Exhibit B

UNITED STATES OF AMERICA

BEFORE THE

NUCLEAR REGULATORY COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR CONSENT TO THE TRANSFER OF LICENSES)	EXHIBIT B to Facility Operating License No. NPF-1 Indemnity Agreement No. B-78

PREFILED TESTIMONY OF DENNIS P. STEINBERG

Exhibit No. 10

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Utah Power & Light Company	)	
PacifiCorp	)	Docket No. EC88-2-000
PC/UP&L Merging Corp.	)	

PREFILED TESTIMONY
OF
DENNIS P. STEINBERG
ON BEHALF OF
PACIFICORP,
UTAH POWER & LIGHT COMPANY
PC/UP&L MERGING CORP.

January 8, 1988

SUMMARY OF TESTIMONY
OF
DENNIS P. STEINBERG

ISSUES ADDRESSED

1. Power supply benefits resulting from the merger.

2. Coal supply arrangements for Pacific Power's and Utah Power's plants.

CONTENT AND CONCLUSIONS

Savings in generation investment and resource acquisition costs result from two factors. Postponement and reduction of new capacity purchases are possible because of peak load diversity, reserve sharing and increases in available capacity. Second, new energy resources are postponed beyond the 1993-94 time frame required by Pacific Power in the absence of the merger. Construction of new generating resources required by Utah Power in the absence of the merger is avoided by increases in less expensive firm purchases. The costs of advancing construction of additional transmission facilities are subtracted from these savings.

Savings in power system operations (Net Power Cost) result from more efficient dispatch of generating resources, displacement of higher-cost purchased power, and the ability to make additional wholesale sales at enhanced sale margins.

COAL SUPPLY ARRANGEMENTS

Pacific Power has an interest in five existing coal-fired generation projects located in Washington, Montana and Wyoming. The coal supply for each plant is described. Utah Power has an interest in four existing coal-fired generation projects.

The coal procurement activities of the merged company will not differ from the current activities of the individual companies. The overall objective will continue to be to provide safe and reliable electric service at the lowest reasonable cost to customers. Preference will not be given to affiliated coal suppliers.

The merged company's coal arrangements and ownership interests will not have any measureable effect on either the availability of coal to other utilities or on wholesale power competition. Four of the five coal-fired power plants in which Pacific Power has an interest are jointly owned with wholesale power competitors and those competitors also wholly own or partially own and control the attendant coal supply. The coal for Pacific Power's wholly-owned coal-fired generating plant, Dave Johnston, is supplied by Pacific Power's Dave Johnston mine and through outside unaffiliated purchases. None of the merged company's wholesale power competitors purchase coal from the Dave Johnston mine. PacifiCorp's NERCO subsidiary sells coal to Platte River Power Authority (PRPA) under a flexible coal supply contract.

No wholesale power competitors of the merged company purchase coal from interests owned by Utah Power. The merged company, including affiliated coal interests, would control less than 6 percent of the controlled, uncommitted coal reserves in the western coal market.

QUESTION

Please state your name, business address, and present position.

ANSWER

My name is Dennis P. Steinberg. My business address is 920 SW Sixth Avenue, Portland, Oregon 97204. My present position is Director of Power Planning with Pacific Power & Light Company (Pacific Power or Company).

QUESTION

Please summarize your education and business experience.

ANSWER

I received a Bachelor of Science degree in Electrical Engineering from Northrop University in 1972. In addition, I have taken courses from the University of Southern California and General Electric Company in the area of Power System Analysis. From 1972 to 1978 I was employed by Southern California Edison Company as a Generation Planning Engineer. I was employed by Pacific Power in 1978 as a Power Resource Engineer, advancing to a Senior Power Resource Engineer in November of 1980, to Power Resource Planning Supervisor in January, 1983, to Power Resource Studies Manager in July, 1984, to Power Planning and Analysis Manager in May, 1985, and to my present position in October, 1987.

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QUESTION

What are your present duties?

ANSWER

As Director of Power Planning, I am responsible for the activities of the Power Planning and Analysis Department, Power Contracts Department, and the Wholesale Power Marketing Department. I am also responsible for the preparation of power resource and power cost information used in retail rate filings.

QUESTION

What activities are performed by the Power Planning and Analysis Department?

ANSWER

The activities of that department include the performance and evaluation of long-range load/resource studies using computer programs which simulate the operation of Pacific Power's system under different operating conditions. The purpose of these studies is to identify the most cost-effective future power supplies and operating strategies for the Company's customers.

QUESTION

Have you previously testified in regulatory proceedings?

ANSWER

Yes. I have testified in regard to many power planning and operation matters in Wyoming, Oregon, Washington, Montana, California, and before the Federal Energy Regulatory Commission.

QUESTION

What is the purpose of your testimony?

ANSWER

The purpose of my testimony is to discuss currently estimated power supply benefits of the merger. I will also discuss the merged company's coal supply arrangements and any attendant effects those arrangements may have on wholesale power competitors. With regard to merged system power supply benefits, these benefits include savings in three areas that have been more generally described in Mr. Boucher's testimony. The first is savings in new resource investments or purchased power costs to meet the merged system's future capacity and energy requirements, as compared with the costs of meeting each individual system's requirements without a merger. Second is savings in future power system operating costs from the more efficient dispatch of the merged system's resources. The third source of power supply benefits is additional net revenues from both nonfirm and firm wholesale sales that the merger makes possible.

QUESTION

Mr. Steinberg, do you have an exhibit in connection with your testimony?

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ANSWER

Yes, I have Exhibit No. 11 which consists of Schedules 1 through 5.

QUESTION

Was the exhibit prepared under your direction and supervision?

ANSWER

Yes, it was.

QUESTION

Please describe the information shown in Schedule 1 of Exhibit No. 11.

ANSWER

Schedule 1 summarizes annual savings in all the areas studied by year over the next five years. Savings are summarized in two categories. The first category is the savings in generation and resource acquisition costs, offset in part by costs of advancing transmission investment. In the second category are savings in power system operations that result from the merger, identified as Net Power Cost Savings in the schedule. Included in the Net Power Cost Savings are revenues from both nonfirm and firm wholesale sales.

QUESTION

How were savings in generation and transmission investment and resource acquisition costs shown in Schedule 1 estimated?

ANSWER

The details of this estimate are summarized in Schedule 2 of Exhibit No. 11. This schedule shows the annual costs associated with new capacity resource and energy resource acquisitions and new transmission investments by operating year from 1988-89 through 2006-07. These data are shown for Utah Power, for Pacific Power, and for the merged system. Also, the differences in these costs between the merged system and the sum of the two separate systems are shown. The costs associated with new transmission investments are based on the information provided in Mr. Boucher's Testimony. They assume Pacific Power's Firehole-to-Bridger Pump and South Trona-to-Monument additions are advanced from 1989 to 1988, and Bridger-to-Rock Springs additions are advanced from 1995 to 1989 as a result of the merger. The new Shute Creek-to-Opal addition is also added in 1989. These transmission lines are shown in Schedule 4, page 1, of Mr. Boucher's Exhibit No. 9. The Bridger System Midline Switching (Treasureton Loop-in) addition is assumed to be required by 1998 for the merged system, in order to meet Utah summer peaks without additional generation, as described by Mr. Boucher.

