December 15, 2005

VIA ELECTRONIC FILING

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City UT 84114

Attention: Julie P. Orchard
Commission Secretary

Re: Docket No. 04-035-42

Enclosed for filing are the original and eight copies of the Utah Cost of Service and Rate Design Taskforce Report to the Utah Public Service Commission. An electronic version of this filing in its original format has been provided to the attention of lmathie@utah.gov.

The Utah Cost of Service and Rate Design Taskforce was established by stipulation and Commission Order in Docket No. 04-035-42 to discuss generation-related cost of service and cost allocation issues, customer charge and rate design issues raised but not resolved in this case. The report had an original due date of November 15, 2005. At the request of the participants and by approval of the Commission the due date was extended to December 15, 2005.

It is respectfully requested that all formal correspondence and Staff requests regarding this filing be addressed to the following:

By E-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 800
Portland, OR 97232

Sincerely,

David L. Taylor
Utah State Manager, Regulation

Utah Cost of Service and Rate Design Taskforce

Report to the

Utah Public Service Commission

December 15, 2005

Submitted by
Utah Cost of Service and Rate Design Taskforce Members

David L. Taylor
Task Force Chairman

UTAH COST OF SERVICE TASKFORCE PARTICIPANTS	
NAME	**REPRESENTING**
Tom Forsgren	AARP
Ron Binz	AARP
Dan Gimble	CCS
Tony Yankel	CCS
Ron Day	Central Valley Water
George Compton	DPU
Andrea Coon	DPU
Abdinasir Abdulle	DPU
Charles Peterson	DPU
Elizabeth Brereton	DPU
Chris Luras	DPU
Ron Slusher	DPU
Artie Powell	DPU
Joni Zenger	DPU
Craig Paulson	FEA
Dennis Goins	FEA
Michael Kurtz	Kroger
Dave Taylor	PacifiCorp
Craig Paice	PacifiCorp
Jeff Larsen	PacifiCorp
Dan Peterson	PacifiCorp
Bill Griffith	PacifiCorp
Michael Reid	PacifiCorp
Rich Anderson	PacifiCorp
Jennifer Martin	PacifiCorp / Stoel Rives
Betsy Wolf	SLCAP
Gary Dodge	UAE
Kevin Higgins	UAE
Neal Townsend	UAE
Vicki Baldwin	UIEC
Maurice Brubaker	UIEC
Roger Swenson	US Mag
Jim Logan	Utah PSC Staff
Lowell Alt	Utah PSC Staff
Becky Wilson	Utah PSC Staff

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Executive Summary

On February 14, 2005, the Parties in PacifiCorp general rate case (Docket No. 04-035-42) submitted a stipulation regarding Revenue Requirement, Rate Spread and Rate Design. In that stipulation the Parties agreed to the formation of a task force to discuss generation-related cost of service and cost allocation issues, customer charge and rate design issues raised but not resolved in this case, and other related issues determined by the task force to be appropriate. The Parties recommended that the chair of this task force be PacifiCorp Regulation Manager, David Taylor and that a report of the task force be filed with the Commission by November 15, 2005. The Revenue Requirement, Rate Spread and Rate Design Stipulation was approved and incorporated in the Utah Public Service Commission's February 25, 2005 Order. At the request of the task force members, the due date for the report was extended to December 15, 2005.

The Cost of Service and Rate Design Task Force involved eleven interested parties who met numerous times over seven months to discuss the assigned issues and other issues proposed by task force participants. During the task force meetings fourteen presentations were made by various taskforce participants covering eleven broad issues.

The presentations and discussions provided a forum to educate task force participants on cost of service and rate design principles. It also provided an opportunity to revisit the appropriateness of the current Utah cost of service methodologies, which have been established over a number of years, and to explore alternative methodologies which may better reflect seasonal load and cost differences. However, due to the complexity of many of the issues together with the significant time commitments of the Scottish Power/PacifiCorp/MidAmerican transaction, many issues were not fully studied. The Task Force was able to achieve a general consensus that we should explore a cost of service methodology that better reflects seasonal and time differentiated load and cost differences. The Task Force, however, did not fully evaluate all proposals and was not able to reach a consensus as to what, if any, methodology that should be. Also, with the exception of one load research issue, the Task Force was unable to reach consensus on any of the other issues discussed. Although resolution of issues did not occur, the task force believes the time spent was worthwhile in helping parties gain a better understanding of the issues.

