EXHIBIT NO.	DPU-1
Case	
Date	2-23-95
Witness	
Reporter	

Division of Public Utilities
For the Utah Demand Side Resource Cost Recovery Collaborative
160 East 300 South
Salt Lake City, Utah 84145-0807
Date Submitted: November 30, 1994

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of Ratemaking Treatment of Demand-Side Resources and the Analysis of Regulatory Changes to Encourage Implementation of Integrated Resource Planning	)	DOCKET NO. 92-2035-04 FIRST REPORT, 1994 JOINT RECOMMENDATION

ISSUED: November 30, 1994

SYNOPSIS

By this Report, the Utah Demand-Side Resource Cost Recovery Collaborative provides the Utah Commission with a preliminary 1994 Net Lost Revenue amount for their review and approval prior to PacifiCorp's January 18, 1995 booking to corporate accounts. This November 30, 1994 report is part of the February 10, 1994 Utah PSC Order approving the Demand Side Resource "Joint Recommendation" under Docket No. 92-2035-04, a 1994 trial program for DSR Cost Recovery.

November 30, 1994 Report of the Utah Demand Side Resource Cost Recovery Collaborative

In the Utah Public Service Commission ("Commission") order dated February 10, 1994 in Docket No. 92-2035-04 ("Order"), the Commission approved the Joint Recommendation establishing Demand Side Resource ("DSR") cost recovery procedures for 1994. The order also established a new DSR cost-recovery collaborative ("Collaborative"), and outlined the responsibilities of the Collaborative. One of the responsibilities of the Collaborative is to monitor PacifiCorp's calculation of Net Lost Revenue ("NLR") for 1994. In addition, the order states that:

> The Collaborative will submit a report to the Commission by November 30, 1994, which quantifies the dollar amount of NLR for 1994 and identifies the inputs which resulted in that dollar amount. The report will also identify the appropriate DSR measure lives for amortization purposes. (See Page 7 of the Order)

The order also states that:

> The Commission finds that the Joint Recommendations's NLR provisions, including the NLR formula and 25 percent adjustment limit, are just, reasonable and in the public interest. The initial determination of PacifiCorp's 1994 NLR will be made by the Commission prior to January 18, 1995, the date on which PacifiCorp closes its books for 1994. (See page 5 of the Order)

The NLR calculated as a part of this report will be updated prior to January 18, 1995 to include actual DSR results for November and December 1994, to revise savings estimates resulting from subsequent program evaluations, and to reflect changes due to the settlement of other unresolved issues addressed in this report. After the Company closes its books for 1994 on January 18, 1995, any subsequent adjustments to the NLR amount are limited to 25% of the booked NLR.

1994 NET LOST REVENUE

The projected Net Lost revenue for 1994 is \$338,723, based on 21,014 MWh of savings (non-annualized). This number is based on the best engineering estimates of installed and projected DSR projects in 1994 currently available. The data reflects installed projects for January to October, and projected projects for November and December. This data is subject to change based on ongoing program evaluation and verification efforts. A detailed listing of 1994 DSR projects is included as Attachment 1. The calculation of the NLR is included as Attachment 2.

DSR Activity in 1994

PacifiCorp DSR activity, as measured through annualized engineering estimates, is estimated at 58,566 MWh and 10.3 MW, exceeding the 40,000 MWh and 6 MW goals stated in the Joint Recommendation. This DSR activity is also expected to exceed the Joint Recommendation goal that at least 20% of the RAMPP-3 DSR goal is achieved in each customer class. Actual MWh savings on a non-annualized basis is estimated to be 21,014, which represents 3.5% of actual energy growth in Utah[1].

The Collaborative believes that the Net Lost Revenue mechanism in place in 1994 was instrumental in encouraging PacifiCorp to acquire the amount of DSR set as a goal in RAMPP-3. The mechanism encouraged PacifiCorp to significantly expand its energy efficiency programs in comparison to previous years. PacifiCorp expects to achieve approximately 97% of its overall target of 60,500 MWh for Utah DSR acquisition set in RAMPP-3 for 1994 and will achieve approximately 140% of its RAMPP-3 target of 7 MW.

PacifiCorp's 1994 DSR programs also improve the energy efficiency of Utah's businesses and homes. This lowers customers bills, helps preserve Utah jobs and makes Utah businesses more competitive. For example, PacifiCorp helped major industrial customers achieve energy savings through the installation of energy efficiency measures (e.g. efficient motors).

Inputs

Exhibit 1 of the joint recommendation approved in the Commission Order identifies the formula to be used to calculate NLR for 1994 (See Attachment 3). The Commission directed this Collaborative to specify the definitions of the inputs to be used in the formula. This section defines those inputs.

Briefly, the formula from Exhibit 1 is :

$$\textbf{Net Lost Revenues} = (\mathbf{R} - \mathbf{AC}) \times (\mathbf{ES} - \mathbf{LG}) + (\mathbf{DC} - \mathbf{ADC}) \times (\mathbf{NCPs} - \mathbf{LGp})$$

where:

R	=	Retail rate per kWh
AC	=	Avoided Energy Cost per kWh
ES	=	Energy Savings in kWh

[1] Utah Energy growth from September 1993 to September 1994.

LG	=	Load building impacts in kWh of DSR programs, including load growth related to DSR programs in the new construction area.
DC	=	Demand Charge per kW for the customer class based on the current tariff
ADC	=	Avoided demand cost savings per kW based on non-coincident peak, with line losses
NCPs	=	Non-coincident peak demand savings in kW
LGp	=	Load building impacts in kW of DSR programs, including load growth related to DSR programs in the new construction area.

The formula used to compute annual net lost revenues in Attachment 2 reflects the time element of the units used in the formula and is thus refined to read:

$$\textbf{Annual Net Lost Revenues} = \text{Sum}_i\,(R - AC_i) \times (ES_i - LG_i) + \text{Sum}_i\,(DC - ADC_i) \times (NCPs_i - LGp_i)$$

where: **i** = month

The following provides a detailed description of where the input values for Attachment 2 come from and why these values were selected to represent the terms in the equation.

R: The retail price is the tail block rate per kWh in the tariff or special contract of the participant in the DSR project. This value best represents marginal lost retail revenue.

The retail price for each program is shown on page 5 of Attachment 2.

AC: The value of energy costs avoided by saving a kWh through a DSR project is represented by the monthly avoided energy costs computed from PacifiCorp's production cost model, PDMac, for the year 1994. The calculation is based on the comparison of two PDMac runs; one with and one without 50 MW average of generation available at zero running cost. The run which includes the 50 MW average generation also includes the value of additional secondary sales made available with the additional 50 MW average. The PDMac analysis is based on RAMPP-3 medium load growth and includes the same resource base as the currently filed QF avoided cost analysis. The only difference between the currently filed QF avoided energy costs and the avoided energy costs employed on page 5 of Attachment 2, is the impact of secondary sales, which adds about 2 mills per kWh.

