PUGET POWER

October 8, 1992

Mr. Paul Curl, Secretary
Washington Utilities and Transportation Commission
P.O. Box 9022
Olympia, WA 98504-8002

Dear Mr. Curl:

Enclosed are 19 copies of the bench requests for Docket No. UE-920499 (rate design).

Please note, these responses may need to be updated since they were prepared prior to the filing of our general rate case.

Sincerely,

Robert J. Kalina

Robert J. Kalina
Rate Coordinator

RJK/ag

Enclosures

CC: Alice Haenle
Service List

RECEIVED
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STATE OF WASH
UTIL. & TRANSP
COMMISSION

Puget Sound Power & Light Company
Docket No. UE-920499
BENCH REQUEST NUMBER 1

Request:

Calculate the cost of service model with the proposed rates and indicate the parity ratios by subclass.

Response by Ms. Lynch:

See the attached spreadsheet, Allocated Costs Versus Revenues, which shows the results of calculating the cost of service using the proposed rates. The resulting parity ratios are shown on line 13.

	Puget Sound Power & Light Company								
	Allocated Costs Versus Revenues								
	10/6/92 10:03								
		Category		Summary	Summary	Summary	Summary	Summary	Summary
		Reference	Total	Class	Class	Class	Class	Class	Class
	Description	ID #	Allocation	Residential	Secondary Gen	Primary Gen'l S\	High Volt Gen'l S	Lighting	Firm Resale
	Operating Expenses								
1	Operation & Maintenance Expense	OME.T	421,977,743	234,463,261	106,933,531	27,024,805	48,004,571	3,602,631	1,948,944
2	Depreciation & Amortization Expense	DAE.T	104,859,160	61,139,489	26,851,570	6,326,523	9,205,693	914,467	421,419
3	Total Taxes	TAX.T	118,641,931	69,405,756	30,192,718	7,124,058	10,376,924	1,069,312	473,164
4	Total Operating Expenses	(1+2+3)	645,478,834	365,008,506	163,977,819	40,475,385	67,587,188	5,586,410	2,843,527
5	Return On Net Investment	RRB.T	189,016,982	112,262,112	48,223,792	11,142,694	14,861,806	1,811,040	715,538
6	Total Cost of Service	TC.T	834,495,816	477,270,618	212,201,610	51,618,079	82,448,994	7,397,450	3,559,065
7	Total Operating Revenues	REV.T3	834,495,813	467,913,756	226,360,306	50,903,205	78,206,376	7,600,848	3,511,322
8	Operating Income Defiency	(6-7)	3	9,356,863	-14,158,696	714,873	4,242,618	-203,398	47,743
9	Adjusted for Conversion Factor	CF.T	4	14,846,337	-22,465,306	1,134,275	6,731,673	-322,728	75,753
10	Total Sales of Electricity	REV.T1	823,563,083	460,450,186	224,671,437	50,378,095	76,994,402	7,575,089	3,493,873
11	Revenues Required From Rates	(9+10)	823,563,087	475,296,524	202,206,132	51,512,369	83,726,075	7,252,362	3,569,626
12	Revenue to Revenue Requirements	(10/11)	100%	97%	111%	98%	92%	104%	98%
13	Adj Revenue to Revenue Requirements	(restate 12)	100%	97%	111%	98%	92%	104%	98%

