DEMAND SIDE RESOURCE COST RECOVERY COLLABORATIVE REPORT

DOCKET NO. 92-2035-04

MARCH 31, 1995

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I. INTRODUCTION

This Demand Side Resource Cost Recovery Collaborative (DSRCRC) Report is the culmination of the CRC Collaborative process established by the Commission in early 1994 to implement and track the 1994 Demand Side Resource (DSR) Joint Recommendation for PacifiCorp's Utah DSR activities. This report responds to the assignments given to this Collaborative in the approved 1994 Joint Recommendation (see Utah PSC Order under Docket No. 92-2035-04, dated February 10, 1994) and to those "carry-over"assignments to this Collaborative from the Demand Side Resource Evaluation Task Force Report, submitted to the Commission on May 20, 1994, under this same Docket Number. In general, this report provides the results of the 1994 Trial Policy for DSR cost recovery and net lost revenue processes, and restates a recommendation for a new DSR regulatory policy for Utah for 1995 and 1996 that is already being considered by the Utah Public Service Commission. The report also tries to shed light on several difficult DSR issues raised by the Commission as long ago as the 1990 General Rate case with PacifiCorp, which have not been answered in previous DSR reports to this Commission. The responses to the Commission's DSR assignments and queries have been discussed and documented in this Final Report by the Collaborative members, however, the conclusions reached and recommendations presented in this report, on DSR issues, should in no way be interpreted as binding individual parties to specific positions in the future.

II. BACKGROUND

Section 54-1-10 of the Utah Code specifies that:

> "The Public Service Commission shall engage in long-range planning regarding public utility regulatory policy in order to facilitate the well-planned development and conservation of utility resources."

The Commission has initiated several proceedings in order to develop the regulatory policy necessary to meet this mandate. A review of the record of proceedings before the Utah Public Service Commission shows that the Utah Commission has had an ongoing, active interest in investigating the implementation of cost effective energy conservation and/or load control measures (Demand Side Resources) by PacifiCorp to counter or delay costly Supply Side Resource acquisitions to meet future capacity needs in the service area of Utah. As early as 1984, in Case No. 84-999-20 dated December 31, 1984, the Commission refers to testimony in Case No. 80-999-06, dated December 17, 1984, saying that the Commission has a desire to manage load and energy consumption as alternatives to future capacity expansion.

In Docket No. 90-2035-01, dated September 3, 1991, in their proposed Standards and Guidelines for Integrated Resource Planning, the Commission says, on page 10:

> "The Integrated Resource Plan must evaluate Supply Side and Demand Side resources on a consistent basis. This means evaluation of the costs and benefits associated with each must be comprehensive and the comparison of alternatives must be performed in an analytically consistent manner. The Commission's statement of Purpose and Intent for Integrated Resource Planning includes as its objective the provision of energy services at a minimum of total cost to the utility and its ratepayers, subject to quality of service and utility financial requirements and consistency with the long run public interest. This means that supply alternatives such as the mix of generating resources and purchases, and demand alternatives such as conservation, load management, and efficiency improvements in end-use products, must be given equal consideration and must be treated on a comparable basis."

In Docket No. 90-035-06, dated April 10, 1992, the Commission, in its Section V, "Direction to Parties", paragraph B, page 62 says:

> "Testimony and evidence show the Company has begun to promote demand side management programs in this jurisdiction. The Commission is aware, however, that the Company's experience is generally in the Pacific Northwest. Circumstances are different in this jurisdiction, and perhaps in ways that may affect program design and application. The Company must employ programs here (in Utah) which recognize such differences."

In this same Order the PSC established the Demand Side Resource Evaluation Task Force (DSRETF). Quoting from this same page 62 of the Commission's Direction to Parties section, it formed a Task Force to find answers to unanswered DSR questions and:

> "....to discuss the evaluation of current and future DSM (demand side management) programs....to develop evaluation criteria for Utah programs and to review the progress of these programs. This will hopefully lead to a joint recommendation to the Commission."

More specifically, the PSC further stated on page 63:

> "The utility industry has had relatively little experience in evaluating the benefits and costs of such (DSR) programs. The Commission finds that these issues can best be discussed in an informal collaborative manner and then brought before the Commission."

Further on the same page:

> "It is the Commission's desire that the (DSR) task force analyze the issues of how best to calculate the savings from DSM measures and what evaluation methods are most appropriate for evaluating the success of the program. The group should discuss such

issues as what perspective should be taken when evaluating the cost effectiveness of such measures and programs, and how can DSM programs be consistently compared to supply side resources. The Commission would like the task force to recommend to the Commission how best to study the issue of eliminating disincentives and creating incentives for the Company (PacifiCorp) to pursue its integrated resource plan and how best to study future ratemaking treatment of DSM programs. The Task Force is also requested to examine targeted residential conservation and load management of the sort recommended in this Docket by the Committee to address the high-use Schedule 5 problem. ......The DSM Task Force established by this Order is requested to analyze the possibility of using Schedule 5 to test appropriate future DSM programs."

In Docket No. 90-2035-01, on June 18, 1992, in "Discussions, Findings, and Conclusions", on the issue of Standards and Guidelines of integrated resource planning, on pages 12 and 13, it says:

"The Commission agrees with the Department of Energy and finds that demand side resources and supply side resources are different resources in terms of their dispatchability, certainty of output, reliability, and the risks associated with environmental externalities. Planning, acquisition, and ratemaking treatment should be consistent and comparable while acknowledging such differences. Ratemaking treatment can affect the Company's willingness to acquire resources. Ratemaking treatment for DSR has yet to be determined in this jurisdiction and this uncertainty might create a disincentive to invest in such resources. The Commission concludes that disincentives must be studied in more detail and assigns this analysis to a task force to be described later in this order. The Commission reaffirms its position on this threshold issue. Demand Side and Supply Side resources must be evaluated on a consistent and comparable basis. The Commission, however, encourages parties to study how best to implement such a requirement."

In the same Docket, in the Section on "Other Comments", under paragraph 3, titled "Regulation Changes to Insure Company Pursuit of Its Integrated Resource Plan", on page 32 (90-2035-01, dated June 18, 1992), it says:

"The Commission finds that demand side resources, which includes end-use efficiencies, load management, and conservation, are more difficult to acquire than supply side resources. Regulatory disincentives may exist.... Given the asymmetry of ratemaking treatment for DSR and the resulting uncertainty of cost recovery, the Commission questions whether the Company has sufficient financial incentive to pursue its IRP..... Therefore, the Commission concludes that further study is warranted and establishes Docket No. 92-2035-04, 'In the Matter of Ratemaking Treatment of Demand Side Resources and the Analysis of Regulatory Changes to Encourage Implementation of Integrated Resource Planning'. The Commission directs the Division to establish a cooperative task force or incorporate these issues into the existing DSR (Evaluation) task force to study these issues and bring recommendations before the Commission. The issues to be analyzed include: the ratemaking treatment of DSR expenditures, approval of energy service charges for efficiency improvements and conservation, electric revenue adjustment mechanisms, the granting of a cost advantage for efficiency or conservation acquisitions, and the decoupling of revenues from profits and any other issues that the group deems germane."

The DSRETF was formed by Docket No. 90-035-06 and met from February 12, 1992 through February 9, 1994. The DSRETF accomplishments were reported to the Commission under Docket No. 92-2035-04 on May 20, 1994. Some of the tasks assigned to this group were not completed by May 1994 and were then assigned to the new Cost Recovery Collaborative and will be responded to in this report.

On December 21, 1992, PacifiCorp filed an accounting application under Docket No. 92-2035-07, to establish cost recovery procedures for demand side resource expenditures. This application by the Company resulted in a series of DSR Technical Conferences and the formation of a Technical Conference Collaborative in February 1993. The Company withdrew the 92-2035-07 application and the Docket was closed. There were eight Technical Conferences held through July of 1993 and the results of that Collaborative's activities were reported to the Commission under Docket No. 92-2035-04 on August 31, 1993.

On October 7, 1993, some of the members of the DSR Technical Conference Collaborative submitted a Trial Policy Joint Recommendation to the Commission as a Stipulation for a cost and lost revenue recovery procedure for calendar year 1994. In their Order of February 10, 1994, the Commission approved the Joint Recommendation for a 1994 interim approach for regulatory treatment of PacifiCorp's demand side resource activities in Utah. This Order also established the DSRCRC which replaced the DSR Evaluation Task Force and the DSR Technical Conference Collaborative. The new Cost Recovery Collaborative started its meetings in January of 1994 and has met at least monthly to the present.

On February 15, 1995, representatives from the CRC petitioned the Utah Commission with a DSR Cost Recovery and Net Lost Revenue stipulation called a "Joint Agreement". This document proposes a continued two year experiment for DSR regulatory treatment for PacifiCorp for 1995 and 1996. A Commission hearing was held regarding this stipulation on February 23, 1995, with the Commission taking the matter under advisement. Section III of this CRC report to the Commission will review the results of the 1994 Joint Recommendation as well as providing details of the 1995-1996 Joint Agreement mentioned above.

Section IV will attempt to answer the remaining Commission DSR questions that were carried over from the DSRETF for resolution.

III. RESPONSES TO 1994 JOINT RECOMMENDATION ASSIGNMENTS

COMMISSION ASSIGNMENTS TO THE COLLABORATIVE:

In its February 10, 1994 Order in Docket No. 92-2035-04, approving the Joint Recommendation for 1994 Cost Recovery and Net Lost Revenue (NLR) accounting treatment for PacifiCorp's DSR programs, the Utah Public Service Commission specified that the following actions be accomplished:

1- That the Division convene, not later than January 31, 1994, a new DSR Cost Recovery Collaborative as described in the Joint Recommendation. That an outside qualified consultant be hired by the Collaborative to provide the Collaborative an impartial review of PacifiCorp's measurement and evaluation of its DSR activities.

2- That the Collaborative report to the Commission the results of the Trial DSR Policy for 1994, including an interim report to the Commission by November 30, 1994, which quantifies the dollar amount of Net Lost Revenue for 1994 and identifies the inputs which resulted in that dollar amount. The November 30th report should also identify the appropriate DSR measure lives for amortization purposes. That the Collaborative also submit another report to the Commission on or before December 31, 1995, which quantifies its final determination of the amount of NLR for 1994 based upon actual energy savings measurements of 1994 projects.

3- That the Collaborative report the results of the one year numerical experiment with Statistical Recoupling.

4- That the option of a Shared Savings Incentive Plan be investigated and reported.

5- That the option of Total Factor Productivity Incentive Plan be investigated and reported.

6- That the Collaborative study and report on the price impact on Non-Participants of DSR programs, or determine what is the best way to reduce the impact on non-participants.

7- That the Collaborative develop Performance Standards to measure DSR programs in Utah and make recommendations to the Commission for their use.

8- That the Collaborative study and make recommendations to the Commission regarding the appropriate regulatory treatment for PacifiCorp's DSR costs, including NLR, if appropriate, beyond 1994.

REPORT TO THE COMMISSION ON 1994 JOINT RECOMMENDATION ASSIGNMENTS:

The CRC Collaborative response to these eight assignments is as follows:

1- Collaborative Formation/Consultant Utilization:

Based upon the December 1, 1993 DSR Joint Recommendation hearing before the Utah Commission and the Bench Order approving the Joint Recommendation, the Division organized the new DSR Cost Recovery Collaborative and held the first meeting on January 19, 1994. Since both the DSRETF and the Technical Conference Collaborative had such a broad set of participants, the Division polled this lengthy list of regulators, PacifiCorp employees, Law Firms, Environmental Groups, Vendors, Professors, etc., and had each one respond as to their interest in the new collaborative. Some people dropped off the list, and the rest were divided into "Active" and "Informational" participants. The Company assumed the responsibility of recording and publication of minutes, and did an excellent job of distributing all the output of the Collaborative to both active and informational members. Appendix I lists Collaborative membership both active and informational, and their organization.

The Collaborative immediately divided the vast majority of work assignments from the Joint Recommendation and the carry-over items from the DSRETF report among five (5) subcommittees. Appendix II lists the subcommittees by designated function, assigned chairperson, and assigned subcommittee membership. These subcommittees attracted great interest as they met to handle their assignments, often attracting unassigned members from other subcommittees, additional Commission staff, and Portland based PacifiCorp personnel. A general overview of each Subcommittee's conclusions and recommendations is included later on in the main report. The five final subcommittee reports are included as appendices to this CRC report.

On May 4, 1994, an extension contract was signed with Xenergy, Inc., of Oakland, California, for a maximum of $65,428, for Dr. Dan Violette and his people to work with the Collaborative during 1994 and 1995 to help the Collaborative with review of PacifiCorp's measurement and evaluation processes and results. Dr. Violette has met periodically with the Collaborative as well as having his staff and himself meet on-site and communicate with the Company's DSR evaluation staff in Portland. Xenergy's new contract is much more narrow in scope than the 1993 contract. The work covered by this contract will continue well into 1995, and will help the Collaborative "true-up" the 1994 Net Lost Revenue figures by year end.

2- Results of 1994 Joint Recommendation Interim Policy

The 1994 Joint Recommendation, in Docket No. 92-2035-04, formally ordered on February 10, 1994, that a Cost Recovery Collaborative be established and indicated that, "The primary focus of this Collaborative will be to examine the Interim Policy and report its conclusions and recommendations to the PSC". The responsibility for continuing analysis and tracking of the DSR Evaluation process, for the day-to-day managing of the Xenergy consultant, and of calculation and preparation of the Net Lost Revenue figures from the Joint Recommendation Formula, was assigned to the Evaluation and Net Lost Revenue Subcommittee of the Collaborative.

The collaborative was ordered to provide three reports to the PSC regarding the 1994 Interim Policy. The first, due November 30, 1994, was to give the Commission an estimate of the amount of savings Pacificorp would acquire through their Demand Side Resource programs in 1994 in Utah, and provide an estimated year end Net Lost Revenue dollar amount for the year. The second, due March 31, 1995, was the final Collaborative report, responding to all Commission assignments from the Joint Recommendation. The third report, due anytime before December 31, 1995, (to be prepared when all actual 1994 savings from Utah DSR programs becomes available) will provide any adjustments to the energy savings amounts and NLR amounts for 1994 for Commission review.

The Evaluation and Net Lost Revenue Subcommittee prepared the first of these reports and submitted it through the Collaborative and through the Division to the Commission by the November 30, 1994 due date. Using 10 months of NLR calculations and engineering estimates of energy savings, and estimating those figures for November and December of 1994, the Collaborative reported that the Company would achieve 58,566 MWh (annualized) and 10.3 MW of conservation in 1994, exceeding the targets of 40,000 MWh and 5.9 MW established in the Joint Recommendation. This led to an estimate that the Company would accrue $338,723 of NLR for 1994. The November report, which is Attachment C, to the Evaluation and Net Lost Revenue Subcommittee Final Report (See Appendix III), included a detailed explanation of the rationale for the inputs to the Net Lost Revenue formula. Additionally, the report identified the appropriate measure lives for amortization of deferred DSR costs. The report stated:

"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 III. The mechanism encouraged Pacificorp to significantly expand its energy efficiency programs in comparison to previous years."

As an added part of meeting the "first report" commitment to the Commission regarding 1994 NLR and energy savings levels, the Subcommittee and the Collaborative submitted a second letter to the Commission on January 13, 1995, updating the November 30, 1994 estimates of NLR and energy conservation achieved. The updated energy conservation achieved was 65,073 MWh (instead of 58,909) and the NLR estimate turned out to be $386,909 (instead of $338,723). It was important for the Commission to see and approve these numbers prior to January 18, 1995, which is the day Pacificorp closed their accounting records for the 1994 financial year. It is further noted that the Company's 1994 DSR results compared favorably with the RAMPP III Action Plan energy conservation level of 60,508 MWh. This January report (see Attachment D, to NLR Subcommittee Final Report in Appendix III) also describes various updates to the NLR Formula used by the Collaborative as well as detail about the types of DSR programs implemented in Utah.

The experience of the Subcommittee and the Collaborative was that the Formula for calculating Net Lost Revenue worked reasonably well during 1994. It was concluded, however, that inputs to the formula needed to be evaluated and refined if it was to be used beyond 1994. The Subcommittee and the other collaborative members worked on those required changes with the resulting revised Formula being part of the new Joint Agreement, submitted to the Commission on February 15, 1995, as a proposed Cost Recovery/ Revenue Adjustment regulatory plan for Utah DSR for 1995 and 1996.

3- <u>Results of One Year Statistical Recoupling Numerical Experiment</u>

Statistical recoupling, as originally conceived, is intended to eliminate the net lost revenue disincentives associated with DSR investment and provide incentives for the utility to provide electric energy services efficiently. It accomplishes this by breaking the utility's financial incentive to promote electricity sales between rate cases.

Like other decoupling methodologies, statistical recoupling first breaks the linkage between utility revenues and actual sales. In a second step, utility revenues are recoupled to estimated electricity usage, or "allowed" sales. Allowed sales are based on *ex post* simulations of energy usage. Operationally, an econometric model of energy usage is estimated using, in this case, quarterly data from 1978 through 1992. Then, at the end of 1993, using actual 1993 data for the explanatory variables in the estimating equation, the model simulates 1993 energy usage. The simulated usage is allowed sales which determine *allowed* revenues.

Allowed revenues for 1993 are then compared with actual revenues. If, for example, actual exceeded allowed revenues, then the difference is entered into a recoupling account. The following year, an adjustment to rates is made in order to reimburse customers for the overcharge that occurred during the previous year. Alternatively, adjustments can be deferred until the next general rate case.

The goal of the Statistical Recoupling Subcommittee is to provide an objective analysis of how statistical recoupling would have performed if it was in place during 1994. In order to broaden the test, the Subcommittee decided to also examine performance in 1993.

Findings

The main findings of the numerical experiment are as follows:

a- Quarterly econometric forecasting models, calibrated on Utah Power service territory data from 1978 to 1992, are able to *ex post* forecast 1993 and 1994 sector kWh sales with an average forecast accuracy of -0.64 percent.

b- Forecasts for 1994 were not as accurate as for 1993. The Subcommittee presumes that this is primarily the result of 1994's summer being the hottest in the last 16 years. Since the models are calibrated on data for years that are *all* characterized by relatively cooler summers, it is not surprising that the models underpredicted usage in 1994. The underprediction is most severe in the heavily weather dependent residential sector. However, for the *entire* year, the forecasts were still all within a 95 percent confidence interval.

c- The numerical experiment indicates that if statistical recoupling was in effect in Utah during 1993 and 1994, then a total of $0.5 million would have been transferred from consumers to the utility in 1993 and a total of $7.4 million would have been transferred from the utility to consumers in 1994.

The Subcommittee identified several issues associated with the Statistical Recoupling methodology:

Performance Criteria

The Subcommittee evaluated the methodology's ability to meet the performance criteria outlined in the August 1993 report on DSR cost recovery.

a- In general, the methodology is fairly understandable, is difficult to manipulate, promotes cost minimization, and lessens the need for DSR program evaluation for NLR determination.

b- The econometric models simulate historical sales with a high degree of accuracy. However, their forecasting ability is challenged when future conditions are outside the historical experience of the models, as was the case in 1994.

c- To the extent that the models accurately simulate actual utility kWh sales, there should not be a substantive shifting of risk from the utility to the ratepayer over the long run. However, in any given year, such as 1994, risk maybe shifted to ratepayers to the extent that the models are inaccurate.

d- If rates are adjusted annually, then it appears the methodology can lead to greater rate instability than the net lost revenue mechanism adopted under the Joint Agreement. However, the rate instability can be lessened by using a deferral account and adjusting rates at the time of a general rate case. Moreover, the size of the adjustment would depend on the magnitude of the annual ex post forecast error and when a rate case took place. For example, the longer the period of time between rate cases, the greater the chance that years in which sales were underpredicted will be offset by years in which sales are overpredicted.

Statistical

a- If the forecasting models generate ex post estimates of kWh sales that do not differ statistically from actual sales, then the revenue transfers called for by the methodology will be essentially random and will sum to zero over the long run.

b- A trend towards revenue transfers from customers to the utility may develop if the utility's DSM programs expand over time and are effective in statistically reducing kWh sales.

c- Forecasting models should be recalibrated on a regular basis in order to expand the "historical experience" of the models and improve their forecasting performance. Recalibration should be done at intervals of no longer than three years.

Legal

a- Statistical recoupling may not be inconsistent with a recent Utah Supreme Court decision that utility rates be cost-based. The methodology does not alter the traditional price setting process that occurs in a rate case in which rates are based on costs.

b- Some parties are of the opinion that in order to avoid a conflict with a 1986 Utah Supreme Court decision that found retroactive ratemaking illegal, the reconciliation mechanism used to implement the methodology can be structured as a deferral account.

c- Other parties remain concerned about the legalities of Statistical Recoupling in Utah and recommend that further legal analysis be conducted as part of the implementation of this regulatory method.

Subcommittee Conclusions

If implemented for the long run, the statistical recoupling methodology may be a workable method to address the problem of eliminating many of the disincentives associated with DSR investment. Moreover, it appears to send the correct signals to the utility to implement its integrated resource plan efficiently.

However, given PacifiCorp's current level of DSR investment, the Subcommittee members remain concerned about the potential size of the revenue transfer created by the methodology. This is the primary reason that the Subcommittee can not recommend the adoption of the statistical recoupling mechanism at this time. However, if DSR becomes a larger portion of the utility's resource mix, this mechanism may hold promise. The Cost Recovery Collaborative generally concurs with the subcommittee conclusions and agrees with the decision not to implement Statistical Recoupling in Utah for Utah PacifiCorp DSR cost recovery for 1995 and 1996. Appendix IV contains the Statistical Recoupling Subcommittee Final Report.

4- <u>Results of Shared Savings Incentive Plan Study</u>

The Shared Savings Subcommittee members concluded that, given that PacifiCorp receives the opportunity to earn a "fair return" on its DSR investments, no other incentive mechanism is needed. A "fair return" may be defined differently by different parties. The subcommittee members believe that PacifiCorp's desire to be a low cost provider of energy services is a powerful incentive to choose the lowest cost portfolio of resources, either by utilizing supply side or demand side resources. Incentive payments increase administration costs and influence program evaluation methods. Also, there are potential unintended consequences of targeting incentives toward only one segment of PacifiCorp's operations.

Based on the foregoing discussion, the subcommittee members determined that their primary recommendations to the Cost Recovery Collaborative should be as follows (The Collaborative supports these subcommittee recommendations):

a- If PacifiCorp is provided with adequate opportunity to receive a fair return on their DSR investments, a DSR incentive is unnecessary. A fair return on DSR investments may be defined as DSR program cost recovery without a carrying charge from the time of capitalization until a rate case, and may include a net lost revenue adjustment or statistical decoupling mechanism. It may also include an AFDUC type carrying charge within the year of construction.

b- A Shared Savings incentive program may not fit within the guidelines established by the Utah Supreme Court in its 1994 decision number 910408 involving US WEST. That order required incentive plans to be linked to cost of service. Shared Savings incentives may not often be linked to cost of service and would require further legal analysis before adoption of this type of method.

c- While the subcommittee is not recommending any type of incentive mechanism, if the Commission determines that an incentive mechanism is needed in addition to a fair return on DSR investment, the mechanism could be an environmental impact incentive related to potential NOX and CO_2 taxes savings and thus more related to cost of service. The incentive could be in the range of 15 mills per kWh of DSR, or about $600,000 for 40,000 MWh of savings.

d- If a fair return on DSR investment is not afforded PacifiCorp, an environmental impact incentive mechanism should be adopted that is large enough to equalize the treatment of DSR and SSR programs.

As a result of the above discussion and recommendations, the Collaborative did not select any type of a Shared Savings incentive mechanism for implementation beyond 1994. See Appendix V for the Shared Savings Subcommittee Final Report.

5- Results of Total Factor Productivity Plan Study

A Total Factor Productivity (TFP) incentive mechanism measures utility productivity over time in several categories and combines the components to determine an overall utility productivity index. The incentive method then rewards the utility by splitting increases in productivity, above an established deadband, between the customers and shareholders. The TFP Subcommittee determined that TFP is not an appropriate candidate to equalize the treatment of DSR and SSR technologies because Utah's DSR activities are too small to measure in comparison to total Company costs. In the recent past, costs have been declining. In order to receive an incentive award during a declining cost period, costs must decrease by a greater amount than they have in the past. The TFP Subcommittee determined, and the Collaborative agrees, that it would be unlikely PacifiCorp would ever earn an incentive award for its DSR activity under the TFP model. The Collaborative did not select the Total Factor Productivity incentive method for implementation beyond 1994. See Appendix V for the Total Factor Productivity Subcommittee Final Report.

6- Non-Participant Impacts - Study Results

The Rate Spread and Non-Participant Impact Subcommittee was formed as a part of the DSR Cost Recovery Collaborative. Its purpose was to explore ways to mitigate any adverse effects of DSR programs on the customers who do not participate in those programs.

The subcommittee concluded that the best way to mitigate impacts of DSR investments on non-participants is to collect as much of the cost as possible from the direct participants in DSR programs. This can be accomplished through increased levels of Energy Service Charge (ESC) payments or some other means of customer participation charges. It can also be accomplished when customers follow effective price signals and pursue energy efficiency on their own.

The subcommittee's analysis of Utah Power's prices in Utah show that they are equal or greater than long run marginal cost in most cases. As such, there are financial incentives for customers to make investments in energy efficiency. The utility should promote energy efficiency by providing information on the benefits and the availability of cost effective DSR measures. The utility can, and perhaps should, facilitate market based transactions between customers and reputable vendors.

The subcommittee also assessed various procedures for allocating DSR costs to customer classes. They determined that all reviewed procedures for allocating DSR costs in embedded cost of service studies had shortcomings. Based upon their study of 1993 and, to a much lesser extent, 1994 DSR expenditures in Utah, they felt that using demand and energy factors to allocate net DSR costs (DSR costs less participation charges) to all customer classes was the best overall approach. While this method may result in some adverse price impact for all customers, it results in the most even distribution of the impacts on non-participants of the methods tested. Additionally, although it is far from ideal, it follows more closely the traditional principles of cost causation. It is based on the belief that DSR investments are made to meet the demand and energy requirements of all customers.

The Direct assignment of all DSR costs to the participant's rate schedule class was rejected. Although it reduces or eliminates adverse price effects on customers buying electricity on other rate schedules, direct assignment results in greater adverse price impacts for the non-participating customers that buy electricity on the same rate schedule as the DSR program participant.

The Collaborative concurs with the subcommittee's finding that non-participant rate impacts should be minimized. However, Collaborative members still feel there is substantial value in continuing utility sponsored DSR programs. The Impact Subcommittee Final Report is attached as Appendix VI to this report.

7- <u>Results and Recommendations From Performance Standards Study Work</u>

The Performance Standards Subcommittee and the Cost Recovery Collaborative recommend the adoption of five economic tests for the review and analysis of DSR programs. The tests provide information on the DSR program's life cycle impact on the Pacificorp system revenue requirement, on total costs for energy services to ratepayers, on total costs for energy related services to society, on Utah jurisdiction rate levels, and on participants in the DSR program.

The five DSR recommended economic tests are:

1- The Utility Cost test,
2- The Participant Cost test,
3- The Ratepayer Impact Measure test for Utah,

4- The Utah Total Resource Cost test, and,
5- The PacifiCorp Total Resource Cost test.

The purpose and application of each test is fully explored and equations for each test are provided and all terms defined in the subcommittee report. The Collaborative members consider the equations and guidelines provided in this report to be subject to revision and refinement as necessary. The Collaborative recommends the use of all five tests to measure the cost effectiveness of a DSR program, as opposed to just one key test (such as TRC) because all perspectives will provide relevant information in determining the value and success of a program. This multi-perspective approach requires PacifiCorp and the Commission to consider tradeoffs between the perspectives and among impacts. The Performance Standards Subcommittee Report provides guidance regarding the analysis of these tradeoffs.

In addition to the test information, the subcommittee recommends the analysis of actual DSR acquisitions relative to PacifiCorp's Least Cost Plan for use in determining cost recovery in a rate case. They also recommend the development of a computer model which generates the results of the five tests recommended in this report and allows for sensitivity analysis.

The Collaborative recommends that the detailed DSR Performance Standards Subcommittee Final Report, attached as Appendix VII, serve as the official reporting guidelines to be used by PacifiCorp for presentation of information regarding the costs and benefits of Utah DSR. Such information is provided for resource planning, for regulatory approval of programs for implementation, in contracts for acquisition of DSR, for DSR program evaluation reports, and for providing cost recovery in a rate case.

The Collaborative recommends that the Commission require PacifiCorp to file DSR information in the manner specified in the Performance Standards Subcommittee report.

8- <u>Recommendation for 1995 and 1996 Regulatory Treatment - Utah - PacifiCorp</u>

At the beginning of 1994, the Collaborative had before it at least four candidate cost recovery proposals that were thought might encourage PacifiCorp to implement its Integrated Resource Plan in Utah, that it could evaluate for consideration beyond the end of 1994 for PacifiCorp's DSR programs. These were: Statistical Recoupling, various combinations of Shared Savings, a modified version of the previously tried 1980's Total Factor Productivity program, and the 1994 Cost Recovery and Net Lost Revenue plan approved by the Commission in the Joint Recommendation. Through its subcommittees and at the Collaborative level these four alternatives were studied, and as the reader can see, the first three are not recommended by the Collaborative for the reasons given above. Various configurations of the NLR plan were evaluated by subcommittee and Collaborative members until the 1995-1996 Joint Agreement plan was developed and jointly agreed to by most members of the Collaborative (the signing Parties to the Joint Agreement). The proposed Utah Regulatory Plan for 1995 and 1996 DSR, called the Joint Agreement, is found in Appendix VIII. The highlights of the 1995-1996 Joint Agreement are as follows:

a. It is a two-year continuation of the DSR cost and NLR recovery experiment in Utah.

b. Parties can petition the Commission to continue this plan beyond 1996.

c. It is recommended that this Joint agreement be retroactive to January 1, 1995.

d. The Joint Agreement represents a compromise between parties and is an effort to remove disincentives to DSR implementation and IRP implementation by the Company.

e. The Agreement establishes an accounting treatment for approved DSR programs in Utah and allows for calculation and recording of Net Lost Revenues to account for lost sales of energy.

f. For 1995 and 1996, program evaluation, monitoring, and reporting costs for Commission approved DSR programs will be expensed in the year incurred. All other program costs and associated carrying charges will be capitalized with amortization beginning January of the year following installation, and continuing over a period no longer than the life of the programs.

g. Capitalized program costs will accrue a carrying charge from the date incurred to the end of each calendar year, at the current Allowance For Funds Used During Construction (AFUDC) rate.

h. Net Lost Revenues are to be calculated by an agreed upon Formula and will be recorded for the subsequent 12 months as they occur. NLR recorded in each year will be capitalized with amortization beginning in January of the following year. NLR for each year cannot exceed $2M.

i. The 1995 target for Utah DSR acquisition for this agreement is 80,923

MWH. The 1996 acquisition target will be determined from the RAMPP 4, to be published in late 1995. The Company expects to invest approximately $15M for DSR in Utah in 1995.

j. DSR acquisition results will be reported by PacifiCorp as part of their Semi-Annual reporting process starting in April 1995.

k. The Company will sponsor Quarterly DSR Update Conferences for regulators and other interested parties to allow for DSR tracking and monitoring of the Company's DSR activities.

The 1995-1996 Joint Agreement was reviewed with the Utah PSC in a hearing on February 23, 1995, prior to the completion of this Collaborative Report, to allow the Commission to have as much time as possible to review the Collaboratives's post 1994 regulatory treatment recommendation. The Company is being asked to increase their DSR efforts in 1995 over 1994 without an approved cost recovery policy in place, thus the early submittal of the Joint Agreement to the Utah Commission.

IV. RESPONSES TO CARRY-OVER ASSIGNMENTS FROM DSRETF REPORT

COMMISSION CARRY-OVER ASSIGNMENTS FROM THE DSRETF FINAL REPORT:

The final DSR Evaluation Task Force Report, submitted to the Utah Public Service Commission on May 20, 1994, contained a list of assignments not completed by that Task Force that were then assigned to the CRC for resolution. These assignments are as follows:

1- Review progress of PacifiCorp's 1994 Utah demand side management programs, discuss the evaluation of current and future DSR programs, and continue to develop evaluation criteria for them.

2- Analyze issues of how best to calculate savings for DSR measures.

3- Determine what methods are most appropriate for evaluating the success of programs in Utah.

4- Determine what perspective should be taken when evaluating the cost effectiveness of DSR measures and programs.

5- Determine how Demand Side Resources can be consistently compared to Supply Side Resources.

6- Examine targeted residential conservation and load management programs of the sort recommended by the Committee of Consumer Services in the 06 Docket, to address high- use, all-electric (Schedule 5) customers.

7. Recommend to the Commission how best to study the issue of eliminating disincentives and creating incentives for the company to pursue its Integrated Resource Plan.

8- Recommend how best to study future ratemaking treatment of DSR programs.

9- Analyze the use of ESC's (Energy Service Charges) for efficiency improvements and conservation.

10- Analyze electric revenue adjustment mechanisms, the granting of a cost advantage for efficiency of conservation acquisitions, and the decoupling of revenues from profits.

<u>REPORT TO THE COMMISSION ON CARRY-OVER ASSIGNMENTS - DSRETF REPORT:</u>

1- <u>Continuation of DSR Program Evaluation/Program Review/Criteria Evolution:</u>

The Evaluation and Net Lost Revenue Subcommittee thoroughly reviewed and monitored the Company's DSR programs. In the November 30, 1994 report to the Utah PSC (see Appendix III, Attachment C), the Subcommittee stated as follows:

> ".....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 RAMMP 3. The mechanism encouraged PacifiCorp to significantly expand its energy efficiency programs in comparison to previous years.
>
> PacifiCorp's 1994 DSR programs also improve the energy efficiency of Utah 's business(es) and homes. This lowers customers bills, helps preserve Utah jobs and makes Utah businesses more competitive. For example, PacifiCorp helped major industrial customers achieve savings through the installation of energy efficiency measures (e.g. efficient motors)."

This Subcommittee supervised the hiring of Dr. Dan Violette of Xenergy, Inc., to assist Pacificorp and the Collaborative with the on-going DSR project evaluation processes. During 1994, PacifiCorp has provided just one preliminary Evaluation Report to the Collaborative, on their Commercial FinAnswer program, dated December 13, 1994. The Collaborative has expressed its interest in keeping these Evaluation Reports on schedule and would like to see more programs than were seen during 1994. This activity will continue to be tracked, beyond the life of the formal collaborative setting, in the proposed Quarterly DSR Tracking Committee meetings to be held by the Company starting in May 1995. The review of the Company's evaluation reports and processes will continue.

2- <u>Savings Calculation Issues:</u>

Program Evaluation is the process by which the company verifies the cost effectiveness and savings achieved by DSR programs and contracts. The Subcommittee carefully monitored the Company's program evaluation activities and processes. To assist the Subcommittee and to provide an independent perspective relative to the evaluation process, Dr. Dan Violette of Xenergy was retained as a consultant. Dr. Violette provided technical briefings in Subcommittee meetings relative to the Company's program evaluation plans, site verification plans, and program evaluation reports. Such consultant briefings together with memorandums detailing the consultant's evaluation of the adequacy of the Company's reports will continue to be received from Dr. Violette through 1995 for 1994 DSR activity under Xenergy's current contract.

3- <u>Evaluating DSR Program Success</u>

This DSRETF carry-over item was assigned to the Performance Standards Subcommittee for study and resolution. A direct response to this carry-over item is covered in detail in the Performance Standards Subcommittee Final Report, found in Appendix VII, on page 2 through 8. The reader is invited to review these pages for the Subcommittee's and the Collaborative's position on this topic.

4- <u>DSR Programs Cost Effectiveness Perspective</u>

This DSRETF carry-over item was assigned to the Performance Standards Subcommittee for study and resolution. A direct response to this carry-over item is covered in detail in the Performance Standards Subcommittee Final Report, found in Appendix VII, on page 1 through 18. The reader is invited to review these pages for the Subcommittee's and the Collaborative's position on this topic.

5- DSR/SSR Consistent Comparison

This DSRETF carry-over item was assigned to the Performance Standards Subcommittee for study and resolution. In preparing the proposed accounting treatment recommendation in the 1995-1996 Joint Agreement presently before the Commission, Collaborative members tried to evaluate DSR and SSR acquisitions in equal light , as nearly as possible. Especially in the treatment of carrying charges and interest during construction, or AFUDC. A direct response to this carry-over item is covered in detail in the Performance Standards Subcommittee Final Report, found in Appendix VII, on page 1 through 18. The reader is invited to review these pages for the Subcommittee's and the Collaborative's position on this topic.

6- Schedule 5 DSR Opportunities - Reduce Rate Shock

In its Order dated April 10, 1992, in Docket No. 90-035-06, the Commission directed the company to analyze the potential of using energy conservation measures to facilitate the transition of Schedule 5 customers to Schedule 1. The assignment to monitor the Company's response to this portion of the commission Order was given to the Evaluation and Net Lost Revenue Subcommittee.

The Company offered Schedule 5 customers a "Water Smart Kit" (a low - flow showerhead, two low-flow sink aerators with installation instructions and various adapters) in return for a completed energy usage survey. The survey information was used to evaluate the possibility of using DSR measures to ease the transition to Schedule 1 if Schedule 5 were terminated.

The company's report concluded that energy education and information as well as certain energy conservation measures could produce significant energy savings for some of the remaining Schedule 5 customers.

The Subcommittee and the Collaborative concluded that a DSR program could be developed to ease the transition of some Schedule 5 customers to Schedule 1, if there should be a desire by regulators or other parties to do so. It was further concluded that it would be preferable to provide such a DSR program at the time of the potential rate schedule termination of Schedule 5 in order to more directly benefit customers affected by such a schedule shift. Therefore, the Collaborative recommends to the Commission that the appropriate time to consider provision of DSR measures to Schedule 5 customers would be concurrent with the rate case that would potentially terminate the Schedule 5 rate schedule. At this writing, there are approximately 4,428 remaining Schedule 5 customers in Utah.

7- Disincentive Elimination/ Incentive Creation Recommendation

The Collaborative supports the conclusion reached by the Shared Savings Subcommittee that "If PacifiCorp is provided with adequate opportunity to receive a fair return on their DSR investments, a DSR incentive in unnecessary". PacifiCorp has stated that they see no incentive in the 1994 Joint Recommendation as implemented, nor in the proposed 1995-1996 Joint Agreement, but they do see a certain reduction in disincentive to the implementation of the DSR portion of their Integrated Resource Plan. The Collaborative thinks they see evidence of this conclusion in the DSR performance of the Company in 1993 versus DSR activity in 1994, as a direct result of the Joint Recommendation conditions. The best recommendation the Collaborative can give the Commission at this time of how to study the issue of eliminating disincentives and creating incentives to encourage implementation of PacifiCorp's IRP will be found in allowing the DSR regulatory treatment experiment proposed in the Joint Agreement, presently before the Commission under Docket No. 92-2035-04, to be implemented and reviewed for success or failure. The Joint Agreement requires an increase of energy savings target from PacifiCorp in 1995 over the 1994 level, which should allow observers to see if disincentives to DSR will be removed sufficiently to motivate the Company to achieve these ramped upward targets. The Joint Agreement for 1995-1996 regulatory treatment of DSR proposes that the Division and the Office of Energy and Resource Planning conduct an annual analysis of PacifiCorp's actual annual and cumulative DSR acquisitions. This analysis may assist in the evaluation of this "incentive/disincentive" issue.

8- Future Rate-Making Treatment Recommendation

The Rate Spread and Non-Participant Impact Subcommittee and the Collaborative recommend that adverse impact on non-participants in DSR programs can be reduced by increasing the level of measure costs born by DSR participants when possible. From a DSR cost allocation standpoint, the Collaborative has considered the recommendation of the Subcommittee, which is to spread DSR costs, above those born by the DSR direct participant, across all customer classes. The Collaborative generally believes that the allocation of DSR costs and NLR's among the various customer classes is an issue to be decided in PacifiCorp's next Utah general rate case. The detail behind the Subcommittee's conclusions is found in Appendix VI, as well as in Section III-6, above.

9- Energy Service Charge Analysis

The Company, the Subcommittee, and the Collaborative are in the process of finalizing a report to the Commission on the impact of the Energy service Charge. The report will include cost effectiveness analysis based on recommendations made by the DSR Performance Standards Subcommittee (see Appendix VII). This Energy Service Charge report is currently in the final stages of development and review. The report will be filed separately with the Commission by PacifiCorp (with outgoing Collaborative member's input) by April 28, 1995.

10- Future Regulatory Treatment Plans

The work of the DSRETF, the Technical Conference Collaborative, and the Cost Recovery Collaborative has centered around the issues of electric revenue adjustment mechanisms, the granting of a cost advantage for efficiency of conservation acquisitions, and the decoupling of revenues from profits. The 1994 Joint Recommendation Trial and the proposed 1995-1996 Joint Agreement, reviewed by various Subcommittees and the Collaborative, analyzed different revenue adjustment mechanisms and methods of granting cost advantages for efficiency of conservation acquisitions, as well as the possibility of decoupling of revenues from profits. The majority of Collaborative members have reached a compromise position in how best to go forward in Utah in regard to these issues in the continued experiment in net lost revenue and program cost recovery outlined in the Joint Agreement stipulation presently before the Utah Public Service Commission.. Appendix VIII contains a copy of the Joint Agreement proposed for 1995-1996 Utah DSR regulatory treatment.

V. SUMMARY OF CRC COLLABORATIVE RECOMMENDATIONS TO UPSC:

The following is a summary of recommendations from the Utah DSR Cost Recovery Collaborative to the Utah Public Service Commission at the conclusion of the Collaborative's work during 1994 and 1995:

RECOMMENDATIONS TO THE UTAH PSC:

1- That the Joint Agreement be approved as soon as possible, retroactive to January 1, 1995, to put in place a Regulatory Plan for DSR cost recovery for PacifiCorp for 1995 and 1996.

2- PacifiCorp should prepare DSR benefit/cost analysis utilizing the five DSR cost effectiveness tests outlined in this report and in the Performance Standards Subcommittee's Final Report. PacifiCorp and interested parties should develop a computer model to generate the results of the five tests and to perform sensitivity analysis. The Commission should request in writing that PacifiCorp file DSR information in the manner specified in the Performance Standards Final Report found in Appendix VII.

3- If and when a decision is made to eliminate Utah's Schedule 5 rate schedule, the Division and the Company and others should be notified in order to review and develop measures that can help ease the transition to Schedule 1. The Collaborative sees advantages in implementing DSR activities for Schedule 5 customers when such schedule is eliminated.

4- If the 1995-1996 Joint Agreement is approved by the Commission, the Cost Recovery Collaborative will be disbanded. Tracking and monitoring of PacifiCorp's DSR activity will occur through the proposed Quarterly Update Conferences to be sponsored by the Company. The reporting of DSR activity will become part of the PacifiCorp Semi-Annual reporting function. The Collaborative recommends the Commission to approve these new processes as part of approving the Joint Agreement.

5- Regulatory review of DSR programs will include an analysis of the Company's implementation of its IRP. It is envisioned that the report conducted by the Division of Public Utilities with the possible assistance of the Office of Energy and Resource Planning which is recommended in the 1995-1996 Joint Agreement will serve as analytical support to this evaluation

6- Continued analysis of Statistical Recoupling should be performed and presented at the Quarterly DSR Update Conferences.

The Cost Recovery Collaborative appreciates the opportunity to present this report and recommendations to the Commission.

APPENDICES

I THROUGH VII

DEMAND SIDE RESOURCE COST RECOVERY COLLABORATIVE REPORT

APPENDIX I

COLLABORATIVE MEMBERS BY NAME AND ORGANIZATION

MARCH 31, 1995

APPENDIX I - DSR COLLABORATIVE MEMBERSHIP LIST

ACTIVE MEMBERS:

NAME	ORGANIZATION
Eric Blank	Land and Water Fund
Ron Burrup	Division of Public Utilities
Pete Catching	PacifiCorp
Mary Cleveland	Committee of Consumer Services
Rich Collins	Public Service Commission Staff
Kevin Duffy-Deno	Office of Energy and Resource Planning
Ellen Eckels	Wasatch Clean Air Coalition
Margo Everett	PaacifiCorp
Mark Flandro	Division of Public Utilities
Dan Gimble	Committee of Consumer Services
Bob Lively	PacifiCorp
Steve McDougal	PacifiCorp
Dave Taylor	PacifiCorp
Ted Weston	PacifiCorp
Rebecca Wilson	Utah Division of Public Utilities

INFORMATIONAL MEMBERS:

NAME	ORGANIZATION
Bruce Armstrong	Armstrong Pacific Corporation
Lori Bement	Codale Electric Supply
Chris Boren	Lighting Maintenance and Services
Lee Brown	MAGCORP
Kenneth Buchi	Wasatch Clean Air Coalition
Mark Case	Etc Group, Inc
Thomas Crockett	OSRAM Sylvania
Gary Dodge	Kimball, Parr, Crockett, and Waddoups
Bill Evans	Parson, Behle, and Latimer
Scott Gutting	Energy Stratigies, Inc.
Craig Hibberd	Western Area Power Administration
Tim Hunter	Stoel, Reeves, Boley, Jones, and Gray
Bruce Hutchinson	NEOS Corporation
Doug Kirk	Public Service Commission Staff
Douglas Larson	PacifiCorp
Brad Markus	Mountain Fuel Supply Company

(Listing continued on the next page).

NAME	ORGANIZATION
Peter Mattheis	Brickfield, Burchette, and Ritts
Gordon McDonald	PacifiCorp
Kenneth Powell	Division of Public Utilities
Scott Robinson	PacifiCorp
Rob Sirvaitis	PacifiCorp
Dan Violette	Xenergy. Inc.
Elgin Ward	Deseret Generation and Transmission
Glen Watkins	Mountain Fuel Supply Company
Kenneth Wilson	Deseret Generation and Transmission
Commissioners	Utah Public Service Commission

All active and informational members of the Utah Cost Recovery Collaborative are hereby thanked for their participation and intelligent input to the workings of this collaborative effort.

