A. Yes. The proposed method is consistent with methodologies authorized in the Company's other jurisdictions, produces results appropriate for the merged Company, is simple to calculate and easy to use and update.

The Company believes consistent pricing of QF purchases is important to a multi-jurisdiction utility because it will allow the Company to more effectively evaluate potential QFs throughout its system and help protect customers from paying too much for QF generation. The Company is authorized to calculate its published avoided costs with either the proposed method or a variation of it in all of its jurisdictions except Utah. In fact, the Company's Oregon, Washington and Wyoming jurisdictions, approximately 60 percent of the Company's retail business, use a methodology that is identical to the methodology the Company is proposing in Utah.

The proposed method provides avoided cost rates that are appropriate for the Company, unlike the settlement conference method, which would require substantial adjustments to the model before reasonable Company results could be produced. I will discuss that point more fully in the next section of my testimony.

Finally, the proposed method is easily updated, simple to use, and easy to understand. The Company believes these are desirable attributes for an avoided cost methodology, because they will allow the Company, potential developers, and the Commission to evaluate potential projects in a timely and cost effective manner.

Q. Please describe the avoided cost methodologies that are currently approved in the Company's other jurisdictions which differ from the Utah proposed avoided cost methodology.

A. The approved avoided cost methodologies for the Company's Idaho, California, and Montana jurisdictions differ slightly in detail from the Utah proposed method, but the underlying principles are the same. They all rely on a differential production cost analysis during a period of resource sufficiency and proxy resources when existing plus non-deferrable resources are insufficient to meet resource requirements. A general description of these methods is shown in Exhibit 1.3 (RW-3).

Comparison to Settlement Conference Agreement / Realized Marginal Energy Cost Method

Q. Are you familiar with the avoided cost rates currently approved by the Commission?

A. Yes. These avoided cost rates were filed by the Company in 1991 as part of a draft Request for Proposals. The Commission approved the rates, but did not adopt the method which produced them.

Q. How does the method used to produce the avoided costs filed in 1991 compare with the method used in the current filing?

A. The methods are essentially the same with only minor differences. These differences can be viewed as evolutionary in nature; their effect is to keep the method current as changes occur in both the western U.S. electric power market and the Company. The differences in avoided cost rates between the filings are primarily attributable to updates in the data to reflect current circumstances.

Q. Are you familiar with the avoided cost methods last approved by the Commission?

A. Yes. In 1987, the Commission adopted the Settlement Conference Agreement (SCA) method for computing avoided capacity cost and the Realized Marginal Energy Cost (RMEC) method for establishing avoided energy cost and updating it on a semiannual basis.

Q. Can you briefly characterize the SCA method?

A. Yes. The SCA method is a version of the differential revenue requirement approach. As implemented, it also has some resemblance to the proxy approach in that the capacity expansion plan component contains only one deferrable unit size and technology. In general, the method computes the present value of the stream of annual revenue requirements associated with a 20 year generation capacity expansion plan in the absence of QF development. It then imposes an assumed future stream of constant annual QF capacity increments (The Commission adopted a 15 MW per year QF capacity addition stream in the 1987 case). This has the effect of moving back the construction date of some (or all) generation units in the expansion plan. (These postponable units are called "deferrable units" in the SCA method.) The cost avoided by the QF stream is then captured in the lower present value of the annual rate base revenue requirements imposed by the deferred construction of the utility's own units in the with-QF case as compared to the without-QF case. If any deferrable units are postponed beyond the 20 year analysis horizon, their costs are entirely avoided as a result of the QF capacity. The avoided cost upon which the QF capacity cost is based is the difference between the with-QF and without-QF revenue requirements.

Q. Can you briefly characterize the RMEC method?

A. Yes. The price paid for QF supplied energy is measured from Company system operations and updated in a report to the Commission every six months. This is not a "model-produced" figure like the SCA-based capacity price, but rather represents current highest-cost energy produced or purchased by the Company as a result of economic dispatch of the Company's resources, and which could be avoided by QF generation.

Q. Can you provide the details of the Company's implementation of the RMEC method?

A. The details are discussed in Exhibit 1.4 (RW-4).

Q. How does the method proposed by the Company in this case compare with the SCA / RMEC methods?

A. Exhibit 1.5 (RW-5) presents a general comparison of the two methods in terms of a number of significant characteristics. The two approaches bear certain similarities. Both are, to some extent, hybrids of the proxy and differential revenue requirements methods. They both recognize that there is no value to additional generating capacity until such new generation is needed to meet load and reserve requirements. (The SCA method offers only the option of levelizing the deferred new generation costs to base year values however.) In addition, both methods use a temporary summer capacity purchase to meet summer capacity requirements. The differences between the methods are more pronounced than the similarities, however.

Q. Using Exhibit 1.4 (RW-4) can you generally describe the differences?

A. Yes. Some of the comparisons appearing in the exhibit are self-explanatory. Others require further discussion and will be addressed here. The rows in the exhibit are organized roughly from more abstract conceptual and theoretical issues toward the top to more practical and implementation oriented issues toward the bottom.

An avoided cost method appropriate for PacifiCorp must have the flexibility to respond to the merged system's load and resource characteristics. It should be able to identify and respond to either total annual energy deficits or winter or summer capacity deficits so that the rates developed will reflect costs that QF generation will allow the Company to avoid. The proposed method has this flexibility because avoided costs can be based on various avoidable resources which can be selected to fit any type of avoidable resource requirement. For example, the proposed method allows the Company to add a peaking resource for an initial period, then convert to a resource that produces energy when energy is needed. Further, the Company's proposed method allows selection of avoidable resources from all types of resources available in the market. Thus, the proposed method computes avoided costs on the basis of resources which can actually be avoided, and enables the Company to more fully comply with the ratepayer neutrality standard. The SCA method on the other hand doesn't have this flexibility, it responds only to summer peak resource deficits, and can add only a single type of resource. This approach may have been appropriate for Utah Power and Light Company prior to the merger and for pre-merger market conditions, but it is not appropriate for the Company in todays market. It can not reflect costs that the Company can actually avoid and therefore will not maintain ratepayer neutrality.