	Puget Sound Power & Light Company								
	Allocated Costs Versus Revenues								
	10/6/92 10:03								
		Residential	Residential	Residential	Secondary Ge	Secondary Ge	Secondary Ge	Secondary Ge	Primary Gen'l
		47	37	27	24	25	26	29	31
	Description	Water Heating	Space Heating	Lighting	0-50 kw	51-350 kw	>350 kw	Irrigation	General Servi
	Operating Expenses								
1	Operation & Maintenance Expense	62,186,675	150,757,867	21,518,719	42,560,263	41,201,642	22,881,457	290,168	22,229,515
2	Depreciation & Amortization Expense	15,473,357	40,194,975	5,471,157	10,572,612	10,207,424	5,978,739	92,795	4,993,226
3	Total Taxes	17,578,761	45,586,517	6,240,478	11,957,745	11,447,580	6,684,942	102,451	5,605,711
4	Total Operating Expenses	95,238,793	236,539,359	33,230,354	65,090,620	62,856,646	35,545,139	485,413	32,828,451
5	Return On Net Investment	27,954,165	74,322,033	9,985,914	19,027,151	18,208,241	10,814,392	174,006	8,607,724
6	Total Cost of Service	123,192,958	310,861,393	43,216,268	84,117,771	81,064,888	46,359,532	659,419	41,436,176
7	Total Operating Revenues	127,938,451	300,520,934	39,454,370	87,871,179	89,954,405	48,056,470	478,252	42,890,887
8	Operating Income Defiency	-4,745,493	10,340,458	3,761,898	-3,753,407	-8,889,517	-1,696,938	181,167	-1,454,711
9	Adjusted for Conversion Factor	-7,529,574	16,406,988	5,968,924	-5,955,452	-14,104,811	-2,692,497	287,454	-2,308,160
10	Total Sales of Electricity	125,881,916	296,035,481	38,532,789	86,910,945	89,499,707	47,792,776	468,010	42,448,598
11	Revenues Required From Rates	118,352,342	312,442,469	44,501,713	80,955,492	75,394,896	45,100,279	755,464	40,140,438
12	Revenue to Revenue Requirements	106%	95%	87%	107%	119%	106%	62%	106%
13	Adj Revenue to Revenue Requirements	106%	95%	87%	107%	119%	106%	62%	106%

	Puget Sound Power & Light Company							
	Allocated Costs Versus Revenues							
	10/6/92 10:03							
		Primary Gen'l	Primary Gen'l	High Volt Gen	High Volt Gen	Lighting	Lighting	Firm Resale
		43	35	49	46	55	50	5
	Description	Interruptible	Irrigation	General Servi	Interruptible	Area	Street	Large & Small
	Operating Expenses							
1	Operation & Maintenance Expense	4,712,220	83,070	43,859,820	4,144,751	434,265	3,168,366	1,948,944
2	Depreciation & Amortization Expense	1,312,863	20,434	8,425,285	780,407	104,963	809,504	421,419
3	Total Taxes	1,495,742	22,605	9,497,407	879,517	125,116	944,196	473,164
4	Total Operating Expenses	7,520,824	126,109	61,782,513	5,804,675	664,344	4,922,066	2,843,527
5	Return On Net Investment	2,499,327	35,643	13,614,056	1,247,751	210,052	1,600,988	715,538
6	Total Cost of Service	10,020,151	161,752	75,396,568	7,052,425	874,396	6,523,054	3,559,065
7	Total Operating Revenues	7,909,557	102,761	71,745,652	6,460,724	676,995	6,923,853	3,511,322
8	Operating Income Defiency	2,110,594	58,991	3,650,917	591,701	197,401	-400,799	47,743
9	Adjusted for Conversion Factor	3,348,835	93,600	5,792,833	938,840	313,212	-635,939	75,753
10	Total Sales of Electricity	7,827,613	101,884	70,554,318	6,440,084	673,765	6,901,325	3,493,873
11	Revenues Required From Rates	11,176,447	195,484	76,347,151	7,378,924	986,976	6,265,386	3,569,626
12	Revenue to Revenue Requirements	70%	52%	92%	87%	68%	110%	98%
13	Adj Revenue to Revenue Requirements	70%	52%	92%	87%	68%	110%	98%

Puget Sound Power & Light Company
Docket No. UE-920499
BENCH REQUEST NUMBER 2

Request:

Provide a copy of the cost of service model and documentation.

Response by Ms. Lynch:

See the Company's response to Staff Data Request No. 2. Additionally, copies of the cost of service model and documentation were distributed to all interested parties who attended the cost of service model training class held on September 29. 1992.

Puget Sound Power & Light Company
Docket No. UE-920499
Response to Bench Request #3

Request

Provide an interpretation of the graphs illustrating the residential rate impacts in Exhibit 14.

