DEMAND-SIDE-RESOURCE COLLABORATIVE REPORT

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I. INTRODUCTION

This Demand-Side-Resource (DSR) Collaborative Report is the culmination of the Technical Conference/Collaborative Process established to achieve the Utah Public Service Commission's (Commission) mandate in 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's mandate was "to define the issues involved both short-run and long-run and bring recommendations on viable options before this Commission for its decision" regarding ratemaking treatment of DSR. To facilitate the Commission's decisionmaking regarding appropriate regulatory policy for DSR in Utah, the Collaborative considered it essential that the report submitted to the Commission provide adequate information regarding possible regulatory treatments for DSR. Given this objective, the report provides the following analysis. First, the report specifies the criteria that the Collaborative deemed relevant in determining appropriate regulatory policy. Second, the report presents solutions to potential problems regarding DSR program cost recovery, lost revenue, and incentives. These solutions are evaluated with respect to the relevant criteria. Finally, the report addresses the provisions of the Energy Policy Act that pertain to regulatory treatment of DSR.

In addition to the analysis discussed above, the report includes proposals for regulatory policy for DSR provided by the following participants: PacifiCorp, Division of Public Utilities (Division), Department of Natural Resources (DNR), Environmental Intervenors (EI), The Committee of Consumer Services (CCS), Deseret Transmission and Generation (DG&T), and the Utah Industrial Energy Consumers (UIEC)[1]. (See Appendix I for proposals.) The purpose of including these proposals is to provide the Commission with a more complete perspective on the individual positions of those parties who elected to submit a position paper.

The intent of this paper is to provide an objective analysis of the issues described above. Given this objective, the analysis presented here represents a common understanding of collaborative participants' views. This common understanding should not be misconstrued as representing unanimity of opinion. Individual parties may disagree with the analysis provided on a particular aspect in the report. Where such dissent exists, parties have been asked to indicate so in their party's proposal provided in Appendix I.

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[1] For the purposes of this DSR technical conference, the Utah Industrial Energy Consumers are Abbott Critical Care, Amoco Oil Company, Hercules, Inc., Holnam, Inc./Ideal Division, Kennecott Utah Copper Corp., Kimberly-Clark, National Semiconductor, Praxair, Inc., and Westinghouse/Western Zirconium.

The following "Background" section provides further information regarding the Technical Conference/Collaborative Process. This information is intended to provide assurance that the process was comprehensive and thoughtful and to describe the evolution of this report.

II. BACKGROUND

In its order dated June 18, 1992 in Docket No. 90-2035-01, the Utah Public Service Commission stated that:

> "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 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."

Docket No. 92-2035-07 was established to consider the Company's initial request for cost recovery of DSR expenses. This docket was closed at the Company's request and the DSR cost recovery issues were rolled into Docket No. 92-2035-04. In its order dated February 12, 1993 which closed Docket No. 92-2035-07, the Commission reaffirmed the above position stating that "The Commission supports the Technical Conference/Collaborative process as a viable step to aid in the commission's decision-making process on the issues presented in this docket".

A series of DSR technical conferences were scheduled in compliance with the Commission's order. The first technical conference was held on March 8, 1993.

Other conferences followed on a regular basis, totaling eight through July 1993. Conference participants represented a broad spectrum of interests affected by DSR programs including utilities, utility customers, regulators, consumer groups, and environmental activists. In consideration of this diversity, PacifiCorp retained professional facilitator Arty Trost to expedite the collaborative process. From the beginning of the process there was some difference of opinion among the parties as to the ultimate goal of the technical conference process. While the group quickly agreed that any form of settlement or stipulation would be inappropriate, they disagreed about the desirability of attempting to resolve specific issues. Some members saw the process as purely educational while others believed that it was important to resolve as many issues as possible. Ultimately, the conferences evolved to address the needs of all participants, providing both a forum for educational presentations by DSR experts, including Dr. Robert Ciliano of RCG/Hagler and Dr. Eric Hirst of Oak Ridge National Laboratory, and an arena for presentation and discussion of specific DSR cost recovery proposals.

The Technical Conference goal, as agreed upon in the March 19, 1993 meeting, was to, "Encourage the Company to implement a least cost plan by developing a cost recovery mechanism which encourages the Company to look at a variety of alternatives for acquiring cost-effective DSR, including rate design". In addition to this primary goal, some of the conference's procedural goals were to: 1) educate the participants as to the background of DSR issues and alternate solutions; 2) prepare a final paper that states the facts and informs the Commission of the results of the conference's investigation; 3) gain a clear understanding of each party's concerns; and 4) keep the Commission informed about the process. It was also decided that since this series of technical conferences was convened as a part of PacifiCorp Docket No. 92-2035-04, that any discussion and recommendations would be directed towards PacifiCorp. These recommendations and proposals are not meant to represent the parties' positions on DSR programs for DG&T, Mountain Fuel, or any utilities other than Pacificorp.

At the first meeting, attorneys for UIEC expressed concern that the technical conference process would place a financial burden on their clients. There was some concern that the high cost of participation would prevent DSR-related issues of importance to industrial customers from being presented to the group. To allow industrial customers representation in a cost-effective manner, time was reserved at both the May 11 and June 1 conferences for interested industrial customers to discuss those issues which they believed were of particular importance to the group in its consideration of DSR cost recovery. On May 11, Maurice Brubaker of Drazen-Brubaker and Associates, Inc., on behalf of UIEC, gave a presentation entitled, "Rate Impact Considerations for Demand Side Resources". On June 1, Dennis Goins of Potomac Management Group representing Nucor and Geneva gave a presentation on "Interruptible Power and Demand-Side Resource Considerations". In addition to scheduling accommodations, industrial customers' representatives were provided complete minutes, including all meeting handouts, for all conferences that they could not attend. In addition to the financial concern, the industrial customers expressed concern that if the Commissioners were involved and informed themselves through this collaborative process, due process of law would be abridged. The UIEC pointed out that the procedural safeguards required by statute and regulation are absent in this collaborative process, and that they believe this Report is not the kind of evidence the Commission can rely on to make decisions regarding DSR accounting treatment. UIEC's concerns regarding the Technical Conference/Collaborative process and this report are detailed in their position paper included in Appendix I. Other participants maintain that this report is only to be used as evidence in a Commission decision-making process in the context of an evidentiary hearing. In addition, the very nature of the Technical Conference/Collaborative process preserves the integrity of the intellectual investigation of DSR regulatory treatment.

The proposals discussed in this paper represent a range of viable alternatives that were presented to and discussed by the group in the course of the eight technical conferences. The group was presented with a vast amount of information about DSR cost recovery options, including the features of ERAM and revenue per customer decoupling, the potential impacts on DSR of rate design and interruptible sales, and the details of numerous incentive programs including shared savings. A more detailed discussion of the items discussed at each of the meetings is contained in the minutes and the detailed attachments to those minutes. This report provides an analysis of the alternatives available for regulatory treatment of DSR. Alternative means for achieving load management were deemed, by the majority of the participants in the March 19 technical conference meeting, to be outside the scope of this process.

During the technical conference process, the parties divided the discussion of the regulatory treatment of DSR into three areas: cost recovery, lost revenues, and incentives. These three areas are treated separately under section IV of this report. Cost recovery deals with the issue of allowing the Company an opportunity to fully recover DSR program costs. Lost revenues is concerned with addressing the decrease in sales, and therefore revenue, that may occur between rate cases due to DSR programs. The incentive section discusses incentive methods which would encourage the Company to invest in DSR programs.

III. CRITERIA

This section of the report provides the overall goal for this proceeding as stated by conference participants and describes the criteria against which alternative ratemaking treatment mechanisms are reviewed. This section is confined to providing a definition of each criteria statement. There is detailed discussion of how each ratemaking solution addresses the following criteria in section IV of this report.

The criteria presented here are referred to in the other chapters of this paper in ***bold italics*** as discussion of the criteria becomes relevant.

A. GOALS

The Commission directive to the technical conference proceeding is to analyze the following issues:

1) the ratemaking treatment of DSR expenditures;
2) approval of energy service charges for efficiency improvements and conservation;
3) electric revenue adjustment mechanisms;
4) the granting of a cost advantage for efficiency or conservation acquisitions; and
5) the decoupling of revenues from profits.

The specific directives in the Commission Order helped to narrow the focus of the conference participants so that the goal for the technical conferences could be defined. The goal is as follows:

> **"Encourage the Company to implement a Least Cost Plan by developing a cost recovery mechanism which encourages the Company to look at a variety of alternatives for acquiring cost effective DSR, including rate design."**

B. DEFINITION OF CRITERIA

The participants identified barriers in achieving the goal stated above, suggested possible solutions to address the barriers and developed a list of features or criteria against which solutions could be evaluated.

The following criteria were identified at the conferences with one added during the draft of this paper; each of the criteria is important to at least one party.

1. Does it provide the opportunity for recovery of prudently incurred DSR costs?
2. Does it align the Company's financial incentives with integrated resource planning?
3. Does it give the Company an incentive to operate efficiently?
4. Does it promote cost minimization?
5. Does it reduce the disincentives associated with lost sales?
6. Does it provide a positive incentive to invest in DSR?

7. Is there equitable allocation of costs and benefits between classes of customers and between participants?
8. Does it appropriately share risk between ratepayers and shareholders?
9. Does it promote rate stability?
10. Is it performance based?
11. Is it understandable?
12. Is it predictable?
13. Does it have the potential for unintended consequences?
14. Is it measurable?
15. Is it administrable?
16. Does it discourage micro-management?
17. Does it minimize impact on evaluation?
18. Does it require few changes in practice?
19. Does it discourage manipulation?
20. Are there few legal restrictions?

A summary of the criteria measured against each ratemaking treatment mechanism considered in this report is provided in Tables I, II, and III. The summary tables indicate whether the ratemaking treatment considered has a positive impact, negative impact, neutral impact or uncertain impact on the criterion addressed. These tables were compiled based on the responses to the individual matrices provided by several parties which are included in Appendix II of this paper.[2]

The following is a discussion of each of the criteria voiced by participants in the collaborative. Criteria are grouped where issues are similar. While the order of presentation is consistent with the summary tables, this order does not follow the order in the individual matrices provided in Appendix II.

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

This inquiry addresses the recovery of DSR program expenditures by PacifiCorp. DSR expenditures in this context include all program costs including administration, measure costs, monitoring, commissioning and evaluation. Issues subject to this criterion include: capitalizing versus expensing costs; type of costs eligible for capitalization inclusion of carrying charges; return allowed on carrying charges; deferral of the amortization; timing and length of amortization period; role of an energy service charge to recover costs, and methods of recovering lost revenues.

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[2] It should be noted that the tables were prepared after the final draft was circulated for comments and therefore have not had the same degree of participant response as the rest of this paper.

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

This inquiry asks to what extent the ratemaking treatments considered in this paper will cause the Company's current financial incentives, which are based on the "utility cost"[3] of providing electricity, to be consistent with resource development in the Utility's Integrated Resource Plan (IRP), which is based on the "total resource cost"[4] of providing electric energy service.

Current Utah regulatory policy relies on an historic test year to determine revenue requirement and an embedded cost-of-service analysis to determine tariffs. Under this regulatory practice "cost" is defined as "cost to the utility". In theory, under this approach, the Company has an incentive between rate cases to reduce costs of providing electricity and to increase electricity sales beyond that amount included in rates to maximize earnings.

Under the Utah Public Service Commission's IRP decision, PacifiCorp's integrated resource plan identifies a least cost mix of demand-side and supply-side resources to provide electric service to meet future load growth based on the minimization of total resource cost. The selection of this mix of resources does not take into account the impacts of the regulatory process, i.e., ratemaking practices to determine revenue requirement and prices and the impact of regulatory lag and the assumption of full cost recovery. The different objectives of regulatory policy and IRP can lead to conflicting utility actions. Because DSR is identified in the IRP as a least "total resource cost" resource, the Utility wants to acquire the requisite amounts of DSR. But, unlike the symmetrical risks presented by weather or economic fluctuations, investment in DSR presents an asymmetrical risk to the Company. Under current regulatory practice, DSR, if successful in reducing electricity consumption, only causes an increase in expenditures not accounted for in revenue requirement *and* a decrease in revenues from reduced sales between rate cases which can directly conflict with the Company's immediate financial interest.

In summary, the conflict arises because the Company's financial incentives are based on utility cost and the IRP is based on total resource cost. The extent to which the ratemaking mechanisms considered attempt to resolve this conflict is measured by this criterion.

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[3] "Utility Cost" is tantamount to cost of service which includes allowed rate of return.

[4] "Total Resource Cost" is defined as utility cost plus participant cost which in the case of PacifiCorp is equal to the energy service charge payments.

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

Traditional economics defines efficient operation as minimizing the cost of producing the optimal level of output. Costs are defined here 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 electric energy service.

4. *Does it promote cost minimization?*

Based upon the definition of "efficiency" noted above, cost minimization is synonymous with efficiency and the two criteria are used interchangeably in this document.

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

Under the current regulatory regime, it is in the Company's financial interest to increase rather than decrease sales between rate cases; DSR may reduce sales between rate cases. See Section IV. B. Statement of Issue of this document for a full discussion of this issue.

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

This criterion refers to whether the ratemaking treatment mechanism provides an "additional" reward to the Company for investment in DSR relative to investment in SSR.

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

This criterion addresses the extent to which the ratemaking mechanism attempts to resolve DSR cost/benefit allocation among classes of customers and between participants and non-participants, e.g., is cross-subsidization encouraged, minimized or not addressed. Issues discussed relative to this criterion could include the use of avoided-cost type tests or cost-of-service analysis to address this issue.

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

This criterion refers to whether the regulatory treatment mechanism provides the opportunity to establish appropriate share of risk as well as the propriety of the risk sharing which results from implementation of the mechanism, both in the short and long-run.

9. Does it promote rate stability?

This criterion refers to the ability of the solution to minimize upward pressure on rates and volatile price swings, both in the short and long-run.

10. Is it performance based?

"Performance based" refers to whether the ratemaking treatment rewards, penalizes or is neutral to PacifiCorp's performance in accomplishing IRP and DSR goals to successfully acquire appropriate amounts of cost-effective DSR.

11. Is it measurable?

There are two components to measurability. The first refers to the ease with which the mechanism can be measured. The second refers to the level of accuracy achievable.

12. Is it understandable?

This criterion evaluates the degree to which the ratemaking treatment is readily grasped by all stakeholders (ratepayers, regulators, utilities, shareholders, intervenors, etc.).

13. Is it predictable?

Predictability refers to the degree to which the outcome of the regulatory treatment mechanism can be determined in advance.

14. Does it have the potential for unintended consequences?

This criterion refers to the degree to which the mechanism is expected to achieve its intent without producing an outcome that is particularly contrary to critical ratemaking goals.

15. Is it administrable?

This criterion refers to how complicated or burdensome the ratemaking treatment is to administer, both for the utility managers and for regulators.

16. Does it discourage micro-management?

Micro-management refers to the level of oversight and excessive intervention in utility decisionmaking perceived by regulators as necessary to assure: 1) that the stated goal is reached; or 2) reduced gaming.

17. Does it minimize impact on evaluation?

Evaluation techniques vary with respect to the type of information needed to implement a cost recovery, lost revenue or incentive mechanism. Currently, the Company conducts annual process and impact evaluations of its tariffed DSR programs. It is necessary to conduct a thorough and unbiased evaluation of the Company's DSR programs. Evaluation efforts may be undertaken for three reasons: 1) update and improve program delivery; 2) to assess program achievement; and 3) to quantify performance for the valuation of lost revenues and incentives and performance based cost recovery mechanisms.

18. Does it require few changes in practice?

This criterion refers to the ease with which the incentive mechanism can be readily incorporated into existing regulation. It also refers to the extent that the incentive requires revision over time or is dependent on adversarial hearings in order to determine the incentive outcome.

19. Does it discourage manipulation?

This criterion refers to the ability of each ratemaking treatment to discourage gaming, i.e., the strategic manipulation of the mechanism to produce an outcome that is at odds with the intended purpose of the mechanism and of regulation. Uneconomic load building, gold-plating, and cream skimming are potential gaming strategies noted in DSR ratemaking literature. Gold-plating refers to padding the ratebase. Cream-skimming is the acquisition of the easy, low-cost, high saving DSR measures while ignoring the more difficult or expensive but cost-effective opportunities.

20. Are there few legal restrictions?

This criterion addresses whether possible legal constraints exist which potentially prevent the implementation of a solution or require legislative action to implement the solution.

IV. REGULATORY TREATMENTS FOR DSR

A. COST RECOVERY

The goal of a cost recovery mechanism is to provide the Company with an opportunity to fully recover DSR program costs. Achieving this goal requires an assessment of the comparability of demand-side and supply-side resources, so that there is no advantage or disadvantage to the Company in investing in DSR relative to SSR. This section summarizes the cost recovery issues. See Appendix I for individual party's positions on these issues. In addition, Table I summarizes how DSR cost recovery mechanisms perform with respect to the aforementioned criteria.

STATEMENT OF THE ISSUES

In deciding on an effective DSR cost recovery mechanism, the following issues need to be resolved.

1) Should DSR related costs be capitalized in ratebase and amortized over future periods, or expensed in the current period?

2) For DSR costs included in ratebase, should the amortization of DSR costs be deferred until a future period or begin when the project is completed? If the amortization of costs is deferred, how long should it be deferred?

3) If DSR costs are included in ratebase, and amortization is deferred until a future period, should a carrying charge be accrued on the ratebase amount during the deferral period?

4) What role should an Energy Service Charge have in recovering DSR program costs?

SOLUTIONS

1. Capitalize vs. Expense

The first area of discussion in the cost recovery area is whether DSR program costs should be capitalized and included in ratebase or expensed during the period in which they occur. Costs are generally capitalized in ratebase when they provide a benefit to future ratepayers, allowing the utility to collect the costs of the asset from the customers who receive the benefit, both current and future. When costs are expensed they are included in rates in the current year and are charged to current ratepayers.

Either approach, capitalizing or expensing, can provide the Company with the same ***opportunity for recovery of prudently incurred DSR costs***, as long as all costs are included in rates.

Whether costs are capitalized or expensed also can affect the ***risk sharing between ratepayers and shareholders*** because of fluctuations in DSR costs between test years. If expensed DSR costs are higher than the DSR expense amount included in the test year, the entire risk for the incremental amount is borne by shareholders unless a balancing account or other recovery mechanism is adopted. Conversely, if expensed DSR costs are lower than the DSR expense amount included in the test year, the risk for the incremental decrease is borne by ratepayers. For items capitalized between rate cases, only the risk for the portion of the costs amortized between rate cases is transferred to the shareholders. However, if expenses are included in rates or a balancing account is used, expensing may be less risky for shareholders than capitalizing DSR program costs because capitalized costs may be re-examined and disallowed in future rate cases.

Capitalizing DSR program costs in ratebase also promotes ***rate stability***. Expensing DSR costs could lead to wider fluctuations in rates than capitalizing DSR costs. Capitalizing spreads the costs over the program lives, reducing the rate impact in any single year, and providing a greater degree of rate ***predictability***. Capitalizing also spreads costs to those customers who receive the benefit thus providing an ***equitable allocation of costs between future and current customers***. Capitalizing is also consistent with SSR cost treatment ***requiring few changes in current practice***.

2. Deferral of Amortization

The next aspect of cost recovery is whether it is appropriate to defer the beginning of amortization of capitalized DSR costs, and if so, for how long. The following four approaches toward deferral were discussed during the collaborative process:

1) do not defer amortization beyond completion of construction;

2) defer the beginning of amortization for one year or until the next rate case (whichever comes first);

3) defer beginning of amortization for three years or until the next rate case (whichever comes first); and

4) defer beginning of amortization until the next rate case.

There are three arguments used to justify the deferral of the amortization. The first argument is that if the amortization is started before a rate case, then the Company does not have the opportunity to include the amortization in rates, and therefore, does not have the ***opportunity for full cost recovery***. The second argument is that DSR comes on line in small increments, whereas SSR comes on line in large increments. Since SSR comes on line in large increments, the Company is more likely to file for an immediate price change to include the SSR in rate base. For

DSR, where the resource comes on line in small increments over a longer period of time, the Company is less likely to request a price change, and therefore less likely to receive full cost recovery. The third argument is that when SSR comes on line, it generally increases the Company's revenue. When DSR comes on line, there is generally a decrease in the Company's revenue.

The argument against deferral is that deferring the amortization gives DSR preferential treatment relative to SSR. SSR investments in transmission and distribution plant also come on line in small increments between rate cases, and are not deferred. Therefore, by not allowing deferral the Company has the same ***opportunity for full cost recovery*** for DSR costs as it has with some SSR costs. The Company has the opportunity to file a rate case any time for DSR, the same as for SSR. To maintain consistency with SSR treatment, DSR should not be singled out for special or separate consideration, but should be considered along with all other costs of the Company in determining whether a rate change is necessary.

The decision to defer the amortization could also affect the ***sharing of risk between the ratepayer and shareholders***. Deferral may transfer some of the risk from the shareholders to the ratepayers since, by giving the shareholders a greater opportunity for full cost recovery, deferral may place greater upward pressure on rates.

Deferral may increase the potential for ***unintended consequences***. The potential for gold-plating is a concern with either DSR or SSR. To the extent that the Company is more likely to receive full cost recovery by deferring the amortization of DSR program costs, there may be greater incentive for a utility to engage in gold-plating. Similarly, whenever full cost recovery is allowed on SSR assets, there may be an increased incentive for gold-plating. Safeguards, e.g. effective monitoring and evaluation of DSR programs, that ensure cost-effective DSR, mitigate the potential for gold-plating.

It is unclear whether deferring the beginning of amortization for capitalized DSR costs is legal. Some parties believe this deferral may constitute retroactive ratemaking which is illegal.

3. Carrying Charge

The use of a carrying charge is another issue to be resolved under cost recovery. A carrying charge is the addition of interest to deferred DSR costs. There are two aspects to the carrying charge issue: 1) should the Company be able to accrue a carrying charge during the deferral period of DSR costs; and 2) if a carrying charge is accrued, what rate should be used.

Two carrying charge proposals have been considered. Proposal 1 would allow a carrying charge on unamortized DSR, to compensate the Company for its DSR investment, until amortization begins. Proposal 2 would allow a carrying charge on unamortized DSR, to compensate the Company for its DSR investment, only during the construction period.

A carrying charge may give DSR investments a ***positive incentive*** not afforded SSR investments. If DSR investments receive preferential treatment over SSR investments as a result of the carrying charge, the potential for over investment in DSR increases, which is inconsistent with ***cost minimization***. If DSR receives a carrying charge on the unamortized balance, then DSR could potentially receive cost recovery in excess of that allowed for SSR. In addition, the time period between rate cases is not generally known, therefore deferral of costs between rate cases reduces the ***predictability*** of the costs.

Alternatively, a carrying charge may only remove the ***disincentives*** associated with DSR investments, and not provide any positive incentive. It is not clear that the carrying charge gives DSR investments preferential treatment over SSR, since there are no SSR assets similar to DSR with which to make any comparisons. A carrying charge will promote ***cost minimization*** by removing the disincentives associated with DSR, and therefore, encourage the Company to follow a least cost planning approach to acquiring resources by ***aligning the Company's financial incentives with those of the IRP***. This will promote long-term ***cost minimization***. In addition, since the capitalized portion of DSR costs is known, and since the rate is known, the carrying charge is extremely ***predictable***.

To calculate the carrying charge the Company can either use the AFUDC rate, which is traditionally used to calculate the return on construction work in progress, or the Company's authorized return on rate base. The calculation of the AFUDC rate includes short-term debt, whereas the Company's authorized return on rate base does not. The AFUDC rate is generally lower than the Company's authorized return on rate base.

It is unclear whether accruing a carrying charge on the unamortized DSR balance is legal. Some parties believe the carrying charge may constitute retroactive ratemaking which is illegal.

4. Energy Service Charge

Energy Service Charge is a mechanism by which participants in DSR programs are required to bear a portion of the cost of the conservation measures. The amount of the participant's contribution is directly tied to the cost of the measure and indirectly tied to their anticipated savings.

The use of an Energy Service Charge reduces non-participant ***rate impacts*** by assigning more of the program costs to those who receive direct bill reductions from the DSR program. This effectively ***reduces the risk*** of DSR cost to both shareholders and non-participant ratepayers and minimizes upward pressure on price increases caused by the reduced sales, thus providing ***rate stability***. To the extent that an Energy Service Charge is successful in acquiring specified cost-effective DSR, the mechanism ***promotes cost minimization.***

One concern with the Energy Service Charge is that charging participants for DSR may decrease participation rates. This could reduce the amount of acquired DSR recommended in the IRP which ***would not promote cost minimization***. Another concern is that the Energy Service Charge is booked as a loan but since it is not an asset like SSR, it is not mortgageable. This is a departure from ***current accounting practice*** and could lead to ***unintended consequences***, e.g., difficulties in financial markets. The implementation of an Energy Service Charge requires monitoring and ***measurement*** of electricity savings over time, increasing the ***administration*** required for implementation of the mechanism and increasing the importance and, hence, rigor of ***evaluation.***

The effectiveness of an Energy Service Charge as currently employed by PacifiCorp is under evaluation and is being discussed in the DSR Evaluation Task Force.