The subcommittee reviewed two different methods for valuing avoided energy costs for the net lost revenue estimate: the Realized Marginal Energy Cost

(RMEC) method and the normalized PDMac method. Each method had strengths and weaknesses. Some of the subcommittee members preferred the PDMac method because it produced normalized avoided energy costs. Since avoided costs are subtracted from normalized retail rates, a normalized number provides consistency in determining net lost revenues to the Company between rate cases. On the other hand, the RMEC method is a real time calculation of potential costs avoided by PacifiCorp based on the highest cost for one MW in each hour purchased or generated by PacifiCorp over six months. It is the method currently used for Sunnyside payments. Some subcommittee members preferred the theoretical appeal of the RMEC method because it could provide a sense of actual revenues lost. However, the computerized (and therefore easily accessible) RMEC method includes some high costs, namely purchases for resale and interruptible buy-throughs, which may not actually be avoidable and, thus, may overstate the avoided costs. The RMEC method can be calculated without these objectionable purchases, however this computation is not currently computerized and is extremely cumbersome at the present time. Further, the resultant avoided energy cost from RMEC computed without the objectionable high cost purchases is consistent in magnitude with the resultant avoided energy costs produced using PDMac with secondary sales. Therefore, the subcommittee concluded that the PDMac method with secondary sales produced a reasonable estimate of avoided energy costs and agreed to adopt this method for the present time.

The subcommittee agreed to use the avoided energy costs which have been filed by PacifiCorp in Utah Docket No. 94-2035-03 regarding QF standard avoided cost rates, adjusted for secondary sales, for this preliminary, November, account of net lost revenues, but reserves the right to revisit this issue when the case is resolved. Because the case will not be resolved prior to January 18, 1985, changes in final avoided costs employed to determine net lost revenues will be limited by the 25% constraint.

The subcommittee also analyzed the value of using time differentiated avoided energy costs and selected to use monthly avoided energy cost values for a more accurate account of net lost revenues. There is significant monthly variation in both avoided energy costs and projected kWh savings. Additionally, there is a differential between on-peak and off-peak avoided costs. Matching the appropriate on-peak and off-peak avoided costs with on-peak and off-peak energy savings will yield a more accurate estimate of net lost revenues. However, estimates will be necessary to quantify on-peak and off-peak avoided costs and kWh savings. This will require significant Company resources and may or may not produce a result more accurate than using monthly avoided costs and kWh savings.

Because the monthly data is available and using the monthly data results in a significantly different estimate of net lost revenues, the monthly variation was selected. Agreement was not reached on the application of peak/off-peak differentiation. Arguments against using the peak/off-peak differentiation are as follows:

- The peak/off-peak values overstate actual differentiation because they are based on the highest avoided cost and lowest avoided cost in a given month, not an average;

- The differentials between highest marginal cost and lowest marginal cost are applied to the PDMac average avoided cost assuming that half of the differential applies to peak and the other half to off-peak periods; this may not be the case and therefore adds uncertainty to the results reported above;

- The biggest impact on 1994 net lost revenues from applying peak/off-peak differentiation will result from the residential hot water saving program which will end in 1994, so on-going impacts will be smaller.

- The NLR subcommittee analysis used four commercial buildings, but industrial savings dominate and industrial savings will have the smallest amount of peak/off-peak variation.

For the reasons stated above, the subcommittee agreed not to apply peak/off-peak differentiation in this preliminary assessment of net lost revenues. The subcommittee is going to review additional information on the variation in system lambda between peak and off-peak periods to gain more confidence in the assessment of the impact of peak/off-peak avoided costs on net lost revenues. This information will be provided in an update letter to the Commission prior to January 18, 1995.

The monthly avoided energy costs employed in the calculation are shown on page 5 of Attachment 2.

ES: All kWh savings in Attachment 2 are engineering estimates for projects installed. Installation is generally measured as the day the Energy Service Charge contract is attached to the participants bill, or when installation and inspection is completed for non ESC projects. This is a very conservative date, as the building may be occupied months prior. The engineering estimates do not include any adjustment for verification, monitoring or estimates of free-ridership. Updates to these numbers will be provided prior to January 18, 1995 to the extent they become available. At that time, all Commercial FinAnswer program estimates will include adjustments for free-ridership and load-building adjustments, which will be available from an evaluation report due in December, 1994, and from Industrial monitoring data. In January, the Residential hot water saving program estimates may also be adjusted to reflect persistence of savings.

Currently, Commercial and Industrial FinAnswer programs provide monthly estimates of kWh. For the Residential programs, only annual data is available at present. Evaluation results will provide better estimate of the monthly variation in Residential energy savings.

Prior to January 18, 1995, the bulk of evaluation reports will be available to adjust the engineering estimates for free-ridership, load building, and persistence. *Verified or measured savings* will not be available until later in 1995, and therefore this adjustment will be subject to the 25% limitation.

Conservation savings achieved in 1994 from programs which are approved by the Commission subsequent to 1994 are included for 1994 NLR purposes.

Included as Attachment 1 is a list of all projects by class listing energy savings per building.

LG: As noted above, the value for load-building impacts in Attachment 2 is zero. Program evaluation results will provide quantification of this value, to the extent that such load building impacts are identified. The January update will include an estimate of this parameter.

DC: The retail demand charge is represented by the tail block demand charge rate for each customer class. (See Attachment 2, page 6)

ADC: The avoided demand charge represents a capacity credit made possible by a saved kW. A saved kW can be turned into a short term firm capacity sale which includes a fixed cost component.

One measure of avoided capacity costs is a comparison to actual capacity sale and purchase agreements. Attachment 2, page 6, shows the capacity purchases from Southern California Edison and The Washington Water Power Company and capacity sales to Eugene Water and Energy Board. Since these are take or pay contracts, it could be argued that there is no related capacity savings from DSR programs. However, the subcommittee believes that additional short term firm sales could result from DSR capacity reductions. The capacity purchase contracts with SCE and TWWP and the EWEB sales contract are used here as a surrogate for the capacity component of short term firm sales agreements for those months in which the sales/purchases occurred. For months with no purchase or sales, a zero value is assigned.

These values are shown in Attachment 2, page 6.

NCPs: The method used to represent this value is dependent on the program. All kW in Attachment 1 are based on engineering estimates. For the Commercial and Industrial FinAnswer programs, DOE-2 modeled kW is used. For the prescriptive Commercial FinAnswer program, DOE-2 modeled kW from the non-prescriptive Commercial FinAnswer is analyzed and prorated on the prescriptive program buildings. For the Residential programs, the low-income retrofit program and the multifamily hot water savings program, conservation load factors were applied to the estimated kWh savings to derive a kW saved. The conservation load factor provides an estimate of the amount of kW available from a given program based on customer class. This estimate is based on assumptions about the typical amount of kW per kWh provided for a given program. The conservation load factors used are based on PacifiCorp's analysis. PacifiCorp will provide analytical support for the conservation load factors used in the NLR calculation to the Collaborative prior to January 1, 1995. Approximately one-fourth of the kW savings are calculated using a conservation load factor (See Attachment 1).