Calculation of Avoided Cost

Q. Please explain what is shown on Exhibit 1.6 (RW-6).

A. Exhibit 1.6 (RW-6) is a three-page exhibit showing the detailed calculation of the Company's proposed avoided cost rates. Page 1 shows the Company's proposed energy and capacity avoided cost rates and the combined rates at capacity factors of 75%, 80%, and 95%. The proposed rates are developed on pages 2 and 3 of this exhibit. Page 2 calculates the long run avoided capacity and capitalized energy costs using financial and operating assumptions that are consistent with RAMPP-3. As shown, the fixed cost of the CCCT is broken into two components, the capacity cost and the capitalized energy component. The fixed cost is equal to the fixed cost of a SCCT. The capitalized energy component is equal to the fixed cost difference between a CCCT and a SCCT. Total avoided energy costs are calculated on page 3 and are equal to the energy only costs shown in Exhibit 1.2 (RW-2) in the short run. In the long run, they are the sum of natural gas fuel expense and the capitalized energy cost developed on page 2.

Q. How were the gas prices used in the Company's avoided cost calculation developed?

A. In late 1993, the Company signed the Hermiston project power purchase agreement mentioned earlier in my testimony. Through the experience gained with Hermiston, it became apparent that the RAMPP-3 medium gas price escalation forecast was above current market conditions, as was the 1994 initial gas price. It was recognized in the RAMPP-3 process itself that the medium gas price escalation rates were higher than prices that could be expected in the market. Chapter 6 of the RAMPP-3 report states:

> The Company believes that the most likely future range for gas prices is between the low and the medium prices used in RAMPP-3.

As a result, the initial gas price and the gas price escalation rate were revised for calculating avoided costs. The 1994 initial gas price was calculated from a starting price of $2.41/MMBtu. This is composed of three parts: 1) commodity, 2) firm transportation, and 3) taxes and shrinkage. The commodity component is the average of the gas futures prices published in The Wall Street Journal on January 12, 1994. This value is $2.09/MMBtu for delivery at Henry Hub. The delivery price at Henry Hub is reduced by $.22/MMBtu to reflect the price differential for delivery in PacifiCorp's service area. This results in a 1994 commodity price of $1.87/MMBtu. Taxes and shrinkage add 5% to the commodity price. Transportation in 1994 is assumed to be $0.45/MMBtu. The transportation, tax, and shrinkage assumptions are those used in RAMPP-3.

The gas escalation utilized for avoided costs is based on the average of RAMPP-3 medium and low gas price escalation forecasts for years 1-20 and is consistent with the RAMPP-3 low gas price escalation forecast for years 21-30. The gas prices used in the calculation of the Company's proposed avoided cost rates are shown in Exhibit 1.7 (RW-7).

Standard Rate Proposal

Q. Please describe the Company's avoided cost rate proposal.

A. The Company's proposed avoided cost rates for purchases from QFs with a design capacity of 1,000 kw or less are shown in Exhibit 1.6 (RW-6), page 1.

Q. Have you prepared a comparison of the Company's proposed avoided cost rates to the currently published avoided cost rates?

A. Yes. Exhibit 1.8 (RW-8) is a comparison of the Company's proposed rates and the current published rates. As shown, the proposed rates are approximately 21 percent lower than the currently published rates.

Q. Why has the Company proposed standard rates for QFs 1,000 kw or less in size?

A. The standard avoided cost rates shown in Exhibit 1.6 (RW-6) assume optimum QF operating characteristics and ability to integrate the power into the Company's system. Therefore, they do not include the impact of transmission constraints, wholesale market competition, dispatchability, and reliability. The Company recognizes that this is unlikely to be the case for all new QFs located in Utah especially as the size of the QF increases. However, the Company believes that the time and cost involved in analyzing all of the operational characteristics of a qualifying facility of 1,000 kw or less would not be justified based on the magnitude of the problems they can impose. Also, for smaller projects, the transaction costs of negotiating these issues might unjustifiably discourage their development.

Q. What are your recommendations to this Commission?

A. I recommend that the Commission adopt the Company's proposed method of calculating avoided cost rates and the proposed avoided cost rates for purchases from QFs with a design capacity of 1,000 kw or less as presented in Exhibit 1.6 (RW-6).

Q. Does this conclude your testimony?

A. Yes.

PacifiCorp Loads & Resources Projection

1994 Avoided Cost Base Study
(Modified RAMPP-3)

	Average Megawatts	1994	1995	1996	1997	1998	1999	2000
	Requirements							
1	System Retail Load (1)	5621	5750	5895	6024	6154	6287	6435
2	Firm Wholesale Sales (2)	1076	1091	1053	1070	1070	1095	1079
3	Total	6697	6842	6948	7093	7225	7383	7513
	Existing & Committed Resources (3)							
4	System Hydro Resources	438	438	438	438	438	438	438
5	Thermal Resources	5663	5800	5805	5804	5804	5804	5805
6	Resource Efficiencies	4	9	13	17	22	26	30
7	Mid Columbia Purchases	199	199	199	199	199	199	199
8	Purchases & Exchanges	499	501	336	283	239	226	218
9	WWP Capacity Purchase (4)	9	9	13	13	13	13	13
10	Demand Side Resources (5)	21	44	73	110	154	190	230
11	APS CT	0	0	0	11	22	22	22
12	CoGen/James River	0	0	48	48	48	48	48
13	CoGen/Hermiston (4)	0	0	219	436	436	436	436
14	Wind	0	0	38	38	38	38	38
15	WWP Seasonal Exchange (4)	4	0	0	0	0	0	0
16	Total Existing & Committed Resources	6837	6999	7182	7397	7412	7440	7476
17	**Balance of Existing & Committed Resources**	**140**	**158**	**234**	**303**	**187**	**57**	**-37**
	Avoidable Resources							
18	Summer Capacity Purchase	0	0	0	0	0	0	0
19	Large CCCT	0	0	0	0	0	0	180
20	**Balance with Avoidable Resources**	**140**	**158**	**234**	**303**	**187**	**57**	**143**