Response by Mr. Hoff

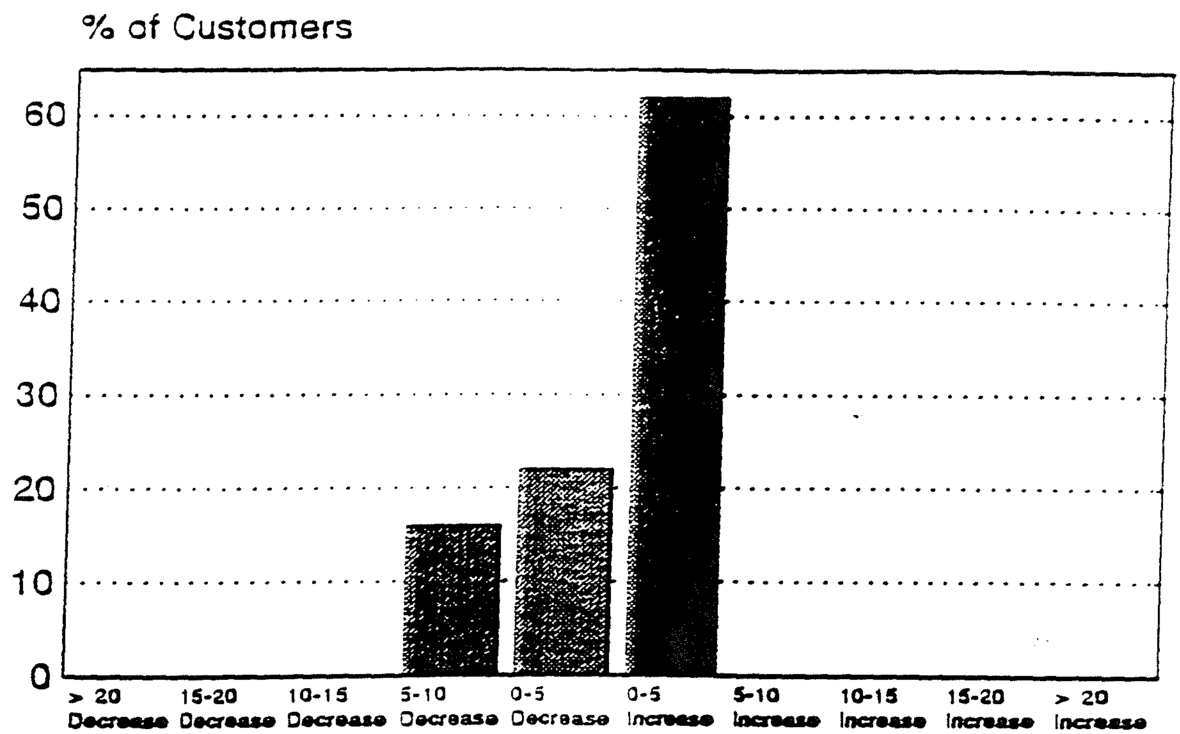
The graph on the top of page 2 of Exhibit 14 illustrates that no residential customers will receive a bill increase of more than five percent. However, approximately 62 percent of the residential customers will receive a bill increase of less than five percent. The remaining customers will receive rate a bill decrease from 0 - 10 percent.

The graph on the bottom of page 2 Exhibit 14 attempts to illustrate what types of residential customers will receive the rate increase and what their monthly bills are. The curved lines marked with boxes shows the percent change in summer and winter bills. (The empty boxes are winter bills.) These lines indicate that customers with **monthly consumption below 700 kWh will receive a bill decrease.** Customers with monthly bills above 700 kWh will receive increases up to five percent. No customers with consumption between 700 - 3000 kWh will receive a bill increase over five percent.