These values are shown on pages 7 and 8 Attachment 2.

LGp: Load-building kW impacts were assigned a zero value at this time. Evaluation reports will update this value for the January update, to the extent load building impacts are identified.

DSR MEASURE LIVES

Attachment 4 outlines the estimated DSR measure lives by energy conservation measure. PacifiCorp plans to use a 10 year amortization period for residential DSR programs, and a 15 year amortization period for commercial and industrial DSR programs, unless the specific characteristics of a project indicate that a different amortization period is more appropriate. After reviewing Attachment 4, the subcommittee determined that the Company's proposed amortization periods are reasonable for the following reasons: 1) they approximate the energy conservation measure lives shown on Attachment 4; 2) a standardized amortization period is easier to administer; 3) this is consistent with PacifiCorp's current practices and the measure lives used in other PacifiCorp jurisdictions; and 4) it is a conservative estimate which takes into account potential technological changes and persistence of savings.

Attachment 1

PacifiCorp

Utah Jurisdiction 1994 DSR Projects

Line No.	Month of Installation	Cust. Class	Program	ID	Sched.	Annualized Gross kWh	Load Growth	Annualized Net kWh	Conserv. Load Factor	kW
1	January	Res.	ECONS	9999	Schedule 1	748,243	0	748,243	48%	178
2	January	Res.	ECONS	9999	Schedule 5	1,117	0	1,117	48%	0
3	February	Comm.	Comm. Finanswer	171	Sch. 6 (< 100 MWh)	37,240	0	37,240	60%	7
4	February	Comm.	Commercial Spec.	3	Sch. 6 (> 100 MWh)	444,219	0	444,219	60%	85
5	February	Comm.	Finanswer 12,000	76	Sch. 6 (< 100 MWh)	63,521	0	63,521	60%	12
6	February	Comm.	Finanswer 12,000	55	Schedule 23	35,070	0	35,070	60%	7
7	March	Res.	ECONS	9999	Schedule 1	987,478	0	987,478	48%	235
8	March	Res.	ECONS	9999	Schedule 5	1,119	0	1,119	48%	0
9	March	Comm.	Comm. Finanswer	159	Sch. 6 (< 100 MWh)	76,610	0	76,610		18
10	March	Comm.	Comm. Finanswer	308	Sch. 6 (< 100 MWh)	591,622	0	591,622		413
11	March	Comm.	Comm. Finanswer	153	Sch. 6 (< 100 MWh)	197,922	0	197,922		28
12	March	Comm.	Comm. Finanswer	264	Sch. 6 (< 100 MWh)	193,295	0	193,295		56
13	March	Comm.	Finanswer 12,000	128	Sch. 6 (< 100 MWh)	10,274	0	10,274		0
14	April	Res.	ECONS	9999	Schedule 1	1,294,284	0	1,294,284	48%	308
15	April	Res.	ECONS	9999	Schedule 5	2,720	0	2,720	48%	1
16	April	Comm.	Comm. Finanswer	232	Sch. 6 (< 100 MWh)	104,168	0	104,168		14
17	April	Comm.	Comm. Finanswer	193	Sch. 6 (< 100 MWh)	167,430	0	167,430		31
18	April	Comm.	Finanswer 12,000	150	Schedule 9	21,000	0	21,000	60%	4
19	May	Res.	ECONS	9999	Schedule 1	963,011	0	963,011	48%	229
20	May	Comm.	Comm. Finanswer	251	Schedule 23	114,411	0	114,411		8
21	May	Comm.	Finanswer 12,000	145	Schedule 23	12,242	0	12,242		0
22	June	Res.	ECONS	9999	Schedule 1	1,597,963	0	1,597,963	48%	380
23	June	Comm.	Comm. Finanswer	160	Sch. 6 (> 100 MWh)	458,784	0	458,784		71
24	June	Comm.	Comm. Finanswer	200	Sch. 6 (< 100 MWh)	143,865	0	143,865		27
25	July	Res.	ECONS	9999	Schedule 1	318,395	0	318,395	48%	76
26	July	Res.	Sch. 5 Water Kits	9999	Schedule 5	1,154,839	0	1,154,839	48%	275
27	July	Comm.	Comm. Finanswer	225	Sch. 6 (< 100 MWh)	120,924	0	120,924		77
28	July	Comm.	Comm. Finanswer	283	Sch. 6 (> 100 MWh)	1,513,908	0	1,513,908		362
29	July	Indus.	Indus. Finanswer	181	Schedule 9	1,432,000	0	1,432,000		225
30	July	Indus.	Major Accounts	9998	Contract 1	4,436,000	0	4,436,000		400
31	August	Res.	ECONS	9999	Schedule 1	1,432,520	0	1,432,520	48%	341
32	August	Comm.	Comm. Finanswer	255	Sch. 6 (< 100 MWh)	58,764	0	58,764		16
33	August	Indus.	Major Accounts	9998	Contract 1	5,316,000	0	5,316,000		607
34	September	Res.	ECONS	9999	Schedule 1	1,658,473	0	1,658,473	48%	394
35	September	Comm.	Comm. Finanswer	298	Sch. 6 (< 100 MWh)	191,181	0	191,181		45
36	September	Indus.	Indus. Finanswer	197	Schedule 39	181,743	0	181,743		23
37	September	Indus.	Major Accounts	9998	Contract 1	4,015,000	0	4,015,000		544
38	September	Indus.	Major Accounts	9997	Contract 2	20,411,000	0	20,411,000		3,100
39	October	Res.	ECONS	9999	Schedule 1	198,697	0	198,697	48%	47
40	October	Res.	ECONS	9999	Schedule 5	15,549	0	15,549	48%	4
41	October	Comm.	Comm. Finanswer	215	Sch. 6 (> 100 MWh)	474,925	0	474,925		93
42	October	Comm.	Comm. Finanswer	162	Sch. 6 (< 100 MWh)	173,874	0	173,874		200
43	November	Comm.	Finanswer 12,000	118	Sch. 6 (< 100 MWh)	72,000	0	72,000	60%	14
44	November	Comm.	Finanswer 12,000	148	Sch. 6 (< 100 MWh)	114,000	0	114,000	60%	22
45	November	Comm.	Comm. Finanswer	145	Sch. 6 (> 100 MWh)	1,600,000	0	1,600,000	60%	304
46	November	Comm.	Comm. Finanswer	199	Sch. 6 (> 100 MWh)	700,000	0	700,000	60%	133
47	November	Comm.	Finanswer 12,000	211	Sch. 6 (< 100 MWh)	90,000	0	90,000	60%	17
48	November	Comm.	Finanswer 12,000	56	Sch. 6 (< 100 MWh)	92,000	0	92,000	60%	18
49	November	Comm.	Comm. Finanswer	218	Sch. 6 (> 100 MWh)	566,000	0	566,000	60%	108
50	November	Comm.	Comm. Finanswer	219	Sch. 6 (< 100 MWh)	290,000	0	290,000	60%	55
51	November	Comm.	Comm. Finanswer	313	Sch. 6 (< 100 MWh)	151,000	0	151,000	60%	29
52	December	Comm.	Comm. Finanswer	252	Sch. 6 (< 100 MWh)	254,000	0	254,000	60%	48
53	December	Comm.	Comm. Finanswer	232	Sch. 6 (< 100 MWh)	232,000	0	232,000	60%	44
54	December	Comm.	Comm. Finanswer	250	Sch. 6 (< 100 MWh)	290,000	0	290,000	60%	55
55	December	Comm.	Comm. Finanswer	185	Sch. 6 (> 100 MWh)	1,059,000	0	1,059,000	60%	201
56	December	Comm.	Comm. Finanswer	146	Sch. 6 (< 100 MWh)	86,000	0	86,000	60%	16
57	December	Comm.	Comm. Finanswer	310	Sch. 6 (< 100 MWh)	307,000	0	307,000	60%	58
58	December	Comm.	Comm. Finanswer	229	Sch. 6 (> 100 MWh)	900,000	0	900,000	60%	171
59	December	Comm.	Comm. Finanswer	221	Sch. 6 (< 100 MWh)	392,000	0	392,000	60%	75