B. LOST REVENUE

STATEMENT OF THE ISSUES

To provide perspective on the ensuing analysis the following discussion elaborates on the Commission's concerns conveyed in Docket No. 90-2035-01. A major concern is the determination of: 1) the degree (if any) to which lost revenue discourages the Company's implementation of its IRP and 2) the appropriate approach for addressing this concern. Lost revenue is oftentimes referred to as net lost revenue since it refers to the lost margin, i.e. the difference between the retail price and the Company's avoided costs, net of available off-system sales. The margin reflects the component of fixed cost recovery that is built into the tariff price. This lost margin arises from the decrease in sales, as a result of utility investment in DSR, that is unaccounted for in rates. Thus, lost revenue is a between rate cases phenomenon.

A difference may exist between a utility's financial incentives to invest in SSR as opposed to DSR. Upon being placed in service, whether included in ratebase or not, an SSR may begin to produce revenue from electricity sales. Margin on these sales, if any exists, may contribute to the recovery of SSR fixed costs. In contrast, a

DSR is created through energy efficiency measures which may reduce retail sales of electricity (but may allow increased non-tariff sales). Since tariff energy charges include a portion of the Company's fixed costs, revenue could decline by more than the variable cost of the energy saved. The margin which may have been acquired by the utility in the absence of the DSR program is potentially lost to the utility. To the extent that lost revenue exists, lost revenue is a cost of DSR which may constitute a penalty to the Company arising from DSR programs. Even with full cost recovery of DSR program expenditures, existing regulation may still strongly discourage PacifiCorp from pursuing even the most cost-effective DSR energy opportunities because the lost revenue could be larger than the acquisition cost in the short-run.

Since the decrease in sales due to DSR may reduce the contribution of sales to fixed costs, lost revenue could potentially pose a significant disincentive for the Company's implementation of its IRP. The degree to which this disincentive exists depends on several factors. First, it depends on the type of DSR program. DSR programs may reduce revenue contribution toward fixed costs. However, some DSR programs may have load-building aspects that combine conservation with fuel switching and/or increased electrification. Such programs may actually increase revenue contribution. If a utility is allowed to recover lost revenue for the conservation component of a DSR program without recognition of possible load building impacts, then it is conceivable that the utility can increase sales, and therefore, revenue, as a result of the increase in load (e.g. due to fuel switching) while simultaneously claiming lost revenue due to a decrease in sales as a result of the DSR program. In that case the baseline upon which lost sales are based may incorrectly overstate lost sales, if any exist, given that the appropriate baseline for energy consumption should reflect energy consumption before fuel switching or increased electrification. Another factor that affects the extent to which lost revenue poses a disincentive to implementation of the IRP is rates. The closer rates are to marginal cost, the smaller the margin, and hence, the smaller the lost contribution toward a utility's fixed cost.

The following solutions attempt to address the concern that PacifiCorp may incur financial hardship from investing in DSR. The ensuing analysis examines eight possible solutions for removing the disincentive for investment in cost-effective DSR due to lost revenue associated with a decrease in sales. These solutions are evaluated with respect to the criteria presented in section III. The solutions discussed below are:

1) no cost recovery of lost revenue;
2) annual reviews;
3) future test period/historical test period with out-of-period adjustments;
4) annual rate case;
5) net lost revenue adjustment;
6) net lost revenue adjustment with a collaborative;
7) decoupling; and

8) statistical recoupling.

For a summary of how the solutions perform with respect to the aforementioned criteria see Table II.

SOLUTIONS

1. No Cost Recovery of Lost Revenue

One option for addressing regulatory treatment for DSR is to not allow PacifiCorp to receive cost recovery of lost revenue. To the extent that lost revenue exists, this approach does not remove the ***disincentive of lost sales*** associated with DSR programs and thus, discourages PacifiCorp's implementation of its IRP. Since total resource ***cost minimization*** is the goal of the IRP and DSR is identified as a least cost resource, the decision not to address the short term disincentive of lost sales due to DSR may discourage full implementation of the IRP and hence, total resource cost minimization.

If no cost recovery of lost revenue is allowed then the entire ***risk*** of lost revenue is borne by shareholders. This is not a ***performance-based*** approach since it does not encourage investment in cost-effective DSR programs.

The appeal of this solution is the certainty of outcomes generated by maintaining the status quo. This approach avoids the potential that exists under a net lost revenue adjustment for ***manipulation*** of lost revenue. It avoids the contentiousness of ***evaluation*** and ***measurement*** in determining lost revenue. Since the Company does not receive recovery of lost revenue, this approach mitigates the impact of DSR on ***rates*** in the short-run. This in turn, improves ***rate stability*** in the short-run which reduces the contentiousness of ***allocating the costs and benefits*** associated with recovery of lost revenue between classes of customers and between participants and non-participants. However, no cost recovery may cause rate instability in the long-run which increases the contentiousness of the allocation of the costs and benefits.

Maintenance of the status quo does not alter the level of ***micro-management*** and does not require ***administration*** of another mechanism.

2. Lost Revenue Recovery Using a Net Lost Revenue Calculation

The following five solutions, annual reviews, future test period/historical test period with out-of-period adjustments, annual rate case, net lost revenue adjustment, and net lost revenue adjustment with a collaborative, all require calculation of net lost revenue. For ease of exposition, the potential problems associated with the calculation of net lost revenue are discussed here. Thus, the following assessment applies to all five solutions.

Calculation of lost revenue is complex since it requires determination of a mechanism (which includes formulation of an equation) to be used in determining lost revenue. One possible equation may calculate lost revenue net of avoided costs plus sales for resale credit, free-riders, and load building kWh. Determining the appropriate equation is likely to be a contentious issue because it affects the dollars that the Company can receive for lost revenue. For example, there is likely to be considerable debate regarding netting lost revenue for load building, "found revenue", or new construction. Found revenue refers to an increase in revenue due to an increase in sales (for any reason). Consider the following two diametrically opposed perspectives regarding the treatment of found revenue. One view is that while revenues may be lost as a result of the implementation of DSR measures, there is no evidence that found revenue is directly or indirectly related to DSR programs and therefore, found revenue should not be netted from lost revenue. An alternative view is that while DSR programs reduce sales, customers may have expanded operations since the previous rate case and this additional revenue has not been accounted for in rates. Furthermore, in a situation where DSR measures make an existing customer more competitive increasing both the customer's sales and the Company's sales, sufficient incentive exists for the Company to install DSR measures.

Solutions that require the calculation of lost revenue using a future test period of out-or-period adjustment require reliance on DSR program planning estimates for kW and kWh savings. Program planning estimates are significantly less certain than engineering estimates based on projects actually completed. Basing lost revenue calculation on program planning estimates of savings may require a significant revision of the initial lost revenue calculation which could reduce ***predictability*** and increase ***rate volatility***. In contrast, initial calculation of lost revenue based on engineering estimates of kW and kWh savings for completed projects potentially requires a smaller revision in the lost revenue calculation.

If the lost revenue calculation does not discriminate among the types of programs for which a utility can recover lost revenue, accounting for lost revenue may inadvertently stimulate investment in uneconomic DSR programs. A lost revenue calculation that does not discriminate between cost-effective and non-cost-effective DSR is not ***performance based***. The lost revenue calculation may bias the Company against certain cost-effective DSR programs for which energy and demand savings due to the program may be extremely difficult to measure, e.g. educational type programs. A lost revenue calculation based on ex ante engineering estimates, i.e. engineering estimates made prior to the implementation of the program, coupled with a cost recovery mechanism devoid of performance standards, may create an inappropriate incentive for the Company to invest in DSR programs that don't perform in reality but look good on paper. The degree to which the lost revenue calculation encourages ***efficiency*** depends upon the conditions (restrictions) of the calculation. Provisions could be established that specify that lost revenue is available for cost-effective programs only. Calculation of lost revenue intensifies the need for defining "reasonable" performance standards and for determining the process by which they should be implemented.

These five solutions do not remove the current incentive to increase sales between rate cases irrespective of the long-run impacts to ratepayers. Consequently, these solutions may not give the Company an incentive to operate ***efficiently*** given that these solutions do not remove the incentive to increase sales associated with inefficient consumption of electricity. If a utility is allowed to receive lost revenue associated with load building programs, then load building may be an ***unintended consequence*** of these five approaches.

Bearing this analysis of a net lost revenue calculation in mind, the following discussion assesses other aspects of the respective five solutions with respect to the criteria.

a. Annual Reviews

An annual rate review recognizes the decrease in sales and DSR expenditures forecasted for the upcoming year. This review would include an assessment of the impact on revenues, expenses, and rate base of forecasted DSR programs as an out-of-period adjustment. Accounting for the decrease in sales due to DSR in this fashion could potentially mitigate the need for a rate decrease or conversely, trigger the need for a rate increase. While this review process may indicate that it is appropriate for rates to increase, it would be incumbent upon the Company to initiate a rate case if it was earning below its authorized rate-of-return since this review would not culminate in an annual adjustment in rates. If the Company was over-earning without an out-of-period adjustment for DSR and hence, prompted regulators to initiate a rate case, inclusion of an out-of-period adjustment for DSR may indicate that the Company is not over-earning and negate the need for a rate case. If no out-of-period adjustment is allowed for DSR, an annual rate review would still be conducted using the test year's impact of DSR programs. This too may mitigate, albeit to a lesser degree, the impact of lost sales due to DSR by recognizing the change in sales due to DSR for the current year on the Company's return.

The annual rate review discussed above attempts to address the ***disincentive of lost sales*** associated with DSR by recognizing DSR programs in the upcoming year. Since the annual rate review does not have an annual rate adjustment associated with it, it may not sufficiently remove the disincentive for investing in cost-effective DSR. This may not ***align the Company's financial goals with the IRP*** and consequently discourage the Company from operating ***efficiently*** because of the lack of full cost recovery. Non-recognition of lost revenue in rates as a result of regulatory lag associated with the annual rate review places increased ***risk*** on shareholders. This could also lead to ***unintended consequences*** if this solution is perceived by the Company as conveying an inconsistent message about the value of investing in DSR resources. This approach also potentially puts the Company in the position of having to file frequent rate cases to recover lost revenue. The prospect of having to file frequent rate cases to recover the revenue from lost sales may constitute a disincentive to DSR investment.

The major advantage of this approach is that the annual rate review tends to maintain ***rate stability*** in the short-run. Other advantages of this approach are that it: maintains consistency with current regulatory practice; is ***legal***; reduces the potential for ***manipulation***; and may reduce the contentiousness of ***evaluation and measurement*** relative to that associated with an NLRA where a utility is annually compensated for lost revenue. With an annual review, the Company would not necessarily receive compensation for lost revenue since lost revenue is only considered in assessing the propriety of the Company's actual return.

This approach does not eliminate the net lost revenue calculation since it requires determination of net lost revenue due to DSR programs on a year-by-year basis. Annual reviews will require additional ***administration*** because of the difficulty in calculating lost revenue.

b. Future Test Period/Historical Test Period With Out-Of-Period Adjustments

An estimated future test year or an historic test year with out-of-period adjustments for costs related to DSR programs would provide utilities with the opportunity for full DSR cost recovery for the year following the rate case. This approach toward recognizing DSR program costs would also eliminate the need for a balancing account generally associated with lost revenue recovery mechanisms. Other advantages of this approach are that it: maintains consistency with current regulatory practice; is ***legal***; reduces the potential for ***manipulation***; and may reduce the contentiousness of ***evaluation and measurement*** relative to that associated with an NLRA where a utility is compensated for lost revenue on an annual basis.

While the use of either a future test period or out-of-period adjustments mitigates the disincentive for adopting a least cost plan that includes DSR since it accounts for lost revenue associated with DSR programs for the year following the rate case, if multiple years lapse between rate cases this regulatory treatment may not sufficiently address lost revenue. A utility may be discouraged from implementing its IRP between rate cases when rates do not recognize the decrease in sales from a utility's increasing the level of DSR program activity associated with non-load building DSR programs. Furthermore, even if a utility's expenditures on non-load building DSR programs remain constant, without annual rate cases, a utility may not receive full recovery of lost revenue. For example, total energy and demand savings during the second year after a rate case are determined by aggregating energy and demand savings from measures installed in year 1 that persist in year 2 and energy and demand savings from measures installed in year 2. Thus, in this example, energy and demand savings in year 2 exceed those in year 1 even though expenditures on DSR have remained constant. This could lead to less than full cost recovery in year 2.

Out-of-period adjustments related to DSR would need to include lower kWh sales, reduced expenses related to lower kWh sales, and levels of deferred DSR program costs and related amortization. The use of either a future test period or out-of-period adjustments for ratemaking would not change the estimation requirement for DSR program costs, including net lost revenue. This approach will require additional ***administration*** because of the difficulty in calculating net lost revenue.

The potential problems associated with the calculation of lost revenue using either a future test period or an historic test period with out-of-period adjustments are mitigated to the extent that this calculation is made only at the time of a rate case. The amount of lost revenue accounted for in rates at the time of the rate case (based on the future test period or the appropriate out-of-period adjustment) would remain constant until the next rate case. (This is in contrast to an NLRA which requires annual calculation of lost revenue.)

This solution does not address how costs and benefits are allocated. This is considered an issue that is appropriately addressed by rate design.

c. Annual Rate Case

Annual rate proceedings that account for lost sales by using a future test year or an historic test period with out-of-period adjustments for costs related to DSR programs would provide utilities with the opportunity for full DSR cost recovery. Annual rate cases address the concern that use of either a future test period or out-of-period adjustments for DSR program costs with multiple years between rate cases may not sufficiently address cost recovery of lost revenue between rate cases. Annual rate cases also eliminate the need for a balancing account generally associated with lost revenue recovery mechanisms. Other advantages of this approach are that it: maintains consistency with current regulatory practice; is ***legal***; and reduces the potential for ***manipulation***. Annual rate cases may significantly reduce the lost revenue problem. (Instead of three to seven years of regulatory lag, there is only one.) As a result, both the dollar amounts at stake and the disputes are far less contentious. Thus, annual rate cases are likely to reduce the contentiousness of ***evaluation and measurement*** relative to that associated with an NLRA. Moreover, by examining lost revenue in the context of a rate case, all factors can be considered at the same time.

Annual rate cases may be difficült to ***administer*** to the extent that extensive resources must be devoted to a general rate proceeding annually.

Annual rate cases may reduce ***predictability*** and reduce ***rate stability*** if the net lost revenue calculation changes from year to year. Uncertainty resulting from revisions in the net lost revenue calculation may increase the risk to shareholders. These factors could discourage long-run investment in DSR programs.

A possible ***unintended consequence*** of an annual rate case is the potential for a decrease in efficiency of Company operations. Regulatory lag gives the Company an incentive to cut costs between rate cases. Since annual rate cases reduce regulatory lag, they may inadvertently reduce the Company's incentive to cut costs.

Annual rate cases using either a future test period or out-of-period adjustment for ratemaking would not change the estimation requirement for DSR program costs, including net lost revenue. While annual rate cases do not remove the incentive to build load between rate cases, this solution mitigates the incentive to build inefficient load because of the shorter time period between rate cases.

The allocation of costs and benefits would be determined during the rate spread portion of a rate case.

d. Net Lost Revenue Adjustment (NLRA)

A Net Lost Revenue Adjustment (NLRA) is a mechanism for addressing a major disincentive for the Company's adoption of its least cost plan -- the decrease in sales and therefore, revenue, that occurs between rate cases (all other things being equal) due to DSR programs. The rationale for adopting an NLRA is that the decrease in sales due to DSR reduces the contribution of sales to fixed costs. Compensating the Company for this lost contribution toward fixed costs may remove a potentially strong deterrent for Company investment in cost-effective DSR. NLRAs account for the impact of the decrease in sales due to DSR by permitting the Company to recoup the lost margin, i.e. the difference between the retail price and the Company's avoided costs, net of available off-system sales, between rate cases. By providing compensation for net lost revenue, NLRAs can alter utility attitudes towards energy ***efficiency***. Thus, this approach can overcome the disincentives to DSR that exist under current regulation.

Given the significant ***potential for gaming*** of an NLRA, an NLRA is potentially very ***unpredictable*** since it could result in compensating the utility for significantly larger lost revenue than expected, depending on the basis and manner in which lost revenue is calculated. Concern regarding gaming of NLRAs tends to increase ***micro-management*** of DSR programs. The increased unpredictability of the NLRA increases the ***risk*** to ratepayers. However, the NLRA potentially reduces the ***risk*** to the utility because of the certainty regarding the method for calculating net lost revenue. The upward pressure on ***rates*** associated with compensating the utility for lost revenue increases the contentiousness of ***allocating the costs and benefits*** between classes of customers and between participants and non-participants. The unpredictability of the NLRA also increases the potential for ***rate instability***, especially if the NLRA is implemented through a balancing account.

NLRAs potentially place substantially more pressure on both DSR program design and ***evaluation*** activities. Debate may arise over issues such as the number of free riders associated with DSR programs since this could potentially have a significant impact on the energy and demand savings attributed to the DSR program and hence, the dollar amount of lost revenue. Contentiousness is likely to arise in the evaluation process since large dollar amounts may hinge on determined savings.

NLRAs could potentially create a regulatory environment in which the ratemaking process for establishing rates to ensure an authorized rate-of-return is conducted independent of implementing rate adjustments due to changes in the NLRA balancing account. Under an NLRA regulatory regime without regulatory safeguards such as caps on lost revenue, the possibility of ***unintended consequences*** is increased, e.g. an NLRA may necessitate a rate increase while Company earnings in excess of its authorized rate-of-return necessitate a rate decrease.

An NLRA requires additional ***administration*** in part because of the difficulty in calculating lost revenue. Complexity is potentially compounded by the potential need for modifications to the mechanism used for calculating lost revenue. NLRAs, if expensed, may require a balancing account which also adds to administrative complexity. Expensing lost revenue potentially places greater upward pressure on ***rates*** in the short-run than capitalizing lost revenue. Capitalization and deferral of net lost revenue for three years or until the next general rate case may not provide an ***equitable distribution of costs*** across generations because future customers would be paying for prior years' lost revenue. However, to the extent that future customers benefit from DSR resource acquisition and lost revenue is a cost associated with acquiring those resources, capitalization and deferral may result in a more ***equitable generational distribution of costs*** given the stream of benefits. NLRAs may tend to be difficult to ***understand***. An NLRA mechanism does not address how costs and benefits are allocated. This is considered an issue that is appropriately addressed by rate design.

There may be potential ***legal*** restrictions to implementation of an NLRA if the mechanism requires deferral as proposed by PacifiCorp or a balancing account. Such mechanisms may be perceived by the courts to constitute retroactive ratemaking. A balancing account may be illegal unless Utah statutes are changed. (See Utah Supreme Court Decision regarding the Energy Balancing Account in Case No. 19361.)

e. NLRA with Collaborative

An NLRA operating under the oversight of a collaborative, established by the Commission to oversee DSR program progress, evaluation, and design, potentially mitigates many of the shortcomings associated with an NLRA. (See discussion above on Net Lost Revenue Adjustment for an assessment of an NLRA with respect to the criteria.) The particular NLRA/Collaborative discussed during the technical conferences would: 1) monitor evaluation of DSR programs; 2) examine program design; and 3) supervise a consultant's review of PacifiCorp's work. This reference to a consultant refers to an impartial, outside consultant hired to provide independent verification of energy and demand savings. (It should be noted that while a consultant is part of this solution, a consultant need not be a part of a collaborative.) Two additional measures were considered for implementation in conjunction with the collaborative. The first measure addresses the concern regarding non-participant rate impacts by establishing a cap to limit the rate impacts associated with PacifiCorp's DSR activities over the next three years. This cap would be set large enough to comfortably support PacifiCorp's expected DSR efforts as set forth in IRP guidelines. (It should noted that while not considered in this report, price caps could be considered with other solutions as well.) The second measure would require PacifiCorp to commit to specific DSR targets for the next few years, perhaps expressed in energy and capacity terms based on the IRP. This is intended to give the Commission and other intervenors clear guidelines against which to measure PacifiCorp's success with DSR, both in terms of costs and benefits.

The proposed collaborative mitigates the potential for PacifiCorp to recover lost revenue for non-cost-effective DSR programs and load building characteristics associated with DSR programs. Therefore, an NLRA/Collaborative is more likely to provide cost recovery of prudently incurred DSR costs than an NLRA without a collaborative. The scope of the Collaborative facilitates implementation of an NLRA that is ***performance based***. Monitoring PacifiCorp's achievement of DSR targets that are consistent with the IRP provides some assurance regarding the cost-effectiveness of the DSR programs. To the extent that the Collaborative examines program design, an assessment of the load building capabilities of DSR programs can be conducted. The collaborative could also ensure that cost-effective DSR programs for which lost revenue is difficult to measure, such as educational programs, are conducted.

While incentives exist for a utility to engage in ***gaming*** of lost revenue under any NLRA, the Collaborative diminishes the potential for ***manipulation*** of lost revenue. The Collaborative potentially reduces the number of DSR programs for which lost revenue should be recovered. In addition, the Collaborative potentially reduces the lost revenue deemed appropriate for a given DSR program. Since the Collaborative works with a consultant on evaluation of the programs this reduces the potential for overstating savings and therefore, lost revenue attributable to DSR programs. Although there may be significant contentiousness within the Collaborative as it attempts to resolve highly disputed issues, the Collaborative is likely to reduce the contentiousness of the ***evaluation*** and ***measurement*** process in hearings. Furthermore, there may be fewer modifications to the equation for calculating lost revenue as a result of the Collaborative.

Given the Collaborative's oversight of the NLRA, ***predictability*** of the NLRA is increased. The price cap would limit and thus, potentially lower impact on ***rates***, thereby reducing the contentiousness of ***allocating costs and benefits*** between classes of customers and between participants and non-participants. The Collaborative and price cap would reduce the ***risk*** to ratepayers *vis a vis* an NLRA with no Collaborative oversight.

An NLRA/collaborative mechanism as proposed here could be difficult to ***administer*** and is likely to increase the level of ***micro-management***.

3. Lost Revenue Recovery Using a Decoupling Mechanism

a. Decoupling

Although other approaches are being developed, there are essentially only two types of decoupling currently in operation: Electric Revenue Adjustment Mechanism (ERAM) decoupling and Revenue Per Customer (RPC) decoupling. Decoupling under an ERAM mechanism breaks the link between revenue and sales by predetermining allowed future revenue based on a future test year. Rates are subsequently adjusted to ensure that the utility earns neither more nor less than this predetermined level of revenue. This mechanism requires the use of balancing accounts or tariff riders. Decoupling under an RPC mechanism breaks the link between revenue and sales by predetermining allowed future revenues based on number of customers (historic or forecasted). The RPC mechanism allows future revenues to grow in proportion to customer growth instead of sales. This also requires the use of a balancing account or tariff rider.

Decoupling removes the ***disincentive of lost sales*** associated with investment in DSR because the decrease in sales due to DSR is considered in determining the appropriate level of allowed revenue. Thus, decoupling, by providing full cost recovery, promotes implementation of the IRP. Since revenue is fixed under decoupling and not profit, utilities maintain the same incentive to cut costs in between rate cases as exists under current regulatory practice. Decoupling is ***performance based,*** to the degree that it removes the incentive to build inefficient load, because revenue from sales exceeding those forecasted in determining allowed revenue is refunded to the customer.

One potential ***unintended consequence*** of RPC decoupling could be a decrease in quality for some customers. This may occur because the Company is allowed a given level of revenue per customer. One means for increasing profit (per customer) is to cut costs associated with the level of quality provided in serving large customers that have costs greater than the average. RPC decoupling may also encourage ***gaming*** in the determination of the number of customers since allowed revenues depend upon the manner in which customers are counted.

Empirical evidence suggests that the decoupling mechanism developed in Maine and Washington was associated with ***rate volatility***. These rate impacts are difficult to predict. The rate impacts in Washington and Maine were due, in part, to the shifting of the ***risks*** of weather and the economy under decoupling from the utility to ratepayers. Such rate volatility increases the contentiousness of ***allocating the costs and benefits*** between participants and non-participants. This solution does not address how costs and benefits are allocated. This is considered an issue that is appropriately addressed by rate design.

Although RPC decoupling is relatively straight-forward to implement, the ERAM approach may be more difficult to ***administer***. The ERAM mechanism works in concert with attrition (mini-rate) cases which adjust the forecast for financial changes. While ERAM mechanisms are ***measurable***, measurement is complex and may involve many balancing accounts. Given this complexity, modifications in the mechanism are more likely.

RPC decoupling does not encourage ***micro-management***. To the extent that ERAM decoupling requires annual mini-rate cases, micro-management may increase. Decoupling 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.

It is unclear whether decoupling is ***legal***. Decoupling may constitute retroactive ratemaking which is illegal.

b. Statistical Recoupling

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.

C. INCENTIVES

The following analysis examines six possible solutions with respect to the criteria presented in section III. The solutions discussed below are:

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

For a summary of how the solutions perform with respect to the aforementioned criteria see Table III.

STATEMENT OF THE ISSUES

Integrated Resource Planning is required of Utah Power by the Utah Public Service Commission, and consists of the analysis of both demand-side and supply-side resources in an effort to reduce the long-term cost of energy services to ratepayers and the utility collectively. In an effort to more closely align implementation of the IRP based on total resource cost with regulatory incentives that are based on utility cost, cost recovery mechanisms, lost revenue adjustments and innovative positive incentives are being employed by utilities around the country. The incentive mechanisms discussed in this section can be structured to recover DSR program costs, to compensate the utility for inadequate cost-recovery mechanisms, for either revenues lost between rate cases or all lost revenues, and to provide an additional incentive to the utility to pursue demand-side management strategies.