Footnotes:

(1) Source RAMPP-3 Report, Load Forecasting Appendix, page 122 plus interruptible loads and excluding Nothern Idaho load.
(2) Source RAMPP-3 Report planning assumptions plus the City of Redding sale.
(3) Source RAMPP-3 Report, Chapter 4 page 35, except as noted.
(4) These resources were added after the RAMPP-3 planning assumptions were set.
(5) Source RAMPP-3 Report, Demand Side Resource Appendix, Appendix H

PacifiCorp Loads & Resources Projection

1994 Avoided Cost Base Study
(Modified RAMPP-3)

	Winter Peak - Megawatts	1994	1995	1996	1997	1998	1999	2000
	Requirements							
1	System Retail Load (1)	7436	7617	7815	7999	8176	8358	8561
2	Firm Sales (2)	1378	1432	1284	1284	1284	1284	1234
3	Total	8814	9049	9099	9283	9460	9642	9795
	Existing & Committed Resources (3)							
4	System Hydro Resources	884	884	884	884	884	884	884
5	Thermal Resources	6616	6844	6849	6849	6849	6849	6849
6	Resource Efficiencies	7	14	21	28	35	42	49
7	Mid Columbia Purchases	420	420	420	420	420	420	420
8	Purchases & Exchanges	2211	2300	2174	2033	2031	2021	1972
9	WWP Capacity Purchase (4)	0	0	0	0	0	0	0
10	Demand Side Resources (5)	34	72	120	180	251	311	377
11	APS CT	0	0	0	0	148	148	148
12	CoGen/James River	0	0	50	50	50	50	50
13	CoGen/Hermiston (4)	0	0	0	469	469	469	469
14	Wind	0	0	13	13	13	13	13
15	Irrigation Load Control (4)	0	0	0	0	0	0	0
16	WWP Seasonal Exchange (4)	0	-50	-50	-50	-50	-50	-50
17	Total Existing & Committed Resources	10171	10484	10481	10876	11100	11157	11181
	Reserve Requirement							
18	Reserve	1332	1360	1367	1395	1422	1449	1472
19	(Reserve+Balance)/Requirements	15%	16%	15%	17%	17%	16%	14%
20	**Balance of Existing & Committed Resources**	**26**	**75**	**15**	**198**	**219**	**66**	**-86**
	Avoidable Resources							
21	Summer Capacity Purchase	0	0	0	0	0	0	0
22	Large CCCT	0	0	0	0	0	0	225
	Reserve Requirement							
23	Reserve	1332	1360	1367	1395	1422	1449	1472
24	(Reserve+Balance)/Requirements	15%	16%	15%	17%	17%	16%	16%
25	**Balance with Avoidable Resources**	**26**	**75**	**15**	**198**	**219**	**66**	**139**

Footnotes:

(1) Source RAMPP-3 Report, Load Forecasting Appendix, page 122 plus interruptible loads and excluding the Nothern Idaho load.
(2) Source RAMPP-3 Report planning assumptions plus the City of Redding sale.
(3) Source RAMPP-3 Report, Chapter 4 page 36, except as noted.
(4) These resources were added after the RAMPP-3 planning assumptions were set.
(5) Source RAMPP-3 Report, Demand Side Resource Appendix, Appendix H

PacifiCorp Loads & Resources Projection

1994 Avoided Cost Base Study
(Modified RAMPP-3)

	Summer Peak - Megawatts	1994	1995	1996	1997	1998	1999	2000
	System Load							
1	System Retail Load (1)	7024	7205	7403	7585	7759	7937	8131
2	Firm Wholesale Sales (2)	1728	1730	1614	1629	1629	1704	1719
3	Total	8752	8935	9017	9214	9388	9641	9850
	Existing & Committed Resources (3)							
4	System Hydro Resources	870	870	870	870	870	870	870
5	Thermal Resources	6732	6830	6835	6835	6835	6835	6835
6	Resource Efficiencies	7	14	21	28	35	42	49
7	Mid Columbia Purchases	420	420	420	420	420	420	420
8	Purchases & Exchanges	1799	1788	1583	1431	1321	1277	1271
9	WWP Capacity Purchase (4)	100	100	150	150	150	150	150
10	Demand Side Resources	34	72	120	180	251	311	377
11	APS CT	0	0	0	148	148	148	148
12	CoGen/James River	0	0	50	50	50	50	50
13	CoGen/Hermiston (4)	0	0	469	469	469	469	469
14	Wind	0	0	13	13	13	13	13
15	Irrigation Load Control (4)	90	90	90	90	90	90	90
16	WWP Seasonal Exchange (4)	50	50	50	50	50	50	50
17	Total Existing & Committed Resources	10102	10234	10671	10735	10702	10725	10792
	Reserve Requirement							
18	Reserve	1324	1351	1370	1402	1428	1475	1497
19	(Reserve+Balance)/Requirements	15%	15%	18%	17%	14%	11%	10%
20	**Balance of Existing & Committed Resources**	**26**	**-52**	**284**	**119**	**-114**	**-390**	**-555**
	Avoidable Resources							
21	Summer Capacity Purchase	0	53	0	0	114	391	0
22	Large CCCT	0	0	0	0	0	0	225
	Reserve Requirement							
23	Reserve	1324	1351	1370	1402	1428	1475	1497
24	(Reserve+Balance)/Requirements	15%	15%	18%	17%	15%	15%	12%
25	**Balance with Avoidable Resources**	**26**	**1**	**284**	**119**	**0**	**1**	**-330**