DEMAND SIDE RESOURCE COST RECOVERY COLLABORATIVE REPORT

APPENDIX II

SUBCOMMITTEE DESIGNATION, CHAIR, AND MEMBERSHIP

MARCH 31, 1995

APPENDIX II - DSR SUBCOMMITTEE MEMBERSHIP

SUBCOMMITTEE	CHAIRPERSON	ASSIGNED MEMBERS
Evaluation and Net Lost Revenue	Bob Lively - PacifiCorp	Ron Burrup - DPU Mary Cleveland - CCS Rich Collins - UPSC Staff Becky Wilson - DPU Steve McDougal - PacifiCorp Ted Weston - PacifiCorp Eric Blank - EI Margo Everett - PacifiCorp Pete Catching - Pacificorp Mark Flandro - DPU
Statistical Recoupling	Kevin Duffy-Deno OE&RP, DNR	Dave Taylor - PacifiCorp Mark Flandro - DPU Eric Blank - EI Becky Wilson - DPU Mary Cleveland - CCS Rich Collins - UPSC Staff
Shared Savings and Total Factor Productivity	Ron Burrup - DPU	Steve McDougal - PacifiCorp Dan Gimble - CCS Mark Flandro - DPU
Rate Spread and Non-Participant Impacts	Dave Taylor - PacifiCorp	Dan Gimble - CCS Mark Flandro - DPU Craig Johnson - PacifiCorp
DSR Performance Standards	Becky Wilson - DPU	Dan Gimble - CCS Rich Collins - UPSC Staff Pete Catching - PacifiCorp Margot Everett - PacifiCorp Bob Lively - PacifiCorp Mary Cleveland - CCS

The chairpersons of these subcommittees thank all those assigned and visitor members that helped study the assigned topics and whose analysis led to the final subcommittee reports.

DEMAND SIDE RESOURCE COST RECOVERY COLLABORATIVE REPORT

APPENDIX III

FINAL REPORT - EVALUATION AND NET LOST REVENUE SUBCOMMITTEE DATED MARCH 24, 1995

SUBMITTED
MARCH 31, 1995

Demand-Side Resource
Cost Recovery Collaborative
Evaluation and Net Lost Revenue Subcommittee

March 24, 1995

Introduction

The Evaluation and Net Lost Revenue Subcommittee (Subcommittee) was formed as a part of the DSR Cost Recovery Collaborative. The Subcommittee consisted of the following members:

Ron Burrup	Division of Public Utilities
Becky Wilson	Division of Public Utilities
Mark Flandro	Division of Public Utilities
Mary Cleveland	Committee of Consumer Services
Rich Collins	Utah Public Service Commission
Eric Blank	Land and Water Fund of the Rockies
Steve McDougal	PacifiCorp
Pete Catching	PacifiCorp
Margot Everett	PacifiCorp
Robert Lively	PacifiCorp
Ted Weston	PacifiCorp

The duties of the Subcommittee were as follows:

1. Monitor the Company's calculation of net lost revenue (NLR) for 1994 per the terms of the Joint Recommendation for the regulatory treatment of 1994 DSR costs (attachment A) which was approved by the Utah Public Service Commission (Commission) in its order in Docket No. 92-2035-04 dated February 10, 1994 (attachment B).

2. Perform an energy survey of Schedule 5 customers to analyze the feasibility of using DSR to facilitate the transition of Schedule 5 customers to Schedule 1 (attachment F).

3. Monitor the Company's ongoing evaluations of energy conservation savings achieved by DSR programs.

4. Provide an evaluation report of the Company's Energy Service Charge(ESC).

5. Make recommendations regarding the method of calculating NLR beyond 1994.

Executive Summary

The Subcommittee met 14 times during 1994. The Subcommittee monitored, evaluated and analyzed the Company's DSR activity, the proper method of calculating and booking NLR, the energy survey of Schedule 5 customers, the Company's program evaluation activity, and prepared a report evaluating the effectiveness of the Company's energy service charge mechanism. Additionally, the members of the Subcommittee participated in the development of a Joint Agreement for the regulatory treatment of DSR costs for 1995 and 1996. The Subcommittee had concern about the amount of time required by Company and regulatory personnel to analyze DSR issues in 1994. Given the current level of DSR investment in Utah, the time spent appeared excessive. However, given the previous level of inexperience in evaluating such resources, the effort was necessary and proved to be worthwhile. With the knowledge and experience gained through the collaborative process the subcommittee recommends that the amount of time dedicated to the regulatory aspects of DSR in the future be reduced.

The Demand-Side Resource Collaborative Report to the Commission, dated August 31, 1993 suggested criteria against which DSR ratemaking mechanisms are to be reviewed. These criteria were used to evaluate alternative ratemaking mechanisms as solutions to barriers to the acquisition of cost effective DSR.

The Subcommittee evaluated the DSR cost recovery mechanism defined in the 1994 Joint Recommendation against the criteria provided in the DSR Collaborative Report (attachment C). The Joint Recommendation DSR cost recovery mechanism measured favorably against the criteria from the DSR Collaborative Report. The conclusion of the Subcommittee based on this analysis is that the Joint Recommendation DSR cost recovery mechanism provides a reasonable method for the recovery of DSR costs, but that it should continue to be developed and refined. The Subcommittee supports the Joint Agreement filed with the Commission on February 15, 1995 which continues the 1994 interim policy (with minor modifications) into 1995 and 1996 and allows for continued development and refinement of the mechanism.

Net Lost Revenue

As directed by the Commission's February 10, 1994 order the Subcommittee prepared two reports regarding 1994 conservation achieved, NLR, and other DSR issues. These reports were submitted to the Commission by the Division of Public Utilities for the Demand-Side Resource Cost Recovery Collaborative.

The first report submitted November 30, 1994 provided the Commission with a preliminary estimate of 1994 NLR (see attachment D). The report reviewed year-to-date demand-side management activity, noting that the Company expected to exceed the 1994 targets of 40,000 Mwh (on an annualized basis) and 5.9 MW of conservation established in the 1994 Joint Recommendation. The report stated:

> 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.

Additionally the report includes an explanation, rationale, and background for the inputs to the net lost revenue formula which produced the 1994 net lost revenue. A detailed explanation of the Subcommittee's analysis relative to the appropriate avoided energy cost ("AC" element) and demand cost ("ADC" element) is included in the report. The preliminary estimate of net lost revenue for 1994 was $338,723 based on estimated annualized conservation savings of 58,556 MWh.

Also the report identifies the appropriate DSR measure lives for amortization purposes.

The second report submitted January 13, 1995 (attachment E) updated the preliminary estimate of NLR provided November 30, 1994 .

The reported final net lost revenue for 1994 was $386,909, based on 20,709 MWh of energy conservation savings (non-annualized). The report noted that on an annualized basis the Company achieved 65,073 MWh and 9.15 MW of conservation, exceeding the Joint Recommendation targets of 40,000 MWh and 6 MW. Additionally the Company's 1994 DSR activity of 65,073 MWh is in line with the RAMPP-3 action plan target of 60,508 MWh of annualized energy savings.

The second report described updates to various net lost revenue formula inputs. It also evaluated the difference between net lost revenue computed with or without peak/off-peak avoided costs used in the "AC" element of the net lost revenue formula. No conclusive difference was found. Therefore, peak/off-peak avoided costs were not used in the net lost revenue formula for 1994. However the issue will be revisited annually until a final method of cost recovery of DSR costs is adopted by the Commission.

The Subcommittee found that the formula to calculate NLR worked reasonably well during 1994 and is relatively simple and straightforward. However, the determination of the appropriate inputs, such as the avoided cost element and the amount of conservation achieved, is less straightforward. Therefore, the Subcommittee supports the approach proposed in the Joint Agreement that the current treatment and method of calculating NLR should be continued and refined during 1995 and 1996.

Schedule 5

In its order dated April 10, 1992 in Docket No. 90-035-06 the Commission directed the Company to analyze the potential of using DSR to facilitate the transition of Schedule 5 customers to schedule 1. The assignment to monitor the Company's response to this Commission order was given to the Evaluation and Net Lost Revenue Subcommittee.

In the February 16, 1994 meeting of the Subcommittee, the Company detailed its plan to survey schedule 5 customers to determine their energy consumption patterns. This information would be used to determine the possibility of using DSR measures to ease these customers transition to Schedule 1, if Schedule 5 were to be terminated. The Company offered Schedule 5 customers a "Water Smart Kit" (a low-flow showerhead, two low-flow sink aerators with installation instructions and various adapters) in return for a completed energy survey.

The Company achieved a 40% response rate to its survey. The survey results were presented by the Company in a report dated December 12, 1994 (attachment F). The report concluded that energy education and information and certain energy conservation measures could produce significant energy savings for some Schedule 5 customers.

The Subcommittee concluded that certain energy education and conservation measures could be packaged as a program to ease the transition of some Schedule 5 customers to Schedule 1. The Subcommittee concluded that it would be preferable to provide such a program at the time of the potential termination of Schedule 5 in order to more directly benefit customers affected by such termination. Therefore the Subcommittee would recommend to the Commission that the appropriate time to provide a conservation program to Schedule 5 customers would be concurrent with the potential termination of Schedule 5.

Monitor Evaluations

Program evaluation is the process by which the Company verifies the cost effectiveness and results achieved by DSR programs and contracts. The Subcommittee carefully monitored the Company's program evaluation activities and processes. To assist the Subcommittee and to provide an independent perspective relative to the evaluation process Dr. Daniel Violette of Xenergy was retained as a consultant. Dr. Violette provided technical briefings in the Subcommittee's meetings relative to the Company's program evaluation plans, site verification plans, and program evaluation reports. Such briefings together with memorandums detailing the consultant's evaluation of the adequacy of the Company's reports and activities for 1994 DSR will continue to be received through 1995. Dr. Violette was also available to the Collaborative during 1994 and will be available in 1995 for guidance and direction on DSR topics not specifically related to evaluation and verification.

The Subcommittee spent considerable time, with the guidance of Dr. Violette, monitoring the Company's verification of savings achieve under the ECONS DSR resource acquisition contract. In a Joint proposal dated September 28, 1993 (attachment G) the Company agreed to perform measurement testing to determine the level of energy savings achieved by the conservation measures installed under the ECONS contract. The testing was to include 60 days each of pre- and post-installation measurement of electricity consumption related to water heating, in 75 units chosen to be representative of those to be treated by ECONS.

The Company's final report on the measurement testing was provided to the Evaluation and Net Lost Revenue Subcommittee on July 12, 1994 (attachment H). The report concluded that ECONS installations provide the Company with a cost effective resource. The result of the testing suggested that ECONS installations produce energy savings of approximately 980 kWh per year per installation. This amount is 92 kWh per year less than the deemed amount of savings (1,072 kWh per year) assumed in the contract with ECONS.

On September 28, 1994 the Subcommittee provided the Company with an appraisal and comments relative to the measurement testing results and the Company's validation of the cost effectiveness of the program based on the results of the measurement testing (attachment I). The appraisal concluded that although the Subcommittee was displeased with the actual study design and that the study results were not as conclusive as anticipated, the ECONS program is more likely than not to produce cost-effective savings and should be eligible for cost recovery in accordance with the Joint Recommendation. ECONS installations produced 9,762 MWh of cost effective energy savings in Utah on an annualized basis in 1994.

Energy Service Charge

In its order dated June 1, 1993 in Docket No.90-2035-01 the Commission ordered the Company to demonstrate the ability of the energy service charge approach to meet DSR acquisition goals.

The Company is in the process of finalizing a report to the Commission on the impact of the Energy Service Charge. The Collaborative is monitoring the preparation of this report. The report will include cost effectiveness analysis based on recommendations made by the DSR Performance Standards Subcommittee.

The report will be filed separately with the Commission by April 28, 1995.

Recommendation for NLR beyond 1994

The Evaluation and Net Lost Revenue Subcommittee participated in and supported the Joint Agreement which was filed with the Commission for approval on February 15, 1995. The Subcommittee is not prepared at this time to recommend a long-term regulatory method for the treatment of DSR costs, however the Subcommittee believes that the calculation and regulatory treatment of NLR under the terms of the 1994 Joint Recommendation was reasonably successful and warrants further development and refinement. Therefore the Subcommittee supports the Joint Agreement which proposes the continuation of NLR for 1995 and 1996 with continued monitoring and evaluation.

Attachment A

EXHIBIT A

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF RATE MAKING TREAT-MENT OF DEMAND-SIDE RESOURCES AND THE ANALYSIS OF REGULATORY CHANGES TO ENCOURAGE IMPLEMENTATION OF INTEGRATED RESOURCE PLANNING	)))))	DOCKET NO. 92-2035-04 JOINT RECOMMENDATION

PacifiCorp, state regulators, and other interested parties have met for several months in a collaborative setting to develop a mutually agreeable regulatory policy regarding demand-side resource investments. The parties have submitted a report to the Utah Public Service Commission (PSC) stating their respective positions.

The Division of Public Utilities (DPU), PacifiCorp dba Utah Power (Company), Committee of Consumer Services (CCS), Department of Natural Resources (DNR) and Environmental Intervenors (EI) desire to move ahead with Commission approved demand side resource programs in 1994. The parties realize that the concept of demand side resources (DSR), the evaluation and measurement of DSR programs and the direction of regulatory policy are still in the formative stages in Utah. Under these circumstances, an interim approach which allows the Company, its customers, and regulators to gain experience in evaluating and measuring the success of these programs is considered reasonable and in the public interest.

The undersigned parties therefore propose an interim one year trial policy (Interim Policy), coupled with further research, for the regulatory treatment of DSR programs in Utah. The Interim Policy will be in effect January 1, 1994 through December 31, 1994 (Interim Period). This Interim Policy does not establish a precedent for future DSR policy. The parties agree that the Interim Policy detailed below is a reasonable short term alternative for addressing DSR cost recovery and program review issues in the State of Utah. This Joint Recommendation represents a compromise. It does not indicate that all parties agree that the Interim Policy provides either complete or incomplete cost recovery of DSR costs or that it equalizes the treatment of DSR and SSR resources.

1. NET LOST REVENUES

1.1 Attached as Exhibit 1 is a description of the Net Lost Revenue Formula (Formula) which the parties agree will be used by the Company to calculate net lost revenues (NLR) during the 1994 Interim Period. This Formula will not be subject to change during the Interim Period. As part of its responsibilities, a collaborative task force (defined in Section 4) will work to quantify the inputs to the Formula, and will issue a report to the Commission indicating areas of agreement by the parties regarding the amount of NLR in 1994, and any remaining NLR issues to be resolved by the Commission. The parties recommend that the Commission adopt the Formula for purposes of calculating NLR for 1994. The burden to show that the inputs to the Formula are reasonable rests with PacifiCorp.

1.2 The amount of NLR calculated under the Formula described in Exhibit No. 1 and ordered by the Commission will begin to be amortized on January 1, 1995, over the average life, as approved by the Commission, of measures within the specific DSR program which created them. PacifiCorp will continue to work with the DSR Collaborative (as defined in Section 4) during 1994 and

1995 to update estimates of 1994 energy and capacity savings (net of load building impacts) based on monitoring and evaluation (M&E) results. These estimates will form the basis for PacifiCorp's NLR calculation. When PacifiCorp files its next general rate case, the amortization of 1994 NLR and program costs, the unamortized balance of NLR and program costs, and energy service charge revenues will be included in the Utah jurisdictional revenue requirement.

1.3 This Interim Policy applies only to NLR from DSR measures installed in 1994. The parties agree that the Formula will be evaluated by the Collaborative for reasonableness and ease of measurement in order to determine whether or not it provides an appropriate basis for NLR calculation in the post-1994 period.

1.4 NLR for any DSR measure will not be annualized during the Interim Period, but will be recoverable only for that portion of the Interim Period remaining after the installation of that measure is complete. The total amount of NLR calculated for all Utah measures installed in calendar year 1994, based on the Formula, and approved by the Commission, shall not exceed the lesser of:

a. The amount derived by applying the Formula described in Exhibit 1 to the DSR program measures installed in 1994; or

b. $2,000,000

1.5 NLR will be calculated monthly by the Formula during the Interim Period. Following program evaluations and determination of the final amount of NLR for 1994 by the Commission, any adjustment to the NLR calculated by the Formula shall not exceed 25%.

2. TARGET FOR 1994 DSR ACTIVITY

2.1 The 1994 DSR target will insure an adequate level of DSM activity in order to provide sufficient data to evaluate and measure the success of the demand side programs in Utah.

2.2 Therefore the minimum energy and capacity target for 1994 DSM activity in Utah will be 40,000 MWh and 5.9 MW, respectively, on an annualized basis. It is the intent of the parties to gain information on a wide variety of DSR programs. Therefore, PacifiCorp agrees to complete at least 20% of each customer class's near term action goals as stated in RAMMP III.

3. DEMAND-SIDE-RESOURCE PROGRAM COSTS

3.1 For the purposes of this Interim Policy the parties concur that program evaluation, monitoring and reporting costs will be expensed in the year incurred. Non-program specific advertising costs will also be expensed in the year incurred. All other DSR program costs, including costs associated with conservation contracts resulting from the bidding process, will be capitalized with amortization beginning January 1, 1995 and continuing over the life of the program measure. This treatment is consistent with the practice in other PacifiCorp jurisdictions.

3.2 The Company will capitalize DSR program costs, including NLR, and will accrue carrying charges at the current AFUDC rate on DSR program costs until the amortization of those costs begins on January 1, 1995. The capitalization of the program costs, NLR, and related carrying charges will be booked to account 182.3 (Other Regulatory Assets). Amortization of these amounts will be booked to account 456 (Other Electric Revenue). The NLR calculation will not be annualized. Customer payments resulting from the energy service charge will be recorded in accounts 124 (Other Investments, for loan principal) and 451 (Miscellaneous Service Revenues, for interest income).

4. COLLABORATIVE TASK FORCE

4.1 The fundamental objective of PacifiCorp's M&E efforts will be to develop the information necessary to make appropriate decisions in regard to DSR investments. However, since NLR recoveries will be tied to the M&E results under the terms of this joint recommendation, there may be a potential for disputes to arise. To help reduce this potential, a new collaborative task force (Collaborative) consisting of representatives from PacifiCorp, the DPU, CCS, DNR, EI, the PSC, and other interested parties, shall be formed prior to 1994 by Commission order. The primary focus of this Collaborative will be to examine the Interim Policy and report its conclusions and recommendations to the PSC. The existing DSR Evaluation Task Force and the former DSR Technical Conference/Collaborative on cost recovery will be subsumed into the new Collaborative. The Collaborative will retain a qualified consultant to provide an impartial review of PacifiCorp's M&E activities. The consultant will be funded by ratepayer monies provided by PacifiCorp. The parties agree that is reasonable to support cost-recovery for PacifiCorp of the consultant expenses. These costs will be capitalized with a carrying charge, at the current

AFUDC rate, in account 182.3 until amortization over a 5 year period begins January 1, 1995. Although the work of the consultant will be directed by a steering committee of collaborative participants, the primary objective of the consultant's work is to analyze PacifiCorp's M&E efforts, data, methods, and results on behalf of the Collaborative and non-utility parties.

4.2 In early 1994 PacifiCorp agrees to provide M&E plans for each DSR program for Collaborative review. These plans will include estimates of the NLR for calendar year 1994. PacifiCorp will keep the Collaborative informed relative to its ongoing M&E activity.

4.3 In addition to its primary task described in section 4.1, the Collaborative will examine several other issues. First, the Collaborative will run a one year numerical experiment with the statistical recoupling program that was proposed by the EI. The purpose of this experiment is to determine what would have happened in calendar 1994 if the Commission had adopted statistical recoupling. Second, the Collaborative will develop options for a shared savings incentive plan and a total factor productivity incentive plan[1]. Third, the Collaborative will assess the price impact of DSR on non-participants in DSR programs. Fourth, the Collaborative will develop performance standards for Commission consideration in determining post-1994 program eligibility for cost recovery. The parties agree that these standards should apply

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[1] Total Factor Productivity is a technique that measures a utility's overall efficiency. Incentives can be applied to reward utility measures that improve this efficiency and thus minimize ratepayer cost.

prospectively only to program activity undertaken subsequent to their adoption by the Commission.

4.4 The Collaborative's report to the Commission shall include, but not be limited to, the following subjects:

(a) the results of the Interim Policy, and make recommendations for a DSR cost recovery policy to be effective in 1995;

(b) the results of the numerical experiment with statistical recoupling;

(c) the options regarding a shared savings incentive program and a total factor productivity incentive program;

(d) the price impact of DSR programs on non-participants;

(e) the development of performance standards; and

(f) quantification of 1994 NLR using the Formula.

5. JOINT RECOMMENDATION

5.1 The parties have agreed to this Joint Recommendation as an integrated document and recommend that the Commission adopt it in its entirety. Accordingly, in the event any part, or all, of this Joint Recommendation is modified or rejected by the Commission, each party reserves the right, upon written notice to the Commission and all other parties within 5 days of the date of the Commission's order, to withdraw from this Joint Recommendation without being bound by its terms in this, or any other proceeding. Any party which elects to withdraw, shall be entitled to proceed having its full claim, defenses and rights and shall otherwise not be prejudiced by the terms of the

Joint Recommendation. The parties respectfully request that the Commission adopt this Joint Recommendation.

Dated this 7th day of October 1993

Anne Eakin
PacifiCorp

Richard J. Anderson
Dept of Natural Resources

Eric Blank
Environmental Intervenors

Division of Public Utilities

Committee of Consumer Svc

Exhibit 1

Formula for Calculation of Net Lost Revenue

For purposes of the Interim Policy 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. 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 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.

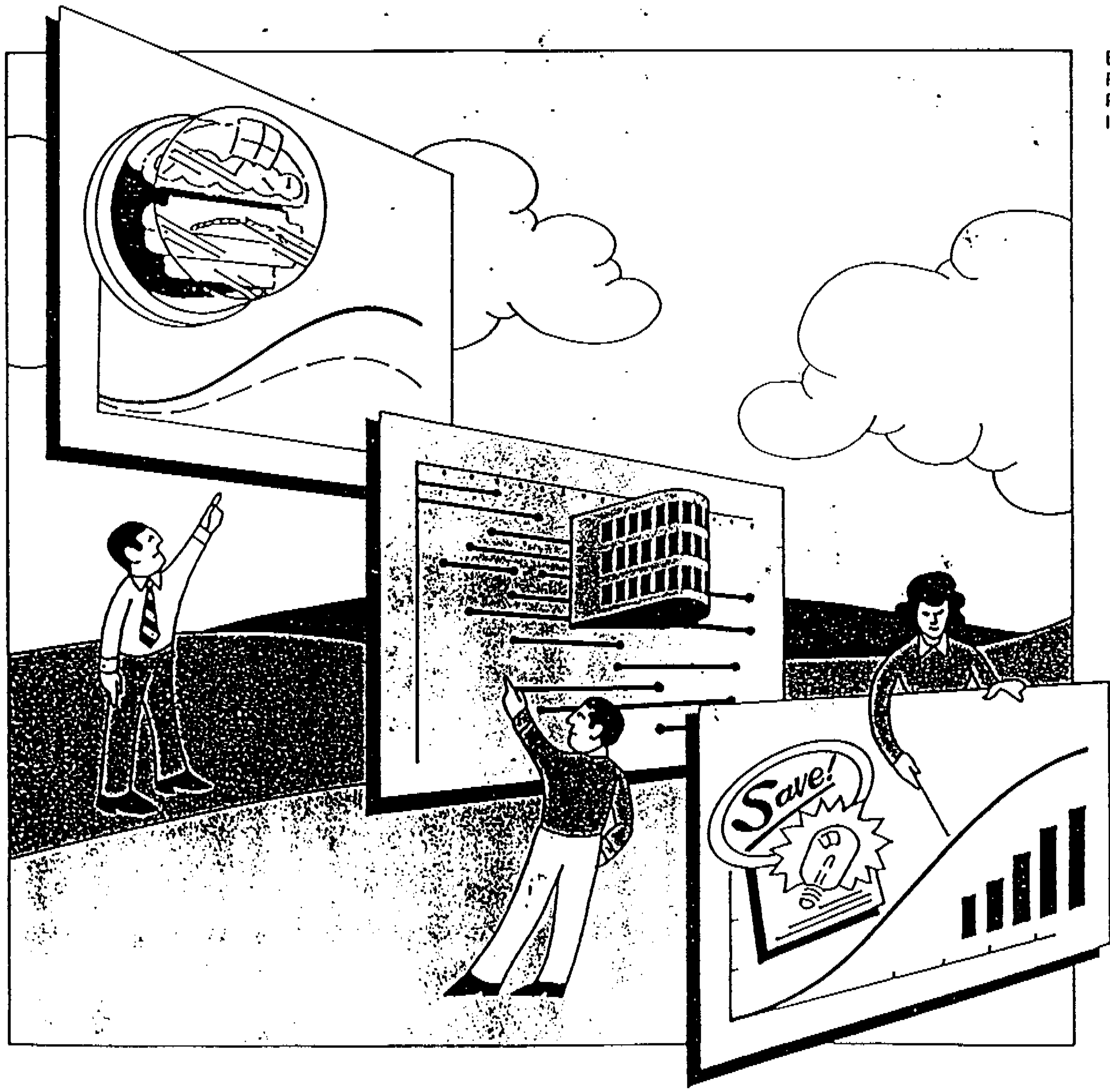
Note 1 Initial engineering analysis employed for purposes of NLR calculation will be those used contractually between the Company and the customer related to conservation savings. Such engineering analysis will be updated based on program evaluation. Some conservation measures do not involve a specific 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.

EPRI

Impact Evaluation of Demand-Side Management Programs

Volume 1: A Guide to Current Practice

Prepared by
RCG/Hagler, Bailly, Inc.
Boulder, Colorado



ELECTRIC
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Disturbance Term: A random (i.e., stochastic) variable which is used to explicitly capture all influences on the statistical model for which there are no data, as well as small errors in functional form.

DOE-2.1: A complex, hourly, building simulation program.

EER: Energy efficiency ratio: A commonly used means of rating the performance of small residential and commercial air conditioning equipment. Expressed in terms of BTU-per-hour output per watt of input power (mixed units).

Efficient: An estimator whose sampling distribution has the smallest variance.

End-use Metering: Direct measurement of electricity consumption for a specific end use, e.g., a refrigerator, at one house, building, or industrial process.

Endogenous: A term meaning the variable is determined within the model; hence, it is contemporaneously correlated with the disturbance term.

Energy: The amount of power (kW) used by a customer over a specified period of time. Measured in kilowatt-hours (kWh).

Energy Utilization Index: Energy use per unit of floor area.

Equipment Efficiency Rating: Measure of useful appliance energy to input energy includes EER, SEER, COP, kW/h and nominal load efficiency.

Equivalent Full Load Hours (EFLH): The number of hours of operation at full load by a cooling unit which results in the same energy consumption as a unit operating under its typical load profile.

Exogenous: A term meaning the variable is determined outside the model. Hence, it is contemporaneously uncorrelated with the disturbance term.

Expected Value: Weighted average of a random variable's possible values, where the weights are the associated probability. Equivalent to the mean of the variable.

Free Driver Savings: The decrease in energy consumption from customers who do not participate in the program, but where the utility's DSM efforts can be viewed as causing the savings. See **moving the market.**

Free Riders: Those individuals who would have undertaken the conservation actions promoted by the program, even if there were no program.

Natural Conservation: The energy conservation that participants would have undertaken had the program not been implemented.

NBECS: Nonresidential Buildings Energy Consumption Survey.

Net Impacts: The change in participants' electricity consumption which is directly attributable to the program.

Net-to-Gross Impacts: Indicates the degree of program induced behavior.

New Construction Programs: Programs designed to induce customers to use energy efficient practices when constructing a new building.

Normalized Annual Consumption: Annual electricity consumption that has been weather normalized for weather conditions.

Ordinary Least Squares: An estimation technique which minimizes the sum of squared residuals (i.e., the difference between the predicted value and the actual value of the dependent variable.)

Panel Data: Data for a group of customers over a period of time, also referred to as longitudinal data or pooled time-series/cross-sectional data.

Participation Bias: A bias which can occur if the savings estimates for a population are based on the savings of early DSM program participants, and the early participants are customers who will benefit the most from programs and this might not be representative of the population.

Payback: The period of time required for the energy savings to equal the cost of the conservation action. For example, if a conservation action costs $240 and saves $10 a month, the payback is 24 months.

Peak Demand: The greatest amount of demand that occurs during a specified time period.

Persistence: Refers to any decline in energy-saving effectiveness that may take place over a conservation measure's life. This is a function of both consumer behavior and equipment degradation.

Pre- and Post-Program Analysis: An analysis that compares data from before the program is implemented with data from after program implementation. Simple comparison or econometric techniques can be used to relate the two.

Response Bias: A bias which can occur when customers who respond to a survey do not complete all the questions and the non-respondents are systematically different for the respondents.

Retrofit Programs: Programs designed to induce customers to change their existing types of energy-using equipment for more efficient ones.

Sample: A sample is a subset of the population which exhibits characteristics of the population.

Sample Bias: A bias which results when the sample is not representative of the population.

Sampling Distribution: The probability distribution of an estimator or of a test statistic.

SC: Shading Coefficient -- The fraction of solar heat gain transmitted through a particular type of glass relative to single-thickness, double strength glass.

Sectional Variation: Variation in energy and use and weather response due to sector characteristics.

Selectivity Correction: This approach to correcting for self-selection bias views the bias as an omitted variables problem and corrects it by adding to the energy use equation an estimate of the omitted variable.

Self-Selection bias: Systematic differences between the control group and the participant group as revealed by the participants choosing to participate in the program and the control group choosing not to participate (i.e., the participation variable is endogenous.)

SIC: Standard industrial classification.

Simple Comparison: Comparing the mean energy consumption of a control group (or pre-participation consumption) to the mean energy consumption of participants.

Snap-back Effect: The argument that by undertaking conservation actions, customers perceive a lowered (relative) price for energy and, therefore, purchase more of the commodity in terms of comfort or appliance use. Also referred to as the tack-back or rebound effect. Includes the productivity effect.

Simulation Model: A type of model which incorporates a series of feed back or reaction loops which allows the model to capture the responses of consumers to price changes, technological innovation, and economic shifts.

Attachment B

FEB 11 1994

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH - Stoel Rives Boley Jones & Grey

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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 REPORT AND ORDER

ISSUED: February 10, 1994

SYNOPSIS

By this Order, the Public Service Commission of Utah approves a Joint Recommendation which establishes an interim policy for the regulatory treatment of PacifiCorp's demand-side resource activities.

Appearances:

Edward A. Hunter	For	PacifiCorp
Michael Ginsberg Assistant Attorney General	"	Division of Public Utilities
Kent Walgren Assistant Attorney General	"	Committee of Consumer Services
Steven F. Alder Assistant Attorney General	"	Office of Energy Resource Planning, Department of Natural Resources
Eric Blank	"	Land and Water Fund of the Rockies
William Evans	"	Utah Industrial Energy Consumers

By the Commission:

PROCEDURAL HISTORY

On February 12, 1993 the Commission issued an Order which closed Docket No. 92-2035-07 and accepted the Company's withdrawal of its petition for an accounting order authorizing its proposed accounting treatment for demand-side resources (DSR). New petitions for DSR cost recovery were ordered to be filed under this present docket. The order expressed the Commission's desire that this docket be investigative in nature. A collaborative process was initiated to analyze the relevant issues surrounding DSR and the implementation of the Company's IRP and to report findings and recommendations to the Commission. On March 8, 1993, a scheduling conference was held to discuss organizational issues. A series of eight collaborative technical conferences was held and a final report was submitted to the Commission on August 31, 1993.

On October 19, 1993, the Division of Public Utilities ("Division"), the Committee of Consumer Services ("Committee"), PacifiCorp, the Office of Energy and Resource Planning ("OER"), and the Environmental Intervenors filed an application with the Utah Public Service Commission ("Commission") seeking approval of a joint recommendation ("Joint Recommendation"). On November 17, 1993, the Utah Industrial Energy Consumer's ("UIEC") filed comments on the Joint Recommendation.

On November 23, 1993, a Technical Conference was held to provide interested parties with an opportunity to obtain information regarding the Joint Recommendation. On December 1, 1993, a hearing was held to consider the application for approval of the Joint Recommendation.

At the hearing, the Division, the Committee, PacifiCorp, OER and the Land and Water Fund for the Rockies presented testimony in support of the Joint Recommendation. No testimony was presented in opposition to the Joint Recommendation.

DISCUSSION WITH FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. PacifiCorp provides retail electric service in the states of California, Idaho, Montana, Oregon, Utah Washington and Wyoming. PacifiCorp operates as a public utility in the state of Utah and is subject to the Commission's jurisdiction.

2. The Commission has jurisdiction over the accounts and records of PacifiCorp pursuant to Utah Code Ann. Sect. 54-4-23 (1990).

3. The Joint Recommendation provides an interim approach for the regulatory treatment of PacifiCorp's demand-side resource ("DSR") activities in Utah. That interim approach involves: (a) the establishment of an accounting mechanism for the costs, including net lost revenues, incurred by PacifiCorp during calendar year 1994 for DSR activities in Utah; (b) the establishment of a formula and a procedure for the determination of net lost revenues ("NLR"); and (c) the establishment of a framework for the evaluation of the results of the interim approach and other DSR issues.

4. Under the Joint Recommendation's proposed accounting mechanism, the costs PacifiCorp incurs in 1994 for the evaluation, monitoring, and reporting of its DSR programs will be expensed as incurred, as will non-program specific advertising costs. PacifiCorp's remaining 1994 DSR program costs, including NLR, will be capitalized and will accrue carrying charges at PacifiCorp's current AFUDC rate until the amortization of those costs begins on January 1, 1995.

5. The Commission finds that the provisions of the Joint Recommendation's proposed accounting mechanism, including the carrying charge and amortization provisions of the proposed mechanism, are a reasonable and proper way to account for PacifiCorp's 1994 DSR costs, including its NLR, and the energy service charge payments it receives from customers during 1994. The proposed accounting mechanism provides PacifiCorp with appropriate direction regarding the accounting treatment for its 1994 DSR activities, while reserving prudence and rate recovery decisions for an appropriate case.

6. Under the NLR provisions of the Joint Recommendation, the Commission will determine, using the formula included in the Joint Recommendation, the amount of NLR incurred by PacifiCorp as a result of its DSR activities during 1994. That determination will be subject to a potential future adjustment by the Commission, based on evaluation and measurement results, of no more than 25

percent. The maximum amount of NLR cannot exceed $2,000,000.

7. The Commission has previously recognized that regulatory policy for DSR is in the formative stages in Utah. In our June 18, 1992, Order in Docket No. 90-2035-01, we stated:

> The Commission finds that currently there is no approved ratemaking treatment for DSR. Given the asymmetry of ratemaking treatment for DSR and the resulting uncertainty of cost recovery, the Commission questions whether the Company has sufficient financial incentive to pursue its IRP. Given the Commission's directive that DSR and SSR be treated on a comparable basis, the Commission finds that clarification of the regulatory treatment of DSR is necessary.

8. The NLR provisions of the Joint Recommendation provide the Commission and other interested parties with an opportunity to acquire data and experience which can be used to develop long-term DSR policy for this jurisdiction. The NLR provisions limit the dollar amount of NLR, provide for Commission determination of the amount of NLR and otherwise address, in a just and reasonable way, concerns regarding the regulatory treatment of PacifiCorp's 1994 NLR. The Commission finds that the Joint Recommendation'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.

9. The Joint Recommendation provides for the establishment of a new DSR cost-recovery collaborative ("Collaborative") to examine the results, both during and after calendar year 1994, of this interim cost-recovery approach to DSR. This Collaborative will replace the DSR Evaluation Task Force and the DSR Technical Conference/Collaborative. While the primary focus of this new Collaborative will be to examine the interim approach for regulatory treatment of PacifiCorp's Utah DSR programs, it will also address the other issues described in the Joint Recommendation.

10. The Joint Recommendation also provides for the retention, at PacifiCorp's expense, of a qualified consultant to provide an impartial review of PacifiCorp's measurement and evaluation of its DSR activities. The costs incurred by PacifiCorp for that consultant will, under the terms of the Joint Recommendation, be capitalized and will accrue a carrying charge at PacifiCorp's current AFUDC rate until amortization, over a five year period, beginning on January 1, 1995.

11. The Commission finds that the Collaborative task force and consultant approach proposed in the Joint Recommendation provides an appropriate way in which to proceed with the evaluation and analysis of the DSR issues identified in the Joint Recommendation. The Commission also finds that the Joint Recommendation's

proposed accounting treatment for consultant costs is reasonable and proper.

12. The Commission adopts the following schedule for the Collaborative reports identified in paragraph 4.4 of the Joint Recommendation:

(a) 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. If the Collaborative participants are unable to reach agreement on those issues, the report should identify the areas of agreement and disagreement.

(b) The Collaborative will submit a report to the Commission by March 31, 1995, which describes the results of the statistical recoupling experiment, the options regarding shared-savings and total factor productivity incentive programs, the price impact of DSR programs on non-participants, the development of performance standards and the results of the interim approach. The report will also make recommendations regarding the appropriate regulatory treatment for the DSR costs, including NLR, incurred by PacifiCorp in 1995. To the extent that the Collaborative participants are unable to reach agreement on those issues, the report should identify areas of agreement and disagreement.

(c) The Collaborative will submit a report to the Commission by December 31, 1995, which quantifies its final determination of the amount of NLR for 1994. That report may, of course, be submitted prior to that date and, to the extent that there are disagreements regarding the quantification, the areas of agreement and disagreement should be identified in the report.

13. In its comments, the UIEC requested that the Commission adopt its cost allocation proposal. The UIEC did not present any evidence to support its proposal. The Commission will defer cost allocation issues to a future appropriate case.

14. The Commission finds that the Joint Recommendation is just, reasonable and in the public interest and should be approved in its entirety.

ORDER

NOW, THEREFORE, IT IS HEREBY ORDERED that:

1. The Joint Recommendation is approved in its entirety.

2. The Division is directed to convene, no later than January 31, 1994, a new DSR cost-recovery Collaborative, as described in the Joint Recommendation, to examine the issues described in the Joint Recommendation and to submit reports, as described in this Order, regarding the results of their work to the Commission .

DATED at Salt Lake City, Utah, this 10th day of February, 1994.

/s/ Stephen F. Mecham, Chairman

/s/ James M. Byrne, Commissioner

(SEAL)

/s/ Stephen C. Hewlett, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary

Attachment C

Evaluation and Net Lost Revenue Subcommittee Appraisal of the Utah Demand-Side Management Cost Recovery Collaborative

Evaluation of Joint Recommendation*

	Evaluation Criterion	Rating (see key)
1.	Opportunity For Cost Recovery	+
2.	Align Incentives with IRP	+/0
3./ 4.	Incentive to operate Efficiently/Minimize Cost	+/0
5.	Reduce Disincentives From Lost Sales	+
6.	Positive Incentive	0
7.	Equitable Allocation of Cost and Benefits	0
8.	Appropriately Share Risk	+/0
9.	Promote Rate Stability	+/-
10.	Performance Based	+/-
11.	Understandable	+
12.	Predictable	+
13.	Potential for Unintended Consequences	+
14.	Measurable	+/0
15.	Administrable	+/-
16.	Discourage Micro-management	-
17.	Minimize impact on Evaluation	-
18.	Require Few Changes in Practice	+
19.	Discourage Manipulation	0
20.	Few Legal Restrictions	+

Key: + = Positive Impact; improves performance on criterion
O = Neutral Impact
- = Negative Impact; worsens performance on criterion
/ = Can include both impacts.

* - Based on the evaluation methodology used in Tables I, II. and III of the "Demand-Side Resource Collaborative Report" dated August 31, 1993

Evaluation and Net Lost Revenue Subcommittee Appraisal of 1994 Net Lost Revenue and Accounting Mechanism (Accounting Mechanism)

1. Does it provide the opportunity for recovery of prudently incurred DSR costs?

Evaluation: The Accounting Mechanism provides an opportunity for the recovery of most DSR program costs and a partial recovery of net lost revenue. As measured by this criterion the Joint Recommendation is a positive impact.

2. Does it align the Company's financial incentives with integrated resource planning?

Evaluation: The question addresses whether or not the Accounting Mechanism provides the Company with incentive to pursue an amount of DSM that produces the least total resource cost.

In 1994 the Company achieved 65,073 MWh (annualized)and 9.15 MW, exceeding the 40,000 MWh and 6 MW DSR acquisition target stated in the Accounting Mechanism. The 1994 DSR activity compares favorably with the RAMPP-3 action plan of 60,508 MWh.

The 1994 Accounting Mechanism did not provide the Company with incentive to pursue an amount of DSM that produces the least total resource cost as indicated in RAMPP-3. The Subcommittee presumes that this may be due to the fact that risk and uncertainty factors are not addressed by the 1994 Accounting Mechanism. Such factors, in addition to least cost principles, are taken into account by the Company in it's resource acquisition decision making process.

The Subcommittee concluded that the Accounting Mechanism removed at least some financial disincentives associated with integrated resource planning. As measured by this criterion the Accounting Mechanism could be either a neutral or a positive impact.

3. Does it give the Company an incentive to operate efficiently?

Evaluation: Efficiency is defined as minimizing the cost of producing the optimal level of output. Costs are defined as total resource cost as applied in integrated resource planning. Optimal level of output is that level of output where the marginal benefit of electric energy service is equal to the marginal cost of energy service.

The Accounting Mechanism, at least, partially removes the disincentives associated with integrated resource planning. By virtue of this removal of the disincentives, the Company is provided some incentive to operate efficiently as defined above. Therefore as measured by this criterion the Accounting Mechanism is a neutral or a positive impact.

4. Does it promote cost minimization?

Evaluation: Cost minimization is considered to be synonymous with "efficiency" as defined in item No. 3 above.

The Accounting Mechanism, at least, partially removes the disincentives associated with integrated resource planning, particularly net lost revenue. However, the Accounting Mechanism provides no explicit incentive for the Company to minimize it's acquisition costs for DSR. This is a weakness of the mechanism. Therefore as measured by this criterion the Accounting Mechanism is a neutral or a positive impact.

5. Does it reduce the disincentive associated with lost sales?

Evaluation: The terms of the Accounting Mechanism allow the Company to calculate and accrue net lost revenues from the month of installation through the end of the year. Amortization of accrued net lost revenue begins at the beginning of the next year and continues over the life of the conservation measure. Revenue lost as a result of conservation programs continue until rates are set in a future rate case. The net lost revenue feature of the Accounting Mechanism provides an opportunity for recovery of a portion of net lost revenue.

Therefore as measured by this criterion the Accounting Mechanism provides a potentially positive impact.

6. Does it provide a positive incentive to invest in DSR?

Evaluation: The Accounting Mechanism provides an opportunity to recover most program costs and some net lost revenues calculated during the year that the conservation measure was installed. The Accounting Mechanism provides no additional incentive or reward relative to investment in DSR as compared with SSR. Beyond this, the Accounting Mechanism provides no rate rider for the recovery of DSR costs, further diminishing it's ability to provide a positive incentive to invest in DSR. Therefore as measured by this criterion the Accounting Mechanism provides a neutral impact.

7. Is there equitable allocation of costs and benefits between classes of customers and between participants and non-participants?

Evaluation: The Accounting Mechanism cost recovery mechanism addresses the accounting treatment of DSR activities and does not address the issue of the cost/benefit allocation among classes of customers or between participants and non-participants. This criterion is not applicable and therefore provides a neutral impact.

8. Does it appropriately share risk between ratepayers and shareholders?

Evaluation: The Accounting Mechanism provides an opportunity for the recovery of most DSM program costs and some net lost revenue related to energy conservation measures installed during 1994. Therefore in the short-run the Accounting Mechanism facilitates risk sharing between ratepayers and shareholders. However the Accounting Mechanism does not address the appropriate level of risk sharing or the propriety of risk sharing which results from implementation of the mechanism. This criterion is only partially applicable to the Accounting Mechanism. Therefore, as related to the risk sharing provided by the cost recovery aspects of the Accounting

Mechanism the impact is positive. However as related to the propriety of the risk sharing, the impact is neutral.

9. Does it promote rate stability?

Evaluation: The Accounting Mechanism provides for the amortization of accrued program costs and net lost revenue over the life of the energy conservation measures. This amortization will be included in rates in the course of the ratemaking process in the next rate-case proceeding. The mechanism does not provide for a rate-rider related to DSR related costs. Therefore the mechanism minimizes volatile price swings. The Accounting Mechanism does not minimize upward pressure on rates. As this criterion relates to the volatility of price swings the Accounting Mechanism provides a positive impact. As this criterion relates to the upward pressure on rates created by DSR the Accounting Mechanism provides a negative impact.

10. Is it performance based?

Evaluation: The Accounting Mechanism provides a target for DSR accomplishment of 40,000 MWh on an annualized basis and 5.9 MW. There are no rewards or penalties in the mechanism for failure to meet the specified targets. To the extent that the target set as part of the Accounting Mechanism is the appropriate target based on IRP and DSR goals the Company is encouraged by the mechanism to achieve such level of DSR. To the extent that the Accounting Mechanism target is not the appropriate target the Company is not encouraged to achieve appropriate DSR levels. Therefore as measured by this criterion the Accounting Mechanism could be either a positive impact or a negative impact.

11. Is it understandable?

Evaluation: The Accounting Mechanism addresses issues related to the accounting and cost recovery of DSR program costs and the calculation of net lost revenue. The mechanism is considered readily understandable by all stakeholders. As measured by this criterion the Accounting Mechanism has a positive impact.

12. It predictable?

Evaluation: The experience of the Evaluation and Net Lost Revenue Subcommittee is that the Accounting Mechanism produces results that are reasonably predicable. Therefore as measured by this criterion the Accounting Mechanism has a positive impact.

13. Does it have the potential for unintended consequences?

Evaluation: The Evaluation and Net Lost Revenue Subcommittee determined that the Accounting Mechanism does not produce an outcome that is contrary to critical ratemaking goals. As measured by this criterion the Accounting Mechanism has a positive impact.

14. Is it measurable?

Evaluation: The Accounting Mechanism is measurable with respect to the calculation of net lost revenue. The net lost revenue as determined by the formula outlined in the Accounting Mechanism is easily calculated. However, various of the elements of the net lost revenue formula, such as the avoided cost element and the amount of conservation savings achieved, are not determined by precise quantification. Therefore as measured by this criterion the Accounting Mechanism could have either a positive of neutral impact.

15. Is it administrable?

Evaluation: It was concluded by the Evaluation and Net Lost Revenue Subcommittee that the accounting, reporting, cost recovery, and the net lost revenue aspects of the Joint agreement were reasonable administrable for utility managers and regulators. The aspects of the Accounting Mechanism relating to the monitoring of the Company's ongoing evaluation activities through the collaborative process was a time consuming process which appeared to be of questionable significance given the amount of DSR activity. As measured by this criterion the Accounting Mechanism has a positive and a negative impact.

16. Does it discourage micro-management?

Evaluation: Based on the experience of the Evaluation and Net Lost Revenue Subcommittee it was concluded that the collaborative process as established by the Accounting Mechanism does not discourage micro-management. Therefore as measured by this criterion the Accounting Mechanism has a negative impact.

17. Does it minimize impact on evaluation?

Evaluation: The experience of the Evaluation and Net Lost Revenue Subcommittee is that evaluation activity is critical to the calculation of net lost revenue as defined in the Accounting Mechanism. The Accounting Mechanism does not minimize the impact of evaluation activity. As measured by this criterion the Accounting Mechanism has a negative impact.

18. Does it require few changes in practice?

Evaluation: The Accounting Mechanism is considered to be easily incorporated into the existing regulation process. The mechanism is for 1994 only and therefore a new mechanism will need to be implemented for 1995 and beyond, however it is not anticipated that adversarial hearings will be required for the 1994 agreement or the new mechanism for after 1994. As measured by this criterion the Accounting Mechanism is a positive impact.