PacifiCorp
Utah Jurisdiction 1994 Net Lost Revenue Calculation
Summary

Line No.		Annualized MWh (1) Residential	Commercial	Industrial	TOTAL	Annualized MW (1) Residential	Commercial	Industrial	TOTAL	1994 NLR (3)
1	JANUARY	749	0	0	749	0.18	0.00	0.00	0.18	$31,771
2	FEBRUARY	0	580	0	580	0.00	0.11	0.00	0.11	13,095
3	MARCH	989	1,070	0	2,058	0.24	0.52	0.00	0.75	77,414
4	APRIL	1,297	293	0	1,590	0.31	0.05	0.00	0.36	44,827
5	MAY	963	127	0	1,090	0.23	0.01	0.00	0.24	26,994
6	JUNE	1,598	603	0	2,201	0.38	0.10	0.00	0.48	41,296
7	JULY	1,473	1,635	5,868	8,976	0.35	0.44	0.63	1.42	55,489
8	AUGUST	1,433	59	5,316	6,807	0.34	0.02	0.61	0.96	31,092
9	SEPTEMBER	1,658	191	24,608	26,457	0.39	0.05	3.67	4.11	(6,206)
10	OCTOBER	214	649	0	863	0.05	0.29	0.00	0.34	7,044
11	NOVEMBER	0	3,675	0	3,675	0.00	0.70	0.00	0.70	11,000
12	DECEMBER	0	3,520	0	3,520	0.00	0.67	0.00	0.67	4,907
13	**TOTAL**	10,374	12,400	35,792	58,566	2.47	2.94	4.90	10.31	$338,723
14	**DSR TARGET** (2)	2,618	3,641	5,843	40,000	0.30	0.40	0.70	6.00	
15	**Percent of 1994 Target Completed**				146%				172%	

Notes: (1) MWh and MW amounts come from project summary by month on pages 7 and 8.
(2) PacifiCorp's DSR commitment per the Joint Recommendation adopted by the Utah PSC. For residential, commercial, and industrial sectors the commitment is 20% of the RAMPP-3 1994 goal. For the total Company the commitment is 40,000 MWh and 6 MW. (Page 4, Exhibit A, Joint Recommendation, Docket No. 92-2035-07 order dated February 10,1994)
(3) Per page 2 of this attachment, DSR summary per month.

Attachment 2
Page 1

PacifiCorp

Utah Jurisdiction 1994 Net Lost Revenue Calculation

Net Lost Revenue Summaries by Rate Schedule and by Month of Installation

Line No.		ACCRUAL MONTH Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	TOTAL NET LOST REVENUES BY RATE SCHEDULE ($) (1)													
1	Schedule 1	1,501	2,543	5,012	10,227	16,552	20,974	17,484	19,610	27,734	34,330	29,921	29,084	214,972
2	Schedule 5	2	4	6	13	20	19	1,402	2,698	3,201	3,665	3,077	2,970	17,077
3	Sch. 6 (< 100 MWh)	0	89	2,866	5,981	6,963	6,916	4,656	4,761	6,068	8,254	7,809	10,492	64,855
4	Sch. 6 (> 100 MWh)	0	409	1,107	1,148	1,307	1,751	2,826	4,081	4,891	6,137	9,107	12,456	45,220
5	Schedule 9	0	0	0	19	45	42	475	824	1,281	1,664	1,250	1,128	6,728
6	Schedule 23	0	37	104	102	256	385	262	236	241	275	310	347	2,555
7	Schedule 39	0	0	0	0	0	0	0	0	103	77	5	5	190
8	Contract 1	0	0	0	0	0	0	215	347	3,825	7,474	5,488	4,318	21,667
9	Contract 2	0	0	0	0	0	0	0	0	(5,362)	(5,517)	(10,959)	(12,694)	(34,532)
10	**TOTAL**	1,503	3,082	9,095	17,490	25,143	30,087	27,320	32,557	41,982	56,359	46,008	48,106	338,732
	TOTAL NET LOST REVENUES BY MONTH OF INSTALLATION ($) (2)													
11	JANUARY	1,503	2,546	3,023	3,215	3,532	3,280	2,279	2,218	2,543	2,826	2,437	2,369	31,771
12	FEBRUARY	0	535	1,450	1,506	1,747	1,678	949	892	1,069	1,249	1,013	1,007	13,095
13	MARCH	0	0	4,621	9,640	10,528	9,934	6,536	6,367	7,553	8,721	6,806	6,708	77,414
14	APRIL	0	0	0	3,128	6,926	6,491	4,401	4,253	4,904	5,459	4,679	4,586	44,827
15	MAY	0	0	0	0	2,411	4,488	3,123	3,023	3,438	3,822	3,371	3,318	26,994
16	JUNE	0	0	0	0	0	4,216	5,695	5,528	6,390	7,193	6,213	6,061	41,296
17	JULY	0	0	0	0	0	0	4,335	7,843	10,553	12,809	10,277	9,672	55,489
18	AUGUST	0	0	0	0	0	0	0	2,433	6,863	8,503	6,930	6,363	31,092
19	SEPTEMBER	0	0	0	0	0	0	0	0	(1,331)	4,025	(3,331)	(5,569)	(6,206)
20	OCTOBER	0	0	0	0	0	0	0	0	0	1,750	2,642	2,652	7,044
21	NOVEMBER	0	0	0	0	0	0	0	0	0	0	4,970	6,030	11,000
22	DECEMBER	0	0	0	0	0	0	0	0	0	0	0	4,907	4,907
23	**TOTAL**	1,503	3,081	9,094	17,489	25,144	30,087	27,318	32,557	41,982	56,357	46,007	48,104	338,723

Notes: (1) Energy NLR plus Demand NLR from Page 3.
(2) The total net lost revenues are calculated identically to those on lines 1 - 10. However, the amounts are summed by month of installation instead of by rate schedule. See the description of the calculations for lines 1 - 10 for detailed information on how the net lost revenues are calculated.