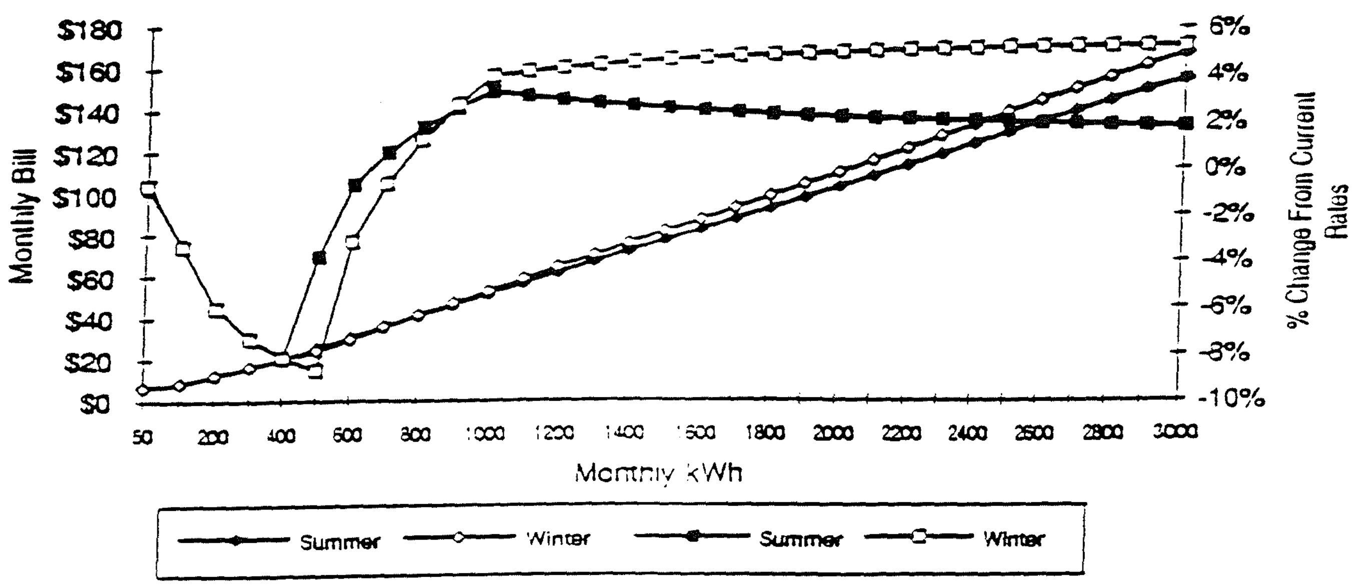
The second set of lines on the graph shown on the bottom of page 2 indicate the monthly summer and winter bills (with PRAM 1). The lines, marked with diamonds, are read with scale on the left side of the graph.

The two sets of lines can be used to examine the impact on a residential customer. For example, a lights and appliance customer using 600 kWh/month in the winter will receive a 3% bill decrease (looking at the line with empty boxes using the scale on the right side.) The customer's winter bill will be approximately $30/month (looking at the line with empty diamonds using the scale on the left side.)

Schedule 7 Impacts
Percent Change In Bills



Impacts Of Proposed Residential Rate



Puget Sound Power & Light Company
Docket No. UE-920499
Response to Bench Request #4

Request

Reconcile the combined cycle combustion turbine cost used in the peak credit method with the avoided cost filing.

Response by Mr. Hoff

The combined cycle combustion turbine (CCCT) is used in the avoided cost analysis as a proxy for the generation resource required starting in 1996. The starting date for the CCCT is based upon an assessment of resource costs and power requirements as of May, 1991. The CCCT is used in the peak credit method as the proxy for the most likely power plant that would be used as the next base generation plant. The costs for this unit are based upon the Integrated Resource Plan (IRP), prepared in the Spring of 1992.

The cost for both the numerator (the CT) and the denominator (the CCCT) of the peak credit calculation are based upon consistent assumptions as documented in the IRP. The major differences between the assumptions for the CCCT cost in the peak credit method and the avoided cost study are:

- The peak credit uses a higher capital plant cost,
- The peak credit uses a higher availability factor, and
- The peak credit uses lower gas costs and different gas escalation rates.

The attached work paper compares the assumptions used in the peak credit and the avoided cost filing.