The costs associated with new capacity resource and energy resource acquisitions are also based on the data provided in Mr. Boucher's Testimony describing the effect of the merger on future capacity expansions. Schedule 2 of

Exhibit No. 11 quantifies the savings that arise from the difference in future resource requirements as shown in Schedules 21 and 22 of Mr. Boucher's Exhibit No. 9, with one difference. That difference is an increase in capacity purchase requirements for the merged system of 200 MW, over and above those shown on line 6 of Schedule 21, Exhibit No. 9., for 1991-92. This additional capacity purchase is required as a result of the additional off-system firm sale by the merged system, which I will describe in more detail below.

Two major savings from the merger are evident from Schedule 2. First, new capacity purchases are postponed and reduced, due to the peak load diversity, reserve sharing, and increases in available capacity described by Mr. Boucher. Second, new energy resources are postponed for several years beyond the 1993-94 time frame required by Pacific Power in the absence of the merger. In addition, the construction of new generating resources required by Utah Power in the absence of the merger is avoided by increases in less-expensive firm purchases. Subtracted from these savings are the costs of advancing the construction of transmission facilities already planned without the merger plus additional transmission construction required to realize additional merged system power supply benefits. The net effect is an increased cost in 1988-90, due to transmission advancements, with substantial savings thereafter.

The net present value of these savings is about \$352 million over the 20-year horizon, as indicated in Schedule 2. The annual cost effects of the merger for 1988-92 are shown on line 1 of Schedule 1, after conversion to a calendar-year basis. The assumptions used to calculate these savings are contained in the workpapers accompanying my testimony.

QUESTION

Do these savings fully reflect the opportunity to substitute transmission facilities for new generation resources that the merger provides?

ANSWER

Yes, the savings reflect our best thinking at this time. The substitution of new transmission and additional purchase power for the construction of new generation occurs in 1998 and beyond. At that point, Utah Power's need for new summer capacity resources has grown to 413 MW (line 6, Schedule 16 of Exhibit No. 9), or almost 350 MW if supplied through firm purchases. By the year 2006, Utah Power's need for new summer capacity resources has grown to 1031 MW, or 860 MW if supplied through firm purchases. Because of the many uncertainties inherent in the resource planning process, we cannot be certain at precisely what point in that extended time frame Utah Power would need to construct new generation resources. However, the plan we have described is a reasonable scenario, and the $352 million net present value savings is a reasonable estimate. Even if there is no long-term need to build new resources, the capacity purchase savings will provide substantial savings to the merged system's customers. Just considering the savings over the next ten years, the net present value of these savings is about $67 million. These savings are in addition to the Net Power Cost Savings shown on line 2 of Schedule 1.

QUESTION

What is the Net Power Cost Savings shown on line 2 of Schedule 1, and how was it estimated?

ANSWER

Net Power Cost is fuel cost plus purchased power cost plus wheeling cost minus sale for resale (firm and nonfirm) revenue. The Net Power Cost benefits shown in Schedule 1 were estimated using Pacific Power's power cost model. The model was adapted by a team of Pacific Power analysts in consultation with Utah Power analysts to simulate either of the power systems operating independently, or the coordinated operation of the merged system. Modifications made to the model included transfer constraints between Utah Power's and Pacific Power's systems, and recognition of the diverse wholesale power marketing and purchase power capability of the merged system.

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Pacific Power's model simulates, on a monthly basis, the complex interactions of Pacific Power, the Bonneville Power Administration (BPA) and other Pacific Northwest utilities, and extra-regional markets. It gives consideration to pooling and coordination agreements, intertie constraints (both electrical and institutional), resource prices and operational limitations, and hydrologic uncertainty. These complexities have a substantial effect on Pacific Power's power costs, and can be expected to have a similar effect on the merged system. Many of these factors are not easily recognized in commercial power cost simulation models. It was therefore appropriate to adapt Pacific Power's existing model to simulate the merged system. The same methods were also used to simulate each individual system as well as the merged system. In that way a consistent comparison could be made, allowing a reasonable estimate of the benefits of the merger.

QUESTION

Does the model provide reasonable estimates of each individual system's power costs?

ANSWER

Yes. Based on our extensive experience with the model for simulating Pacific Power's system, we believe that the model provides reasonable estimates of that system's power costs. In the case of Utah Power's system, we verified the model by comparing results with power cost simulations that Utah Power had performed using the models and methods they normally employ for power cost estimating purposes. For the 1988-92 period, the adapted model's results were within 2% of those estimated by Utah Power for sales and purchases, within 0.2% of the Utah Power estimates for fuel burn expense, and within 0.5% of the Utah Power estimates of the Net Power Cost.

QUESTION

Please describe the results of the power cost simulations.

ANSWER

The results are summarized in Schedule 3 of Exhibit No. 11. This schedule compares Net Power Cost and its major components for the two individual systems, the sum of the two individual systems, the merged system, and the difference between the merged system and the sum of the two individual systems. Schedule 4 shows a comparison of energy requirements and sources of energy for the stand-alone and merged company. Schedules 3 and 4 are derived from the more detailed data itemized in Schedule 5 of Exhibit No. 11.

The total estimated savings in Net Power Cost (line 24 of Schedule 3) amount to about $16.7 million in 1988, increasing to about $44.2 million in 1992. These savings reflect the major effects of the merger on power system operation: more efficient dispatch of generating resources, displacement of higher-cost purchased power, and the ability to make additional wholesale sales at enhanced sales margins.

Several results from the simulations stand out as significant. First, the energy sources and uses summarized in Schedule 4 indicate that the merged system increases thermal generation about 1.5-2% in each year. These increases come about because the merged system is able to decrease secondary purchases up to about 3% and increase wholesale sales in the range of about 7-10%. Second, with regard to the Net Power Cost components shown in Schedule 3, purchased power expense is reduced, even in those years when total purchased energy is about the same, because of the merged system's better ability to access diverse sources when they are cost-effective. Third, wholesale power revenues are increased because of increased efficiencies. Finally, the net effect of all of these changes results in a reduction in Net Power Cost from about 5% to 10%. These benefits result from relatively modest changes in total system operation, not radical departures from past practices. The model input assumptions used to calculate the Net Power Cost Savings, as well as detailed model output for the merged system and the two individual systems, are contained in my workpapers.

QUESTION

You mentioned that the merged system is expected to increase thermal generation over the period simulated. Where do the studies indicate increases in generation occur?