Footnotes:

(1) Source RAMPP-3 Report, Load Forecasting Appendix, page 122 plus interruptible loads and excluding the Nothern Idaho load.
(2) Source RAMPP-3 Report planning assumptions plus the City of Redding sale.
(3) Source RAMPP-3 Report, Chapter 4 page 37, except as noted.
(4) These resources were added after the RAMPP-3 planning assumptions were set.
(5) Source RAMPP-3 Report, Demand Side Resource Appendix, Appendix H

PacifiCorp

1994 Avoided Cost Prices for Purchase Power

Summary of PD/Mac Avoided Cost Output
Mills/kWh

Operating Year	31 Jul	31 Aug	30 Sep	31 Oct	30 Nov	31 Dec	31 Jan	28 Feb	31 Mar	30 Apr	31 May	30 Jun	OPER-YR AVG
						Mills/kWh							
1993-94	18.19	17.36	18.43	18.53	17.86	16.72	14.96	14.62	15.49	13.55	10.64	10.65	15.60
1994-95	15.64	20.02	21.61	17.58	17.11	17.10	15.57	14.44	15.52	14.31	11.76	11.70	16.04
1995-96	16.06	20.66	22.41	18.15	17.65	17.20	16.78	15.11	17.26	14.49	12.07	12.31	16.69
1996-97	17.51	22.00	23.44	18.31	18.21	18.32	15.47	15.36	16.08	14.14	12.39	12.31	16.97
1997-98	21.53	23.84	27.34	19.07	18.97	18.06	16.64	16.37	17.24	16.66	13.48	13.57	18.58
1998-99	24.44	25.31	29.09	20.22	20.12	19.32	18.84	17.97	19.25	18.40	13.51	14.75	20.11
1998-99	26.62	29.99	30.85	31.12	22.05	21.50	20.85	19.01	20.84	19.40	14.25	15.80	22.73

Calendar Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	OPER-YR AVG
1994	14.96	14.62	15.49	13.55	10.64	10.65	15.64	20.02	21.61	17.58	17.11	17.10	15.72
1995	15.57	14.44	15.52	14.31	11.76	11.70	16.06	20.66	22.41	18.15	17.65	17.20	16.26
1996	16.78	15.11	17.26	14.49	12.07	12.31	17.51	22.00	23.44	18.31	18.21	18.32	17.12
1997	15.47	15.36	16.08	14.14	12.39	12.31	21.53	23.84	27.34	19.07	18.97	18.06	17.85
1998	16.64	16.37	17.24	16.66	13.48	13.57	24.44	25.31	29.09	20.22	20.12	19.32	19.34
1999	18.84	17.97	19.25	18.40	13.51	14.75	26.62	29.99	30.85	31.12	22.05	21.50	22.01

Source: Produced as the difference of two Production Dispatch Model (PD/Mac) runs: A base case including existing and committed resources, and a comparison run which includes a 50 MWa zero cost resource as a proxy for QF generation.

Each monthly figure represents the change in net power cost divided by the 50 MWa resource

Based on Final RAMPP-3 Avoided Costs

PacifiCorp
Avoided Costs Calculation Methods
Idaho, California, Montana

Idaho Avoided Cost - Surrogate Avoidable Resource Method (SAR)

The Idaho avoided cost methodology can be broken down into two distinct periods based on a utility's load and resource plan: 1) Short Run: A period of energy surplus in which avoided costs are based on normalized non-firm energy sales prices; 2) Long Run: A period in which new resources are required to provide energy to meet a specific utility's load. Long run costs are based on the fixed and variable cost of a SAR.

Short Run Avoided Costs

During periods of energy surplus, a utility's short run avoided costs are based on normalized non-firm energy sales prices. The period of energy surplus is determined from a utility specific load and resource plan that is consistent with a utility's most recent Resource Management Report (RMR), updated for known and measurable changes. Future Qualifying Facility (QF) resources and demand side management resources that have not been contracted for are not includable as resources. On the other hand, PacifiCorp is allowed to include a generic 65 aMW resource in its load and resource plan because of the Company's ability to purchase firm resources from the integrated Western Systems and the Desert Southwest.

Long Run Avoided Costs

Beginning with the first deficit year, shown in the load and resource plan described above, the avoided costs are based on the fixed and variable costs of a SAR plus any avoidable transmission costs. The currently approved SAR for all Idaho utilities is a hypothetical coal fired steam plant with state of the art emission controls located in the powder river basin.

The non-levelized avoided cost rates are equal to the summation of: 1) annual capital costs of the SAR, 2) fixed operating maintenance (O&M) expense of the SAR, 3) variable O&M expense of the SAR, and 4) fuel costs of the SAR. However, these costs are split between adjustable and non-adjustable portions for the determination of final avoided costs. Final approved avoided costs are equal to the sum of the non-adjustable portion levelized and the adjustable portion.

The adjustable portion is comprised of variable O&M expense and fuel expense. These expenses are fixed when the avoided costs are adopted by the Commission and updated annually on the basis of actual Colstrip variable operating expenses for the prior calendar year, as reported by the Washington Water Power Company to the Idaho Commission. The non-adjustable portion of the avoided costs is calculated by removing the escalated adjustable portion of avoided costs from the total non-levelized avoided costs and levelizing the remaining balance.

Current Idaho Filing

Recently, the Company and other Idaho utilities have filed requests with the Idaho Public Utilities Commission to change the SAR from a generic coal plant to a combined cycle combustion turbine (CCCT) and to eliminate the separation of avoided costs between variable and non-variable components. The proposed change, if adopted, would make the Idaho methodology consistent with the methodology proposed in Utah.