PacifiCorp

Utah Jurisdiction 1994 Net Lost Revenue Calculation
Accumulated Energy & Demand NLR Savings by Rate Schedule

Line No.	Rate Schedule	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	ENERGY NET LOST REVENUES ($) (1)													
1	Schedule 1	1,501	3,077	5,012	10,227	16,552	22,570	21,314	24,024	30,455	34,330	36,747	35,910	241,719
2	Schedule 5	2	4	6	13	20	20	1,790	3,470	3,588	3,665	3,950	3,843	20,371
3	Sch. 6 (< 100 MWh)	0	38	558	1,337	2,132	2,801	1,082	929	1,057	1,211	2,067	3,203	16,415
4	Sch. 6 (> 100 MWh)	0	177	389	430	589	902	922	1,154	1,239	1,367	2,946	4,312	14,427
5	Schedule 9	0	0	0	7	21	24	117	121	258	320	621	498	1,987
6	Schedule 23	0	28	65	63	195	324	221	195	179	192	274	311	2,047
7	Schedule 39	0	0	0	0	0	0	0	0	81	0	0	0	81
8	Contract 1	0	0	0	0	0	0	(399)	(1,813)	(1,892)	(1,630)	1,223	53	(4,458)
9	Contract 2	0	0	0	0	0	0	0	0	(6,385)	(11,903)	(7,673)	(9,408)	(35,369)
10	**TOTAL**	1,503	3,324	6,030	12,077	19,509	26,641	25,047	28,080	28,580	27,552	40,155	38,722	257,220
	DEMAND NET LOST REVENUES ($) (2)													
11	Schedule 1	0	(534)	0	0	0	(1,596)	(3,830)	(4,414)	(2,722)	0	(6,827)	(6,827)	(26,750)
12	Schedule 5	0	0	0	0	0	(1)	(388)	(773)	(386)	0	(874)	(874)	(3,296)
13	Sch. 6 (< 100 MWh)	0	51	2,307	4,644	4,832	4,115	3,574	3,832	5,011	7,043	5,742	7,289	48,440
14	Sch. 6 (> 100 MWh)	0	232	718	718	718	850	1,904	2,927	3,652	4,770	6,161	8,144	30,794
15	Schedule 9	0	0	0	12	23	18	358	703	1,024	1,344	630	630	4,742
16	Schedule 23	0	9	39	39	61	62	41	41	62	83	36	36	509
17	Schedule 39	0	0	0	0	0	0	0	0	22	77	5	5	109
18	Contract 1	0	0	0	0	0	0	614	2,160	5,717	9,104	4,265	4,265	26,125
19	Contract 2	0	0	0	0	0	0	0	0	1,023	6,386	(3,286)	(3,286)	837
20	**TOTAL**	0	(242)	3,064	5,413	5,634	3,448	2,273	4,476	13,403	28,807	5,852	9,382	81,510

Notes: (1) Calculated by taking the MWh savings by schedule on page 4, multiplied by 1000 to convert to kWh, multiplied by the net energy rate by schedule on page 5.
(2) Calculated by taking the kW savings by schedule on page 4, multiplied by the net demand rate by schedule on page 6.

PacifiCorp

Utah Jurisdiction 1994 Net Lost Revenue Calculation
Demand and Energy Savings by Rate Schedule

Line No.	Rate Schedule	Annual. Amount	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	ENERGY TOTALS (MWh) (1)														
1	Schedule 1	9,199.1	31.2	62.4	103.5	198.6	292.6	399.3	479.2	552.1	680.9	758.3	766.6	766.6	5,091.3
2	Schedule 5	1,175.3	0.0	0.1	0.1	0.3	0.4	0.4	48.5	96.7	96.7	97.3	97.9	97.9	536.4
3	Sch. 6 (< 100 MWh)	4,500.7	0.0	3.2	50.3	94.3	110.8	146.0	151.3	150.4	143.0	152.5	194.9	336.8	1,533.5
4	Sch. 6 (> 100 MWh)	7,716.8	0.0	17.3	41.5	34.9	34.3	52.7	165.6	249.1	213.6	216.1	331.6	550.4	1,907.2
5	Schedule 9	1,453.0	0.0	0.0	0.0	0.8	1.6	1.8	61.5	121.1	120.9	121.0	121.0	121.2	671.0
6	Schedule 23	161.7	0.0	1.4	3.3	2.8	7.0	11.6	13.9	13.0	11.1	11.5	14.1	17.0	106.5
7	Schedule 39	181.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.7	0.0	0.0	0.0	17.7
8	Contract 1	13,767.0	0.0	0.0	0.0	0.0	0.0	0.0	184.8	591.2	980.0	1,147.3	1,147.3	1,147.3	5,197.7
9	Contract 2	20,411.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	850.5	1,700.9	1,700.9	1,700.9	5,953.2
	DEMAND TOTALS (kW) (2)														
10	Schedule 1	2,188	89	178	296	567	836	1,140	1,368	1,577	1,944	2,165	2,188	2,188	
11	Schedule 5	280	0	0	0	1	1	1	139	276	276	278	280	280	
12	Sch. 6 (< 100 MWh)	1,395	0	10	277	557	579	593	645	691	722	844	1,099	1,395	
13	Sch. 6 (> 100 MWh)	1,528	0	43	85	85	85	121	337	518	518	565	1,156	1,528	
14	Schedule 9	229	0	0	0	2	4	4	117	229	229	229	229	229	
15	Schedule 23	15	0	4	7	7	11	15	15	15	15	15	15	15	
16	Schedule 39	23	0	0	0	0	0	0	0	0	12	23	23	23	
17	Contract 1	1,551	0	0	0	0	0	0	200	704	1,279	1,551	1,551	1,551	
18	Contract 2	3,100	0	0	0	0	0	0	0	0	1,550	3,100	3,100	3,100	

lotes:

(1) Monthly energy from program summary on Pages 7 & 8. These are calculated by taking half a months amount in the month of installation, plus the full months amount for all DSR installed in prior months. The monthly amount comes from either DOE-2, engineering estimates and metering, or one-twelfth of the annual amount. (See Pages 7 & 8 for more details on how monthly amounts are calculated for specific programs)

(2) Monthly demand from program summary on Pages 7 & 8. These are calculated by taking half a months amount in the month of installation, plus the full amounts for all DSR projects installed in prior months.