ANSWER

As indicated in Schedule 5, the increases are spread roughly evenly between Utah Power's and Pacific Power's generating units. As a result of this increase in thermal generation requirements, the merged company's coal consumption is expected to increase over the 1988-1992 period by about 1,000,000 tons, 325,000 tons and 290,000 tons from facilities located in Wyoming, Washington and Utah, respectively.

QUESTION

How much of the Net Power Cost savings result from system operating benefits, as compared to the additional firm and nonfirm sales that the merger allows?

ANSWER

As I previously described, Net Power Cost Savings reflect the combination of many effects of the merger. The fuel and wheeling expense associated with the additional firm and nonfirm sales summarized in Schedule 5 are not identified separately in the power cost simulations, so the wholesale power sales contributions cannot be isolated from those simulations alone. We estimate from other analyses contained in my workpapers that Net Power Cost Savings of the merger due solely to operating efficiencies contribute between about $5 million and about $9 million per year to total New Power Cost savings.

QUESTION

How were these additional wholesale sales revenues estimated?

ANSWER

With regard to nonfirm sales, the ability of the merged system to make additional sales was simulated by the power cost model. The assumptions we used about the size of wholesale markets were consistent between the simulations of the individual systems and the combined system. In the case of the unmerged system simulations, the individual systems did not have cost-effective generating capability to fill those wholesale demands during some time periods. With the same market size for the merged system, however, additional sales were feasible, due to the load and resource diversities of the two systems.

QUESTION

Why have you included an additional off-system firm sale in your benefits analysis?

ANSWER

As Mr. Boucher discussed in his testimony, the merged system will have more flexibility to offer marketable energy services with attractive pricing and packaging. We assumed an additional firm sale of 50 average MW beginning in June 1988, increasing to 100 average MW in January of 1990 can be achieved by the merged system, with prices similar to those of recent contracts. Because this firm sale was not included in the merged system's loads and resources study, as summarized in Mr. Boucher's Testimony, Schedule 23 of Exhibit No. 9, the additional capacity required to complete this transaction through 1992 necessitates the additional firm capacity purchase in 1991-92 I previously described.

<u>QUESTION</u>

How would your estimates of Net Power Cost savings be different if the additional firm wholesale sale were not assumed?

<u>ANSWER</u>

Without the assumed firm sale, Net Power Cost savings would be lower by about $4 million in 1988, and lower by about $22 million in 1992, compared with the savings shown on line 2 of Schedule 1. This estimate is based on simulations without the additional firm sale, as shown in my workpapers. It reflects both the lower wholesale sales revenue in the absence of the additional firm sale, as well as the reduction in fuel expense and purchase power expense and increases in nonfirm sales that would occur without the firm sale. Without the firm sale, the savings shown on line 1 of Schedule 1 would also be higher by about $4 million in 1991 and 1992, reflecting the lower capacity purchase requirement without the firm sale.

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QUESTION

Do you anticipate other savings in Net Power Cost that have not been included in your studies to date?

ANSWER

Yes. In addition to the savings that I have already discussed, there is also the potential for additional system benefits through additional off-system sales and displacement of higher-cost system resources. Achieving these benefits would involve thermal generating performance higher than we have required on a sustained basis at some units, the implications of which require more study than time has yet allowed. Further, we have not yet attempted to optimize thermal maintenance schedules to improve wholesale sales or reduce fuel and purchased power expense for the merged system. Any of these factors could add substantially to the Net Power Cost savings I have already described.

QUESTION

Do you expect changes in the wheeling expense component of Net Power Cost as a result of the merger?

ANSWER

Yes. Schedule 5 indicates changes in two areas. The first is an increase in wheeling expense associated with an increase in nonfirm wholesale power sales over the Pacific Intertie. The second is a reduction in other wheeling expense associated with expected exchange arrangements with BPA that the merger allows. The net savings in wheeling expense increases to about 1.3 million in 1992.

QUESTION

Please discuss Pacific Power's current coal supply arrangements for its generating plants.

ANSWER

Pacific Power has an interest in five coal-fired generation projects located in Washington, Montana and Wyoming.

In Washington, Pacific Power owns a 47.5 percent interest in the Centralia Generating Plant. Coal for this facility is supplied through long-term contractual agreements with the Centralia mine which is jointly owned by Pacific Power and the Washington Irrigation and Development Company, a wholly-owned subsidiary of The Washington Water Power Company, which also operates the mine. The Washington Water Power Company, which has a 15 percent interest in the Centralia generation facility, is a wholesale power competitor of the merged company.

In Montana, Pacific Power owns a 10 percent interest in Colstrip units 3 and 4. The coal for these generating units is supplied through long-term contractual agreements with the Western Energy Company, a wholly-owned subsidiary of the Montana Power Company. The Montana Power Company, which has a 30 percent interest in these units, is a wholesale power competitor of the merged company.

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In Wyoming, Pacific Power has an 80 percent interest in the Wyodak Plant, a 100 percent interest in the Dave Johnston Plant, and a 66.7 percent interest in the Jim Bridger Generating Plant. Coal for the Wyodak facility is supplied through long-term contractual agreements with Wyodak Resources Development Company, a wholly-owned subsidiary of Black Hills Power and Light Company. Black Hills, which has a 20 percent interest in the Wyodak generation facility, is a wholesale power competitor of the merged company. The coal supply for the Dave Johnston Plant, the Dave Johnston mine, is owned by Pacific Power. In an effort to further stabilize its power supply costs and power prices, Pacific Power is also purchasing coal from unaffiliated outside suppliers to satisfy a portion of its Dave Johnston coal supply needs. Coal for the Jim Bridger generating facility is primarily supplied through long-term contractual agreements with Bridger Coal Company, which is one-third owned by Idaho Energy Resources Company, a wholly-owned subsidiary of Idaho Power Company, and two-thirds owned by Pacific Minerals, Inc., a wholly-owned subsidiary of NERCO. NERCO, the majority of which is owned by PacifiCorp, also sells coal to other electric utilities, which I will discuss later in my testimony. Idaho Power Company, which owns one-third interest in the Jim Bridger generation facility, is a wholesale power competitor of the merged company. The Jim Bridger plant owners also purchase some of their coal supply needs from outside unaffiliated suppliers to help stabilize their power prices.

QUESTION

Please discuss Utah Power's current ccal supply arrangements.

ANSWER

As Mr. Topham has previously testified, Utah Power has an interest in four coal-fired generation projects currently available for service located in Wyoming and Utah.

In Wyoming, Utah Power owns 100 percent of the Naughton Plant which coal is supplied through exclusive long-term agreement with an unaffiliated supplier, Pittsburg and Midway Coal Company.