PEAKAVOD.XLS UE-920499 14-Aug-92

Comparison of Assumptions in Peak Credit Method and Avoided Cost

Element	Peak Credit	Avoided Cost
Starting Year	1991	1996
Capital Cost ($/kW)	670	615
Fixed O&M (mills/kWh)	0.8	0.8
Variable O&M (mills/kWh)	3.2	3.2
Heat Rate (BTU/kWh)	7,740	7,740
Availability Factor	80%	75%
Gas Cost ($/mmBTU)	$2.00	$2.60
Fixed Charge Rate	13.16%	13.16%

Escallation Rates

Year	Peak Credit O&M	Avoided Cost O&M	Peak Credit Gas	Avoided Cost Gas
1992	2.80%	3.70%	2.80%	4.60%
1993	2.70%	3.10%	4.41%	4.60%
1994	2.90%	3.10%	5.59%	17.40%
1995	3.00%	3.70%	5.95%	17.40%
1996	3.40%	3.90%	5.64%	9.30%
1997	3.50%	4.00%	6.01%	9.30%
1998	3.50%	4.10%	6.87%	9.30%
1999	3.60%	4.10%	7.46%	9.30%
2000	3.90%	4.40%	7.63%	9.30%
2001	4.00%	4.80%	7.61%	4.80%
2002	4.10%	5.00%	7.59%	5.00%
2003	4.10%	4.90%	7.47%	4.90%
2004	4.10%	4.90%	6.87%	4.90%
2005	4.10%	4.90%	7.04%	4.90%
2006	4.20%	4.90%	7.06%	4.90%
2007	4.20%	5.00%	6.98%	5.00%
2008	4.30%	5.10%	7.01%	5.10%
2009	4.40%	5.10%	6.83%	5.10%
2010	4.40%	5.10%	6.56%	5.10%
2011	4.40%	5.10%	5.00%	5.10%
2012	4.50%	5.10%	5.00%	5.10%
2013	4.60%	5.10%	5.00%	5.10%
2014	4.80%	5.20%	5.00%	5.20%
2015	4.80%	5.20%	5.00%	5.20%
2016	4.80%	5.00%	5.00%	5.00%
2017	5.00%	5.00%	5.00%	5.00%
2018	5.00%	5.00%	5.00%	5.00%
2019	5.00%	5.00%	5.00%	5.00%
2020	5.00%	5.00%	5.00%	5.00%

Puget Sound Power & Light Company
Docket No. UE-920499
Response to Bench Request #5

Request

Provide the calculations of marginal costs in all rates incorporating marginal costs.

Response by Mr. Hoff

The company used estimates of marginal cost to develop the tail blocks of the residential rate (schedule 7) and the voluntary large power rates (schedules 30 and 48). In addition, marginal costs were used to estimate the benefits from having a customer on an interruptible rate for large power (schedules 36, 38, and 39) and for interruptible water heat (schedule 6).

Attachment I shows the derivation of the schedule 30 and 48 rates. Table 1 shows the avoided cost allocated to energy and demand using the 83/17 peak credit. This is the basis of the marginal cost calculations. Table 2 levelizes the avoided cost using a ten year horizon. The marginal production costs are adjusted for each schedule using the loss factors shown in Table 3. The losses adjusted marginal cost are used in the tail blocks shown in Table 4. The first block rates are set so that the weighted average rate of the two blocks equals the flat rate in the associated schedule (31/49).

Attachment II shows the derivation of the marginal cost tail block for schedule 7. The marginal production costs, from Puget Power's avoided cost, are shown in Table 7. These marginal costs are applied to the water heat load shape and the loss adjustment factors shown in Table 6. The result is the table of summer and winter combined energy and demand costs shown in the last two columns in Table 8. These numbers are levelized using a twelve year time horizon, the typical life of a water heater.

Attachment III shows the derivation of the value of large power interruptions based upon a one and five year estimate of marginal costs. The one year marginal cost is based upon the San Diego peak capacity contract and the calculations are shown in lines 1 - 8. The thirty year marginal cost is based upon the assumptions used to value capacity in the peak credit method. These costs are shown in lines 9 - 10. The five year marginal cost of capacity is assumed to be 1/4 of the way between the one and thirty year capacity values. This calculation is shown in lines 11-13. The remainder of the worksheet shows the application of these marginal costs to the large power interruptible rate design.