19. Does it discourage manipulation?

Evaluation: The terms of the Accounting Mechanism require a collaborative process to monitor the Company's DSR acquisition activity. This monitoring process has the effect of discouraging manipulation. However, the collaborative monitoring process proved to be time consuming and burdensome. Therefore as the benefit of discouraging manipulation was weighed against the burdensome nature of the collaborative process it was determined that as measured by this criterion the Accounting Mechanism has a neutral impact.

20. Are there few legal restrictions?

Evaluation: It was determined by the Evaluation and Net Lost Revenue Subcommittee that the Accounting Mechanism appears to present no legal constraints preventing its implementation or requiring legislative action to implement. Therefore as measured by this constraint the Accounting Mechanism has a positive impact.

Attachment D

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	)))))	<u>DOCKET NO. 92-2035-04</u> <u>FIRST REPORT, 1994</u> <u>JOINT RECOMMENDATION</u>

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 :

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

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.

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.

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.

Exhibit 1

Formula for Calculation of Net Lost Revenue

For purposes of the Interim Policy 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) = $(R - AC) \times (ES - LG)$

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. 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) = $(DC - ADC) \times (NCP_s - LGp)$

where:

- DC = Demand charge per kW for the customer class based on 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.

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

Attachment E

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UTAH ... SERVICE COMMISSION

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: January 13, 1995

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 UPDATE REPORT, 1994 JOINT RECOMMENDATION

ISSUED: January 13, 1995

SYNOPSIS

By this Report, the Utah Demand-Side Resource Cost Recovery Collaborative provides the Utah Commission with an update to the preliminary 1994 Net Lost Revenue report provided on November 30, 1994. This information is provided for Commission review and approval prior to PacifiCorp's January 18, 1995 booking of Net Lost Revenue to corporate accounts. The November 30, 1994 report and this update are provided pursuant to the February 10, 1994 Utah PSC Order approving the Demand Side Resource "Joint Recommendation" under Docket No. 92-2035-04, including the 1994 trial policy for DSR Cost Recovery.

Update to November 30, 1994 Report to the
<u>Utah Demand Side Resource Cost Recovery Collaborative</u>

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:

> 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:

> The Commission finds that the Joint Recommendation'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)

On November 30, 1994 the Division of Public Utilities for the Utah Demand Side Resources Cost Recovery Collaborative submitted to the Commission a report addressing the following issues:

- Projected amount of NLR for 1994
- DSR activities in Utah in 1994
- Inputs to NLR formula
- DSR measure lives for amortization purposes

This report provides updated information based on actual information and program evaluations available subsequent to the November 30, 1994 report. Also provided is the resolution of issues unresolved in the November 30, 1994 report.

<u>Projected amount of NLR for 1994</u>
Net Lost Revenue for 1994 is $386,909 based on 20,709 MWh of energy conservation savings (non-annualized). This NLR is the amount to which the 25% adjustment limit established in the Joint Recommendation will apply, except as noted below. Adjusted NLR for 1994 is not expected to exceed approximately $480,000 or be less than approximately $290,000. A detailed listing of 1994 DSR

projects in included as Attachment 1. The calculation of NLR is included as Attachment 2.

On December 30, 1994, the Company filed an application for approval of four conservation programs (Super Energy Efficient Refrigerator Program, Schedule 5 Showerheads, MagCorp, and Geneva (Phase II). These programs produced conservation savings which are included in 1994 NLR. The subcommittee determined that adjustments to these programs prior to Commission approval will be excluded from the 25% adjustment limit. Adjustments to these programs subsequent to Commission approval will be subject to the 25% adjustment limit.

DSR activities in Utah in 1994

PacifiCorp DSR activity for 1994, based on the best available engineering studies and program evaluations, is 65,073 MWh and 9.15 MW, exceeding the 40,000 MWh and 6 MW goals stated in the Joint Recommendation. The 1994 DSR activity also exceeded the Joint Recommendation goal of 20% of the RAMPP-3 DSR target in each customer class. Additionally, the Company's Utah DSR activity compares favorably with the Company's RAMPP III action plan for 1994 of 60,508 MWh.

Inputs to NLR formula

As described in the November 30, 1994, report agreement was not reached on the application of peak/off-peak differentiation in the "**AC**" (avoided energy cost) input to the NLR formula. It was described in the November 30th report, that peak/off-peak differentiation would not be applied in the determination of NLR, subject to the review of additional information on the variation in the system lambda between peak and off-peak periods. Such information was reviewed in the January 6, 1995 meeting of the Net Lost Revenue subcommittee. The information supported initial indications that NLR calculated with peak/off-peak differentiation was not materially different from NLR calculated without peak/off-peak differentiation. Since the available evidence did not support a conclusion that there is a significant difference between NLR computed with or without peak/off-peak avoided costs, it was concluded that for 1994 NLR peak/off-peak differentiation would not be applied. It was additionally determined that the issue of peak/off-peak differentiation would be revisited on an annual basis until a final method of cost recovery of DSR costs is adopted by the Commission.

The "**ES**" (energy savings) input to the NLR formula has been updated for November and December actual information available subsequent to the November 30th report. The "**ES**" input has also been updated for the result of program evaluation reports available subsequent to the November 30th report.

The "**LG**" (load growth) input to the NLR formula has been updated for load growth which was identified subsequent to the November 30th report.

The **"ADC"** (avoided demand cost) input to the NLR formula has been updated for November and December actual information available subsequent to the November 30th report.

The **"NCPs"** (non-coincident peak savings) input has been updated based on re-evaluation and change (from 48% to 87%) of the conservation load factor used to determine kW savings from the ECONS program and the Schedule 5 Showerhead program.

DSR measure lives for amortization
The information provided November 30, 1994 requires no update.

Attachment 1

PacifiCorp

Utah Jurisdiction 1994 DSR Projects

Line No.	Month of Installation	Program	ID	Sched.	Annualized Gross kWh	Load Growth	Annualized Net kWh	Conserv. Load Factor	kW
1	January	ECONS	9999	Schedule 1	748,243	0	748,243	87%	98
2	January	ECONS	9999	Schedule 5	1,117	0	1,117	87%	0
3	February	Comm. Finanswer	171	Sch. 6 (< 100 MWh)	32,399	50,000	(17,601)	60%	(3)
4	February	Commercial Spec.	3	Sch. 6 (> 100 MWh)	386,471	0	386,471	60%	74
5	February	Finanswer 12,000	499	Sch. 6 (< 100 MWh)	63,521	0	63,521	60%	12
6	February	Finanswer 12,000	465	Schedule 23	35,070	0	35,070	60%	7
7	March	ECONS	9999	Schedule 1	987,478	0	987,478	87%	130
8	March	ECONS	9999	Schedule 5	1,119	0	1,119	87%	0
9	March	Comm. Finanswer	159	Sch. 6 (< 100 MWh)	66,651	0	66,651		16
10	March	Comm. Finanswer	308	Sch. 6 (< 100 MWh)	514,711	0	514,711		359
11	March	Comm. Finanswer	153	Sch. 6 (< 100 MWh)	172,192	0	172,192		24
12	March	Comm. Finanswer	264	Sch. 6 (< 100 MWh)	168,167	0	168,167		49
13	March	Finanswer 12,000	128	Sch. 6 (< 100 MWh)	10,274	0	10,274		0
14	April	ECONS	9999	Schedule 1	1,294,284	0	1,294,284	87%	170
15	April	ECONS	9999	Schedule 5	2,720	0	2,720	87%	0
16	April	Comm. Finanswer	232	Sch. 6 (< 100 MWh)	90,626	0	90,626		12
17	April	Comm. Finanswer	193	Sch. 6 (< 100 MWh)	145,664	0	145,664		27
18	April	Finanswer 12,000	150	Schedule 9	21,000	0	21,000	60%	4
19	May	ECONS	9999	Schedule 1	963,011	0	963,011	87%	126
20	May	Comm. Finanswer	251	Schedule 23	99,538	0	99,538		7
21	May	Finanswer 12,000	145	Schedule 23	12,242	0	12,242		0
22	June	ECONS	9999	Schedule 1	1,597,963	0	1,597,963	87%	210
23	June	Comm. Finanswer	160	Sch. 6 (> 100 MWh)	399,142	0	399,142		62
24	June	Comm. Finanswer	200	Sch. 6 (< 100 MWh)	125,163	0	125,163		23
25	July	ECONS	9999	Schedule 1	318,395	0	318,395	87%	42
26	July	Sch. 5 Water Kits	9999	Schedule 5	1,154,839	0	1,154,839	78%	169
27	July	Comm. Finanswer	225	Sch. 6 (< 100 MWh)	105,204	0	105,204		67
28	July	Comm. Finanswer	283	Sch. 6 (> 100 MWh)	1,317,100	0	1,317,100		315
29	July	Indus. Finanswer	181	Schedule 9	1,432,000	0	1,432,000		225
30	July	Major Accounts	9998	Contract 1	4,436,000	0	4,436,000		400
31	August	ECONS	9999	Schedule 1	1,432,520	0	1,432,520	87%	188
32	August	Comm. Finanswer	255	Sch. 6 (< 100 MWh)	51,125	0	51,125		14
33	August	Major Accounts	9998	Contract 1	5,316,000	0	5,316,000		607
34	September	ECONS	9999	Schedule 1	1,658,473	0	1,658,473	87%	218
35	September	Comm. Finanswer	298	Sch. 6 (< 100 MWh)	166,327	0	166,327		39
36	September	Indus. Finanswer	197	Schedule 39	181,743	0	181,743		23
37	September	Major Accounts	9998	Contract 1	4,015,000	0	4,015,000		544
38	September	Major Accounts	9997	Contract 2	20,411,000	0	20,411,000		3,100
39	October	ECONS	9999	Schedule 1	199,944	0	199,944	87%	26
40	October	ECONS	9999	Schedule 5	14,302	0	14,302	87%	2
41	October	Comm. Finanswer	215	Sch. 6 (> 100 MWh)	413,185	0	413,185		81
42	October	Comm. Finanswer	162	Sch. 6 (< 100 MWh)	151,270	0	151,270		174
43	November	ECONS	9999	Schedule 1	538,712	0	538,712	87%	71
44	November	ECONS	9999	Schedule 5	3,883	0	3,883	87%	1
45	November	Comm. Finanswer	313	Sch. 6 (< 100 MWh)	68,434	0	68,434		12
46	November	Comm. Finanswer	310	Sch. 6 (< 100 MWh)	267,184	0	267,184		81
47	November	Comm. Finanswer	146	Sch. 6 (< 100 MWh)	74,815	0	74,815		28
48	December	SERP	9993	Schedule 1	70,372	0	70,372	100%	8
49	December	Low Income - Shell	9994	Schedule 1	76,500	0	76,500	100%	9
50	December	Low Income - Showerheads		Schedule 1	6,270	0	6,270	61%	1
51	December	Low Income - Lights	9996	Schedule 1	1,600	0	1,600	100%	0
52	December	Major Accounts	9998	Contract 1	10,909,000	0	10,909,000		548
53	December	Indus. Finanswer	181	Schedule 9	141,000	0	141,000		28
54	December	Finanswer 12,000	148	Sch. 6 (< 100 MWh)	113,826	0	113,826	60%	22
55	December	Finanswer 12,000	159	Sch. 6 (< 100 MWh)	84,100	0	84,100	60%	16
56	December	Comm. Finanswer	185	Sch. 6 (< 100 MWh)	394,425	0	394,425		117
57	December	Comm. Finanswer	172	Sch. 6 (< 100 MWh)	394,425	0	394,425		117
58	December	Comm. Finanswer	218	Sch. 6 (< 100 MWh)	250,396	0	250,396		87
59	December	Comm. Finanswer	219	Sch. 6 (< 100 MWh)	186,955	0	186,955		93
60	December	Comm. Finanswer	229	Sch. 6 (> 100 MWh)	827,481	0	827,481		271

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	0.10	0.00	0.00	0.10	$33,795
2	FEBRUARY	0	467	0	467	0.00	0.09	0.00	0.09	11,099
3	MARCH	989	932	0	1,921	0.13	0.45	0.00	0.58	77,000
4	APRIL	1,297	257	0	1,554	0.17	0.04	0.00	0.21	47,576
5	MAY	963	112	0	1,075	0.13	0.01	0.00	0.13	29,135
6	JUNE	1,598	524	0	2,122	0.21	0.09	0.00	0.30	44,649
7	JULY	1,473	1,422	5,868	8,764	0.21	0.38	0.63	1.22	62,072
8	AUGUST	1,433	51	5,316	6,800	0.19	0.01	0.61	0.81	37,443
9	SEPTEMBER	1,658	166	24,608	26,433	0.22	0.04	3.67	3.92	19,329
10	OCTOBER	214	564	0	779	0.03	0.26	0.00	0.28	8,268
11	NOVEMBER	543	410	0	953	0.07	0.12	0.00	0.19	5,759
12	DECEMBER	155	2,252	11,050	13,456	0.02	0.72	0.58	1.32	10,784
13	TOTAL	11,072	7,159	46,842	65,073	1.47	2.21	5.48	9.15	$386,909
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				163%				153%	

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

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 ($) (1)													
1	Schedule 1	1,501	2,783	5,012	10,227	16,552	21,689	19,200	21,588	28,953	34,333	37,828	38,469	238,135
2	Schedule 5	2	4	6	13	20	20	1,553	2,997	3,351	3,663	3,953	3,852	19,434
3	Sch. 6 (< 100 MWh)	0	51	2,410	5,109	5,910	5,858	3,952	4,055	5,184	7,091	9,477	14,139	63,236
4	Sch. 6 (> 100 MWh)	0	356	963	999	1,138	1,525	2,460	3,553	4,258	5,342	6,249	8,729	35,572
5	Schedule 9	0	0	0	18	45	39	475	824	1,281	1,664	1,965	2,031	8,342
6	Schedule 23	0	37	104	102	239	354	239	215	221	252	325	358	2,446
7	Schedule 39	0	0	0	0	0	0	0	0	123	77	77	77	354
8	Contract 1	0	0	0	0	0	0	215	347	3,825	7,474	10,327	12,395	34,583
9	Contract 2	0	0	0	0	0	0	0	0	(5,362)	(5,517)	(1,287)	(3,022)	(15,188)
10	TOTAL	1,503	3,231	8,495	16,468	23,904	29,485	28,094	33,579	41,834	54,379	68,914	77,028	386,914
	TOTAL NET LOST REVENUES BY MONTH OF INSTALLATION ($) (2)													
11	JANUARY	1,503	2,786	3,023	3,215	3,532	3,392	2,503	2,442	2,655	2,826	2,993	2,925	33,795
12	FEBRUARY	0	444	1,192	1,229	1,387	1,316	739	700	848	1,014	1,114	1,116	11,099
13	MARCH	0	0	4,280	8,939	9,767	9,356	6,372	6,214	7,155	8,072	8,471	8,374	77,000
14	APRIL	0	0	0	3,085	6,825	6,581	4,731	4,589	5,035	5,388	5,719	5,623	47,576
15	MAY	0	0	0	0	2,394	4,600	3,388	3,291	3,562	3,800	4,079	4,021	29,135
16	JUNE	0	0	0	0	0	4,241	6,061	5,898	6,501	7,039	7,530	7,379	44,649
17	JULY	0	0	0	0	0	0	4,299	7,804	10,236	12,222	14,060	13,451	62,072
18	AUGUST	0	0	0	0	0	0	0	2,640	7,059	8,483	9,915	9,346	37,443
19	SEPTEMBER	0	0	0	0	0	0	0	0	(1,218)	3,960	9,412	7,175	19,329
20	OCTOBER	0	0	0	0	0	0	0	0	0	1,575	3,343	3,350	8,268
21	NOVEMBER	0	0	0	0	0	0	0	0	0	0	2,277	3,482	5,759
22	DECEMBER	0	0	0	0	0	0	0	0	0	0	0	10,784	10,784
23	TOTAL	1,503	3,230	8,495	16,468	23,905	29,486	28,093	33,578	41,833	54,379	68,913	77,026	386,909

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 ($) (1)													
1	Schedule 1	1,501	3,077	5,012	10,227	16,552	22,570	21,314	24,024	30,455	34,333	37,828	38,469	245,362
2	Schedule 5	2	4	6	13	20	20	1,790	3,470	3,588	3,663	3,953	3,852	20,381
3	Sch. 6 (< 100 MWh)	0	27	466	1,133	1,771	2,334	888	767	881	1,033	1,683	2,573	13,556
4	Sch. 6 (> 100 MWh)	0	154	338	374	512	784	802	1,004	1,078	1,189	1,754	1,943	9,932
5	Schedule 9	0	0	0	7	21	21	117	121	258	320	621	522	2,008
6	Schedule 23	0	28	65	63	181	297	201	177	164	175	248	281	1,880
7	Schedule 39	0	0	0	0	0	0	0	0	100	0	0	0	100
8	Contract 1	0	0	0	0	0	0	(399)	(1,813)	(1,892)	(1,630)	1,223	74	(4,437)
9	Contract 2	0	0	0	0	0	0	0	0	(6,385)	(11,903)	(7,673)	(9,408)	(35,369)
10	TOTAL	1,503	3,290	5,887	11,817	19,057	26,026	24,713	27,750	28,247	27,180	39,637	38,306	253,413
	DEMAND NET LOST REVENUES ($) (2)													
11	Schedule 1	0	(294)	0	0	0	(881)	(2,114)	(2,436)	(1,502)	0	0	0	(7,227)
12	Schedule 5	0	0	0	0	0	0	(237)	(473)	(237)	0	0	0	(947)
13	Sch. 6 (< 100 MWh)	0	24	1,944	3,976	4,139	3,525	3,064	3,288	4,302	6,059	7,794	11,566	49,681
14	Sch. 6 (> 100 MWh)	0	202	625	625	625	740	1,658	2,548	3,180	4,153	4,495	6,785	25,636
15	Schedule 9	0	0	0	12	23	18	358	703	1,024	1,344	1,344	1,509	6,335
16	Schedule 23	0	9	39	39	58	57	38	38	57	77	77	77	566
17	Schedule 39	0	0	0	0	0	0	0	0	22	77	77	77	253
18	Contract 1	0	0	0	0	0	0	614	2,160	5,717	9,104	9,104	12,321	39,020
19	Contract 2	0	0	0	0	0	0	0	0	1,023	6,386	6,386	6,386	20,181
20	TOTAL	0	(59)	2,608	4,652	4,845	3,459	3,381	5,828	13,586	27,200	29,277	38,721	133,498

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	9,893.8	31.2	62.4	103.5	198.6	292.6	399.3	479.2	552.1	680.9	758.4	789.1	821.2	5,168.5
2	Schedule 5	1,178.0	0.0	0.1	0.1	0.3	0.4	0.4	48.5	96.7	96.7	97.2	98.0	98.2	536.7
3	Sch. 6 (< 100 MWh)	3,647.9	0.0	2.2	42.0	79.9	92.1	121.6	124.2	124.1	119.2	130.1	158.7	270.5	1,264.6
4	Sch. 6 (> 100 MWh)	3,343.4	0.0	15.1	36.1	30.4	29.8	45.8	144.1	216.7	185.9	188.0	197.4	248.1	1,337.4
5	Schedule 9	1,594.0	0.0	0.0	0.0	0.8	1.6	1.6	61.4	121.1	121.0	121.1	121.1	127.2	676.9
6	Schedule 23	146.9	0.0	1.4	3.3	2.8	6.5	10.6	12.6	11.9	10.1	10.5	12.8	15.3	97.6
7	Schedule 39	181.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.0	0.0	0.0	0.0	22.0
8	Contract 1	24,676.0	0.0	0.0	0.0	0.0	0.0	0.0	184.8	591.2	980.0	1,147.3	1,147.3	1,601.8	5,652.3
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	1,297	49	98	163	313	461	629	755	870	1,073	1,195	1,279	1,297	
11	Schedule 5	172	0	0	0	0	0	0	85	169	169	170	172	172	
12	Sch. 6 (< 100 MWh)	1,386	0	5	233	477	496	508	553	593	620	726	934	1,386	
13	Sch. 6 (> 100 MWh)	803	0	37	74	74	74	105	294	451	451	492	532	803	
14	Schedule 9	257	0	0	0	2	4	4	117	229	229	229	229	257	
15	Schedule 23	14	0	4	7	7	11	14	14	14	14	14	14	14	
16	Schedule 39	23	0	0	0	0	0	0	0	0	12	23	23	23	
17	Contract 1	2,099	0	0	0	0	0	0	200	704	1,279	1,551	1,551	2,099	
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.

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								0.00	0.00
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	0.00	0.00
	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	0.00	0.00
15	Schedule 5	0.00	(3.00)	0.00	0.00	0.00	(1.40)	(2.80)	(2.80)	(1.40)	0.00	0.00	0.00
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	8.35	8.35
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	8.45	8.45
18	Schedule 9	5.87	2.87	5.87	5.87	5.87	4.47	3.07	3.07	4.47	5.87	5.87	5.87
19	Schedule 23	5.50	2.50	5.50	5.50	5.50	4.10	2.70	2.70	4.10	5.50	5.50	5.50
20	Schedule 39	3.33	0.33	3.33	3.33	3.33	1.93	0.53	0.53	1.93	3.33	3.33	3.33
21	Contract 1	5.87	2.87	5.87	5.87	5.87	4.47	3.07	3.07	4.47	5.87	5.87	5.87
22	Contract 2	2.06	(0.94)	2.06	2.06	2.06	0.66	(0.74)	(0.74)	0.66	2.06	2.06	2.06

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 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	199,944	0	199,944	87%	26	$1,956	(5)
36	October	ECONS	(1)	Residential	Schedule 5	14,302	0	14,302	87%	2	$117	(5)
37	October	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	151,270	0	151,270		174	$3,873	(6)
38	October	Comm. Finanswer	(3)	Commercial	Sch. 6 (> 100 MWh)	413,185	0	413,185		81	$2,322	(6)
39	November	ECONS	(1)	Residential	Schedule 1	538,712	0	538,712	87%	71	$3,179	(6)
40	November	ECONS	(1)	Residential	Schedule 5	3,883	0	3,883	87%	1	$19	(6)
41	November	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	410,433	0	410,433		121	$2,561	(7)
42	December	Low Income	(11)	Residential	Schedule 1	84,370	0	84,370	87%	10	$314	(6)
43	December	SERP	(12)	Residential	Schedule 1	70,372	0	70,372	100%	8	$137	(6)
44	December	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	1,226,201	0	1,226,201		414	$3,982	(6)
45	December	Comm. Finanswer	(3)	Commercial	Sch. 6 (> 100 MWh)	827,481	0	827,481		271	$2,524	(6)
46	December	Finanswer 12,000	(3)	Commercial	Sch. 6 (< 100 MWh)	197,926	0	197,926	60%	38	$400	(6)
47	December	Indus. Finanswer	(3)	Industrial	Schedule 9	141,000	0	141,000		28	$188	(6)
48	December	Major Accounts	(4)	Industrial	Contract 1	10,909,000	0	10,909,000		548	$3,238	(6)
	PROGRAM SUMMARY											
49		ECONS	(1)	Residential		9,762,164	0	9,762,164		1,282	$237,978	
50		Sch. 5 Water Kits	(2)	Residential		1,154,839	0	1,154,839		169	$19,138	
51		Low Income	(11)	Residential		84,370	0	84,370		10	$314	
52		SERP	(12)	Residential		70,372	0	70,372		8	$137	
53		Comm. Finanswer	(3)	Commercial		6,482,579	50,000	6,432,579		2,072	$89,101	
54		Commercial Spec.	(4)	Commercial		386,471	0	386,471		74	$9,028	
55		Finanswer 12,000	(3)	Commercial		340,033	0	340,033		61	$3,369	
56		Indus. Finanswer	(3)	Industrial		1,754,743	0	1,754,743		276	$8,448	
57		Major Accounts	(4)	Industrial	Contract 1	24,678,000	0	24,678,000		2,099	$34,583	
58		Major Accounts	(4)	Industrial	Contract 2	20,411,000	0	20,411,000		3,100	($15,188)	
59		TOTALS				65,122,571	50,000	65,072,571		9,151	$386,908	

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.
(11) The Company provides a rebate for the installation of energy efficient measures in low income homes.
(12) The SERP program was directed at the design and marketing of refrigerators that are between 25% and 50% more efficient than 1993 government standards.

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	87%	98	$33,751	(5)
2	January	ECONS	(1)	Residential	Schedule 5	1,117	0	1,117	87%	0	$44	(5)
3	February	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	32,399	50,000	(17,601)	60%	(3)	($415)	(6)
4	February	Commercial Spec.	(4)	Commercial	Sch. 6 (> 100 MWh)	386,471	0	386,471	60%	74	$9,028	(6)
5	February	Finanswer 12,000	(3)	Commercial	Sch. 6 (< 100 MWh)	63,521	0	63,521	60%	12	$1,541	(7)
6	February	Finanswer 12,000	(3)	Commercial	Schedule 23	35,070	0	35,070	60%	7	$947	(7)
7	March	ECONS	(1)	Residential	Schedule 1	987,478	0	987,478	87%	130	$36,890	(5)
8	March	ECONS	(1)	Residential	Schedule 5	1,119	0	1,119	87%	0	$36	(5)
9	March	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	921,721	0	921,721		448	$39,982	(6)
10	March	Finanswer 12,000	(3)	Commercial	Sch. 6 (< 100 MWh)	10,274	0	10,274		0	$90	(7)
11	April	ECONS	(1)	Residential	Schedule 1	1,294,284	0	1,294,284	87%	170	$42,966	(5)
12	April	ECONS	(1)	Residential	Schedule 5	2,720	0	2,720	87%	0	$79	(5)
13	April	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	236,290	0	236,290		39	$4,285	(6)
14	April	Finanswer 12,000	(3)	Commercial	Schedule 9	21,000	0	21,000	60%	4	$245	(7)
15	May	ECONS	(1)	Residential	Schedule 1	963,011	0	963,011	87%	126	$27,637	(5)
16	May	Comm. Finanswer	(3)	Commercial	Schedule 23	99,538	0	99,538		7	$1,354	(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	87%	210	$38,469	(5)
19	June	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	125,163	0	125,163		23	$1,706	(6)
20	June	Comm. Finanswer	(3)	Commercial	Sch. 6 (> 100 MWh)	399,142	0	399,142		62	$4,475	(6)
21	July	ECONS	(1)	Residential	Schedule 1	318,395	0	318,395	87%	42	$6,412	(5)
22	July	Sch. 5 Water Kits	(2)	Residential	Schedule 5	1,154,839	0	1,154,839	78%	169	$19,138	(5)
23	July	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	105,204	0	105,204		67	$3,078	(6)
24	July	Comm. Finanswer	(3)	Commercial	Sch. 6 (> 100 MWh)	1,317,100	0	1,317,100		315	$17,222	(6)
25	July	Indus. Finanswer	(3)	Industrial	Schedule 9	1,432,000	0	1,432,000		225	$7,908	(8)
26	July	Major Accounts	(4)	Industrial	Contract 1	4,436,000	0	4,436,000		400	$8,313	(5)
27	August	ECONS	(1)	Residential	Schedule 1	1,432,520	0	1,432,520	87%	188	$24,129	(5)
28	August	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	51,125	0	51,125		14	$651	(6)
29	August	Major Accounts	(4)	Industrial	Contract 1	5,316,000	0	5,316,000		607	$12,663	(5)
30	September	ECONS	(1)	Residential	Schedule 1	1,658,473	0	1,658,473	87%	218	$22,294	(5)
31	September	Comm. Finanswer	(3)	Commercial	Sch. 6 (< 100 MWh)	166,327	0	166,327		39	$1,501	(6)
32	September	Indus. Finanswer	(3)	Industrial	Schedule 39	181,743	0	181,743		23	$352	(8)
33	September	Major Accounts	(4)	Industrial	Contract 1	4,015,000	0	4,015,000		544	$10,369	(5)
34	September	Major Accounts	(4)	Industrial	Contract 2	20,411,000	0	20,411,000		3,100	($15,188)	(5)

RESULTS OF PACIFICORP'S
UTAH SCHEDULE 5
HOME ENERGY SURVEY

December 12, 1994

PACIFICORP

UTAH SCHEDULE 5
HOME ENERGY SURVEY

Background

In March 1994, PacifiCorp designed a mail survey for their Utah Schedule 5 customers to determine this customer class's energy use patterns and conservation needs. The survey was sent out on April 1, 1994 to a total of 6,538 customers. Upon completion and return of the survey, the customer was sent a "Water Smart Kit", which contained one low flow showerhead, 2 faucet aerators, and various adapters. The cut-off date was stated as May 2, 1994 with a promise to deliver these kits within 4 to 6 weeks.

The response to this saving was very positive, with 40% of the customers responding (2,646 surveys returned). Some customers mailed the surveys after the May 2 deadline and the water kits were provided to these customers as well.

Sample Representativeness

Typically, mail surveys result in response bias, since those customers that respond to the survey have an interest in the topic. In this case, it could be expected that those individuals that responded to this survey are more likely to conserve, and/or they are more concerned with their energy use, both indicated by their request for a conservation kit. To test whether these customers were systematically different from one another with respect to energy use, the average annual use of the population of respondents was compared to the average annual use of the non-respondents. A student t-test was used to make the comparison:

$$t = \frac{AU_R - AU_{NR}}{\sqrt{\frac{SE_R^2}{n_r} + \frac{SE_{NR}^2}{n_{nr}}}}$$

where

AU_R	=	annual use of respondent;
AU_R	=	annual use of non-respondent;
SE_R	=	standard error of respondent;
SE_{NR}	=	standard error of non-respondent;
n_R	=	number of respondents; and
n_{nr}	=	number of non-respondents.

Table 1 (page 7) shows this computation. As this table demonstrates, the t-test shows the statistical difference between the two population means is 6.35, which is greater than the critical value of 1.96 at the 95% confidence level for a 2 tailed test. That is, the two population averages are statistically different, thus the sample of respondents is different with regard to usage (use approximately 10% less electric energy) of the population of Schedule 5 customers.

The total number of Schedule 5 customers at the time of this analysis varied from that at the time the surveys were mailed since these customers are moved from Schedule 5 to Schedule 1 whenever there is tenant turnover or at the customers' request, or automatically if their billing analysis shows they will do better on Schedule 1.

Deemed Savings

The savings assumed from these "Water Smart Kits" are summarized below:

- Faucet Aerator 150 kWh each; and
- Low Flow Showerhead 381 kWh each.

Given there were two faucet aerators in each kit, the total savings from the kit is assumed to be 681 kWh. These savings are based upon estimated deemed savings developed for the ECONs multi-family water heater program. This estimate may be low as water savings from a multi-family unit are expected to be less than a single family unit since single family homes usually have more occupants and could have heaters in unconditioned spaces. Using the results of their Oregon Showerhead Giveaway program, an installation rate of 70% was assumed, equating to an expected value of 477 kWh per kit mailed. This estimate may be a conservative estimate as the 70% is based on a mailing to a group of customers that were not required to respond to a survey to receive the showerhead. That is, since these customers actually requested these kits, it is likely that more than 70% installed these measures.

Comparison to Energy Decisions

The first phase in this analysis reviewed results from Energy Decisions regarding Schedule 5 customers in Utah. This survey showed that, on average, Schedule 5 customer 5 had higher incomes and bigger homes than Schedule 1 customers. Further, this survey revealed that Schedule 5 homes were typically occupied all the time and these customers' energy use was 3 times higher than Schedule 1 customers. Although Schedule 5 was designed for customers with all electric homes, only 66% of the Schedule 5 customer base that responded to the Energy Decision Survey used electricity to heat their homes with an additional 19% using wood.

Demographics of Survey Respondents

A review of the demographic information provided by surveys respondents revealed:

- 95% of the respondents were owners, with 97% of single family homes being owner occupied;

- 87% of respondents were single family homes.

- Average family sizes was 4.3 with the average size for a single family home being slightly higher at 4.4.

- Most homes were built after 1971 with the average age of these homes being 20 years; and

- 46% of the respondents were from larger homes (homes greater than 2,000 sqft) with that same percentage applying to single family homes over 2,000 sqft.

Table 2 (page 8) summarizes these customers demographics by building type and in total.

Heat and Cooling

Customers were asked a series of 5 questions regarding their heating and cooling systems and their use of these systems. These respondents indicated that they keep their home rather cool with an average setting of 67.3^0 F. Further, they typically lowered their thermostats at night since the average night time setting was 63.9^0 F, a change of 3.4 degrees. Table 3 (page 9) shows these average thermostat settings by building type, renter versus owner, and family size.

The typical heating source for these respondents was electric heat (74% of respondents), with slightly more single family homes being heated electrically (83%). The most common electric heating system was electric ceiling cable, with baseboard or wall units being the second most popular. Of the secondary heat sources mentioned, wood was the most common. Table 4 (page 10) summarizes these results.

Only 69% of all respondents have cooling systems, with the most popular cooling system being a swamp cooler (40% with cooling, 28% of the population). The second most popular cooling system was a heat pump, with 14% of respondents with cooling reporting this type of system (10% of the population). Table 4 also summarizes these results.

Appliance Use

Appliance Use

The survey asked questions about each customer's appliance inventory, to include refrigerators, freezers, ovens and ranges, dishwashers, clothes washer and dryer, and water heater. The survey also addressed whether or not the customer had an extra energy user, such as a water pump, and the type of electronic equipment in the house. Most of the respondents (64%) had newer refrigerators (less than 7 years old), were between 16 and 20 cubic feet (65%), and were frost free (91%). Only 26% of respondents had second refrigerators. These results are shown in Table 5 (page 11).

A total of 64% of the respondents had separate freezers with 17% having at least 2 freezers. Table 6 (page 12) summarizes these findings. Of these respondents 57% reported they preferred upright freezers to chest type freezers, were between 16 and 20 cubic feet (52%), and were less than 7 years old (86%).

Almost all respondents (98%) had electric ranges, ovens, and microwaves (97%). Most of these customers use their cooking elements less than one hour per week, while 70% use their oven for 4 hours or less per week. Customers also reported they use their microwaves at least 30 minutes per day (79%). Table 7 (page 13) demonstrates these results.

Most customers responding stated they owned a clothes washer and used warm or hot water to wash clothes (92%). Further, 98% reported they had clothes dryers, with 94% of those, or 92% of the population, being electric dryers. Respondents also reported an average of 7 loads of wash per week in warm or hot water, with single family home owners washing 8 loads per week in warm or hot water. Also, respondents used their dryer for an average of 9 loads per week. Table 8 (page 14) summarizes these results.

Table 9 (page 15) shows the results of survey questions regarding each respondents water heating system and use. Only 14% of these respondents reported having more than one water heater, with 84% of the primary water heaters being electric and 71% of the second water heaters being electric. Also, most water heaters were larger, with 78% of the primary water heater being larger than 40 gallons.

Respondents were also asked about dishwasher use, with 77% reporting they owned and used their dishwasher an average of 5 times a week. Also, all homes owned a color TV, which was used only 3 hours per day. A total of 92% of respondents owned VCRs and operated them 6 hours per day. 82% owned CD/stereos and operated this equipment 10 hours per week. Only 49% of respondents or 53% of single family home owners owned computers, and the average run time for these computers was 10 hours per week for all, but only 4 hours per week for single family home owners. Table 10 summarizes the results of the survey regarding other appliances.

Finally, respondents were asked about the most commonly used small appliances. Their small appliances used more than 4 times a week are:

- Hair dryers (69%);
- Curling irons (60%);
- Toasters (70%); and
- Vacuum cleaners (75%).

Also, only 24% of respondents reported having a domestic water pump. Table 11 (page 17) shows these survey results.

With respect to lighting use, the majority of respondents (98%) used 100 watt bulbs, or less. A total of 60% of these respondents used indoor lighting for at least 6 hours per day, with less than half (43%) having outdoor security lighting. Also, 75% have fluorescent fixtures, with 92% of these respondents using at least 40 watt bulbs. Table 12 (page 18) presents these results.

Energy Conservation Equipment

Customers were also asked about the existing energy conservation equipment in their homes. Most (74%) stated they had at least double pane windows, almost half (46%) have metal insulated doors while an additional 33% have solid core wood doors. Also, almost all (93%) stated they had wall insulation. Also, only 25% of homes have crawl spaces under their floors, but only 24 % have 10 inches or more of insulation (70% with 6 inches or more). Only 19% of homes have plastic ground covers. Also, almost all respondents reported ceiling insulation (98%) with 99% of single family homes having ceiling insulation. Most of these respondents reported having loose fill insulation (73%), with a slightly higher percentage for single family homes (73%). However only 14% of respondents, and only 12% of single family home owner, reported insulation greater than 13 inches. These findings have been summarized in Table 13 (page 19).

Energy savings measure related to hot water use were also addressed. Only half (56%) of respondents had water heaters in conditioned spaces. Further, few (27%) reported insulation blankets on their water heater, 27% reported owning low-flow showerheads, and a third (37%) stated they installed faucet aerators. These findings are reported in Table 14 (page 20).

Conclusions

The conclusions that can be drawn from this survey include:

- Most respondents perceive these homes to be energy efficient, with 98% reporting they had wall insulation, 73% reporting energy efficient windows, and 69% reporting floor insulation if applicable (not a slab floor).

- Respondents may be more energy aware, represented by the lower average annual use of these customers and their expressed interest in receiving a "Water Smart Kit".

- Water use may be high, as indicated by the number of occupants (more than 4 on average) versus 2.3 people per household in Oregon.

- Few respondents used electric water heaters effectively, with only 56% of the customers reporting their water heater was in a conditioned space and only 27% stating they had an insulation blanket on their water heater.

- Few respondents conserved water, with only 27% reporting low flow showerheads and 37% reporting faucet aerators.

- Weatherization measures are not likely to have a significant effect for respondents and the effect is unknown for non-respondents.

- There is a need for additional information regarding possible benefits of weatherizing Schedule 5 homes.

- Water measures are likely to have a significant effect for respondents, but this effect is unknown for non-respondents.

- Lighting measures are likely to have a significant effect for respondent, but is unknown for non-respondents.

- Energy education and additional information on energy use behavior may prove beneficial for all Schedule 5 customers.

Table 1
Annual kWh Usage

	Average	Standard Error	Observation Numbers
Respondent	17,528	8,277	2,177
Non-Respondent	19,536	13,067	2,587

Table 2
Housing Characteristics

	Total		Single Family		Duplex/Condo		Mobile Home		Apartment	
	Count	%	Count	%	Count	%	Count	%	Count	%
Total	2,626		2,291	87%	190	7%	121	5%	24	1%
Don't Know/NA	17									
Total Eligible	2,643		2,291		190		121		24	
Conditioned Space										
<1,000	124	5%	62	3%	18	9%	34	28%	10	42%
1,001-1,500	680	27%	562	25%	59	31%	51	42%	5	21%
1,501-2,000	662	26%	565	25%	66	35%	27	22%	2	8%
2,001-2,500	474	18%	454	20%	15	8%	2	2%	1	4%
>2,500	623	24%	591	26%	25	13%	0	0%	2	8%
Don't Know/NA	80									
Total Eligible	2,643		1,643		158		114		18	
Own Versus Rent										
Own	2,447	95%	2,169	97%	150	83%	111	96%	4	18%
Rent	116	5%	61	3%	31	17%	5	4%	18	82%
Don't Know/NA	80									
Total Eligible	2,643									
Family Size										
1	86	4%	53	3%	20	12%	11	11%	2	10%
2	567	24%	460	22%	67	42%	33	33%	5	24%
3-4	741	31%	650	31%	44	27%	26	36%	9	43%
5	966	41%	905	44%	30	19%	20	20%	5	24%
Don't Know/NA	283									
Total Eligible	2,643		2,068		161		100		21	
Average	4.3		4.4		3.2		3.5		4.5	
Year Built										
<1920	40	2%	38	2%	1	1%	0	0%	0	0%
1921-1950	66	3%	64	3%	1	1%	0	0%	1	5%
1951-1965	153	6%	135	6%	15	9%	1	1%	2	11%
1966-1970	207	8%	172	8%	29	17%	2	2%	3	16%
1971-1975	592	24%	499	23%	66	38%	21	19%	5	26%
1976-1980	913	37%	827	38%	36	21%	44	41%	2	11%
1981-1985	349	14%	294	14%	21	12%	29	27%	3	16%
1986-1990	119	5%	101	5%	4	2%	9	8%	3	16%
>1990	32	1%	29	1%	1	1%	2	2%	0	0%
Don't Know/NA	172									
Total Eligible	2,643	100%	2,159	100%	174	100%	108	100%	19	100%
Average	1974		1974		1974		1979		1973	

Table 3
Thermostat Settings

	Daytime		Night-time		Average
	Average	%>70	Average	%>70	Change
Total	67.3	26	63.9	13	3.4
Home Type					
Single Family	67.2	27	64.1	13	3.1
Duplex/Condo	67.9	22	62.4	11	5.5
Mobile Home	67.3	18	63.6	9	3.7
Apartment	68.6	25	65.9	9	2.7
Own or Rent					
Own	67.3	27	64	13	3.3
Rent	65	15	62.9	12	2.1
Family Size					
1	67.7	21	62.8	9	4.9
2	68.8	31	63.5	14	5.3
3-4	67.2	24	64.5	11	2.7
5	66	25	63.5	12	2.5

Table 4
Heating/Cooling Use

	Total		Single Family		Duplex/Condo		Mobile Home		Apartment	
	Count	%	Count	%	Count	%	Count	%	Count	%
Main Heating System										
Electric Forced Air	409	13%	251	11%	55	27%	92	72%	8	32%
Electric Heat Pump	302	10%	285	12%	4	2%	9	7%	3	12%
Electric Ceiling Cable	1,011	33%	944	40%	56	27%	0	0%	3	12%
Baseboard/Wall Units	548	18%	469	20%	65	32%	5	4%	7	28%
Gas/Oil	278	9%	258	11%	6	3%	11	9%	1	4%
Wood Stove/Fireplace	399	13%	62	3%	17	8%	8	6%	1	4%
Wood Furnace	19	1%	18	1%	0	0%	1	1%	0	0%
Central System*	1	0%	0	0%	0	0%	0	0%	1	4%
None/Other	88	3%	82	3%	3	1%	2	2%	1	4%
Don't Know/NA	10									
Total Eligible	3,065	100%	2,369	100%	206	100%	128	100%	25	100%
Cooling System										
Central Electric	288	11%	179	8%	92	48%	10	8%	7	28%
Heat Pump	331	12%	313	14%	4	2%	9	8%	3	12%
Electric Window/Wall	144	5%	125	5%	9	5%	4	3%	4	16%
Swamp Cooler	1,056	40%	934	40%	30	16%	83	70%	2	8%
Central Gas	16	1%	16	1%	0	0%	0	0%	0	0%
Central Fan	26	1%	21	1%	3	2%	1	1%	0	0%
Central System*	3	0%	1	0%	1	1%	0	0%	1	4%
None/Other	801	30%	725	31%	51	27%	12	10%	8	32%
Don't Know/NA	26									
Total Eligible	2,691	100%	2,314	100%	190	100%	119	100%	25	100%
Secondary Heating										
Electric Forced Air	54	2%	48	2%	3	2%	3	3%	0	0%
Electric Heat Pump	36	1%	34	2%	1	1%	1	1%	0	0%
Electric Ceiling Cable	119	5%	113	5%	6	3%	0	0%	0	0%
Baseboard/Wall Units	380	15%	333	15%	36	21%	6	5%	3	13%
Gas/Oil	113	4%	106	5%	3	2%	2	2%	0	0%
Wood Stove/Fireplace	930	36%	866	39%	22	13%	33	30%	3	13%
Wood Furnace	27	1%	25	1%	0	0%	2	2%	0	0%
Central System*	2	0%	1	0%	0	0%	0	0%	1	4%
None/Other	910	35%	723	32%	102	59%	63	57%	16	70%
Don't Know/NA	1									
Total Eligible	2,572	100%	2,249	100%	173	100%	110	100%	23	100%

* Central system that cools/heats several apartments or condominiums.
**Multiple responses allowed.