California Avoided Cost Method

The California avoided cost methodology can be broken down into two distinct periods based on a utility's load and resource plan: 1) Short Run: A period of energy surplus in which avoided costs are based on the marginal production cost of resources plus a capacity cost which is based on Bonneville Power Administration's (BPA) New

Resource firm rate adjusted for capacity requirements ; 2) Long Run: A period in which new resources are required to provide energy to meet a specific utility's load. Long run costs are based on BPA's New Resource firm rate capacity and energy costs.

Short Run Avoided Costs

During periods of resource sufficiency, the Company's avoided energy costs are based on the displacement of purchased power and existing thermal resources. The model input data includes the monthly load and resource data which are the basis for the annual summary of loads and resources. To calculate short-term avoided energy costs, two production cost model studies are performed. The only difference between the two studies is an assumed zero running cost 50 average megawatt increase in monthly system resources. The 50 average megawatt resource serves as a proxy for qualifying facility generation. The resulting differences in system production costs between the two studies represents PacificCorp's avoided energy costs. The avoided energy costs could be thought of as the highest variable cost incurred to serve total system load from existing and non-deferrable resources.

Short Run capacity costs are based on BPA's New Resource firm rate capacity costs adjusted by an electric reliability index (ERI). The ERI determines the Company's capacity requirements on the basis of a target reserve margin. If the Company forecasted reserve margin developed in the loads and resources balance is less than the target reserve margin, the BPA New Resource firm rate is multiplied by a factor of 1.0. However, if the forecasted reserve margin is greater than the target reserve margin the BPA capacity rate is multiplied by a factor less than 1.0.

Long Run Avoided Costs

Beginning with the first deficit year, shown in the load and resource plan described above, the avoided costs are based on BPA's New Resource firm rate capacity and energy prices.

Current California Filing

Recently, the Company filed to update its California published avoided cost rates rates. Those rates are expected to become effective on May 1, 1994.

Montana Avoided Cost Methodology

The avoided cost calculations can be broken into two distinct periods based on the load and resource Plan: 1) Short Run: A period of sufficiency in which the avoided costs are based on the marginal production cost of existing resources, plus adders for wholesale sales, non-fuel O&M production costs and transmission losses ; 2) Long Run: A period in which new resources are required to provide both capacity and energy to meet the Company's loads. Avoided costs during the second period are based on the cost of a CCCT.

Short Run Avoided Costs

During periods of resource sufficiency, the Company's avoided costs are based on the displacement of purchased power and existing thermal resources, and are an energy-only calculation. The model input data includes the monthly load and resource data which are the basis for the annual summary of loads and resources shown. To calculate short-term avoided costs two production cost model studies are performed. The only difference between the two studies is a 10 average megawatt increase in monthly system resources. The 10 average megawatt resource serves as a proxy for qualifying facilities generation. The resulting differences in system production costs between the two studies represent PacifiCorp's avoided energy costs. The avoided energy cost could be thought of as the highest variable cost incurred to serve total system load.

Long Run Avoided Costs

The avoided costs are determined to be the fixed cost and the variable costs of the planned resource which could be avoided or deferred, which in this case is a combined CCCT. Since CCCTs are built as base load units which provide both capacity and energy, it is appropriate to split the fixed cost of that unit into capacity and energy components. The fixed cost of a simple cycle combustion turbine (SCCT), usually acquired as a capacity resource, defines the portion of the fixed cost of the CCCT that is assigned to capacity. The fixed cost of a CCCT in excess of the SCCT costs is assigned to energy and is added to the variable production (fuel) cost of the CCCT, along with transmission losses and an operating and maintenance expense adder to determine the total avoided energy cost.

REALIZED MARGINAL ENERGY COST METHOD (RMEC)

This description of the RMEC energy pricing method details the data source and calculation procedures used to compute the energy price paid for qualifying facility (QF) produced energy purchased by PacifiCorp under the method adopted by the Commission in the April 3, 1987, Report and order in Docket No.80-999-06.

Beginning in the second half of 1987, the Company has submitted every six months an "Update to Avoided Energy Cost" report to the Commission. The most recent of these (for July-December 1993, dated January 25, 1994) appears as the last page of this exhibit. Until the July-December 1991 report, the calculations were done by individuals. The last three were produced by a computer program developed to read the Company's dispatch data to produce the Utah requirements.

Specifically, the computer creates a file containing data for each hour on the highest cost resource operating on the system during that hour. At the end of the hour, the computer adds a new record to the file describing that hour's marginal resource and its running cost. The record specifies the year, month, date, hour, the name of the hour's marginal resource, whether the resource is a purchase or a Company-owned resource, and the cost or price of running that resource in that hour. These data represent the most expensive MWH acquired or produced by the Company in that hour for whatever purpose -- firm load, interruptible buy through, or economy or emergency sale for resale. The figures for the individual hours are then aggregated for the month into purchase and Company-owned-resource categories. The number of hours each type of resource was on the margin and the average price/cost in each category is computed.

The monthly summary data is then presented each six months in the Update to Avoided Energy Cost report delivered to the Commission. In the report, avoidable purchased energy costs appear in the "PURCHASED ENERGY" columns and Company-owned-generation avoidable energy costs appear in the "STEAM ENERGY" columns. At this stage, a variable O&M cost adder has been included in Company-owned steam energy costs. In both sets of columns, the column labeled "MWH" specifies the number of hours in the month that type of resource was on the margin (note that the MWH values sum to the number of hours in the month.) The "MILLS/KWH" column shows the average of the hourly marginal running costs of each type of resource in the hours it was on the margin. Finally, the "TOTAL" columns compute the weighted average of the two categories of marginal energy costs. The average of the six reported months then becomes the QF energy purchase price for the following six months.