There are potential ***unintended consequences*** of targeting incentives toward a particular aspect of PacifiCorp's operations, namely DSR. An incentive for DSR is analogous to a subsidy to the utility for DSR. This subsidy alters the optimal mix of DSR and SSR that a utility invests in to efficiently produce electrical energy services. Investment in DSR clearly increases as DSR becomes more attractive relative to SSR. The impact of subsidizing DSR on the level of SSR investment is unclear. This uncertainty regarding investment in SSR could potentially have a deleterious long-run impact on the risk associated with financing investment in SSR.

SOLUTIONS

1. No Incentives

One option is to not employ the innovative incentive mechanisms presented below to address the regulatory concerns noted in this paper. Cost-recovery mechanisms plus a mechanism to address lost sales in between rate cases can be structured to remove perceived disincentives for the utility to invest in DSR vis a vis SSR.

This approach implies that the issues raised in this paper are satisfactorily addressed elsewhere or do not require additional treatment. The advantage of this approach is that it is easy to ***understand***, requires no ***administration*** and has no impact on ***evaluation*** methods.

The disadvantage with this approach is that if the Company perceives that either it does not have an opportunity for full recovery of DSR costs, or that the approach does not adequately reduce the disincentives associated with lost sales, failing to develop an incentive mechanism noted below may not ***align*** the Company's financial incentives with the IRP, and thus discourage ***cost minimization.*** If DSR program costs are not included in rates, this alternative may inappropriately burden the shareholder with the ***risk*** of DSR costs.

2. Shared Savings

Shared savings is a DSR incentive mechanism that allows the utility to keep a share of DSR program savings as retained earnings. The incentive payment is based on sharing the "net resource value" of the DSR between the ratepayer and shareholder. Net resource value is the difference between the cost of the DSR and the value of the benefits of DSR and is typically defined as the measured or estimated load reductions in kW or kWh multiplied by the value of avoided supply costs minus DSR program costs. Program costs can be defined either as utility costs or total resource costs.

Shared savings is the most common form of regulatory incentive to encourage utility companies to implement DSR plans and can be structured a number of ways. The incentive can be structured as a ***positive incentive*** and can also be used to address ***recovery of program costs and lost revenues***. A threshold kW or kWh target can be established that must be met for a utility to receive the incentive. The incentive may be front-loaded, i.e., the cumulative amount of the net resource value can be earned by the utility at the time the DSR project is completed, or the incentive can be earned annually by the utility.

Shared savings is ***performance based*** and since the incentive is based on net resource value, shared savings rewards cost-effective DSR and thus promotes ***cost minimization.*** The flexibility in structuring a shared savings mechanism allows the procedure to address risk sharing between the ratepayer and shareholder. Once the mechanics of the shared savings formula are established, the results are relatively ***predictable*** to all parties. Sharing net savings is ***understandable*** because it is relatively intuitive.

Shared savings may be difficult to ***administer*** because of the difficulty with ***measurement*** and ***evaluation*** and may require revision of the mechanism due to contentious issues affecting the magnitude of the incentive. Because the magnitude of the dollars can be significant and kW and kWh savings can not be directly observed, measurement of savings may be contentious and increase the rigor and, hence, cost of evaluation efforts. Since this approach is based on the *dollar value* of the net savings, the incentive magnitude also depends upon avoided cost and program cost estimates, which can prove to be contentious as well. There may be an incentive in the short-run for cream-skimming under this approach because low-cost, high electricity saving projects will provide a higher reward. If the shared savings is based upon total resource cost rather than utility cost, the mechanism will require an estimate of participant cost which in some cases can increase the difficulty of ***administering*** the program. Whether the incentive is based on utility cost or total resource cost will affect the ***unintended consequences*** of the effort unless evaluation methods to establish free-ridership and other factors are agreed upon initially. This is because if these factors are not agreed upon initially, the value of these factors can have a significant impact on the magnitude of the incentive, be bitterly contested and the resulting incentive be very different from the amount expected by the utility.

3. Bounty Per Unit Savings

Bounty per unit savings is an incentive payment that is based on kW or kWh savings to the utility that can be shared between ratepayers and stockholders. Also known as Bonus per unit, a utility receives a specific bonus dollar amount per kW or kWh saved from DSR programs. This solution can provide a positive incentive as well as recovery of DSR program costs and lost revenues.

It is easier to ***administer*** than shared savings because neither calculation of program cost nor of avoided cost is necessary. However, it relies on kW or kWh savings estimates which can be contentious and can increase the rigor and, hence, cost of ***evaluation***. Since the incentive is not dependent on the cost of the DSR, it does not provide an incentive to secure appropriate amounts of cost-effective DSR investment, which may produce an incentive for ***cream-skimming***. The advantages of this solution are that it is ***understandable***, ***measurable***, and can be structured to share ***risk*** between ratepayers and shareholders.

4. Markup on Expenditures

This solution provides the utility with an incentive payment based upon DSR program expenditures. The incentive is a percentage adder on DSR program costs which may be measured. This approach is ***measurable*** to the extent that program costs can be tracked with accuracy. And since it is not based on kW or kWh savings, ***evaluation*** efforts may be minimized.

Because the incentive payment is based on one relatively easy number to measure, namely the cost of the program, it is ***understandable*** and is relatively easy to ***administer***. Markup on expenditures does not provide an incentive for ***cream-skimming*** because minimizing the cost and maximizing the savings would result in a smaller incentive payment; there would, however, be an incentive in the short-run to ***gold-plate***, because the more dollars spent on DSR, the greater the incentive payment. To the extent that gold-plating occurs, this incentive does not ***minimize costs.*** With only an assessment of cost and no assessment of benefits, this approach could shift the risk of DSR cost from shareholders to ratepayers.

5. Adjustment to Overall Return On Equity

To compensate a utility for loss of profit due to DSR investment, commissions could adjust a utility's allowed rate of return in relation to a specified accomplishment, such as achieving a target level of conservation.[5]

This solution could be structured to be ***performance based.*** Performance criteria can be based on the utility's ability to achieve a specified level of capacity or energy savings, or the adjustment can be measured in relation to changes in customer bills. Payment can be structured to include ***recovery of program costs***. If the adjustment is based on the difference between actual load and forecasted load, it can address the ***disincentive of lost sales. Measurement*** can vary depending on the type of performance criteria: a) estimated savings; b) actual savings; c) load versus forecast; and d) efficiency measure. Efficiency measure refers to a British Thermal Units/dollar of Gross National Product or kWh/customer type scale. The

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[5] David Moskovitz, 1989. *Profits and Progress through Least-Cost Planning,* page 17, prepared for National Association of Regulatory Utility Commissioners.

difference between actual and adjusted forecast efficiency is the yardstick.[6] The method adopted will affect the rigor of ***evaluation.***

6. Bonus Return On Equity on Capitalized DSR

This approach assumes that DSR costs are capitalized and is very similar to rate-of-return adjustment on total investment except that the increased rate-of-return is applied only to investments in conservation or load management activities. It differs from rate-of-return adjustment on overall ROE in that the incentive is very small and in fact may not provide a noticeable incentive to the utility.[7] If used to include recovery of program costs this solution may not provide sufficient incentive to encourage the utility to implement it's integrated resource plan, and therefore, ***minimize cost.***

D. CONCLUDING REMARKS

As indicated previously, the goal of this paper is to provide an objective analysis of the issues pertaining to regulatory treatment of DSR. The purpose of providing this analysis is to facilitate the Commission's decisionmaking regarding appropriate regulatory policy for DSR in Utah. Section III identified and defined the criteria for evaluating possible regulatory treatments for DSR. This section, Section IV, examined the areas of cost recovery, lost revenue, and incentives. Analysis of these three areas entailed identifying the relevant issues, describing possible solutions for addressing those issues, and evaluating those solutions with respect to the criteria. The analysis indicates that the issues are very complex and parties have widely differing views on these issues.

The report does not provide conclusions regarding the overall effectiveness of a solution in achieving the goal of encouraging the Company to implement a least cost plan. Formulating such conclusions here is precluded for the following three reasons. First, participants do not agree on the relevance of <u>all</u> the criteria identified in the report. Second, participants prioritize the criteria differently. Third, oftentimes, there are numerous caveats that preclude definitive assessment of a particular solution with respect to the criteria.

It should be re-emphasized that the analysis presented here represents a common understanding of collaborative participants' views and may not represent a particular party's view on certain aspects of the report.

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[6] Ibid., page 19.

[7] Ibid., page 24.

V. ENERGY POLICY ACT RECOMMENDATIONS

Several parties have provided their position statements regarding the adoption of the National Energy Policy Act's (NEPA) standard regarding "Investment in Conservation and Demand Management".

The NEPA states:

> (8) INVESTMENT IN CONSERVATION AND DEMAND MANAGEMENT - The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investment in and expenditures for conservation and efficiency, as its investments in and expenditures for the construction of new generation, transmission and distribution equipment. Such energy conservation, energy efficiency resources and other demand side management measures shall be appropriately monitored and evaluated.

If adopted, the Commission must also consider the impact on small businesses.

The Act also requires a state regulatory authority to:

(1) Consider the impact that implementation of such standards would have on small businesses engaged in the design, sale, supply, installation, or servicing of energy conservation, energy efficiency, or other demand-side management measures; and

(2) Implement such standards so as to insure that utility actions would not provide such utilities with unfair competitive advantage over such small business.

The positions of the parties are compiled in Appendix III and are summarized in the following paragraphs. Please refer to the Appendix for a more detailed description of each parties opinion.

PACIFICORP

The Company recommends not adopting the federal standard on DSR investment, but rather adopt a standard specific to Utah. The parties are already engaged in a Collaborative/hearing process that is contributing toward defining a Utah standard.

UTAH INDUSTRIAL ENERGY CONSUMERS

The UIEC has no opinion on whether the Commission adopts the standard relating to investments in DSR because the parties are already in the process of addressing the issue. They do recommend that the Commission adopt the standard relating to small businesses. They point out that there are significant, detrimental anti-competitive consequences of utility- subsidized DSM.

ENVIRONMENTAL INTERVENORS

The EI recommends that the Commission adopt the standard because existing regulation in Utah contains incentives that are inconsistent with PacifiCorp's IRP. The standard will encourage PacifiCorp to implement its IRP, and, in some sense, codify and sustain any interim DSR treatment proposal. Adoption of the standard does not compromise the party's abilities to address incentives.

DEPARTMENT OF COMMERCE
DIVISION OF PUBLIC UTILITIES
and
DEPARTMENT OF NATURAL RESOURCES
OFFICE OF ENERGY AND RESOURCE PLANNING

The DPU and DNR believe that it is premature for the Commission to either adopt or reject the standard on DSR investments. The DPU and DNR recommend an interim trial policy for 1994. This trial period coupled with further research will allow the Commission to make a more informed decision on whether the federal standard should be adopted. State commissions have until October 23, 1995 to adopt or reject this standard. However, the impact on small business standard should be addressed by the Commission.

Table I - Evaluation of Cost Recovery Mechanisms

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

KEY:
+ = Positive Impact; improves performance on criterion
0 = Neutral Impact
- = Negative Impact; worsens performance on criterion
? = Impact of mechanism on criterion depends on situation. Will vary depending on the structure of the mechanism.
/ = Can include both impacts

Table II - Evaluation of Lost Revenue Recovery Mechanisms

		No Cost Recovery	Annual Reviews	Future Test Periods	Annual Rate Cases	NLRA	NLRA with Collaborative	Decoupling	Statistical Recoupling
1.	Opportunity For Cost Recovery	-/0	-/0/+	-/0/+	+	+	+	+	+
2.	Align Financial Incentives with IRP	-	-/0	-/0/+	0/+	0/+	0/+	+	+
3./4.	Incentive to operate Efficiently/Minimize Cost	-	0	0/+	+	-/+	-/+	+/?	+
5.	Reduce Disincentives From Lost Sales	-	-/0	-/0/+	+	+	+	+	+
6.	Positive Incentive	0	0	0	0	0/+	0/+	0	0
7.	Equitable Allocation of Cost and Benefits	0	0	0	+	0	0	0	0
8.	Appropriately Share Risk	0	-/+	0/+	+	-/0/+	+	-	0/+
9.	Promote Rate Stability	-/+	-/+	+	-/+	-/+	-/+	-/+	+/?
10.	Performance Based	-/0	-/0	-/+	-/+	-/+	+	?	+
11.	Understandable	+	-/0	-/0	-/0	-	-	-	-
12.	Predictable	+	+	+	-/+	-/+	-/0/+	-	?
13.	Potential for Unintended Consequences	+	+	+	-/+	-/+	0/+	-	?
14.	Measurable	0	-	-	-	-	-	+	+
15.	Administrable	0	-	-	-	-	-	-/+	-/+
16.	Discourage Micro-management	0	-/0	-/0	-/0	-/0	-	+	+
17.	Minimize impact on Evaluation	+	-/0	-/0	-	-	-/0	+	+
18.	Require Few Changes in Practice	0	-	-	-	-	-	-	-
19.	Discourage Manipulation	+	0	0	0	-	-/0	+	+
20.	Few Legal Restrictions	0	0	0	0	-/0	-/0	-/0	-/0

KEY:
+ = Positive Impact; improves performance on criterion
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- = Negative Impact; worsens performance on criterion
? = Impact of mechanism on criterion depends on situation. Will vary depending on the structure of the mechanism.
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Table III - Evaluation of Incentive Mechanisms

		No Incentives	Shared Savings	Bounty per Unit Saving	Markup on Expenditures	Adjustment to Overall ROE	Bonus ROE on Ratebased DSR
1.	Opportunity For Cost Recovery	-	+	+	+	+	+
2.	Align Financial Incentives with IRP	-	+	+	+	+	-
3./4.	Incentive to operate Efficiently/Minimize Cost	-	+	-	-	+	+
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	0	-	-	-	-	-
10.	Performance Based	0	+	+	-	?	?
11.	Understandable	+	-/+	-/+	+	?	?
12.	Predictable	+	?	+	+	?	?
13.	Potential for Unintended Consequences	0	?	+	+	?	?
14.	Measurable	0	-/+	-/+	+	+	+
15.	Administrable	0	-/+	-/+	+	?	?
16.	Discourage Micro-management	0	-	-	-	+	+
17.	Minimize impact on Evaluation	0	-	-	+	?	?
18.	Require Few Changes in Practice	+	-	-	-	-	-
19.	Discourage Manipulation	0	+/-	-	-	?	?
20.	Few Legal Restrictions	+	?	?	?	?	?

KEY:
+ = Positive Impact; improves performance on criterion
0 = Neutral Impact
- = Negative Impact; worsens performance on criterion
? = Impact of mechanism on criterion depends on situation. Will vary depending on the structure of the mechanism.
/ = Can include both impacts

APPENDIX I

DEMAND-SIDE-RESOURCE COLLABORATIVE REPORT

APPENDIX I
PARTICIPANT POSITION PAPERS

AUGUST 31, 1993

DEMAND SIDE RESOURCE COLLABORATIVE REPORT

APPENDIX I
PARTICIPANT POSITION PAPERS

Table of Contents

I. PACIFICORP

PacifiCorp Cost Recovery Proposal

PacifiCorp proposes adoption of the following accounting mechanisms for DSR cost recovery: 1) ratebasing all DSR program costs with amortization over the life of the installed measures; 2) deferral of the amortization of these costs for three years or until the next general rate case; and 3) accrual of a carrying charge on unamortized DSR ratebase at the authorized rate-of-return.

Adoption of these mechanisms will ensure comparable rate making treatment for both demand-side and supply-side resources. For rate making purposes the Company proposes to determine DSR program costs on the basis of a future test period.

PacifiCorp believes that the accounting mechanisms described in its cost recovery proposal will remove disincentives for acquisition of cost-effective DSR and allow the Company to earn its authorized rate of return on DSR investments. In the course of the technical conferences the Company presented a detailed analysis which demonstrates that ratebasing with a carrying charge, deferred amortization and lost revenue recovery must occur in conjunction before PacifiCorp can earn its authorized return on DSR investments. Operating together, these mechanisms create comparable ratemaking treatment for both demand-side and supply-side resources.

Of the evaluation criteria identified by technical conference participants, the Company attaches particular significance to cost recovery, measurability, understandability, administrability, predictability and rate stability. The Company believes its proposal performs strongly against these criteria.

PacifiCorp believes that neither the DPU nor the CCS cost recovery proposal can achieve the objective of encouraging the Company to implement its IRP because neither proposal provides the opportunity for full recovery of DSR program costs. Specifically, neither proposal addresses the recovery of DSR program costs that are incurred between the date of program inception and the date at which the costs are reflected in customer prices through a general rate case. These "interim" costs are very real to the Company and the absence of a mechanism for their recovery is a significant disincentive to DSR investment. The only proposal to date for recovering these costs is the amortization deferral proposed by the Company. The "AFUDC" proposed by the DPU and CCS is more apparent than real since the short construction period for DSR would cause the actual carrying charge amounts to be immaterial. It is simply not true, as has been suggested, that interim DSR program costs are analogous to between-rate-case supply-side additions. Even in the absence of rate relief, supply-side additions generate revenues that contribute to cost recovery while demand-side additions reduce revenues and aggravate the cost recovery problem.

The DPU would like to make DSR cost recovery dependent on annual results of operations. PacifiCorp believes that it is important to separate the issue of DSR cost recovery from other aspects of the Company's annual operating results. The decision whether or not to invest in DSR programs is an economic decision that is largely independent of other aspects of electric operations. The DPU proposal attempts to fold DSR costs into the Company's annual results of operations and effectively makes cost recovery contingent upon the overall level of financial performance. Clearly, evaluating a utility's financial results with respect to its authorized rate of return in an important function of regulation. However, PacifiCorp believes that making DSR cost recovery a factor in evaluating annual operating results is misguided. This approach could put the Company in the position of having to file frequent, small rate cases to obtain full recovery of DSR costs. Frequent rate cases are expensive, time consuming and send confusing price signals to customers. The better course is to put appropriate DSR cost recovery mechanisms in place and allow their effects to flow naturally through the results of operations. Regulatory oversight would then take its normal course. To do otherwise must inevitably influence resource acquisition decisions in favor of supply-side resources that at a minimum create additional sales opportunities rather than lost revenues. The inclusion of DSR, as a cost effective resource for the Company, in the Company's IRP is predicated on the assumption of full cost recovery. If the opportunity for such cost recovery is not available, the acquisition of DSR no longer remains a least cost alternative for the Company's customers or its shareholders.

The cost recovery approach proposed by the Environmental Intervenors appears to be consistent with the Company's proposal and should provide the opportunity for full cost recovery.

The DNR is concerned that the proper amount of DSR cost be included in rate base and has proposed that performance standards be developed for ratebased costs. The Company also believes that determining the appropriate amount of ratebase will be an important issue. However, the DNR position with respect to carrying costs and delayed amortization is not clear from their proposal. These are important elements of a comprehensive DSR cost recovery proposal.

PacifiCorp Lost Revenue Proposal

Pacificorp proposes to calculate a Net Lost Revenue Adjustment ("NLRA") (including both a demand and energy component) based on program engineering estimates. Estimates would be trued up on a going forward bases. The Company proposes to accrue net lost revenues in ratebase, to calculate a carrying charge and to delay amortization for three years or until the next general rate case. The Company proposes collecting the lost revenues through a balancing account. Price changes resulting from the balancing account would be included as a rider on the customer's bill. The Company proposes that the Utah Commission adopt either an estimated future test year or an historic test year with out-of-period adjustments for costs related to DSR programs. Changes in net lost revenues between rate cases would be reflected in the balancing account through an indexing mechanism.

The issue of lost revenue gets at the heart of the distinction between supply-side and demand-side options. SSR's are assets, i.e., generating plants, which produce electricity for sale to customers. Immediately upon being placed in service, whether included in ratebase or not, an SSR begins to produce revenues from electricity sales. The margin on these sales contributes to the recovery of fixed costs. In contrast, a DSR is created through energy efficiency measures which reduce sales of electricity. Because tariff energy charges include a portion of the fixed costs of the Company, revenues decline by more than the variable cost of the energy saved. This component of fixed cost recovery, built into the tariff price, is often called the "margin". The margin which would have been received but for the DSR program, is lost to the Company. The lost revenues which occur when DSR is acquired, have no parallel in the acquisition of a SSR option. Lost revenues are a hidden cost of DSR, which constitute a penalty to the Company arising from DSR programs. PacifiCorp's proposed net lost revenue adjustment mechanism effectively removes this disincentive to DSR acquisition.

One of the more difficult problems in reaching agreement on DSR cost recovery is the debate over the appropriateness of offsetting "lost revenues" and "found revenues." One point of view is that lost and found revenues are two sides of the same coin and must be considered together for DSR cost recovery purposes. The other perspective is that while revenues are clearly lost as a result of the implementation of DSR measures, there is no evidence that so-called found revenues are directly or indirectly related to DSR programs. Proponents of this second view believe that consideration of found revenues is a broader regulatory issue that falls outside the sphere of DSR cost recovery. The disagreement over lost vs. found revenues has the potential to distract attention from elements of cost recovery that may be less controversial, i.e., the deferral with carrying charge and subsequent amortization of DSR program costs.

In order to circumvent the lost revenue/found revenue debate and provide utilities with the opportunity for DSR cost recovery, PacifiCorp included an estimated future test year or an historic test year with out of period adjustments for costs related to DSR programs in its lost revenue proposal. Both lost and found revenues are created by regulatory lag. Thus, matching prices with test period conditions through estimates of DSR program impacts on revenues and expenses will render the lost/found revenue issue moot. It would also eliminate the need for the balancing account generally associated with lost revenue recovery mechanisms. Out of period adjustments related to DSR would need to include lower kWh sales, reduced expenses related to lower kWh sales, and levels of deferred DSR program costs and related amortization. Though limiting out of period adjustments to DSR issues would minimize departure from the Commission's preference for historic test periods, it seems likely that once the door is opened many other adjustments will be proposed to maintain consistency. Therefore, the Company would prefer that its next Utah general rate case be based on an estimated future test year for all elements of revenue requirement.

While the use of estimated future period amounts would do much to defuse the lost vs. found revenue issue, it will not remove all the complexities of DSR cost recovery. For example, if significant DSR program costs are incurred prior to the test period on which prices are set, it will still be necessary to defer those costs with a carrying charge until they can be reflected in prices. Timely recovery of DSR costs inherently requires estimation. The use of a future period for ratemaking would not change the estimation requirement for DSR program costs, including lost revenues, but it would ensure consistent treatment for all components of revenue requirement.

It has been suggested that a net lost revenue recovery mechanism could actually deter PacifiCorp from engaging in educational DSR programs because the revenues lost from such programs would be very hard to quantify. However, it is Company's opinion that DSR educational programs would be undertaken whenever they were determined to be cost effective; and the lost revenue impact, if deemed to be material, could be determined in a manner acceptable to all parties.

From PacifiCorp's perspective, the Division's lost revenue proposal has the same problem as its cost recovery proposal. It potentially puts the Company in the position of having to file frequent small rate cases to recover lost revenues. As explained in the section on cost recovery, DSR's are inherently different from SSR's because they are not revenue producing assets. To the contrary, they actually reduce sales of electricity. The prospect of frequent rate cases to recover the revenue from lost sales can only be a disincentive to DSR investment. Since the Division's proposal requires a mechanism for calculating lost revenues, the Company believes it is a logical step to allow recovery of those revenues as they occur and to evaluate overall results of operations in the normal manner.

The environmental intervenors' statistical recoupling approach is an innovative and well-reasoned approach to decoupling profits from sales. It is superior to other decoupling approaches in that it does not shift the risks of weather and economic changes from shareholders to customers. It also encourages economic development by recognizing the beneficial effects of electricity sales that increase economic productivity. Finally, statistical recoupling retains an incentive for the Company to decrease costs between rate cases.

Though the statistical recoupling approach is theoretically impressive, PacifiCorp believes that it would be premature to apply it in Utah at this time. The current proposal aggregates all customer classes. The Company believes that in practice statistical recoupling would need to be done by class. The implications of a class distinction needs more analysis. The current proposal is also sketchy about the workings of the "recoupling (balancing) account." It is not clear how such an account would handle significant fluctuations between actual and allowed revenues in a manner which minimizes price changes and stabilizes the account balance. This area needs additional clarification. The Company believes its customers would be better served by proceeding with a net lost revenue recovery mechanism while continuing to evaluate and monitor the acceptance of statistical recoupling in other jurisdictions. In fact the approach to a net lost revenue mechanism described by the environmental intervenors in their backup proposal has merit and deserves careful consideration.

Like the environmental intervenors, the DNR prefers statistical recoupling. They also could support a net lost revenue recovery mechanism though concern was expressed that this approach was subject to "gaming." PacifiCorp believes that the DNR's concerns about net lost recovery mechanisms can be addressed through careful design and implementation.

PacifiCorp Incentive Proposal

PacifiCorp believes that if the Company is provided with an 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. However, as the scope and maturity of the Company's Utah DSR investments increase, some type of incentive could encourage continued development of cost-effective DSR by the Company.