Attachment 2
Page 4

PacifiCorp

Utah Jurisdiction 1994 Net Lost Revenue Calculation

Energy Rate Calculation (All amounts are cents/kWh unless noted)

Line No.				Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Avoided Cost Calculation														
1	Avoided Energy Cost		(4)	1.8150	1.7090	1.7910	1.5150	1.0610	1.0650	2.1450	2.2320	2.1230	2.0740	1.8350	1.9330
2	Energy Loss	Secondary Distribution		11.47%	11.47%	11.47%	11.47%	11.47%	11.47%	11.47%	11.47%	11.47%	11.47%	11.47%	11.47%
3	Factors (5)	Primary Distribution		7.04%	7.04%	7.04%	7.04%	7.04%	7.04%	7.04%	7.04%	7.04%	7.04%	7.04%	7.04%
4		Transmission		4.08%	4.08%	4.08%	4.08%	4.08%	4.08%	4.08%	4.08%	4.08%	4.08%	4.08%	4.08%
5	Net Avoided	Secondary Distribution		2.0232	1.9050	1.9964	1.6888	1.1827	1.1872	2.3910	2.4880	2.3665	2.3119	2.0455	2.1547
6	Costs (6)	Primary Distribution		1.9428	1.8293	1.9171	1.6217	1.1357	1.1400	2.2960	2.3891	2.2725	2.2200	1.9642	2.0691
7		Transmission		1.8891	1.7787	1.8641	1.5768	1.1043	1.1085	2.2325	2.3231	2.2096	2.1586	1.9099	2.0119
	Tail Block Rates (7)														
8	Schedule 1			6.8391	6.8391	6.8391	6.8391	6.8391	6.8391	6.8391	6.8391	6.8391	6.8391	6.8391	6.8391
9	Schedule 5			6.0786	6.0786	6.0786	6.0786	6.0786	6.0786	6.0786	6.0786	6.0786	6.0786	6.0786	6.0786
10	Sch. 6 (< 100 MWh)			3.1059	3.1059	3.1059	3.1059	3.1059	3.1059	3.1059	3.1059	3.1059	3.1059	3.1059	3.1059
11	Sch. 6 (> 100 MWh)			2.8525	2.8525	2.8525	2.8525	2.8525	2.8525	2.8525	2.8525	2.8525	2.8525	2.8525	2.8525
12	Schedule 9			2.4227	2.4227	2.4227	2.4227	2.4227	2.4227	2.4227	2.4227	2.4227	2.4227	2.4227	2.4227
13	Schedule 23			3.9856	3.9856	3.9856	3.9856	3.9856	3.9856	3.9856	3.9856	3.9856	3.9856	3.9856	3.9856
14	Schedule 39			2.8231	2.8231	2.8231	2.8231	2.8231	2.8231	2.8231	2.8231	2.8231	2.8231	2.8231	2.8231
15	Contract 1			2.0165	2.0165	2.0165	2.0165	2.0165	2.0165	2.0165	2.0165	2.0165	2.0165	2.0165	2.0165
16	Contract 2			1.4588	1.4588	1.4588	1.4588	1.4588	1.4588	1.4588	1.4588	1.4588	1.4588	1.4588	1.4588
	Net Energy Rates														
17	Schedule 1		(1)	4.8159	4.9341	4.8427	5.1503	5.6564	5.6519	4.4481	4.3511	4.4726	4.5272	4.7936	4.6844
18	Schedule 5		(1)	4.0554	4.1736	4.0822	4.3898	4.8959	4.8914	3.6876	3.5906	3.7121	3.7667	4.0331	3.9239
19	Sch. 6 (< 100 MWh)		(1)	1.0827	1.2009	1.1095	1.4171	1.9232	1.9187	0.7149	0.6179	0.7394	0.7940	1.0604	0.9512
20	Sch. 6 (> 100 MWh)		(2)	0.9097	1.0232	0.9354	1.2308	1.7168	1.7125	0.5565	0.4634	0.5800	0.6325	0.8883	0.7834
21	Schedule 9		(3)	0.5336	0.6440	0.5586	0.8459	1.3184	1.3142	0.1902	0.0996	0.2131	0.2641	0.5128	0.4108
22	Schedule 23		(1)	1.9624	2.0806	1.9892	2.2968	2.8029	2.7984	1.5946	1.4976	1.6191	1.6737	1.9401	1.8309
23	Schedule 39		(1)	0.7999	0.9181	0.8267	1.1343	1.6404	1.6359	0.4321	0.3351	0.4566	0.5112	0.7776	0.6684
24	Contract 1		(3)	0.1274	0.2378	0.1524	0.4397	0.9122	0.9080	-0.2160	-0.3066	-0.1931	-0.1421	0.1066	0.0046
25	Contract 2		(3)	-0.4303	-0.3199	-0.4053	-0.1180	0.3545	0.3503	-0.7737	-0.8643	-0.7508	-0.6998	-0.4511	-0.5531

Notes:
(1) Tail block rate minus avoided cost adjusted for secondary distribution line losses.
(2) Tail block rate minus avoided cost adjusted for primary distribution line losses.
(3) Tail block rate minus avoided cost adjusted for transmission line losses.
(4) Per the 1994 Utah & Oregon Avoided Cost filings. with a sales for resale adjustment.
(5) Per PacifiCorp's December 31, 1993 Embedded Cost Study filed with the Utah Public Service Commission.
(6) Avoided energy cost on line 1, increased by line loss percents on lines 2 - 4.
(7) Tail block rates by rate schedule as currently approved by the Utah PSC.

PacifiCorp

Utah Jurisdiction 1994 Net Lost Revenue Calculation
Demand Rate Calculation (All amounts are $/kW-mo)