Table 5
Appliances - Refrigerators

	Total		Single Family		Duplex/Condo		Mobile Home		Apartment	
	Count	%	Count	%	Count	%	Count	%	Count	%
Number of Refrigerators	1.3		1.3		1.2		1.2		1.5	
Refrigerator #1										
Age										
< 7 years old	1,668	64%	1,446	64%	122	66%	79	66%	13	57%
> 7 years old	927	36%	806	34%	63	34%	40	34%	10	43%
Type of Defrost										
Manual	230	9%	170	10%	18	10%	31	27%	9	43%
Partial	79	3%	64	3%	6	3%	6	5%	2	10%
Frost Free	2,268	88%	2,011	87%	158	87%	76	67%	10	48%
Size										
Small (>16 cu.ft.)	192	8%	142	14%	26	14%	15	14%	6	26%
Medium (16 -20 cu.ft.)	1,646	65%	1,425	64%	117	64%	82	75%	14	61%
Large (< 20 cu.ft.)	705	28%	644	22%	41	22%	13	12%	3	13%
Refrigerator #2										
Age										
< 7 years old	537	78%	494	78%	21	70%	16	80%	4	100%
> 7 years old	155	22%	141	22%	9	30%	4	20%	0	0%
Type of Defrost										
Manual	238	35%	212	34%	12	39%	9	45%	2	50%
Partial	55	8%	52	8%	2	6%	1	5%	0	0%
Frost Free	393	57%	364	58%	17	55%	10	50%	2	50%
Size										
Small (>16 cu.ft.)	205	30%	188	30%	10	30%	4	22%	1	25%
Medium (16 -20 cu.ft.)	337	49%	308	49%	18	55%	9	50%	1	25%
Large (< 20 cu.ft.)	147	21%	135	21%	5	15%	5	28%	2	50%

Table 6
Appliances - Freezers

	Total		Single Family		Duplex/Condo		Mobile Home		Apartment	
	Count	%	Count	%	Count	%	Count	%	Count	%
Number of Freezers										
No Freezer	535	21%	359	16%	114	63%	47	41%	14	58%
1 Freezer	1,670	64%	1,531	68%	61	34%	60	52%	7	29%
Number >1	399	15%	377	17%	6	3%	9	8%	3	13%
Freezer #1										
Age										
< 7 years old	1,764	86%	1,641	86%	52	79%	55	81%	8	80%
> 7 years old	295	14%	261	145	14	21%	13	19%	2	20%
Type										
Chest	847	41%	791	42%	16	25%	26	38%	5	50%
Upright	1,208	59%	1,108	58%	48	75%	42	62%	5	50%
Size										
Small (>16 cu.ft.)	356	18%	310	17%	22	35%	19	29%	4	44%
Medium (16 -20 cu.ft.)	1,041	52%	965	52%	30	48%	32	49%	3	33%
Large < 20 cu.ft.)	612	30%	583	31%	11	17%	14	22%	2	22%
Freezer #2										
Age										
< 7 years old	275	73%	260	72%	5	83%	6	75%	2	100%
> 7 years old	103	5%	99	5%	1	2%	2	3%	0	0%
Type										
Chest	134	35%	129	36%	1	17%	2	25%	1	50%
Upright	246	65%	231	64%	5	83%	6	75%	1	50%
Size										
Small (>16 cu.ft.)	65	18%	61	17%	2	40%	1	14%	1	17%
Medium (16 -20 cu.ft.)	195	53%	185	53%	1	20%	5	71%	4	67%
Large < 20 cu.ft.)	108	29%	104	30%	2	40%	1	14%	1	17%

Table 7
Appliances - Range & Oven

	Total		Single Family		Duplex/Condo		Mobile Home		Apartment	
	Count	%	Count	%	Count	%	Count	%	Count	%
Type of Range										
Electric	2,567	98%	2,227	98%	189	100%	113	93%	23	100%
Gas	65	2%	56	2%	0	0%	8	7%	0	0%
Cooking Elements Used										
1	482	18%	407	18%	37	20%	28	24%	7	29%
2	1,866	71%	1,626	71%	133	72%	82	69%	14	58%
3	255	10%	228	10%	13	7%	8	7%	3	13%
4-5	16	1%	14	1%	1	1%	1	1%	0	0%
Average	2		2		2		2		2	
Hours per Week										
>15 Minutes	337	14%	319	15%	32	19%	14	13%	20	59%
15-30 Minutes	914	37%	797	37%	73	42%	33	30%	6	18%
31-60 Minutes	916	37%	810	37%	55	32%	41	38%	7	21%
61-120 Minutes	236	10%	207	10%	11	6%	17	16%	1	3%
>120 Minutes	40	2%	33	2%	1	1%	4	4%	0	0%
Average	44		45		37		54		33	
Type of Oven										
Electric	2,559	98%	2,222	98%	188	100%	111	94%	23	100%
Gas	59	2%	51	2%	0	0%	7	6%	0	0%
Hours of Oven Use										
Less than 3 hours	1,006	40%	829	38%	105	59%	50	43%	17	74%
3 to 4 hours	765	30%	675	31%	44	25%	37	32%	2	9%
More than 4 hours	770	30%	705	32%	28	16%	29	25%	4	17%
Average	5		5		3		5		3	
Own Microwave										
Yes	2,498	97%	2,179	98%	172	93%	110	94%	20	83%
No	72	3%	49	2%	12	7%	7	6%	4	17%
Minutes per Day										
5 Minutes or Less		0%		0%		0%		0%		0%
6 to 10 Minutes	463	21%	376	19%	49	33%	32	32%	4	27%
11 to 20 Minutes	787	35%	702	36%	49	33%	29	29%	3	20%
21 to 30 Minutes	533	24%	481	24%	26	18%	20	20%	4	27%
31 to 60 Minutes	377	17%	337	17%	20	14%	12	12%	4	27%
More than 60 Minutes	86	4	75	4%	3	2%	6	6%	0	0%
Average										

Table 8
Appliances - Clothes Washer & Dryer & Dishwasher

	Total		Single Family		Duplex/Condo		Mobile Home		Apartment	
	Count	%	Count	%	Count	%	Count	%	Count	%
Own Clothes Washer										
Yes	2,402	92%	2,112	93%	156	86%	103	85%	15	68%
No*	204	8%	152	7%	26	14%	18	15%	7	32%
Loads of Wash per Week										
1 to 3 Loads	511	21%	408	19%	64	41%	29	28%	4	27%
4 to 6 Loads	741	31%	637	30%	52	32%	42	39%	5	26%
7 to 10 Loads	652	27%	598	28%	29	18%	18	17%	5	26%
11 to 20 Loads	423	9%	398	9%	9	3%	13	6%	1	3%
More than 20 Loads	74	1%	71	2%	2	1%	1	0%	0	0%
Average	7		8		5		5		4	
Own Dryer										
Yes	2,541	98%	2,234	99%	161	92%	116	97%	13	65%
No**	58	2%	32	1%	14	8%	4	3%	7	35%
Type of Dryer										
Electric	2,451	94%	2,143	94%	162	92%	116	96%	15	79%
Gas	121	5%	113	5%	3	2%	3	2%	1	5%
Other	39	1%	22	1%	11	5%	2	1%	3	14%
Loads Dryer per Week										
1 to 3 Loads	384	15%	296	13%	52	32%	28	24%	2	15%
4 to 6 Loads	779	31%	665	30%	59	35%	44	36%	8	47%
7 to 10 Loads	734	29%	671	30%	34	20%	21	17%	2	12%
11 to 20 Loads	547	12%	509	13%	14	4%	21	11%	1	3%
More than 20 Loads	97	2%	93	2%	2	1%	2	1%	0	0%
Average	9		9		6		8		4	
Own Dishwasher										
Yes	2,012	77%	1,767	78%	151	84%	71	59%	13	59%
No**	593	23%	500	22%	29	16%	49	41%	9	41%
Dish Loads per Week										
1 to 3 Loads	563	28%	459	26%	65	43%	30	42%	4	31%
4 to 6 Loads	530	26%	462	26%	47	30%	16	21%	5	23%
7 to 10 Loads	772	38%	710	40%	35	23%	24	31%	0	0%
More than 10 Loads	147	7%	136	8%	4	3%	1	1%	4	18%
Average	5		5		4		5		9	

*Don't own clothes washer or only use cold water
** Don't own or don't use

Table 9
Appliances - Water Heater

	Total Count	Total %	Single Family Count	Single Family %	Duplex/Condo Count	Duplex/Condo %	Mobile Home Count	Mobile Home %	Apartment Count	Apartment %
Number of Water Heaters										
1	2,285	87%	1,962	86%	169	89%	169	98%	20	95%
2	333	13%	312	14%	17	9%	17	2%	0	0%
3 to 4	18	1%	14	1%	3	2%	3	0%	1	5%
Average	1		1		1		1		1	
Water Heater #1										
Type of Water Heater										
Electric	2,235	85%	1,917	84%	178	94%	110	91%	17	85%
Gas	312	12%	288	13%	10	5%	10	8%	2	10%
Solar/Electric Backup	43	2%	43	2%	0	0%	0	0%	0	0%
Heat Pump	20	1%	19	1%	0	0%	1	1%	0	0%
Solar/Gas Backup	4	0%	3	0%	1	1%	0	0%	0	0%
Other	15	1%	14	1%	0	0%	0	0%	0	0%
Don't Know/No Response	7		4		0		0		1	5%
Gallons for Water Heater									1	
Small (< 45 gallons)	561	22%	435	20%	62	36%	49	42%	13	65%
Medium (45-80 gallons	1,776	70%	1,591	72%	100	59%	65	56%	7	35%
Large (<30 gallons)	194	8%	183	8%	8	5%	3	3%	0	0%
Don't know/no response	105		79		19		4		1	
Average	59		60		54		51		44	
Water Heater #2										
Type of Water Heater										
Electric	247	72%	227	71%	19	95%	0	0%	0	0%
Gas	57	17%	55	17%	0	0%	1	100%	0	0%
Solar/Electric Backup	22	6%	21	7%	1	5%	0	0%	0	0%
Heat Pump	5	1%	4	1%	0	0%	0	0%	1	100%
Solar/Gas Backup	1	0%	1	0%	0	0%	0	0%	0	0%
Other	13	4%	13	4%	0	0%	0	0%	0	0%
Don't Know/No Response	6									
Gallons for Water Heater										
Small (< 45 gallons)	100	30%	93	29%	5	31%	2	67%	0	
Medium (45-80 gallons	198	59%	189	60%	8	50%	1	33%	0	
Large (<30 gallons)	37	11%	34	11%	3	19%	0	0%	0	
Don't know/no response	16		10		4		1		1	
Average	57		57		59		63		0	

Table 10
Appliances - Other

	Total		Single Family		Duplex/Condo		Mobile Home		Apartment	
	Count	%	Count	%	Count	%	Count	%	Count	%
Own Color TV										
Yes	2,613	100%	2,269	100%	184	99%	1210	100%	22	96%
No	10	0%	8	0%	1	1%		0%	1	4%
Hours TV is on										
1-2	275	11%	237	10%	24	13%	7	6%	3	14%
3	306	12%	268	12%	19	10%	13	11%	3	14%
4	444	17%	389	17%	42	23%	11	9%	1	5%
5	341	13%	303	13%	18	10%	16	13%	2	9%
6	416	16%	364	16%	22	12%	26	21%	2	9%
7-10	543	21%	459	20%	40	22%	35	29%	5	23%
More Than 10	288	11%	249	11%	19	10%	13	11%	6	27%
Average	6		6		6		7		7	
Own Black & White TV										
Yes	223	9%	200	13	13	8%	7	6%	1	5%
No	2,229	91%	1,932	155	155	92%	107	94%	21	95%
Hours TV is on										
1	108	48%	98	6	6	46%	3	43%	1	100%
2	64	29%	57	3	3	23%	3	43%	0	0%
3	19	9%	18	2	2	15%	0	0%	0	0%
4	11	5%	9	2	2	15%	0	0%	0	0%
5 or more	21	9%	19	0	0	0%	1	14%	0	0%
Average	3		3	2	2		3		1	
Own VCR										
Yes	2,366	92%	2,084	93%	155	84%	100	84%	16	67%
No	209	8%	149	7%	29	16%	19	16%	8	33%
Average Hours Used	6		6		6		9		6	
Own CD/Stereo										
Yes	2,129	82%	1,872	84%	137	74%	88	73%	20	83%
No	456	18%	367	16%	48	26%	32	27%	4	17%
Average Used	10		10		7		11		7	
Own Computer										
Yes	1,286	49%	1,189	53%	59	32%	30	25%	4	17%
No	1,319	51%	1,069	47%	127	68%	91	75%	20	83%
Average Used	10		5		4		5		4	

Table 11
Appliances Used More Than 4 Times Per Week

	Total		Single Family		Duplex/Condo		Mobile Home		Apartment	
	Count	%	Count	%	Count	%	Count	%	Count	%
Total Sample	2,643		2,291		190		121		24	
Hair Dryer	1,814	69%	1,620	71%	105	55%	64	53%	17	71%
Portable/Ceiling Fan	951	36%	860	38%	44	23%	38	31%	5	21%
Curling Iron	1,743	66%	1,570	69%	84	44%	67	55%	14	58%
Toaster Oven	409	15%	335	15%	45	24%	15	12%	6	25%
Toaster	1,857	70%	1,634	71%	116	61%	84	69%	14	58%
Slow Cooker	335	13%	297	13%	18	9%	14	12%	3	13%
Coffeemaker	850	32%	675	29%	99	52%	65	54%	9	38%
Electric Fry Pan/Wok	755	29%	674	29%	39	21%	31	26%	6	25%
Iron	1,205	46%	1,062	46%	79	42%	43	36%	14	58%
Vacuum Cleaner	1,994	75%	1,755	77%	113	59%	94	78%	19	79%
Other	157	6%	130	6%	7	4%	10	8%	1	4%
Extra Energy Users										
Own Water Pump										
Yes	597	24%	561	25%	6	3%	25	22%	3	14%
No	1,934	76%	1,641	75%	173	97%	89	78%	18	86%

Table 12
Lighting Use

	Total		Single Family		Duplex/Condo		Mobile Home		Apartment	
	Count	%	Count	%	Count	%	Count	%	Count	%
Size of Most Light Bulbs										
> 100 Watts	2,524	98%	2,210	98%	172	91%	115	97%	22	92%
> 100 Watts	53	2%	31	1%	16	8%	3	3%	2	8%
Don't Know	10	0%	8	0%	1	1%	1	1%	0	0%
No Response	56		51		1		2		0	
Use Indoor Lighting										
> 6 Hours/Day	1,585	60%	1,374	60%	113	59%	72	60%	16	67%
< 6 Hours/Day	1,000	38%	868	38%	71	37%	47	39%	7	29%
Don't Know	1	0%	0	0%	1	1%	0	0%	0	0%
No Response	57	2%	49	2%	5	3%	2	2%	1	4%
Outdoor Security Light										
Yes	1,121	43%	972	43%	78	42%	55	46%	9	39%
No	1,474	57%	1,280	57%	106	58%	64	54%	14	61%
No Response	48		39		6		2		1	
Fluorescent Fixtures										
Yes	1,946	75%	1,725	76%	124	67%	75	62%	8	36%
No	660	25%	536	24%	62	33%	46	38%	14	64%
Don't Know	1		0		1		0		0	
No Response	36		30		3		0		2	
Number of Fixtures										
1	391	21%	331	20%	33	29%	18	25%	5	71%
2	414	23%	358	22%	27	24%	27	38%	2	29%
3	245	13%	217	13%	17	15%	7	10%	0	0%
4	238	13%	226	14%	5	4%	5	7%	0	0%
5	104	6%	99	6%	3	3%	2	3%	0	0%
6 to 7	194	11%	177	11%	7	6%	8	11%	0	0%
8 to 10	142	8%	121	7%	15	13%	5	7%	0	0%
More than 10	102	6%	96	6%	6	5%	0	0%	0	0%
Average	4		4		4		3		1	0%
Wattage of Fixture										
Under 40 Watts	74	9%	57	8%	7	13%	9	22%	0	0%
40 Watts	433	53%	379	54%	25	48%	21	51%	3	60%
More than 40 Watts	303	37%	269	38%	20	38%	11	27%	2	40%
Unsure	466		415		34		13		2	
No Response	670		605		38		21		1	
Average	64		64		59		47		244	

Table 13
Energy Conservation Equipment - Shell

	Total		Single Family		Duplex/Condo		Mobile Home		Apartment	
	Count	%	Count	%	Count	%	Count	%	Count	%
Windows										
Single Pane	160	6%	118	5%	25	13%	13	11%	3	12%
Single W/Storm Windows	273	10%	194	8%	12	5%	54	44%	7	28%
Double Pane	1,956	71%	1,751	73%	139	74%	48	39%	10	40%
Combination	294	11%	268	11%	12	6%	6	5%	5	20%
Three Pane	52	2%	50	2%	1	1%	1	1%	0	0%
Other	21	1%	21	1%	0	0%	0	0%	0	0%
Don't Know/No Response	35		22		5		3		3	
Doors										
Wood-Solid Core	949	33%	840	34%	76	38%	19	13%	7	27%
Wood-Hollow Core	264	9%	193	8%	25	13%	40	26%	5	19%
Metal Insulated	1,345	46%	1,215	49%	65	33%	50	33%	9	35%
Combination	297	10%	193	8%	25	13%	40	26%	5	19%
Other	38	1%	20	1%	7	4%	2	1%	0	0%
Don't Know/No Response	85		54		13		11		6	
Wall Insulation										
Yes	2,264	93%	2,020	94%	125	87%	95	86%	10	77%
No	63	3%	49	2%	8	6%	5	5%	1	8%
Partially	108	45	84	4%	11	8%	10	9%	2	15%
Don't Know/No Response	208		138		46		11		11	
Floor Insulation										
Yes	718	25%	572	23%	7	3%	110	78%	2	7%
No	1,713	60%	1,543	63%	141	68%	8	6%	14	47%
Partial	123	4%	116	5%	3	1%	2	1%	1	3%
Don't Know/No Response	89		60		19		1		7	
Thickness										
3.5 Inches	106	20%	81	18%	3	27%	22	34%	0	0%
6 Inches	242	46%	205	47%	4	36%	27	42%	1	100%
10 Inches	123	23%	111	25%	4	36%	8	12%	0	0%
Other	53	10%	45	10%	0	0%	8	12%	0	0%
Don't Know/No Response	194		129		16		45		1	
Plastic Ground Cover										
Yes	287	19%	258	19%	9	13%	17	16%	2	20%
No	1,230	79%	1,064	78%	62	87%	87	84%	8	80%
Partially	34	2%	34	3%	0	0%	0	0%	0	0%
Don't Know	1,092		835		119		17		14	
Ceiling Insulation										
Yes	2,440	98%	2,198	99%	128	93%	88	91%	10	91%
No	49	2%	30	1%	9	7%	9	9%	1	9%
Don't Know/No Response	154		63		24		24		13	
Ceiling Insulation-Type										
Loose Fill	1,692	71%	1,605	73%	67	66%	7	11%	4	67%
Rolled/Bat	682	29%	583	27%	35	34%	55	89%	2	33%
Foam	8	0%	8	0%	0	0%	0	0%	0	0%
Don't Know/No Response	171		112		27		25		4	
Depth of Insulation										
1-6 Inches	676	36%	590	35%	43	48%	39	80%	1	17%
7 to 12 Inches	942	50%	882	52%	40	45%	9	185	5	83%
13 to 18 Inches	217	11%	210	12%	4	4%	1	2%	0	0%
More than 19 Inches	55	3%	5	0%	2	2%	0	0%	0	0%
Don't Know/No Response	550		463		39		39		4	
Average	9		10		8		6		8	

Table 14
Energy Conservation Equipment - Water Heater

	Total		Single Family		Duplex/Condo		Mobile Home		Apartment	
	Count	%	Count	%	Count	%	Count	%	Count	%
In Conditioned Space										
Yes	1,475	56%	1,276	56%	124	67%	51	43%	15	71%
No	1,135	43%	996	44%	61	33%	67	57%	6	29%
Some	5	0%	5	0%	0	0%	0	0%	0	0%
Don't Know/No Response	28		14		5		3		3	
Insulation Blanket										
Yes	696	27%	604	27%	37	20%	42	36%	6	29%
No	1,905	73%	1,658	73%	148	80%	75	64%	15	71%
Some	5	0%	5	0%	0	0%	0	0%	0	0%
Don't Know/No Response	37		24		5		4		3	
Low-flow Showerheads										
Yes	707	27%	631	28%	44	24%	22	18%	3	13%
No	1,882	72%	1,613	72%	141	76%	98	82%	20	87%
Some	12	0%	11	0%	1	1%	0	0%	0	0%
Don't Know/No Response	42		36		4		1		1	
Faucet Aerators										
Yes	948	37%	828	37%	73	39%	38	100%	5	100%
No	1,614	63%	1,394	62%	111	60%		0%		0%
Some	13	1%	11	0%	1	1%	0	0%	0	0%
Don't Know/No Response	68		58		5		4		1	

Attachment G

Economic Regulation

One Utah Center
Suite 800
Salt Lake City, Utah 84140-0008

PACIFICORP
PACIFIC POWER • UTAH POWER

September 28, 1993

Honorable Stephen F. Mecham, Chairman
Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84111

Re: PacifiCorp's Application for an Order Approving a Demand-Side Resource Acquisition Contract with ECONS, Inc.

Dear Chairman Mecham:

In its March 5, 1993 application to the Utah Public Service Commission (Commission) in Docket No. 93-2035-01, Utah Power (Company) requested approval of the demand-side resource acquisition contract with ECONS, Inc. The contract was the result of the Commission Order in Docket No. 91-2035-01 requiring the Company to "...consider bids for demand-side resources in the state of Utah in its competitive bidding program." The Company entered into the ECONS contract on November 23, 1992. In its application, the Company requested the Commission find the terms, conditions, and prices to be paid under the contract to be just and reasonable and in the public interest, and that the contract be found a cost effective demand-side resource (DSR) consistent with RAMPP II.

In a joint recommendation to the Commission dated June 30, 1993, the Utah Division of Energy, the Committee of Consumer Services, and the Division of Public Utilities concluded that there is insufficient information at this time to determine the prudence of the terms, conditions, and prices to be paid under the ECONS contract. The parties made recommendations concerning the determination of achieved energy savings and the analysis of cost effectiveness of the contract.

In its July 20, 1993 letter to the Commission, the Company responded to the comments of the parties. While concurring with certain recommendations in the joint recommendation, the Company disputed some recommendations and attempted to clarify others.

Subsequent discussion between the parties to the joint recommendation and the Company have led to the following Joint Proposal which is supported by the undersigned parties:

> The ECONS contract provides a potential benefit to the State of Utah in the form of energy conservation. The parties therefore agree that given the safeguards for the utility customer and the Company provided by the conditions of this Joint Proposal, the Commission should approve the ECONS contract with a finding that it is in the public interest to initiate the contract and conditions as follows:
>
> 1. The Company will perform measurement testing to determine the level of energy savings achieved by the conservation measures installed under the ECONS contract. Such testing shall include 60 days each of pre- and post-installation measurement of electricity consumption related to water heating, in 75 units chosen to be representative of those to be treated by ECONS. The measurement testing design has been reviewed and approved by the members of the Utah DSR Evaluation Task Force.

2. The information obtained from the measurement testing will be used by the Company to validate its cost-effectiveness analysis of the resources acquired by the ECONS contract. The results of the testing and validation of the cost-effectiveness analysis will be presented to the DSR Task Force within 15 days of the end of the measurement testing. Within 15 days of such presentation, the DSR Task Force will provide the Company an appraisal and comments relative to the measurement test results and the Company's validation of the cost effectiveness of the program given the results of measurement testing. If the Company analysis indicates that the resource is cost-effective, performance of the contract will continue without further Commission action. If the Company analysis indicates the resource in not cost-effective, the Company may terminate the contract or modify it so as to provide for a cost-effective resource acquisition. In the case of termination or modification of the contract, the Company will provide notice to the Commission; however, no additional Commission action will be required.

3. A sharing of the risk of non-cost effectiveness of installed measures is considered reasonable. Therefore, utility customers will bear such risk for the first 1,000 ECONS installations. The non-cost effectiveness risk for the second 1,000 installations will be borne equally by utility customers and the Company. For all installations beyond 2000, the Company will bear the full risk of non-cost effectiveness.

4. The risk of non-cost effectiveness of ECONS installed conservation measures borne by the Company or its customers will not be the full cost of the measures determined non-cost effective. Rather, the risk will be the cost increment above which the measures are not cost effective.

5. The standard of prudence for DSR in the State of Utah has not been established by Utah Commission order. The prudence of the ECONS contract will be determined by the Commission in a future proceeding. The standard for cost effectiveness of the ECONS contract will be based on the methodology for determining cost-effectiveness employed in the ECONS standard data request. This standard for cost effectiveness, by which the ECONS contract will be evaluated, will not set precedent for the evaluation of future contracts.

6. Approval of the contract is conditioned on ECONS' agreement to amend the contract to provide implementation of the above-described provisions.

PacifiCorp

By Anne Eakin
Date 9-28-93

Utah Division of Public Utilities

By Kenneth B Powell
Date 9-28-93

Utah Committee of Consumer Services
Neither supporting nor objecting

By
Date 28 September 1993

Attachment H

(503) 464-5000

PACIFICORP
PACIFIC POWER UTAH POWER

July 12, 1994

Utah Cost Recovery Collaborative
Net Lost Revenue Subcommittee

Dear Subcommittee Member:

Attached you will find the final report on the analysis of the ECONs multi-family water heater pay-for-performance program pilot study. Based on the results from this report, there is an 85% probability that the program will yield cost-effective savings of at least 750 kWh/year per customer.

If you have any questions regarding this report, please contact Margot Everett at (503) 464-6518.

Sincerely,

Margot C. Everett

DSR Program Evaluation & Market Research

Attachments

ECONS Inc. Utah Water Heater Program
Pilot Study

Introduction

PacifiCorp and ECONs Inc. have signed a contract to install energy efficient measures at multi-family units in an effort to reduce the overall water heating energy use of this sector in a cost-effective manner. These measures include low-flow showerheads, faucet aerators, water tank wrap and pipe insulation. To determine the cost-effectiveness of this program, a pilot study was undertaken to estimate the average annual savings from such a program. This report presents PacifiCorp's evaluation of the pilot.

Sample Selection

A sample of seventy-four all-electric multi-family units was selected from the population of multi-family units in PacifiCorp's Watsatch Front territory. These units were chosen as a representative sample of the population of potential participants using a stratified sampling technique. Specifically, the Watsatch Front area was segmented into four geographic areas: the Northeast, Northwest, Southwest, and Southeast. The average annual usage for multi-family units for each of these four geographic areas, and the related population sizes and standard errors, are shown in Table 1.

Table 1
Comparison of Means of Population and Sample

Area	Building	Mean of Sample (kWh)	n of Sample	Standard Error of Sample	Mean of Population (kWh)	n of Population	Standard Error of Population	t-statistic Comparing Means of Population and Sample
SE	Ashley Diane	10,537	13	2,076	10,870	1,398	6,300	-0.56
NW	Sprucewood	7,806	8	1,818	8,400	2,526	6,000	-0.91
NW	Village North	8,527	6	860	8,400	2,526	6,000	0.34
NE	Westminster	9,367	11	2,423	8,500	4,089	3,640	1.18

Four building complexes were then chosen from these areas, with two buildings coming from the same area since one was chosen to specifically represent the low-income population. At each building, half the units chosen were treated immediately and metered for 120 days while the other half were treated after 60 days of metering and then metered for an additional 60 days. Throughout this report, the 38 treated after 60 days of metering will be referred to as Group A, while the 36 treated at the beginning of the metering project are called Group B. Originally those units in Group B were to have the measures removed after 60 days and then have water heater use metered for an additional 60 days. However, it was decided after the metering equipment was in place that in order to avoid disturbing the customers, the measures would not be removed. Of these 74 sites at these four buildings, 36 were in Group B while the other 38 were in Group A.

Since the evaluation requires a review of pre-treatment energy use as compared to post-treatment energy use, only the sample of 38 customers in Group A could be used to determine program savings. As a result, a check of the representativeness of Group A of the population as a whole was performed. Table 1 shows the average annual usage for units in Group A as compared to the average annual usage for multi-family units in the related geographic area. As this table shows, the average annual usage for units in Group A are not statistically different from multi-family units in the related population as the t-statistics for the comparison of means[1] is less than the critical value of 1.96[2]. Therefore, it is reasonable to assume that savings from the program estimated from the samples of units could be representative of savings that would be achieved in the related populations.

Savings Estimation Methodology and Results

This analysis involved computing an average difference from pre- to post-treatment consumption using only those customers from Group A, which had 60 days of pre-treatment data and 60 days of post-treatment data. This analysis yielded an average daily savings of 2.7 kWh, with a standard deviation of 2.8, from a sample of 22. Using the paired-sample difference t-test[3], the computed t-statistic was 4.46. Extrapolating the daily average to a year provided an estimate of 980 kWh per year of savings, which is greater than the estimated cost-effective savings threshold of 750 kWh per year. In fact, based on this pilot study, there is an 85% probability[4] that cost-effective savings, or savings greater than 750 kWh per year, would be achieved.

This pilot study was also used to compute average daily water heater use prior to treatment. This estimate was also derived only from Group A units since these were the only units metered before any treatments were completed. This estimate is 9.5 kWh/day with a standard deviation of 4.4 from a sample of 33.. This equates to an average annual water heater use of 3,463 kWh. The upper bound of the 80% confidence interval at for this estimate is 6,107 kWh/year while the lower bound is 713 kWh/year.

Differences Between PacifiCorp's and etc. Group's Analyses

A similar study was completed by the metering contractor, etc. Group, and the results presented earlier in several reports and memos. The analysis summarized in this report differs from those previous presentations for several reasons.

First, there were errors in the spreadsheets used to estimate savings that were corrected for this analysis. Second, several data points were used in etc. Group's analysis and were not used in this analysis. These include:

- All customers whose water heater was replaced;

- All units where tenants moved in or out after the first reading (if a tenant moved during the first reading, only that reading was discarded); and.

- Any unit that had the data logger replaced.

Table 2 shows an attrition table by metering period to show the results of PacifiCorp's screening process. These data points were removed because they would prevent a reasonable comparisons among reading periods, such as pre-treatment to post-treatment periods.

Lastly, additional statistical tests were run for the PacifiCorp study that were not included in etc. Group's analysis. These included t-tests to determine the probability of achieving cost-effectiveness measures.

Lessons Learned

Lessons learned from this study to be applied to future studies include:

- If a cluster sampling design is used, it can be done more effectively by using a random sample of units and building complexes rather than a sample of units within a building complex that was chosen at random.

- Metering both the top and bottom heating elements separately or determining whether or not the water heater has a inter-lock preventing simultaneous operation of both heating elements.

- Monitoring a true control group that is not treated at all during the study period.

- Monitoring a sufficient sample of treated and control customers to compensate for lost readings due to metering errors, water heater replacements, and customer turnover.

Table 2
Summary of Data Point Attrition

Reason for Eliminating Data Point	First Read Period	Second Read Period	Third Read Period	Fourth Read Period	Fifth Read Period	For Calculating Difference
Questionable data	1	4	2	2	4	0
Water heater replaced	4	4	4	4	4	4
Data logger not attached properly	5	4	3	2	3	0
Tenant moved	5	3	3	3	3	2
Field tested bad data logger	0	0	5	1	0	0
No data recorded	0	0	0	5	9	0
Data logger failed	0	0	0	0	0	4
No valid pre-treatment data	0	0	0	0	0	5
No valid post-treatment data	0	0	0	0	0	1
Data used	23	23	21	21	16	22
Total	38	38	38	38	38	38

Summary of Findings

This study, although not comprehensive, shows that there is an 85% probability that this program will yield cost-effective savings. The PacifiCorp study approach and conclusions differ some from those of the etc. Group's analysis, however the savings estimates do not differ greatly.

Endnotes

[1] The t-statistic for comparing two sample means is calculated as follows:

$$t = \frac{\overline{X_p} - \overline{X_s}}{\sqrt{\frac{S_P^2}{n_P} + \frac{S_S^2}{n_S}}}$$

where:

X_p	=	average annual household use for population;
X_s	=	average annual household use for sample;
S_p	=	standard deviation of average annual household use for population calculated as follows:

$$S = \sqrt{\frac{n\sum X^2 - (\sum X)^2}{n(n-1)}};$$

S_s	=	standard deviation of average annual household use for sample calculated as shown for S_p;
n_p	=	number of observations in population; and
n_s	=	number of observations in sample.

(Reference: Book, Stephen A. and Mark J. Epstein, *Statistical Analysis: Resolving Decision Problems in Business Management,* *Scott Foresman & Co., Glenview, Ill., 1982.)*

[2] The critical value for a t-statistic at the 95% confidence level with degrees of freedom greater than 60 is 1.96.

(Reference: Book, Stephen A.)

[3] The t-test for paired sample differences is calculated as follows:

$$t = \frac{\bar{d}\sqrt{n}}{S},$$

where:

d	=	difference in pre- and post-treatment period water heater use;
n	=	number of observations in sample;
S	=	standard deviation of the differences computed as shown in endnote 1 above for S_p.

(Reference: Book, Stephen A.)

[4] The probability was calculated as follows:

$$\Pr(\overline{d} > 750) = \Pr(\frac{(\overline{d} - d_0)\sqrt{n}}{S_d})$$

where:

d_0 - 750 kWh (or daily kWh savings of 2.1 kWh as compared to a mean of 2.7 kWh)

(Reference: Book, Stephen A.)

September 28, 1994

TO: Mr. Doug Larson, Director
Economic Regulation, PacifiCorp

FROM: Utah DSR Cost Recovery Collaborative
Net Lost Revenue and Evaluation Subcommittee

RE: ECONS Inc. Utah Water Heater Program Pilot Study

BACKGROUND:

On March 5, 1993, PacifiCorp, dba Utah Power & Light Company ("PacifiCorp or "Company") filed an application for the approval of a contract with ECONS, Inc. Under the Contract, ECONS is to provide the Company with 25,728 megawatt-hours of electricity savings per year in the Company's Washington and Utah service territories. The savings are to be achieved through the installation in multi-family residences of faucet aerators, low-flow showerheads, water insulation kits, and pipe insulation at water heaters.

ECONS' proposal was based on an "ex ante" (before verification) energy savings of 1,072 kWh per dwelling unit per year for the four measures to be installed. This ex ante savings were based on a Puget Power collaborative consensus for water heating savings measures in Washington state. This savings estimate was of particular concern to regulators and other parties since it amounted to approximately 60% of the estimated 1,800 kwh per year baseline hot water consumption for a Utah multifamily dwelling unit determined by a conditional demand analysis conducted for PacifiCorp. Additionally, verified energy savings for these measures in other states were about half to two-thirds of the contract deemed savings of 1,072 kWh. Furthermore, although the Request for Proposal issued to secure this contract explicitly indicated bidders must "specify in detail the method that will be used to measure or verify the claimed amount of energy savings", the ECONS contract did not include verification.

In a Joint Recommendation submitted to the Utah Public Service Commission ("Commission") the Utah Division of Energy, the Committee of Consumer Services and the Division of Public Utilities stated:

> "Given that the cost-effectiveness of the ECONS contract is inconclusive at this time, but that PacifiCorp has confidence that this is a cost-effective resource, we

> jointly recommend that PacifiCorp proceed with the contract and conduct an evaluation of savings during the first six months from commencement of ECONS' work in Utah. **This verification of savings will include spot metering on an appropriate number of installations, bill comparisons, and completion of the Energy Decisions Survey by all participants in the program which will aid in ultimate determination of the value of this resource. The DSR Evaluation Task Force established in Docket No. 90-035-06 should be consulted in determining: 1) the appropriate level of metering; 2) any additional relevant information that would be gathered in conducting sample verification of energy savings, taking into consideration the tradeoff between precision and the costs of conducting evaluation; and 3) how this information should be used in revising the terms of the contract, if necessary, with respect to payments to ECONS for any work conducted subsequent to the initial six month period."**

Subsequently, a verification plan was developed in which 75 multifamily units were to be metered. For each of these units, meters would be installed for 60 days each for pre- and post-installation measurement of electricity consumption related to water heating.

On October 12, 1993, the Commission approved the Contract conditioned on ECONS and PacifiCorp amending the Contract to provide for the measurement testing. Specifically,

> "Such testing shall include 60 days each of pre-and post-installation measurement of electricity consumption related to water heating, in 75 units chosen to be representative of those treated by ECONS in Utah. The information obtained from the measurement testing will be used by the Company to validate its cost-effectiveness analysis of the resources acquired under the Contract. The results of the testing and validation of the cost-effectiveness analysis will be presented to the DSR Task Force (established in Docket No. 90-035-06) . . . the DSR Task Force will provide the Company an appraisal and comments relative to the measurement test results and the Company's validation of the cost effectiveness of the program given the results of the measurement testing."

This letter provides the Company with an appraisal of the test results, recommendation for the Company's validation of program cost-effectiveness, and comments on the study from the Cost Recovery Collaborative, Net Lost Revenue and Evaluation Subcommittee ("Subcommittee") which inherited this task from the original DSR Task Force.

APPRAISAL OF TEST RESULTS:

The Subcommittee finds that the test results appear to confirm that it is more likely than not, that the ECONS program will yield cost-effective energy savings. If we assume that the sample of units metered represents a random sample of the total population to be treated through the ECONS contract, the test results indicate that there is an 85% probability that average energy savings will be greater than 750 kWh per year, which when evaluated against RAMPP-2 avoided costs, yields a cost-effective resource as measured under the total resource cost test. However, since the sample was not random and since many of the data points are not independent of one another and represent only a portion of the total population, (all 22 data points come from 4 buildings, the 4 buildings represent 3 out of 4 regions of the Wasatch Front geographic region) the sample selected introduces an unknown bias which affects the statistical significance of the test results. Given this unknown bias, the 85% probability of cost-effective savings may be overstated. We assume that the unknown bias is not greater than 34% and therefore find that the test results give a good indication that it is more probable than not that average savings per unit treated will be greater than or equal to 750 kWh per year for the four measures installed..

RECOMMENDATIONS FOR VALIDATION OF PROGRAM COST-EFFECTIVENESS:

We recommend that the Company acquire specific data on end-uses which effects hot water consumption from the 22 useful data points and to also acquire *this same data* for an adequately large random sample of the total treated units. This effort could tell us something about the unknown bias of the 22 metered units thus strengthening the statistical significance of the metered data and would enable the use of the ratio-estimate technique to greatly enhance the billing analysis which will be conducted for the impact evaluation of the total program and thus give us program evaluation results closer to the originally designed verification plan.

COMMENTS:

We must note that we are disappointed that the study plan as discussed and agreed to by the DSR Task Force was not implemented, nor was the revised study plan discussed with the Task Force/Subcommittee prior to its implementation. The purpose of the original verification plan as discussed by the DSR Task Force and written in the joint recommendation noted above, was to meter, pre and post installation, 75 units and to gather specific, consumption related data on all treated units. The relationship of the specific data to the metered data could then be analyzed and extrapolated to the total population of treated units to produce a very cost-effective impact evaluation relative to the precision level achieved. This verification plan would have provided feedback on savings from the initial units treated, thus satisfying ECONS' need to move forward without unnecessary delay, and could also then be used in the complete evaluation of the contract to produce results in which we would have high confidence at a relatively low cost. This approach also helped to justify the increased cost, over the original contract cost, of metering a sample of participants. Because the necessary specific data was not collected, the metered data is of limited value. Additionally, if an appropriate number of independent data points had been collected from a random stratified sample, pre and post installation, as originally planned, we would have greater confidence in the current test results.

We understand that due to personnel changes within the Company, a lack of communication between the DSR program contract managers, the Company's DSR program evaluation group and the DSR Task Force/Subcommittee resulted and hence, a mediocre study was conducted. We wish to add that in spite of the mediocre study design, we are impressed with the final report providing the statistical analysis of the metered data. We look forward to reviewing further work of this caliber and trust that the communication problem between DSR program contract managers and the DSR program evaluation unit has been resolved and that in the future the Subcommittee will be apprised of significant evaluation plan changes.

SUMMARY:

Although displeased with the manner in which the study was conducted, as well as the lack of communication received from Company personnel regarding significant changes made as the study progressed, the Net Lost Revenue and Evaluation Subcommittee has concluded that the ECONS program is more likely than not to produce cost-effective savings and should be eligible for cost recovery in accordance with the full program evaluation results and the terms stated in the Commission order Docket No. 93-2035-01 which approved the ECONS contract.

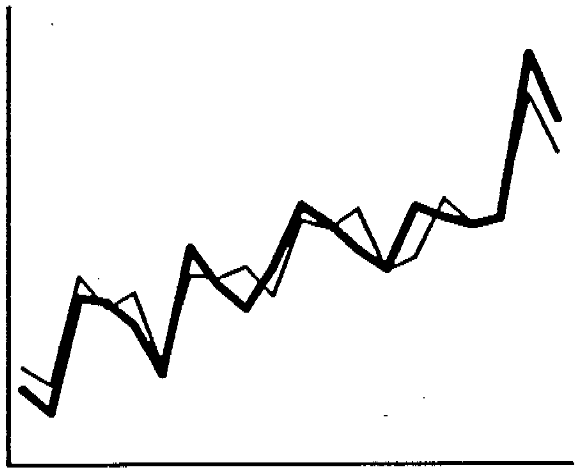
cc: DSR Cost Recovery Collaborative Net Lost Revenue and Evaluation Subcommittee Members

DEMAND SIDE RESOURCE COST RECOVERY COLLABORATIVE REPORT

APPENDIX IV

FINAL REPORT - STATISTICAL RECOUPLING SUBCOMMITTEE DATED MARCH 1995

SUBMITTED
MARCH 31, 1995



Statistical Recoupling in Utah

Report to the DSR Cost Recovery Collaborative from the Statistical Recoupling Subcommittee

March 1995

This report was authored by Kevin T. Duffy-Deno, Ph.D. of the Office of Energy and Resource Planning (Utah Department of Natural Resources, 3 Triad Center, Suite 450, Salt Lake City, Utah 84180, 801-538-5428), Eric Blank of the Law and Water Fund of the Rockies (2260 Baseline Road, #200, Boulder, CO 80302, 303-444-1188), and Rich Collins, Ph.D. of the Utah Public Service Commission (Public Service Commission, PO Box 45809, Salt Lake City, Utah 84115, 801-530-6770). Guidance was provided by the remaining members of the Statistical Recoupling Subcommittee to the DSR Cost Recovery Collaborative:

Mary Cleveland	Utah Committee of Consumer Services
Mark Flandro	Utah Division of Public Utilities
David Taylor	PacifiCorp
Rebecca Wilson	Utah Division of Public Utilities
Paul Wrigley	PacifiCorp

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Executive Summary

The goal of the Statistical Recoupling Subcommittee to the DSR Cost Recovery Collaborative is to provide an objective analysis of how statistical recoupling would have performed if it was in place during 1993 and 1994.

The main findings of the numerical experiment are as follows:

- Quarterly econometric forecasting models, calibrated on Utah Power service territory data from 1978 to 1992, are able to *ex post* forecast 1993 and 1994 sector kWh sales with an average forecast accuracy of -0.64 percent.

- Forecasts for 1994 were not as accurate as for 1993. The Subcommittee presumes that this is primarily the result of 1994's summer being the hottest in the last 16 years. Since the models are calibrated on data for years that are *all* characterized by relatively cooler summers, it is not surprising that the models underpredicted usage in 1994. The underprediction is most severe in the heavily weather dependent residential sector. However, for the *entire* year, the forecasts were still all within a 95 percent confidence interval.

- The numerical experiment indicates that if statistical recoupling had been in effect in Utah during 1993 and 1994, then a total of $0.5 million would have been transferred from consumers to the utility in 1993 and a total of $7.4 million would have been transferred from the utility to consumers in 1994.

- The two year experiment suggests that the methodology will lead to annual price changes that are, on average, within the plus or minus 0 to 2 percent range. For the entire Utah service territory during 1993 and 1994, statistical recoupling would have resulted in a change in the average price of -0.46 percent.

- The numerical experiment indicates that if statistical recoupling had been in effect in Utah during 1993: $1.0 million would have been transferred from the utility to residential customers (equivalent to a 0.39 percent decline in average price); $1.6 million would have been transferred from commercial customers to the utility (equivalent to a 0.65 percent increase in average price); and $0.1 million would have been transferred from the utility to industrial customers (equivalent to a 0.06 percent decline in average price).

- The numerical experiment indicates that if statistical recoupling had been in effect in Utah during 1994: $4.2 million would have been transferred from the utility to residential customers (equivalent to a 1.63

percent decline in average price); $2.6 mllion would have been transferred from the utility to commercial customers (equivalent to a 1.01 percent decline in average price); and $0.6 million would have been transferred from the utility to industrial customers (equivalent to a 0.27 percent decline in average price).

The Subcommittee identified several issues associated with the methodology worthy of note:

Performance Criteria

The Subcommittee evaluated the methodology's ability to meet the performance criteria outlined in the August 1993 report on DSR cost recovery.

- In general, the methodology is fairly understandable, is difficult to manipulate, promotes cost minimization, and lessens the need for DSR program evaluation or net loss revenue determination.

- The econometric models simulate historical sales with a high degree of accuracy. However, their forecasting ability is challenged when future conditions are outside the historical experience of the models, as was the case in 1994.

- To the extent that the models accurately simulate actual utility kWh sales, there should not be a substantive shifting of risk from the utility to the ratepayer over the long run. However, in any given year, such as 1994, risk may be shifted to ratepayers to the extent that the models are inaccurate.

- If rates are adjusted annually, then it appears the methodology can lead to greater rate instability than the net lost revenue mechanism adopted under the Joint Agreement. However, the rate instability can be lessened by using a deferral account and adjusting rates at the time of a general rate case. Moreover, the size of the adjustment would depend on the magnitude of the annual ex post forecast error and when a rate case took place. For example, the longer the period of time between rate cases, the greater the chance that years in which sales were underpredicted will be offset by years in which sales are overpredicted.

Statistical

- If the forecasting models generate ex post estimates of kWh sales that do not differ statistically from actual sales, then the revenue transfers called for by the methodology will be essentially random and will sum to zero over the long run.

- A trend towards revenue transfers from customers to the utility may develop if the utility's DSM programs expand over time and are effective in statistically reducing kWh sales.

- Forecasting models should be recalibrated on a regular basis in order to expand the "historical experience" of the models and improve their forecasting performance. Recalibration should be done at intervals of no longer than three years.

Legal

- Statistical recoupling may not be inconsistent with a recent Utah Supreme Court decision that utility rates be cost-based. The methodology does not alter the traditional price setting process that occurs in a rate case in which rates are based on costs.

- Some parties are of the opinion that in order to avoid a conflict with a 1986 Utah Supreme Court decision that found retroactive ratemaking illegal, the reconciliation mechanism used to implement the methodology can be structured as a deferral account.

The Subcommittee made the following conclusion and recommendation:

- If implemented for the long run, the statistical recoupling methodology may be a workable method to address the problem of eliminating many of the disincentives associated with DSR investment. Moreover, it appears to send the correct signals to the utility to implement its integrated resource plan efficiently.

- However, given PacifiCorp's current level of DSR investment, the Subcommittee members remain concerned about the potential size of the revenue transfer created by the methodology. This is the primary reason that the Subcommittee can not recommend the adoption of the statistical recoupling mechanism at this time. However, if DSR becomes a larger portion of the utility's resource mix, then this mechanism may hold promise.

Background

This report summarizes the analysis of the Statistical Recoupling Subcommittee consistent with the decision of the Utah Public Service Commission (Commission) which established the Demand-Side Resource Cost Recovery Collaborative.

In a resource planning order (in Docket No. 90-2035-01), the Commission stated that:

> *"The Commission finds that demand-side resources (DSR) ... are more difficult to acquire than supply-side resources. Regulatory disincentives may exist... Given [these disincentives], the Commission questions whether the Company has sufficient financial incentive to pursue its IRP ..."*

To begin to provide answers to these questions, the Commission authorized a six-month study of DSR incentive mechanisms to be completed during the summer of 1993.

On August 31, 1993 the parties submitted a detailed report to the Commission explaining and evaluating the alternative mechanisms for addressing the financial incentive issues surrounding DSR. Among other things, the report identified two primary incentive concerns[1] surrounding PacifiCorp's energy efficiency investments: 1) PacifiCorp's ability to recover direct DSR program costs consistent with supply-side investments; and 2) regulatory treatment of the net lost revenues associated with DSR-induced sales reductions.

The report concluded that there were a number of straightforward methods for addressing the first problem, providing cost recovery such that DSR investments were on a more level playing field with supply-side expenditures. In contrast, however, there was substantial disagreement about the best regulatory approach for dealing with net lost revenues. In the end and given a number of criteria that the parties deemed to be important, the report identified two approaches -- Net Lost Revenue Adjustments (NLRAs) and Statistical Recoupling (SR) -- that appeared to be particularly promising for implementation in Utah.

Another subcommittee has focused on evaluating NLRAs for the purposes of removing the disincentives associated with PacifiCorp's DSR efforts. This subcommittee's assignment has been to evaluate the statistical recoupling approach.

Like other decoupling methodologies, statistical recoupling first breaks the linkage between utility revenues and sales. In a second step, utility revenues are recoupled to estimated electricity usage as based on statistical equations. Also like other decoupling mechanisms, statistical recoupling does not alter the regulatory determination of utility revenue requirements or the method for setting utility prices coming out of a rate case.

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[1] See DSRC Report, filed August 31, 1993, at pp. 10-29.