An incentive method used in connection with DSR expenditures, which has been gaining popularity nationally, is the shared savings approach. Shared savings is an approach the Company favors exploring in more detail, and an option that may prove beneficial in the future. If properly structured, a shared savings feature should provide a useful tool for encouraging continued development of cost-effective DSR while balancing risks between the Company and its customers.

PacifiCorp believes that any incentive program be considered separate from the cost recovery and lost revenue provisions. The proposals adopted for cost recovery and lost revenue should provide the Company with full recovery of their DSR costs, plus a reasonable rate of return. The purpose of any incentive should be to share the risks and the rewards associated with DSR programs between the shareholders and the customers. The Company needs to be rewarded for exceeding a specified level of DSR effectiveness, not simply given the opportunity to earn a fair rate of return. In addition, any possible penalties should not exceed the possible rewards.

The Company believes that the Environmental Intervenors, DPU and DNR proposals appear reasonable. However, the Company believes the CCS proposal would not function as a DSR incentive because most of the risk is born by shareholders, while most of the rewards are going to the customers. The Company and shareholders should not be expected to absorb the risk with no appropriate level of possible reward for absorbing those risks.

II. DIVISION OF PUBLIC UTILITIES

DIVISION OF PUBLIC UTILITIES' POSITION AS OF 6/22/93 AND RESPONSE TO OTHER PARTIES' POSITIONS

DEMAND-SIDE-RESOURCE TECHNICAL CONFERENCE/ COLLABORATIVE PROCESS JULY 1, 1993

In accordance with the agreement established at the 6/22/93 demand-side-resource (DSR) Technical Conference/Collaborative Process, the Division of Public Utilities (Division) presents its position as of 6/22/93 and evaluates this position with respect to the criteria generated during this process. The Division also provides an assessment of positions presented by PacifiCorp, the Environmental Intervenors, the Division of Energy, and Deseret Generation & Transmission Co-operative (DG&T) on 6/22/93 with respect to the aforementioned criteria.

Each position is evaluated below with respect to the issues of cost recovery, lost revenues, and incentives for prudently incurred DSR programs. Prior to assessing the positions of the various parties, the Division prioritized the list of criteria and determined that the following six criteria receive the greatest weight:

1) Promotes Cost Minimization;
2) Provides Cost Recovery;
3) Performance Based;
4) Equitable Allocation of Costs Among Ratepayers;
5) Rate Stability; and
6) Appropriate Risk Sharing Between Shareholders and Ratepayers.

(See the criteria provided in the 6/1/93 minutes for a complete listing of criteria.) The Division maintains that it is of paramount importance that DSR policy promote cost minimization. Attainment of the criterion of promoting cost minimization is essential in achieving the goal established by this collaborative which is to encourage PacifiCorp to adopt a least cost plan. The second most important criterion is that the DSR policy provide cost recovery to PacifiCorp. If cost recovery is not provided the Company will have little incentive to pursue DSR despite the fact that it is determined to be a least cost resource in the integrated resource planning process. The third criterion of importance is that the DSR policy be performance based. The Division defines performance based policy as policy that promotes not only the most cost-effective DSR but also policy that promotes overall efficiency with respect to all resources. The fourth criterion of importance is that the DSR policy permit attaining equitable allocation of the costs of DSR within and across customer classes for participants and non-participants. The fifth criterion of importance is that the DSR policy maintain rate stability. Both rate stability and equitable allocation of costs are two of the Division's regulatory objectives as outlined in the Utah Code

Title 54 Public Utilities Statutes and Public Service Commission Rules Section 54-4a-6. The sixth criterion of importance is that the DSR policy maintain appropriate sharing of the risks between PacifiCorp shareholders and ratepayers.

I. DIVISION OF PUBLIC UTILITIES' POSITION

A. COST RECOVERY

The Division considers it appropriate to ratebase certain DSR expenditures. Those DSR costs that are recurring should be expensed. The Division supports the accrual of a carrying charge on DSR-related construction work in progress (CWIP) at the AFUDC rate during the construction period. These measures ensure cost recovery of DSR that is consistent with cost recovery treatment of supply side resources (SSR). As such, this policy attains the criterion of providing cost recovery while promoting cost minimization that does not inappropriately bias the Company toward selection of DSR relative to SSR.

B. LOST REVENUES

The Division recognizes that the decrease in sales as a result of DSR programs (which are appropriately non-load building) can be a temporary disincentive for investment in cost-effective DSR. Therefore, the Division recommends an annual rate review which recognizes the decrease in sales and DSR expenditures forecasted for the upcoming year. This review would include an assessment of the impact on revenues, expenses, and rate base of forecasted DSR programs as an out-of-period adjustment. Accounting for the decrease in sales due to DSR in this fashion could potentially mitigate the need for a rate decrease or conversely, trigger the need for a rate increase. While this review process may indicate that it is appropriate for rates to increase, it would be incumbent upon the Company to initiate a rate case if it was earning below its authorized rate-of-return since this review would not culminate in an automatic adjustment in rates. If the Company was over earning without an out-of-period adjustment for DSR and hence, prompted the Division to initiate a rate case, inclusion of an out-of-period adjustment for DSR may indicate that the Company is not over earning and negate the need for a rate case. If no out-of-period adjustment is allowed for DSR, an annual rate review will still be conducted using the test year's impact of DSR programs. This too will mitigate, albeit to a lesser degree, the impact of lost sales due to DSR by recognizing the change in sales due to DSR for the current year on the Company's return.

In order for a policy to successfully meet the criterion of promoting cost minimization, the Division considers it essential that policy address the issue of lost sales since lost sales associated with DSR can generate a significant deterrent to the Company's adoption of a least cost plan that includes expenditures on DSR programs that significantly reduce sales and therefore, revenues that contribute to fixed costs. The annual rate review discussed above attempts to address this concern by recognizing DSR programs in the upcoming year. Since the annual rate review does not have an automatic rate adjustment associated with it, it may not sufficiently remove the disincentive for investing in cost-effective DSR. However, the annual rate review does address the Division's concern about maintaining rate stability. Furthermore, this review would not require a balancing account which may be illegal unless Utah statutes are changed. (See Utah Supreme Court Decision in Case No. 19361.) The Division approach does not eliminate the net lost revenues calculation since it requires determination of net lost revenues due to DSR programs on a year-by-year basis.

C. INCENTIVES

It is not clear to the Division that incentives are necessary. The Division is continuing to assess the need for incentives. 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 at which time the propriety and necessity of the incentive mechanism would be revisited;
2) symmetry between the rewards for achieving savings above a threshold level and penalties for not attaining savings above a requisite level; and
3) ex ante estimates of savings adjusted on a forward-going basis consistent with verified achieved savings.

This shared savings program is consistent with the criterion of being performance based. To the degree that it is performance based and therefore, encourages the Company to invest in the most cost-effective DSR programs, it aids in promoting cost minimization. This mechanism also permits appropriate risk sharing between shareholders and ratepayers.

The Division recognizes that altering the corporate view that the Company sells electricity to that of selling energy services may be difficult. It is not clear what measures are necessary to facilitate this transition in corporate approach to ensure the Company's adoption of cost-effective DSR consistent with the Company's least cost plan. Perhaps a temporary incentive specifically targeted toward DSR is necessary in the interim. However, the Division maintains that any long-term DSM incentive should be part of a more extensive total factor efficiency incentive program. Within two years parties can design such a program with the Company.

D. AN INTERIM DSR POLICY

The Collaborative conducted a rigorous investigation of DSR alternatives. However, it is clear to the Division that given the shortcomings encountered by other jurisdictions, further investigation is needed before the Division can support a particular regulatory treatment for DSR longterm. This concern coupled with the need to encourage PacifiCorp to implement its IRP in a timely manner compels the Division to conclude that an interim trial policy is essential.

We recommend that an interim trial policy be crafted and implemented for 1994. This interim approach includes DSR targets which would encourage a reasonable level of DSR activity during 1994. This trial period should include safeguards to insure that DSR costs are treated like SSR costs, and to limit the dollar risk to ratepayers. It should also allow for a collaborative to continue investigation of other solutions, and to evaluate and oversee the results. The Division will work with other parties to see if a trial policy can be developed that accomplishes these goals.

II. PACIFICORP'S PROPOSAL

A. COST RECOVERY

PacifiCorp proposes: 1) ratebasing all DSR program costs; 2) deferral of the amortization of these costs for three years or until the next general rate case; and 3) accrual of a carrying charge on CWIP at the authorized rate-of-return.
The Division maintains that ratebasing all costs associated with DSR is inconsistent with standard accounting procedures as applied to SSR. The Division also considers deferral of these costs to be retroactive ratemaking and therefore, illegal. Finally the Division considers accrual of a carrying charge on CWIP at the authorized rate-of-return to be inconsistent with the treatment of CWIP for SSR which incurs a carrying charge at the lower AFUDC rate. This preferential treatment of DSR relative to SSR is inconsistent with promoting cost minimization consistent with the least cost plan. Furthermore, biasing selection of resources toward DSR as proposed by PacifiCorp does not necessarily encourage the most cost-effective DSR.

B. LOST REVENUES

The Company proposes to accrue net lost revenues in rate baseand to delay amortization for three years or until the next general rate case. The Company proposes collecting the lost revenues through a balancing account. Price changes resulting from the balancing account would be included as a rider on the customer's bill.

NLRAs are a means for addressing a major disincentive for the Company's adoption of its least cost plan -- the decrease in sales and therefore, profits that occurs between rate cases due to DSR programs. NLRAs account for the impact of the decrease in sales due to DSR by permitting the Company to recoup the lost profit margin, i.e. the difference between the retail price and their avoided cost, net of off-system sales. The rationale for adopting an NLRA is that the decrease in sales due to DSR reduces the contribution of sales to fixed costs. Compensating the Company for this lost contribution toward fixed costs may remove a potentially strong deterrent for Company investment in cost-effective DSR.

The Division has the following concerns regarding net lost revenue adjustments (NLRAs) in general. NLRAs do not necessarily promote cost minimization because they may bias the

Company against certain cost-effective DSR programs for which energy and demand savings due to the program may be extremely difficult to measure, e.g. educational type programs. Consequently, NLRAs do not necessarily promote performance-based DSR. NLRAs may be difficult to administer and not easy to measure because of the potential contentiousness that may arise in the evaluation process when large dollar amounts hinge on determined savings. NLRAs also do not discourage load building that is not economic. The NLRA may create an undesirable 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 to the balancing account. Under an NLRA regulatory regime the possibility of perverse outcomes is greatly increased, e.g. an NLRA may necessitate a rate increase while Company earnings in excess of its authorized rate-of-return necessitate a rate decrease.

With respect to PacifiCorp's proposal to ratebase net lost revenues and receive recovery through a balancing account, it is not clear that it is appropriate to ratebase net lost revenues rather than expense them. The deferral of net lost revenues for three years or until the next general rate case does not provide an equitable distribution of costs across generations because future customers will be paying for prior years' lost revenues. The implementation of this NLRA through a balancing account could potentially result in rate instability. As indicated previously, the balancing account may be illegal.

PacifiCorp also proposes the use of a future test year, thereby accounting for DSR programs in the upcoming year. The Division supports this view since it believes that this mitigates the disincentive for adopting a least cost plan that includes DSR since it accounts for lost revenues associated with DSR programs for that future test year.

C. INCENTIVES

PacifiCorp introduced the option of a shared savings incentive. No details were provided regarding the mechanism. See the discussion under section I part C of the Division of Public Utilities' Proposal for a discussion of shared savings mechanisms.

III. ENVIRONMENTAL INTERVENORS' PROPOSAL

A. COST RECOVERY

The Environmental Intervenors (EI) support cost recovery of DSR consistent with SSR. However, EI indicated that where this is not feasible it supports asymmetric treatment that recognizes differences between DSR and SSR, such as delayed amortization. The Division considers amortization upon completion of a DSR measure to be feasible and deems delayed amortization as neither necessary nor desirable. The Division recommends symmetric treatment of DSR and SSR for cost recovery. However, the Division potentially supports asymmetric treatment of DSR relative to SSR that is performance-based such as providing incentives for DSR.

B. LOST REVENUES

EI advocates statistical recoupling which breaks the link between revenue and sales as its preferred solution to the lost revenue problem. The Division considers statistical recoupling intuitively appealing. Statistical recoupling addresses many of the shortcomings of decoupling. Decoupling under an Electric Revenue Adjustment Mechanism breaks the link between profit and sales by predetermining allowed future profits based on a future test year. Rates are subsequently adjusted to ensure that the utility earns no more or no less than this predetermined profit. Decoupling under a revenue-per-customer mechanism breaks the link between revenue and sales by predetermining allowed future revenues based on number of customers (historic or forecasted). The revenue-per-customer mechanism allows future revenues to grow in proportion to customer growth instead of sales. Statistical recoupling resolves the problem of shifting the risks of weather and the economy from shareholders to ratepayers under decoupling. Under statistical recoupling PacifiCorp retains those risks. Statistical recoupling does not have the disincentive for maintaining quality inherent in revenue-per-customer decoupling which predetermines revenues 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 Company to keep revenues between rate cases associated with sales due to increased productivity. Since statistical recoupling breaks the link between revenues and sales, not profit and sales, statistical recoupling does not discourage cost minimization as it maintains the same incentive to decrease costs between rate cases as does rate-of-return regulation.

Despite the appeal of statistical recoupling on a theoretical level, the Division is concerned about the effectiveness of the model in practice, given that there is only three years of data on PacifiCorp to empirically examine the stability of the statistical recoupling methodology. Empirical analysis conducted by Eric Hirst and Eric Blank on five utilities yielded very stable results, i.e. relatively small rate impacts. (See "Regulatory Reforms that Remove Disincentives to Electric-utility DSM Programs in Utah", June 1993.) Given the Division's criterion of maintaining rate stability, the Division considers it premature to advocate statistical recoupling at this point in time when no state has yet adopted this relatively new approach toward resolving the lost revenue problem. Statistical Recoupling may create an undesirable 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 perverse outcomes is greatly 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. Furthermore, statistical recoupling involves a balancing account which may be illegal.

As an alternative to statistical recoupling, EI proposes an NLRA that is overseen by a collaborative which addresses both evaluation and program design. EI also supports a price cap which limits the rate impacts associated with PacifiCorp's DSR activities. Finally, EI recommends that PacifiCorp commit to specific DSR targets for the next few years perhaps based on RAMPP2.

The Division indicated its concerns regarding NLRAs in section II part B of PacifiCorp's proposal. EI's recommendation that a collaborative and price cap be established in conjunction with the NLRA mitigates some of the concerns that the Division has regarding NLRAs. As indicated previously, the Division is concerned that an NLRA may result in rate instability and may also result in an unfair allocation of costs between participants and non-participants. While the price cap may mitigate non-participant impacts it could potentially violate the criterion of cost recovery. The Division also indicated that it is concerned that NLRAs do not necessarily encourage cost-effective DSR. The collaborative could oversee DSR efforts in ensuring that cost-effective DSR programs, such as educational programs, are conducted. The collaborative may reduce the contentiousness associated with administering and evaluating DSR programs. However, concerns remain concerning the ease of implementation of an NLRA/collaborative mechanism as proposed here. The Division is concerned that a collaborative could potentially violate the criterion of minimizing micromanagement.

C. INCENTIVES

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 a linking would encourage adoption of PacifiCorp's least cost plan given DSR targets based on RAMPP. See the discussion under section I part C of the Division of Public Utilities' Proposal for a discussion of shared savings mechanisms.

IV. DIVISION OF ENERGY'S PROPOSAL

A. COST RECOVERY

The Division of Energy supports cost recovery treatment of DSR that is consistent with that of SSR. This view is consistent with that advocated by the Division. (See discussion in section I part A of the Division of Public Utilities' Position.) The Division of Energy indicated that all program costs, excepts those for evaluation and program development and research, should be ratebased.
(DIVISION DISCUSS)

B. LOST REVENUES

The Division of Energy advocates statistical recoupling as its preferred method of addressing the lost revenue problem. As a second best alternative to statistical recoupling the Division of Energy advocates an NLRA mechanism. This NLRA mechanism would entail a forward looking true-up of savings where savings are net of avoided costs plus sales for resale credit, free-riders, and load building kwh. The Division of Energy also supports an expanded collaborative effort on program design and evaluation. Finally, the Division of Energy is interested in exploring a cap on lost revenues.

The Division provided its views on statistical recoupling in section III part B of the Environmental Intervenor's Proposal and its views on NLRAs in section II part B of PacifiCorp's Proposal. The Division maintains that the NLRA proposed by the Division of Energy appropriately accounts for free-riders and load building that are not accounted for in PacifiCorp's derivation of lost revenues in its proposed NLRA mechanism. Netting out these factors appropriately reduces the impact of cost recovery of lost revenues on rates.

C. INCENTIVES

The Division of Energy maintains a position similar to that of the Division regarding incentives. See the Division of Public Utilities response in section I part C under Division of Public Utilities' Position.

V. DESERET GENERATION & TRANSMISSION CO-OPERATIVE'S PROPOSAL

A. COST RECOVERY

DG&T considers it inappropriate for the forthcoming Commission's order in Docket No. 92-2035-04 regarding DSR regulatory policy for PacifiCorp to become precedent setting for DG&T and its members. The Division concurs with this view. DG&T supports cost recovery treatment of DSR that is consistent with that of SSR. This view is consistent with that advocated by the Division. (See discussion in section I part A of the Division of Public Utilities' Position.)

B. LOST REVENUES

DG&T did not explicitly comment on lost revenues.

C. INCENTIVES

DG&T does not advocate incentives for DSR. See the Division of Public Utilities response in section I part C under Division of Public Utilities' Position.

III. ENVIRONMENTAL INTERVENORS

Three regulatory changes are necessary to make it financially possible for PacifiCorp to implement its integrated resource plan in Utah in regard to energy efficiency: (1) DSR cost recovery; (2) some mechanism for dealing with DSR-induced net lost revenues; and (3) a small financial incentive.

I. Cost-Recovery

Under current regulation, PacifiCorp has no mechanism for recovering its DSR-related costs in between rate cases. Moreover, since DSR tends to be a flexible resource that comes online in relatively small increments, PacifiCorp is unlikely to call a rate case just to recover DSR costs. In contrast, the costs associated with supply-side resources can be recovered (with AFUDC). Additionally, supply-side expenditures often come in large increments such that PacifiCorp is strongly encouraged to file a rate case when a new resource comes online.

To help level the playing field between DSR and SSR, PacifiCorp should be allowed to ratebase its prudently incurred DSR costs. PacifiCorp should also be able to accrue carrying charges on DSR-related expenses at the AFUDC rate, maintaining consistency with the treatment of supply-side resources. (Other expenses, such as for DSR pilots, might be better expensed as per the State Energy Office's suggestion).

In addition, to account for the fact that DSR comes online incrementally, PacifiCorp should be allowed to delay amortization of DSR-related costs until a rate case is filed. This will also allow PacifiCorp to recover its actual expenditures associated with investing in DSR.

This approach to cost-recovery will likely perform well when measured against our criteria for a good incentive mechanism. By enabling PacifiCorp to recover its costs, this approach helps to encourage PacifiCorp to acquire cost-effective electricity savings. Moreover, those concerned with non-participant rate impacts should not oppose this approach as it treats DSR the same as SSR: in either case, utility customers will be faced with the costs associated with meeting the growing demand for energy services.

Finally, this approach is amenable to regulatory oversight at reasonable cost. Since this DSR approach mimics SSR cost recovery, and parties have significant experience in making SSR cost recovery workable, this DSR cost recovery mechanism should be predictable, produce measurable results, be understandable, discourage manipulation, and be administratible.

II. Net Lost Revenues

Even with a cost-recovery mechanism, existing regulation still strongly discourages PacifiCorp from pursuing even the most cost-effective energy efficiency opportunities. Our analysis shows that the lost revenues resulting from even a moderate DSR program could lower PacifiCorp's rate of return by about 100 basis points.

A. Statistical Recoupling

Statistical recoupling is our preferred solution for this lost revenue problem. Like other "decoupling" approaches, statistical recoupling ("SR") 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.

Implementing a SR mechanism requires the use of statistical models that explain the effects of weather and economic activity on electricity sales. Such a system might be developed as follows. The utility would statistically analyze historical data (e.g., over the past 10 to 15 years) on quarterly electricity sales as a function of weather severity (e.g., heating and cooling degree days), service-area economic activity (e.g., personal income, employment, or industrial output), retail electricity prices, and other factors that materially affected electricity sales.

The coefficients from this statistical model would then be used to estimate electricity use for each future year, given the actual weather patterns, economic conditions, and electricity prices for that year. For example, the utility might use data from 1975 to 1991 to create this model. The model would then be used to calculate electricity use for the year 1993, based on actual weather, economic conditions, and electricity prices for 1993.[1] The utility's allowed revenue in 1993 would then be the product of the computed value of electricity use and the average retail price of electricity minus the base energy cost. The difference between actual 1993 electric revenues and the computed value for allowed revenues is the amount of money flowing through the utility's recoupling account. A more detailed description of the statistical recoupling approach appears in the Appendix.

Statistical recoupling retains many of the positive attributes of existing regulation. Weather and economic risks remain with the utility. Moreover, 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. Finally, statistical recoupling retains utility incentives to cut costs.

[1] When utilities use statistical models to forecast electricity sales, they must make assumptions about the future values for the explanatory variables. For example, a utility in 1993 wanting to forecast sales for 1994 and 1995 will have to assume values for income, number of customers, and other factors for these two future years. In contrast, in SR these statistical models are used to determine allowed sales for the most recent year. Thus, the values for all the explanatory variables are available at that time. In other words, SR involves no assumptions on what the values will be for heating degree days, income, electricity price, and so on.

Additionally, by comprehensively breaking the linkage between revenues 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 also meets other important objectives of the parties. For those concerned with non-participant rate impacts, this approach, by itself, should neither raise nor lower rates on an expected value basis. Furthermore, our analysis shows that rate volatility is extremely small, peaking in the 1-2% range.

Furthermore, regulators likely will be able to oversee this approach at a low cost. 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. Similarly, this approach should be predictable, administratible, and produce measurable results.

B. <u>Net Lost Revenue Adjustments</u>

Despite our preference for statistical recoupling, we recognize that this approach may not be acceptable to all parties in Utah. Accordingly, we have examined a variety of alternative mechanisms that have been used to deal with DSR-induced lost revenue problems. We have also reviewed the experience other states have had in implementing these mechanisms.

This review suggests that net lost revenue adjustments ("NLRAs") can produce acceptable results under certain conditions. NLRAs are designed to compensate utilities for changes in revenues associated with utility DSM programs, accounting for the possibility of off-system sales. As such, they are more sharply focused than mechanisms (like statistical recoupling) that break the linkage between utility sales and revenues.

By providing compensation for net lost revenues, NLRAs can make an enormous difference in utility attitudes towards energy efficiency. Indeed, utilities in New York, Massachusetts, and Maryland appear to have increased their DSM activities dramatically after regulators approved NLRAs. Thus, this approach can overcome the disincentives to DSR that exist under current regulation.

Nevertheless, NLRAs (by themselves) may not meet the objectives of all parties. For one, they place substantially more pressure on both DSM program design and evaluation activities. In states that have had little upfront agreement on program design and monitoring efforts, significant disputes have arisen in regard to NLRAs as various intervenors have challenged utility claims as to the size of the net lost revenue recoveries. Moreover, NLRAs will not lessen utility incentives to promote sales growth. Given this potential for utility manipulation, NLRAs have tended to work in states where parties collaboratively work on DSM program design and evaluation from the beginning.

As a result of this experience, any NLRA in Utah should be accompanied by an expanded Collaborative effort on DSR program design and evaluation. Moreover, we believe that the Division (and perhaps other intervenors) should be empowered to supervise outside consultants that would review PacifiCorp's work. As such, this process would perhaps be broader than the current DSR Evaluation Task Force, would have a more precisely defined mission, and would have clear rules for non-utility management of outside technical consultants.

Other elements would likely need to be added to this package to make it workable. For one, PacifiCorp's DSR activities can create non-participant rate impacts. To address this concern, we would support a cap that would limit the rate impacts associated with PacifiCorp's DSR activities over the next, say, three years. This cap (which must be big enough to comfortably support PacifiCorp's expected DSR efforts as set forth in RAMPP2) should help to directly address the concerns, expressed by various customer group interests, about non-participant rate impacts.

Finally, the purpose of providing cost- and net lost revenue recovery is to encourage PacifiCorp to implement its least-cost plan. Thus, as part of this total incentive package we believe that PacifiCorp should commit to specific DSR targets for the next few years, perhaps based on RAMPP2. This should give the Commission and other intervenors clear guidelines against which to measure PacifiCorp's success with DSR, both in terms of costs and benefits.

C. Annual Rate Reviews

The Division of Public Utilities uses an annual rate review to develop information about the impacts of lost revenues on PacifiCorp's earnings. However, since the annual rate review does not automatically adjust electricity prices, it will not remove the disincentives associated with PacifiCorp's energy efficiency investments. As a result, PacifiCorp is unlikely to take advantage of the economic and environmental benefits of DSR.

The primary benefit of this approach is that it will maintain rate stability. Given that PacifiCorp's investments in DSR are currently small, however, we believe that it is possible to encourage PacifiCorp to acquire the cost-effective resource for 1993-95 as shown in RAMPP2 with only minimal rate impacts. Indeed, with a rate cap the parties can specify exactly the acceptable rate impact.