The current value, based on the last half of 1993, is 23.95 mills per kWh. For projects specified by the Commission, this value is increased to 25.15 mills by a 5 percent credit for transmission loss reduction.

PACIFICORP
UPDATE TO AVOIDED ENERGY COST: JULY - DECEMBER 1993

MONTH	PURCHASE ENERGY		STEAM ENERGY		TOTAL	
	MWH	MILLS/KWH	MWH	MILLS/KWH	MWH	MILLS/KWH
JUL	743	21.12	1	20.03	744	21.12
AUG	729	25.15	15	16.55	744	24.98
SEP	638	22.28	82	17.62	720	21.75
OCT	674	23.31	71	14.91	745	22.51
NOV	706	27.06	14	23.31	720	26.99
DEC	707	26.68	37	19.67	744	26.33
TOTAL	**4197**	**24.28**	**220**	**17.39**	**4417**	**23.94**

Adjusted for Avoided Operation and Maintenance Expense — 23.95 MILLS/KWH

The Avoided Energy Cost related to qualifying Facilities in the Utah Jurisdiction is 23.95 Mills per Kilowatt hour for the July through December 1993 period.

General Comparison of PacifiCorp Method and SCA / Realized Marginal Energy Cost Method

PacifiCorp Method	SCA / RMEC Method
Capacity & energy from single method	Separate methods for capacity & energy
Proxy / differential revenue requirement method hybrid	Differential revenue requirement / proxy method hybrid for capacity, Actual marginal energy
Responds to energy, summer peak, or winter peak trigger	Responds to summer peak trigger only
Sensitive to load forecast only through sufficiency period	Sensitive to load forecast through entire (20-year) analysis horizon
Capacity & energy both normalized values	Capacity normalized; energy actual
Incorporates "today's" market resources	Does not incorporate "today's" market resources
Levelized or non-levelized pricing options for both capacity & energy	Levelized capacity payments only, non-levelized energy prices only
Operator-designed resource selection given load requirements	SCA method automatic "one-resource-fits-all" for all types of requirements
No avoided energy cost floor/balancing account	Complex RMEC floor/balancing account mechanism
Implemented for system	Not implemented for system -- substantial work required for one jurisdiction
Accepted in Oregon, Washington, Wyoming	Accepted in Utah only

PacifiCorp

1994 AVOIDED COSTS

RAMPP-3

Summary

	Year	Avoided Firm Capacity Costs ($/kW-mo)	Avoided Energy Costs $/MWh	Total Avoided Costs 75% CF $/MWh	Total Avoided Costs 80% CF $/MWh	Total Avoided Costs 95% CF $/MWh
		(1)	(2)	(3)	(4)	(5)
1	1994	0.00	15.72	15.72	15.72	15.72
2	1995	0.76	16.26	17.65	17.56	17.36
3	1996	0.00	17.12	17.12	17.12	17.12
4	1997	0.00	17.85	17.85	17.85	17.85
5	1998	0.96	19.34	21.10	20.99	20.73
6	1999	1.00	22.01	23.84	23.73	23.46
7	2000	5.04	30.56	39.76	39.18	37.82
8	2001	5.21	32.04	41.55	40.96	39.55
9	2002	5.39	33.60	43.44	42.82	41.37
10	2003	5.57	35.25	45.43	44.79	43.28
11	2004	5.76	37.00	47.52	46.87	45.31
12	2005	5.95	38.86	49.73	49.05	47.44
13	2006	6.16	40.82	52.07	51.36	49.70
14	2007	6.37	42.90	54.52	53.80	52.08
15	2008	6.58	45.09	57.12	56.37	54.59
16	2009	6.81	47.42	59.85	59.07	57.23
17	2010	7.04	49.88	62.74	61.93	60.03
18	2011	7.28	52.49	65.78	64.95	62.98
19	2012	7.52	55.25	68.99	68.14	66.10
20	2013	7.78	58.17	72.39	71.50	69.39
21	2014	8.05	60.79	75.49	74.57	72.39
22	2015	8.32	63.54	78.73	77.78	75.53
23	2016	8.60	66.42	82.13	81.15	78.82
24	2017	8.89	69.44	85.68	84.67	82.26
25	2018	9.20	72.61	89.41	88.36	85.87
26	2019	9.51	75.94	93.31	92.22	89.65
27	2020	9.83	79.43	97.39	96.27	93.61
28	2021	10.17	83.09	101.66	100.50	97.75
29	2022	10.51	86.94	106.14	104.94	102.10
30	2023	10.87	90.97	110.83	109.58	106.65
31	2024	11.24	95.21	115.73	114.45	111.41
32	2025	11.62	99.65	120.88	119.55	116.41
33	2026	12.02	104.31	126.26	124.89	121.64
34	2027	12.43	109.21	131.90	130.48	127.12

Column Notes:

(1) Based on a 3 month (June-August) summer capacity purchase for the years 1995, 1998 and 1999 and the fixed cost of simple cycle combustion turbine beginning in the year 2000.

(2) Based on production cost model results through 1999. Beginning in the year 2000, combined cycle fuel cost and capitalized fixed cost of combined cycle combustion turbine which is in excess of a simple cycle combustion turbine.

(3) Combined costs, assuming 75% Capacity Factor.

(4) Combined costs, assuming 80% Capacity Factor.

(5) Combined costs, assuming 95% Capacity Factor.