Caveat: On November 23, 2005, PacifiCorp filed with the Commission an Application for Approval of Its Proposed Power Cost Adjustment ("PCAM"). The Cost of Service and Rate Design Task Force did not evaluate PacifiCorp's PCAM application or any interdependence of a PCAM and the issues and proposals presented in this report.

Introduction

On February 14, 2005, the Parties in PacifiCorp general rate case (Docket No. 04-035-42) submitted a stipulation regarding Revenue Requirement, Rate Spread and Rate Design. In that stipulation the Parties agreed to the formation of a task force to discuss generation-related cost of service and cost allocation issues, customer charge and rate design issues raised but not resolved in this case, and other related issues determined by the task force to be appropriate. The Parties recommended that the chair of this task force be PacifiCorp Regulation Manager, David Taylor and that a report of the task force be filed with the Commission by November 15, 2005. The Revenue Requirement, Rate Spread and Rate Design Stipulation was approved and incorporated in the Utah Public Service Commission's February 25, 2005 Order. At the request of the task force members, the due date for the report was extended to December 15, 2005.

Task Force Assignment

The Revenue Requirement, Rate Spread and Rate Design Stipulation detailed the task force assignment as follows:

> 16. Cost of Service and Rate Design. The Parties stipulate and agree to the formation of a task force to discuss generation-related cost of service and cost allocation issues, customer charge and rate design issues raised but not resolved in this case, and other related issues determined by the task force to be appropriate. The Parties recommend that the chair of this task force be PacifiCorp Principal Consultant, Regulation, David Taylor. The initial meeting of the task force will be no later than April 15, 2005. Other interested parties may also participate in this task force. PacifiCorp will file with the Parties no later than March 23, 2005 an initial list of issues to be addressed by the task force. The task force should be directed to submit a report to the Commission explaining information obtained and analyzed, consensus positions, and issues still in dispute no later than November 15, 2005. Any interested party may file comments or position statements relating to the task force report by November 30, 2005.

Results

The Cost of Service and Rate Design Task Force involved eleven interested parties who met numerous times over seven months to discuss the assigned issues and other issues proposed by task force participants. During the task force meetings fourteen presentations were made by various taskforce participants covering eleven broad issues.

The presentations and discussions provided a forum to educate task force participants on cost of service and rate design principles. It also provided an opportunity to revisit the current Utah cost of service methodologies, which have been established over a number of years, and to explore alternative methodologies which may better reflect seasonal and time-differentiated cost and load differences. However, due to the complexity of many of the issues together with the significant time commitments of the Scottish Power/PacifiCorp/MidAmerican transaction, many issues were not fully studied.

Nine specific proposals were made by taskforce participants on the following general issues:

1. Adjusting peak loads of temperature sensitive classes
2. Seasonal and hourly variation in both class loads and the resource costs
3. Treatment of the MSP rate mitigation cap
4. Spreading generation costs on the basis of energy.
5. Customer Charge
6. New irrigation load studies
7. Pricing of distribution costs

Each of these issues is explained in additional detail later in this report in conjunction with a discussion of the proposals. The Task Force was able to achieve a general consensus that a cost of service methodology that reflects seasonal and possible time differentiated cost and load differences should be further explored. However, with the exception of the irrigation load study proposal, the task force was unable to reach consensus on any of the specific proposals.

Although resolution of issues did not occur, the task force believes the time spent was worthwhile in helping parties gain a better understanding of the issues. This report describes each studied issue as well as the outcome of the task force work.