The derivation of the value of the water heater interruptions is shown in DWH-8, Exhibit 15.

UE92-0499 Reco

Table 1. Avoided Costs

Discount Rate: 10.22%
Base Year: 1991

	Year	Winter mills/kWh	Summer mills/kWh	Capacity $/kw-mon	Total $/mWh
1	1992	28.67	23.84	3.98	32.10
2	1993	23.36	21.14	0.00	22.44
3	1994	25.09	23.01	0.00	24.22
4	1995	26.51	23.84	0.00	25.40
5	1996	46.96	39.04	6.53	52.58
6	1997	49.90	41.48	6.93	55.87
7	1998	53.11	44.15	7.38	59.46
8	1999	56.61	47.06	7.87	63.38
9	2000	60.44	50.25	8.40	67.67
10	2001	62.71	52.13	8.71	70.21
11	2002	65.19	54.20	9.06	72.99
12	2003	67.74	56.32	9.41	75.85
13	2004	70.42	58.55	9.79	78.85
14	2005	73.24	60.89	10.18	82.00
15	2006	76.18	63.34	10.59	85.30
16	2007	79.34	65.96	11.02	88.83
17	2008	82.72	68.77	11.49	92.62
18	2009	86.28	71.73	11.99	96.60
19	2010	90.01	74.83	12.51	100.78
20	2011	93.93	78.09	13.05	105.17

Based Upon September, 1991 RFP For Resources. Modified for 17% Peak Credit

UE92-0499

Table 2. Levelized Avoided Costs

Time Frame	Winter $/kWh	Summer $/kWh	Capacity $/kW-mon	Total $/mWh
10	0.03583	0.03042	3.82	38.80

Table 3. Loss Factors (Used to adjust marginal energy and demand costs.)

Schedule	Energy	Demand
31	5%	7%
49	3%	4%

Table 4. Marginal Rate Calculations for Schedules 30 & 48

Rate	Block Factor	Block (1)	Block 2 - Winter $ / kWh	Block 2 - Summer $ / kWh	Block 1 $ /kW	Block 2 $ /kW
49		none	0.02517	0.02288	2.79	2.79
48	75%	0.02066	0.03690	0.03133	2.40	3.87
31 (a)		none	0.02827	0.02570	4.51	4.51
30 (b)	75%	0.02439	0.03762	0.03194	4.29	5.16
30	75%	0.02439	0.03762	0.03194	4.65	4.09

(a) Demand rate is class weighted average summer / winter demand

(b) Demand tail block set at $1 above marginal cost in order to have an inverted demand rate

$1 adder based upon marginal distribution cost of $12.04 /kW-year from marginal cost distribution model

Rate Design Case UE-920499 - Bench Request #5
Calculation Of Levelized Cost For Residential Marginal Cost Rate

Table 5. Water Heat Load Shape

	Water Heat kWh	kW
Jan	452	1.259
Feb	403	1.32
March	418	1.247
April	383	1.242
May	377	1.177
June	347	0.977
July	325	0.73
August	314	0.739
Septembe	331	1.091
October	365	1.141
November	391	1.151
December	436	1.274
Seasonal Totals		
Summer	2077	1.242
Winter	2465	1.32