PacifiCorp

1994 AVOIDED COSTS

RAMPP-3

Calculation of Avoided Capacity and Capitalized Energy Costs

Cost of capital	10.43%
Discount Rate	8.81%
Inflation rate	3.40%
Real Discount Rate	5.23%

Simple cycle CT		Combined cycle CT		
1994 Capital	$462 /kW	1994 Capital	$663 /kW	
Carrying Charge	9.50%	Carrying Charge	9.50%	(assume 30 year book life)
Non-Fuel O&M	5.60 /kW	Non-Fuel O&M	17.01 /kW	

	Year	Simple Cycle Fixed Costs ($/kW-yr) (1)	Simple Cycle Fixed Costs ($/kW-mo) (2)	Combined Cycle Fixed Costs ($/kW-yr) (3)	Combined Cycle Fixed Costs ($/kW-mo) (4)	Capitalized Energy Cost ($/kW-mo) (4) - (2) = (5)	Capitalized Energy Cost 80% CF ($/MWh) (6)
1	1994	49.47		79.92		0.00	0.00
2	1995	51.15		82.63		0.00	0.00
3	1996	52.89		85.44		0.00	0.00
4	1997	54.68		88.35		0.00	0.00
5	1998	56.54		91.35		0.00	0.00
6	1999	58.47		94.46		0.00	0.00
7	2000	60.45	5.04	97.67	8.14	3.10	5.31
8	2001	62.51	5.21	100.99	8.42	3.21	5.49
9	2002	64.64	5.39	104.42	8.70	3.32	5.68
10	2003	66.83	5.57	107.98	9.00	3.43	5.87
11	2004	69.11	5.76	111.65	9.30	3.55	6.07
12	2005	71.45	5.95	115.44	9.62	3.67	6.28
13	2006	73.88	6.16	119.37	9.95	3.79	6.49
14	2007	76.40	6.37	123.43	10.29	3.92	6.71
15	2008	78.99	6.58	127.62	10.64	4.05	6.94
16	2009	81.68	6.81	131.96	11.00	4.19	7.17
17	2010	84.46	7.04	136.45	11.37	4.33	7.42
18	2011	87.33	7.28	141.09	11.76	4.48	7.67
19	2012	90.30	7.52	145.88	12.16	4.63	7.93
20	2013	93.37	7.78	150.84	12.57	4.79	8.20
21	2014	96.54	8.05	155.97	13.00	4.95	8.48
22	2015	99.82	8.32	161.28	13.44	5.12	8.77
23	2016	103.22	8.60	166.76	13.90	5.30	9.07
24	2017	106.73	8.89	172.43	14.37	5.48	9.38
25	2018	110.36	9.20	178.29	14.86	5.66	9.69
26	2019	114.11	9.51	184.35	15.36	5.85	10.02
27	2020	117.99	9.83	190.62	15.89	6.05	10.36
28	2021	122.00	10.17	197.10	16.43	6.26	10.72
29	2022	126.15	10.51	203.81	16.98	6.47	11.08
30	2023	130.44	10.87	210.73	17.56	6.69	11.46
31	2024	134.87	11.24	217.90	18.16	6.92	11.85
32	2025	139.46	11.62	225.31	18.78	7.15	12.25
33	2026	144.20	12.02	232.97	19.41	7.40	12.67
34	2027	149.10	12.43	240.89	20.07	7.65	13.10

Column Notes:
(1) Real levelized annual cost of simple cycle CT, represents the capacity portion of fixed avoided costs.
(2) Columm (1) divided by 12.
(3) Real levelized annual cost of combined cycle CT.
(4) Columm (3) divided by 12.
(5) Column (4) minus Column (2), represents the portion of fixed costs assigned to energy.
(6) Equal to Column (5), converted to $/MWh assuming the stated capacity factor.

PacifiCorp

1994 AVOIDED COSTS

RAMPP-3

	Year	Avoided Fuel or Purchase Cost ($/MWh) (1)	Updated Gas Price ($/MBtu) (2)	CCCT Energy Costs 7518 Btu/kWh ($/MWh) (3)	Variable Avoided Energy Cost ($/MWh) (1) + (3) =(4)	Capitalized Energy Cost 80% CF ($/MWh) (5)	Total Avoided Energy Cost ($/MWh) (4) + (5) =(6)
1	1994	15.72	2.41		15.72		15.72
2	1995	16.26	2.55		16.26		16.26
3	1996	17.12	2.69		17.12		17.12
4	1997	17.85	2.85		17.85		17.85
5	1998	19.34	3.01		19.34		19.34
6	1999	22.01	3.18		22.01		22.01
7	2000		3.36	25.25	25.25	5.31	30.56
8	2001		3.53	26.54	26.54	5.49	32.04
9	2002		3.71	27.92	27.92	5.68	33.60
10	2003		3.91	29.38	29.38	5.87	35.25
11	2004		4.11	30.93	30.93	6.07	37.00
12	2005		4.33	32.58	32.58	6.28	38.86
13	2006		4.57	34.33	34.33	6.49	40.82
14	2007		4.81	36.18	36.18	6.71	42.90
15	2008		5.08	38.15	38.15	6.94	45.09
16	2009		5.35	40.24	40.24	7.17	47.42
17	2010		5.65	42.46	42.46	7.42	49.88
18	2011		5.96	44.82	44.82	7.67	52.49
19	2012		6.29	47.32	47.32	7.93	55.25
20	2013		6.65	49.97	49.97	8.20	58.17
21	2014		6.96	52.31	52.31	8.48	60.79
22	2015		7.28	54.77	54.77	8.77	63.54
23	2016		7.63	57.35	57.35	9.07	66.42
24	2017		7.99	60.06	60.06	9.38	69.44
25	2018		8.37	62.92	62.92	9.69	72.61
26	2019		8.77	65.91	65.91	10.02	75.94
27	2020		9.19	69.06	69.06	10.36	79.43
28	2021		9.63	72.38	72.38	10.72	83.09
29	2022		10.09	75.86	75.86	11.08	86.94
30	2023		10.58	79.51	79.51	11.46	90.97
31	2024		11.09	83.36	83.36	11.85	95.21
32	2025		11.63	87.40	87.40	12.25	99.65
33	2026		12.19	91.65	91.65	12.67	104.31
34	2027		12.78	96.11	96.11	13.10	109.21