Caveat: On November 23, 2005, PacifiCorp filed with the Commission an Application for Approval of Its Proposed Power Cost Adjustment ("PCAM"). The Cost of Service and Rate Design Task Force did not evaluate PacifiCorp's PCAM application or any interdependence of a PCAM and the issues and proposals presented in this report.

Meetings

The task force met seven times. Each meeting focused on a pre-assigned subset of the issues with individual participants making presentations and leading the discussion on the various issues and proposals. Many of the presentations were circulated in advance of the meeting where that issue or proposal would be discussed. The Utah Cost of Service and Rate Design Taskforce held meetings on the following dates:

1. April 13, 2005
2. May 23, 2005
3. June 15, 2005
4. July 13, 2005
5. August 25, 2005
6. October 26, 2005
7. December 1, 2005

Participating Parties

Individuals representing the following organizations participated in the Cost of Service and Rate Design Task Force:

1. AARP
2. Committee of Consumer Services (CCS)
3. Central Valley Water
4. Division of Public Utilities (DPU)
5. Federal Executive Agencies (FEA)
6. Kroger
7. PacifiCorp
8. Salt Lake Community Action Program(SLCAP)/Crossroads
9. US Magnesium
10. Utah Association of Energy Users (UAE)
11. Utah Industrial Energy Consumers (UIEC)
12. Utah Public Service Commission Staff (PSC)

Issues

At the first meeting of the Utah Cost of Service and Rate Design Taskforce participants reviewed the Taskforce's assignment and agreed upon the following list of eleven issues to be discussed in preparation for a report to the Utah Commission on November 15, 2005.

1. Should the cost of service study be built off of the Utah allocated results of operations as calculated under the MSP Revised Protocol or as calculated under the Rolled-In method?
2. How should the MSP Rate Mitigation Cap be treated in the cost of service study?
3. Should Utah use the same allocation methodology in class cost of service studies as is used for jurisdictional allocation?
4. Classification of Generation and Transmission fixed costs between demand and energy. Should the current 75%/25% classification be retained? What are the other alternatives?

5. Allocation of G&T demand related costs. Should the 12CP allocation method be retained? Should the allocation reflect load and costs differences between seasons? What are the other alternatives?
6. Should loads for temperature sensitive classes be adjusted to reflect a portion of the Company's planning margin?
7. Other alternatives for classification and allocation of G&T costs.
8. Should the customer charge for the residential and other classes be raised to full cost of service? How should the cost of service basis for the customer charge be calculated?
9. What is the basis for allocating distribution costs among customer classes? (Class demand? Class demographics?) What portion of distribution costs are not caused specifically by demand, per se? How should the non-demand-related distribution costs be allocated? How should the non-demand-related distribution costs be priced?
10. Is it cost beneficial to collect accurate and timely load research data and do cost of service analysis on the irrigation class?
11. How closely should rate design follow the demand and energy components from the cost of service study?

COS Methodology Evaluation Criteria

At the first meeting of the Utah Cost of Service and Rate Design Taskforce participants developed the following set of criteria that would be used to evaluate any cost of service methodology proposal:

1. Cost causation
2. Cost shifting
3. Stability over time
4. Simplicity/understandability
5. Reasonableness
6. Historical experience
7. Appropriate price signals (customer incentives)
8. Unintended consequences
9. Consistency with state energy policy

While this set of criteria was not used as an explicit checklist for each proposal, the criteria did form the basis for many of the questions and much of the discussion surrounding each presentation and proposal.

Presentations

During the course of the task force the following fourteen presentations on a variety of topics were made by taskforce participants:

1. Dave Taylor - Overview on cost of service principles and methodologies currently used by PacifiCorp in Utah and other states
2. Lowell Alt - Historical perspective on the currently approved Utah cost allocation practices.
3. Maurice Brubaker – Seasonality in G&T Allocation
4 Jim Logan – Review of MSP Classification and Allocation decision process
5. Dave Taylor – Paper on Classification and Allocation of G&T Costs
6. Kevin Higgins – Planning Margin and Temperature Sensitive Loads
7. George Compton – Distribution Cost Allocation and Pricing
8. Craig Paice – Review of Oregon distance sensitive distribution allocation
9. Dave Taylor – Review of Utah Power 1995 Zonal Cost of Service Study
10. Dave Taylor – Follow up on Brubaker Presentation
11. Kevin Higgins – How to treat MSP Rate Mitigation Cap
12. Rich Anderson – Utah Irrigation Load Research
13. Tony Yankel – System vs Jurisdictional Cost Allocation and Retail Load Patterns vs Total System Load Patterns. (Follow up on June and July presentations on load variability)
14. Dave Taylor – Allocation options that reflect seasonal and time of day differences

Several of the presentations were strictly educational while others provided the foundation for specific allocation proposals. A copy of the hand out materials from each presentation is included in the appendices of this report.

Specific Proposals

Nine cost of service and rate design proposals were presented during the course of the taskforce. The following pages contain a description of each of the proposals followed by comments from the participating parties.

Proposal #1
Utah Class Cost-of-Service under MSP: How to Treat MSP Rate Mitigation Cap

Recommended by UAE
Presented by Kevin Higgins of Energy Strategies

Why does this matter?

- Interjurisdictional costs are now allocated pursuant to the MSP Revised Protocol ("MSP").
- Class cost of service is based on a specific set of jurisdictional costs. If jurisdictional costs are changed, Utah class cost-of-service is changed.
- The MSP Revised Protocol requires jurisdictional costs to be calculated under both Rolled-in and MSP methods.
- Until 2014, the final allocation to Utah is (generally) the lower of MSP or "Rolled-in + 1.x%".
- Utah class cost-of-service under MSP is different than under Rolled-in.

Issue 1: What set of jurisdictional costs should be used for Utah cost allocation?

- Proposal:

  - If Utah's jurisdictional allocation is based on unconstrained MSP results (i.e., if MSP produces lower jurisdictional costs than Rolled-in), then use MSP for Utah COS.
    - Note: The only functional cost difference between MSP and Rolled-in is related to generation. Therefore, the jurisdictional allocation of non-generation costs should be the same between Rolled-in and MSP.

  - If jurisdictional allocation is based on "Rolled-in + 1.x%", then for Utah COS use either:
    - Rolled-in, or
    - "Constrained MSP", where "Constrained MSP" refers to an MSP interjurisdictional allocation that is capped at the "Rolled-in + 1.x%" revenue requirement.

Issue 2: If "Constrained MSP" is the basis for Utah jurisdictional costs, how should this information be incorporated in the class COS analysis?

- Proposal:

  - If "Constrained MSP" is the basis for Utah class COS, the MSP rate mitigation cap should be treated as lowering the generation expense allocated to Utah relative to "unconstrained" MSP.

    - Note: UAE believes this treatment is appropriate because MSP is implemented primarily via generation expense adjustments among the state jurisdictions. Constraining the MSP result, then, is a matter of reversing a portion of these expense adjustments.

  - The target returns for, and allocation of, non-generation function costs (and income taxes) to Utah remain equal between Rolled-in and MSP.
    - Note: Failure to retain this equality produces irrational results (e.g., changes in Utah distribution costs between Rolled-in and MSP).

  - Class cost responsibility (and relative returns) is then calculated based on the "Constrained MSP" costs allocated to Utah, with the functionalized costs determined as stated above.

Comments on Proposal #1

PacifiCorp's Comments
Issue 1: PacifiCorp believes that the cost of service study should incorporate the jurisdictional costs as calculated under the Revised Protocol. Revised Protocol is the approved inter-jurisdictional allocation methodology in Utah. The MSP Rate Mitigation Cap of Rolled-in + 1.x% does not change the jurisdictional allocation method, it just limits the amount of revenue PacifiCorp can collect.

Issue 2: PacifiCorp believes the implication of the MSP Rate Mitigation Cap should be reflected in the return component of the cost of service study. The reduction in revenue from the MSP Cap results in a lower return on equity for Company shareholders. It is not a disallowance of expenses. While the Utah Commission did not designate the MSP Cap as specifically generation related, PacifiCorp is not opposed to reflecting this lower return in the generation function only.