In Utah, Utah Power owns 100 percent of the Carbon and Huntington generation facilities and about 85 percent of the Hunter plant. Carbon's fuel requirements are supplied by an unaffiliated supplier, the Valley Camp Coal Company, pursuant to an agreement which expires in 1995. The coal supply for the Huntington and Hunter plants, the Cottonwood and Deer Creek mines, is owned by Utah Power.

QUESTION

Will the coal procurement activities of the merged company be different from the current activities of the individual companies?

ANSWER

No. The overall objective of the merged company will be the same as currently exists for the individual companies. As such, the objective of the merged company will be to provide safe and reliable electric service at the lowest reasonable cost to customers, both retail and wholesale. Because fuel costs are the largest operating cost incurred by Pacific Power and Utah Power, both companies have pursued fuel procurement strategies that lower or stabilize power prices. Many of the actions taken by Pacific Power and Utah Power in this regard have already resulted in substantial benefits to their respective customers. The companies will continue to pursue fuel cost reduction and stabilization strategies subsequent to the merger within the framework of existing contractual arrangements.

QUESTION

Will preference be given to affiliated coal suppliers for future coal supplies subsequent to the merger?

ANSWER

No. Such is not the case now, nor will it be the case in the future. As I have already testified, Pacific Power currently purchases coal from unaffiliated suppliers to help meet its fuel needs at the Dave Johnston and Jim Bridger generation facilities, even though Company-owned or affiliated coal supplies are available. It is likely that Pacific Power will further increase its use of outside coal supplies at those plants in the future. Pacific Power is also in the process of test burning outside coal at its Centralia generation facility in an effort to reduce or stabilize power production costs at that plant.

QUESTION

What effect will the merged company's various coal supply arrangements and ownership interests have on the availability of coal to wholesale power competitors?

ANSWER

The merged company's coal arrangements and ownership interests will not have any measurable effect on either the availability of coal to other utilities or on wholesale power competition. As I have previously testified, four of the five coal-fired power plants in which Pacific Power has an interest are jointly-owned with wholesale power competitors and those competitors also wholly-own or partially-own and control the attendant coal supply. As a result, all of the plant and mine owners have the common interest of low-cost plant and mine operation. This situation will be unaffected by the merger. The coal for Pacific Power's wholly-owned coal-fired generating plant, Dave Johnston, is supplied by the Company's Dave Johnston mine and through outside unaffiliated purchases. None of the merged company's wholesale power competitors purchase coal from the Dave Johnston mine. Also, no wholesale power competitor of the merged company purchases coal from interests owned by Utah Power. This situation is indicative of the existing and expected future highly competitive coal supply market in which electric utilities have many viable coal supply options. Further, the merged company, including affiliated coal interests, would control less than 6 percent of the controlled, uncommitted coal reserves in the western coal market. Consequently there is no reason to suspect that the merger would lessen competition or restrict access to coal by competitors.

<u>QUESTION</u>

What do you mean by the terms "controlled, uncommitted" coal reserves?

<u>ANSWER</u>

The term "controlled" refers to coal reserves that are held by a coal-marketing company through ownership and lease arrangements. The term "uncommitted" refers to that portion of the controlled reserves that are not currently assigned or dedicated to satisfying existing coal supply arrangements.

<u>QUESTION</u>

You testified that PacifiCorp's NERCO subsidiary sells coal to other electric utilities. Are any of these utilities wholesale power competitors of the merged company?

<u>ANSWER</u>

The only electric utility currently served by NERCO that could be reasonably considered as a wholesale power competitor of the merged company is Platte River Power Authority (PRPA). It is my understanding that NERCO supplies coal for only PRPA's 250 MW Rawhide 1 unit located in North Central Colorado and that the contract provides PRPA with substantial flexibility. This situation will not alter any current competitive relationships subsequent to the merger.

QUESTION

Does this conclude your direct testimony?

ANSWER

Yes.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

STATE OF OREGON) Docket No. EC88-2-00
COUNTY OF MULTNOMAH))

Affidavit of Dennis P. Steinberg

Dennis P. Steinberg, being first duly sworn, on oath states that he is Director, Power Planning of Pacific Power & Light Company, whose Prefiled Testimony was served on all parties to the above-referenced proceeding. Dennis P. Steinberg further states that if asked the questions contained in the text of such testimony that he would give the answers that are herein set forth and that he adopts the aforesaid answers as his direct testimony in this proceeding.

Dennis P. Steinberg

Subscribed and sworn to before me this 6th Day of January, 1988.

Mona L. Hamlin
Notary Public

My commission expires May 18, 1989.

Exhibit No. 11

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Utah Power & Light Company	)	
PacifiCorp	)	Docket No. EC88-2-000
PC/UP&L Merging Corp.	)	

EXHIBITS ACCOMPANYING
PREFILED TESTIMONY
OF
DENNIS P. STEINBERG
ON BEHALF OF
PACIFICORP,
UTAH POWER & LIGHT COMPANY
PC/UP&L MERGING CORP.

January 8, 1988

Estimated Power Supply Savings from Merger
(Millions of Dollars)

	1988	1989	1990	1991	1992
(1) Net Savings in New Generation and Transmission Capacity	-1.8	-2.2	-0.2	2.2	8.6
(2) Net Power Cost Savings	16.7	22.4	35.5	40.2	44.2
(3) Total	14.9	20.2	35.3	42.4	52.8

Total Cost Associated with
Capacity, Energy, and Transmission Additions
($000)