Line No.		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Avoided Cost Calculation												
1	SCE Winter Capacity Purchase (1)	0.00	3.00	0.00								3.12	3.12
2	TWWP Summer Capacity Purchase (2)						1.40	2.80	2.80	1.40			
3	EWEB Summer Capacity Sale (3)						0.00	0.00	0.00	0.00			
4	AVERAGE	0.00	3.00	0.00	0.00	0.00	1.40	2.80	2.80	1.40	0.00	3.12	3.12
	Tail Block Rates (4)												
5	Schedule 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	Schedule 5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	Sch. 6 (< 100 MWh)	8.35	8.35	8.35	8.35	8.35	8.35	8.35	8.35	8.35	8.35	8.35	8.35
8	Sch. 6 (> 100 MWh)	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45	8.45
9	Schedule 9	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87
10	Schedule 23	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50
11	Schedule 39	3.33	3.33	3.33	3.33	3.33	3.33	3.33	3.33	3.33	3.33	3.33	3.33
12	Contract 1	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87
13	Contract 2	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06
	Net Demand Rates (5)												
14	Schedule 1	0.00	(3.00)	0.00	0.00	0.00	(1.40)	(2.80)	(2.80)	(1.40)	0.00	(3.12)	(3.12)
15	Schedule 5	0.00	(3.00)	0.00	0.00	0.00	(1.40)	(2.80)	(2.80)	(1.40)	0.00	(3.12)	(3.12)
16	Sch. 6 (< 100 MWh)	8.35	5.35	8.35	8.35	8.35	6.95	5.55	5.55	6.95	8.35	5.23	5.23
17	Sch. 6 (> 100 MWh)	8.45	5.45	8.45	8.45	8.45	7.05	5.65	5.65	7.05	8.45	5.33	5.33
18	Schedule 9	5.87	2.87	5.87	5.87	5.87	4.47	3.07	3.07	4.47	5.87	2.75	2.75
19	Schedule 23	5.50	2.50	5.50	5.50	5.50	4.10	2.70	2.70	4.10	5.50	2.38	2.38
20	Schedule 39	3.33	0.33	3.33	3.33	3.33	1.93	0.53	0.53	1.93	3.33	0.21	0.21
21	Contract 1	5.87	2.87	5.87	5.87	5.87	4.47	3.07	3.07	4.47	5.87	2.75	2.75
22	Contract 2	2.06	(0.94)	2.06	2.06	2.06	0.66	(0.74)	(0.74)	0.66	2.06	(1.06)	(1.06)

Notes: (1) Delivery period: October 15 to March 15. Energy was not taken in January or March. Information on November and December purchases is not yet available; therefore, it is being assumed that power will be taken during those months. This will be trued up when information on November and December purchases becomes available. See the letter on why this is used to approximate monthly avoided demand.

(2) Delivery period: June 15 to September 15. Energy was taken each month. June and September capacity is billed at half the normal monthly rate.

(3) Delivery period: June 1 to September 30. The pure capacity rate included in the contract is $2.12. The contract includes a ratchet which increases this rate by $.75/kW-mo for each week during the month that power was taken. No energy was sold under the contract in 1994.

(4) Tail block rates by rate schedule as currently approved by the Utah PSC.

(5) Tail Block rates minus the avoided cost amount on line 4.

PacifiCorp

Utah Jurisdiction 1994 Net Lost Revenue Calculation
DSR Projects by Month of Installation (Page 1 of 2)

Line No.	Month	DSR Program		Customer Class	Rate Schedule	Gross Annualized kWh	Load Growth kWh	Annualized kWh	Conservation Load Factor (10)	Demand kW (9)	Approx. NLR	Monthly Method
1	January	ECONS	(1)	Residential	Schedule 1	748,243	0	748,243	48%	178	$31,728	(5)
2	January	ECONS	(1)	Residential	Schedule 5	1,117	0	1,117	48%	0	$44	(5)
3	February	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	37,240	0	37,240	60%	7	$885	(6)
4	February	Commercial Spec.	(4)	Commercial	Sch. 6 (> 100 MWh)	444,219	0	444,219	60%	85	$9,842	(6)
5	February	Finanswer 12,000	(3)	Commercial	Sch. 6 (< 100 MWh)	63,521	0	63,521	60%	12	$1,466	(7)
6	February	Finanswer 12,000	(3)	Commercial	Schedule 23	35,070	0	35,070	60%	7	$903	(7)
7	March	ECONS	(1)	Residential	Schedule 1	987,478	0	987,478	48%	235	$34,542	(5)
8	March	ECONS	(1)	Residential	Schedule 5	1,119	0	1,119	48%	0	$36	(5)
9	March	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	1,059,449	0	1,059,449		515	$42,746	(6)
10	March	Finanswer 12,000	(3)	Commercial	Sch. 6 (< 100 MWh)	10,274	0	10,274		0	$89	(7)
11	April	ECONS	(1)	Residential	Schedule 1	1,294,284	0	1,294,284	48%	308	$39,885	(5)
12	April	ECONS	(1)	Residential	Schedule 5	2,720	0	2,720	48%	1	$64	(5)
13	April	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	271,598	0	271,598		45	$4,656	(6)
14	April	Finanswer 12,000	(3)	Commercial	Schedule 9	21,000	0	21,000	60%	4	$222	(7)
15	May	ECONS	(1)	Residential	Schedule 1	963,011	0	963,011	48%	229	$25,343	(5)
16	May	Comm. Finanswer	(3)	Commercial	Schedule 23	114,411	0	114,411		8	$1,505	(6)
17	May	Finanswer 12,000	(3)	Commercial	Schedule 23	12,242	0	12,242		0	$146	(7)
18	June	ECONS	(1)	Residential	Schedule 1	1,597,963	0	1,597,963	48%	380	$34,789	(5)
19	June	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	143,865	0	143,865		27	$1,819	(6)
20	June	Comm. Finanswer	(3)	Commercial	Sch. 6 (> 100 MWh)	458,784	0	458,784		71	$4,688	(6)
21	July	ECONS	(1)	Residential	Schedule 1	318,395	0	318,395	48%	76	$5,747	(5)
22	July	Sch. 5 Water Kits	(2)	Residential	Schedule 5	1,154,839	0	1,154,839	48%	275	$16,829	(5)
23	July	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	120,924	0	120,924		77	$3,057	(6)
24	July	Comm. Finanswer	(3)	Commercial	Sch. 6 (> 100 MWh)	1,513,908	0	1,513,908		362	$17,534	(6)
25	July	Indus. Finanswer	(3)	Industrial	Schedule 9	1,432,000	0	1,432,000		225	$6,504	(8)
26	July	Major Accounts	(4)	Industrial	Contract 1	4,436,000	0	4,436,000		400	$5,817	(5)
27	August	ECONS	(1)	Residential	Schedule 1	1,432,520	0	1,432,520	48%	341	$21,573	(5)
28	August	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	58,764	0	58,764		16	$645	(6)
29	August	Major Accounts	(4)	Industrial	Contract 1	5,316,000	0	5,316,000		607	$8,875	(5)
30	September	ECONS	(1)	Residential	Schedule 1	1,658,473	0	1,658,473	48%	394	$19,712	(5)
31	September	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	191,181	0	191,181		45	$1,450	(6)
32	September	Indus. Finanswer	(3)	Industrial	Schedule 39	181,743	0	181,743		23	$189	(8)
33	September	Major Accounts	(4)	Industrial	Contract 1	4,015,000	0	4,015,000		544	$6,975	(5)
34	September	Major Accounts	(4)	Industrial	Contract 2	20,411,000	0	20,411,000		3,100	($34,532)	(5)

PacifiCorp

Utah Jurisdiction 1994 Net Lost Revenue Calculation
DSR Projects by Month of Installation (Page 2 of 2)