Statistical recoupling is intended to address a number of financial incentives issues. First, by breaking the linkage between revenues and sales, it can comprehensively address PacifiCorp's lost revenue problem. Given that DSR-induced sales reductions no longer adversely affect PacifiCorp's earnings, this mechanism is designed to allow PacifiCorp to explore a broad range of demand-side management activities including building codes, educational programs, and appliance efficiency standards.[2] Second, statistical recoupling significantly lessens PacifiCorp's incentive to promote additional, potentially uneconomic, sales growth.

In the August, 1993 report, statistical recoupling was analyzed by the key stakeholders against a number of criteria that were deemed to be important by the parties. The report found that statistical recoupling performed well against most of these criteria. More specifically, the report found that statistical recoupling addressed the lost revenue disincentive issue, minimized risks and costs, avoided micro-management, was predictable, limited contentiousness over evaluation, was administrable, and likely to have relatively small rate impacts. A copy of the key conclusions of this report on statistical recoupling is found in the Appendix.

Based on the results contained in the DSR Collaborative Report, the parties agreed to further analyze statistical recoupling for possible implementation in Utah. More specifically, in a Joint Application filed with the Commission in October of 1993 the parties agreed to:

> *"run a one year numerical experiment with the statistical recoupling program that was proposed by the Environmental Intervenors (EI). The purpose of this experiment is to determine what would have happened in calendar 1994 if the Commission had adopted statistical recoupling."*

Since the Joint Application was filed, several events have occurred in other states that are relevant to the subcommittee's analysis of statistical recoupling. For one, regulators in Oregon and Montana have adopted decoupling approaches that use statistical indices. More recently, the Florida Commission adopted a statistical recoupling approach for the second largest utility in that state. In addition, regulators in New York and Colorado are also considering statistical recoupling approaches. As a result, it is now becoming possible to rely on the growing experience of other states in implementing statistical recoupling.

Much of the recent interest in statistical recoupling is arising as a result of a movement -- called "Performance Based Regulation" (PBR) -- which provides utilities with strong cost cutting incentives. In essence, one approach for implementing a PBR (using a revenue cap) involves the predetermination of utility revenues in the context of a rate case. At the same time, regulators identify a series of indices -- such as economic and weather variables -- which influence how revenues are allowed to grow over time. Typically, states have been using statistical analyses to identify and quantify

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[2] In contrast, NLRAs are more narrowly focused on specific PacifiCorp educational, rebate, or loan programs.

the key indices which allow for revenue growth over time. As a result, these types of PBR mechanisms tend to be very similar to statistical recoupling. Given these fixed revenue streams, utilities will have a strong incentive to cut costs.

Section III of this report describes the development of the statistical recoupling experiment, while Section IV provides the numerical results. In general, the numerical experiment re-affirms the central conclusions contained in the August 31, 1993 Report to the Commission and summarized above. Finally, some issues associated with the statistical recoupling methodology are discussed in the concluding section.

Model Development

As part of the original DSR Collaborative that ended in August of 1993, the EI (one party to the Collaborative) had developed a new approach, called statistical recoupling, for breaking the linkage between utility revenues and sales. To facilitate the Collaborative process, during the summer of 1993 EI developed statistical equations that could be potentially used to implement this approach.

Since none of the other parties were involved in the development of these equations and since the EI did not claim that these initial equations were "regulatory grade", the Statistical Recoupling Subcommittee developed a revised set of equations. In developing these equations, the Subcommittee relied on additional technical expertise that was not available to the EI, ensured that all parties were involved, and incorporated the latest data available.

Models were developed by the Subcommittee for each of PacifiCorp's major customer classes (sectors) in Utah: residential, commercial, and industrial. A "model" of total service territory kWh sales is obtained by summing the findings for the three customer classes

Methodology

The statistical recoupling methodology calls for the linking of utility revenues to "allowed" rather than actual sales. Allowed sales are based on *ex post* simulations of energy usage. Operationally, an econometric model of energy usage is estimated using, in this case, quarterly data from 1978 through 1992. Then, at the end of 1993, using actual 1993 data for the explanatory variables in the estimating equation, the model simulates 1993 energy usage. The simulated usage are allowed sales which determine *allowed* revenues.

Allowed revenues for 1993 are then compared with actual revenues. If, for example, actual exceeded allowed revenues, then the difference is entered into a recoupling account. The following year, an adjustment to rates is made in order to reimburse customers for the overcharge that occurred during the previous year.

Allowed sales are based on an estimated demand equation for energy which includes variables typical to aggregate utility forecasting equations:

$$E_{t,i} = f(\text{Energy Price}_{t,i}, \text{Other Prices}_{t,i}, \text{Customers}_{t,i}, \text{Weather}_t, \text{Economics}_t) + u_{t,i}$$

where $E_{t,i}$ is energy usage in time period t and sector i (residential, commercial, or industrial), Energy Price is usually an average sector retail price, Other Prices can include the average retail cost of energy other than that under study as well as the costs of other production inputs in the case of the commercial and industrial sectors, Customers reflects the number of customers in the sector, Weather captures seasonal variation in energy usage, Economics includes variables that measure economic activity such as personal income and industrial output, and u is a sector error term which captures the remaining variation in energy usage. These equations are estimated using multiple regression techniques.

The selection of the equation specification used for the numerical experiment is based on a number of criteria. As evidenced by the adjusted R-squared, the selected specification is able to explain a very high percentage of the quarterly variation in kWh sold. In addition, only variables that statistically contribute to the explanatory power of the specification are included. Finally, the selected specification yields the most accurate simulation of historical energy usage, as evidenced by the average percent deviation between predicted and actual usage (percent root mean squared error, %RMSE). The specification that yields the most accurate portrayal of historical usage is assumed to be the one that will yield the most accurate ex post forecast for the experiment years.

Time Period:	1978 - 1994
Frequency:	quarterly
Geographic Extent:	Utah Power service territory in Utah for electricity data; Mountain Fuel Utah service territory for natural gas data; State of Utah for all other data except weather and bond rate.

Data	Source
kWh, revenues, customers	Utah Power (PacifiCorp, Portland)
natural gas price (decatherms)	Mountain Fuel (Salt Lake City)
heating, cooling degree days (Salt Lake City)	NOAA
Moody's national AAA bond rate	Wharton Economic Forecasting
personal income, industrial output index, population, households	Data Resource Inc.
industrial coal price	US Department of Energy

Table 1. Data Sample.

Data

PacifiCorp provided to the Subcommittee Utah service territory quarterly energy usage, customer, and revenue data for the 1978 to 1993 period by sector: residential, commercial, and industrial. The Subcommittee decided to use quarterly data for the 1978 to 1992 period for equation estimation. This allows for a test of how statistical recoupling would have performed in *both* 1993 and 1994. Complete variable definitions are shown in Tables 2, 4, and 5 and data sample information is shown in Table 1.

Customer Sector Models

Preliminary estimations suggest that total sales rather than per customer sales equations yield a slightly better fit to historical energy usage data. In addition, since using lagged values for several of the explanatory variables also improves the equations' fit, the equations were estimated using data from 1979 through 1992. What follows is a brief discussion of each equation specification and the specification's ex post forecast accuracy for 1993 and 1994.

Residential Sector

In the residential sector, quarterly variation in electricity sales (kWh) is most accurately explained by the following variables: the number of residential customers; the average, inflation adjusted (real) residential kWh price; real, per capita personal income; the number of heating and cooling degree days; the average size of Utah households; and a dummy variable for the second quarter. This specification, shown in Table 2, explains approximately 97 percent of the variation in quarterly residential usage over the 1979 to 1992 period and yields a %RMSE (simulation error) of 2.5 percent. That is, on average, the specification yields a simulated value that is within plus or minus 2.5 percent of the actual value.

The coefficients of the included variables have plausible signs and, for the most part, differ significantly from zero. Although all variables contribute significantly to the explanatory power of the model, multicollinearity can increase the standard error (i.e., reduce the t-value) for a given variable. An increase in the average, real price of electricity is negatively associated

DEPENDENT VARIABLE:	Total kWh		
TIME PERIOD:	Quarterly, 1979 - 1992		
INDEPENDENT VARIABLE	COEFFICIENT	STANDARD ERROR	t-RATIO
Residential customers	1.3171	0.077	17.120
Average real residential kWh price	-0.028	0.030	-0.949
Real per capita personal income, 4 quarter MAV	0.241	0.110	2.205
Population per household	0.935	0.138	6.782
Heating degree days	0.0001	0.00001	10.260
Cooling degree days	0.0002	0.00003	6.129
Quarter 2 dummy	-0.054	0.016	-3.356
ADJUSTED R-SQUARE	0.967		
DURBIN WATSON	1.979		
SIMULATION % RMSE	2.464		
SUM OF SQUARED ERRORS	0.034		

ESTIMATION NOTES:

1. Dependent and all independent variables (where appropriate) are in logs.
2. Ordinary least squares estimation.
3. % RMSE based on 1979-1992 simulation.
4. Constant not included as it does not significantly add to the explanatory power of the model.

Table 2. Residential Sector Model Specification.

with residential usage, all else constant. Residential electricity usage is positively associated with per capita income and the average size of a Utah household, all else constant. Residential usage is also affected by weather. Usage increases with both higher and lower temperatures as evidenced by the signs and significance of the heating and cooling degree days variables.

Only a dummy variable for the second quarter statistically adds to the explanatory power of the model. The remaining quarterly variation is explained, for the most part, by the number of customers, heating, and cooling degree days. The addition of an intercept does not statistically increase the explanatory power of the model. Since statistically unnecessary variables increase the forecast standard errors, an intercept was not included.

The residential sector ex post forecasts, for 1993 and 1994, are shown in Table 3. These annual forecasts are obtained by summing the quarterly forecasts generated by the specification shown in Table 2. As a percentage of actual usage, the specification underpredicted usage in 1993 by 0.56 percent and underpredicted usage in 1994 by 2.19 percent.

	1993			1994		
	Actual (GWh)	**Forecast (GWh)**	**Forecast Error**	**Actual (GWh)**	**Forecast (GWh)**	**Forecast Error**
Residential	3,531	3,511	-0.56%	3,778	3,695	-2.19%
Commercial	4,246	4,290	1.03%	4,614	4,545	-1.50%
Industrial	5,811	5,804	-0.13%	6,047	6,016	-0.50%
Total Sector	13,589	13,605	0.12%	14,438	14,256	-1.26%

Table 3. Model Forecast Errors.

The poorer performance of the model in 1994 is the result of an uncharacteristically hot summer, at least from the model's point of view. The residential model is calibrated on data from the 1979 to 1992 period, during which time the number of summer cooling degree days (third quarter) averaged 912. During third quarter of 1994, cooling degree days numbered 1,182, 30 percent higher than the sample's historical average and 11 percent higher that the greatest number of cooling degree days during the 1979 to 1989 period (1,062 in 1990)..

The challenge faced by econometric modeling is ex post forecasting usage for years during which values of the explanatory variables fall outside of the historical data range upon which the model is calibrated. The underprediction of the residential model in 1994 highlights the importance of regularly recalibrating the models in order to update the models' coefficients.

Figure 1 presents actual and simulated quarterly usage in the Utah residential sector from 1990 through 1992 as well as the ex post forecast and actual usage for 1993 and 1994. The specification's ability to accurately simulate usage is visually evident by the close match between the plots of actual and simulated usage. Figure 1 also shows the 95 percent upper and lower confidence limits for 1993 and 1994 ex post forecasted usage. If both actual and forecasted usage fall within this confidence band, then, statistically, the hypothesis that actual and forecasted usage are the same cannot be rejected at the 95 percent level of confidence. This is what one would hope for when constructing an accurate forecasting model.

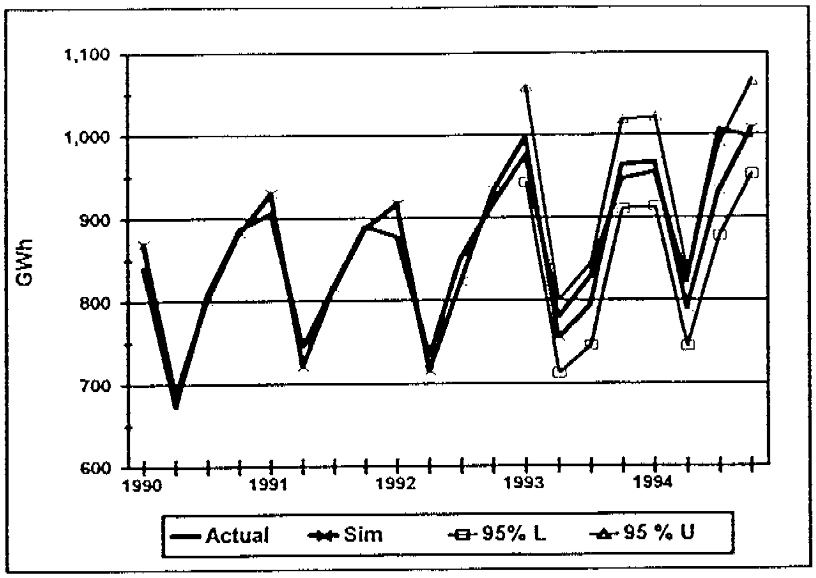

Figure 1. Residential Sector Historical and Forecasted Usage.

Commercial Sector

In the commercial sector, quarterly variation in electricity sales (kWh) is most accurately explained by the following variables: the number of commercial customers; the average, real commercial kWh price; the real price of natural gas to the commercial sector; a measure of the real cost of borrowing; the number of heating and cooling degree days; the total population; and quarterly dummy variables. This specification, shown in Table 4, explains approximately 98 percent of the variation in quarterly commercial usage over the 1979 to 1992 period and yields a %RMSE (simulation error) of 2.4 percent.

The coefficients of the included variables have plausible signs. Moreover they all contribute statistically to the explanatory power of the model although multicollinearity reduces some of the t-values. For example, although the coefficient of the real average price of electricity is negative, it does not differ significantly from zero. This, however, results from collinearity with the real AAA bond rate, the inclusion of which improves the specification's fit. The coefficient of the real average electricity price is highly significant before the inclusion of the AAA bond rate.

The AAA bond rate is a proxy for commercial sector borrowing costs. As interest rates increase, firms may substitute away from capital expenditures. The effect on electricity usage depends on the relationship between electricity and capital in the commercial sector production process. The finding shown in Table 4 suggests that this relationship may be complementary.

Commercial sector firms appear to substitute away from natural gas as real natural gas prices rise. That is, higher real natural gas prices four quarters past is associated with higher electricity usage in the current quarter. Commercial firms also use more electricity during both hotter and colder quarters, as evidenced by the signs and significance of the coefficients of the weather variables. Population captures the demand for the commercial sector's product and the quarterly dummy variables capture the remaining explained variation in quarterly usage.

The commercial sector ex post forecasts, for 1993 and 1994, are shown in Table 3. These annual forecasts are obtained by summing the quarterly forecasts generated by the specification shown in

DEPENDENT VARIABLE:	Total kWh		
TIME PERIOD:	Quarterly, 1979 - 1992		
INDEPENDENT VARIABLE	COEFFICIENT	STANDARD ERROR	t-RATIO
Commercial customers	0.644	0.198	3.247
Average real commercial kWh price	-0.019	0.054	-0.350
Average real commercial decatherm price, lagged 4 quarters	0.085	0.053	1.598
Real Moody's AAA bond rate, 8 quarter MAV	-0.162	0.031	-5.299
Population	0.510	0.419	1.217
Heating degree days	0.00005	0.00002	2.506
Cooling degree days	0.0001	0.00006	1.977
Quarter 1 dummy	6.635	4.323	1.535
Quarter 2 dummy	6.678	4.326	1.544
Quarter 3 dummy	6.732	4.335	1.553
Quarter 4 dummy	6.662	4.326	1.540
ADJUSTED R-SQUARE	0.978		
DURBIN WATSON	2.251		
SIMULATION % RMSE	2.368.		
SUM OF SQUARED ERRORS	0.032		

ESTIMATION NOTES:

1. Dependent and all independent variables (where appropriate) are in logs.
2. Ordinary least squares estimation.
3. % RMSE based on 1979-1992 simulation.
4. No evidence of simultaneity.
5. All variables significantly contribute to explanatory power of model.

Table 4. Commercial Sector Model Specification.

Table 4. As a percentage of actual usage, the specification overpredicted usage in 1993 by 1.03 percent and underpredicted usage in 1994 by 1.50 percent.

Figure 2 presents actual and simulated quarterly usage in the Utah commercial sector from 1990 through 1992 as well as the ex post forecast and actual usage for 1993 and 1994. The 95 percent confidence band is also shown. Visually, the specification shown in Table 4 does a good job of simulating electricity usage in the commercial sector.

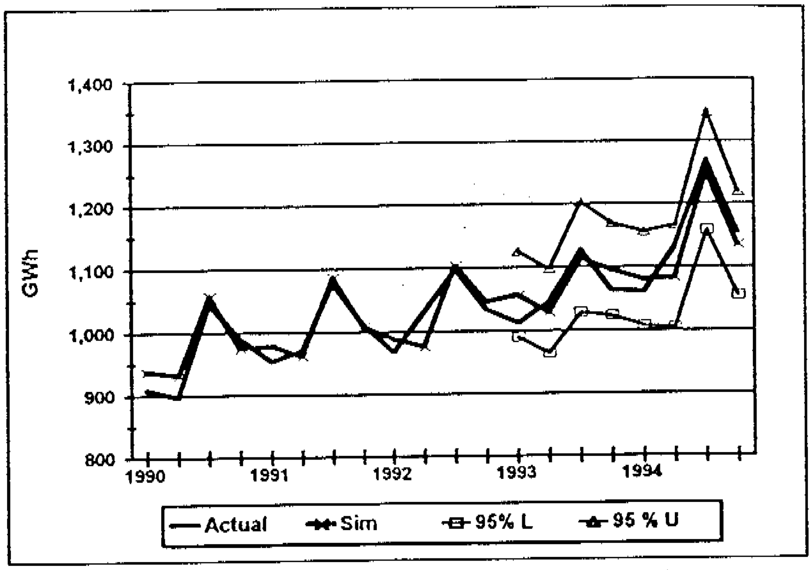

Figure 2. Commercial Sector Historical and Forecasted Usage.

Industrial Sector

Economic theory posits that the demand for electricity on the part of industrial firms depends upon how much output they produce and the cost of other productive inputs. In the industrial sector, quarterly variation in electricity sales (kWh) is most accurately explained by the following variables: the average, real industrial kWh price; an index of industrial sector output; the real price of natural gas to the industrial sector; the real price of coal to the industrial sector; a measure of the real cost of borrowing; the number of heating and cooling degree days; and quarterly dummy variables. This specification, shown in Table 5, explains approximately 96 percent of the variation in quarterly industrial sector usage over the 1979 to 1992 period and yields a %RMSE (simulation error) of 3.2 percent.

The coefficients of the included variables all have plausible signs. As economic theory predicts, increased electricity usage is associated with increased output and lower real electricity prices. The positive coefficient on the natural gas price suggests that gas exhibits a substitutive relationship with electricity in the industrial sector production process. The use of a one quarter lag improves the specification's fit the most. The negative coefficient on the real coal price suggests that electricity and coal may be complementary inputs. An increase in the cost of borrowing, proxied by the real AAA bond rate, is positively associated with electricity usage. This is consistent with industrial capital and electricity being productive substitutes. That is, as higher interest rates reduce capital spending, existing and possibly less energy efficient capital equipment is used more intensively. Industrial sector electricity usage is also sensitive to fluctuations in weather.

DEPENDENT VARIABLE:	Total kWh		
TIME PERIOD:	Quarterly, 1979 - 1992		
INDEPENDENT VARIABLE	COEFFICIENT	STANDARD ERROR	t-RATIO
Average real industrial kWh price	-0.544	0.064	-8.496
Industrial output index	0.902	0.150	5.999
Average real industrial decatherm price, lagged 1 quarter	0.203	0.062	3.288
Real Moody's AAA bond rate, 8 quarter MAV	0.557	0.123	4.532
Real coal price ($/short ton)	-0.152	0.079	-1.929
Heating degree days	0.00003	0.00002	1.391
Cooling degree days	0.0002	0.00007	2.321
Quarter 1 dummy	21.737	0.344	63.260
Quarter 2 dummy	21.825	0.336	64.960
Quarter 3 dummy	21.781	0.332	65.690
Quarter 4 dummy	21.802	0.342	63.730
ADJUSTED R-SQUARE	0.956		
DURBIN WATSON			
SIMULATION % RMSE	3.190		
SUM OF SQUARED ERRORS	0.058		

ESTIMATION NOTES:

1. Dependent and all independent variables (where appropriate) are in logs.
2. Two stage least squares estimation with first-order autocorrelation correction (rho=0.45).
3. % RMSE based on 1979-1992 simulation.

Table 5. Industrial Sector Model Specification.

The industrial sector ex post forecasts, for 1993 and 1994, are shown in Table 3. These annual forecasts are obtained by summing the quarterly forecasts generated by the specification shown in Table 5. As a percentage of actual usage, the specification underpredicted usage in 1993 by 0.13 percent and underpredicted usage in 1994 by 0.50 percent. The industrial sector model is the best performing model, in terms of 1993 and 1994 forecast errors, of the three customer class models.

Figure 3 presents actual and simulated quarterly usage in the Utah industrial sector from 1990 through 1992 as well as the ex post forecast and actual usage for 1993 and 1994. The 95 percent confidence band is also shown.

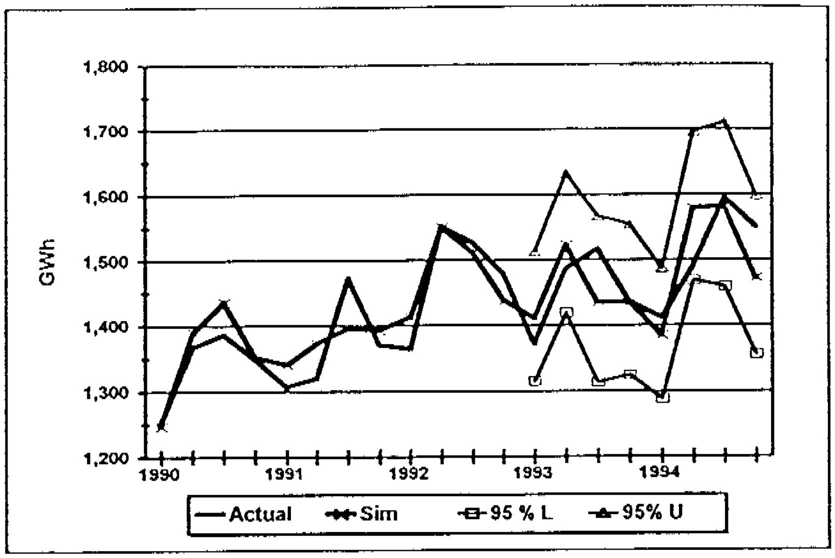

Figure 3. Industrial Sector Historical and Forecasted Usage.

Total Sector

Forecasts for total Utah service territory sales can be obtained by summing the individual customer class forecasts or through the use of a total territory equation. The latter technique would be appropriate if one did not have data at the sector level or if the aggregate model performed better. However, in order to fully exploit the detail of the supplied data and in order for the total sales forecasts to be consistent with the sector forecasts, the former methodology is employed below.

The total sector ex post forecasts, for 1993 and 1994, are shown in Table 3. These annual forecasts are obtained by summing the quarterly forecasts generated by the sector specifications shown in Tables 2, 4, and 5. As a percentage of actual usage, the specification overpredicted usage in 1993 by 0.12 percent and underpredicted usage in 1994 by 1.26 percent. The underprediction in 1994 is primarily the result of the weather induced underprediction of the residential model and, to a lesser extent, of the commercial model.

Figure 4 presents actual and simulated quarterly total usage in the Utah service territory from 1990 through 1992 as well as the ex post forecast and actual usage

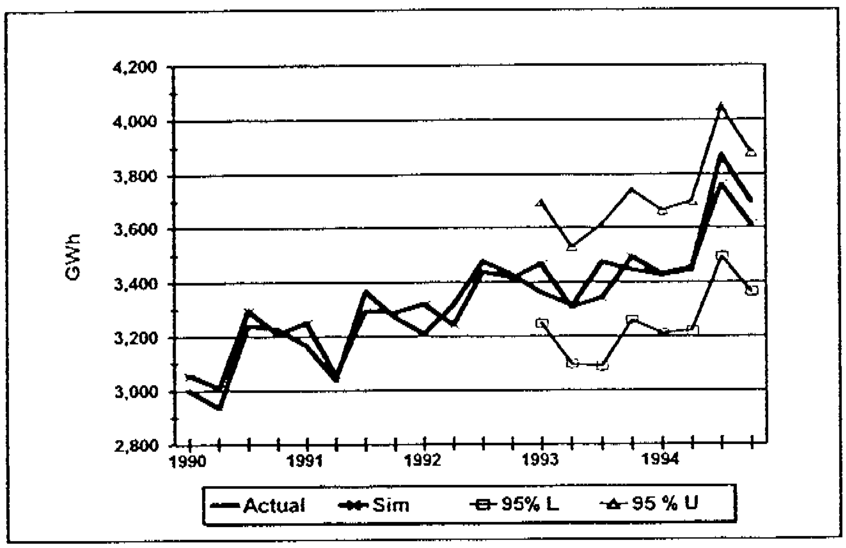

Figure 4. Total Sector Historical and Forecasted Usage.

for 1993 and 1994. The 95 percent confidence band is also shown. Visually, Figure 4 shows that the methodology yields a fairly accurate portrayal of total electricity usage in the Utah service territory.

The Numerical Experiment

The Subcommittee decided to conduct a two year experiment to estimate the effects of using the statistical recoupling methodology for PacifiCorp's Utah service territory. The experiment years are 1993 and 1994. That is, the model specifications shown in Tables 2, 4, and 5, which are based on data from 1978 to 1992, are used to ex post forecast usage in both 1993 and 1994.

Accounting Methodology

A detailed description of the statistical recoupling accounting methodology is found in Hirst (1993). Essentially, the methodology consists of three parts.

First, energy usage is ex post forecasted (simulated) for 1993 and 1994 as shown above. These forecasts yield *allowed* sales.

The second step involves estimating the revenue that is directly related to the recovery of fixed costs, defined on a per kWh basis as

$$P_{f,i} = ((\text{Total Revenue}_i\text{-Customer Charge Revenue}_i)/\text{Sales}_i) - P_{v,i}$$

where $P_{v,i}$ is energy cost per kWh and i is the customer class. The values used for $P_{v,i}$, taken from PacifiCorp's RAMPP II and III avoided costs with secondary sales, are 1.98 cents per kWh in 1993 and 1.77 cents per kWh in 1994. Customer Charge Revenue$_i$ refers to the revenue received from the tariff-listed customer charge and, hence, does not necessarily reflect the true cost of adding an additional customer to the system, as in the case of the Utah residential sector.

The final step involves calculating the dollars that flow through the recoupling account:

$$\text{Recoupling Account}_i = P_{f,i} * (\text{Allowed}_i - \text{Actual Sales}_i).$$

The methodology allows the utility to fully recover its energy cost and, except for the residential sector, most of its customer related cost. However, the portion of its fixed costs that it is allowed to recover depends upon the ex post forecasted sales. The dollars in the recoupling account represent by how much, in the following year, revenue should be changed to account for the discrepancy between actual and allowed revenues in the current year. These dollars can be expressed, for comparative purposes, in terms of the current year's allowed sales ($/kWh) and as a percentage of the current year's average sector price.

Findings

A summary of the Subcommittee's findings from this two year experiment are presented in Table 6.

Residential Sector

Actual residential sector usage in 1993 was 3,531 GWh yielding $247.0 million in revenue (shown in the first column of Table 6, upper portion). The residential model specification shown in Table 2 ex

1993	Residential	Commercial	Industrial	Total Sector
Without Statistical Recoupling				
Total Sales (GWh)	3,531	4,246	5,811	13,589
Total Revenues (million $)	$247.0	$241.0	$214.4	$702.4
Average Retail Price ($/kWh)	$0.070	$0.057	$0.037	$0.052
With Statistical Recoupling				
Actual				
Total Sales (GWh)	3,531	4,246	5,811	13,589
Total Revenues (million $)	$247.0	$241.0	$214.4	$702.4
Average Retail Price ($/kWh)	$0.070	$0.057	$0.037	$0.052
Allowed				
Total Sales (GWh)	3,511	4,290	5,804	13,605
Total Revenues (million $)	$246.0	$242.6	$214.2	$702.9
Revenue Difference (million $)	($1.0)	$1.6	($0.1)	$0.5
Recoupling Account (million $)	($1.0)	$1.6	($0.1)	$0.5
Price Adjustment Next Year				
$/allowed kWh	($0.000)	$0.000	($0.000)	$0.000
% change	-0.39%	0.65%	-0.06%	0.07%

1994	Residential	Commercial	Industrial	Total Sector
Without Statistical Recoupling				
Total Sales (GWh)	3,778	4,614	6,047	14,438
Total Revenues (million $)	$264.1	$257.6	$229.3	$750.9
Average Retail Price ($/kWh)	$0.070	$0.056	$0.038	$0.052
With Statistical Recoupling				
Actual				
Total Sales (GWh)	3,778	4,614	6,047	14,438
Total Revenues (million $)	$263.1	$259.2	$229.1	$751.4
Average Retail Price ($/kWh)	$0.070	$0.056	$0.038	$0.052
Allowed				
Total Sales (GWh)	3,695	4,545	6,016	14,256
Total Revenues (million $)	$259.9	$255.0	$228.6	$743.5
Revenue Difference (million $)	($3.2)	($4.2)	($0.5)	($7.9)
Recoupling Account (million $)	($4.2)	($2.6)	($0.6)	($7.4)
Price Adjustment Next Year				
$/allowed kWh	($0.001)	($0.001)	($0.000)	($0.001)
% change	-1.63%	-1.01%	-0.27%	-0.99%

Table 6. 1993 and 1994 Statistical Recoupling Effects.

post forecasts a usage level of 3,511 GWh in 1993. Since actual usage exceeds *allowed* sales, an adjustment to revenue is called for by the statistical recoupling methodology. In particular, revenue should be *reduced* in 1994 as the utility over-recovered its fixed costs in 1993 from the residential sector.

The difference between allowed and actual sales (20 GWh) multiplied by $P_{f,i}$ for the residential sector ($0.049/kWh) yields the amount that flows through the recoupling account ($1.0 million). Allowed fixed cost recovery revenue plus energy cost revenue (based on actual sales) plus customer charge revenue yields total allowed revenue of $246.0 million in 1993. Since actual sales exceeds allowed sales in 1993, the $1.0 million that flows through the recoupling account should be *subtracted* from total actual revenue in 1994. As a percentage of 1993 actual average price, this adjustment is equivalent to a change in the average price to the residential sector of -0.39 percent.

Actual residential sector usage in 1994 was 3,778 GWh yielding $263.1 million in revenue (shown in the first column of Table 6, lower portion). Total 1994 revenue consists of $264.1 million from actual sales *less* the $1.0 million adjustment from 1993. Allowed sales in 1994, determined by the specification shown in Table 2, are 3,695 GWh. Since actual usage exceeds *allowed* sales, revenue should be again subtracted in 1995 as the utility over-recovered its fixed costs in 1994 from the residential sector.

The difference between allowed and actual sales (83 GWh) multiplied by $P_{f,i}$ for the residential sector ($0.051/kWh) yields the amount that flows through the recoupling account ($4.2 million). Allowed fixed cost recovery revenue plus actual energy cost revenue plus customer charge revenue yields total allowed revenue of $259.9 million in 1994. Since actual sales exceeds allowed sales in 1994, the $4.2 million that flows through the recoupling account should be subtracted from total actual revenue in 1995. As a percentage of 1994 actual average price, this adjustment is equivalent to a change in the average price to the residential sector of -1.63 percent.

The net effect over the two year period is a transfer of $5.2 million from the utility to residential customers. The equivalent average change in the average price to the residential sector is -1.01 percent.

Commercial Sector

Actual commercial sector usage in 1993 was 4,246 GWh yielding $241.0 million in revenue (shown in the second column of Table 6, upper portion). The commercial model specification shown in Table 4 ex post forecasts a usage level of 4,290 GWh in 1993. Since *allowed* usage exceeds actual sales, revenue should be increased in 1994 as the utility under-recovered its fixed costs in 1993 from the commercial sector.

The difference between allowed and actual sales (44 GWh) multiplied by $P_{f,i}$ for the commercial sector ($0.036/kWh) yields the amount that flows through the recoupling account ($1.6 million). Allowed fixed cost recovery revenue plus actual energy cost revenue plus customer charge revenue yields total allowed revenue of $242.6 million in 1993. Since allowed sales exceeds actual sales in 1993, the \$1.6 million that flows through the recoupling account should be *added to* total actual revenue in 1994. As a percentage of 1993 actual average price, this adjustment is equivalent to a change in the average price to the commercial sector of 0.65 percent.

Actual commercial sector usage in 1994 was 4,614 GWh yielding \$259.2 million in revenue (shown in the second column of Table 6, lower portion). Total 1994 revenue consists of \$257.6 million from actual sales plus the \$1.6 million adjustment from 1993. Allowed sales in 1994, determined by the specification shown in Table 4, are 4,545 GWh. Since actual usage exceeds *allowed* sales, revenue should be reduced in 1995 as the utility over-recovered its fixed costs in 1994 from the commercial sector.

The difference between allowed and actual sales (69 GWh) multiplied by $P_{f,i}$ for the commercial sector (\$0.037/kWh) yields the amount that flows through the recoupling account (\$2.6 million). Allowed fixed cost recovery revenue plus actual energy cost revenue plus customer charge revenue yields total allowed revenue of \$255.0 million in 1994. Since actual sales exceed allowed sales in 1994, the \$2.6 million that flows through the recoupling account should be subtracted from total actual revenue in 1995. As a percentage of 1994 actual average price, this adjustment is equivalent to a change in the average price to the commercial sector of -1.01 percent.

The net effect over the two year period is a transfer of \$1.0 million from the utility to commercial customers. The equivalent average change in the average price to the commercial sector is -0.18 percent.

Industrial Sector

Actual industrial sector usage in 1993 was 5,811 GWh yielding \$214.4 million in revenue (shown in the third column of Table 6, upper portion). The industrial model specification shown in Table 5 ex post forecasts a usage level of 5,804 GWh in 1993. Since actual usage exceeds *allowed* sales, revenue should be *reduced* in 1994 as the utility over-recovered its fixed costs in 1993 from the industrial sector.

The difference between allowed and actual sales (8 GWh) multiplied by $P_{f,i}$ for the industrial sector (\$0.017/kWh) yields the amount that flows through the recoupling account (\$0.1 million). Allowed fixed cost recovery revenue plus actual energy cost revenue plus customer charge revenue yields total allowed revenue of \$214.2 million in 1993. Since actual sales exceeds allowed sales in 1993, the \$0.1 million that flows through the recoupling account should be *subtracted* from total actual revenue in 1994. As a percentage of 1993 actual average price, this adjustment is equivalent to a change in the average price to the industrial sector of 0.07 percent.

Actual industrial sector usage in 1994 was 6047 GWh yielding \$229.1 million in revenue (shown in the third column of Table 6, lower portion). Total 1994 revenue consists of \$229.3 million from actual sales less the \$0.1 million adjustment from 1993. Allowed sales in 1994, determined by the specification shown in Table 5, are 6,016 GWh. Since actual usage exceeded *allowed* sales, revenue should be reduced in 1995 as the utility over-recovered its fixed costs in

1994 from the industrial sector.

The difference between allowed and actual sales (30 GWh) multiplied by $P_{f,i}$ for the industrial sector ($0.020/kWh) yields the amount that flows through the recoupling account ($0.6 million). Allowed fixed cost recovery revenue plus actual energy cost revenue plus customer charge revenue yields total allowed revenue of $228.6 million in 1994. Since actual sales exceed allowed sales in 1994, the $0.6 million that flows through the recoupling account should be subtracted from total actual revenue in 1995. As a percentage of 1994 actual average price, this adjustment is equivalent to a change in the average price to the industrial sector of -0.27 percent.

The net effect over the two year period is a transfer of $0.7 million from the utility to industrial customers. The equivalent average change in the average price to the industrial sector is -0.17 percent.

Total Sector

The total sector effect is simply the sum of the individual sector effects.

Actual total sector usage in 1993 was 13,589 GWh yielding $702.4 million in revenue (shown in the fourth column of Table 6, upper portion). The sum of sector ex post forecasted usage for 1993 is 13,605 GWh. Since *allowed* total usage exceeds actual total sales, total revenue should be *increased* in 1994 as the utility under-recovered its fixed costs in 1993 from the Utah service territory.

The total amount that flows through the recoupling account is $0.5 million: ($1.0), $1.6, and ($0.1) million from the residential, commercial and industrial sectors. Since allowed total sales exceeds actual total sales in 1993, the $0.5 million that flows through the recoupling account should be *added* to total actual revenue in 1994. As a percentage of 1993 actual average price, this adjustment is equivalent to a change in the average total price of 0.07 percent.

Actual total sector usage in 1994 was 14,438 GWh yielding $750.9 million in revenue (shown in the fourth column of Table 6, lower portion). The sum of sector ex post forecasted usage for 1994 is 14,256 GWh. Since actual total usage exceeds *allowed* total sales, total revenue should be reduced in 1995 as the utility over-recovered its fixed costs in 1994 from the Utah service territory.

The total amount that flows through the recoupling account is ($7.4) million: ($4.2), ($2.6), and ($0.6) million from the residential, commercial and industrial sectors. Since actual total sales exceed allowed total sales in 1994, the $7.4 million that flows through the recoupling account should be subtracted from total actual revenue in 1995. As a percentage of 1994 actual average price, this adjustment is equivalent to a change in the average total price of -0.99 percent.

The net effect over the two year period for the Utah service territory is a transfer of $6.9 million from the utility to Utah service territory customers. The equivalent average change in the average price to the total sector is -0.46 percent.

Summary

The two year experiment suggests that the statistical recoupling methodology will lead to annual price changes that are, on average, within the plus or minus 0 to 2 percent range.

It should be noted that as long as actual and forecasted usage are within the 95 percent confidence interval graphically shown in Figures 1 - 4, the revenue transfers called for by the statistical recoupling methodology are essentially random and will sum to zero over the long run.

Discussion

The Subcommittee's discussion of the statistical recoupling experiment focuses on four topics: the performance criteria outlined in the August 1993 report on DSR cost recovery; statistical issues concerning implementation of the methodology and interpretation of findings; potential legal challenges to implementation of the methodology; and policy considerations.

Performance Criteria

After reviewing the results of the statistical recoupling experiment, the Subcommittee evaluated the methodology's ability to meet the performance criteria outlined in the August 1993 report on DSR cost recovery. What follows is an update to the 1993 report discussion on statistical recoupling presented in the Appendix. In general, the experiment showed that statistical recoupling has a number of advantages as well as some disadvantages to its implementation.

Understandable

A priori, statistical recoupling was assumed to be fairly understandable. However, initially, there was some confusion on the part of the Subcommittee members as to exactly what statistical recoupling sought to address and how it would actually work in practice. The methodology is *not* a mechanism for estimating net loss revenues. Rather, it simply removes the disincentive for the utility to pursue DSR investments. This initial confusion suggests that implementation of the methodology should be accompanied by additional education to eliminate such misunderstandings.

Predictable

From an econometric perspective, the ability of the models to explain the historical variation in quarterly utility kWh sales is very impressive. From the perspective of ex post forecasting actual sales, the models produced mixed results. For 1993, the models' predictions were fairly accurate. For 1994, the residential and, to a lesser extent, commercial models underpredicted kWh sales. This would have resulted in a substantial refund to customers.

The most plausible reason for the underprediction in 1994 is that the summer was abnormally hot. The actual number of heating degree days used to predict 1994 revenue was *outside* the range of observed heating degree days used to calibrate the models. The forecasting ability of econometric models is challenged when future conditions are outside the historical experience of the models.

Over the long run, differences between predicted sales and actual sales should sum to zero, assuming the models are unbiased. However, there can be a significant over- or underprediction in any given year.

Implementation of the methodology requires a fairly sophisticated level of econometric understanding and practical experience, similar to that exhibited in this report. This will help to ensure that the models are historically accurate and that the uncertainty surrounding the ex post forecasts is minimized.

Manipulation

Statistical recoupling potentially diminishes the incentive for manipulation. There may be some incentive to manipulate the estimation of the statistical recoupling model, but unless the manipulator can predict what economic or weather conditions will prevail in the future, the results of the manipulation cannot be forecasted. This will curtail manipulation.

Cost Minimization

Under statistical recoupling, the utility has no incentive to overstate its savings from DSR programs or to inflate the cost of such programs. Statistical recoupling will allow the utility to pursue low-cost energy saving programs such as building code revisions and educational programs, both of which lack incentives under a net lost revenue regime. In this way, statistical recoupling promotes cost minimization. In contrast, the net lost revenue mechanism appears to be susceptible to micro-management. As evidenced by members of the various subcommittees, a net lost revenue regime produced substantial debate and concern over what types of DSR programs should be implemented and how they should be evaluated. It is assumed that such discussion and debate would be minimized under a statistical recoupling mechanism.

DSR Program Evaluation

Statistical recoupling appears to substantially lessen the need for DSR program evaluation or net loss revenue determination. Moreover, it would make evaluation less contentious because explicit cost recovery issues are not involved. In contrast, the net loss revenue mechanism under the 1994 Commission adopted Joint Agreement requires a substantial amount of utility and regulatory resources to evaluate DSR programs and savings. The net lost revenue mechanism entails the actual determination of DSR savings by rate class. Although it does not completely eliminate the need for DSR evaluation, statistical recoupling appears to lessen the level of precision required. In addition, statistical recoupling eliminates the utility's incentives to overstate savings from such investments.

Rate Stability

Statistical recoupling appears to lead to greater rate instability than the net lost revenue mechanism adopted under the Joint Agreement. Statistical recoupling requires that the revenue discrepancy between allowed and actual revenues be transferred between ratepayers and the utility. Although, there are a variety of ways to handle this revenue transfer, the suggested approach is through a balancing account held in a deferred account until the next rate case. This minimizes rate instability under this regime. However, overall, statistical recoupling appears to lead to greater rate instability than a net lost revenue mechanism, at least, given PacifiCorp's recent levels of expenditure on DSR.

This was particularly true for the uncharacteristically hot year of 1994. The statistical recoupling mechanism, if in place in 1994 would have produced a revenue transfer of $7.4 million from the utility to the customers. This amounts to slightly less than one percent of gross revenues in 1994, but was substantially higher than the approximately $380,000 of net lost revenues calculated under the Joint Agreement. As mentioned above, over the long run, revenue transfers should sum to zero if the models are unbiased. However, in any given year, there can be a significant revenue transfer called for by the statistical recoupling methodology.

Risk

The $7.4 million difference between actual and allowed revenues in 1994 gave some members of the Subcommittee reason for concern. There was speculation that such large differences could have a financial impact on the utility. That is, the financial community (Wall Street) would evaluate this utility as being more risky. This led to a lengthy discussion on whether this mechanism provided an appropriate sharing of risk.

Under traditional regulation rates are set under certain assumptions regarding weather and economic conditions that affect the utility's sales. The utility and its shareholders are at risk if weather and economic conditions differ from the ratemaking assumptions. Statistical recoupling attempts to keep such weather and economic-related risks with the utility. To the extent that the models accurately simulate actual utility kWh sales, there should not be a substantive shifting of risk from the utility to the ratepayer over the long run. However, in any given year, such as 1994, risk maybe shifted to ratepayers to the extent that the models are inaccurate. In the final analysis, the impact of statistical recoupling on the utility's financial risk would depend on Wall Street's reaction to the methodology.

Other Criteria

Since this report covers a *hypothetical* experiment, the Subcommittee was unable to fully evaluate whether statistical recoupling would fulfill criteria that measure explicit changes in utility behavior. Definitive conclusions could not be drawn on whether this mechanism gave the utility the incentive to operate efficiently, whether it promoted the implementation of IRP principles, or eliminated disincentives to invest in DSR. However, it is the committee's opinion that statistical recoupling would likely promote these important performance criteria.

With regards to the cost recovery of actual DSR expenditures, statistical recoupling does not explicitly deal with the issue. It is meant to address the recovery of the implicit costs of net lost revenues. Hence, this criteria is not relevant to statistical recoupling.

Statistical

Confidence Intervals

The methodology calls for statistical forecasts of energy usage for the just completed year. These forecasts are statistical estimates about which there is some uncertainty. Since these forecasts make use of actual data (for the explanatory variables in the estimating equations), the quantification of the uncertainty surrounding the forecasts is facilitated (Pindyck and Rubinfeld, 1991). The uncertainty is graphically shown by the confidence intervals that are presented with the 1993 and 1994 forecasts in Figures 1-4. Statistically, if actual and forecasted energy usage fall within the shown confidence intervals, then the hypothesis that the two are equal cannot be rejected at the 95 percent level of confidence.

The issue concerns the practical

significance of this statistical finding. Clearly, one performance criterion for a forecasting model is that it generate forecasts that fall within the 95 percent confidence interval. However, whether recoupling adjustments should be made if actual and forecasted usage are *statistically* the same is a debatable issue.

Although yearly adjustments may not be justified on statistical grounds, they are probably necessary to secure the affected parties' cooperation. Over the long run, as long as the forecasting models continue to perform well (i.e., actual and forecasted usage fall within the 95 percent confidence interval), these adjustments should sum to zero.

Omitted Variable Bias

A variable that statistically affects energy usage but is not directly included in the forecasting equations will lead to biased forecasts. The magnitude of the bias depends upon the importance of the excluded variable in explaining energy usage.

Consider demand side management (DSM) programs as an example. If DSM programs are successful in *statistically* reducing energy usage, then forecast equations that do not directly include a DSM variable will generate *upwardly* biased forecasts. During the first year or two of DSM program development, this bias is likely to be small. However, if DSM programs expand and are effective in reducing energy usage, over time this bias will increase.

One of the characteristics of the statistical recoupling methodology is that, conceptually, it leads to small, random year-to-year changes in prices (via the recoupling account). However, the exclusion of a DSM variable will lead to non-random price changes over time, assuming that DSM programs statistically reduce energy usage. Moreover, over time, more and more dollars will flow through the recoupling account to the utility. This also assumes that there are no other omitted variables whose exclusion may offset the DSM bias.

The direct inclusion of a DSM variable in the estimating equations should lead to unbiased forecasts. However, it will not reverse the trend toward non-random price changes over time. The coefficient on the included DSM variable would capture the marginal effect of an increase in DSM activity (e.g., expenditures) on usage. If the utility is *not* to be dissuaded from engaging in DSM projects in the first place, then this estimated DSM effect will have to be added to the ex post forecasted sales. That is, allowed sales, and, hence, allowed revenues, will have to be adjusted upwards by the estimated DSM effect, assuming the estimated coefficient differs statistically from zero. The end result will be same as if the DSM variable was omitted from the equation. Over time, more and more dollars will flow through the recoupling account to the utility.