		1988-89	1989-90	1990-91	1991-92	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-00	2000-01	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07
	Pacific Power & Light Company Without Merger																			
[1]	Capacity	0	3,868	4,553	55,330	73,117	77,213	80,789	80,817	95,614	98,605	107,385	117,802	131,829	147,312	161,021	173,849	191,026	219,690	232,436
[2]	Energy	0	0	0	0	0	10,355	28,790	40,560	52,495	94,660	113,777	125,515	138,445	191,996	208,407	225,912	275,697	341,966	331,802
[3]	Transmission	888	1,485	1,447	1,407	1,369	1,332	2,421	3,142	3,061	2,978	2,898	2,819	2,743	2,668	2,594	2,521	2,447	2,374	2,301
[4]	Revenue Requirement	888	5,352	6,000	56,737	74,485	88,899	112,000	124,519	151,171	196,244	224,060	246,136	273,017	341,975	372,021	403,282	469,170	564,030	566,539
	Utah Power & Light Company Without Merger																			
[5]	Capacity	0	304	878	1,291	2,183	3,064	3,190	3,559	4,138	7,766	41,487	71,454	103,454	168,601	198,847	230,572	300,052	330,362	362,344
[6]	Energy	0	0	0	0	2,273	4,637	7,050	9,559	11,496	14,301	20,976	27,128	33,959	47,040	54,898	63,557	79,285	89,179	100,017
[7]	Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
[8]	Revenue Requirement	0	304	878	1,291	4,456	7,701	10,240	13,118	15,634	22,067	62,463	98,582	137,413	215,641	253,744	294,129	379,337	419,541	462,361
	Pacific Power plus Utah Power Without Merger																			
[9]	Capacity	0	4,171	5,432	56,621	75,300	80,277	83,979	84,376	99,752	106,371	148,872	189,256	235,283	315,913	359,867	404,421	491,078	550,052	594,781
[10]	Energy	0	0	0	0	2,273	14,991	35,840	50,119	63,991	108,962	134,754	152,643	172,404	239,036	263,304	290,469	354,982	431,145	431,819
[11]	Transmission	888	1,485	1,447	1,407	1,369	1,332	2,421	3,142	3,061	2,978	2,898	2,819	2,743	2,668	2,594	2,521	2,447	2,374	2,301
[12]	Revenue Requirement	888	5,656	6,878	58,028	78,941	96,600	122,239	137,637	166,805	218,311	286,523	344,718	410,430	557,616	625,765	697,411	848,508	983,571	1,028,900
	PacifiCorp After Merger																			
[13]	Capacity	0	0	0	47,940	57,243	60,191	68,471	66,779	79,966	87,146	100,438	111,236	133,397	154,685	178,551	202,549	230,113	272,306	281,531
[14]	Energy	0	0	0	0	2,273	11,456	22,372	31,994	41,610	95,013	102,131	119,596	164,619	213,733	257,966	325,125	370,460	455,697	502,704
[15]	Transmission	4,453	6,569	6,398	6,222	6,054	5,893	5,738	5,589	5,444	10,314	13,539	13,180	12,811	12,453	12,103	11,761	11,427	11,098	10,772
[16]	Revenue Requirement	4,453	6,569	6,398	54,162	65,571	77,539	96,581	104,361	127,020	192,473	216,108	244,012	310,827	380,871	448,619	539,435	612,000	739,101	795,007

		1988-89	1989-90	1990-91	1991-92	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98	1998-99	1999-00	2000-01	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07
[17]	**Total Net Benefits**	(3,565)	(913)	480	3,866	13,371	19,061	25,657	33,275	39,785	25,838	70,415	100,707	99,603	176,744	177,146	157,976	236,508	244,469	233,894

[18] **Net Present Value** 352,047
[at 11.24%]

		1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
[19]	**Total Net Benefits**	(1,782)	(2,239)	(236)	2,173	8,618	16,216	22,359	29,466	36,530	32,811	48,127	85,561	100,155	138,174	176,945	167,561	197,242	240,489	239,182

Estimated Net Power Cost Savings from Merger
(Thousands of Dollars)

line		1988	1989	1990	1991	1992
	UTAH POWER					
(1)	Sale for Resale Revenue	56,198	56,882	70,754	79,065	78,121
(2)	Purchased Power Expense	34,951	38,643	45,738	51,622	53,895
(3)	Thermal Fuel Expense	202,568	206,659	212,918	220,172	231,489
(4)	Net Power Cost (line 2 + line 3 - line 1)	181,321	188,420	187,902	192,729	207,263
	PACIFIC POWER					
(5)	Sale for Resale Revenue	114,224	146,916	145,977	148,825	151,328
(6)	Purchased Power Expense	124,320	142,297	164,183	180,470	190,077
(7)	Thermal Fuel Expense	185,895	204,662	209,409	222,947	233,124
(8)	Wheeling Expense	29,134	32,593	32,275	32,211	33,275
(9)	Net Power Cost (line 6 + line 7 + line 8 - line 5)	225,125	232,636	259,890	286,803	305,148
	UTAH POWER + PACIFIC POWER					
(10)	Sale for Resale Revenue	170,422	203,798	216,731	227,890	229,449
(11)	Purchased Power Expense	159,271	180,940	209,921	232,092	243,972
(12)	Thermal Fuel Expense	388,463	411,321	422,327	443,119	464,613
(13)	Wheeling Expense	29,134	32,593	32,275	32,211	33,275
(14)	Net Power Cost (line 11 + line 12 + line 13 - line 10)	406,446	421,056	447,792	479,532	512,411
	MERGED SYSTEM					
(15)	Sale for Resale Revenue	187,313	224,512	250,208	265,717	266,772
(16)	Purchased Power Expense	154,029	177,033	202,658	224,278	232,092
(17)	Thermal Fuel Expense	394,014	414,213	428,346	449,531	470,918
(18)	Wheeling Expense	29,009	31,951	31,499	31,199	31,970
(19)	Net Power Cost (line 16 + line 17 + line 18 - line 15)	389,739	398,685	412,295	439,291	468,208
	MERGED SYSTEM - UTAH POWER - PACIFIC POWER					
(20)	Sale for Resale Revenue	16,891	20,714	33,477	37,827	37,323
(21)	Purchased Power Expense	-5,242	-3,907	-7,263	-7,814	-11,880
(22)	Thermal Fuel Expense	5,551	2,892	6,019	6,412	6,305
(23)	Wheeling Expense	-125	-642	-776	-1,012	-1,305
(24)	Net Power Cost (line 21 + line 22 + line 23 - line 20)	-16,707	-22,371	-35,497	-40,241	-44,203

Estimated Net Power Cost Savings from Merger
(Thousands of MWH)

line		1988	1989	1990	1991	1992
	UTAH POWER					
(1)	Net System Load	16,768	16,768	17,096	17,369	17,560
(2)	Sale for Resale	2,597	2,553	2,739	2,832	2,716
(3)	Total Requirements	19,365	19,321	19,835	20,201	20,276
(4)	Purchased Power	2,239	2,222	2,421	2,670	2,731
(5)	Thermal Generation	16,732	16,706	17,020	17,137	17,152
(6)	Other Resources	394	393	394	394	394
(7)	Total Resources	19,365	19,321	19,835	20,201	20,277
	PACIFIC POWER					
(8)	Net System Load	24,519	25,119	25,654	26,785	27,280
(9)	Sale for Resale	4,290	5,160	4,761	4,336	4,081
(10)	Total Requirements	28,809	30,279	30,415	31,121	31,361
(11)	Purchased Power	5,294	5,414	5,794	6,189	6,437
(12)	Thermal Generation	19,014	20,373	20,131	20,440	20,420
(13)	Other Resources	4,501	4,492	4,490	4,492	4,503
(14)	Total Resources	28,809	30,279	30,415	31,121	31,360
	UTAH POWER + PACIFIC POWER					
(15)	Net System Load	41,287	41,887	42,750	44,154	44,840
(16)	Sale for Resale	6,887	7,713	7,500	7,168	6,797
(17)	Total Requirements	48,174	49,600	50,250	51,322	51,637
(18)	Purchased Power	7,533	7,636	8,215	8,859	9,168
(19)	Thermal Generation	35,746	37,079	37,151	37,577	37,572
(20)	Other Resources	4,895	4,885	4,884	4,886	4,897
(21)	Total Resources	48,174	49,600	50,250	51,322	51,637
	MERGED SYSTEM					
(22)	Net System Load	41,286	41,887	42,750	44,154	44,840
(23)	Sale for Resale	7,493	8,260	8,177	7,942	7,488
(24)	Total Requirements	48,779	50,147	50,927	52,096	52,328
(25)	Purchased Power	7,301	7,637	8,132	8,886	9,168
(26)	Thermal Generation	36,584	37,624	37,911	38,325	38,265
(27)	Other Resources	4,894	4,886	4,884	4,886	4,895
(28)	Total Resources	48,779	50,147	50,927	52,097	52,328
	MERGED SYSTEM - UTAH POWER - PACIFIC POWER					
(29)	Net System Load	0	0	0	0	0
(30)	Sale for Resale	606	547	677	774	691
(31)	Total Requirements	605	547	677	774	691
(32)	Purchased Power	-232	1	-83	27	0
(33)	Thermal Generation	838	545	760	748	693
(34)	Other Resources	0	0	0	0	-2
(35)	Total Resources	605	547	677	775	691