Energy Losses	8.00%
Demand Losses	12.00%
Discount Rate	10.22%

Table 7. Firm Power Avoided Cost - Peak Credit 17%

Year		Winter $/mWh	Summer $/mWh	Capacity $/kW-mon	Total $/mWh
1	1992	28.67	23.84	3.98	32.10
2	1993	23.36	21.14	0.00	22.44
3	1994	25.09	23.01	0.00	24.22
4	1995	26.51	23.84	0.00	25.40
5	1996	46.96	39.04	6.53	52.58
6	1997	49.90	41.48	6.93	55.87
7	1998	53.11	44.15	7.38	59.46
8	1999	56.51	47.06	7.87	63.38
9	2000	60.44	50.25	8.40	67.67
10	2001	62.71	52.13	8.71	70.21
11	2002	65.19	54.20	9.06	72.99
12	2003	67.74	56.32	9.41	75.85
13	2004	70.42	58.55	9.79	78.85
14	2005	73.24	60.89	10.18	82.00
15	2006	76.18	63.34	10.59	85.30
16	2007	79.34	65.96	11.02	88.83
17	2008	82.72	68.77	11.49	92.62
18	2009	86.28	71.73	11.99	96.60
19	2010	90.01	74.83	12.51	100.78
20	2011	93.93	78.09	13.05	105.17

Rate Design Case UE-920499 - Bench Request #5

Calculation Of Levelized Cost For Residential Marginal Cost Rate

Table 8. Water Heat Customer Marginal Costs

Year	Winter Energy $	Summer Energy $	Annual Capacity $	Total	$/ kWh	Winter Capacity $	Summer Capacity $	Winter Total	Summer Total	Winter $ /kWh	Summer $/kWh
1992	$76.33	$53.48	$70.61	$200.41	0.044124	$37.39	$33.22	$113.72	$86.69	0.046132	0.041740
1993	$62.19	$47.42	$0.00	$109.61	0.024132	$0.00	$0.00	$62.19	$47.42	0.025229	0.022831
1994	$66.79	$51.62	$0.00	$118.41	0.026070	$0.00	$0.00	$66.79	$51.62	0.027097	0.024851
1995	$70.57	$53.48	$0.00	$124.05	0.027312	$0.00	$0.00	$70.57	$53.48	0.028631	0.025747
1996	$125.02	$87.57	$115.85	$328.44	0.072311	$61.35	$54.50	$186.36	$142.07	0.075604	0.068403
1997	$132.84	$93.05	$122.94	$348.83	0.076802	$65.10	$57.84	$197.95	$150.89	0.080303	0.072646
1998	$141.39	$99.04	$130.93	$371.35	0.081760	$69.33	$61.60	$210.72	$160.63	0.085485	0.077338
1999	$150.71	$105.56	$139.62	$395.89	0.087162	$73.94	$65.68	$224.64	$171.25	0.091133	0.082450
2000	$160.90	$112.72	$149.02	$422.64	0.093053	$78.91	$70.11	$239.82	$182.83	0.097289	0.088025
2001	$166.95	$116.94	$154.52	$438.40	0.096522	$81.83	$72.70	$248.77	$189.63	0.100922	0.091301
2002	$173.55	$121.58	$160.73	$455.86	0.100365	$85.11	$75.62	$258.66	$197.20	0.104934	0.094943
2003	$180.34	$126.33	$166.94	$473.61	0.104274	$88.40	$78.54	$268.74	$204.87	0.109022	0.098639
2004	$187.47	$131.34	$173.68	$492.49	0.108431	$91.97	$81.71	$279.44	$213.05	0.113365	0.102574
2005	$194.98	$136.59	$180.60	$512.17	0.112762	$95.64	$84.96	$290.62	$221.55	0.117897	0.106669
2006	$202.81	$142.08	$187.88	$532.76	0.117297	$99.49	$88.39	$302.29	$230.47	0.122635	0.110962
2007	$211.22	$147.96	$195.50	$554.68	0.122123	$103.53	$91.98	$314.75	$239.93	0.127686	0.115520
2008	$220.22	$154.26	$203.84	$578.32	0.127327	$107.94	$95.90	$328.16	$250.16	0.133128	0.120443
2009	$229.69	$160.90	$212.71	$603.31	0.132829	$112.64	$100.07	$342.34	$260.97	0.138878	0.125649
2010	$239.62	$167.86	$221.94	$629.42	0.138577	$117.53	$104.41	$357.15	$272.27	0.144889	0.131087
2011	$250.06	$175.17	$231.52	$656.75	0.144594	$122.60	$108.92	$372.66	$284.09	0.151180	0.136777
Levelized Cost 12 Years					0.055					0.057496	0.052038