Recalibration

Econometric models stand a better chance of forecasting usage accurately when future conditions are similar to those in the past. As evidenced by the residential model's underprediction of usage in 1994, resulting from the uncharacteristically hot summer, it is important to recalibrate the models on a regular basis. Certainly no more than three years should pass before the models are reestimated using updated data.

Legal

Parties to the Subcommittee have raised two legal concerns surrounding the implementation of statistical recoupling. First, a recent Utah Supreme Court decision requires that utility rates be cost-based. As a result, incentives over-and-above utility costs are inconsistent with public utilities law in Utah.

This legal issue, however, may not be a barrier to the implementation of statistical recoupling. Statistical recoupling does not alter either the revenue requirement or price setting process that traditionally occurs in a rate case. As a result, rates will continue to be based on costs *at the time* of a rate case.

Over time and subsequent to a rate case, current regulation allows utility revenues to grow with sales. Depending on cost trends, revenues may or may not accurately reflect actual costs. To address these differences between revenues and costs, the DPU audits the Company's books to ensure that the divergence between costs and revenues is not too large and that rates continue to generally reflect costs.

Statistical recoupling would not materially change this process. Under statistical recoupling, utility revenues would grow according to the statistical relationships between sales and the other driving variables (e.g., economy, weather, etc) as captured in the historical models. On an expected value basis, this approach should generally yield the exact same amount of revenues as under current regulation where revenue is tied to sales growth. In any event, the DPU would still be auditing the Company's books to ensure that the divergence between costs and revenues is not too large and that rates continue to reflect costs. As a result, statistical recoupling is not a significant change from current regulation in this regard.

The second legal problem involves a 1986 Utah Supreme Court Decision that found that retroactive ratemaking was illegal under public utilities law in Utah. Concerns have arisen that this decision would make the implementation of statistical recoupling problematic in Utah. Again, the Subcommittee believes that this problem can be surmounted. The key finding in the Utah Supreme Court decision was that individual pieces of the revenue requirement formula can not be adjusted outside the context of a rate case. In a rate case, all costs and revenues can be comprehensively examined.

To avoid this problem, the reconciliation mechanism used to implement statistical recoupling can be structured as a deferral account. Under this approach, none of the expenses associated with the recouping mechanism will flow into utility prices until the time of the next rate case. This approach is consistent with the treatment of a number of supply-side investments and does not violate Utah public utilities law. As a result, by using deferral accounting mechanisms, the Subcommittee believes it could be legal to implement statistical recoupling in Utah.

Policy Considerations

Statistical recoupling is intended to eliminate the net lost revenue disincentives associated with DSR investment and provide broad incentives for the utility to supply electric energy services efficiently. Under traditional regulation, the utility has an incentive to increase sales between rate cases since any sales over the assumed level used in the prior rate case can result in additional profits for the utility. Under statistical recoupling, the utility's between-rate-case revenues are determined by the ex post simulation of the model, *not* actual kWh sales. Thus, the utility has less incentive to increase sales and less disincentive to pursue DSR investments, particularly if they are more economical than supply-side resources.

If statistical recoupling had been in effect during 1993 and 1994, and assuming that a rate case were held in 1995, ratepayers would see a $6.9 million reduction in the revenue requirement associated with the implementation of this methodology. This would have been the short run impact. In future rate cases, the adjustment could prove to be in favor of the utility. Moreover, the size of the adjustment would depend on the magnitude of the annual ex post forecast error and when a rate case took place. For example, the longer the period of time between rate cases, the greater the chance that years in which sales were underpredicted will be offset by years in which sales are overpredicted. That is, in the long run, the expected value of the revenue transfer is zero.

If implemented for the long run, the statistical recoupling methodology may be a workable method to address the problem of eliminating many of the disincentives associated with DSR investment. Moreover, it appears to send the correct signals to the utility to implement its integrated resource plan efficiently.

However, given PacifiCorp's current level of DSR investment, the Subcommittee members remain concerned about the potential size of the revenue transfer created by the methodology. This is the primary reason that the Subcommittee can not recommend the adoption of the statistical recoupling mechanism at this time. However,if DSR becomes a larger portion of the utility's resource mix, then this mechanism may hold promise.

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Appendix

Demand-Side-Resource Collaborative Report

August 31, 1993

Statistical Recoupling: pp. 24-26

Like other "decoupling" approaches, statistical recoupling first breaks the linkage between utility revenues and sales. In a second step, revenues are recoupled to estimated electricity use. Also like other decoupling mechanisms, this approach does not alter the regulatory determination of utility revenue requirements or the method for setting utility prices coming out of a rate case.

Statistical recoupling promotes implementation of the IRP and hence, the requisite investment in DSR, because it removes the ***disincentive of lost sales*** due to DSR that exists under current regulation. Statistical recoupling entails specifying an econometric model that explains the relationship between sales and the explanatory variables that are deemed appropriate to include in the model. Thus, statistical recoupling potentially provides full cost recovery for DSR that is consistent with the IRP. This explanatory relationship between sales and the explanatory variables is determined based on historical data. To determine the appropriate (allowed) level of sales in the current year, values for the explanatory variables in the current year are plugged into the model to determine the appropriate level of sales upon which the revenue requirement is determined. This process removes the Company's incentive to increase inefficient consumption of electricity since the Company will not be allowed to keep revenue due to sales that exceed the level determined by the statistical recoupling model. The difference between the allowed revenue and actual revenue goes either into a balancing account or a tariff rider. If the Company acquired revenue in excess of the allowed level, rates would decrease, giving the difference to ratepayers. If the Company's revenue fell short of the allowed level, rates would increase, providing the Company with the allowed level of revenue.

Statistical recoupling breaks the link between revenue and sales in a manner that addresses many of the shortcomings of decoupling. Statistical recoupling resolves the problem of shifting the ***risks*** of weather and the economy from shareholders to ratepayers under decoupling. Under statistical recoupling the utility retains those risks. Statistical recoupling does not have the disincentive for maintaining quality inherent in RPC decoupling which predetermines revenue based on the number of customers, independent of quality of service. Statistical recoupling also removes the incentive to build load yet does not discourage economic development since it allows the utility to keep revenue between rate cases associated with sales due to increased productivity. In fact, statistical recoupling retains an incentive for economic development, explicitly linking allowed revenues to an index such as employment or industrial output. In contrast, current regulation rewards PacifiCorp for selling more electricity no matter how inefficiently or uneconomically that electricity is used. Since statistical recoupling breaks the link between revenue and sales, not profit and sales, statistical recoupling does not discourage ***cost minimization*** as it maintains the same incentive to decrease cost between rate cases as does rate-of-return regulation. Additionally, by comprehensively breaking the linkage between revenue and sales, statistical recoupling would enable PacifiCorp to promote a diverse range of ***efficiency*** activities including information programs, building and appliance efficiency standards, and innovative rate designs, options that are likely to be especially cost-effective. Thus, this regulatory reform can help reorient PacifiCorp's corporate culture towards an energy services future that realizes the economic and environmental benefits of greater energy efficiency.

This approach appears to have little potential for ***gaming*** because the parameters of the model, i.e. coefficients on the explanatory variables, are determined using data prior to the current year. It seems extremely difficult to strategically game the model when one cannot predict the values for the explanatory variables in the current year. Before-the-fact the utility should not be able to game model development, unless it is able to forecast accurately the weather and economic indices.

Coupled with a DSR program cost recovery mechanism, it has the virtues of making the Company whole with respect to DSR investment and appropriately shares ***risk*** and benefits between ratepayers and shareholders. Since it does not require calculation of lost revenue, ***micro-management*** and oversight of programs is reduced. Statistical Recoupling reduces the contentiousness of ***evaluation*** because DSR programs are evaluated for the purpose of assessing performance and not for determining a dollar amount upon which the Company receives lost revenue.

Concerns regarding the ***unpredictability*** of this approach arise not because of an inherent feature in the methodology but rather because of the inexperience of regulators with this approach. No state has yet adopted this relatively new approach toward resolving the lost revenue problem. Only three years of data on the merged Company are available to empirically examine the stability of the statistical recoupling methodology using PacifiCorp data. Results of an analysis of the impact of statistical recoupling on Utah Power & Light (UP&L) using fifteen years of data for UP&L provide an opportunity to examine and evaluate the statistical recoupling methodology. Empirical analysis conducted by Eric Hirst and Eric Blank on five utilities indicated relatively small ***rate*** impacts, i.e. rates peaking in the 1-2% range on a total company basis. (See "Regulatory Reforms that Remove Disincentives to Electric-utility DSR Programs in Utah", June 1993. For a more extensive analysis of statistical recoupling see "Statistical Recoupling: A New Way to Break the Link Between Electric-Utility Sales and Revenues", Eric Hirst, Oak Ridge National Laboratory, forthcoming.) This approach, by itself, should neither raise nor lower rates on an expected value basis. To the extent that statistical recoupling does indeed have relatively small ***rate*** impacts, this reduces the contentiousness of ***allocating the costs and benefits*** between classes of customers and between participants and non-participants. Statistical recoupling does not address how costs and benefits are allocated. This is considered an issue that is appropriately addressed by rate design.

The model does not appear excessively difficult to ***administer***. Eric Hirst recommended reexamining the relationship between sales and the relevant explanatory variables every three years. This allows for respecification and reestimation of the model as appropriate. However, to the extent that specifying an econometric equation that appropriately captures the impact of the relevant explanatory variables on sales of electricity is difficult, this can increase administrative complexity. Statistical recoupling may be implemented by using a balancing account which increases administrative complexity to the degree that balancing accounts are difficult to administer. (Alternatively, statistical recoupling could be implemented using a tariff rider.) Once the model is specified, allowed revenues are relatively easily measured. The process may require a few ***modifications*** in implementation as experience necessitates, given the relatively novel nature and complexity of statistical recoupling. The methodology of statistical recoupling is easier to ***understand*** than that of decoupling, but in any case, complex relative to other mechanisms for addressing lost revenue.

Statistical Recoupling may create a regulatory environment similar to the environment under the former Energy Balancing Account in which the ratemaking process for establishing rates to ensure an authorized rate-of-return was conducted independent of implementing rate adjustments due to changes in the balancing account. Under a statistical recoupling regulatory regime the possibility of ***unintended consequences*** is increased, e.g. statistical recoupling may necessitate a rate increase while Company earnings in excess of its authorized rate-of-return necessitate a rate decrease.

It is unclear whether statistical recoupling is ***legal***. Statistical recoupling may constitute retroactive ratemaking which is illegal.

DEMAND SIDE RESOURCE COST RECOVERY COLLABORATIVE REPORT

APPENDIX V

FINAL REPORT - SHARED SAVINGS AND TOTAL FACTOR PRODUCTIVITY SUBCOMMITTEE DATED FEBRUARY 8, 1995

SUBMITTED
MARCH 31, 1995

SHARED SAVINGS AND TOTAL FACTOR PRODUCTIVITY
SUBCOMMITTEE REPORT
February 8, 1995

THE SUBCOMMITTEE

The Joint Recommendation listed Shared Savings and Total Factor Productive (TFP) mechanisms as important issues for the new Cost Recovery Collaborative to study and report on. The Cost Recovery Collaborative created a subcommittee called the Shared Savings and Total Factor Productivity Subcommittee to study and provide recommendations on these issues. The Subcommittee is comprised of representatives from the DPU, CCS and the PacifiCorp. This is the report to the Cost Recovery Collaborative of subcommittee:

The report is divided into six parts;

I. SUBCOMMITTEE CONCLUSIONS AND RECOMMENDATIONS

The subcommittee members concluded that, given that PacifiCorp receives the opportunity to earn a "fair return" on its DSR investments no other incentive mechanism is needed. A "fair return" may be defined differently by different parties. The subcommittee members believe that PacifiCorp's desire to be the low cost provider of energy services is a powerful incentive to choose the lowest cost portfolio of resources, either supply side or demand side. Incentive payments add to the cost of DSR programs and put additional upward pressure on rates thus reducing the utilities ability to be competitive. Incentive payments increase administration costs and influence program evaluation methods. Also, there are potential unintended consequences of targeting incentives toward only one segment of PacifiCorp's operations.

Based on the foregoing discussion, the subcommittee members determined that their primary recommendations to the Cost Recovery Collaborative should be;

1. If PacifiCorp is provided with adequate opportunity to receive a fair return on their DSR investments, a DSR incentive mechanism is unnecessary. A fair return on DSR investments may be defined as DSR program cost recovery without a carrying charge from the time of capitalization until a rate case, and may include a net lost revenue adjustment or statistical decoupling mechanism. It may also include an AFUDC type carrying charge within the year of construction.

2. A Shared Savings incentive program may not fit within the guidelines of the recent Utah Supreme Court order in the U S West case. That order required incentive plans to be linked to cost of service. Shared saving incentives may not be linked to cost of service and would require further legal analysis before adoption.

3. While this subcommittee is not recommending any incentive mechanism, if the Commission determines that an incentive mechanism is needed in addition to a fair return on DSR investment, the mechanism could be an environmental impact incentive related to potential NOX and CO2 taxes savings and thus more related to cost of service. The incentive could be in the range of 15 mills per kWh of DSR, or about $600,000 for 40,000 MWH of savings.

4. If a fair return on DSR investment is not afforded PacifiCorp, an environmental impact incentive mechanism should be adopted that is large enough to equalize the treatment of DSR and SSR programs.

5. A Total Factor Productivity mechanism that rewards the utility for increases in efficiency is not an appropriate candidate to equalize the treatment of DSR and SSR measures because Utah's DSR measures are too small to measure in comparison to total company costs.

II. HISTORY OF FINANCIAL INCENTIVES FOR DSR

An October 1993 NARUC survey on state-specific approaches to DSR incentive mechanisms indicated that approximately 30 state commissions have experimented with various types of incentive mechanisms. These incentive mechanisms have tended to be utility-specific rather than generically developed and applied within a given state. In the past, it appears that some state commissions played loose and fast with financial incentives for DSR as they attempted to levelize the playing field between DSR and SSR. However, many of the incentive experiments that were launched over the past few years are coming up for evaluation and state commissions are either rethinking the need for DSR incentives or are reinventing incentive mechanisms with different objectives in mind (e.g., incentives should be linked to performance standards rather than DSR expenditure targets).

The predominant incentive scheme implemented by commissions is the shared savings method (approximately 17 states). At this juncture there has been minimal assessment of this method, or of alternative DSR incentive mechanisms, as to whether any method has been effective in stimulating utilities to acquire economically feasible amounts of DSR. Finally, some states have adopted financial incentives along with lost revenue mechanisms, while other states view that financial incentives obviate the need for recovery of lost revenues.

During the year that this subcommittee has met it has become abundantly clear that the electric utility industry is about to undergo radical transformation. The Energy Policy Act, California's PUC's proposal to allow direct access and technical changes in resource generation are opening the industry to new market forces. The emergence of competition in the industry influenced the subcommittee's decisions regarding incentive programs that tend to increase utility prices.

Also during the past year the Utah Supreme Court issued an order reversing prior Utah PSC decisions adopting incentive regulation for U S West. This order also influenced the subcommittee opinions and decisions on incentives for PacifiCorp's DSR programs.

The principal purpose of an incentive mechanism is to create a regulatory environment in which the utility is neutral in its selection of either demand-side resources or supply-side resources based on total resource cost. The incentive mechanism can be used alone (i.e., in place of) or in combination with other mechanisms such as lost revenues or recoupling.

The subcommittee members decided to make three alternative recommendations to the Cost Recovery Collaborative and to the Utah Public Service Commission. Each addresses a different alternative available to the Commission. These alternative recommendations are:

1. An incentive mechanism used in conjunction with other cost recovery mechanisms; such as Net Lost Revenues (NLR), recovery of program costs, or statistical recoupling;

2. An incentive mechanism that could be used alone without any other cost recovery mechanisms; this would be a substitute for NLR and reasonable recovery of program costs;

3. A total factor productivity mechanism that could be used in lieu of specific DSR incentives; but would still require recovery of program costs.

There is a potential for unintended consequences in targeting an incentive toward a particular aspect of PacifiCorp's operations, namely DSR. Unintended consequences refers to the tendency of a mechanism to produce an outcome that is contrary to ratemaking goals. Therefore the subcommittee studied a total factor productivity mechanism that would reward efficient performance in all aspects of utility operations.

III. <u>INCENTIVE MECHANISMS</u>

A. Types of incentive mechanism

As previously reported to the Commission in the August 1993 DSR Collaborative/Technical Conference Report (Report), there are six solutions based on incentives mechanisms used by other state commissions. They are:

1. no incentive mechanism
2. shared savings
3. bounty per unit savings
4. markup on expenditures
5. adjustment on overall return on equity
6. bonus return on equity on capitalized DSR

1. No Incentive

This solution has two options. If PacifiCorp is given an opportunity to earn a fair return on its DSR investments, including NLR, there may be no need for additional incentives. If this opportunity does not exist, then incentives could play an important role in equalizing the treatment of DSR and SSR.

The disadvantage to this solution is that if PacifiCorp perceives that either it does not have an opportunity for full recovery of DSR costs, or that the solution does not adequately reduce the disincentives associated with NLR, PacifiCorp may not have the incentive necessary to follow its IRP.

However, PacifiCorp's desire to be the low-cost provider is a powerful incentive to choose the lowest cost portfolio of resources. PacifiCorp's position is that with fair rate treatment of DSR investment no additional incentives are necessary. Incentive payments add to the cost of DSR programs and put additional upward pressure on rates. PacifiCorp states in its RAMPP-3 Report at page 239:

> "The company's largest concern is the impact on price levels. The company takes very seriously the changes which are making the business environment more competitive. This has led to a strong commitment to be a low-cost producer and to keep retail prices competitive. **The market may preclude higher prices even if the regulatory commissions were willing to allow prices high enough to provide for full cost recovery.**" (emphasis added)

Additional disadvantages of incentive payments include increased administration and influence on program evaluation methods. Also, there are potential unintended consequences of targeting incentives toward one segment of PacifiCorp's operations.

2. Shared Savings

This mechanism allows the utility to keep a share of DSR program savings as retained earnings. The incentive payment is a portion of the difference between the cost of the DSR program and the value of its benefits. This is typically defined as the measured or estimated load reduction in kW or kWh multiplied by the value of avoided supply cost minus DSR program costs. Program costs can be defined as either utility costs or total resource costs.

Shared savings is the most common form of regulatory incentive. The incentive is typically structured as a reward-penalty mechanism or it can be structured to address recovery of program costs and net lost revenue. A threshold kW or kWh target can be established that must be met for a utility to receive the incentive. The incentive can be front end loaded or earned annually by the utility or delayed and recovered in the context of a rate case.

Since the incentive is based on net resource value, shared savings is performance based and rewards cost-effective DSR. The flexibility in structuring shared savings allows the procedure to address risk sharing between ratepayers and shareholders. Once established, a shared savings mechanism should be predictable and transparent.

The main disadvantage of shared savings stems from administration difficulties. Highly subjective or imprecise measurement and evaluation techniques may invariably foster contentious issues affecting the magnitude of the incentive reward or penalty. A second disadvantage relates to its potential for unintended consequences because only one aspect of the utility operations is being considered for incentive rewards.

3. Bounty Per Unit Savings

Bounty per unit savings is an incentive payment that is based on a fixed dollar amount for each kW or kWh saved from DSR programs. Since the incentive is not dependent upon the costs of the DSR program, this method does not provide any incentive to secure the appropriate amounts of cost-effective DSR.

4. Markup on Expenditures

This solution provides the utility with an incentive payment based on DSR program expenditures. The incentive is a percentage adder on DSR program costs which is readily measurable. The advantage of this approach is that it requires no measurement or evaluation of program-specific kW and kWh savings (i.e., program cost-effectiveness). The chief disadvantage with this method is that the incentive is activity based and not performance based. Stated differently, such a scheme provides a perverse incentive to the utility to increase DSR spending because the more dollars spent the greater the incentive payment. Consequently, most commissions have rejected this method because it may paradoxically reward a utility for investing in DSR that fails to meet cost-effectiveness criteria

5. Adjustment to Overall Return on Equity

To compensate a utility for lost profit due to DSR investments, or as an incentive for meeting DSR targets, commissions could increase a utility's overall rate of return during rate cases to a higher level.

This solution could be structured to be performance based, and could include program costs and net lost revenue. Due to the infrequency of PacifiCorp rate cases, once started this method is difficult to adjust or stop. Timing differences between DSR expenditures and subsequent recovery through a higher rate of return leads to uncertainty of recovery.

6. Bonus Return on Equity on Capitalized DSR

This approach assumes that DSR costs are capitalized and an increased rate of return is applied to only the investment in DSR in rate base. This incentive tends to be very small because the investment in DSR is not large compared to total rate base. If used to include recovery of program costs this solution may not provide sufficient incentive to encourage the utility to implement DSR measures even where cost effective because the incentive is not directly linked to the DSR activity..

B. Impact of the Utah Supreme Court Decision

On July 29, 1994, the Utah Supreme Court issued an opinion in Docket 910405, entitled petitioners v. Utah Public Service Commission and US West Communications. The order addressed the Commission's order allowing USWest an incentive program. The order stated:

> The Commission's order is defective for a number of reasons. First, it was entered without notice to any party or a hearing on the merits of the plan. Second, the plan essentially forsakes cost-of-service principles as required by Title 54 of the Public Utilities Code. The sharing of revenues begins at 12.2%, but all earnings over and above that percentage that USWC can retain are necessarily excessive because they are not justified by any cost-of-service principle. Nor can they be justified that they provide an "incentive" for USWC to invest in Utah....For all the above reasons, the Commission's incentive plan is arbitrary, capricious, and unlawful.

It is appears that for any future incentive plans to pass muster they must be tied to cost-of-service principles. The subcommittee necessarily found that a Shared Savings plan in which the difference between avoided cost and resource acquisition cost are shared between customers and investors may not be tied to cost of service. Indeed it is difficult to craft any incentive plan that is based on cost-of-service principles. This issue requires further legal analysis.

C. Environmental Impact Incentive Option

One incentive plan that it may be argued is tied to cost-of-service is an environmental impact incentive. It is anticipated that in the future taxes may be based on the tons of NOX and CO2 that plants emit into the atmosphere. PacifiCorp's RAMPP II uses estimates of $2,000 per ton for NOX and $25 per ton for CO2. These estimates may also represent an estimate of the damage done to the environment by these substances.

If DSR programs reduce kWh consumption and therefore emissions, then there may be some future tax savings or some measure of reduced environmental impact. Using the estimates stated above, the impact of 40,000 MWh of DSR can be measured at approximately 33 mills per kWh or $1,320,000. An environmental incentive that was split between customers and shareholders may pass cost-of-service standards. This would put an incentive in the 15 mills per kWh range or about $600,000 for shareholders and customers. A disadvantage to adopting an environmental incentive is that it could take lengthy hearings to arrive at the appropriate environmental damage estimates.

IV. TOTAL FACTOR PRODUCTIVITY

The subcommittee built a model following the outline of the previously proposed TFP model. The original model was constructed in the 1980 when costs were rising and the Energy Balancing Account existed. The subcommittee measured the actual results from 1989 through 1992, and attempted to determine if an incentive award would have been available to the Company based on 1993 actual results. By using this time period, only post merger results were measured. The subcommittee also created a submodel to measure production costs since the EBA no longer exists. The model consists of 5 submodels that measure different components of the utility. These results are combined to determine if the current years' operating results falls with in a 5% deadband around the statistically projected results. Four of the submodel results had downward trend, this required increased efficiency measures to obtain operating results below the 5% deadband.

Four of the five submodels were based on total company operating results, only the distribution submodel was based on Utah costs. When the impact of DSR programs is added back to the kWh figure, total company DSR program activity was the appropriate figure to use, not Utah only kWh savings. In addition it was found that DSR savings were immaterial when compared to the total company kWh generation.

The subcommittee determined that the TFP model was inappropriate to use in equalizing DSR and SSR treatments. The model requires the use of total company expenses and rate base and to be comparable total company DSR savings estimates must be used. If Utah only DSR savings are used they are immaterial in comparison to the total company figures. Also the model was designed to measure reductions in areas where costs are normally increasing. The current period, 1990 to 1994, reflects declining costs. In order to achieve any incentive award during a declining costs period, costs must decrease greater than they have in the past. That is an unlikely outcome, and it is unlikely PacifiCorp would ever earn an incentive award under the TFP model, even if DSR activity in Utah had been exceptional.

V. POSITIONS OF THE PARTIES

The subcommittee reviewed the positions of the parties contained in the August 1993 *Demand-Side-Resource Collaborative Report* Appendix 1 and found their positions to be very similar to our recommendations. Therefore we have restated these positions below.

PacifiCorp stated, "PacifiCorp believes that if the Company is provided with adequate opportunity to receive a fair return on their DSR investments, an additional incentive program may be unnecessary. However, if an incentive program is desired, the Company feels a shared savings approach may be beneficial. A shared savings approach could provide a useful tool for encouraging development of cost-effective DSR while balancing risks between the Company and its customers. If the Cost Recovery and Lost Revenue proposals that are adopted give the Company an adequate opportunity to receive a fair return on their DSR investments, then this should provide the Company with sufficient incentive to invest in DSR programs.

The **Division of Public Utilities** stated, "It is not clear to the Division that incentives are necessary. Out of the possible incentive mechanisms examined during this technical conference / collaborative process, the Division considers shared savings to be the most effective mechanism for encouraging the Company to invest in cost-effective DSR. One shared savings mechanism under consideration entails the following:

1) a two-year sunset provision...
2) symmetry between rewards...and penalties...
3) ex ante estimates of savings adjusted on a forward-going basis consistent with verified achieved savings."

The **Committee of Consumer Services** stated, "The Committee firmly believes that financial incentives are not required to spur the Company to acquire demand-side resources. In adhering to its IRP, Company management has the responsibility to acquire the cost minimizing combination of resources, whether they be supply-side or demand-side resources."

The **Environmental Intervenors** stated, "EI recommends that a small financial incentive, perhaps a shared savings incentive mechanism be adopted. EI suggests linking these incentives to PacifiCorp's ability to meet its DSR and rate impact targets. Such linking would encourage adoption of PacifiCorp's least cost plan given DSR target based on RAMPP."

"Although important in encouraging desired utility behavior, financial incentives mechanisms tend to result in relatively small dollar transfers when compared to net lost revenue and cost-recovery adjustments. Thus, any final determination about financial incentives should probably await greater clarity on these other issues. As a general matter, however, we support shared savings approaches, They provide a strong incentive for the utility to obtain large electricity savings, but leave the majority of the benefits with utility customers. Moreover, these approaches appear to have worked fairly well in other states that have used them."

Deseret Generation and Transmission stated, "DG&T does not advocate incentive for DSR."

The **Office of Energy and Resource Planning** stated, "We are not convinced that an incentive mechanism is the best way to address providing regulatory incentives for DSR at this time. We think that the incentive mechanisms discussed in the collaborative report require further exploration. We are especially interested exploring the development of a performance based shared savings mechanism. Such a mechanism could assist regulators in reviewing the achievements of the Company efforts in relation to the goals set forth in the Company's IRP. It could also promote cost minimization by encouraging the Company to implement its IRP, could identify and address inequities between ratepayers and shareholders and could reduce the disincentives associated with lost sales absent statistical recoupling or net lost revenue adjustment. We prefer to address the ratemaking treatment problems outlined in the beginning of this paper by focusing on removing the disincentives to DSR investment. However, we consider the development of an incentive mechanism as a viable option to be considered."

The **Utah Industrial Energy Consumers** stated, "UIEC is strongly opposed to attempts to provide incentives or rewards to utility management that are targeted specifically to DSR. It is inappropriate to focus the appraisal of management performance on a single item. This approach substantially tilts the playing field and could easily lead to the implementation of DSR that is not cost-effective and not in the best interest of customers.... No other party is seriously advancing the concept of shareholder incentives....While UIEC is opposed to the provision of incentive specifically targeted to one area, it does believe that a shared savings approach is the most logical, if incentives for DSR are adopted."

VI. SYNOPSIS OF THE CONCLUSION

While none of the parties believes that the incentives mechanisms reviewed in this report are currently appropriate, the parties do agree that two years of additional experience in administrating a net lost revenue program will be beneficial particularly during a time when the electric utility industry is undergoing dramatic change. During this time the parties may return to reexamine the alternatives described in this report. One method of particular interest for reexamination is the environmental incentive mechanism.

DEMAND SIDE RESOURCE CAST RECOVERY COLLABORATIVE REPORT

APPENDIX VI

FINAL REPORT - RATE SPREAD AND NON-PARTICIPANT IMPACTS SUBCOMMITTEE DATED MARCH 14, 1995

SUBMITTED
MARCH 31, 1995

Demand Side Resource
Cost Recovery Collaborative

Rate Spread & Non-Participant Impact Subcommittee

Final Report

March 14, 1995

INTRODUCTION

The Rate Spread and Non-Participant Impact Subcommittee (Impact Subcommittee) was formed as a part of the DSR Cost Recovery Collaborative. Its purpose was to explore ways to mitigate any adverse effects of DSR programs on the customers who do not participate in those programs. The subcommittee was established with three members, but because of increased interest in the topic it grew to the following seven members.

Lowell Alt	Division of Public Utilities
Ron Burrup	Division of Public Utilities
Mark Flandro	Division of Public Utilities
Dan Gimble	Committee of Consumer Services
Craig Johnson	PacifiCorp
Jim Logan	Utah Public Service Commission Staff
Dave Taylor	PacifiCorp

Mission of DSR Impact Subcommittee

Assess and make recommendations regarding the impact of DSR programs on non-participants.

Goals of DSR Impact Subcommittee

Review and apply different methods for evaluating the impact of DSR investments on non-participants

Look at Company programs and assess their impact on non-participants

Examine ways to minimize the impact of DSR programs on non-participants

Review and make recommendations on how DSR costs should be treated in class cost of service studies

Summarize findings and recommendations in a letter to the DSR Cost Recovery Collaborative and the Commission

RECOMMENDATIONS

DSR Program Strategies

The subcommittee concluded that the best way to mitigate impacts of DSR investments on non participants is to collect as much of the cost as possible from the direct participants. This can be accomplished through increased levels of Energy Service Charge (ESC) payments or some other means of customer participation charges. It can also be accomplished when customers follow effective price signals and pursue energy efficiency on their own.

Our analysis of Utah Power's prices in the State of Utah show that they are equal or greater than long run marginal cost in most cases. As such there are financial incentives for customers to make investments in energy efficiency. The utility should promote energy efficiency by providing information on the benefits and the availability of cost effective DSR measures. The utility can, and perhaps should, facilitate market based transactions between customers and reputable vendors.

Cost of Service Allocation Methods

The subcommittee determined that all reviewed procedures for allocating DSR costs in embedded cost of service studies had shortcomings. Based on our study of 1993 DSR expenditures in Utah, we felt that using demand and energy factors to allocate net DSR costs (DSR costs less participation charges) to all customer classes was the best overall approach. While this method may result in some adverse price impact for all customers, it results in the most even distribution of the impacts on nonparticipants of the methods tested.

Preliminary studies performed using available 1994 data appear to support this recommendation. As more complete 1994 data become available, a more thorough analysis will be performed and the results communicated to the DSR Cost Recovery Collaborative.

Additionally, although it is far from ideal, it follows more closely the traditional principles of cost causation. It is based on the belief that DSR investments are made to meet the demand and energy requirements of all customers.

The Direct Assignment and Split Rim methods were rejected because, although they reduced or eliminated adverse effects on customers in classes other than the participants class, the methods resulted in greater adverse impacts on non participating customers within the participants class. We felt that, just because they happen to purchase electricity on the same rate schedule as the participant, a customer should not bear a greater responsibility to pay for DSR programs than any other customer. This is particularly true when many of these customers are not eligible to participate in the utility's programs.

This procedure for allocating DSR costs to customer classes differs in some respects from the treatment of DSR costs in the interjurisdictional allocation process. Upon the agreement of the PITA members, DSR costs are assigned to the states in which they are incurred and in which the various programs are offered. We feel that procedure is appropriate. Each of the seven states PacifiCorp serves has a different philosophy toward Demand Side Resources. Those philosophies may differ in the level of DSR that should be acquired, what types of programs a utility should offer, and to what level they are willing to let prices increase to recover DSR costs.

Once costs have been assigned to a specific state, however, those costs still must be recovered from customers. This is true for DSR costs, distribution costs, or any other costs that are assigned directly to states. DSR costs, at the level agreed upon in a state, should then be allocated to customer classes in that state in a way that minimized the impacts on all nonparticipating customers.

ANALYSIS

In the process of developing the above recommendations, the subcommittee conducted a review of much of the literature, filed testimony, and regulatory action relating to mitigating the impacts of DSR investments on non participating customers. These items were discussed by the subcommittee and augmented by each member's view of how demand side resources fit into the ratemaking process. The subcommittee focused its efforts in three areas: How the impacts of DSR investments are measured, how to design strategies and programs in such a way as to mitigate rate impacts, and how to treat the costs of DSR programs in class cost of service studies.

How the impacts of DSR investments are measured

In our review of the impacts of DSR investments on non participants we reviewed the four California Standard Practices Manual Tests. These test look at how DSR costs and benefits are measured in total. Each of the four tests measures the impact of DSR investments on a different parameter.

Participant Test	=	Impact on Direct Participants
Utility Cost Test	=	Impact on Utility Revenue Requirement
RIM Test	=	Impact on Average Cost per kWh
TRC Test	=	Impact, in the aggregate, on All Parties

While these test may do an effective job of measuring the effects of DSR costs in total, only the RIM test makes an attempt to address the impact on non participants. Even the RIM test measures the effect of DSR investments on the average cost per kWh, not the effect on individual customers.

DSR Program Strategies designed to mitigate rate impacts

The subcommittee identified eight DSR program strategies designed to mitigate rate impacts on non participants. Several of these are discussed in an article published in *The Electricity Journal* written by John Chamberlain, Patricia Herman and Greg Winkler. These strategies, plus several pro and cons of each, are:

1. Only accept DSR programs that pass the Rate Impact Measure (RIM) test.

Advantages: By definition, programs that pass RIM do not increase the unit cost per kWh. As a result, prices for non-participating customers would not be increased. This strategy would be easy to understand and implement.

Disadvantages: Because rates are very often above avoided costs, very few DSR programs pass the RIM test. This has certainly been the case at Utah Power. If this is the case at Utah Power, where rates are below national average, it would be even more the case for most other utilities. It is doubtful that Utah Power, or most any other utility can meet their targeted DSR energy savings, as determined by TRC, by employing only programs that pass RIM.

2. Ensure that all customers have access to feasible DSR programs.

Advantages: This option plays upon fairness. Each customer has the chance to offset the rate increase caused by DSR programs, with the bill reducing benefits of that program. If all customers participate, all customers benefit. This strategy also provides for the greatest total amount of DSR to be implemented.

Disadvantages: This strategy may be difficult to execute in practice. The direct and administrative cost of having a DSR program menu that meets the needs or desires of every customer might be impractical and economically unacceptable. Additionally, it is unlikely that all customers would choose to participate. Some have already installed the most cost effective measures.

3. Charge for energy services, such as lighting or hot water, instead of kWh.

Advantages: This strategy changes the entire concept behind pricing utility services. This was the original Thomas Edison approach to utility billing. It focuses on charging for the benefits provided rather than the commodity delivered. Customers would pay the same for lighting or other services both before and after energy efficiency measures have been implemented. Since there would be no revenue loss, more programs would pass RIM.

Disadvantages: Such a program would be extremely difficult to administer. Kilowatt hours are much easier to measure than are energy services. A utility would have to develop methods to identify and measure each of the many types of energy services provided.

4. Recover all or a portion of the DSR program costs or revenue loss through an Energy Service Charge (ESC).

Advantages: This is a more workable refinement of the above strategy. In fact, the Utah Power Energy FinAnswer programs offer this approach. The ESC can be designed to recover the cost of the measures, the total program costs, or the total lost revenue. Rate increases to non participants are mitigated by the fact that the participating customer pays for much of the costs.

Disadvantages: Penetration levels may be lower than a program that doesn't require such a high level of customer financial participation. When participating customer pays only portion of the program costs, non-participants may still end up with price increases.

5. Use an up front Bonus Payment to encourage participation coupled with a higher ESC payment to recover program costs and lost revenue.

Advantages: The Bonus Payment may enable utilities to encourage more customers to participate in DSR programs. Through larger ESC payments, it may also allow for recovery of a larger portion of program costs and net lost revenues.

Disadvantages: A Bonus Payment program has not been tested in practice. It also has similar disadvantages as ESC programs.

6. Utility provides energy efficiency information and facilitates DSR projects only.

Advantages: In this strategy, the customer makes the investment with their own funds. Since there is no utility money involved in the project, there is less of an adverse effect on utility prices. This approach is similar to the Utah Power Path B projects, where customers take advantage of the Company's engineering studies and inspections, but use their own financing for DSM measures. The approach is even more similar to Path C projects, where the Company becomes the facilitator that brings customers and equipment vendors together.

Disadvantages: Since the utility provides none of the capital, less DSR may occur. Lack of available capital is one of the reasons customers do not install DSR measures on their own. The effects of reduced consumption may still result in increased utility prices in the near term when current prices are above short run marginal costs.

7. Redesign rates with higher fixed components and lower usage charges or with declining block structures.

Advantages: Lower usage charges make it easier for programs to pass the RIM test because the portion of the rates affected by DSR will be closer to variable costs. As such, lost revenues will be more in line with avoided costs.

Disadvantages: Lower usage charges will provide less of an incentive for customers to invest in energy efficiency measures on their own.

8. Redesign rates with higher usage charges such as inverted block rates.

Advantages: Higher usage charges provide a greater incentive to customers to make energy efficiency investments, or reduce their consumption on their own.

Disadvantages: Rates that are specifically designed to be above long run marginal cost appear to promote conservation for the sake of conservation itself. When rates are above the full, long run, cost of production, the benefits of many economically responsible uses of electricity are lost because of an artificially high price. Rates above long run marginal cost also make it very difficult to implement utility programs without creating adverse impacts on non participating customers.

Mitigation of DSR costs through cost allocation procedures

Through use of a NARUC survey, the subcommittee prepared a summary of how DSR costs are allocated in other jurisdictions. We noted that allocation of DSR costs remains unresolved in many jurisdictions. There doesn't yet seem to be a consensus.

This is not surprising. None of the generally used methods is a clear cut winner from either a practical or theoretical basis. We reviewed the three major approaches to cost allocation being used in most jurisdictions as well as one non traditional approach..

1. DSR costs are recovered through a uniform energy charge.

Advantages: A uniform energy charge is easy to understand and to calculate. In some jurisdictions, DSR costs are allocated in cost studies using an energy factor. In other jurisdictions, DSR costs are accumulated in a balancing account, similar to the former Utah EBA, and billed to all customers as a surcharge. If the surcharge is shown on the bill as a separate rider, customers are aware of how much they are paying for DSR.

Disadvantages: A uniform energy charge does not follow cost causation principles. It assumes that all DSR costs are classified as energy related, which is not correct. An energy charge assigns a disproportionate share of the costs to high load factor customers. Fairness may be an issue since direct beneficiaries (participants) and indirect beneficiaries (non participants) pay the same uniform energy charge. In some states a DSR balancing account and rider may not be allowed by law. Further research would be needed to determine the legality of such a procedure in Utah.

2. Costs assigned to customer classes that are eligible to participate:

Advantages: Allocation of DSR costs to participating or beneficial customer classes is an effort to better match program costs and benefits. Customers in classes not eligible to participate in the program are not required to pay any of the costs. This method is relatively straightforward and easy to understand. Recovering the costs of DSR programs from the participants' class may also bring closer scrutiny of proposed programs that are targeted for specific classes of customers.

Disadvantages: Under this method cost causation principles are ignored. It disregards the concept that DSR investments resources that benefit all customers. Because of this, indirect beneficiaries outside of the participants class are allocated none of the costs. While program participants will see net bill reductions, non-participating customers that purchase electricity on the participants' rate schedule will experience bill increases even greater than if costs were allocated system wide.

3. Allocating DSR costs to all customer classes using demand and energy factors:

Advantages: While this method results in some adverse price impacts on all customers, of the methods tested, it results in the most even distribution of those price impacts. All non participants are treated similarly, regardless of their rate schedule. This method also comes closer to following the traditional principles of cost causation. It assumes that DSR investments are made to meet the demand and energy requirements of all customers and that all customers benefit to some degree from these investments because new Supply Side Resources are avoided. As such, the costs of DSR investments are allocated using traditional cost of service demand and energy allocation factors.

Disadvantages: No attempt is made to collect a greater portion of the costs of DSR investments from participants. Direct beneficiaries (participants) and indirect beneficiaries are allocated the same level of costs. Classification of DSR investments between demand or energy related components is difficult and may seem arbitrary. Allocating the costs of DSR programs to all customer classes could theoretically encourage special interest groups to pursue targeted DSR programs that are not cost effective.

4. Split Rim Approach

The subcommittee used these concepts to develop what became known as the "Split Rim Approach". This Split RIM approach selectively allocates costs to minimize the impact on non-participating customers. The theory behind this approach is that costs up to the RIM level benefit all customers by meeting customer's energy & capacity needs in a way that does not increase prices to a customer class any more than a supply-side resource would affect prices. As such, these cost are allocated to all customers just as supply side resources. The costs above RIM do not directly benefit non-participating customers in the near term or on a present value basis, so they are assigned to the participating customer class.

Advantages: In theory, Split Rim is a good balance or compromise that embraces the positive aspects of the various cost recovery approaches. It separates the costs of DSR programs into two categories, those that benefit all customers (non-participants), and those that benefit direct participants.

Disadvantages: In practice, several challenges were discovered in the application of the method. For programs that don't pass RIM, non-participating customers in the eligible class pick up extra costs and are worse off than if costs are allocated system wide. In practice it was found that even when all utility costs are removed, some Utah Power programs still didn't pass RIM. While the Split Rim approach may reduce price impacts for some non-participating customers, it also may increase upward pressure on prices for others.

Effect of different approaches on Utah Cost of Service

The subcommittee specifically examined the impact of actual 1993 PacifiCorp DSR expenditure on cost of service results using the four allocation approaches discussed above. The results are shown in Exhibits 1, 2, & 3. The results of preliminary studies performed using available 1994 data indicated similar relationships between participants and non participants. As more complete 1994 data become available, a more thorough analysis will be performed.

Exhibit 1 shows the actual dollars of class revenue requirement directly identified with 1993 DSR expenditures. The class revenue requirements were calculated using the 1993 embedded cost of service study filed in conjunction with the 1993 results of operations. The study was run four different times with DSR rate base investment and associated expenses allocated to customer classes using one of the discussed allocation approaches each time.

Exhibit 2 shows the effect of the revenue requirements in Exhibit 1 in costs per kWh. The class revenue requirement directly associated with DSR expenditures was divided by the annual kWh sales for that class.

Exhibit 3 shows the change in the percent increase or decrease required to reach full class cost of service (class revenue requirement at jurisdictional average rate of return) between the identified allocation methodology and the 50% demand/50% energy allocator. It assumes that DSR cost, net of ECS revenues, are included in revenue requirement. The 50% demand/50% energy allocator was used in the embedded class cost of service study filed in conjunction with the 1993 results of operations.

The 1993 DSR expenditures were relatively small compared to the total Utah Jurisdiction revenue requirement. Consequently the 1993 expenditures were multiplied by factors of 10 and 100 to amplify impact of each scenario.

Demand/Energy Factor Allocation

While this method resulted in some impact on all non participating customers, it does result in the most evenly distributed impacts among all customers. Because of the relationship of DSR investments to the total cost of service, the impact on all customers, both participants and non participants, is relative minor.

Energy Factor Allocation

The examination showed that the energy factor allocation produced very similar results to the demand/energy factor.

Direct Assignment to Participating Class

Direct assignment of costs to participating customer classes pushes up revenue requirement in the participating classes as expected. While the impact upon customers not in the participants classes is essentially eliminated, the impact upon non-participants within the same class as the participant is greatly increased.

Split Rim

The Split RIM approach produced results even more skewed toward the direct participants class than did the direct assignment approach. This is because in our study only the large industrial programs passed the RIM test. All other programs had lost revenue above avoided costs so that even with all utility cost removed the programs still didn't pass RIM. The cost of these programs were directly assigned to the participating class. These two circumstances resulted in participating class, other than the large industrial class, being allocated a portion of the cost of the large industrial programs plus 100% of the cost of their own programs.

Summary

Of the options reviewed, all cost allocation methodologies allocate some costs to non-participating customers. However, because current investments in DSR are relatively small in comparison to total cost of service, the impact on relative prices is minimal. Only the studies where DSR investments were increased by 100 times showed a measurable difference between the methods.

DEMAND SIDE RESOURCE COST RECOVERY COLLABORATIVE REPORT

APPENDIX VII

FINAL REPORT - DSR PERFORMANCE STANDARDS SUBCOMMITTEE DATED MARCH 1995

SUBMITTED
MARCH 31, 1995

Utah Demand Side Resource Program Performance Standards

Report to the DSR Cost Recovery
Collaborative from the Performance
Standards Subcommittee

March 1995

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Mandate

In the Joint Recommendation for Docket No. 92-2035-04, *"In the Matter of Rate Making Treatment of Demand-Side Resources and the Analysis of Regulatory Changes to Encourage Implementation of Integrated Resource Planning"*, the signing parties proposed to develop performance standards for Commission consideration in determining post-1994 program eligibility for cost recovery. The Utah Public Service Commission approved the Joint Recommendation in its February 10, 1994 order, including the directive to develop performance standards. The Cost Recovery Collaborative, formed in response to the Commission order approving the Joint Recommendation, formed this subcommittee to develop performance standards for DSR.

The Performance Standards Subcommittee defined the following goal:

> *To recommend to the Commission the adoption of consistent methods and standards by which demand side resource acquisitions are determined to be in the public interest. To this end, we will define and recommend DSR performance standards which employ consistent methods and that provide guidelines for the Company and Regulators for integrated resource planning, DSR program approval, evaluation and cost recovery purposes.*

Three additional issues were assigned to the Performance Standards Subcommittee in the Demand Side Resource Evaluation Task Force (DSRETF) Final Report to the Commission dated May 20, 1994. The three tasks are listed as tasks 3, 4 and 5 and discussed on pages 19-22 of the DSRETF Final Report to the Commission. Briefly stated here, they are to:

- *Determine what methods are most appropriate for evaluation of the success of the DSR programs.*
- *Determine what perspective should be taken when evaluating the cost-effectiveness of such measures and programs.*
- *Determine how demand side resources can be consistently compared to supply side resources.*

We will address all three of these issues in the context of developing the performance standards for DSR recommended in this report.