D. Other Issues

PacifiCorp's idea of allowing out-of-period adjustments to reflect known and measurable ramp-ups in DSR expenditures and sales reductions is sensible. Although this will not cure the lost revenue problem, when combined with either SR or an NLRA, it will lessen the amount of money flowing through these mechanisms. Nevertheless, this does not justify a shift to a future test year in regard to other, non-DSR related accounts. Such a shift is likely to be beyond the scope of these technical conferences.

Other partial approaches to ameliorating DSR-induced lost revenues are likely to be too small to address the underlying problem. As a result, PacifiCorp will still be strongly discouraged from pursuing its least-cost plan in regard to energy efficiency. Thus, we find these approaches inadequate.

Our evaluation of the various mechanisms for dealing with the net lost revenue problem is summarized in an Exhibit B.

III. Financial Incentives

Although important in encouraging desired utility behavior, financial incentive 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 the states that have used them.

IV. DG&T

This draft **POSITION PAPER RE IRP & DSM** ("Draft Paper") is prepared by Deseret's staff pursuant to Pacificorp's request for comments by interested parties. However, this Draft is presented subject to submission to, review and revision by, and final approval of Deseret's Governing Board.

Furthermore, in anticipation of the possibility of a formal hearing ("Formal Hearing") before the Utah Public Service Commission ("Commission") regarding the subject matter of the above-captioned workshops ("Workshops"), Deseret reserves the right, subject to and consistent with applicable law, to make an appearance in any such Formal Hearing, to therein represent and defend Deseret's interests in any and all of these matters and, to the extent Deseret's deems appropriate, to take any position in any such Formal Hearing whether consistent or inconsistent with any position taken or otherwise expressed herein.

Deseret's *Draft* Position

The collective goal of Deseret and its six distribution cooperative members[2] ("Members") is to operate a low cost, highly reliable, efficient generation, transmission and distribution system. Deseret and its Members intend to follow an Integrated Resource Plan ("IRP") which results in the lowest cost to all customers through Supply Side Resources and, when appropriate, through Demand Side Resources. The current intent of Deseret's Board of Trustees is to have Deseret prepare a joint IRP for Deseret and its Members.

Presently, Deseret has surplus Supply Side Resources and a very high load factor which severely limits the ability of Deseret and its Members to take advantage effectively of Demand Side Resources. At the present system growth rates, Deseret and its Members now possess resources sufficient to last 10 to 15 years or more, which is longer than Deseret's present planning horizon.

Deseret feels that both its needs and those of its Members should be evaluated when looking at long term power supply resources, whether Supply Side or Demand Side. A Member may potentially be able to decrease its total cost for electricity by reducing the amount of its purchases by application of Demand Side Management ("DSM"). However, any such reduction in purchases by Members may force Deseret to raise rates. Such a rate increase could negate or devalue any Supply Side cost savings achieved by reducing retail sales.

At a time when many owners of agricultural, commercial and other loads are shopping around the more than 25 different power systems in Utah looking for the "best deal", Deseret feels it needs to offer comparable and competitive services and prices to maintain its market

[2] The six Members of Deseret are: Bridger Valley Electric Association, Dixie-Escalante Rural Electric Association, Inc., Flowell Electric Association, Inc., Garkane Power Association, Moon Lake Electric Association, Inc., and Mt. Wheeler Power, Inc.

position when competing with other utilities offering various grades of service such as interruptible, time of day and direct local control. However, since Deseret has already purchased enough generation and transmission capacity for firm reliable service for its Members for the foreseeable future, since Deseret presently has surplus capacity, and since Deseret must pay for ALL of its capacity, whether or not used, Deseret is faced with a serious dilemma: if Deseret and its Members offer graded service, such as interruptible service, to customers for a lower price, such price reduction may result in revenues insufficient to cover Deseret's debt service, requiring Deseret and its Members to make up the shortfall by raising rates to other customers or to customers of other classes. This could result in disparate treatment among customers or classes of customers of Deseret and its Members.

DSM with Relationship to Pacificorp

In these proceedings Pacificorp has requested comments by interested parties on items proposed by Pacificorp which it claims would provide financial incentives to implement DSM as a viable alternative to Supply Side Resources. Deseret feels DSM should be fairly evaluated by unbiased objective criteria that neither inherently favors nor disadvantages DSM as compared to Supply Side Resources. However, all of the costs associated with DSM must be scrutinized and evaluated with at least the same degree of detail and objectivity applied to costs associated with Supply Side Resources. DSM should not be given unfair favoritism because of questionable environmental externalities which some allege exist in connection with Supply Side Resources. If a resource is appropriately designed, whether Supply Side or Demand Side, the environmental externalities are minimized.

Deseret's comments on certain items and issues specifically raised in Pacificorp's Workshops are as follows:

Cost Recovery - Each utility needs to be able to appropriately recover the costs of the DSM programs just as cost for Supply Side Resources are recovered. However, the effectiveness of DSM is more difficult to determine than for Supply Side Resources. If cost recovery is based on performance, it may cause the cost of DSM projects to increase because substantial resources will be required to measure the performance. The evaluation efforts in any DSM option need to be reasonable to keep costs down. If costs go up, this will act as a disincentive for DSM.

Incentives - Deseret does not have a position on whether or not a rate of return should be given to Pacificorp on lost revenues as an incentive for doing DSM. Cooperatives, such as Deseret, are non-profit and rates of return for stock holders on lost revenues because of reduced sales do not exist. There is no profit motive which can be given to cooperatives to implement DSM. The best incentive for cooperatives to perform DSM is to find DSM programs which keep the overall expenses of the cooperatives as low as possible.

Efficiency - Deseret feels that any Least Cost Plan ought to encourage efficiency within the utility. This strategy will keep the overall expenses of the cooperatives down and give the customers of the cooperatives the proper price signals.

Non-participant cost - As different grades of service are sold to different customer classes in connection with DSM, it should be demonstrated that other customers and other classes of customers are not adversely impacted, i.e., that such other customers and classes of customers are not cross-subsidizing such DSM. If DSM is implemented, the direct impact of the benefits and the costs associated with such DSM should be limited, as much as possible, to those customers directly involved with such programs. Every reasonable effort should be made to assure that the costs and other burdens of the implementation and performance of DSM programs are not imposed upon the non-participants of the programs. This procedure would minimize snapback, make the program simple to administer, make the programs easy to understand, and be performance based.

Share risk - In any financial investment there are risks. If the benefits of a DSM program are received by a customer, then that customer ought also to bear the costs and risks associated with such program. A customer thus exposed to costs and risks will then be motivated to ensure desired and anticipated benefits are achieved. Pacificorp does this effectively when offering low cost loans to customers who install high-efficiency appliances. It also minimizes the issues of whether DSM costs, risks and savings are measurable, understandable, administrable and predictable. If other customers who are not participating in a DSM program share in the cost of a DSM program but not the associated benefits, they are then exposed to risks outside their control without any corresponding benefit. When benefits are not realized, there may be instability in rates. When risks are appropriately borne, inaccurate rate signals, which may result in gaming and/or cream skimming, would likely be minimized.

Decoupling revenue from sales - While decoupling mechanism which would decouple sales from revenues may look attractive to some, it does NOT encourage a utility to be efficient and maintain the lowest overall costs. Market forces are among the MOST IMPORTANT to keep and maintain low costs, and are MOST LIKELY to result in each customer's receiving the appropriate price signal for electrical energy.

Concerns re CHANGE in Nature of Proceedings

It would appear that the Utah Public Service Commission's order orally issued in the June 2, 1993 PRE-HEARING CONFERENCE in cases captioned Docket No. 93-999-03 and Docket No. 93-999-04 has changed the fundamental nature of the above-referenced Workshops. That oral order, now in the process of being reduced to writing by the attorney for the Division of Public Utilities, provided, among other things, that the Utah Public Service Commission will, as a part of the above-captioned Workshops, consider establishing for **ALL** utilities in the State of Utah "standards for electric [utilities consistent with those]... found in [PURPA] § 111(d)(7-10)..."

relative to "b. Investments in conservation and demand management." This oral order was a partial affirmative grant by the Commission of the Division's recommendation that,

> the consideration of the electric standards be held in a generic proceeding applicable to all electric utilities who are covered under PURPA rather than in Utah Power & Light's next general rate case.[3]

Hence, it would seem that the above-referenced Workshops have, by the Commission's oral order, been transformed from mere Workshops for the exchange of information regarding DSM to a "generic proceeding" in which possible standards for "investments in conservation and demand management" will be reviewed and final standards established for all of the electric utilities in the State of Utah. This would seem to necessitate the Commission's invoking the application and use of its regulations and procedural rules regarding Rule Making, including without limitation appropriate notice and opportunity to participate being given to interested utilities within the State of Utah.

[3] Petition By The Division Of Public Utilities To Initiate A Generic Proceeding dated May 12, 1993, page 3, paragraph 4.

V. DIVISION OF NATURAL RESOURCES

UTAH DEPARTMENT OF NATURAL RESOURCES
Office of Energy and Resource Planning
VIEWS ON RATEMAKING TREATMENT FOR PACIFICORP DSR INVESTMENT
August 30, 1993

In this statement, the Utah Department of Natural Resources, Office of Energy and Resource Planning will discuss our views to date on three components of ratemaking treatment for Demand Side Resource (DSR) investment by PacifiCorp.

- Recovery of Costs
- Treatment of Lost Revenues
- Incentive Mechanisms

Philosophical Orientation and Goals for this Proceeding

We first state why this proceeding is important to the Department of Natural Resources and indicate DNR's goal for the proceeding.

Under Utah state statute, 63-34-6 (3), the Department of Natural Resources (DNR) is authorized to engage in studies and comprehensive planning for the development and conservation of the state's natural resources. Through statutes 63-34-5c (ii) and 63-34-5c (vi), DNR is authorized to facilitate the development and implementation of policies and programs relating to energy production and utilization and to participate in regulatory proceedings as appropriate to this mandate.

DNR notes that PacifiCorp has identified cost-effective demand side resources (DSR) in the RAMPP-2 Integrated Resource Plan recently acknowledge by the Utah Public Service Commission. However, we also note that current regulatory policy provides a financial incentive during the lag between rate cases for PacifiCorp to *increase* rather than *decrease* electricity sales. This regulatory phenomenon coupled with regulatory reliance on an historic test year for establishing revenue requirement combines to form a financial barrier to the development and acquisition of DSR which by its nature *reduces* sales between rate cases and imposes *additional and increasingly significant* costs to PacifiCorp not accounted for in the established revenue requirement. The outcome of the current regulatory approach is that PacifiCorp is likely to prudently balance short and long-run profit maximization against reduction of long-run ratepayer costs.

Amidst the perception of an increasingly competitive market for electricity which puts pressure on maintaining competitive rates and with current uncertainty of regulatory treatment of DSR costs in Utah, we believe that PacifiCorp will continue to favor SSR options despite the cost and environmental advantages of DSR to Utah ratepayers and citizens. Accordingly, DNR finds that it is necessary to examine options to address the regulatory treatment of DSR investments versus SSR investment and to make necessary changes to the current regulatory incentive scheme. We take this opportunity to assist in the development of regulatory treatment that removes the current incentive to prefer supply side resources over demand side resources in order to assure the long-run cost advantage and environmental quality benefits to Utah citizens of DSR development.

There are three overriding goals we wish to see DSR ratemaking treatment achieve:

1. the timely, cost-effective acquisition of DSR identified in IRP;
2. assurance that DSR investment is as profitable to PacifiCorp as SSR;
3. equitable DSR cost distribution among ratepayers;

This paper is organized into three sections: Recovery of DSR Program Costs; Recovery or Treatment of Lost Revenues; DSR Investment Incentive Mechanisms. Within each of these sections DNR evaluates the solutions proposed in this paper against germane criteria noted in section III of this paper.

RECOVERY OF DSR PROGRAM COSTS

We have a preference for capitalizing direct DSR program costs primarily because it will mitigate price impacts to ratepayers. Capitalizing the investment also mirrors SSR cost recovery practice and has the intuitive appeal of matching costs of the investment to the recipients who benefit from the investment over time. To protect ratepayers from the manipulation of DSR capitalization that could result in gold-plating, we suggest the required adherence to performance standards as a prerequisite for capitalization; if a program is cost-effective from a TRC and UC perspective, then it should be allowed in ratebase.

We suggest that guidelines governing "eligible costs" for recovery be spelled out up front so that PacifiCorp and regulators know what is likely to be reviewed in a prudency hearing. Specifically, a distinction should be made between program delivery or direct costs (loans, administration, marketing, commissioning, etc.), which could be capitalized, and recurring costs (evaluation, program research and development) which could be expensed in the year they occur.

In order to assure the opportunity for full recovery of prudent costs, we support deferring the beginning of amortization for three years or until a rate case with the accrual of a carrying charge on the unamortized portion at the AFUDC rate. Although this treatment is not consistent with SSR, it is consistent with providing a cost recovery mechanism that is at least as profitable as SSR and provides the opportunity for appropriate share of risk between shareholders and ratepayers. Under regulatory treatment for SSR investment, deferral is allowed only until the time the plant goes into service. However, SSR investments include a revenue stream that can compensate the utility for costs that may go unrecovered between the in-service date and a rate case. There is no corresponding compensation for DSR investment and so allowing deferral of the amortization can serve to reduce the increased risk of not receiving full cost recovery perceived for DSR investments.

Further, we recommend that only full-scale programs that are cost-effective from both a TRC and UC perspective and small scale pilot or demonstration programs be eligible for capitalization, with deferral of the amortization as noted above and carrying charges. The amortization period for cost-effective expenditures should comport with the expected useful life of electricity savings, per energy conservation measure, which should be collaboratively established when the program is proposed or evaluated. Small-scale pilot programs should be excepted from the cost-benefit performance standard but should be held to a minimum annual expenditure, i.e., under $200,000 for eligibility. The performance standards will reduce micro-management of programs by regulators and explicitly place the responsibility of program performance compliance on PacifiCorp. This would also reduce gold-plating (padding the ratebase with DSR expenditures with no corresponding benefit), and thus promote cost-minimization as defined in the IRP. This approach would result in the emphasis of evaluation efforts rather than minimization; however, current evaluation methods may likely be sufficient.

We do not consider it appropriate to discuss how DSR costs will be spread amongst ratepayer classes; we recommend that that issue be addressed in a rate case. However, cost-benefit analysis conducted for performance standard compliance relies upon avoided cost tests which can be structured to identify the impact of the program on all ratepayers and which yields an estimate of cost to non-participants by program type, and hence by sector, for identification of class cost share.

TREATMENT OF REVENUES "LOST" BETWEEN RATE CASES

We strongly support the development of a mechanism to address the loss of revenue incurred between rate cases due to DSR performance vis a vis what would have occurred absent the Company's efforts to reduce or to increase sales.

Our preferred method of addressing this problem is statistical recoupling. We currently find it to be the most reasonable alternative to address the short-run lost margin to fixed costs due to DSR. Coupled with a cost recovery mechanism, it has the virtues of making the Company whole with respect to DSR investment and more appropriately aligns the Company's short-term financial interest with implementation of it's IRP. Since statistical recoupling does not require calculation of lost revenues, micro-management and oversight of programs is reduced and the role of evaluation is minimized, and therefore, appears to be relatively easy to administer. Because Company costs are not part of the equation, the regulatory incentive to decrease costs between rate cases is preserved. The method removes the current incentive for the Company to build load irrespective of the long-run consequences of that induced load growth; however, the incentive to induce load growth that results in increased economic output is maintained. And because it permits the Company revenue for lost sales shown to be due to factors outside of weather and economic fluctuation, lost sales due to DSR efforts will be recovered between rate cases.

A net lost revenue adjustment mechanism could also be structured to address the lost margin problem; however, we consider it an inferior solution because it is likely to be more contentious than statistical recoupling and does not remove the incentive to build load. However, if structured satisfactorily to address "net program performance", with forward looking true-up through greater collaboration and agreement on program design and evaluation, we could support this approach. Specifically, lost revenues could be calculated as net of avoided costs plus sales for resale credit, free-riders, and load building kwh and this would provide a reasonable starting point for addressing the problem.

We envision that the adjustment would be available for cost-effective programs only. Providing the amount is relatively small, we support either expensing or ratebasing of this adjustment. If the amount of net lost revenues exceeded a dollar limit, we could accept ratebasing of this adjustment in order to assure gradual rate impact. We concur with the LAW fund that increased attention and collaboration would need to be employed in program design and evaluation. Greater attention will need to be given to the values used to compute the net lost revenue amount, i.e., annual savings, avoided cost streams, free-ridership, load-building kwh, level of precision with respect to evaluation results. PSC approval of a process to provide on-going improvement of the estimates used to calculate lost revenues is advisable.

Despite our support for a net lost revenue adjustment, we consider this approach to be subject to gaming. Since it does not remove the current incentive to increase sales between rate cases irrespective of the long-run impacts to ratepayers, we suggest this method does not give the Company an incentive to operate efficiently; that is, efforts to increase sales between rate cases will be conducted simultaneously with efforts to decrease sales between rate cases. In fact, given a net lost revenue adjustment based on ex-ante engineering estimates coupled with a cost recovery mechanism devoid of performance standards, it would be in the Company's interest to run DSR programs that don't perform in reality but look good on paper.

We are also interested in exploring the idea of a "cap" on lost revenues in order to mitigate rate impacts. However, we suggest that the issue of how the cost of lost revenue is spread over customer classes be dealt with in a rate case.

INCENTIVE MECHANISMS

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 in exploring the development of a performance based shared savings mechanism. Such a mechanism could assist regulators in reviewing the achievements of Company efforts in relation to the goals set forth in the Company's IRP. It could also promote system 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.

VI. COMMITTEE OF CONSUMER SERVICES

COST RECOVERY

The primary objective of any demand-side resource (DSR) cost recovery mechanism is to place DSR expenditures on an equal footing with supply-side resource (SSR) expenditures. Essentially this means that the utility, as well as the ratepayer, should remain indifferent as to whether or not KWHs are derived from demand-side or supply-side resources.

Currently, the PacifiCorp, as well as other Demand-Side Task Force participants, have proposed that certain DSR expenditures be deferred (i.e. ratebased) and amortized over a certain time period at a later date. Until such time as these DSR expenditures are amortized, they would accrue interest (AFUDC). In other words, ratepayers would reimburse the Company for its demand-side expenditures, plus interest, at a later date.

The Committee currently does not object to the deferral (i.e. ratebasing) of certain DSR expenditures. In order to qualify for deferral, we believe that a DSR expenditure should be a directly identifiable expenditure made by the utility for a specific demand-side resource (i.e. legislative lobbying efforts would not qualify), and not be reimbursable by another party (i.e. low interest loans provided by PacifiCorp to customers). We note that currently financing programs are accounted for below-the-line. The capitalization of overhead costs would be allowed for programs which qualify under this scenario.

We tend to agree with the Division of Public Utilities that there should be no deferral of amortization. That is, DSR expenditures for completed installations deferred in year 1 should begin amortization in year 2. AFUDC would be allowed up to the time of amortization. The unamortized portion would be allowed in ratebase for ratemaking purposes.

LOST REVENUE

The Committee's current position is that lost revenue should not be included as a DSR cost for existing customers and definitely not be included as a DSR cost for new customers.

It is true that if a demand-side measure is successful for an existing customer, the utility will realize a reduction in revenue from its current level, all else being equal. But the revenue lost may not have been previously included in the determination of the revenue requirement. Perhaps the customer expanded its operations since the previous rate case. Additionally, the demand-side measure could have made an existing customer more competitive and thereby prevented what would have otherwise been a loss of revenue. In this latter instance, it would seem that the utility had a sufficient incentive to install demand-side measures.

The Committee has prepared an analysis of PacifiCorp's lost revenue recovery proposal, attached as Exhibit A. Turning to Exhibit A, let's assume a demand-side measure is installed at the beginning of year 1. Let's further assume that it results in a reduction in the utility's margin (i.e. sales minus energy costs plus any margin realized from off-system sales) of $100,000. Further assume new rates are established at the beginning of year 4, which take into account the $100,000 lost margin (i.e. rates are increased $100,000 due to this particular demand-side measure). Under this scenario the lost revenue would have been deferred for three years---PacifiCorp's current proposal. Further assume a tax rate of 40% and a discount rate of 10%.

If the Company were allowed no recovery of lost revenues (item A), its net dollar amount available for return would be reduced by $60,000, in each of the first three years. The net reduction in each of the first three years would not be $100,000, since the reduced margin would result in reduced income taxes. In year 4, the Company would no longer realize a reduction, since the lost revenues would be recovered by the new rates. The net present value of this lost revenue stream, discounted at 10% is ($149,211).

If the Company were allowed recovery of lost revenues in the manner which it has currently proposed, it would defer additional DSR costs of $364,100, as shown in item B. In year 4, these additional program costs would begin amortization over a ten year period, resulting in an additional cost to be recovered from ratepayers of $36,410. The net present value of this additional margin, $36,410, to be collected from ratepayers over ten years beginning in year 4, is $168,087, which is greater than the net present value of the lost revenue stream.

Unlike other costs, lost revenues would not be tax deductible. Thus, in order to actually collect $36,410, PacifiCorp would have to increase rates an additional $60,683. Therefore, beginning in year 4, rates would increase an additional $160,683. This compares to the $100,000 rate increase which would have occurred had no recovery been allowed for lost revenues.

Other members of the Task Force have proposed decoupling/statistical recoupling as an alternative to the inclusion of lost revenues as a DSR program cost. The Committee currently has two problems with decoupling/statistical recoupling. First, it constitutes one item ratemaking. Second, it introduces another element into the ratemaking process, namely the determination of the appropriate statistical formula, which by its very nature must be updated/revised over time.

INCENTIVES

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 (subject to constraints such as reliability, environmental risk, technological diversity, etc.) combination of resources, whether they be supply-side or demand-side resources.

Hypothetically speaking, if the Commission directed parties to develop incentive mechanisms for consideration, we believe such a mechanism should be **performance-based** and not merely based on the volume of DSR activity. We would argue for an asymmetrical reward-penalty mechanism where penalties would be increasingly severe the lower actual energy savings are compared to threshold performance standards. For example, the reward for achieving savings 5% above the threshold level would be comparably less than the penalty imposed for savings 5% less than the target level. Furthermore, in considering that we are establishing the expected performance level based on engineering estimates and experience with similar programs in other states, a "dead zone" band could be established above and below the threshold level where no penalty would be exacted and no reward would be granted.

Response to Other Parties Positions:

Akin to the Committee position, most parties perceive that incentives are not necessary to stimulate the Company to acquire demand-side resources. If an incentive method were to be developed, most parties favor a shared savings mechanism characterized by reward-penalty symmetry. The Committee's thinking on reward-penalty symmetry differs somewhat as depicted above. In reviewing the DPU's position on incentives, we agree with: (1) the notion of a sunset provision for incentive mechanisms; (2) resetting threshold levels based on energy savings actually realized; and (3) not tying incentives to DSR activity levels.

PERFORMANCE STANDARDS

The development of reasonable DSR program performance standards is a critical piece in the **program evaluation--performance standards--cost recovery** linkage. While considerable time has been spent examining the evaluation and cost recovery pieces of this trilogy, the development of reasonable performance standards (that program evaluation will be measured against and cost recovery be predicated on) has yet to receive the attention it deserves. Defining what are "reasonable" performance standards and by what process they should be effectuated are clearly important, and presently unresolved, issues. The Commission ultimately needs to hear recommendations on these issues and set policy.

RATEPAYER/NONPARTICIPANT IMPACTS

Ratepayer impacts perhaps top the list of concerns the Committee has regarding DSR. From a fairness standpoint we support the concept that program beneficiaries should bear the lion's share of program costs. While the Energy Service Charge should result in program participants shouldering the majority of cost responsibility, there may be significant rate impacts on customers who are not the principal beneficiaries of DSR programs. Because lost revenues are not accounted for in performing the TRC test, program nonparticipants may end up paying considerably more for a DSR program than the "pricetag" ascribed to it in PacifiCorp's IRP.

Dave Engberg of the Company prepared a preliminary (Systemwide) RAMPP III Study indicating that near-term rate impacts for the residential class could be in the neighborhood of 4%. Moreover, his study showed that, on a present value basis, acquiring gas-fired peakers may be a lower cost resource strategy vis-a-vis DSR over the short run. What this suggests to the

Committee is that the potential DSR rate impacts for Utah jurisdictional ratepayers require further, and careful, examination.

The Committee position is that we should move cautiously and amass as much empirical evidence as possible through program evaluation and rate impact studies before diving headlong into muddy DSR waters. Such studies should analyze both intra-class and inter-class rate impacts at the Utah Jurisdictional level. We believe the Company should take the lead in performing these rate impact studies that will hopefully uncover useful information on the distributional ramifications of DSR.

VII. UTAH INDUSTRIAL ENERGY CONSUMERS

POSITION STATEMENT OF UTAH INDUSTRIAL ENERGY CONSUMERS CONCERNING DSR ISSUES

This statement sets forth the initial position of Utah Industrial Energy Consumers (UIEC)[4] on the principal DSR issues that have been addressed in the Technical Conference.