Large Power Interruptible Rates
San Diego Contract Model

Line	Item	Calculation	Cost
1	Escalation Rate 1991 - 1993		5.60%
2	Contract Cost / kW-Month		2.00
3	Number of Months (Nov - Feb)		4.00
4	Annual Capacity Cost	(L1*L2*L3)	8.45
5	Energy Cost (mills/kWh)		36
6	Wheeling Cost (mills/kWh)		4
7	Total Energy Cost (mills/kWh)	(L5+L6)*L1	42
8	Annual Cost - 200 hours		16.90

Peak Allocation of Combustion Turbine (30 Years)

Line	Item	Calculation	Cost
9	1/2 Fixed CT Cost ($/kW Year) - Peak Credit Number 1991$		53.06
10	1/2 Cost CT in 1993 $	(1 + L1)*L8	56.03

5 Year Contract Value

Line	Item	Calculation	Cost
11	5 Year Value Adjustment - 1/4 Between 1 and 30 Contract ($/yr)	(0.75*L8)+0.25*L10	27
12	Capacity Payment ($/kw-Yr)	(0.55 * L11)	14.67
13	Energy Payment (mills / kWh)	(L11 - L12)/5	60

Additional Monthly Charge Calculations

Line	Item	Calculation	Cost
14	Printer / Modem Capital Cost		1200.00
15	Printer Life		5
16	Fixed Charge Rate		34.42%
17	Annual Printer Cost	(L14*L16)	412.99
18	Printer/Modem/Customer Maintenance		340.00
19	Sched 24 / 31 Meter Upgrade		200.00
20	Meter Life		30
21	Fixed Charge Rate		19.99%
22	Meter Annual Cost	(L19*L21)	39.99

Additional Monthly Charges If An Interruption

Line	Item	Calculation	Cost
23	Meter Reading - Schedule 49		$0.00
24	Meter Reading - Schedule 24 & 31		$11
25	Data Processing - Schedule 49		$0.00
26	Data Processing - Schedule 24 & 31		$11

Additional Charges Per Interruption

Line	Item	Calculation	Cost
27	Notification Call		$1.50

Large Power Interruptible Rates

Lost Revenues

Line	Item	Calculation	Cost
28	Winter Schedule 26 ($/kWh)		0.032990
29	Winter Schedule 31 ($/kWh)		0.028190
30	Winter Schedule 49 ($/kWh)		0.025180

Value of Interruptible Load

Line	Interruptle Demand Type	Calculation	$/kW -Year	$/kWh
31	Short Term Firm, 1 Year Contract	L4 & L7	$8.45	0.0422
32	Long Term Firm, 5 Year Contract	L12 & L13	$14.67	0.0600
33	Non-Firm - 50% of 1 Year Contract		$0.00	0.0422
34	Short Term Firm, 1 Year Contract - Restated		9	0.0410
35	Long Term Firm, 5 Year Contract - Restated		15	0.0600
36	Non-Firm - 50% of 1 Year Contract - Restated			0.0410

Credits By Schedule

Line	Interruptle Demand Type	Calculation	$/kW -Year	$/kWh
37	Schedule 36 - Short Term Firm, 1 Year Contract	L34 & L34 - L28	9	0.0080
38	Schedule 36 - Long Term Firm, 5 Year Contract	L35 & L35 - L28	15	0.0270
39	Schedule 36 - Non-Firm - 50% of 1 Year Contract	L36 - L28	0	0.0080
40	Schedule 38 - Short Term Firm, 1 Year Contract	L34 & L34 - L29	9	0.0128
41	Schedule 38 - Long Term Firm, 5 Year Contract	L35 & L35 - L29	15	0.0318
42	Schedule 38 - Non-Firm - 50% of 1 Year Contract	L36 - L29	0	0.0128
43	Schedule 39 - Short Term Firm, 1 Year Contract	L34 & L34 - L30	9	0.0158
44	Schedule 39 - Long Term Firm, 5 Year Contract	L35 & L35 - L30	15	0.0348
45	Schedule 39 - Non-Firm - 50% of 1 Year Contract	L36 - L30	0	0.0158