Current Practice for Assessing Successful DSR Acquisition

Commission Guidance

To date, the Utah Public Service Commission has not formally adopted a method of analysis for use in approving proposed DSR programs and contracts, for assessment of verified[1] DSR savings or for DSR program cost recovery purposes. However, the Commission's June 18, 1992 Report and Order on Standards and Guidelines for Integrated Resources Planning for PacifiCorp provided preliminary Commission thinking on how to judge the success of DSR programs and requested that the CRC make further recommendations. The Commission's Order states:

> "that the integrated resource planning process must evaluate all known resources on a consistent and comparable basis in order to meet current and future customers electric energy service needs at the lowest total cost to the utility and its customers,"[2]

The Order defines lowest cost as:

> "the Total Resource Costs defined as the discounted sum of the direct costs of production and consumption of electric energy services incurred by the utility and its ratepayers."[3]

In addition, the Commission directed parties to evaluate DSR acquisitions from a variety of perspectives, including the utility system as a whole as well as different classes of ratepayers. A description of how social concerns might affect cost effectiveness estimates of resource options was also to be included in the evaluation.

To date, absent further formal rules on use of economic tests, such information has been provided by PacifiCorp and regulators to the Commission for consideration in the approval of programs for implementation and in tariffs governing the acquisition of DSR.

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[1] The term "verified" energy savings will be used in this paper to refer to "ex post" energy savings as distinguished from "ex ante" engineering estimates. Ex ante engineering estimates are predictions of DSR performance based on computer modeling prior to project installation. Ex post savings are determined by applying samples of metered data, survey research and analysis of actual bills to the ex ante engineering estimates after the installation is complete or actual conditions can be taken into account.

[2] page 16 of Commission's June 18, 1992 Report and Order on Standards and Guidelines for PacifiCorp.

[3] see page 25, Ibid

Comparison of Supply Side Resources and Demand Side Resources

At the heart of current economic analysis of demand side resources is a comparison to supply-side resource alternatives. Demand side and supply side resources differ in four major ways: 1) costs are borne differently; 2) benefits accrue differently; 3) investment risk is different; 4) resources characteristics are very different.

Costs borne differently: The allowed cost of supply side investment is borne in its entirety and relatively equally by all ratepayers to the extent that the rate change associated with the investment is spread according to cost of service. However, the spread of the allowed cost of a demand side investment is dependent upon program design. For energy service charge programs or lease contracts, costs are borne unequally among customers, with current participants contributing a greater portion of the cost than the non-participant. Non-participants bear the cost to the extent that rates increase as a result of the DSR investment and that this increase is translated into higher bills for the non-participant. For programs that do not require the participant to pay for the energy conservation item installed, costs can be spread relatively equally among ratepayers; however, benefits will then accrue unevenly.

Benefits accrue differently: When a DSR program design does not require the participant to pay for part of the cost of the energy conservation item installed, and the cost is spread equally among all ratepayers, then participants benefit to a greater extent than non-participants. The participant benefits through reduced bills.

Benefits are also unevenly distributed because revenues increase when a supply side resource comes on line and the revenues offset some of the cost of the investment, and this offset is shared relatively equally by all ratepayers. Since no new revenues from electric sales offset the cost of DSR, and indeed successful DSR will reduce revenues or slow revenue growth, there may be upward impact on rates which could then fall unequally among customers.

For example, if a DSR program causes average rates to increase for all customers relative to a supply side alternative, but average bills to decrease, a participant in a company-sponsored DSR program would benefit from lower bills. However, non-participants would incur a higher bill when rates are reset at a higher level at the next rate case. The amount of the impact would vary depending on the spread of the costs between the participant and the non-participant: the greater the contribution by the participant, the less the impact on rising bills for current non-participants.[4]

Because rates are not reset in-between rate cases, PacifiCorp may suffer a loss of revenues in-between rate cases that would have contributed to fixed costs. Earnings on the lost sales are also lost; thus shareholders earn less in-between rate cases from DSR than from SSR.

The essence of these first two distinctions between supply side and demand side resource

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[4] See separate report on spread of costs and non-participant impacts.

investment is that supply side investments can be economically assessed from one perspective because the impact of the costs and benefits on ratepayers and shareholders can be evaluated from one perspective. Alternatively, the economic impact of demand side resource investment must be viewed from several perspectives in order to get a full picture of the costs and benefits of the resource across stakeholders.

Investment Risk is Different: The third distinction to be considered is how risk is defined for supply versus demand side investments to meet load growth.

Ultimate cost per kWh or kW is uncertain for either investment. However, the uncertainty lies in knowing the cost of a supply side investment whereas the uncertainty lies in knowing the amount and persistence of the kWh and kW of a demand side resource.

Risk associated with the lead time for bringing on a supply versus demand side resource also differs. Shorter lead time may have more value than long lead time due to the uncertainty of cost recovery and to the better match of loads to resources which mitigates errors in load forecasts.

Differences in risk of cost recovery and the impact of this risk on reliability and finances is also important. There is substantial uncertainty on the future structure of the electric industry and therefore on the impact of changes on the ability of the utility to recover costs. For example, supply side resources provide the Company with a revenue generating, physical asset which earns a return and can be sold for market value if necessary. DSR investment creates a "regulatory asset" which may or may not earn a return (depending on regulatory treatment) and which may or may not be sold for recovery of the costs if necessary (depending on how the program is structured).

Different resource characteristics: Supply side and Demand side resources have different non-cost characteristics. For example, the resources have different capabilities regarding dispatchability and environmental impact.

The essence of these last two distinctions is that all economic assessment of a supply side investment versus a demand side investment is subject to assumptions made regarding cost of supply, deliverability of demand and risk associated with recovery of costs.

Currently, we assume that supply side costs are known with perfect certainty[5] and that demand side resources will accrue as ex post engineering estimates predict and for the full life of the product installed.

We also assume that risk of cost recovery is equivalent for supply side resources and demand side resources.

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[5] As captured in avoided supply costs used to evaluate demand side resource benefits and as reflected in IRP supply side cost assumptions.

We also assume that dispatch and environmental characteristics are captured in the IRP analysis of supply versus demand side resources. Resource characteristic differences are also taken into account in program design. For example, if a dispatchable resource is required, a DSR load management program like an irrigation load control program can be implemented. Additionally, at the implementation, acquisition and evaluation stages, total resource cost analysis currently provides DSR with a 10% adder to avoided costs to account for unquantified environmental benefits.

Given the distinctions between supply side and demand side resources and the assumptions regarding comparison of demand side and supply side resources, the subcommittee advocates the adoption of a variety of economic tests to compute the impacts of DSR given several points of view. We believe this will enable the consistent comparison of supply side and demand side resources on a forward going basis. We define the tests, inputs to the tests, and recommend how the tests should be used in the various stages of DSR acquisition.

Current PacifiCorp Analysis

DSR is evaluated at five different stages in the process of DSR identification and acquisition:

1. At the ***planning stage*** in the integrated resource plan (IRP) process; this is the point where demand side and supply side resources compete, based on lowest cost, to meet forecasted load growth.
2. at the ***implementation stage*** when specific programs, tariffs, and contracts are proposed and reviewed for approval by regulators that the programs are found to be in the public interest and consistent with the IRP; information is provided to regulators at this stage by PacifiCorp in response to the Utah Standard Information Request.
3. at the ***acquisition stage*** when measure funding limits are established and DSR energy service charge and other acquisition contracts are signed;
4. at the ***evaluation stage***, when actual costs and verified energy savings estimates are available; and,
5. at the ***cost recovery stage*** when DSR acquisition costs are evaluated for recovery of costs in a rate case setting.

Total Resource Cost analysis is performed by PacifiCorp at the first four stages. Additional perspectives are provided at the planning, implementation and evaluation stages.

One of this subcommittee's initial tasks was to determine how PacifiCorp performed total resource cost (TRC) analysis at each stage of DSR analysis. This task would assure that whatever performance standard was adopted, actual achievements could then be compared to planned achievements in a consistent manner. A preliminary analysis, provided in Attachment A, pages 1-3, provides a description of the inputs into the TRC formula at the planning stage, the implementation and acquisition stages, and the evaluation stage.

At the planning stage, i.e., in the IRP selection process, PacifiCorp currently inputs life-cycle levelized cost per MWh (over a 50 year period) for each potential resource, both for supply-side and demand-side resources. This levelized cost per MWh for DSR is computed based on the present value of total resource cost (including administration costs) of a program rather than utility cost, in order to compare it on an equivalent basis with supply-side resources which are computed based on the total cost of the resource. Total resource cost is the sum of the utility's cost and the participating customer's cost. For SSR, there are no "participants" so total resource cost and utility cost are equal. Given these costs, specified resource characteristics, and the demand forecast for additional load, the IRP selects the optimum type and amount of resources to meet load.

But at the implementation stage, it should be noted that actual supply side investments are evaluated using different methods than demand side investments. Supply side investment alternatives are compared to "incremental" costs and judged or ranked based on internal rate of return. Demand side investment alternatives are compared to "avoided supply costs".[6]

At the planning stage, PacifiCorp looks at the impact on revenue requirements as well as total resource costs. At the implementation stage and the evaluation stage, PacifiCorp examines the expected impact of a program on system revenue requirements, total resource costs, participants and non-participants. At the acquisition stage, only total resource cost analysis is conducted. We will discuss these perspectives in greater detail later in this report.

We consider all of these stages to be important in developing performance standards and we want to assure methodological consistency at each stage so that we are always comparing apples to apples as we move sequentially from planning to rate making. In examining how DSR is currently evaluated at each step in the PacifiCorp DSR development process, the subcommittee determined that it is not clear that inputs for the same equations are consistently applied at each stage. Rather than focus on past practice, the subcommittee recommends guidelines on a forward going basis for inputs and equations to be used for all stages. This approach should mitigate what inconsistency might be in place. The subcommittee also reviewed the Oregon UM 551 order on conservation cost-effectiveness to assure regional consistency of equations and input guidelines to the extent practicable.

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[6] Avoided supply costs are the same as the rates to PURPA qualifying facilities which are less than one megawatt in size plus a value for secondary sales plus avoided transmission and distribution costs plus a 10% adder.

Recommended Economic "Tests" for DSR Program Assessment

As noted above, the economic analysis of DSR varies depending on who incurs the costs, who receives benefits, and upon the resultant impact examined. A collaborative of California state officials, regulators, utilities and other interested parties developed a series of tests representing a variety of perspectives which resulted in a report entitled *Standard Practice Manual, Economic Analysis of Demand-Side Management Programs*. The perspectives and the resultant formulas were developed in 1983 and revised in 1987 in order to provide standardization for the review, approval and evaluation of utility-sponsored DSR programs.

The California tests examine a given DSR program's impact on (1) utility costs, i.e., revenue requirement and average customer bills, (2) participant costs, (3) average rates (indicating non-participant impacts as noted earlier), (4) total resource costs, i.e., efficiency of providing energy services to ratepayers as a whole, and (5) total resource costs for energy services to society. These tests are used throughout the nation, as well as by PacifiCorp, with varying degrees of adherence to the specific formulas or nomenclature developed in the 1987 California *Standard Practice Manual*.

A detailed description of the calculation and meaning of the tests we recommend follows. Specific equations and sources for inputs to be used by PacifiCorp in each test are provided in the Appendix to this report. Both the following information and the equations and input definitions in the Appendix are drawn from the California *Standard Practice Manual*, from presentation materials of Barakat & Chamberlin, Inc, and from PacifiCorp evaluation reports. Additionally, the subcommittee revised the ratepayer impact measure test to be consistent with the proposed lost revenue and cost accounting mechanism for Utah DSR investments; the subcommittee also redefines the total resource cost and societal cost perspectives to reflect a Utah version of total resource cost and a PacifiCorp version of total resource cost.

UTILITY COST TEST: IMPACT ON REVENUE REQUIREMENT

The **Utility Cost test (UC)** evaluates the effect of the DSR acquisition on revenue requirements and, hence, on average bills, relative to an alternative supply-side resource.[7] Briefly, costs are measured by direct costs of program implementation to the utility and benefits are measured by the product of net energy and demand savings at the point of generation times the avoided energy and demand costs of generation, transmission and distribution.

If the net present value of **UC** is positive or the benefit cost ratio is greater than one, then the DSR investment reduces revenue requirement and reduces average customer bills relative to

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[7] *Cost-Effectiveness Analysis for DSM Programs,* presentation materials by Patricia Herman, Barakat & Chamberlin, Inc, page 1-37.

the supply-side alternative measured by avoided cost. The benefit cost ratio gives an indication as to whether the revenue requirement increases or decreases and the net present value gives an indication of the magnitude of the change. **UC** analysis also produces a "levelized cost per kWh or per kW" figure for comparison and ranking of alternative investments over the life cycle of the investments.

The **UC** test mirrors supply-side investment analysis in the sense that only utility system costs and benefits are considered in the economic evaluation of the investment. No other impacts of the program are included.

PacifiCorp performs some type of **UC** analysis at the planning, implementation, acquisition and evaluation stages of DSR program analysis because it is a component in RIM analysis which is a component in TRC analysis (described in greater detail further on in this report) which is computed at all stages.

PacifiCorp presents the specific results of **UC** analysis for regulatory review at two stages of DSR program analysis. **UC** results are first presented to regulators at the time a program or contract is provided to the Commission for regulatory approval. This analysis is provided in Utah's *Standard Data Request* filings when the Company requests Commission approval of a DSR program or contract. Generally all inputs are proforma expectations based on engineering estimates for generic installations, market penetration analysis and currently available avoided cost estimates. The Company also presents the results of **UC** analysis for regulatory review using verified energy savings from actual program installations. This analysis is provided to regulators in the Company's annual evaluation of each program.

PARTICIPANT COST TEST: IMPACT ON DSR PROGRAM PARTICIPATION

The **Participant Cost test (PC)** evaluates the costs and benefits from the participant's perspective. **PC** analysis indicates how economically attractive a DSR program is from the participants' point of view and therefore how likely a program is to attract participation and achieve the necessary market penetration in order to acquire a given level of DSR. Briefly, costs include all participant out of pocket expenses to fund the energy efficiency project. Benefits are measured by the annual gross energy savings valued at current and forecasted retail rates over the life of the program savings. Benefits additionally include other direct, measurable cost savings, such as operation and maintenance cost savings.

If the net present value of **PC** is positive or the benefit cost ratio is greater than one, then the DSR investment is cost-effective to participants as a whole, and indicates that the participant has an economic interest in participating. **PC** analysis also produces a "discounted payback" figure in years which can give a sense for how attractive the program is to the participant. Further research and analysis could determine whether the discounted payback could be increased without sacrifice to program participation in order to reduce non-participant impacts.

As noted above, **PC** analysis is an important program design tool to ensure that the program is attractive enough to encourage participation yet at the same time encourage maximum contribution by the participant to the cost of the DSR program in order to mitigate possible rate impacts to non-participating utility customers. The trade-offs between increasing participation and reducing the non-participant impacts apparent from RIM analysis is discussed in detail on pages 16 and 17 of this report.

PC analysis is additionally important because its costs and benefits are considered in the TRC test defined later in this report.

PacifiCorp performs some type of **PC** analysis at all stages of DSR program analysis, that is, at the planning stage in IRP, at the implementation stage both when requesting Commission approval to implement a program or contract and also in designing and implementing a DSR program tariff, and finally, at the evaluation stage. This is because components of **PC** analysis, like UC, are included in the TRC which is computed at all stages. Specific results of the **PC** analysis are currently presented to regulators at two stages: At the implementation stage when the Company requests Commission approval through its Utah *Standard Data Request* filing and at the evaluation stage in the annual evaluation reports.

RATEPAYER IMPACT MEASURE TEST: IMPACT ON RATES AND NON-PARTICIPATING CUSTOMERS' BILLS

The **Ratepayer Impact Measure test (RIM)** traditionally measures what happens to average total system cost per kWh due to changes in utility revenues and operating costs caused by the program. The test indicates the direction and magnitude of the expected change in average system rate levels. The test can also provide the cost per kWh required to reset revenues with revenue requirement over the life of the DSR program. This test traditionally indicates the impact on the system wide non-participant's average bill.

We recommend a version of this test that will examine the impact on the Utah jurisdiction non-participant's average bill. Since the traditional computation of RIM is a component of TRC, we will discuss both the traditional computation and the Utah jurisdiction computation. We recommend that the traditional computation continue to be computed for input in TRC calculations. However, when RIM results are presented for regulatory review, we recommend that the Utah jurisdiction computation be employed. We will make the distinction between the two computations by referring to the computation of RIM for purposes of computing TRC as the "traditional" calculation of RIM.

Traditionally, **RIM** benefits are measured by system avoided cost as defined and calculated in the UC test. **RIM** costs are defined as the UC costs plus the value of revenue loss. Revenue loss is measured by the annual net energy savings for the program valued at forecasted retail rates. The difference between gross energy savings, upon which PC benefits are computed, and net energy savings, upon which **RIM** is computed, is caused by netting out energy savings associated with free-rider and load building impacts from gross energy savings for the **RIM** analysis. This test relies upon both a forecast of retail rates as well as a forecast of avoided costs (discussed under **UC**) for the utility over a period of 15 to 20 years: two cost streams that are difficult to quantify with certainty. Since **RIM** results are sensitive to this uncertainty, test results must be viewed more cautiously than the other test results. However, it is an important tool of analysis because it is the only economic test presented in this paper that attempts to measure the impact to utility customers not participating in utility sponsored DSR programs.

If the net present value of **RIM** is positive or the benefit cost ratio is greater than one, then the DSR investment reduces average system costs per kWh, and thus average system rate levels, relative to the supply side alternative measured in avoided cost. Alternatively, if the net present value of **RIM** is negative or the benefit cost ratio is less than 1, then the DSR investment increases system costs per kWh relative to the supply side alternative measured in avoided cost. This latter case is generally the case when forecasted values of prices always exceed forecasted values of avoided costs over the life of the program savings. This is also PacifiCorp's current expectation of the forecasts for their system.

RIM analysis also produces the "life cycle revenue impact" (LRI) of the program which measures the one time rate change required to reset the present value of revenues with the present value of revenue requirement over the life of the program. LRI is equal to the net present value of **RIM** divided by the discounted system energy sales over the life of the program savings.

PacifiCorp performs some type of **RIM** analysis at all stages of DSR program analysis because it is a component in TRC. Although a form of RIM analysis is used as a screening tool at the IRP level, it is not used as a screening tool when actually acquiring resources. PacifiCorp may have performed analysis at the IRP level similar to the Annual Revenue Impact (ARI) analysis noted in the Appendix which looks at annual revenue impacts on a nominal basis. Different inputs were used than noted in the Appendix and the specific results were not presented for regulatory review.

Specific results of **RIM** analysis are currently presented to regulators at two stages: At the implementation stage when the Company requests Commission approval through its Utah *Standard Data Request* filing and at the evaluation stage in the annual evaluation reports.

Since DSR costs are assigned situs, the subcommittee recommends that **RIM** analysis be conducted on a Utah jurisdictional basis. We recommend that the test reflect the accounting and lost revenue mechanisms proposed in the Joint Recommendation. The primary distinction in the Utah jurisdictional perspective is the amount of revenues assumed to be lost over the course of DSR acquisition. Under the Utah definition of **RIM**, one year of revenues would be added to revenue requirement in addition to DSR acquisition costs bulked up for carrying charges and taxes. The equations in the Appendix reflect our recommended version of **RIM.**

However, as noted earlier, for use in computing TRC, **RIM** should be computed including all revenue loss over the life of the program. This approach will ensure consistency of TRC results reported from the planning through to the cost recovery stages and avoid unnecessary confusion.

TOTAL RESOURCE COST TEST (Utah Version): IMPACT ON EFFICIENCY OF PROVIDING ENERGY SERVICES TO RATEPAYERS

The **Total Resource Cost test (TRC)** measures the effect of the program on the cost to serve the "average" ratepayer relative to a supply-side alternative. This test attempts to combine the costs and benefits associated with participants, and with all customers. Cost is measured as the sum of the costs associated with the PC and traditional RIM perspectives, with one little twist: Participant costs are net of "other participant benefits" defined in the OBR_t term. Benefits are measured as the sum of the benefits associated with the PC and RIM perspectives. The result of this summation is that benefits are equal to avoided costs as measured in UC plus the value of the energy savings associated with free riders; costs are equal to UC costs plus the difference between net and gross savings so that the test ultimately evaluates the total cost of the program against the avoided system cost benefits plus direct project-associated non-energy benefits accruing to the participant.

If the net present value of **TRC** is positive or the benefit cost ratio is greater than one, then the DSR investment reduces revenue requirement and reduces average customer bills relative to the supply-side alternative measured by avoided cost. **TRC** analysis evaluates the impact of the DSR program on the costs of providing energy services to the average ratepayer. **TRC** analysis also produces a "levelized cost per kWh or per kW" figure for comparison and ranking of alternative investments over the life cycle of the investments.

This test attempts to mirror supply-side investment in that the full cost of the investment, regardless of who pays, is examined in comparison to the benefits to the "average" ratepayer. The total resource costs of demand-side programs are used in the IRP selection process for comparable evaluation of demand-side and supply-side options.

PacifiCorp presents the specific results of **TRC** analysis for regulatory review at all stages of DSR program analysis. PacifiCorp first presents the results of **TRC** analysis at the IRP stage during subgroup meetings in the public advisory process. Levelized **TRC** per kWh is presented in the final IRP report alongside the levelized costs of supply side resources. PacifiCorp also presents the results of **TRC** to regulators at the time a program or contract is provided to the Commission for regulatory approval. This analysis is provided in Utah's *Standard Data Request* filings when the Company requests Commission approval of a DSR program or contract. Generally all inputs are proforma expectations based on engineering estimates for generic installations, market penetration analysis and currently available avoided cost estimates. The Company also presents the results of **TRC** analysis for regulatory review using verified energy savings from actual program installations. This analysis is provided to regulators in the Company's annual evaluation of each program.

PacifiCorp's version of **TRC** includes a 10% adder to avoided costs and includes the costs and benefits of supplemental funding. We recommend that a distinction be made between PacifiCorp's **TRC** and the Utah recommended version of **TRC** which does not include the adder nor supplemental spending as a benefit. To denote this distinction, the PacifiCorp version will be noted as **PTRC** and the Utah version will be noted as **UTRC.**

It is unclear whether the current computation of **TRC** is consistent from planning through to implementation and evaluation. The components in **TRC** that lack clarity involve both cost and benefit terms. On the cost side, it is unclear if taxes and carrying charges are treated consistently at all stages and it is unclear whether participant costs are always net of participant benefits at each stage. Additionally, we need to understand how administrative costs are computed and to determine if evaluation costs bulk-up program costs at each stage. On the benefits side, it is unclear if "background" conservation and "free rider" estimates are treated consistently at each stage. It is also unclear how demand savings are estimated in the planning stage.

We expect that adoption of the equations presented in this report, along with necessary modifications made in the development of a computer model for these equations, will mitigate our concern with inconsistent application of TRC terms.

TOTAL RESOURCE COST TEST (PacifiCorp Version): IMPACT ON EFFICIENCY OF PROVIDING ENERGY SERVICES TO SOCIETY

The **Societal Cost test** as described in the California Standard Practice Manuel, is a variant of the TRC test and treats costs and benefits the same as in TRC; however, indirect project associated non-energy or external costs and benefits for DSR are included in the equation and a societal discount rate may be employed.

As noted above, PacifiCorp's interpretation of TRC includes a 10% adder to the benefits of DSR programs and includes indirect non-energy benefits associated with supplemental funding by netting them out of the cost side of the equation. Although this is not a strict interpretation of TRC as defined in the California Standard Practice Manual, which includes direct costs and benefits only, it is not quite a Societal Cost perspective either, because a societal discount rate is not employed.

We recommend that PacifiCorp's practice of TRC analysis be continued and for consistency, remain a TRC form of analysis and denoted as PTRC.

Recommended Performance Standards

The Performance Standards Subcommittee has been requested to review regulatory standards for evaluating demand side resources and to make recommendations on how best to judge the performance of these resources. We have just described five economic tests that have traditionally been used by the regulatory community to judge the cost-effectiveness of DSR and have provided recommended equations in the Appendix for how these tests should be performed by PacifiCorp for Utah DSR. We recommend adoption of the five tests as noted above. Test results should be computed and reviewed on a per program basis. We recommend that the results of the tests be presented to regulators at the following stages and expressed in the following forms:

Economic Test	Stages	Forms
Utility Cost test	Implementation, Evaluation, Cost Recovery	NPV, BCR, levelized cost per kW, kWh
Participant Cost test	Implementation, Evaluation, Cost Recovery	NPV, BCR, discounted payback, kW, kWh
Utah Ratepayer Impact test	Implementation, Evaluation, Cost Recovery	NPV, BCR, life cycle revenue impact per kW, kWh
Utah Total Resource Cost test	Implementation, Evaluation, Cost Recovery	NPV, BCR, levelized cost per kW, kWh
PacifiCorp Total Resource Cost test	Planning, Implementation, Acquisition, Evaluation, Cost Recovery	NPV, BCR, levelized cost per kW, kWh

The subcommittee recommends the use of the five tests because these perspectives will provide relevant information in determining the value and success of a program. This multi-perspective approach requires PacifiCorp and the Commission to consider tradeoffs between the perspectives and among impacts at each stage of analysis.

It is expected that the most critical decisions on acquisition of DSR occur at the planning and acquisition levels. Because PTRC is the primary test used at the planning stage, we recommend that it also govern acquisitions. Should the primary test at the planning level change, we recommend change of the primary test at the acquisition stage; analysis at these two stages must be consistent. That is, the economic test used to determine the measure funding limits in a filed DSR tariff must be consistent with the economic perspective used to set goals in the IRP analysis. This policy will ensure that DSR acquisitions planned for are the ones actually acquired.

It is envisioned that at the implementation stage, all test results should be provided and the program should pass all tests except for RIM. RIM test results should be considered in the DSR program approval process in order to assess that implementation of the program is in the public interest. Such assessment should include analysis of the proposed program's impact on the cumulative price impact of all approved DSR programs.

All tests should also be presented at the evaluation stage. At this stage we recommend that PacifiCorp explain actions to be taken which are consistent with test results. For example, a marginal UTRC result may indicate the need for program design modification.

In a rate case, the information from evaluation reports together with analysis of PacifiCorp's implementation of its least cost plan will be used to determine recovery of costs booked. It is expected that the report recommended in the 1995-1996 Joint Agreement to be conducted by the Office of Energy and Resource Planning and the Division of Public Utilities will assist in this analysis.

Guidance on Review of Test Results: Hierarchy and Interaction

A basic hierarchy was indicated by the Commission for comparing supply side and demand side resources in the IRP to meet load growth. The Commission directed the Company to determine the costs incurred by the utility, that is, the present value of total revenue requirements of the Company's various resource acquisition strategies. If different strategies have the same total resource costs, the Company was directed to choose that strategy that has the lowest total revenue requirement.[8]

Given the Commission's preliminary direction, we will attempt to further explain and delineate a hierarchy for allowed cost recovery of DSR expenditures and lost revenues.

The first issue regarding cost recovery of DSR expenditures is whether the Company has obtained the least cost combination of SSR and DSR. This least cost combination is determined through the IRP process. Utah IRP Standards and Guidelines require that resources selected to meet load growth be based on minimizing total resource costs. PacifiCorp's current and the subcommittee's recommended interpretation of total resource cost for IRP is to include a 10% adder and allow supplemental costs to be included as a reduction to cost through the "other benefits" term. This by definition is equal to the PTRC test described in this report. Thus, the PTRC test should be passed for DSR expenditures to be recovered in rates. This is also the analysis conducted at the point of acquisition and therefore should be met at the point of cost recovery.

The PTRC test which includes external benefits and costs of resource acquisitions is also an important tool to assess environmental risk mitigation strategies. The IRP Standards and Guidelines require that the Company analyze resource acquisition strategies that will lower the risk that future environmental regulations will result in higher costs to the Company. Commission

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[8] see page 17, Ibid

Standards and Guidelines require that the Company attempt to quantify external costs associated with the acquisition of new resources and analyze strategies that will mitigate the risk that those costs will be internalize through new environmental regulations.

However, it is conceivable that a program could fail this test and still be allowed recovery of costs. An example might be a program that is in an early stage of implementation, a ramp-up stage, which could cause high administrative costs relative to the level of acquired savings at the point in time of a rate case. This type of circumstance will need to be considered in a review of cost allowance. Thus, the PTRC is a critical test for recovery of costs; however, circumstances as noted above should also be considered in the final determination of cost recovery.

The UTRC test provides information on how cost-effective the DSR program is in comparison to a supply side alternative based on the costs and benefits of the reduction in electricity consumption to all ratepayers. This test provides useful comparison to the levelized cost of a supply-side investment. Additionally, this perspective will provide useful information on the impact of supplemental spending on the cost-effectiveness of a given program design. PTRC includes indirect, non-energy related benefits associated with supplemental funding whereas UTRC does not. A comparison of the two results will provide PacifiCorp and regulators with information regarding the value of supplemental funding, which may increase participation rates, in comparison to the cost of providing supplemental funding.

The UC test, which measures the cost of DSR from the utility's perspective, must pass in order for the resource to be deemed lowest cost. This cost test is extremely important. The goal is to minimize the cost of acquiring DSR to the utility and its ratepayers while achieving the requisite amount of DSR that is specified under the IRP. This can be done by lowering administrative and evaluation costs, as well as incentive payments, by achieving savings where marginal costs are highest and by having the participant contribute as large a share as is possible. A tradeoff occurs in that by increasing participant charges and decreasing administrative costs, lower participation rates can result and lead to the failure to acquire the requisite amount of DSR. There could be some instances where the Commission would be willing to tolerate lower DSR acquisitions if it could be shown that utility costs were substantially lowered and that non-participants were greatly benefited. It is envisioned that such a strategy would receive prior Commission approval rather than the Company justify, after the fact, its failure to achieve DSR acquisition goals.

The PC test must yield positive results if the program is to be economically attractive to the participant. However, this test only includes benefits and costs to the participant that can be quantified; there could be instances where the benefits can not be quantified and yet produce real benefit to the participant. In such cases failure to pass this test would not be grounds for imprudence. However, programs which failed the participant test would require close scrutiny. The Company would have to show that the participant made a fully informed decision to participate and that these unquantified benefits were paid for by the participant before cost recovery would be allowed. Benefits that do not relate to energy savings should not be funded by other ratepayers. Thus, the PC test is neither a necessary nor sufficient condition for cost recovery. It is a very important test for review of program design, and should be reviewed in conjunction with review of RIM results as noted in the following discussion.

The RIM test is perhaps the most controversial of the cost-effectiveness tests. Passage of RIM is not a necessary condition for recovery of costs. In fact, the failure of the RIM test is expected in most DSR programs where rates are above the marginal costs that are avoided by the utility. The passage of the RIM test, in most all cases, is a sufficient condition for allowing costs in rates.

The RIM test, though not essential for a determination of cost recovery, is an important cost-effectiveness test from a public policy perspective because there is a tradeoff between PC analysis and RIM analysis with regard to determining the appropriate incentives to attract participation yet minimize rate impacts to other customers.

For example, an energy service charge program that consistently yields a relatively high PC benefit cost ratio indicates that the participant may be able to bear a higher percentage of the cost of the program. Sensitivity analysis should be conducted to determine the tradeoff between DSR participation rates and rate impacts on non-participants. As the participant bears a higher portion of the cost of a program, upward impact on average rates in the long run is reduced. The tradeoff is presented by the test results of the RIM test, i.e., a higher BCR_{RIM}. It is the interplay between the results of the PC and RIM tests that allows one to balance long run impacts on non-participants with the design of a DSR acquisition program that captures the least cost amount of DSR as determined by the Company's IRP. Again, the tradeoff here is that higher required participant contributions can result in lower participation rates for DSR programs and result in the failure to acquire the appropriate amount of DSR relative to SSR.

Summary of Recommended Performance Standards

1. **Planning Stage:** At IRP stage, levelized PTRC should be used. PTRC should include taxes, revenue requirement, carrying charges and background conservation. PacifiCorp's previous definition of TRC is equivalent to the recommended definition of PTRC.

2. **Implementation Stage:** All tests should be provided to regulators in the Standard Data Request Response and should be computed per the equations in the Appendix of this report. At this stage the proposed program must pass all tests except for the RIM test. LRI for RIM should be provided for each program along with the cumulative LRI from Utah approved programs. Analysis of this cumulative impact should be available for review each time a program is proposed, in each evaluation report, and in a rate case setting for analysis of costs to be recovered in rates.

3. **Acquisition Stage:** The economic perspective conducted at the IRP level determines the economic perspective which governs acquisition. Currently, PTRC is the analytical basis for comparing demand side and supply side resources at the IRP stage and therefore should be used to establish measure funding limits which govern acquisition. If the type of analysis used to establish planned DSR targets changes from PTRC, the analysis must also be changed at the acquisition stage. For example, if lost revenue analysis is conducted at the IRP level, the Utah version of RIM needs to be incorporated into the tariff requirements of all programs.

4. **Evaluation Stage:** All tests will be provided for regulatory review at the evaluation stage in the annual evaluation reports. An assessment of the test results and of necessary changes to improve test results will be included. BCR, NPV, levelized cost for UTRC, PTRC, and UC will be included, and LRI for RIM per program and cumulatively will be provided. At this point, if a program does not pass a test, or passes marginally, PacifiCorp needs to discuss what actions will be taken in order to address the issue.

5. **Cost Recovery:** At the cost recovery stage, allowance of costs booked will be based on the performance of the economic tests per program respective of the hierarchy discussed above. Additionally, success will be measured by a comparison of IRP analysis and actual supply and demand side resource acquisitions. In addition to the test results, an analysis of planned versus achieved DSR acquisitions will be used. Review of the test results will need to consider whether a program is in an early implementation phase or a full implementation phase; programs which are in a full implementation phase will be expected to perform best.

6. Conservation Cost-effectiveness spreadsheets need to be provided to regulators each time the economic test results are presented for regulatory review.

7. A computer model based on the equations in this report and which enables sensitivity analysis should be developed over the coming year.

APPENDIX: RECOMMENDED ECONOMIC TEST EQUATIONS AND INPUTS

UTILITY COST TEST

The current and recommended equations and sources for inputs for **UC** are as follows:

$$\mathbf{NPV_{UC}} = \mathbf{B_{UC}} - \mathbf{C_{UC}}$$

$$\mathbf{BCR_{UC}} = \mathbf{B_{UC}} / \mathbf{C_{UC}}$$

$$\mathbf{LC_{UC}} = \mathbf{LCUC_{UC}} \ / \ \mathbf{IMP}$$

where:

$\mathbf{NPV_{UC}}$	=	Net present value of utility costs
$\mathbf{BCR_{UC}}$	=	Benefit-cost ratio of utility costs
$\mathbf{LC_{UC}}$	=	Levelized cost per kW or kWh over life of program savings
$\mathbf{B_{UC}}$	=	Utility system benefits of the program, measured by the present value of avoided generation, transmission and distribution costs multiplied by the annual expected kWh and kW savings (net of free riders and load building impacts) over the life of the program.
$\mathbf{C_{UC}}$	=	Present value of the direct utility costs to implement a program net of the Energy Service charge payments by participating customers.
$\mathbf{LCUC_{UC}}$	=	Total utility costs used for levelization
IMP	=	Total discounted load impacts in kW or kWh over life of program savings

These terms are further defined by the following equations:

$$\mathbf{B_{UC}} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{At}}{(1+d)^{t-1}}$$

$$\mathbf{C_{UC}} = \sum_{t=1}^{N} \frac{UC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCUC_{UC} = \sum_{t=1}^{N} \frac{UC_t + INC_t}{(1 + d)^{t-1}}$$

$$IMP = \sum_{t=1}^{N} \frac{\left| \langle \sum_{t=1}^{N} \Delta EN_{it} \rangle \text{ or } \langle \Delta DN_{it} \text{ where I = peak period} \rangle \right.}{(1 + d)^{t-1}}$$

where:

UACt = Utility avoided generation, transmission and distribution supply costs in year t.

Current and Recommended Inputs: The avoided cost of generation is based on the most recently available forecasted rates for PURPA Qualifying Facilities standard rate tariff. The value of secondary sales, made possible by DSR freeing up generation, is added to the PURPA rates. Additionally, transmission and distribution avoided demand costs are also added to the PURPA rates. The avoided transmission and distribution costs come from PacifiCorp's Marginal Cost analysis.

Recommended Guidelines: Each time **UC** analysis is presented for regulatory review, it is expected to employ the most currently available avoided cost values and current cost of capital and inflation assumptions. The "Conservation Cost-effectiveness Spreadsheet" provides the relevant avoided cost values and all assumptions regarding avoided cost and needs to be included as an attachment whenever the **UC** test is presented for regulatory review. If a contract was approved based on a previously published avoided cost which was current at the time of contract selection but no longer reflective of avoided costs, the avoided costs used in that analysis may be used to perform additional **UC** test results but may not supplant current avoided cost analysis. This guideline applies both to proforma estimates of a program's expected performance when filing for Commission approval of programs and contracts and to annual evaluations to verify program or contract performance. A sample of the Conservation Cost-Effectiveness spreadsheet is included as Attachment C.

UAC_{At} = The avoided supply costs of the alternate utility fuel company. This term should be included for fuel substitution programs.

Current Inputs: Unclear

Recommended Inputs: Mountain Fuel avoided supply costs are best represented by the most recently available IRP avoided costs. See Attachment D.

d = Discount rate for present value computation.

Current and Recommended Inputs: PacifiCorp's most recently available after-tax real cost of capital as shown on conservation cost-effectiveness spreadsheets. Theoretically, since utility costs are bulked up for taxes, we should be using a pre-tax cost of capital, however, for consistency with the Oregon order which requires grossing up for taxes and use of an after-tax cost of capital, we will accept this practice.

UC_t = Utility cost is measured by *net utility cost.* Net utility cost is total program cost to the utility, including administrative costs, installation costs, monitoring and evaluation costs, all bulked up for taxes and revenue requirement, but *net of energy service charge payments* to the utility from the participant.

INC_t = Incentive payments PacifiCorp provides to the participant. Examples include the showerhead program and the FinAnswer programs. In the showerhead program, the incentive is the cost of the showerhead which the participant receives free of charge. In the FinAnswer programs, the lower interest rate is translated into an incentive payment.

UIC_t = Utility increased costs for supply. This term must be included for load building, load management and load retention programs. For programs without such impacts, the term can be ignored. This term is not included for computation of levelized cost per kW or kWh.

The terms above are further defined in the equations below. The avoided cost terms are further determined by costing period to reflect time-variant costs of supply as follows:

$$\mathbf{UAC_t} = \sum_{t=1}^{I} (\Delta EN_{it} \times MC{:}E_{it} \times K_{it}) + \sum_{t=1}^{I} (\Delta DN_{it} \times MC{:}D_{it} \times K_{it})$$

$\mathbf{UAC_{At}}$ = (Same as UAC_t formula above except with marginal costs and costing periods appropriate for the alternate fuel utility.)

$$UC_t = \sum_{t=1}^{I} (IC_t + DFC_t + CC_t + T_t + (ESc_t - LC_t))$$

$$UIC_t = \sum_{t=1}^{I} (\Delta EN_{it} \times MC{:}E_{it} \times (K_{it}-1)) + \sum_{t=1}^{I} (\Delta DN_{it} \times MC{:}D_{it} \times (K_{it}-1))$$

where:

ΔEN_{it}	=	Reduction in net energy use in costing period I in year t
ΔDN_{it}	=	Reduction in net demand in costing period I in year t
$MC{:}E_{it}$	=	Marginal cost of energy in costing period I in year t
$MC{:}D_{it}$	=	Marginal cost of demand in costing period I in year t
K_{it}	=	1 when ΔEN_{it} or ΔDN_{it} is positive in year t, and zero otherwise
IC_t	=	Installed Cost of Project; dollar rebate for rebate programs; measure costs for direct install
DFC_t	=	Deferred Costs, Administration, Overhead and Evaluation
T_t	=	Taxes
CC_t	=	Carrying Charge
ESc_t	=	Energy Service Charge payments
LC_t	=	Loan cost to PacifiCorp (net present value of loaning ESc_t)

PARTICIPANT COST TEST

The current and recommended equations and sources for inputs for **PC** are as follows:

$\mathbf{NPV_{PC}}$	=	$\mathbf{B_{PC} - C_{PC}}$
$\mathbf{NPV_{AVP}}$	=	$\mathbf{B_{PC} - C_{PC} / P}$
$\mathbf{BCR_{PC}}$	=	$\mathbf{B_{PC} / C_{PC}}$
$\mathbf{DP_{PC}}$	=	**Min j such that Bj > or = Cj**

where:

$\mathbf{NPV_{PC}}$	=	Net present value to all participants
$\mathbf{NPV_{AVP}}$	=	Net present value to the average participant
$\mathbf{BCR_{PC}}$	=	Benefit-cost ratio to participants
$\mathbf{DP_{PC}}$	=	Discounted payback in years
$\mathbf{B_{PC}}$	=	Benefits to participants, measured as the present value of gross energy and demand savings multiplied by forecasted weighted average retail tail block rates over the life of program savings plus other bill reductions.
$\mathbf{C_{PC}}$	=	Out of pocket costs to participants
Bj	=	Cumulative benefits to participants in year j
Cj	=	Cumulative costs to participants in year j
P	=	Number of program participants
j	=	First year in which discounted cumulative benefits are greater than or equal to discounted cumulative costs

These terms are further defined as follows:

$$\mathbf{B_{PC}} = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{At} + PAC_{At}}{(1+d)^{t-1}}$$

$$C_{PC} = \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

where:

$\mathbf{BR_t}$	=	Bill reductions in year t
$\mathbf{BI_t}$	=	Bill increases in year t
$\mathbf{TC_t}$	=	Tax credits in year t; There are no state or federal taxes currently available
$\mathbf{INC_t}$	=	Incentives paid to the participant by PacifiCorp in year t
$\mathbf{PC_t}$	=	Participant costs in year t
$\mathbf{PAC_{At}}$	=	Participant avoided costs in year t for alternate fuel devices (cost of alternate device not chosen). This term is included for fuel substitution programs.
$\mathbf{AB_{At}}$	=	Avoided bill from alternate fuel in year t

Current Inputs: Unclear

Recommended Inputs: Current and forecasted retail prices from Mountain Fuel most recently available IRP. See Attachment D.

These terms are further defined as follows:

$$\mathbf{BR_t} = \sum_{t=1}^{I} (\Delta EG_{it} \times RT{:}E_{it} \times K_{it}) + \sum_{t=1}^{I} (\Delta DG_{it} \times RT{:}D_{it} \times K_{it}) + OBR_t$$

$\mathbf{AB_t}$ = Use BR_t formula but with rates appropriate for alternate fuel utility

$$\mathbf{BI_t} = \sum_{t=1}^{I} (\Delta EG_{it} \times RT{:}E_{it} \times K_{it} - 1) + \sum_{t=1}^{I} (\Delta DG_{it} \times RT{:}D_{it} \times K_{it} - 1) + OBI_t$$

where:

ΔEG_{it}	=	Reduction in gross energy use in year t
ΔDG_{it}	=	Reduction in gross billing demand in year t
$RP{:}E_{it}$	=	Retail average tail block price for energy in year t
$RP{:}D_{it}$	=	Retail average tail block price for demand in year t
K_{it}	=	1 when ΔEG_{it} or ΔDG_{it} is positive in year t, and zero otherwise
OBR_t	=	Other bill reductions or avoided bill payments (water bill savings that accrue to participant, operation and maintenance bill reductions, customer charges, standby rates). These benefits will include non-direct, unmeasured benefits, such as non-energy or non-measurable benefits related to supplemental spending by the participant when PC is incorporated into PTRC. That is, if the participant chooses to implement a non-cost-effective measure as measured by direct energy or energy related benefits, this is measured as an out-of-pocket cost to the participant. The subcommittee recommends that supplemental spending analysis be included in the PTRC test and not in the UTRC test. The discussion above is consistent with a recent Oregon order allowing quantified non-energy benefits to the participant in the TRC analysis provided that the non-energy benefits are significant and there is a reasonable and practical method for calculating them.[9]
OBI_t	=	Other bill increases (customer charges, standby rates)

[9] Oregon Public Utility Commission, UM 551, Order No. 94-590; *In the Matter of the Investigation into the Calculation and Use of Cost-Effectiveness Levels for Conservation,* April 6, 1994, pages 14 and 15.

RATEPAYER IMPACT MEASURE TEST

The current and recommended equations and sources for inputs for **RIM** are as follows:

$$\mathbf{LRI_{RIM}} = (\mathbf{B_{RIM}} - \mathbf{C_{RIM}}) / \mathbf{E}$$

$$\mathbf{ARI_{RIM}} = (\mathbf{B_{RIMt}} - \mathbf{C_{RIMt}}) / \mathbf{E_t} \qquad \textbf{for } t = 1,\ldots,N$$

$$\mathbf{NPV_{RIM}} = \mathbf{B_{RIM}} - \mathbf{C_{RIM}}$$

$$\mathbf{BCR_{RIM}} = \mathbf{B_{RIM}} / \mathbf{C_{RIM}}$$

where:

$\mathbf{LRI_{RIM}}$	=	Life cycle revenue (rate) impact per kWh, per kW or per customer
$\mathbf{ARI_{RIM}}$	=	Annual revenue (rate) impact per kWh, per kW or per customer
$\mathbf{NPV_{RIM}}$	=	Net present value of revenue/rate levels
$\mathbf{BCR_{RIM}}$	=	Benefit-cost ratio for rate levels
$\mathbf{B_{RIM}}$	=	Benefits to rate levels
$\mathbf{C_{RIM}}$	=	Costs to rate levels

The B_{RIM} and C_{RIM} terms are further defined as follows:

$$B_{RIM} = \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{At}}{(1+d)^{t-1}}$$

$$C_{RIM} = \sum_{t=1}^{N} \frac{UIC_t + RL_t + UC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{At}}{(1+d)^{t-1}}$$

$$E_{RIM} = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

where:

UACt	=	Utility avoided generation, transmission and distribution supply costs in year t. Previously defined under the UC test.
UIC_t	=	Utility increased costs for supply. This term must be included for load building, load management and load retention programs. For programs without such impacts, the term can be ignored.
RG_t	=	Net revenue gain from increased sales in year t. This term should be included for load building or load retention programs.
RL_t	=	Net revenue loss from reduced sales in year one only. Revenue loss is net of free-riders and load building impacts.
UC_t	=	Utility program cost in year t; measured by *net utility cost.* Previously defined under the UC test.
E_t	=	System sales in kWh, kW or therms in year t or first year customers. Most recent IRP data for forecasted sales in Utah over life of program savings is source for this term.
UAC_{At}	=	Utility avoided supply costs for the alternate fuel in year t. Previously defined in UC test.
RL_{At}	=	Revenue loss from avoided bill payments for alternate fuel in year t; (i.e., device not chosen in a fuel substitution program).