Note - numbers may not add or subtract precisely, due to rounding

Merged Model
Pacific Power and Utah Power
Net Power Cost Analysis
($)

Merged Utah and Pacific
Base Case
with 50 years of hydro

	1988	1989	1990	1991	1992
SPECIAL SALES FOR RESALE					
Black Hills	21,739,348	25,948,092	26,224,031	26,513,763	26,817,301
P G & E	6,792,178	6,560,824	6,451,336	6,695,040	7,030,720
Puget Power	4,727,399	5,163,602	5,730,725	3,568,449	0
So Cal Edison	49,031,020	52,339,833	41,097,714	45,005,027	48,704,821
SMUD	0	0	8,296,594	8,712,347	9,171,547
PP&L to UP&L	0	0	2,830,000	3,235,000	3,608,000
Other Firm	8,476,050	15,330,000	34,164,000	36,792,000	38,649,600
Nevada	0	0	17,359,833	26,309,097	26,328,452
Sierra Pacific	21,613,026	21,415,106	21,500,354	21,793,122	22,253,496
Secondary Sales	74,934,082	97,754,157	86,553,458	87,093,006	84,207,652
TOTAL SPECIAL SALES	187,313,103	224,511,614	250,208,045	265,716,851	266,771,589
PURCHASED POWER & NET INTERCHANGE					
Pacific Firm	35,427,627	38,103,023	52,282,814	66,650,369	66,580,268
BPA Peak Purchase	45,763,704	48,486,300	50,282,088	50,910,615	52,796,196
Q.F. Contracts - PP&L	34,423,608	45,626,412	47,784,444	48,404,580	49,256,700
UP&L from PP&L	0	0	2,830,000	3,235,000	3,608,000
Gram State	0	1,261,000	1,261,000	1,261,000	1,261,000
GSLM	0	308,000	308,000	308,000	308,000
QF Contracts - UP&L	7,125,000	12,770,000	14,626,000	14,626,000	14,668,000
Secondary Purchases	31,289,037	30,478,225	33,283,377	38,882,848	43,614,011
TOTAL PURCH PW & NET INT.	154,028,976	177,032,960	202,657,723	224,278,412	232,092,175
WHEELING & U. OF F. EXPENSE					
BPA Intertie	5,560,604	7,909,925	6,895,749	6,292,218	6,142,656
Other	23,448,321	24,041,404	24,603,154	24,906,310	25,827,628
TOTAL WHEELING & U. OF F. EXPENSE	29,008,925	31,951,329	31,498,903	31,198,528	31,970,284
THERMAL FUEL BURN EXPENSE					
Jim Bridger	83,850,307	90,551,520	92,274,171	96,834,105	102,830,223
Dave Johnston	43,395,882	44,915,937	46,828,216	48,518,357	51,741,457
Centralia	41,517,992	51,281,075	53,150,961	57,449,375	57,852,544
Wyodak	13,917,087	14,356,193	15,152,305	16,041,500	16,531,593
Colstrip	6,459,431	6,692,219	6,966,633	7,302,889	7,723,269
Carbon	20,853,379	21,477,682	22,015,745	22,688,337	23,361,852
Naughton	51,598,459	50,296,833	58,971,640	61,735,913	62,325,722
Huntington	58,919,393	59,066,537	57,761,367	64,083,850	66,470,361
Hunter	69,328,507	71,353,278	70,928,760	70,504,708	77,609,508
Blundell	4,173,120	4,223,415	4,296,350	4,372,195	4,471,200
TOTAL FUEL BURN EXPENSE	394,013,556	414,212,689	428,346,153	449,531,230	470,917,7[illegible]
NET POWER COST	389,738,354	398,685,364	412,294,734	439,291,319	468,208,600

Merged Utah and Pacific
Base Case
with 50 years of hydro

Merged Model
Pacific Power and Utah Power
Net Power Cost Energy Analysis
(MWH)

	1988	1989	1990	1991	1992
NET SYSTEM LOAD	41,286,402	41,886,927	42,749,764	44,154,277	44,839,795
SPECIAL SALES FOR RESALE					
Black Hills	459,901	459,901	459,901	459,901	459,901
PG&E	250,000	250,000	250,000	250,000	250,000
Puget Power	240,901	240,901	240,901	139,893	0
So Cal Edison	1,485,373	1,481,314	993,387	993,387	996,108
SMUD	0	0	367,920	367,920	368,928
PP&L to UP&L	0	0	85,300	94,700	104,100
Other Firm	256,850	438,000	876,000	876,000	878,400
Nevada	0	0	432,100	620,700	621,900
Sierra Pacific	628,800	627,100	627,100	627,100	628,800
Secondary Sales	4,170,777	4,762,442	3,844,711	3,512,732	3,179,869
TOTAL SPECIAL SALES	7,492,602	8,259,658	8,177,320	7,942,333	7,488,006
TOTAL REQUIREMENTS	48,779,004	50,146,585	50,927,084	52,096,610	52,327,801
PURCHASED POWER & NET INTERCHANGE					
Pacific Firm	3,570,755	3,590,419	3,778,825	4,158,944	4,196,278
Q.F. Contracts - PP&L	614,880	683,280	700,800	700,800	702,720
UP&L from PP&L	0	0	85,300	94,700	104,100
Gem State	0	37,100	37,100	37,100	37,100
GSLM	0	25,900	25,900	25,900	25,900
QF Contracts - UP&L	162,700	274,600	314,500	314,500	315,400
Secondary Purchases	2,952,409	3,026,005	3,189,734	3,554,215	3,786,072
TOTAL PURCH PW & NET INT	7,300,744	7,637,304	8,132,159	8,886,159	9,167,570
THERMAL COAL-FIRED GENERATION					
Jim Bridger	8,566,999	8,871,775	8,706,399	8,740,905	8,861,430
Dave Johnston	5,371,469	5,217,840	5,226,188	5,169,071	5,241,754
Centralia	2,788,059	3,954,548	4,014,833	4,095,815	3,936,936
Wyodak	1,860,950	1,855,328	1,894,863	1,934,448	1,900,523
Colstrip	864,138	861,567	861,567	861,596	864,142
Carbon	952,320	949,241	949,301	949,304	952,311
Naughton	4,116,501	3,803,021	4,326,174	4,466,699	4,359,422
Huntington	5,459,822	5,421,766	5,188,261	5,576,546	5,437,667
Hunter	6,454,349	6,540,376	6,595,381	6,382,187	6,561,621
Blundell	149,040	148,190	148,150	148,210	149,040
TOTAL THERMAL	36,583,647	37,623,652	37,911,117	38,324,781	38,264,846
SYSTEM HYDRO	4,730,365	4,712,877	4,712,710	4,712,641	4,729,400
Draft From Storage	(1,861)	7,188	5,534	7,465	(124)
TROJAN GENERATION	166,109	165,564	165,564	165,564	166,109
TOTAL RESOURCES	48,779,004	50,146,585	50,927,084	52,096,610	52,327,801