Introduction

The UIEC have objected to this Technical Conference because the process does not provide basic constitutional and statutory guarantees of due process and because it is financially burdensome. At the first meeting of the Technical Conference, the UIEC expressed their concern that if the Commissioners were involved and informed themselves through this Technical Conference, due process of law would be abridged. Because the procedural safeguards required by statute and regulation were absent, the information contained in this Report has come from sources who were not subject to discovery procedures, were not testifying under oath subject to cross-examination, and whose credentials and expertise are not of record. For those reasons, the Report is not the kind of evidence the Commission can rely on to make decisions regarding DSR accounting treatment.

Apart from its legal infirmities, the collaborative process does not provide to all parties a suitable forum for deciding, or even for airing issues like those under consideration here. The weakness of the process is due at least in part to the necessarily limited participation of those who are not willing to spend substantial sums at the technical conference stage when formal proceedings are ultimately inevitable. The UIEC do not have revenues directly at issue in this case like the Company and they are not charged with advising the Commission or protecting other consumers. They have participated reluctantly and attended the meetings only on a part-time basis. Some industrials did not participate at all. Some of the industrial customers, including the UIEC, sponsored presentations and submitted materials advocating their points of view, but at best, the presentations could only summarize their general positions. The UIEC found it difficult and even potentially counterproductive to settle on specific recommendations before their interests could be considered in the light of actual rather than speculative situations and numbers. The UIEC and others have had to respond to the collaborative process via

[4] For the purposes of this DSR technical conference, the Utah Industrial Energy Consumers are Abbott Critical Care, Amoco Oil Company, Hercules, Inc., Holnam, Inc./Ideal Division, Kennecott Utah Copper Corp., Kimberly-Clark, National Semiconductor, Praxair, Inc., and Westinghouse/Western Zirconium.

summaries and generalities while the agendas of the Company and the state agencies have dominated the process and dictated the Report.

The UIEC are also concerned that much of the information contained in the Report, including the selecting and prioritizing of criteria and the positions of the participants on each criterion, was evoked through an informal process of polling the participants for quick and short answers to complex and largely speculative questions. The parties to the Technical Conference were asked to provide responses to three matrices which compare cost recovery mechanisms, lost revenue treatment, and incentives against 19 predetermined criteria. (See Appendix II - Participant Matrices). The responses were to be compiled and presented as part of the Report of the Technical Conference to the Commission. Some of the participants in the Technical Conference proposed this "matrix" approach because, due to the diversity of positions among the parties, a compilation of written comments proved too cumbersome to distill into a coherent report.

The UIEC believe that the use of the matrices to formulate a report is even more confining and less informative than written comments. To adequately respond to the matrices and provide unambiguous information would require lengthy explanations, exceptions, and equivocations. It is the UIEC's view, therefore, that any report that could result from general summaries or the kind of abbreviated responses called for in the matrices may be ambiguous to the point of being virtually meaningless and, at the very least, subject to material misinterpretations. In order to avoid misstating their position or leading the Commission to believe that the UIEC concurred on issues when, in fact, they did not concur, the UIEC have elected not to participate in that portion of the report to the Commission.

For the reasons stated here, the UIEC believe that the process by which the Report evolved has left it incomplete, unreliable, and susceptible to misinterpretations. The UIEC urge the Commission, therefore, to avoid placing undue confidence in the Report and to refrain from using it to form opinions regarding the advisability of any cost accounting method for DSM programs or any participant's position with respect to the issues addressed in the Report.

UIEC's Position on Cost Recovery

UIEC's position is that costs associated with demand-side resources (DSR or DSM) should be treated in the same manner as costs associated with supply-side resources. Those costs which are associated with the creation of an asset should be capitalized and depreciated or amortized over the useful life of the asset. Other costs should be expensed in the year incurred. During the time of construction, an allowance for funds used during construction (AFUDC) rate may be applied and these costs capitalized along with the underlying capital, labor and other costs. Accrual of AFUDC should cease at the time the asset goes in service, thereby affording DSR the same treatment as supply-side resources.

DSR costs are not large, volatile, nor are they outside of the control of the utility. Accordingly, there is no reason to establish special mechanisms or treatment for DSR cost recovery.

Comments on Cost Recovery Proposals of Other Parties

PacifiCorp proposes to rate base DSR costs and to amortize them over the life of the installed measure, a position with which UIEC agrees. However, PacifiCorp also proposes to defer initiation of amortization of these costs for three years or until the time of the next general rate case, and to accrue a carrying charge on the unamortized expenditures at the authorized rate of return. UIEC takes exception to these two elements of PacifiCorp's proposal. Deferral of costs as PacifiCorp proposes is not only unnecessary in light of the magnitude of the expenditures, but it may also be in conflict with the law. Recovery in a future period, of cost incurred in a prior period falls into the category of retroactive ratemaking, and is impermissible. Furthermore, it is inappropriate to allow carrying charges to accrue after an asset has been placed in service.

The cost of DSR is but one of many costs incurred by PacifiCorp. After rates are established in a rate case, a number of factors will change. Sales volumes may change for a variety of reasons, including weather related factors, economic conditions, new customers, etc. Revenue requirements may decrease because of the impact of depreciation and deferred taxes on rate base, a reduction in interest rates and cost of equity, improved productivity, etc.; and may increase because of capital additions, increased interest rates, etc. The general regulatory policy followed by most commissions, including the Utah Commission, has been to establish base rates using representative and consistent values for all elements in the revenue requirement equation. If the sum total of all changes that occur after rates are set produces a revenue deficiency, the utility can file a rate case to recover these additional costs. There is no reason to single out DSR for special treatment. It should be considered along with all other costs. The utility is free to file a rate case application whenever it believes it can prove an entitlement to higher rates.

PacifiCorp's proposal is essentially equivalent to a balancing account, wherein costs are accumulated and retained for recovery in a future period of time. The only commonly used balancing account is one to track energy cost changes. Utah used to have such a mechanism. It was known as the Energy Balancing Account ("EBA"). At PacifiCorp's own request, the EBA has been eliminated. In its December 24, 1992 Petition to Eliminate the EBA, PacifiCorp stated at page 12:

> The scenario described above demonstrates a fundamental flaw with <u>any</u> balancing account. That is, such mechanisms isolate, for regulatory purposes, one or a subset of the Company's revenue requirement component. The result is that the Company's results of operations are prepared and reviewed in a fragmented manner rather than as a whole. The risk is therefore increased that regulatory issues which impact both

general rates and the balancing mechanism may not be treated properly in each mechanism or between the mechanisms. (Emphasis supplied.)

We could not have said it better.

UIEC's Position on Lost Revenues

When a utility engages in a DSM program, revenues are allegedly "lost" because customers purchase less electricity then they otherwise would have in the absence of the DSM. But, sales impacts resulting from DSR are only one factor which influences a utility's performance. Even with DSR in place, sales levels may be higher than the level used to establish rates in the last rate case. Also, it is likely that factors such as weather and economic cycles will have a much greater effect on a utility's sales levels than will the incremental impact of DSR. Furthermore, UIEC must question PacifiCorp's claims with regard to lost revenues in light of the repeated assurances given that resources acquired in advance of their need (from APS and Colorado-Ute, for example) could be temporarily sold in the wholesale market and would not pose a burden to native load customers.

Also problematical is the ability to identify and quantify lost revenue impacts. The UIEC seriously question the ability to accurately determine the magnitude of lost revenues. This determination depends heavily upon the specific performance of the DSM measure during the period being analyzed. An accurate assessment requires a determination not only of the demand and energy impacts of the implemented DSM measures, but also the determination of a baseline to define what the sales would have been had the customer(s) not engaged in the specific DSM activity. This also involves the interactive effects among the various DSM programs, and the consideration of free riders, customers who would have engaged in conservation even without the DSM program. A task force has been formed to develop evaluation methods, but it is too early to know whether it can produce reliable, useful results.

Another major problem is isolation of the effects of additional load that may be provided by a DSM program. If a DSM program induces a customer to purchase an additional appliance, or to purchase an electric appliance rather than a gas appliance, then the actual effect of the DSM program provides the utility with additional load that it otherwise would not have experienced. The same would be true if the DSM program induces a customer to purchase a larger appliance then the customer otherwise would have purchased. Unless these effects can be accurately isolated, the utility will be rewarded with lost revenues for "found load."

UIEC believes that the most logical approach to lost revenues is to include appropriate pro forma adjustments when utility rates are established in a rate case. These pro forma adjustments will take into account the expected impact on sales volumes on a pro forma basis. This approach automatically builds the anticipated effect of DSR into the revenue requirement determination and the base rates, and obviates any perceived need to create special mechanisms. While it is still true that some estimates must be made, UIEC believes that the rate case process provides an adequate forum for analysis and testing of the basic assumptions.

<u>Comments on Lost Revenue Proposals of Other Parties</u>

PacifiCorp proposes to estimate and accrue net lost revenues in rate base, with a carrying charge, coupled with delayed amortization of such costs for three years or until the next rate case. PacifiCorp apparently wants to track and account for changes in net lost revenues between rate cases even if the Commission adopts a future test year or an historic test year with an out-of-period adjustment. UIEC opposes PacifiCorp's proposal because it attempts to isolate a specific effect (which is likely to be minimal in any event) without considering the changes in other factors that affect the revenue requirement, and because the entire process of estimating lost revenues is speculative. The lost revenue adjustment is also in the nature of a balancing account. The criticisms that PacifiCorp leveled at balancing accounts, referenced previously in this Statement, apply with equal force here.

UIEC does not oppose the Division's recommendation to examine the potential consequences of lost revenue during the course of the semiannual rate reviews. This approach does allow some estimate of the impact which DSR has on PacifiCorp's operations, while avoiding the problem of providing for automatic revenue adjustments.

The environmental intervenors and DNR propose a method which they call "statistical recoupling" (SR). The concept of SR is to break the link between revenues and sales. SR uses statistical analyses to estimate the level of electric sales given actual weather patterns, economic conditions and electricity prices. This approach has not been tested in practice, and relies heavily upon the ability of statistics to determine the impact of weather, economic cycles, and other major factors influencing sales levels. UIEC does not place a high degree of confidence on this type of exercise. In addition, there is no evidence that the SR proposal considers PacifiCorp's ability to offset lost retail revenues through expanded sales in the wholesale market. Furthermore, the SR proposal suffers from the previously mentioned infirmity that it attempts to examine individual factors in isolation from other factors which impact a utility's earnings level. This practice is contrary to the objective of making management responsible for utility decisions.

In a memorandum dated July 13, 1993, the Division set forth an interim proposal on treatment of lost revenues and other issues. Essentially, the Division proposes that PacifiCorp be allowed to calculate and defer lost revenues during 1994, and to allow such lost revenues to be included in the revenue requirement if a general rate case is filed in 1995. UIEC opposes this recommendation for the reasons stated above. The Division makes a companion proposal to initiate a <u>new</u> Collaborative Task Force to deal with lost revenues, shared savings incentive plans, statistical recoupling and impact on participants and non-participants. UIEC opposes the establishment of this task force. It is time to move forward with implementation of cost-effective DSR and supply-side resources. It continues to be UIEC's position that the collaborative approach abridges its rights of due process as afforded under the Constitution and applicable statutes.

UIEC believes that there is no benefit to be gained by further studying lost revenues, shared savings, incentive plans or statistical recoupling. As noted in our "other comments" section, UIEC remains vitally concerned about impacts on participants and non-participants. UIEC would not oppose a limited task force to further consider these questions.

UIEC's Position on Incentives

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 interests of the customers.

UIEC believes that the Commission should appraise the overall quality of utility management during the course of a rate case. Performance on DSR is certainly a factor to be considered, but so is performance in all other areas of operations. If, on balance, the Commission finds that PacifiCorp has been doing an exceptional job it can certainly allow PacifiCorp a return on equity at the upper end of the range of reasonableness. Conversely, if it finds that PacifiCorp has not been doing a good job, it can set the return equity at the lower end of the range of reasonableness. The Company's performance could be assessed much as it would be with a supply-side resource, by comparing actual savings with engineering estimates and actual costs with estimated costs.

Comments on Incentive Proposals of Other Parties

No other party is seriously advancing the concept of shareholder incentives. However, PacifiCorp conditions its position on adoption of its proposals for cost recovery and lost revenues. Most parties seem to agree that if an incentive proposal is adopted, it should be "shared savings". While UIEC is opposed to the provision of incentives specifically targeted to one area, it does believe that a shared savings approach is the most logical, if incentives for DSR are adopted. However, there must be strict monitoring, evaluation and performance reviews associated with such a program, the utility must be held accountable for the actual, and not the estimated performance of DSR, and any such shared savings bonus must be paid over the life of the DSM measure, not all in advance.

Other Comments of UIEC

UIEC remains vitally concerned about rate impacts and the specific mechanism(s) by which DSR costs will be collected from customers. This concern exists in the context of a base rate proceeding or whenever rates are established. It is clear that even DSR which is cost-effective on an overall basis, and beneficial for the participants, may turn out to be adverse to non-participants unless cost recovery is carefully crafted. UIEC references the reader to its May 11, 1993 presentation for further detail.

Another major concern is the anticompetitive effect of the proposed DSR cost recovery mechanisms.[5] In the long run, there may be significant, detrimental, anticompetitive consequences if the Company is allowed to subsidize demand-side programs by recovering a portion of the costs from customers who are not direct participants in the program. While the utility would be able to offer its products and services at prices below cost, other private providers would be forced out of the market. The result would be to create a monopoly situation in a previously competitive market for the utility or for the few private companies it may contract with to provide such products or services. In order to prevent injury to competition and to future consumers of these products, the UIEC advocate that to the fullest extent possible, the costs of a DSM program should be recovered from those customers participating in the program and that the practices and policies of the company in offering DSM programs be appropriately monitored to ensure that private competitors offering similar products and services are not adversely affected.

Finally, demand-side resource programs should be treated no differently than supply side resources with respect to the requirement that they be used and useful. So long as a participant in a DSM program bears all of the costs, the question of whether the measure is used and useful need not be satisfied before the program is undertaken. If, however, a non-participant is required to bear any costs of the program, the non-participant must have an opportunity to challenge the prudency of the program at the time the investment is made and at every point at which the decision is made to require a non-participant to bear any of those costs.

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[5] While the PSC does not have explicit jurisdiction to hear antitrust matters, its decisions may immunize PP&L against future antitrust actions. In enacting the recent amendments to the National Energy Policy Act, Congress contemplated that if a state regulatory body implements the federal standards with respect to integrated resource planning and demand-side management, it must "do so in a way that assures that the utility actions would not provide utilities with unfair competitive advantages over small businesses." (H.R. No. 102-474(I) on the Energy Policy Act of 1992.)

Exhibit A

ANALYSIS OF PACIFICORP'S LOST REVENUE PROPOSAL
PREPARED BY
COMMITTEE OF CONSUMER SERVICES

(A) NO RECOVERY OF LOST REVENUE:

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10	YEAR 11	YEAR 12	YEAR 13
LOST MARGIN	($100,000)	($100,000)	($100,000)										
INCOME TAX RATE	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%	40%
NET AVAILABLE FOR RETURN	($60,000)	($60,000)	($60,000)										
NET PRESENT VALUE:	($149,211)												
REVENUE REQUIREMENT:				$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
NET PRESENT VALUE	$461,650												

(B) RECOVERY OF LOST REVENUE AS PROPOSED BY PACIFICORP:

	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10	YEAR 11	YEAR 12	YEAR 13
ADDITIONAL PROGRAM COST:													
BEGINNING BALANCE	$0	$110,000	$231,000										
LOST MARGIN	$100,000	$100,000	$100,000										
INTEREST RATE	10%	10%	10%										
ENDING BALANCE	$110,000	$231,000	$364,100										
REVENUE REQUIREMENT: AMORTIZATION OF LOST REVENUES (10 YRS)				$36,410	$36,410	$36,410	$36,410	$36,410	$36,410	$36,410	$36,410	$36,410	$36,410
NET PRESENT VALUE	$168,087												
GROSS UP FOR INCOME TAX				24,273	24,273	24,273	24,273	24,273	24,273	24,273	24,273	24,273	24,273
TOTAL				$60,683	$60,683	$60,683	$60,683	$60,683	$60,683	$60,683	$60,683	$60,683	$60,683
LOST MARGIN				$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
TOTAL REVENUE REQUIREMENT				$160,683	$160,683	$160,683	$160,683	$160,683	$160,683	$160,683	$160,683	$160,683	$160,683
NET PRESENT VALUE	$741,795												

Exhibit B

ENVIRONMENTAL INTERVENORS LOST REVENUE CRITERIA ANALYSIS

Core Values	Statistical Recoupling	NLRAs	Annual Review/ Status Quo
Acquisition of cost-effective DSM?	Encourages utility to pursue cost-effective DSM	Encourages utility to pursue cost-effective DSM	Discourages utility from pursuing DSM
Acceptable rate impact and volatility?	Should have only limited rate impacts	Should have only limited rate impacts	No impacts until new supply is needed
Amenability to regulatory oversight?	Hard to manipulate; encourages economic development, not load building	Subject to gaming: Encourages load building and high savings estimates	Subject to gaming: encourages load building
Fair Risk sharing?	Leaves weather and economic risks with utility	Leaves weather and economic risks with utility	Leaves weather and economic risks with utility
Micro-Management?	Allows utility to pursue a broad range of DSR activities	Allows utility to pursue easily measured DSR activities	Relies primarily on command and control regulation
Unintended consequences?	Although analysis has been done for many utilities, it's never been tried	Experience in 10 or more states	Environmental and economic consequences are well established

APPENDIX II

DEMAND-SIDE-RESOURCE COLLABORATIVE REPORT

APPENDIX II
PARTICIPANT MATRICES

AUGUST 31, 1993

DEMAND-SIDE-RESOURCE COLLABORATIVE REPORT

APPENDIX II
PARTICIPANT MATRICES

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DSR COLLABORATIVE REPORT
PACIFICORP COST RECOVERY MATRIX

Criteria	Ratebase vs. Expense	Deferral of Amortization	Carrying Charge
1. Does it provide opportunity for recovery of prudently incurred DSR costs?	In order to provide the opportunity for recovery of prudently incurred costs, all DSR program costs should be capitalized over the life of the installed measures. This is consistent with SSR where all costs associated with new construction is capitalized. This also helps spread the costs over all those who will benefit from the programs. This is consistent with the definition of an asset, which should be properly included in ratebase.	In order to provide the opportunity for recovery of prudently incurred costs, the Company should be allowed to defer the amortization of DSR costs, including the carrying charge, until the next general rate case. If the Company is required to amortize DSR costs before the next rate case, it will not have the opportunity to recover these costs in rates.	In order to provide the opportunity for recovery of prudently incurred costs, the Company should be allowed a carrying charge on the unamortized balance. Since these assets should be included in ratebase, the recovery should be at the Company's authorized rate of return. A carrying charge is analogous to the AFUDC calculated during construction of a supply-side resource.
2. Is it performance based?	No Difference between alternatives.	No Difference between alternatives.	No Difference between alternatives.
3. Is it measurable?	No Difference between alternatives.	No Difference between alternatives.	No Difference between alternatives.
4. Is it understandable?	No Difference between alternatives.	No Difference between alternatives.	No Difference between alternatives.
5. Is it administrable?	No Difference between alternatives.	No Difference between alternatives.	No Difference between alternatives.
6. Is it predictable?	No Difference between alternatives.	No Difference between alternatives.	No Difference between alternatives.
7. Does it discourage manipulation (gaming, skimming, gold-plating, etc.)?	No Difference between alternatives.	No Difference between alternatives.	No Difference between alternatives.
8. Does it appropriately share risk between ratepayers and shareholders?	If DSR program costs are expensed rather that ratebased, current ratepayers will be charged with more than their fair share of the costs. In addition, expensing the items before the next rate case when they can be included in rates will unfairly force the shareholders to pay for the DSR programs.	If amortization of DSR program costs is not deferred until the next rate case, the risk of the programs is being shifted to shareholders, who will be forced to absorb the costs without receiving any cost recovery.	The shareholders are entitled to receive a fair return on their investment. Since the DSR costs are a ratebase item, they should be allowed to recover a carrying charged at the Company's authorized rate of return until the next rate case.
9. Is there an equitable allocation of costs and benefits between classes of customers and between participants and non-participants?	No Difference between alternatives.	No Difference between alternatives.	No Difference between alternatives.
10. Does it discourage micro-management?	No Difference between alternatives.	No Difference between alternatives.	No Difference between alternatives.

Criteria	Ratebase vs. Expense	Deferral of Amortization	Carrying Charge
11. Does it have the potential for unintended consequences?	No Difference between alternatives.	No Difference between alternatives.	No Difference between alternatives.
12. Does it promote cost minimization?	No Difference between alternatives.	No Difference between alternatives.	No Difference between alternatives.
13. Does it promote rate stability?	Ratebasing eligible costs would spread the DSR program costs over the life of the programs, and would therefore have the least impact on rate stability. This would also provide for appropriate matching of DSR program costs and benefits.	No Difference between alternatives.	No Difference between alternatives.
14. Does it minimize impact on evaluation?	No Difference between alternatives.	No Difference between alternatives.	No Difference between alternatives.
15. Does it require few changes in practice?	No Difference between alternatives.	Deferring the amortization would require minimal changes. This same methodology is being used by PacifiCorp in other jurisdictions.	The carrying charge is calculated the same as other rate base items.
16. Are there few legal restrictions?	No Difference between alternatives.	In the Company's opinion, there are no legal restrictions on the deferral of DSR program costs. This is consistent with the manner in which Mountain Fuel was allowed to account for their DSR costs, and the method previously used by Utah Power to account for their pilot water heater load control program.	No Difference between alternatives.
17. Does it provide a positive incentive?	Ratebasing DSR program costs does not provide a positive incentive, it only attempts to remove disincentives. Whereas expensing DSR costs items would provide a disincentive.	Deferral of DSR program costs removes a disincentive to DSR investment, but does not provide a positive incentive. Lack of deferral does not remove the current disincentives to DSR investments.	A carrying charge is not designed to produce a positive incentive, but to allow the Company to earn its authorized rate of return on DSR costs. It is necessary to remove DSR disincentives.
18. Does it give the Company an incentive to operate efficiently?	No Difference between alternatives.	No Difference between alternatives.	No Difference between alternatives.

PACIFICORP COST RECOVERY MATRIX (Continued)

Criteria	Ratebase vs. Expense	Deferral of Amortization	Carrying Charge
19. Does it reduce the disincentives associated with lost sales?	Not applicable.	Not applicable.	Not applicable.

MATRIX 2

DSR COLLABORATIVE REPORT
PACIFICORP LOST REVENUE TREATMENT MATRIX

Criteria	No Cost Recovery	Annual Reviews	Future Test Period	NLRA	NLRA With Collaborative	Decoupling	Statistical Recoupling
1. Does it provide opportunity for recovery of prudently incurred DSR costs?	These proposals do not provide the Company with the opportunity for recovery of prudently incurred DSR costs.		Using a future test year will provide full recovery if a rate case is filed annually or lost revenues are indexed between rate cases.	These proposals, if properly administered, would provide the Company with the opportunity for recovery of prudently incurred DSR costs.			
2. Is it performance based?	Not Performance Based	No material difference between alternatives.					
3. Is it measurable?	N/A	The Company believes that both the direct measurement of lost revenues required for an annual review or an NLRA, and the development of the statistical recoupling model involve estimates. It is not clear that either set of estimates is more precise than the other.				Decoupling is the hardest to measure due to the complexity of the variables.	See Discussion for annual reviews, NLRA, etc.
4. Is it understandable?	These proposals do not differ significantly in complexity.					Decoupling is the hardest to understand due to its differences from traditional methodologies.	Statistical recoupling would initially be more complex. However, once the recoupling model is in place, its implementation is straight forward
5. Is it administrable?	These proposals do not differ greatly in administrability.					Once the decoupling method is developed, this proposal may have a slight advantage.	Once the recoupling model is developed, this proposal may have a slight advantage.

PACIFICORP LOST REVENUE TREATMENT MATRIX (Continued)

Criteria	No Cost Recovery	Annual Reviews	Future Test Period	NLRA	NLRA With Collaborative	Decoupling	Statistical Recoupling
6. Is it predictable?	No recovery is more predictable, because you would always under-earn on DSR investments	No proposal is clearly more predictable that another since all are based to some extent on estimates.					
7. Does it discourage manipulation (gaming, skimming, gold-plating, etc.)?	This discourages manipulation by discouraging DSR.	The differences in cost recovery proposals have little impact on the opportunities for manipulation. Gaming, skimming and gold-plating must be addressed through stringent DSR program criteria and controls.					
8. Does it appropriately share risk between ratepayers and shareholders?	All or most of the risk is borne by the shareholders.		Assuming adequate DSR program evaluation, these proposals should result in appropriate risk sharing between customers and shareholders.				
9. Is there an equitable allocation of costs and benefits between classes of customers and between participants and non-participants?	None of the proposals specifically address the allocation of costs between customers classes and between participants and non-participants. This is a class cost of service issue which would be dealt with in a general rate case. All of the proposals are consistent with the Company's Energy Service Charge concept which attempts to maximize the level of cost recovery from program participants.						If statistical recoupling is done on a total Company rather than customer class basis it would be more likely to unequitably allocate costs to non-participants
10. Does it discourage micro-management?	This is more an issue in weighing potential DSR program evaluation techniques than in evaluating current proposals.						
11. Does it have the potential for unintended consequences?	The greater the departure from current regulatory practices, the greater the potential for "unintended consequences." These proposals, which differ little from current regulation, are the least likely to have unintended consequences; however, they achieve this at the expense of full cost recovery.			Using an NLRA, without proper oversight and review, would have a little more potential for producing "unintended consequences."		Decoupling and statistical recoupling have the highest possibility of "unintended consequences." This is because they represent the greatest departure from current regulatory practices. Statistical recoupling has never been applied in practice.	