The revenue impact terms (RG_t, RL_t and RL_{At}) are the same as the bill impact terms in PC except that the net impact to load are used instead of gross impacts and except that only one year of RL is used. If a net-to-gross ratio is used to differentiate savings from net savings, the revenue terms and the participant's bill terms will be related as follows:

$$RG_t = BI_t * \text{(net-to-gross ratio)}$$

$$RL_1 = BR_1 * \text{(net-to-gross ratio)}$$

$$RL_{At} = AB_{At} * \text{(net-to-gross ratio)}$$

UTAH TOTAL RESOURCE COST TEST

The recommended equations and sources for inputs for **UTRC** at all stages are as follows:

$$\mathbf{NPV_{UTRC}} = \mathbf{B_{UTRC}} - \mathbf{C_{UTRC}}$$

$$\mathbf{BCR_{UTRC}} = \mathbf{B_{UTRC}} / \mathbf{C_{UTRC}}$$

$$\mathbf{LC_{UTRC}} = \mathbf{LCUTRC} \; / \; \mathbf{IMP}$$

where:

$\mathbf{NPV_{UTRC}}$	=	Net present value of utility costs
$\mathbf{BCR_{UTRC}}$	=	Benefit-cost ratio of utility costs
$\mathbf{LC_{UTRC}}$	=	Levelized cost per unit of utility cost of the resource
$\mathbf{B_{UTRC}}$	=	Benefits of the program
$\mathbf{C_{UTRC}}$	=	Costs of the program.
LCUTRC	=	Total resource costs used for levelization
IMP	=	Total discounted load impacts in kW or kWh over life of program savings

These terms are further defined as follows:

$$\mathbf{B_{UTRC}} = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{At} + PAC_{At}}{(1+d)^{t-1}}$$

$$\mathbf{C_{UTRC}} = \sum_{t=1}^{N} \frac{UC_t + PC_t + UIC_t}{(1+d)^{t-1}}$$

$$\mathbf{LCUTRC} = \sum_{t=1}^{N} \frac{UC_t + PC_t - TC_t}{(1+d)^{t-1}}$$

$$\text{IMP} = \sum_{t=1}^{N} \frac{\left| \left\langle \sum_{t=1}^{N} \Delta EN_{it} \right\rangle \text{ or } \left\langle \Delta DN_{it} \text{ where I = peak period} \right\rangle \right.}{(1+d)^{t-1}}$$

where:

UACt = Utility avoided generation, transmission and distribution supply costs in year t.

Current Inputs: PacifiCorp uses utility avoided cost as defined in the UC test plus a 10% adder at the request of the Northwest Power Planning Council and the Oregon Public Utility Commission. Montana Commission rules request a 15% adder on UTRC, although it is not clear if this request is implemented.

Recommended Inputs: No 10% adder in this test.

Recommended Guidelines: Each time UTRC analysis is presented for regulatory review, it is expected to employ the most recently published avoided cost values and current cost of capital and inflation assumptions. The "Conservation Cost-effectiveness Spreadsheet" provides the relevant avoided cost values and all assumptions regarding avoided cost and needs to be included as an attachment whenever the UTRC test is presented for regulatory review. If a contract was approved based on a previously published avoided cost which was current at the time of contract selection but no longer reflective of avoided costs, the avoided costs used in that analysis may be used to perform additional UTRC test results but may not supplant current avoided cost analysis. This guideline applies both to proforma estimates of a program's expected performance when filing for Commission approval of programs and contracts and to annual evaluations to verify program or contract performance. A sample of the Conservation Cost-Effectiveness spreadsheet is included as Attachment B.

UAC_{At} = The avoided supply costs of the alternate utility fuel company. This term should be included for fuel substitution programs.

Recommended Inputs: Mountain Fuel avoided supply costs are best represented by the most recently available IRP avoided costs.

d = Discount rate for present value computation.

$$\text{IMP} = \frac{\sum_{t=1}^{N} \mid \langle \sum_{t-1}^{N} \Delta EN_{it} \rangle \text{ or } \langle \Delta DN_{it} \text{ where I = peak period} \rangle}{(1+d)^{t-1}}$$

where:

UACt = Utility avoided generation, transmission and distribution supply costs in year t.

Current Inputs: PacifiCorp uses utility avoided cost as defined in the UC test plus a 10% adder at the request of the Northwest Power Planning Council and the Oregon Public Utility Commission. Montana Commission rules request a 15% adder on UTRC, although it is not clear if this request is implemented.

Recommended Inputs: No 10% adder in this test.

Recommended Guidelines: Each time UTRC analysis is presented for regulatory review, it is expected to employ the most recently published avoided cost values and current cost of capital and inflation assumptions. The "Conservation Cost-effectiveness Spreadsheet" provides the relevant avoided cost values and all assumptions regarding avoided cost and needs to be included as an attachment whenever the UTRC test is presented for regulatory review. If a contract was approved based on a previously published avoided cost which was current at the time of contract selection but no longer reflective of avoided costs, the avoided costs used in that analysis may be used to perform additional UTRC test results but may not supplant current avoided cost analysis. This guideline applies both to proforma estimates of a program's expected performance when filing for Commission approval of programs and contracts and to annual evaluations to verify program or contract performance. A sample of the Conservation Cost-Effectiveness spreadsheet is included as Attachment B.

UAC_{At} = The avoided supply costs of the alternate utility fuel company. This term should be included for fuel substitution programs.

Recommended Inputs: Mountain Fuel avoided supply costs are best represented by the most recently available IRP avoided costs. See Attachment C.

d = Discount rate for present value computation.

Recommended Inputs: PacifiCorp's most recently available after-tax real cost of capital as shown on conservation cost-effectiveness spreadsheets. Theoretically, since utility costs are bulked up for taxes, we should be using a pre-tax cost of capital, however, for consistency with the Oregon order which requires grossing up for taxes and use of an after-tax cost of capital, we may want to go along with this.

UC_t = Utility cost is measured by *net utility cost.* Net utility cost is total program cost to the utility, including administrative costs, installation costs, monitoring and evaluation costs, all bulked up for taxes and revenue requirement, but *net of energy service charge payments* to the utility from the participant. See definition under UC Test.

PC_t = Participant direct costs

Recommended Inputs: Net participant cost should be used and should reflect participant cost net of quantified, energy-related benefits such as operation and maintenance benefits and water benefits.

UIC_t = Utility increased costs for supply. This term must be included for load building, load management and load retention programs. For programs without such impacts, the term can be ignored. This term is not included for computation of levelized cost per kW or kWh.

The terms above are further defined in the equations below. The avoided cost terms are further determined by costing period to reflect time-variant costs of supply as follows:

$$\mathbf{UAC_t} = \sum_{t=1}^{I} (\Delta EN_{it} \times MC{:}E_{it} \times K_{it}) + \sum_{t=1}^{I} (\Delta DN_{it} \times MC{:}D_{it} \times K_{it})$$

$\mathbf{UAC_{At}}$ = (Same as UAC_t formula above except with marginal costs and costing periods appropriate for the alternate fuel utility and no 10% factor.)

$$\mathbf{UC_t} = \sum_{t=1}^{I} (IC_t + DFC_t + CC_t + T_t + (ESc_t - LC_t))$$

$$\mathbf{UIC_t} = \sum_{t=1}^{I} (\Delta EN_{it} \times MC{:}E_{it} \times (K_{it}-1)) + \sum_{t=1}^{I} (\Delta DN_{it} \times MC{:}D_{it} \times (K_{it}-1))$$

where:

ΔEN_{it}	=	Reduction in net energy use in costing period I in year t
ΔDN_{it}	=	Reduction in net demand in costing period I in year t
$MC{:}E_{it}$	=	Marginal cost of energy in costing period I in year t
$MC{:}D_{it}$	=	Marginal cost of demand in costing period I in year t
K_{it}	=	1 when ΔEN_{it} or ΔDN_{it} is positive in year t, and zero otherwise
IC_t	=	Installed Cost of Project
DFC_t	=	Deferred Costs, Administration, Overhead and Evaluation
T_t	=	Taxes
CC_t	=	Carrying Charge
ESc_t	=	Energy Service Charge payments
LC_t	=	Loan cost to PacifiCorp (net present value of loaning ESc_t)

PACIFICORP TOTAL RESOURCE COST TEST

All equations for **PTRC** are identical to UTRC except for two terms. Utility avoided cost includes a 10% adder and supplemental benefits are included in OBR for computation of net participant cost. This test is equivalent to PacifiCorp's previous definition of TRC.

$$\mathbf{UAC_t} = \sum_{t=1}^{I} (\Delta EN_{it} \times (MC{:}E_{it} \times 1.1) \times K_{it}) + \sum_{t=1}^{I} (\Delta DN_{it} \times (MC{:}D_{it} \times 1.1) \times K_{it})$$

Total Resource Cost Analysis By Stage

Stage		IRP	
DSR Estimates	Technical Potential	Program Potential	Action Plan
Equation	TRC = ((NPV of avoided cost plus 10% with secondary sales * kWh)+ non-eenrgy benefits)-(First Cost + NPV of O&M costs) where avoided cost includes line losses and assumes a conservation load factor to value capacity benefits.	TRC = ((NPV of avoided cost plus 10% with secondary sales * kWh)+ non-eenrgy benefits)-(NPV of Revenue requirement) where: avoided cost includes line losses and assumes a conservation load factor to value capacity benefits; and, where: revenue requirement includes taxes.	RIM=[(incremental power cost * savings*(1+.15)+ESc+line losses)-(program investment+(lost revenues@projected retail price by jurisdiction)+income taxes+ +bad debt on ESc(.005)]/annual energy saved
MODEL ASSUMPTIONS			
Revenue Requirements - Deferred - Expensed	No; incremental first cost of measure used. (this is like California Std. Practice Mnuel)	Yes administration, measure costs; not really clear. (page 105) administration; evaluation costs not explicitly addressed.	Yes? Operating revenue, expenses, taxes. ?
Levelization	LC = (first cost + NPV of O&M) * CRF/annual kWh savings	LC=[((deferred utility cost *NPV multiplier)+(loan investment * NPV multiplier)+utility expense+NPV of customer costs) * CRF] / annual energy saved	Unclear; real levelized used for costs, nominal levelized used for price impact analysis.
Taxes	Not included.	Included in NPV multipliers noted above.	Included but not clear how.
Freeriders/Background	Prototype modeling estimates of future efficiency (codes) are given to forecasting department for "frozen efficiency" in load forecasts. Additionally, measures under 10 mills levelized are removed from Tech. potential and netted out of the load forecasts. Commercial only; industrial background is captured in econometric forecasts and no background assumed in residential. (pp. 81-83)	Freeriders subtracted from technical potential for commercial programs, new and existing.	Unclear
Normalization	Yes; based on long-term forecast.	Yes	Unclear
INPUT ASSUMPTIONS			
Discount Rate	Real, after tax 5.23% used for levelization.	Real, after tax 5.23% used for levelization.	Nominal 8.8%
Savings Estimates - Energy	Based on engineering prototypes and conditional demand analysis adjusted for actual consumption, end-use saturation and vacancy rates.	kWh saved= (constant+slope* dUA)*(1-fuel (adj) factor)*(1-take-back factor)*Acceptance factor*penetration factor. Tack-back factor applied to existing buildings, res. and com. only; acceptance factor refers to the % of relevant population eligible for measure; penetration rate refers to % of the market defined by the acceptance factor expected to be reached by program. 6%, 10.5% and 12% line losses added.	Unclear how this was derived, i.e., which forecast used, where initial estimates come from (medium DSR?)
- Capacity	Unclear	Average reduction in four season peak derived from load shapes of programs input to IPM. Relies on load profiles developed for programs which is an aggregate of measure load profiles.	Unclear how this was derived.
Avoided Cost - Energy - Capacity	Uses assumed conservation load factor to assign $ value to energy and demand savings. Provides 10% adder for benefits to society too difficult to quantify. Avoided generation capacity and energy costs based on R-2, transmission, distribution costs and line losses. Unclear what discount rate was used, i.e., RAMPP-2 or current assumptions regarding after tax cost of capital and long-term inflation rate. Secondary sales incl.	Uses assumed conservation load factor to assign $ value to energy and demand savings. Provides 10% adder for benefits to society too difficult to quantify. Avoided generation capacity and energy costs based on R-2, transmission, distribution costs and line losses. Unclear what discount rate was used, i.e., RAMPP-2 or current assumptions regarding after tax cost of capital and long-term inflation rate. Secondary sales incl.	Uses incremental power cost plus line losses (valued at zero) plus 15% to account for deferral of T&D investment and 10% conservation advantage. Capacity estimates unclear.
Prices - Gas - Electric	Unclear how non-energy benefits valued. Since TRC, lost rev's and customer cost savings cancel.	Unclear how non-energy benefits valued. Since TRC, lost rev's and customer cost savings cancel.	Unclear. Average retail price by jurisdiction
Costs - Measures - Administrative	No supplemental measures; no background measures	As proxy for supplemental costs, costs raised by 30% and savings raised by 20%; no background measures.	Supplemental costs reduced; savings reduced. Unclear as to how much reduced. Background measures included?
Benefits			Line losses valued at zero in example; deferred O&M valued at zero in example.

Total Resource Cost Analysis By Stage

Stage	IMPLEMENTATION AND ACQUISITION	
DSR Estimates	Program Approval Process	Measure Funding Limits
Equation	TRC = ((NPV of avoided cost plus 10% with secondary sales * kWh)+ non-eenrgy benefits)-(NPV of Revenue requirement) where: avoided cost includes line losses and assumes a conservation load factor to value capacity benefits; and, where: revenue requirement includes taxes.	TRC = ((NPV of avoided cost plus 10% with secondary sales * kWh)+ non-eenrgy benefits)-(First Cost + NPV of O&M costs) where avoided cost includes line losses and assumes a conservation load factor to value capacity benefits.
MODEL ASSUMPTIONS		
Revenue Requirements - Deferred - Expensed	Yes All utility program costs Evaluation	No
Levelization	LC=NPV of revenue requirements*CRF/annual energy savings	
Taxes	Included in revenue requirement calc.	Not included in analysis.
Freeriders/Background	Background included in costs.	Background included in costs.
Normalization		
INPUT ASSUMPTIONS		
Discount Rate	Real, after tax.	
Savings Estimates - Energy	Based on market potential for territory.	DOE-2 modeling and prototype prescriptive estimates.
- Capacity	Assumed through CLF	Assumed through CLF?
Avoided Cost - Energy - Capacity	Uses assumed conservation load factor to assign $ value to energy and demand savings. Provides 10% adder for benefits to society too difficult to quantify. Avoided generation, transmission and distribution (with line losses) capacity and energy costs based on most recent IRP avoided cost assumptions and plus updates to cost of capital and inflation.	Uses assumed conservation load factor to assign $ value to energy and demand savings. Provides 10% adder for benefits to society too difficult to quantify. Avoided generation, transmission and distribution (with line losses) capacity and energy costs based on most recent IRP avoided cost assumptions and plus updates to cost of capital and inflation.
Prices - Gas - Electric	Unclear. Marginal retail price by jurisdiction	Unclear. Marginal retail price by rate schedule.
Costs - Measures - Administrative	Supplemental and background included.	Supplemental and background costs included in measure costs.
Benefits		

Total Resource Cost Analysis By Stage

Stage DSR Estimates	EVALUATION
Equation	TRC=NPV of Benefits-NPV of Costs Where Benefits include supplemental costs plus (kWh*AC w/10% and secondary sales with assumed CLF); and where Costs = revenue requirements?
MODEL ASSUMPTIONS	
Revenue Requirements - Deferred - Expensed	Yes?
Levelization	
Taxes	Included?
Freeriders/Background	Background included in costs.
Normalization	
INPUT ASSUMPTIONS	
Discount Rate	Real, after tax.
Savings Estimates - Energy	DOE-2 modeling and prototype prescriptive estimates. Metering and statistical billing analysis.
- Capacity	DOE-2 modeling and prototype prescriptive estimates. Metering and statistical billing analysis.
Avoided Cost - Energy - Capacity	Uses assumed conservation load factor to assign $ value to energy and demand savings. Provides 10% adder for benefits to society too difficult to quantify. Avoided generation, transmission and distribution (with line losses) capacity and energy costs based on most recent IRP avoided cost assumptions and plus updates to cost of capital and inflation.
Prices - Gas - Electric	 Unclear. Marginal retail price by rate schedule.
Costs - Measures - Administrative	Supplemental included as a benefit; background measures included in cost side.
Benefits	

PACIFICORP
Conservation Cost Effectiveness
Retrofit Water Heat Measures

RAMPP-2 approved avoided costs with secondary sales

(A) Year	(B) Generation, Transmission & Distribution Marginal Capacity Cost $/kW (EOY$)	(C) Generation, Transmission & Distribution Marginal Capacity Cost Cents/kWh (EOY$) (B) X 100/ (8760 x 0.480)	(D) Marginal Energy w/losses Cents/kWh (EOY$)	(E) Total Marginal Costs Cents/kWh (EOY$) (C)+(D)	(F) Plus 10% Conservation Advantage (E) x 1.1	(G) Present Value Discount Rate 8.79% (to 12/93 $'s)	(H) Present Value Marginal Costs Cents/kWh (to 12/93 $'s) (F) x (G)	(I) Sum Conservation Cost Effectiveness Cents/kWh (to 12/93 $'s)	(J) Annual Charge	(K) Real Levelized Cents/kWh	(L) Measure Life Years
1993			1.98	1.98	2.18	1.0000	2.18				1
1994			2.10	2.10	2.31	0.9192	2.12				2
1995			2.14	2.14	2.35	0.8449	1.99				3
1996			2.33	2.33	2.57	0.7767	1.99				4
1997	97.10	2.31	3.04	5.35	5.88	0.7139	4.20				5
1998	100.41	2.39	3.32	5.70	6.27	0.6562	4.12				6
1999	103.76	2.47	3.64	6.11	6.72	0.6032	4.05	20.651	16.55%	3.418	7
2000	107.39	2.55	3.99	6.55	7.20	0.5545	3.99				8
2001	110.93	2.64	4.36	7.00	7.70	0.5097	3.93				9
2002	114.77	2.73	4.78	7.51	8.26	0.4685	3.87	32.440	12.44%	4.034	10
2003	118.64	2.82	5.21	8.03	8.84	0.4306	3.81				11
2004	122.68	2.92	5.66	8.58	9.43	0.3958	3.73				12
2005	126.89	3.02	6.07	9.09	9.99	0.3639	3.64				13
2006	131.15	3.12	6.47	9.59	10.55	0.3345	3.53				14
2007	135.70	3.23	6.91	10.14	11.15	0.3074	3.43	50.575	9.29%	4.698	15
2008	140.31	3.34	7.40	10.74	11.81	0.2826	3.34				16
2009	145.08	3.45	7.88	11.33	12.47	0.2598	3.24				17
2010	149.92	3.57	8.37	11.93	13.13	0.2388	3.13				18
2011	155.05	3.69	8.88	12.57	13.83	0.2195	3.03				19
2012	160.36	3.81	9.43	13.24	14.57	0.2017	2.94	66.259	7.76%	5.145	20
2013	165.74	3.94	10.01	13.96	15.35	0.1854	2.85				21
2014	171.41	4.08	10.64	14.71	16.18	0.1705	2.76				22
2015	177.28	4.22	11.30	15.51	17.06	0.1567	2.67				23
2016	183.21	4.36	12.00	16.36	17.99	0.1440	2.59				24
2017	189.46	4.51	12.75	17.25	18.98	0.1324	2.51	79.642	6.89%	5.486	25
2018	195.90	4.66	13.54	18.20	20.02	0.1217	2.44				26
2019	202.65	4.82	14.39	19.21	21.13	0.1119	2.36				27
2020	209.49	4.98	15.29	20.27	22.30	0.1028	2.29				28
2021	216.64	5.15	16.25	21.40	23.54	0.0945	2.22				29
2022	224.00	5.33	17.28	22.59	24.85	0.0869	2.16	91.118	6.33%	5.771	30

Footnotes:

Column (B) 1997 Generation Demand Cost is $63.36, from RAMPP-2 avoided costs.
Transmission Demand Cost is $25.70, based on December 1992 dollars, escalated by 3.4% inflation thereafter.
Distribution Demand Cost is $2.85, based on December 1992 dollars, escalated by 3.4% inflation thereafter.

Column (C) Conservation Load Factor = 0.480.

Column (D) 1993-1996 production cost model results, 1997-2022 fuel cost of combined cycle CT. Also includes the capital cost of combined cycle combustion turbine which is in excess of a simple cycle combustion turbine. System-wide secondary energy loss factor of 1.1050, applied to avoided costs.

Column (G) Discount rate for present value calculations is based on the Company's weighted Cost of Capital with after-tax cost of debt.

Column (I) Corresponds to Measure Funding Limit in Tariff.

Annual Charge Formula
k/(1-1/(1+k)^a)/(1+k)

where
a = number of years
k = real cost of capital
5.21%

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DEMAND SIDE RESOURCE COST RECOVERY COLLABORATIVE REPORT

APPENDIX VIII

PROPOSED 1995-1996 REGULATORY PLAN, PETITION, NOTICE OF HEARING, JOINT AGREEMENT, INDUSTRIAL COMMENTS ON JOINT AGREEMENT

SUBMITTED
MARCH 31, 1995

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Rate making	)	
Treatment of Demand-Side Resources	)	DOCKET NO. 92-2035-04
and the Analysis of Regulatory Changes	)	PETITION FOR
to Encourage Implementation of	)	APPROVAL OF A
Integrated Resource Planning	)	JOINT AGREEMENT

The Division of Public Utilities ("Division"), PacifiCorp, dba Utah Power ("Company"), the Office of Energy and Resource Planning ("OE&RP"), and the Environmental Intervenors ("EI"), hereinafter collectively referred to as the "Parties", hereby apply to the Public Service Commission of Utah ("Commission") for an Order approving a Joint Agreement, a copy of which is attached hereto as Exhibit A.

In support of this Application, the Parties state as follows:

1. In its February 10, 1994, Order in this Docket that approved a Joint Recommendation which established an interim policy for the regulatory treatment of demand-side resource activities, the Commission stated:

> The Commission finds that the provisions of the Joint Recommendation's proposed accounting mechanism, including the carrying charge and amortization provisions of the proposed mechanism, are a reasonable and proper way to account for PacifiCorp's 1994 DSR costs, including its NLR, and energy service charge payments it receives from customers during 1994. The proposed accounting mechanism provides PacifiCorp with appropriate direction regarding the accounting treatment for its 1994 DSR activities, while reserving prudence and rate recovery decisions for an appropriate case.
>
> The Commission finds that the Joint Recommendation is just, reasonable and in the public interest and should be approved in its entirety.

2. Based on the Commission's order the Parties and representatives of other interested parties have met in a Cost Recovery Collaborative during 1994 to implement the Joint Recommendation and examine the issues described in it.

3. The Parties are now preparing a report to the Commission to be submitted on March 31, 1995, describing the results of the 1994 Joint Recommendation and the conclusions and recommendations of the Cost Recovery Collaborative (CRC). Assembling the volumes of work into a conclusive body of evidence will take several months. The Parties are presently aware of the work accomplished and conclusions likely to be reached by the CRC's various subcommittees.

4. The Parties believe that it is necessary to continue to remove DSR disincentives and provide direction to PacifiCorp's DSR efforts during the period between the expiration of the 1994 Joint Recommendation and Commission action on the March 31, 1995 CRC Report. Continuity and consistent direction are important to assure that PacifiCorp sets appropriate levels of DSR in Utah in the RAMPP IV report and in setting corporate budgets for 1995 and 1996.

5. The Parties also believe that certain aspects of DSR cost recovery deserve additional study before embracing a long term policy on cost recovery. The final report of the CRC will specify issues for continuing study. The new Joint Agreement narrows the scope of issues being addressed in 1995 and 1996 because the work of the CRC's subcommittees resolved a number of concerns of the Parties.

6. Therefore the Parties have agreed to a second accord entitled the "Joint Agreement". This agreement is for a two year term, 1995 and 1996. It establishes a framework for the regulatory treatment of DSR program costs and net lost revenue during this period that is similar to the prior Joint Recommendation but with significant improvements based upon the experience gained by the parties during the implementation of the prior Joint Recommendation. This agreement contains goals for PacifiCorp's DSR acquisition in Utah and requires quarterly meeting of interested parties to review and discuss DSR issues.

7. The Parties submit that the Joint Agreement will continue to encourage the reasonable

development of Commission approved DSR programs in Utah during 1995 and 1996. It will provide the Commission and the Parties with additional information to formulate a longer-term DSR policy, and is otherwise in the public interest.

WHEREFORE, the Parties respectfully request an order of the Commission approving the Joint Agreement and authorizing the accounting and regulatory treatment specified in the Joint Agreement.

Dated this 15 day of February 1995

Respectfully Submitted

By Frank Johnson

Frank Johnson, Director
Division of Public Utilities

- 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 NOTICE OF HEARING

ISSUED: February 15, 1995

Appearances:

Edward A. Hunter	For	PacifiCorp
Michael Ginsberg Assistant Attorney General	"	Division of Public Utilities
Kent Walgren Assistant Attorney General	"	Committee of Consumer Services
Steven F. Alder Assistant Attorney General	"	Office of Energy Resource Planning, Department of Natural Resources
Eric Blank	"	Land and Water Fund of the Rockies
William Evans	"	Utah Industrial Energy Consumers

By the Commission:

On February 10, 1994, the Commission issued a Report and Order adopting a joint recommendation which provided an interim approach for the regulatory treatment of PacifiCorp's demand-side resource ("DSR") activities in Utah for 1994. This interim approach involved: (a) the establishment of an accounting mechanism for DSR costs, including net lost revenues, incurred by PacifiCorp during calendar year 1994; (b) the establishment of a formula and a procedure for the determination of net lost revenues ("NLR"); and (c) the establishment of a framework for the evaluation of the results of the interim approach and other DSR issues. This accounting mechanism provided PacifiCorp with appropriate direction regarding the accounting treatment for its 1994 DSR activities, while reserving prudence and rate recovery decisions for an appropriate case.

The Company is currently without an approved accounting treatment for its DSR activities that take place in 1995 and beyond. The Commission desires to remedy this situation. Parties have indicated to the Commission that a stipulation on how to approach future regulatory treatment of the Company's DSR costs is being negotiated and they request the opportunity to present a stipulation for Commission review. The Commission is of the opinion that a hearing process is the most efficient way to proceed on this issue.

ORDER

NOW, THEREFORE, IT IS HEREBY ORDERED that a hearing on this matter be scheduled for Thursday, the 23rd day of February, 1995, at 10:00 a.m., in the Commission's hearing room #426, at 160 East 300 South, Heber M. Wells Building, Fourth Floor, Salt Lake City, Utah.

In compliance with the American's with Disabilities Act, individuals needing special accommodations (including auxiliary communicative aids and services) during this hearing should notify Julie Orchard, Commission Secretary, at 160 East 300 South, Salt Lake City, Utah, 84111 (801)530-6713, at least three working days prior to the hearing.

DATED at Salt Lake City, Utah, this 15th day of February, 1995.

/s/ Stephen F. Mecham, Chairman

(SEAL) /s/ James M. Byrne, Commissioner

/s/ Stephen C. Hewlett, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF RATE MAKING TREAT- MENT OF DEMAND SIDE RESOURCES AND THE ANALYSIS OF REGULATORY CHANGES TO ENCOURAGE IMPLEMENTATION OF INTEGRATED RESOURCE PLANNING.	)))))	<u>DOCKET NO. 92-2035-04</u> <u>JOINT AGREEMENT</u> <u>FOR DEMAND SIDE RESOURCE</u> <u>REGULATORY TREATMENT -</u> <u>1995 AND 1996</u>

PacifiCorp, state regulators, and other interested parties have met each month in 1994 in a collaborative setting made up of subcommittees and the central collaborative to implement the 1994 Demand Side Resource Interim Policy and to develop a mutually agreeable and ongoing regulatory policy (this Joint Agreement) to be used in 1995 and 1996 regarding demand side resource investments. Prior to the fourth quarter of 1996, any interested party can request that the Utah Public Service Commission evaluate the appropriateness of continuing this 1995 - 1996 Joint Agreement (once it is approved and implemented) for application to 1997 and beyond. Absent such action, this Joint Agreement will expire on January 1, 1997.

The Division of Public Utilities (DPU), PacifiCorp dba Utah Power (Company), Department of Natural Resources, Office of Energy and Resource Planning (OE&RP), and Environmental Intervenors (EI) desire to move ahead with Commission approved demand side resource programs (DSR) in 1995 and 1996. The 1994 Interim Policy has given all parties experience in most aspects of demand side resources and has led to this Joint Agreement (Agreement) for DSR regulatory treatment starting with 1995 DSR projects.

The undersigned parties (Parties) propose a new agreement for the regulatory treatment of DSR programs in Utah. This new agreement will be in effect when approved by the Utah Commission, but the Parties agree that it should be retroactive to January 1, 1995. The Parties agree that the Utah 1995 - 1996 DSR Regulatory Treatment Agreement detailed below is a reasonable approach for addressing DSR cost recovery and program review issues for the next two years in the State of Utah. This Agreement represents a compromise among the DSR Cost Recovery Collaborative (Collaborative) members signing this Agreement. The Agreement represents an effort to remove disincentives to DSR implementation and thus Integrated Resource Plan (IRP) implementation by the Company, and the Agreement attempts to equalize and simplify cost recovery treatment of DSR, and make it comparable, to the extent possible, with treatment of Supply Side Resource acquisitions. The Parties agree that this Joint Agreement is a continuation of the DSR experiment in Utah, and as such, neither explicitly or implicitly includes any rewards or penalties regarding success or failure of the Company's accomplishment of DSR savings levels and acquisitions.

UTAH 1995 - 1996 DSR REGULATORY TREATMENT AGREEMENT

This agreement establishes an accounting treatment for Utah Public Service Commission approved DSR programs and calculation and recording of Net Lost Revenues (NLR). Recovery of booked costs and NLR's will be addressed in a future rate case.[1] Nothing in this Agreement precludes or prohibits any Party from challenging the recovery of PacifiCorp's DSR costs in a future rate case proceeding.

During the term of this Agreement, the Parties agree that the Company should be allowed to record all DSR costs for Commission approved programs per the accounting treatment specified in this Agreement. The Parties also agree that the Company should be allowed to record an amount of Net Lost Revenue (NLR) associated with Commission approved DSR programs. This Agreement specifies the terms, conditions and formula to compute the amount of NLR associated with Commission approved DSR acquisitions. Additionally, the Agreement specifies goals and expectations for the amount of DSR to be acquired by PacifiCorp in 1995 and 1996, provides for DSR reporting to regulators and the Commission and allows for further analysis of other future options for cost recovery.

1. DEMAND SIDE RESOURCE PROGRAM COSTS

1.1 For 1995 and 1996, the Parties agree that program evaluation, monitoring, and reporting costs for Commission approved programs will be expensed in the year incurred. Non-program specific advertising costs will also be expensed in the

[1] The Performance Standards Subcommittee of the Cost Recovery Collaborative will present the Commission with recommended guidelines to be used by regulators and PacifiCorp to assess cost effectiveness associated with the Company's DSR acquisitions. The guidelines include definition of cost effectiveness tests and how such tests should be used in determining cost effectiveness. The recommended guidelines will be provided to the Commission in the March, 1995, final report of the Cost Recovery Collaborative.

year incurred. All other DSR program costs and associated carrying charges for Commission approved DSR programs, including costs associated with conservation contracts resulting from bidding processes or from bilateral conservation contracts, will be capitalized with amortization beginning January of the year following installation, and continuing over a period no longer than the life of the programs.

1.2 Capitalized program costs will accrue a carrying charge from the date incurred to the end of each calendar year, at the current Allowance For Funds Used During Construction (AFUDC) rate.

1.3 Capitalization of program costs and NLR will be booked to account 182.3 (Other Regulatory Assets). Amortization of these amounts will be booked to account 456 (Other Electric Revenue). Customer payments resulting from Energy Service Charge (ESC) will be recorded in accounts 124 (Other Investments, For Loan Principal) and 451 (Miscellaneous Service Revenues, For Interest Income). It is expected that the ESC will be approximately 40-50% of the total program costs. Total program costs in 1995 are expected to be approximately $15 million for the DSR target established.

2. NET LOST REVENUE

2.1 Attached as Exhibit 1 is a description of the Net Lost Revenue Formula (Formula) which Parties agree will be used by the Company to calculate NLR starting with new DSR installations from Commission approved DSR programs which occurred after January 1, 1995. The Parties agree that the Commission should adopt the Formula for purposes of calculating NLR for 1995 and 1996. The burden to show that the inputs to the Formula are reasonable rests with PacifiCorp.

2.2 The annual amount of NLR calculated under the Formula in Exhibit 1, available to the Company to offset DSR disincentives, will be based upon energy savings obtained from DSR projects installed during each calendar year starting with 1995 and will be recorded as they occur for the subsequent 12 months. NLR recorded in each year will be capitalized with amortization beginning in January of the following year. Additionally, NLR's will be accrued in 1995 only for up to 12 months from installation for 1994 Commission approved projects. This applies to all installations (all those except 1994 and 1995 ECONS and 1994 Schedule 5, both of which are not considered to be ongoing programs. Recording of NLR's for these two programs will terminate at the end of each calendar year). NLR will not accrue a carrying charge.

PacifiCorp agrees to continue work during 1995 and 1996 to update estimates of energy savings based upon monitoring and evaluation results. These verified estimates of kWh and kW savings will form the basis for PacifiCorp's NLR calculations. When PacifiCorp files its next general rate case, the amortization of NLR's and program costs, the unamortized balance of NLR and program costs, and energy service charge revenues will be included in the Utah jurisdictional revenue requirement subject to regulatory review. The total amount of NLR calculated for all Utah measures installed in each of the calendar years 1995 and 1996, based on the Formula, shall not exceed $2,000,000 in each year.

2.3 NLR will be calculated monthly utilizing the Formula during each calendar year starting with January 1995. Following completed program evaluations and determination of verified DSR savings, PacifiCorp will adjust the NLR amount booked. This process is designed to allow for the 12-15 month interval between DSR program implementation (where projected energy savings amounts are based upon engineering estimates) and the time when actual data is available through program evaluation reports to estimate verified net energy and capacity savings obtained by the DSR programs.

Qualified expertise may be retained to review Company evaluations and monitoring activities and reports. Such expertise will be selected and directed by a committee of interested parties. PacifiCorp agrees to fund up to $50,000 for this effort. After 1995 installations are evaluated, it is the expectation of the Parties that this work will be accomplished without the need for outside expertise funded by PacifiCorp. Such funds will be capitalized by PacifiCorp and amortized along with other program costs.

3. ANNUAL TARGET FOR UTAH DSR ACTIVITY

3.1 Utah DSR targets for 1995 and 1996 will be based upon the Company's current Demand Side Resources Acquisition Plan published as part of the Integrated Resource Plan (IRP) to provide state specific detail consistent with the IRP Action Plan. PacifiCorp's current IRP is designated RAMPP-3, dated April 1994, and contains a DSR Acquisition Plan for 1995. The Utah DSR target for 1996 will be based upon the DSR Acquisition Plan to be published as part of RAMPP-4, which will be published in late 1995. All Parties may not agree with the level of DSR activity stated in the RAMPP DSR Acquisition Plans, however, for purposes of this Agreement, RAMPP DSR Acquisition Plans are adopted. Nothing in this Agreement precludes or prohibits any Party from challenging the prudence of PacifiCorp's DSR activity in a future rate case proceeding. The burden of demonstrating the prudence of Utah DSR activity rests with PacifiCorp.

3.2 The 1995 target for Utah DSR acquisition for this agreement is **80,923 MHW** as reflected in RAMPP-3. A capacity target distinct from the energy target is not included in the DSR Acquisition Plan for Utah, and therefore a capacity target is not included in this Agreement.

The 1996 target for Utah DSR acquisition will be as published as part of RAMPP-4 in late 1995.

It is the expectation of the Parties that this Agreement will allow PacifiCorp to meet the Utah DSR savings levels published in the Acquisition Plans for 1995 and 1996. PacifiCorp will bear the burden to demonstrate the reasonableness of any fluctuation from the Acquisition Plan amounts.

3.3 The **minimum** target for Utah DSR energy savings acquisition in 1995 will be **60,692 MHW** (75% of the Utah DSR Acquisition Plan target stated in RAMPP-3). The minimum target for Utah DSR acquisition in 1996 will be 75% of the DSR savings stated in the RAMPP-4 Acquisition Plan. The minimum DSR target in each year represents the threshold of a good-faith effort on the part of the Company to achieve cost effective demand side resources.

4. REPORTS

4.1 Continuation of Quarterly DSR Report Preparation

The Parties agree that PacifiCorp should continue to prepare quarterly reports showing quarterly DSR activity, savings, and program costs for Utah. This written report should be presented by the Company as an agenda item at their quarterly DSR Update Conference (see Section 5). After the submittal of the Company's fourth quarter 1994 report, the Parties agree that the quarterly reports will no longer have to be submitted directly to the Utah PSC. This is because this same information will now be reported to the Commission in the Company's Semi-Annual Report (see paragraph 4.2). The Parties also agree that the Company will provide their most recent report of Net Lost Revenues (monthly and quarterly) as an agenda item at the quarterly DSR Update Conferences.

4.2 DSR Reporting As Part Of Normal Semi-Annual Report To Regulators

The Parties agree that PacifiCorp will report their DSR activity to Regulators in much the same manner as they provide reporting of other Company operations, specifically in the Semi-Annual Report, recognizing DSR as more of a "business as usual" activity. This Semi-Annual DSR report should provide the same information provided in the Quarterly Activity Reports, but should also include the "building specific" information PacifiCorp has provided semi-annually in past Collaborative meetings. It is the expectation that the Company's Semi-Annual DSR Report will appear as a tab in the Semi-Annual Report. The parties agree that DSR semi-annual reporting should begin with the next Semi-Annual Report due from the Company, which will be April 30th of 1995.

4.3 Annual DSR Report To The Commission

The Division of Public Utilities and the Office of Energy and Resource Planning, will conduct an annual analysis of PacifiCorp's actual annual and cumulative DSR acquisitions.

5. DSR TRACKING AND MONITORING - QUARTERLY UPDATE CONFERENCE

5.1 By the end of March, 1995, the Utah DSR Cost Recovery Collaborative will finish all of its assignments, will report the results to the Commission, and will be disbanded. In order to provide for continued regulatory oversight of the DSR process, the Parties agree that the Company will sponsor a quarterly DSR update conference for regulators and other interested parties where the following topics will be reviewed:

a. DSR Evaluation Reports,

b. Standard Data Requests for DSR Projects,

c. Other DSR contracts or commitments,

d. Monthly, quarterly, and annual Net Lost Revenue calculations based upon the agreed upon Formula,

e. Actual energy and capacity savings vs prior engineering estimates of savings,

f. Updates to or modifications of NLR calculations,

g. Quarterly Activity Reports,

h. Semi-Annual DSR reports prior to submittal in the official Company Semi-Annual Report,

I. Comparison of Statistical Recoupling results to NLR, *

j. Market Transformation efforts,

k. Additional study work to determine the appropriate Avoided Demand Costs to be used in the Formula, (issues such as, but not limited to, transmission and distribution avoided costs),

l. Other DSR topics, as needed.

* The Office of Energy and Resource Planning agrees to provide updated results, using Company provided data, of the statistical recoupling method for addressing the issue of revenue loss between rate cases for comparison to the NLR approach.. This information will be provided in context with the Quarterly Update Conference as data becomes available.

The first Quarterly Update Conference will be scheduled for the third or fourth week in May 1995 at the request of the Company.

6. JOINT AGREEMENT FOR DSR REGULATORY TREATMENT 1995 AND 1996

6.1 The Parties have agreed to this Joint Agreement as an integrated document and recommend that the Commission adopt it in its entirety. Accordingly, in the event any part, or all, of this Joint Agreement is modified or rejected by the Commission, each Party reserves the right, upon written notice to the Commission and all other Parties within 5 days of the date of the Commission's order, to withdraw from this Joint Agreement without being bound by its terms in this, or any other proceeding. Any Party which elects to withdraw, shall be entitled to proceed having its full claim, defenses and rights and shall otherwise not be prejudiced by the terms of the Joint Agreement. The Parties respectfully request that the Commission adopt this Joint Agreement.

Utah Demand Side Resources 1995 and 1996 Joint Agreement - Signature Page

Dated this 15th day of February 1995.

PacifiCorp

Environmental Intervenors

Office of Energy & Resource Planning

Division of Public Utilities

The Committee of Consumer Services, having participated in the Demand Side Resource Task Force and the Cost Recovery Collaborative, and intending to continue to participate in any further Demand Side Resource deliberations, is unable to oppose or support this Joint Agreement as the Committee of Consumer Services is unable to objectively determine whether to oppose or support this Joint Agreement.

Committee of Consumer Services

Attachment: Exhibit 1 - Net Lost Revenue Formula

Exhibit 1

Net Lost Revenue Formula

For purposes of the Joint Agreement Net Lost Revenue (NLR) shall be calculated for a period of 12 months from the installation date of each energy conservation project. NLR shall be the sum of lost energy revenue and lost demand revenue. Both an energy and demand component will be calculated for each energy conservation project. The formulas for these calculations are defined below:

Energy : Net Lost Revenue (energy) $= \text{Sum}_i\,(R - AC_i) \times (ES_i - LG_i)$

where:

- i = Month
- R = Tail block rate per kWh (per the current tariff) for the participant in the energy conservation project.
- AC_i = Monthly short-run avoided costs per kWh based on PacifiCorp's production cost model. The calculation is based on the comparison of two PDMac runs; one with and one without 50 MW of generation available at zero running cost. The AC is adjusted for sales for resale credit and average line losses.
- ES_i = Monthly kWh energy savings achieved by energy conservation projects installed during the period of the Joint Agreement. A full months energy savings will be assumed in the month of installation. ES_i will be initially based on engineering analysis which will be subsequently updated for the results of program evaluations as such information becomes available. Evaluations will include the appropriate treatment of issues such as free riders, free drivers, snapback, persistence of savings, and other appropriate issues.
- LG_i = Monthly kWh sales growth related to load building aspects of Demand Side Resource (DSR) projects. This component will be initially based on engineering analysis and will be subsequently updated based on the results of program evaluations as such information becomes available.

Demand: Net Lost Revenue (demand) $= \text{Sum}_i\,(DC - ADC_i) \times (NCPs_i - LGp_i)$

where:

- i = Month
- DC = Demand charge per MW (per the current tariff) for the participant in the energy conservation project.
- ADC_i = Monthly avoided demand costs stated in dollars per $NCPs_i$ that result from DSR installations. This component is measured by current purchase contracts with Southern California Edison and The Washington Water Power Company and a sales contract with Eugene Water and Energy Board. The value of these transactions are used as a surrogate for ADC_i for the months in which sales or purchase contracts occur. For months in which no sales of purchase contracts occur, a zero value is assigned.
- $NCPs_i$= Monthly non-coincident peak (MW) savings achieved by the DSR installation. The non-coincident peak (MW) savings will be based upon DOE-2 modeling analysis. In the event that DOE-2 modeling is not available non-coincident peak (MW) savings will be based on conservation load factor analysis.
- LGp_i = Monthly impact on the $NCPs_i$ of load building aspects of DSR projects. This component will be initially based on engineering analysis and will be subsequently updated based on the results of program evaluations as such information becomes available.

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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

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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 COMMENTS ON JOINT AGREEMENT FOR DEMAND-SIDE RESOURCE REGULATORY TREATMENT-1995 AND 1996

* * * * * * *

The Utah Industrial Energy Consumers submit the following comments on the proposed Joint Agreement for Demand-Side Resource Regulatory Treatment-1995 and 1996 ("Joint Agreement").

The UIEC incorporate and reaffirm the comments they filed on November 17, 1993, regarding the Petition for Approval of the Joint Recommendation for Accounting Treatment that was effective during the year 1994. Those comments apply with equal force to the current Petition for Approval of the Joint Agreement ("Petition").

In addition to the points raised in UIEC's earlier comments, the UIEC believe that the present Petition is premature. The Joint Agreement apparently incorporates some of the conclusions reached by the Cost Recovery Collaborative ("CRC") whose Report is to be submitted on or before March 31, 1995. That Report, when it issues, will be the product of more than a full year's study of cost accounting methods, including net lost revenue ("NLR") calculations, by a collaborative that the Commission established when it approved a one-year interim Joint Recommendation for 1994. Given the concerns about the NLR formula and other aspects of the 1994 Joint Recommendation, the Commission was willing to adopt the 1994 Recommendation only temporarily pending further study. The present Petition requests that the Commission essentially extend the 1994 order, including the NLR formula, for two more years without the benefit of the Report or comments on the Report.

The Petition suggests that the Joint Agreement is necessary to allow PacifiCorp to continue its DSR efforts "during the period between the expiration of the 1994 Joint Recommendation and Commission action on the March 31, 1995 CRC Report." (Petition at ¶ 4.) If that is the case, then the Commission should extend the 1994 Joint Recommendation or approve the proposed Joint Agreement for temporary implementation until the Commission can act on the Collaborative's Report. There does not appear to be any reason that the Commission should hurry to approve a two-year proposed accounting methodology.

The UIEC also continue to be concerned that an order on DSR accounting treatment will tend to establish presumption that DSR is used and useful, that it is a prudent investment, that there are net lost revenues associated with DSR, that there are disincentives to the Company to acquire DSR, that if there are disincentives they should be removed, or that the Company ought to be able to recover from ratepayers any DSR costs at all. In their initial comments filed in this docket, the UIEC protested Commission reliance on a collaborative process such as this one in which policy is formulated by regulators, public interest groups, and the utility without the participation of ratepayers. The UIEC protested that their right to due process is abridged when the Commission implements policies and procedures based on collaborative recommendations in the absence of procedural and evidentiary safeguards because such policies and procedures acquire presumptive validity. In the present case, for example, the NLR formula has acquired such a presumption of validity that the Petitioners are urging that it be implemented for another two years before anyone other than the CRC has had an opportunity to review and comment on the Report. The process, in this case, acts as a surrogate for rulemaking and effectively denies ratepayers the protections afforded by statute.

The UIEC are concerned that if the Commission approves another Joint Agreement to extend DSR accounting procedures for another two years, those procedures and the CRC's view of DSR will become further entrenched, will acquire presumptive validity in the eyes of regulators, and will have the effect of improperly shifting away from the Company and on to the ratepayers the burden of proving that DSR is used and useful or prudent.

The UIEC, therefore, recommend against adopting a 2-year term for the Joint Agreement, and against the issuance of any order approving the Joint Agreement until the Commission and interested parties have had a chance to review and comment on the CRC's report.

Finally, although the UIEC do not formally object to the Joint Agreement, they expressly reserve their right to comment on and/or oppose the CRC's Report, including the calculation of net lost revenues, to challenge any and all elements of the Company's accounting procedures, to oppose cost recovery for DSR, and to raise any other related issue in the appropriate evidentiary proceeding.

DATED this 22nd day of February, 1995.

F. ROBERT REEDER
WILLIAM J. EVANS
PARSONS BEHLE & LATIMER
Attorneys for Utah Industrial
Energy Consumers