energy supplies to sustain a healthy economy" (Oregon energy policy, as summarized in the ODOE's Third Biennial Energy Plan), and to serve customers' needs "if it is the lowest cost provider of a customer's needs" (OPUC Order 89-507).

The Company intends to address OPUC's questions with regard to long-term wholesale sales, as part of the ongoing planning process.