PACIFICORP LOST REVENUE TREATMENT MATRIX (Continued)

Criteria	No Cost Recovery	Annual Reviews	Future Test Period	NLRA	NLRA With Collaborative	Decoupling	Statistical Recoupling
12. Does it promote cost minimization?	There is no difference between proposals.						
13. Does it promote rate stability?	This proposal would have the least impact on rate stability by not allowing the Company full cost recovery.	Rate stability is best achieved when the cost of DSR measures is borne by program participants. These proposals would have minimal impact on rate stability.		Rate stability is best achieved when the cost of DSR measures is borne by program participants. These proposals would require some sort of indexing method or balancing account which, if properly administered, would have minimal impact on rate stability.			
14. Does it minimize impact on evaluation?	Since this proposal would provide no recovery of costs, it would require no additional evaluation.	All of these proposals rely on adequate DSR program evaluation to ensure that only cost-effective programs are implemented.				Decoupling might have lower program evaluation costs because it does not require an explicit calculation of lost revenues.	Statistical Recoupling might have lower program evaluation costs because it does not require an explicit calculation of lost revenues.
15. Does it require few changes in practice?	These proposals differ little from current regulation; however, they achieve this at the expense of full cost recovery.			These proposals differ from current practice to allow the opportunity for full cost recovery		These proposals differ the most from current practice.	
16. Are there few legal restrictions?	PacifiCorp does not believe legality is an issue with any of the proposals described in this document.						

PACIFICORP LOST REVENUE TREATMENT MATRIX (Continued)

Criteria	No Cost Recovery	Annual Reviews	Future Test Period	NLRA	NLRA With Collaborative	Decoupling	Statistical Recoupling
17. Does it provide a positive incentive?	These proposals perpetuate the current disincentives for DSR as compared to SSR.		This proposals does not provide any positive incentive for DSR; However, if used with an NLRA or indexing between rate cases, it could remove the current disincentives to DSR.	These proposals do not provide any positive incentive for DSR; However, they can remove the current disincentives to DSR.			
18. Does it give the Company an incentive to operate efficiently?	As previously mentioned, under any of the cost recovery proposals it is in PacifiCorp's interest to operate efficiently.						
19. **Does it reduce the disincentives associated with lost sales?**	**These options do not remove any of the disincentives associated with lost sales.**		**When used with an index in between rate cases, this option can remove the disincentives associated with lost sales.**	These proposals reduce the disincentives associated with lost sales.			

DSR COLLABORATIVE REPORT
PACIFICORP INCENTIVES MATRIX

Criteria	No Incentive	Shared Savings	Bounty Per Unit Saving	Markup on Expenditures	Adjustment to Overall ROE	Bonus ROE on Ratebased DSR
1. Does it provide opportunity for recovery of prudently incurred DSR costs?	The cost recovery and lost revenue proposals should provide the Company the opportunity for recovery of prudently incurred DSR costs. Therefore, this criteria is not applicable to the incentive proposals.					
2. Is it performance based?	N/A	The Company and shareholders are rewarded for investing in cost-effect DSR programs.	The Company is rewarded for investing in cost-effect DSR programs.	The incentive is based on the level of DSR, and not on efficiency or effectiveness.	The Company is rewarded for investing in cost-effect DSR programs.	The incentive is based on the level of DSR, and not on efficiency or effectiveness.
3. Is it measurable?	N/A	Once defined, all incentive mechanisms are measurable.				
4. Is it understandable?	N/A	Once defined, all incentive mechanisms are understandable.				
5. Is it administrable?	N/A	Once defined, all incentive mechanisms are administrable.				
6. Is it predictable?	N/A	Once defined, all incentive mechanisms are predictable.				
7. Does it discourage manipulation (gaming, skimming, gold-plating, etc.)?	N/A	Manipulation would be unlikely.	Manipulation would be unlikely.	This method would be susceptible to manipulation.	Manipulation would be unlikely.	This method would be susceptible to manipulation.
8. Does it appropriately share risk between ratepayers and shareholders?	N/A	Risk and rewards are shared equally.	Risk is not shared between ratepayers and shareholders.			
9. Is there an equitable allocation of costs and benefits between classes of customers and between participants and non-participants?	N/A	No difference between proposals.				
10. Does it discourage micro-management?	N/A	No significant difference between alternatives				

PACIFICORP INCENTIVES MATRIX (Continued)

Criteria	No Incentive	Shared Savings	Bounty Per Unit Saving	Markup on Expenditures	Adjustment to Overall ROE	Bonus ROE on Ratebased DSR
11. Does it have the potential for unintended consequences?	No	Has a minimal chance for unintended consequences.	May produce unintended consequences.	These are more likely to have unintended consequences than the other proposals.		
12. Does it promote cost minimization?	No difference between alternatives.					
13. Does it promote rate stability?	Yes	This would depend on the level of incentive. It would not be dependant upon the individual proposal.				
14. Does it minimize impact on evaluation?	Yes	Would require little additional evaluation beyond that which is already done.			Could require a significant amount of evaluation, depending on variables.	Would require little if any evaluation.
15. Does it require few changes in practice?	No changes.	No additional changes other than calculating incentive.				
16. Are there few legal restrictions?	None	The Company knows of no legal restrictions on DSR incentive programs.				
17. Does it provide a positive incentive?	No	All incentives, if properly structured, should provide the company with a positive incentive to invest in DSR programs.				
18. Does it give the Company an incentive to operate efficiently?	No change from current methodologies.	Rewards the Company for investing in cost-effect DSR programs.		Could lead to inefficiencies by rewarding the Company for DSR dollars spent, not DSR savings.	Rewards the Company for investing in cost-effect DSR programs.	Could lead to inefficiencies by rewarding the Company for DSR dollars ratebased, not DSR savings.
19. Does it reduce the disincentives associated with lost sales?	Not applicable. The disincentives associated with lost sales should be recovered through a lost revenue mechanism, not through an incentive.					

DSR COLLABORATIVE REPORT
DPU COST RECOVERY MATRIX

Criteria	Ratebase vs. Expense	Deferral of Amortization	Accrue Carrying Charge During Deferral
1. Does it provide opportunity for recovery of prudently incurred DSR costs?	Yes. Ratebase similar to SSR. Yes. Expense dependent upon test year.	Yes. Guarantees cost recovery between cases.	Yes. Guarantees cost recovery between cases.
2. Is it performance based?	No	No	No
3. Is it measurable?	Yes	Yes. Provides opportunity for measurement.	Yes
4. Is it understandable?	Yes	Yes	Yes
5. Is it administrable?	Yes	Yes	Yes
6. Is it predictable?	Ratebase - Very predictable Expense - Less predictable	Not very predictable	Yes
7. Does it discourage manipulation (gaming, skimming, gold-plating, etc.)?	No	Increased manipulation	Encourages manipulation
8. Does it appropriately share risk between ratepayers and shareholders?	Ratebase - Less risk to shareholders Expense - More risk to shareholders	Shareholder risk passed on to ratepayers; no risk to shareholders.	No risk to shareholders.
9. Is there an equitable allocation of costs and benefits between classes of customers and between participants and non-participants?	Ratebase - Increases non-participant costs Expense - Reduces non-participant costs	Increases cost to all.	Increases costs to all.

DPU COST RECOVERY MATRIX (Continued)

MATRIX 1

Criteria	Ratebase vs. Expense	Deferral of Amortization	Accrue Carrying Charge During Deferral
10. Does it discourage micro-management?	Ratebase - Yes Expense - Somewhat	Increases micro-management	No impact
11. Does it have the potential for unintended consequences?	Ratebase - Little Expense - Some potential	Increases potential	Increases potential
12. Does it promote cost minimization?	Ratebase - Somewhat Expense - No	No. Increases costs.	No. Increases costs.
13. Does it promote rate stability?	Ratebase - Yes Expense - No. Promotes instability.		
14. Does it minimize impact on evaluation?	Ratebase - Yes Expense - No	No	No
15. Does it require few changes in practice?	Ratebase - Yes Expense - No. Changes needed.	No. Changes needed.	No. Changes needed.
16. Are there few legal restrictions?	None	Appears illegal; retroactive ratemaking.	Appears illegal
17. Does it provide a positive incentive?	Yes	Yes	Yes
18. Does it give the Company an incentive to operate efficiently?	No	Definitely not	Definitely not

DPU COST RECOVERY MATRIX (Continued)

Criteria	Ratebase vs. Expense	Deferral of Amortization	Accrue Carrying Charge During Deferral
19. Does it reduce the disincentives associated with lost sales?	No	Somewhat reduced	Somewhat reduced

DSR COLLABORATIVE REPORT
DPU LOST REVENUE TREATMENT MATRIX

Criteria	No Cost Recovery	Annual Reviews	Future Test Period	NLRA	NLRA With Collaborative	Decoupling	Statistical Recoupling
1. Does it provide opportunity for recovery of prudently incurred DSR costs?	No. Does not address lost sales.	Partially recognizes lost sales (no automatic rate adjustment).	Partially recognizes lost sales (no automatic rate adjustment).	Full cost recovery. (May also recover imprudent DSR.)	Full cost recovery. (Less likely to recover imprudent DSR.)	Full cost recovery.	Full cost recovery.
2. Is it performance based?	No. Does not address performance.	Not performance based.	Not performance based.	Partially performance based.	Potentially provides lost revenues for only efficient DSR.	Performance based. Removes incentive to build load.	Performance based. Recognizes DSR due to economic development.
3. Is it measurable?	No measurement required.	Requires measuring lost revenues (potentially difficult).	Requires measuring lost revenues (potentially difficult).	Measurement potentially contentious.	Mitigates contentiousness of measurement.	Appears measurable.	Appears measurable.
4. Is it understandable?	Understandable since no action required.	Fairly easy to understand.	Fairly easy to understand.	Not easily understood.	Not easily understood.	Difficult to understand process.	Slightly difficult to understand.
5. Is it administrable?	No administration required.	Fairly easy to administer.	Fairly easy to administer.	Difficult to administer.	Difficult to administer.	Difficult to administer (requires annual reconciliation).	Not excessively difficult to administer (model revised every 3 years).
6. Is it predictable?	Nothing to predict.	Fairly predictable.	Fairly predictable.	Potentially very unpredictable.	Collaborative mitigates unpredictability of NLRA.	Rate impacts not predictable.	Rate impacts appear fairly predictable.
7. Does it discourage manipulation (gaming, skimming, gold-plating, etc.)?	Discourages gaming associated with lost sales.	Limited potential for manipulation of lost sales.	Limited potential for manipulation of lost sales.	Encourages manipulation of lost revenues.	Collaborative diminishes manipulation of NLRA.	Potentially encourages gaming, e.g., customer count.	Little potential for gaming.

DPU LOST REVENUE TREATMENT MATRIX (Continued)

Criteria	No Cost Recovery	Annual Reviews	Future Test Period	NLRA	NLRA With Collaborative	Decoupling	Statistical Recoupling
8. Does it appropriately share risk between ratepayers and shareholders?	Maintains status quo risk.	Little shifting in risk from status quo.	Risk shifting potential associated with FTY as opposed to HTY.	Increases risk on ratepayers.	Potentially diminishes increased risk on ratepayers.	Shifts risk of weather and economy to ratepayers.	Maintains risk sharing of status quo.
9. Is there an equitable allocation of costs and benefits between classes of customers and between participants and non-participants?	No allocation issue for lost revenues.	Likely to result in equitable allocation.	Can potentially result in equitable allocations.	More difficult to achieve equitable allocation.	Collaborative may reduce non-participant impacts due to NLRA.	Rate volatility not likely to result in equitable allocation.	Equitable allocation appears feasible.
10. Does it discourage micro-management?	Yes	Yes	Yes	May encourage micro-management.	May encourage micro-management.	Yes	Yes
11. Does it have the potential for unintended conse-quences?	No unintended consequences.	Unintended consequences not likely.	Unintended consequences not likely.	May result in undesirable load building.	May result in undesirable load building.	RPC decoupling may decrease quality.	Does not appear to result in unintended consequences.
12. Does it promote cost minimization?	No, since does not remove disincentive to implement IRP.	Partially promotes cost minimization.	Partially promotes cost minimization.	Promotes implementation of IRP, but may encourage inefficient DSR.	Promotes implementation of IRP, but may encourage inefficient DSR.	Promotes implementation of IRP, but diminishes cost minimization.	Promotes implementation of IRP; retains current incentive to decrease costs.
13. Does it promote rate stability?	Promotes rate stability.	Generally promotes rate stability.	Generally promotes rate stability.	Potentially increases rate volatility.	Potentially increases rate volatility.	Potentially increases rate volatility.	Appears to promote rate stability.
14. Does it minimize impact on evaluation?	Yes	Does not significantly alter impact on evaluation.	Does not significantly alter impact on evaluation.	Increases contentiousness of evaluation.	Potentially increases contentiousness of evaluation.	Does not significantly alter impact on evaluation.	Does not significantly alter impact on evaluation.

DPU LOST REVENUE TREATMENT MATRIX (Continued)

Criteria	No Cost Recovery	Annual Reviews	Future Test Period	NLRA	NLRA With Collaborative	Decoupling	Statistical Recoupling
15. Does it require few changes in practice?	Maintains status quo (no change).	Not likely to require modification.	Not likely to require modification.	Potentially may require several modifications.	Reduces potential number of modifications.	Potentially requires several modifications.	May require some modification.
16. Are there few legal restrictions?	Status quo (no problem legally).	No legal restrictions.	Potential restriction by Commission.	Potential legal restrictions if deferral or balancing account.	Potential legal restrictions if deferral or balancing account.	Potential legal restriction-balancing account (retroactive).	Potential legal restriction-balancing account (retroactive).
17. Does it provide a positive incentive?	Neither provides positive incentive nor removes disincentive.	Partially removes disincentive.	Partially removes disincentive.	Removes disincentive of lost sales.	Removes disincentive of lost sales.	Removes disincentive of lost sales.	Removes disincentive of lost sales.
18. Does it give the Company an incentive to operate efficiently?	Company may not implement IRP due to lost sales.	Partial incentive to operate efficiently.	Partial incentive to operate efficiently.	Incentive to implement IRP, but may also have incentive to inefficiently increase sales.	Incentive to implement IRP, but also incentive to inefficiently increase sales.	Incentive to implement IRP; reduce incentive to minimize costs.	Incentive to implement IRP and to reduce costs.
19. Does it reduce the disincentives associated with lost sales?	Does not reduce incentive.	Partially removes disincentive.	Partially removes disincentive.	Removes disincentive.	Removes disincentive.	Removes disincentive.	Removes disincentive.

DSR COLLABORATIVE REPORT
DPU INCENTIVES MATRIX

Criteria	No Incentive	Shared Savings	Bounty Per Unit Saving	Markup on Expenditures	Adjustment to Overall ROE	Bonus ROE on Ratebased DSR
1. Does it provide opportunity for recovery of prudently incurred DSR costs?	Not applicable.	Exceeds cost recovery.	Exceeds cost recovery.	Exceeds cost recovery.	Exceeds cost recovery.	Exceeds cost recovery.
2. Is it performance based?	No	Highly performance based; encourages cost-effective DSR.	Does not necessarily encourage cost-effective DSR.	Does not encourage investment in DSR with greatest savings.	Indirectly performance based.	Potentially performance based.
3. Is it measurable?	No measurement required.	Measurable-requires determining energy and demand savings.	Measurable-requires determining energy and demand savings.	Easily measured.	Easily measured.	Easily measured.
4. Is it understandable?	Understandable-no action required.	Easily understandable (intuitive).	Understandable	Understandable	Understandable	Understandable
5. Is it administrable?	No administration required.	Administered with moderate difficulty.	Administered with moderate difficulty.	Easily administered.	Easily administered.	Easily administered.
6. Is it predictable?	No prediction required.	Fairly predictable.	Fairly predictable.	Easily predicted.	Easily predicted.	Easily predicted.
7. Does it discourage manipulation (gaming, skimming, gold-plating, etc.)?	No incentive to game.	Discourages gaming.	May encourage gold-plating.	Encourages gold-plating.	May encourage gold-plating.	May encourage gold-plating.
8. Does it appropriately share risk between ratepayers and shareholders?	Maintains status quo risk.	Can easily structure risk sharing as desired.	Increases risk to ratepayers.	Potentially increases risk to ratepayers.	Potentially increases risk to ratepayers.	Potentially increases risk to ratepayers.
9. Is there an equitable allocation of costs and benefits between classes of customers and between participants and non-participants?	No allocation issue, since no incentive.	Likely to result in equitable allocation.	More difficult to achieve equitable allocation.	More difficult to achieve equitable allocation.	More difficult to achieve equitable allocation.	More difficult to achieve equitable allocation.

Criteria	No Incentive	Shared Savings	Bounty Per Unit Saving	Markup on Expenditures	Adjustment to Overall ROE	Bonus ROE on Ratebased DSR
10. Does it discourage micro-management?	Yes	Potentially increases micro-management slightly.	Potentially increases micro-management slightly.	Potentially increases micro-management slightly.	Yes	Yes
11. Does it have the potential for unintended consequences?	No unintended consequences.	Little potential for unintended consequences.	Some potential for unintended consequences.	Significant potential for unintended consequences.	Some potential for unintended consequences.	Some potential for unintended consequences.
12. Does it promote cost minimization?	If an incentive is necessary, this does not promote cost minimization.	Yes. Encourages implementation if IRP (i.e., investment in cost-effective DSR).	May promote cost minimization <u>if</u> invest only in cost-effective DSR.	No. Encourages expenditures on <u>non</u> cost-effective DSR.	No, <u>if</u> gold-plating occurs.	No, <u>if</u> gold-plating occurs.
13. Does it promote rate stability?	Yes	Upward pressure on rates.	Upward pressure on rates.	Upward pressure on rates.	Upward pressure on rates.	Upward pressure on rates.
14. Does it minimize impact on evaluation?	Yes	Potentially increases contentiousness of evaluation.	Potentially increases contentiousness of evaluation.	Does not significantly alter impact on evaluation.	Does not significantly alter impact on evaluation.	Does not significantly alter impact on evaluation.
15. Does it require few changes in practice?	Maintains status quo (no change).	Potentially requires several modifications.	Potentially requires several modifications.	Potentially requires several modifications.	Not likely to require modification.	Not likely to require modification.
16. Are there few legal restrictions?	Status quo (no problem legally).	Potentially no problem legally (depends on mechanism).	Potentially no problem legally (depends on mechanism).	No problem legally.	No problem legally.	No problem legally.
17. Does it provide a positive incentive?	No	Yes	Yes	Yes	Yes	Yes

DPU INCENTIVES MATRIX (Continued)

Criteria	No Incentive	Shared Savings	Bounty Per Unit Saving	Markup on Expenditures	Adjustment to Overall ROE	Bonus ROE on Ratebased DSR
18. Does it give the Company an incentive to operate efficiently?	Not clear incentive is necessary to operate efficiently.	Yes. Incentive to invest in cost-effective DSR.	May encourage inefficient investment in DSR.	No. Encourages expenditures on DSR not investment in DSR with greatest savings.	May encourage inefficient investment in DSR.	May encourage inefficient investment in DSR.
19. Does it reduce the disincentives associated with lost sales?	No	Mitigates disincentive of lost sales.	Mitigates disincentive of lost sales.	Mitigates disincentive of lost sales.	Mitigates disincentive of lost sales.	Mitigates disincentive of lost sales.

DSR COLLABORATIVE REPORT
ENVIRONMENTAL INTERVENORS COST RECOVERY MATRIX

Criteria	Ratebase vs. Expense	Deferral of Amortization	Accrue Carrying Charge During Deferral
1. Does it provide opportunity for recovery of prudently incurred DSR costs?	Yes. We prefer ratebasing of costs.	Yes. Without deferral, utility cannot recover its costs.	Yes
2. Is it performance based?	Yes	Yes	Yes
3. Is it measurable?	Yes. Same as supply side.	Yes	Yes
4. Is it understandable?	Yes. Same as supply side.	Yes	Yes
5. Is it administrable?	Yes. Same as supply side.	Yes	Yes
6. Is it predictable?	Yes. Same as supply side.	Yes	Yes
7. Does it discourage manipulation (gaming, skimming, gold-plating, etc.)?	Yes. Same as supply side.	Yes	Yes
8. Does it appropriately share risk between ratepayers and shareholders?	Yes	Yes	Yes
9. Is there an equitable allocation of costs and benefits between classes of customers and between participants and non-participants?	Yes	Yes. Without deferral, utility does not recovery its costs.	Yes

ENVIRONMENTAL INTERVENORS COST RECOVERY MATRIX (Continued)

Criteria	Ratebase vs. Expense	Deferral of Amortization	Accrue Carrying Charge During Deferral
19. Does it reduce the disincentives associated with lost sales?	No	No	No

ENVIRONMENTAL INTERVENORS COST RECOVERY MATRIX (Continued)

Criteria	Ratebase vs. Expense	Deferral of Amortization	Accrue Carrying Charge During Deferral
10. Does it discourage micro-management?	Yes	Yes	Yes
11. Does it have the potential for unintended consequences?	Not really	Not really	Not really
12. Does it promote cost minimization?	Yes. Allows for DSR expenditures which are at least cost.	Yes. Allows for DSR expenditures which are at least cost.	Yes. Allows for DSR expenditures which are at least cost.
13. Does it promote rate stability?	Yes	Yes	Yes
14. Does it minimize impact on evaluation?	Yes	Yes	Yes
15. Does it require few changes in practice?	Yes	Yes	Yes
16. Are there few legal restrictions?	Yes	Yes	Yes
17. Does it provide a positive incentive?	Yes	Yes	Yes
18. Does it give the Company an incentive to operate efficiently?	Yes	Yes	Yes

DSR COLLABORATIVE REPORT

ENVIRONMENTAL INTERVENORS LOST REVENUE TREATMENT MATRIX

Criteria	No Cost Recovery	Annual Reviews	Future Test Period	NLRA	NLRA With Collaborative	Decoupling	Statistical Recoupling
1. Does it provide opportunity for recovery of prudently incurred DSR costs?	No	No	No	No	No	No	No
2. Is it performance based?							Yes
3. Is it measurable?							Yes
4. Is it understandable?							Yes
5. Is it administrable?				No	Yes		Yes
6. Is it predictable?							Yes
7. Does it discourage manipulation (gaming, skimming, gold-plating, etc.)?				No	Yes		Yes
8. Does it appropriately share risk between ratepayers and shareholders?				Yes	Yes	No	Yes
9. Is there an equitable allocation of costs and benefits between classes of customers and between participants and non-participants?				Yes	Yes	Yes	Yes

ENVIRONMENTAL INTERVENORS LOST REVENUE TREATMENT MATRIX (Continued) MATRIX 2

Criteria	No Cost Recovery	Annual Reviews	Future Test Period	NLRA	NLRA With Collaborative	Decoupling	Statistical Recoupling
10. Does it discourage micro-management?				No	No	Yes	Yes
11. Does it have the potential for unintended consequences?				Yes	No	Some	Some
12. Does it promote cost minimization?				Yes	Yes	Yes	Yes
13. Does it promote rate stability?							Yes
14. Does it minimize impact on evaluation?				No	No	Yes	Yes
15. Does it require few changes in practice?				Yes	Yes	Yes	Yes
16. Are there few legal restrictions?				Yes	Yes	Yes	Yes
17. Does it provide a positive incentive?	No	No	No	No	No	No	No
18. Does it give the Company an incentive to operate efficiently?	No	No	No	No	No	No	No

ENVIRONMENTAL INTERVENORS LOST REVENUE TREATMENT MATRIX (Continued)

Criteria	No Cost Recovery	Annual Reviews	Future Test Period	NLRA	NLRA With Collaborative	Decoupling	Statistical Recoupling
19. Does it reduce the disincentives associated with lost sales?	No	No	No	Yes	Yes	Yes	Yes

DSR COLLABORATIVE REPORT
ENVIRONMENTAL INTERVENORS INCENTIVES MATRIX

Criteria	No Incentive	Shared Savings	Bounty Per Unit Saving	Markup on Expenditures	Adjustment to Overall ROE	Bonus ROE on Ratebased DSR
1. Does it provide opportunity for recovery of prudently incurred DSR costs?	No	No	No	No	No	No
2. Is it performance based?		Yes	Yes	No	Yes	Yes
3. Is it measurable?		Yes	Yes	Yes	Yes	Yes
4. Is it understandable?		Yes	Yes	Yes	Yes	Yes
5. Is it administrable?		Yes	Yes	Yes	Yes	Yes
6. Is it predictable?		Yes	Yes	Yes	Yes	Yes
7. Does it discourage manipulation (gaming, skimming, gold-plating, etc.)?		Yes	No	No	No	No
8. Does it appropriately share risk between ratepayers and shareholders?		Yes	Yes	Yes	Yes	Yes
9. Is there an equitable allocation of costs and benefits between classes of customers and between participants and non-participants?		Yes	Yes	Yes	Yes	Yes

ENVIRONMENTAL INTERVENORS INCENTIVES MATRIX (Continued)

Criteria	No Incentive	Shared Savings	Bounty Per Unit Saving	Markup on Expenditures	Adjustment to Overall ROE	Bonus ROE on Ratebased DSR
10. Does it discourage micro-management?		Yes	Yes	Yes	Yes	Yes
11. Does it have the potential for unintended consequences?		No	Maybe	Yes. Encourages spending, not savings.	Yes. Encourages spending, not savings.	Yes. Encourages spending, not savings.
12. Does it promote cost minimization?		Yes	Yes	No	No	No
13. Does it promote rate stability?		Yes	Yes	Yes	Yes	Yes
14. Does it minimize impact on evaluation?		Yes	Yes	No	No	No
15. Does it require few changes in practice?		Yes	Yes	Yes	Yes	Yes
16. Are there few legal restrictions?		Yes	Yes	Yes	Yes	Yes
17. Does it provide a positive incentive?		Yes	Yes	Yes	Yes	Yes
18. Does it give the Company an incentive to operate efficiently?		Yes	Yes	No	No	No

ENVIRONMENTAL INTERVENORS INCENTIVES MATRIX (Continued)

Criteria	No Incentive	Shared Savings	Bounty Per Unit Saving	Markup on Expenditures	Adjustment to Overall ROE	Bonus ROE on Ratebased DSR
19. Does it reduce the disincentives associated with lost sales?		No	No	No	No	No

DSR COLLABORATIVE REPORT
DNR COST RECOVERY MATRIX

Criteria	Ratebase vs. Expense	Deferral of Amortization	Accrue Carrying Charge During Deferral
1. Does it provide opportunity for recovery of prudently incurred DSR costs?	Ratebase: Yes Expense: difficult to account for ramping up of programs	Yes; because DSR by definition does not produce a revenue stream which could be used to offset unrecovered program costs between rate cases. Deferral of amortization is necessary to ensure opportunity for full cost recovery.	Yes; at AFUDC rate.
2. Is it performance based?	Can be based on performance.	Can be based on performance.	Can be based on performance.
3. **Is it measurable?**	Yes	Yes	Yes
4. Is it understandable?	Yes	Yes	Yes
5. Is it administrable?	Yes	Yes	Yes
6. Is it predictable?	Can be if guidelines for eligibility are established.	Can be if guidelines for eligibility are established.	Can be if guidelines for eligibility are established.
7. Does it discourage manipulation (gaming, skimming, gold-plating, etc.)?	Without performance requirements for eligibility, gold-plating would be advantageous to Company.	Without performance requirements for eligibility, gold-plating would be advantageous to Company.	Without performance requirements for eligibility, gold-plating would be advantageous to Company.
8. Does it appropriately share risk between ratepayers and shareholders?	Yes; if performance based ratepayers pay for cost effective resource. No; if not performance based, ratepayers bear all risk.	Yes; if performance based ratepayers pay for cost effective resource. No; if not performance based, ratepayers bear all risk.	Yes; if performance based ratepayers pay for cost effective resource. No; if not performance based, ratepayers bear all risk.
9. Is there an equitable allocation of costs and benefits between classes of customers and between participants and non-participants?	To be determined in a rate case.	To be determined in a rate case.	To be determined in a rate case.