Pacific Power
Base Case
with 50 years of hydro

Combined Base Case
Sum of Stand Alone
Net Power Cost Analysis
($)

Utah Power
Base Case
with 50 year of hydro

	1988	1989	1990	1991	1992
SPECIAL SALES FOR RESALE					
Black Hills	21,739,348	25,948,092	26,224,031	26,513,763	26,817,301
PG&E	6,792,178	6,560,824	6,451,336	6,695,040	7,030,720
Puget Power	4,727,399	5,163,602	5,730,725	3,568,449	0
So Cal Edison	49,031,020	52,339,833	41,097,714	45,005,027	48,704,821
SMUD	0	0	8,296,594	8,712,347	9,171,547
Utah Sales	0	0	2,830,000	3,235,000	3,608,000
Other Firm	0	0	0	0	0
Nevada	0	0	17,359,833	26,309,097	26,328,452
Sierra Pacific	21,613,026	21,415,106	21,500,354	21,793,122	22,253,496
Secondary Sales	66,519,007	92,370,189	87,240,054	86,058,938	85,534,631
TOTAL SPECIAL SALES	170,421,978	203,797,646	216,730,641	227,890,783	229,448,968
PURCHASED POWER & NET INTERCHANGE					
Pacific Firm	35,427,627	38,103,023	52,282,814	66,650,369	66,580,268
BPA Peak Purchase	45,763,704	48,486,300	50,282,088	50,910,615	52,796,196
Q.F. Contracts - PP&L	34,423,608	45,626,412	47,784,444	48,404,580	49,256,700
PP&L	0	0	2,830,000	3,235,000	3,608,000
Gem State	0	1,261,000	1,261,000	1,261,000	1,261,000
GSLM	0	308,000	308,000	308,000	308,000
QF Contracts (committed)	7,125,000	12,770,000	14,626,000	14,626,000	14,668,000
Secondary Purchases	36,530,430	34,384,933	40,546,659	46,695,845	55,494,232
TOTAL PURCH PW & NET INT.	159,270,369	180,939,668	209,921,005	232,091,409	243,972,396
WHEELING & U. OF F. EXPENSE					
BPA Intertie	4,261,935	6,799,391	5,790,732	5,375,421	5,375,915
Other	24,872,321	25,793,404	26,484,754	26,835,310	27,898,828
TOTAL WHEELING & U. OF F. EXPENSE	29,134,256	32,592,795	32,275,486	32,210,731	33,274,743
THERMAL FUEL BURN EXPENSE					
Jim Bridger	80,294,665	88,155,503	89,940,936	94,665,711	100,391,429
Dave Johnston	43,395,882	44,913,937	46,828,216	48,518,357	51,741,457
Centralia	41,827,943	50,544,515	50,521,021	56,418,405	56,735,795
Wyodak	13,917,087	14,356,193	15,152,305	16,041,500	16,531,593
Colstrip	6,459,431	6,692,219	6,966,633	7,302,889	7,723,269
Carbon	20,956,394	21,583,541	22,122,721	22,797,104	23,478,812
Naughton	50,471,500	51,502,060	58,419,979	59,006,958	59,625,926
Huntington	58,273,122	58,635,883	58,813,209	65,259,620	67,855,990
Hunter	68,694,121	70,714,356	69,265,688	68,736,500	76,057,181
Blundell	4,173,120	4,223,415	4,296,350	4,372,195	4,471,200
TOTAL FUEL BURN EXPENSE	388,463,265	411,321,622	422,327,058	443,119,239	464,612,652
NET POWER COST	406,445,912	421,056,439	447,792,908	479,530,596	512,410,823

Pacific Power
Base Case
with 50 years of hydro

Combined Base Case
Sum of Stand Alone
Net Power Cost Energy Analysis
(MWH)

Utah Power
Base Case
with 50 year of hydro

	1988	1989	1990	1991	1992
NET SYSTEM LOAD	41,286,402	41,886,927	42,749,764	44,154,277	44,839,795
SPECIAL SALES FOR RESALE					
Black Hills	459,901	459,901	459,901	459,901	459,901
PG&E	250,000	250,000	250,000	250,000	250,000
Puget Power	240,901	240,901	240,901	139,893	0
So Cal Edison	1,485,373	1,481,314	993,387	993,387	996,108
SMUD	0	0	367,920	367,920	368,928
Utah Sales	0	0	85,300	94,700	104,100
Other Firm	0	0	0	0	0
Nevada	0	0	432,100	620,700	621,900
Sierra Pacific	628,800	627,100	627,100	627,100	628,800
Secondary Sales	3,822,284	4,654,075	4,043,429	3,613,820	3,367,403
TOTAL SPECIAL SALES	6,887,259	7,713,291	7,500,038	7,167,421	6,797,140
TOTAL REQUIREMENTS	48,173,661	49,600,218	50,249,802	51,321,698	51,636,935
PURCHASED POWER & NET INTERCHANGE					
Pacific Firm	3,570,054	3,589,641	3,778,320	4,158,312	4,195,672
Q.F. Contracts - PP&L	614,880	683,280	700,800	700,800	702,720
PP&L	0	0	85,300	94,700	104,100
Gem State	0	37,100	37,100	37,100	37,100
GSLM	0	25,900	25,900	25,900	25,900
QF Contracts (committed)	162,700	274,600	314,500	314,500	315,400
Secondary Purchases	3,185,315	3,025,219	3,273,196	3,528,131	3,787,101
TOTAL PURCH PW & NET INT	7,532,949	7,635,740	8,215,116	8,859,443	9,167,993
THERMAL COAL-FIRED GENERATION					
Jim Bridger	8,098,228	8,567,387	8,420,840	8,486,790	8,588,693
Dave Johnston	5,371,469	5,217,840	5,226,188	5,169,071	5,241,754
Centralia	2,819,004	3,870,979	3,727,377	3,987,855	3,825,385
Wyodak	1,860,950	1,855,328	1,894,863	1,934,448	1,900,523
Colstrip	864,138	861,567	861,567	861,596	864,142
Carbon	957,025	953,920	953,913	953,855	957,078
Naughton	3,978,430	3,874,246	4,271,419	4,198,071	4,101,330
Huntington	5,316,998	5,319,374	5,386,639	5,804,026	5,677,407
Hunter	6,330,324	6,410,118	6,260,089	6,032,817	6,267,060
Blundell	149,040	148,190	148,150	148,210	149,040
TOTAL THERMAL	35,745,606	37,078,949	37,151,045	37,576,739	37,572,412
SYSTEM HYDRO	4,731,055	4,712,956	4,712,654	4,712,612	4,730,226
Draft From Storage	(2,058)	7,009	5,423	7,340	195
TROJAN GENERATION	166,109	165,564	165,564	165,564	166,109
TOTAL RESOURCES	48,173,661	49,600,218	50,249,802	51,321,698	51,636,935