Column Notes:
(1) Avoided energy costs from PD/Mac Production Cost Studies.
(2) Gas commodity prices are based on futures prices as quoted in the Wall Street Journal January 12, 1994, adjusted for the Henry Head basis differental, escalated at 2.75% real (avg. of RAMPP 3 low & medium) per year through 2013, and escalated at 1.7% real (RAMPP-3 low)thereafter. In addition to the commodity price, firm transportation and shrinkage costs have been added consistent with RAMPP 3.
(3) Fuel cost of large combined cycle combustion turbine.
(4) Total avoided variable energy costs, Column (1)+column(3)+ Column(4)
(5) Fixed energy costs, fixed cost of CCCT less fixed cost SCCT
(6) Total avoided energy costs, Column(5) + Column (6)

PacifiCorp
1994 Avoided Cost
Gas Price Forecast

	Fuel Cost MMBtu /1	Transport /2	Taxes & Shrinkage /3	Total Gas Price	Fuel /4 Escalation Rate
1994	1.87	0.45	0.09	2.41	
1995	1.98	0.47	0.10	2.55	6.15%
1996	2.11	0.48	0.11	2.69	6.15%
1997	2.24	0.50	0.11	2.85	6.15%
1998	2.37	0.51	0.12	3.01	6.15%
1999	2.52	0.53	0.13	3.18	6.15%
2000	2.67	0.55	0.13	3.36	6.15%
2001	2.84	0.55	0.14	3.53	6.15%
2002	3.01	0.55	0.15	3.71	6.15%
2003	3.20	0.55	0.16	3.91	6.15%
2004	3.39	0.55	0.17	4.11	6.15%
2005	3.60	0.55	0.18	4.33	6.15%
2006	3.83	0.55	0.19	4.57	6.15%
2007	4.06	0.55	0.20	4.81	6.15%
2008	4.31	0.55	0.22	5.08	6.15%
2009	4.57	0.55	0.23	5.35	6.15%
2010	4.86	0.55	0.24	5.65	6.15%
2011	5.15	0.55	0.26	5.96	6.15%
2012	5.47	0.55	0.27	6.29	6.15%
2013	5.81	0.55	0.29	6.65	6.15%
2014	6.10	0.55	0.31	6.96	5.10%
2015	6.41	0.55	0.32	7.28	5.10%
2016	6.74	0.55	0.34	7.63	5.10%
2017	7.09	0.55	0.35	7.99	5.10%
2018	7.45	0.55	0.37	8.37	5.10%
2019	7.83	0.55	0.39	8.77	5.10%
2020	8.23	0.55	0.41	9.19	5.10%
2021	8.64	0.55	0.43	9.63	5.10%
2022	9.09	0.55	0.45	10.09	5.10%
2023	9.55	0.55	0.48	10.58	5.10%
2024	10.04	0.55	0.50	11.09	5.10%
2025	10.55	0.55	0.53	11.63	5.10%
2026	11.09	0.55	0.55	12.19	5.10%
2027	11.65	0.55	0.58	12.78	5.10%

/1 The 1994 price is equal to the January 12, 1994 futures prices from the Wall Street Journal for delivery at Henry Hub adjusted for delivery to PacifiCorp's system.

/2 Westside firm transportation

/3 5.0% added for taxes and shrinkage

/4 Assumed a 6.15% escalation rate (2.75%) real for the first 20 years and a 5.10% escalation rate (1.7% real) for the remaining 10 years. The escalation rate for the years 1 through 20 is equal to the average of the RAMPP-3 low and medium rates, and for the years 21 through 30 is equal to the RAMPP-3 low rate.

PacifiCorp

Comparison of Proposed Avoided Cost Rates to Authorized Avoided Cost Rates

		Utah Proposed Avoided Cost Rates 75% CF (¢/kWh)	Utah Authorized Avoided Cost Rates 75% CF (¢/kWh)	Difference
		(1)	(2)	(3)
1	1994	1.57	1.68	-0.11
2	1995	1.76	1.81	-0.04
3	1996	1.71	2.97	-1.26
4	1997	1.78	3.23	-1.44
5	1998	2.11	3.50	-1.39
6	1999	2.38	3.82	-1.43
7	2000	3.98	4.00	-0.02
8	2001	4.15	4.22	-0.07
9	2002	4.34	4.48	-0.14
10	2003	4.54	4.56	-0.01
11	2004	4.75	4.92	-0.17
12	2005	4.97	5.87	-0.89
13	2006	5.21	5.91	-0.70
14	2007	5.45	6.60	-1.15
15	2008	5.71	7.31	-1.60
16	2009	5.99	8.20	-2.21
17	2010	6.27	8.59	-2.31
18	2011	6.58	9.09	-2.51
19	2012	6.90	9.61	-2.71
20	2013	7.24	10.17	-2.93
21	2014	7.55	10.77	-3.22
22	2015	7.87	11.39	-3.52
23	2016	8.21	N/A	N/A
24	2017	8.57	N/A	N/A
25	2018	8.94	N/A	N/A
26	2019	9.33	N/A	N/A
27	2020	9.74	N/A	N/A
28	2021	10.17	N/A	N/A
29	2022	10.61	N/A	N/A
30	2023	11.08	N/A	N/A

20 Year Net Present Value:	32.57	40.79	
20-year Nominal Levelized	3.52	4.41	-0.89
20-year Real Levelized	2.66	3.34	-0.67
22 Year Net Present Value:	35.08	44.40	
22-year Nominal Levelized	3.66	4.63	-0.97
22-year Real Levelized	2.72	3.44	-0.72