Line No.	Month	DSR Program		Customer Class	Rate Schedule	Gross Annualized kWh	Load Growth kWh	Annualized kWh	Conservation Load Factor (10)	Demand kW (9)	Approx. NLR	Monthly Method
35	October	ECONS	(1)	Residential	Schedule 1	198,697	0	198,697	48%	47	$1,651	(5)
36	October	ECONS	(1)	Residential	Schedule 5	15,549	0	15,549	48%	4	$103	(5)
37	October	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	173,874	0	173,874		200	$3,203	(6)
38	October	Comm. Finanswer	(3)	Commercial	Sch. 6 (> 100 MWh)	474,925	0	474,925		93	$2,087	(6)
39	November	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	441,000	0	441,000		84	$1,355	(6)
40	November	Comm. Finanswer	(3)	Commercial	Sch. 6 (> 100 MWh)	2,866,000	0	2,866,000		545	$8,442	(6)
41	November	Finanswer 12,000	(3)	Commercial	Sch. 6 (< 100 MWh)	368,000	0	368,000		71	$1,203	(7)
42	December	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	1,561,000	0	1,561,000		296	$2,280	(6)
43	December	Comm. Finanswer	(3)	Commercial	Sch. 6 (> 100 MWh)	1,959,000	0	1,959,000		372	$2,627	(6)
	PROGRAM SUMMARY											
44		ECONS	(1)	Residential		9,219,569	0	9,219,569		2,193	$215,217	
45		Sch. 5 Water Kits	(2)	Residential		1,154,839	0	1,154,839		275	$16,829	
46		Comm. Finanswer	(3)	Commercial		11,445,923	0	11,445,923		2,763	$98,979	
47		Commercial Spec.	(4)	Commercial		444,219	0	444,219		85	$9,842	
48		Finanswer 12,000	(3)	Commercial		510,107	0	510,107		94	$4,029	
49		Indus. Finanswer	(3)	Industrial		1,613,743	0	1,613,743		248	$6,693	
50		Major Accounts	(4)	Industrial	Contract 1	13,767,000	0	13,767,000		1,551	$21,667	
51		Major Accounts	(4)	Industrial	Contract 2	20,411,000	0	20,411,000		3,100	($34,532)	
52		**TOTALS**				58,566,400	0	58,566,400		10,309	$338,724	

Notes:
(1) DSR acquisition contract under which ECONS provides electric water heating conservation measures to multi-family dwellings
(2) The Company distributed approximately 2,500 water conservation kits to Schedule 5 customers as an inducement to complete and return an energy consumption survey. The survey will be used to assess the energy conservation needs of this group of customers.
(3) Tariffed program under which the Company provides energy conservation services and initial funding for energy conservation measures. The customer pays the Company back through an energy service charge on the customers bill. The Customer has the option to participate in the program services without accepting Company funding of measures.
(4) The Company provides customized engineering support and financing to major accounts for comprehensive DSM projects.
(5) Monthly savings calculated as one-twelfth of the annual amount.
(6) Monthly savings calculated from DOE-2 outputs.
(7) Monthly savings calculated using the average of similar Commercial Finanswer projects.
(8) Monthly savings calculated from preliminary engineering analysis and metering.
(9) Net of demand Load Growth
(10) Used to calculate demand savings if specific information is not available.

TO BE REVISED SLIGHTLY FOR 1995 AND BEYOND

Exhibit 1

Formula for Calculation of Net Lost Revenue

For purposes of ~~the Interim Policy~~ 1995 and Subsequent years NLR shall be the sum of lost energy revenue and lost demand revenue. Both an energy and demand component will be calculated for each rate schedule. The formulas for these calculations are defined below:

Energy : Net Lost Revenue (energy) = (R - AC) x (ES - LG)

where:

- R = Tail block rate per kWh for the customer class per the current tariff.
- AC = Monthly short-run avoided costs per kWh based on modeled production costs. Adjusted for sales for resale credit and average line losses.
- ES = kWh energy savings actually incurred or estimated by engineering analysis for conservation measures during the ~~Interim Period.~~ Calendar Year. Engineering analysis will be updated with the most current evaluation information. ~~through 1995.~~ Such evaluation shall include the appropriate treatment of free riders, free drivers, snapback and persistence of savings (See Exhibit 2) to the extent such elements can be quantified. (see note 1)
- LG = kWh sales increase related to load building impacts of DSR programs. This component will be based on engineering analysis and will be updated based on program evaluation. ~~through 1995.~~ Load growth related to DSR programs in the new construction area will be included in this component of the Formula.

Demand: Net Lost Revenue (demand) = (DC - ADC) x (NCP_s - LGp)

where:

- DC = Demand charge per kW for the customer class based on each month the current tariff.
- ADC = The identified avoided demand cost savings for ~~1994~~ that result from DSR programs. This component will be adjusted to an NCP basis and will be adjusted for line losses.
- NCP_s = Non-coincident peak (kW) savings at the sales level produced by energy conservation measure. The non-coincident peak savings will be based upon engineering analysis. In the event that engineering analysis of the non-coincident peak savings is not available, the NCP_s component will be estimated based on the best available data.
- LGp = The impact on the NCP of load building affects of DSR programs. This component will be based on engineering analysis and will be updated based on program evaluation. ~~through 1995.~~

Note 1 Initial engineering analysis employed for purposes of NLR calculation will be those used contractually between the Company and the customer related to conservation savings. Such engineering analysis will be updated based on program evaluation. Some conservation measures do not involve a specific contract between the Company and the customer. The NLR for these measures will be based on the engineering analysis included in the program design. Certain DSR programs may include a combination of DSR activities and increased electrification. The energy savings of such programs will be the efficiency increment (based on engineering analysis) over the "base line" of what the customer would have installed absent the Company's involvement.

ALSO ADD SOMETHING LIKE: "The NLR amounts will be booked during the subsequent 12 months following project installation."

MEASURE LIVES
ENERGY CONSERVATION MEASURES

	Measure Life
BUILDING ENVELOPE	
• High Efficiency Glazing	20
• Perimeter Floor Slab Insulation	30
• Exposed Floor Insulation	30
• Roof Insulation	30
• Wall Insulation	30
WATER HEAT MEASURES	
• Time Clock Control - SHW Recirc. Pumps	10
• Flow Efficient Shower Head	10
• Heat Pump Water Heater	15
LIGHTING MEASURES	
• Compact Fluorescent Light	15
• 4 Foot ES Fluorescent Lamps	15
• Electronic Ballast	15
• Exit Sign	30
• High Pressure Sodium	15
• Occupancy Sensors	10
HVAC	
• Airside Economizer	15
• Energy Management System	10
• High Efficiency Chiller	15
• Programmable Thermostats	10
• Water Source Heat Pumps	15
• Efficient Air-Source Heat Pumps	15
• Exhaust Air Heat Recovery	15
• Heat Recovery Chiller	15
• Tower Free Cooling	15
• Variable Speed Drives Fans & Pumps	15
• Direct-Indirect Evaporative Cooling	15
OTHER	
• Energy Efficient Motor	15
• Vegetation for Cooling	15
• Efficient Refrigeration	10