Pacific-Utah Merged Model
Difference With Sum of Stand Alone
Net Power Cost Analysis
($)

Merged Utah and Pacific
Base Case
with 50 years of hydro

Merged Model minus Combined

	1988	1989	1990	1991	1992
SPECIAL SALES FOR RESALE					
Black Hills	0	0	0	0	0
PG&E	0	0	0	0	0
Puget Power	0	0	0	0	0
So Cal Edison	0	0	0	0	0
SMUD	0	0	0	0	0
PP&L to UP&L	0	0	0	0	0
Other Firm	8,476,050	15,330,000	34,164,000	36,792,000	38,649,600
Nevada	0	0	0	0	0
Sierra Pacific	0	0	0	0	0
Secondary Sales	8,415,075	5,383,968	(686,596)	1,034,068	(1,326,979)
TOTAL SPECIAL SALES	16,891,125	20,713,968	33,477,404	37,826,068	37,322,621
PURCHASED POWER & NET INTERCHANGE					
Pacific Firm	0	0	0	0	0
BPA Peak Purchase	0	0	0	0	0
Q.F. Contracts - PP&L	0	0	0	0	0
UP&L from PP&L	0	0	0	0	0
Gem State	0	0	0	0	0
GSLM	0	0	0	0	0
QF Contracts - UP&L	0	0	0	0	0
Secondary Purchases	(5,241,393)	(3,906,708)	(7,263,282)	(7,812,997)	(11,880,221)
TOTAL PURCH PW & NET INT.	(5,241,393)	(3,906,708)	(7,263,282)	(7,812,997)	(11,880,221)
WHEELING & U. OF F. EXPENSE					
BPA intertie	1,298,669	1,110,534	1,105,017	916,797	766,741
Other	(1,424,000)	(1,752,000)	(1,881,600)	(1,929,000)	(2,071,200)
TOTAL WHEELING & U. OF F. EXPENSE	(125,331)	(641,466)	(776,583)	(1,012,203)	(1,304,459)
THERMAL FUEL BURN EXPENSE					
Jim Bridger	3,555,642	2,396,017	2,333,235	2,168,394	2,438,794
Dave Johnston	0	0	0	0	0
Centralia	(309,951)	736,560	2,629,940	1,030,970	1,116,749
Wyodak	0	0	0	0	0
Colstrip	0	0	0	0	0
Carbon	(103,015)	(105,859)	(106,976)	(108,767)	(116,960)
Naughton	1,126,959	(1,205,227)	551,661	2,728,955	2,699,796
Huntington	646,271	430,654	(1,051,842)	(1,175,770)	(1,385,629)
Hunter	634,386	638,922	1,663,077	1,768,208	1,552,327
Blundell	0	0	0	0	0
TOTAL FUEL BURN EXPENSE	5,550,291	2,891,067	6,019,095	6,411,991	6,305,078
NET POWER COST	(16,707,558)	(22,371,075)	(35,498,174)	(40,239,277)	(44,202,223)

Merged Utah and Pacific
Base Case
with 50 years of hydro

Pacific-Utah Merged Model
Difference With Sum of Stand Alone
Net Power Cost Energy Analysis
(MWH)

Merged Model minus Combined

	1988	1989	1990	1991	1992
NET SYSTEM LOAD	0	0	0	0	0
SPECIAL SALES FOR RESALE					
Black Hills	0	0	0	0	0
PG&E	0	0	0	0	0
Puget Power	0	0	0	0	0
So Cal Edison	0	0	0	0	0
SMUD	0	0	0	0	0
PP&L to UP&L	0	0	0	0	0
Other Firm	256,850	438,000	876,000	876,000	878,400
Nevada	0	0	0	0	0
Sierra Pacific	0	0	0	0	0
Secondary Sales	348,493	108,367	(198,718)	(101,088)	(187,534)
TOTAL SPECIAL SALES	605,343	546,367	677,282	774,912	690,866
TOTAL REQUIREMENTS	605,343	546,367	677,282	774,912	690,866
PURCHASED POWER & NET INTERCHANGE					
Pacific Firm	701	778	505	632	606
Q.F. Contracts - PP&L	0	0	0	0	0
UP&L from PP&L	0	0	0	0	0
Gem State	0	0	0	0	0
GSLM	0	0	0	0	0
QF Contracts - UP&L	0	0	0	0	0
Secondary Purchases	(232,906)	786	(83,462)	26,084	(1,029)
TOTAL PURCH PW & NET INT.	(232,205)	1,564	(82,957)	26,716	(423)
THERMAL COAL-FIRED GENERATION					
Jim Bridger	468,771	304,388	285,559	254,115	272,737
Dave Johnston	0	0	0	0	0
Centralia	(30,945)	83,569	287,456	107,960	111,551
Wyodak	0	0	0	0	0
Colstrip	0	0	0	0	0
Carbon	(4,705)	(4,679)	(4,612)	(4,551)	(4,767)
Naughton	138,071	(71,225)	54,755	268,628	258,092
Huntington	142,824	102,392	(198,378)	(227,480)	(239,740)
Hunter	124,025	130,258	335,292	349,370	294,561
Blundell	0	0	0	0	0
TOTAL THERMAL	838,041	544,703	760,072	748,042	692,434
SYSTEM HYDRO	(690)	(79)	56	29	(826)
Draft From Storage	197	179	111	125	(319)
TROJAN GENERATION	0	0	0	0	0
TOTAL RESOURCES	605,343	546,367	677,282	774,912	690,866