Criteria	Ratebase vs. Expense	Deferral of Amortization	Accrue Carrying Charge During Deferral
10. Does it discourage micro-management?	Yes; mechanism is not burdensome.	Yes; mechanism is not burdensome.	Yes; mechanism is not burdensome.
11. Does it have the potential for unintended consequences?	Only to extent that eligibility standards are not clear.	Only to extent that eligibility standards are not clear.	Only to extent that eligibility standards are not clear.
12. Does it promote cost minimization?	Yes; mechanism provides opportunity to recover DSR program costs which lead to implementation of IRP.	Yes; mechanism provides opportunity to recover DSR program costs which lead to implementation of IRP.	Yes; mechanism provides opportunity to recover DSR program costs which lead to implementation of IRP.
13. Does it promote rate stability?	Ratebase does. Expensing could be lumpy.	Ratebase does. Expensing could be lumpy.	Ratebase does. Expensing could be lumpy.
14. Does it minimize impact on evaluation?	Impact on evaluation will be minimized if no performance requirements; however, establishing performance requirements will have insignificant impact on current evaluation efforts.	N/A	N/A
15. Does it require few changes in practice?	Yes	Yes	Yes
16. Are there few legal restrictions?	Yes	?	Yes
17. Does it provide a positive incentive?	No; it removes disincentive.	No; it removes disincentive.	No; it removes disincentive.
18. Does it give the Company an incentive to operate efficiently?	It does not alter current ratemaking incentives; uneconomic load building is still encouraged.	It does not alter current ratemaking incentives; uneconomic load building is still encouraged.	It does not alter current ratemaking incentives; uneconomic load building is still encouraged.
19. Does it reduce the disincentives associated with lost sales?	No	No	No

DSR COLLABORATIVE REPORT

DNR LOST REVENUE TREATMENT MATRIX

Criteria	No Cost Recovery	Annual Reviews	Future Test Period	NLRA	NLRA With Collaborative	Decoupling	Statistical Recoupling
1. Does it provide opportunity for recovery of prudently incurred DSR costs?	N/A. Does not address direct program costs.	N/A. Does not address direct program costs.	N/A. Does not address direct program costs.	N/A. Does not address direct program costs.	N/A. Does not address direct program costs.	N/A. Does not address direct program costs.	N/A. Does not address direct program costs.
2. Is it performance based?	No	No	No	No	Yes	Yes	Yes
3. Is it measurable?	N/A	?	Difficult	Difficult	Yes	Yes	Yes
4. Is it understandable?	Yes	Yes	Yes	Yes	Yes	Yes	Yes
5. Is it administrable?	Yes	Yes	Maybe	Maybe	Yes, but a lot of work.	Yes	Yes
6. Is it predictable?	Yes	No	No	No	Yes	No	Yes
7. Does it discourage manipulation (gaming, skimming, gold-plating, etc.)?	No	No	No	No	Yes; if targets set.	unclear	Yes
8. Does it appropriately share risk between ratepayers and shareholders?	No, risk is on shareholders.	Yes	No; unclear.	Yes	Yes	Yes	Yes
9. Is there an equitable allocation of costs and benefits between classes of customers and between participants and non-participants?	N/A. To be decided in rate case.	N/A. To be decided in rate case.	N/A. To be decided in rate case.	N/A. To be decided in rate case.	N/A. To be decided in rate case.	N/A. To be decided in rate case.	N/A. To be decided in rate case.

DNR LOST REVENUE TREATMENT MATRIX (Continued)

Criteria	No Cost Recovery	Annual Reviews	Future Test Period	NLRA	NLRA With Collaborative	Decoupling	Statistical Recoupling
10. Does it discourage micro-management?	No; since regulatory incentive is unclear, it will require greater regulatory oversight to determine results of DSR.	No; since regulatory incentive is unclear, it will require greater regulatory oversight to determine results of DSR.	No; since regulatory incentive is unclear, it will require greater regulatory oversight to determine results of DSR.	No; since regulatory incentive is unclear, it will require greater regulatory oversight to determine results of DSR.	No; requires considerable participation by all parties.	?	Yes
11. Does it have the potential for unintended conse-quences?	Yes; could lead to underinvest-ment in IRP	Yes	Yes	Yes	No; with targets set.	Yes	Yes
12. Does it promote cost minimization?	No; mechanism does not address prompt reconciliation of DSR disincentives and therefore does not promote IRP.	No; mechanism does not address prompt reconciliation of DSR disincentives and therefore does not promote IRP.	No; mechanism does not address prompt reconciliation of DSR disincentives and therefore does not promote IRP.	No; mechanism does not address prompt reconciliation of DSR disincentives and therefore does not promote IRP.	Yes	Unclear	Yes
13. Does it promote rate stability?	Yes; in short-run. No in long-run.	Yes; in short-run. No in long-run.	Yes; in short-run. No in long-run.	No	Yes, with caps on NLRA amount.	Unclear	Yes
14. Does it minimize impact on evaluation?	Yes	Yes	No	No	No	Yes	Yes
15. Does it require few changes in practice?	Yes; virtually none.	Yes; virtually none.	Yes; change in regulatory policy.	Yes; minor change in accounting.	Yes; minor change in accounting.	Yes; minor change in accounting.	Yes; minor change in creation of rider.
16. Are there few legal restrictions?	Yes	Yes	?	?	?	?	?

DNR LOST REVENUE TREATMENT MATRIX (Continued)

Criteria	No Cost Recovery	Annual Reviews	Future Test Period	NLRA	NLRA With Collaborative	Decoupling	Statistical Recoupling
17. Does it provide a positive incentive?	No; a negative one.	No; a negative one.	No; a negative one.	Possibly; if not performance based.	No; removes disincentive.	No; removes disincentive.	No; removes disincentive.
18. Does it give the Company an incentive to operate efficiently?	No; does not encourage implementation of IRP.	No; does not encourage implementation of IRP.	No; does not encourage implementation of IRP.	No; retains current incentive to increase load.	No; unless net of uneconomic load building.	Yes	Yes
19. Does it reduce the disincentives associated with lost sales?	No	No	No	Yes	Yes	Yes	Yes

DSR COLLABORATIVE REPORT
DNR INCENTIVES MATRIX

Criteria	No Incentive	Shared Savings	Bounty Per Unit Saving	Markup on Expenditures	Adjustment to Overall ROE	Bonus ROE on Ratebased DSR
1. Does it provide opportunity for recovery of prudently incurred DSR costs?	N/A. May not effect recovery of direct costs.	N/A. May not effect recovery of direct costs.	N/A. May not effect recovery of direct costs.	N/A. May not effect recovery of direct costs.	N/A. May not effect recovery of direct costs.	N/A. May not effect recovery of direct costs.
2. Is it performance based?	No	Yes	Does not address cost effective acquisition, but can address savings targets.	No; based on costs only.	Yes; if tied to performance standards.	Maybe
3. Is it measurable?	N/A	Yes	Yes	Yes	Yes	Yes
4. Is it understandable?	Yes	Yes	Yes	Yes	Yes	Yes
5. Is it administrable?	Yes	Yes	Yes	Yes	Yes	Yes
6. Is it predictable?	No; absent lost revenue treatment, utility behavior with respect to DSR and IRP is uncertain.	Yes	Yes	Yes	Yes	Yes
7. Does it discourage manipulation (gaming, skimming, gold-plating, etc.)?	No	Yes; possible cream skimming in short run. Needs targets.	No; cream skimming would be attractive.	No; gold plating would be attractive.	Yes, if tied to performance standards.	Yes, if tied to performance standards.
8. Does it appropriately share risk between ratepayers and shareholders?	N/A	Yes	Yes	May shift costs to ratepayer.	May shift costs to ratepayer.	May shift from shareholder to ratepayer.

DNR INCENTIVES MATRIX (Continued)

Criteria	No Incentive	Shared Savings	Bounty Per Unit Saving	Markup on Expenditures	Adjustment to Overall ROE	Bonus ROE on Ratebased DSR
9. Is there an equitable allocation of costs and benefits between classes of customers and between participants and non-participants?	N/A. To be determined in a rate case.	N/A. To be determined in a rate case.	N/A. To be determined in a rate case.	N/A. To be determined in a rate case.	N/A. To be determined in a rate case.	N/A. To be determined in a rate case.
10. Does it discourage micro-management?	Yes	Yes	Yes	Yes	Yes	Yes
11. Does it have the potential for unintended consequences?	Yes; if no treatment of lost revenues may discourage implementation of IRP.	No	None outside of those mentioned under "gaming".	None outside of those mentioned under "gaming".	None outside of those mentioned under "gaming".	None outside of those mentioned under "gaming".
12. Does it promote cost minimization?	No	Yes	Uncertain	No	No	No
13. Does it promote rate stability?	Promotes status quo.	If successful, yes.	Can be structured to promote rate stability.	Can be structured to promote rate stability.	Can be structured to promote rate stability.	Can be structured to promote rate stability.
14. Does it minimize impact on evaluation?	Yes	Yes; Increase in current effort is small.	Yes	Yes	Yes	Yes
15. Does it require few changes in practice?	Yes	Yes	Yes	Yes	Yes	Yes
16. Are there few legal restrictions?	Yes	Yes	Yes	Yes	Yes	Yes
17. Does it provide a positive incentive?	No	Yes; to achieve cost-effective savings.	Yes; to produce savings.	Yes; to spend money on DSR.	Yes	Yes

DNR INCENTIVES MATRIX (Continued)

Criteria	No Incentive	Shared Savings	Bounty Per Unit Saving	Markup on Expenditures	Adjustment to Overall ROE	Bonus ROE on Ratebased DSR
18. Does it give the Company an incentive to operate efficiently?	No; if lost revenues are not addressed.	Yes	Maybe	No	Maybe, if performance based.	If performance based.
19. Does it reduce the disincentives associated with lost sales?	No	Could, although not explicit.	Could, although not explicit.	Could, although not explicit.	Could, although not explicit.	Could, although not explicit.

DSR COLLABORATIVE REPORT
DG&T COST RECOVERY MATRIX

Criteria	Ratebase vs. Expense	Deferral of Amortization	Accrue Carrying Charge During Deferral
1. Does it provide opportunity for recovery of prudently incurred DSR costs?	Would like ability to Expense or Ratebase as appropriate. Deseret would expense unless expensing would cause adverse rate increases.	Presently not necessary.	Presently not necessary.
2. Is it performance based?	Same for Ratebase or Expense.	Not applicable.	Not applicable.
3. Is it measurable?	Immaterial to whether Ratebased or Expensed.	Immaterial to question.	Immaterial to question.
4. Is it understandable?	Both are regularly performed by utilities and are equally understood.	Adds some complexity but not significantly.	Adds some complexity but not significantly. authorized rate of return can be difficult to understand.
5. Is it administrable?	Equal	A little more complicated to administer.	More complicated to administer but not significantly so.
6. Is it predictable?	Immaterial to whether Ratebased or Expensed.	Immaterial to question.	Immaterial to question.
7. Does it discourage manipulation (gaming, skimming, gold-plating, etc.)?	Maybe. Expensing is least likely to cause gaming.	Adds some potential for manipulation but not significantly.	More potential for manipulation versus expensing.
8. Does it appropriately share risk between ratepayers and shareholders?	Not applicable	Not applicable.	Not applicable.
9. Is there an equitable allocation of costs and benefits between classes of customers and between participants and non-participants?	No. Ratebasing may cause costs to non-participants favoring participants.	May favor participants if spread over non-participants.	Carrying charges may favor participants if spread over non-participants.
10. Does it discourage micro-management?	If not properly done, Ratebase could have some micro-management.	May cause some if not properly administered.	May cause some if not properly administered.

DG&T COST RECOVERY MATRIX (Continued)

Criteria	Ratebase vs. Expense	Deferral of Amortization	Accrue Carrying Charge During Deferral
11. Does it have the potential for unintended consequences?	Expensing may cause more fluctuation in rates. Ratebasing is more rate stabilizing although it is slightly more expensive.	Presently not needed.	Adds to cost of DSM measures.
12. Does it promote cost minimization?	Expensing has lower overhead cost. Ratebasing is slightly more expensive.	Some cost to administer.	A carrying charge adds to the cost of DSM measures
13. Does it promote rate stability?	Ratebasing helps with rate stabilization.	Delays potential rate cases but the rate increases will be larger.	Adds cost to DSM measures and may cause higher rate increases.
14. Does it minimize impact on evaluation?	Evaluation is equivalent.	Not applicable.	Not applicable.
15. Does it require few changes in practice?	Equivalent	Requires a few changes but not significant.	Requires a few changes but not significant.
16. Are there few legal restrictions?	No	Maybe	Maybe
17. Does it provide a positive incentive?	Equivalent	None	None
18. Does it give the Company an incentive to operate efficiently?	Not applicable.	Not applicable.	Some disincentive to operate efficiently by increasing cost of DSM.
19. Does it reduce the disincentives associated with lost sales?	No difference.	No difference.	No difference.

DSR COLLABORATIVE REPORT
DG&T LOST REVENUE TREATMENT MATRIX

Criteria	No Cost Recovery	Annual Reviews	Future Test Period	NLRA	NLRA With Collaborative	Decoupling	Statistical Recoupling
1. Does it provide opportunity for recovery of prudently incurred DSR costs?	No	Yes	Yes	Yes	Yes	Yes	Yes
2. Is it performance based?	No	Yes	No	Yes	Yes	No	No
3. Is it measurable?	Not applicable.	Annual measurement can be done but it is very expensive.	All forecast.	Yes, but is subject to debate.	Yes, but is subject to debate.	No	No
4. Is it understandable?	Not applicable.	Very complex, making it very difficult for average consumer to understand.					
5. Is it administrable?	Not applicable.	Complexity increases administration costs.					
6. Is it predictable?	Not applicable.	Yes	Subject to substantial errors.	Yes	Yes	Yes	Yes
7. Does it discourage manipulation (gaming, skimming, gold-plating, etc.)?	Yes	Yes	No, may encourage manipulation.	No	No	No	No
8. Does it appropriately share risk between ratepayers and shareholders?	Not applicable.	Not applicable.	Not applicable.	Not applicable.	Not applicable.	Not applicable.	Not applicable.
9. Is there an equitable allocation of costs and benefits between classes of customers and between participants and non-participants?	Yes	Measurement can be expensive, which may add costs to non-participants.	May bring additional costs to non-participants.	May add to the cost of non-participants.	May add to the costs of non-participants.	May cause increase cost to non-participants.	May cause cost to non-participants.

DG&T LOST REVENUE TREATMENT MATRIX (Continued)

Criteria	No Cost Recovery	Annual Reviews	Future Test Period	NLRA	NLRA With Collaborative	Decoupling	Statistical Recoupling
10. Does it discourage micro-management?	Yes	No	No	No	No	No	No
11. Does it have the potential for unintended conse-quences?	Yes	Yes	Yes	Yes	Yes	Yes	Yes
12. Does it promote cost minimization?	Yes	No. Increases the cost of administering DSR measures.	No	No	No	No	No
13. Does it promote rate stability?	Yes	No	No	No	No	No	No
14. Does it minimize impact on evaluation?	Yes	No	No	No	No	No	No
15. Does it require few changes in practice?	Yes	Yes	No	No	No	No	No
16. Are there few legal restrictions?	Yes	Yes	Maybe	Maybe	Maybe	Maybe	Maybe
17. Does it provide a positive incentive?	No	No	Maybe	Maybe	Maybe	Maybe	Maybe
18. Does it give the Company an incentive to operate efficiently?	Not applicable.	Not applicable.	Not applicable.	Not applicable.	Not applicable.	Not applicable.	Not applicable.
19. Does it reduce the disincentives associated with lost sales?	No	Maybe	Maybe	Yes	Yes	Maybe	Maybe

DSR COLLABORATIVE REPORT
DG&T INCENTIVES MATRIX

Criteria	No Incentive	Shared Savings	Bounty Per Unit Saving	Markup on Expenditures	Adjustment to Overall ROE	Bonus ROE on Ratebased DSR
1. Does it provide opportunity for recovery of prudently incurred DSR costs?	Incentives are not applicable. Therefore, this incentive matrix was not answered.					
2. Is it performance based?						
3. Is it measurable?						
4. Is it understandable?						
5. Is it administrable?						
6. Is it predictable?						
7. Does it discourage manipulation (gaming, skimming, gold-plating, etc.)?						
8. Does it appropriately share risk between ratepayers and shareholders?						
9. Is there an equitable allocation of costs and benefits between classes of customers and between participants and non-participants?						

DG&T INCENTIVES MATRIX (Continued)

Criteria	No Incentive	Shared Savings	Bounty Per Unit Saving	Markup on Expenditures	Adjustment to Overall ROE	Bonus ROE on Ratebased DSR
10. Does it discourage micro-management?						
11. Does it have the potential for unintended consequences?						
12. Does it promote cost minimization?						
13. Does it promote rate stability?						
14. Does it minimize impact on evaluation?						
15. Does it require few changes in practice?						
16. Are there few legal restrictions?						
17. Does it provide a positive incentive?						
18. Does it give the Company an incentive to operate efficiently?						
19. Does it reduce the disincentives associated with lost sales?						

DSR COLLABORATIVE REPORT
UIEC MATRIX POSITION

The UIEC have declined to participate in this part of the Report because they do not believe that meaningful responses to these issues can be formulated in this format.

APPENDIX III

DEMAND-SIDE-RESOURCE COLLABORATIVE REPORT

APPENDIX III
PARTICIPANT ENERGY POLICY ACT RECOMMENDATIONS

AUGUST 31, 1993

DEMAND SIDE RESOURCE
COLLABORATIVE REPORT

APPENDIX III
PARTICIPANT ENERGY POLICY ACT RECOMMENDATIONS

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I. PACIFICORP

Pacificorp believes that adoption of the Federal standard for investments in conservation and demand management is unnecessary and that the public interest would be best served if the Utah Commission were to adopt DSR cost recovery standards which are specifically tailored to fit the unique circumstances and needs of Utah customers and the utilities who serve them. PacifiCorp supports the collaborative process initiated by the Commission through the recently concluded series of DSR Technical Conferences. The Company believes that continuation of this collaborative effort will be an important element of the process through which an appropriate Utah-specific DSR cost recovery policy will ultimately be established by the Commission.

III. ENVIRONMENTAL INTERVENORS

EPACT 16 U.S.C. § 2621, Sec. 111

The Environmental Intervenors believe that the standard embodied in the Energy Policy Act of 1992, § 2621, Sec. 111(8) is good public policy and urges the Utah Public Service Commission to adopt it.

Under the 1992 Amendments to the Public Utilities Regulatory Policies Act, it states Public Utility Commissions are required to consider whether or not to adopt the following standard:

> The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investment in and expenditures for conservation and efficiency, as its investments in and expenditures for the construction of new generation, transmission, and distribution equipment. Such energy conservation, energy efficiency resources and other demand-side management measures shall be appropriately monitored and evaluated.

Existing regulation in Utah contains incentives that are inconsistent with PacifiCorp's least-cost plan. More specifically, for every kwh saved through a cost-effective investment in energy efficiency, PacifiCorp will lose revenues and profits. In contrast, supply-side investments provide PacifiCorp with a full opportunity to earn its allowed rate of return. As a result of these financial incentives, we believe that PacifiCorp has been reluctant to take advantage of the economic and environmental benefits of energy efficiency.

To address this problem, the Commission established Docket No. 92-2035-04. As a result of this docket, a number of parties will likely endorse a joint recommendation which creates an incentive mechanism that meets the above Federal standards. We believe this joint recommendation is good public policy and begins to address the fundamental incentive distortions that exist under current regulation.

Nevertheless, this joint recommendation is not a substitute for an overall policy statement like the Federal standard. The joint recommendation is only an initial step in addressing the underlying problem. As such, it would be useful for the Commission to state its commitment to sustaining the start made in the joint recommendation.

By adopting the above standard, the Commission will be endorsing a standard that encourages PacifiCorp to implement its least-cost plan. Moreover, this standard is likely, in some sense, to codify and sustain the joint recommendation developed by many of the parties to Docket 92-2035-04. Finally, this standard in no way compromises the ability of the parties to address these incentive issues in a careful and considered manner. Accordingly, we urge the Commission to adopt this standard.

IV. UTAH INDUSTRIAL ENERGY CONSUMERS

The National Energy Policy Act requires state Public Service Commissions to consider, but not necessarily to adopt, standards with respect to investments in conservation and demand-side management. The suggested standard requires regulatory treatment such that investment in energy conservation and load management programs becomes "at least as profitable" as prudent investment in the acquisition or construction of supply-side facilities. This standard suggests that (a) regulators link the utility's net revenues, at least in part, to the utility's performance in implementing cost-effective programs promoted by this section; and (b) regulators insure that for purposes of recovery of fixed costs, including its authorized return, the utility's performance is not affected by reductions in its retail sales volume.

The UIEC have advocated that demand-side resources be treated like supply-side resources for purposes of cost recovery. Base rate recovery of DSR expenses and an opportunity for the Company to file a rate case to recover DSR expenses is consistent with supply-side treatment and consistent with the National Energy Policy Act. The UIEC also submits that a performance-based mechanism to adjust for lost sales, if any, is consistent with the Act.

The UIEC have advocated that the impact of DSR on sales volume be considered on a pro forma basis when utility rates are established in a rate case. This approach builds the anticipated effect of DSR into the revenue requirement determination and the base rates and insures that, all other things being equal, the Company's investment in DSR is at least as profitable as investment in supply-side resources.

The Act also requires a state regulatory authority to:

1. Consider the impact that implementation of such standards would have on small businesses engaged in the design, sale, supply, installation, or servicing of energy conservation, energy efficiency, or other demand-side management measures; and

2. Implement such standards so as to insure that utility actions would not provide such utilities with unfair competitive advantages over such small businesses.

In their position statement, the UIEC have pointed out that there may be significant, detrimental, anti-competitive consequences if the Company is allowed to subsidize demand-side programs by recovering a portion of the costs from customers who are not direct participants in the program. Placing the cost of DSR directly on the participants would mitigate the anti-competitive effects of DSR in accordance with the Federal standard.