UIEC Comments
The difference between the Rolled-in and the MSP is in the treatment of generation costs. Accordingly, the effect of any adjustment should be reflected in the generation cost category. UIEC cannot support or oppose until more is known of the results of this proposal.

DPU Comments
- An "unconstrained MSP" allocation to Utah would currently result in a greater allocation of system generation costs than would a Rolled-In-based allocation. "Constraining" the MSP allocation means that Utah does not receive its full, MSP-based generation cost allocation. Transmission costs and Utah site-specific costs (e.g., customer and distribution costs) are what they are and should not be affected by the stipulated MSP constraint.
- Observing no compelling argument in this instance against the standard (but not sacrosanct) objective of matching intrastate allocations with interstate

allocations, the cost-causation criterion would support reducing generation costs from the full Utah MSP level in establishing the revenue requirement and its specific cost components -- rather than reducing costs across the board, as the Company did in the last rate case.

- If the customer class allocations were based upon an across-the-board Rolled-In plus 1.5%, the residential and commercial classes would have received a *greater* allocation than occurred under the Company's approach. That is because the former would have expanded the distribution cost element (which is principally allocated to the residential and commercial classes) and shrunk the generation portion (which is proportionately allocated more to the industrial class), while, compared to Rolled-In, the Company's approach did the reverse.
    - Adding to the generation cost element the 1.5% portion of the total revenue requirement that was based on Rolled-In plus 1.5% would yield class costs comparable to the UEA proposal.

<u>DPU Recommendation:</u> The Division does not have a strong preference as between the UAE proposal and the Company's approach.

FEA Comments
FEA takes no position on Proposal 1, Issue 1 at this time. With respect to Proposal 1, Issue 2, FEA generally agrees that if "Constrained MSP" is the basis for Utah class COS, the MSP rate mitigation cap should be treated as lowering the generation expense allocated to Utah relative to "unconstrained" MSP.

AARP Comments
The appropriate basis for Utah rates is the constrained MSP. The constraint imposed on the MSP is a constraint on total revenues collected in Utah, not on generation costs alone.

CCS Comments
The Committee's acceptance of the Revised Protocol IJA Method was specifically predicated on using roll-in plus the 1.5% cap for establishing the level of revenue requirement in Utah. The Committee is open to further exploring UAE's proposal that the percentage adjustment factor (currently 1.5%) should only reflect generation costs.

Proposal #2

Adjust CP for weather-sensitive classes by the share of the planning margin allocated to the class

Recommended by UAE
Presented by Kevin Higgins of Energy Strategies

Statement of the Issue

- Meeting summer peak load requirements is a major driver of PacifiCorp's capacity expansion plans.
- PacifiCorp must plan for and acquire production capacity to meet peak load during periods of **abnormal** temperature.
- Some customer classes are more temperature-sensitive than others, and thus place a greater demand on the system during periods of abnormally-high temperature.
- In allocating class cost responsibility for production plant, PacifiCorp utilizes **temperature-normalized** data.
- Assuming a normal weather year in class cost allocation inadvertently ignores cost responsibility for the portion of production capacity that is acquired to maintain service during periods of abnormally-high temperatures.

Objective of UAE proposed adjustment to current cost-of-service method

Allocate appropriate class cost responsibility for costs associated with providing generation resources to accommodate above-normal temperatures.

UAE Proposed Approach

The UAE proposed approach retains PacifiCorp's existing cost allocation methodology, but adjusts the measurement of contribution to peak demand to account for the costs imposed on the system to meet the needs of temperature-sensitive classes.

- Identify what portion of the planning margin is attributable to temperature contingency.
- Assign an appropriate portion of planning margin costs to weather-sensitive classes (e.g., Schedules 1, 6, 8 and 23) based on degree of temperature sensitivity.
- Adjust CP for weather-sensitive classes by the share of the planning margin allocated to the class.
- Perform COS analysis using adjusted class CPs.

Specific Proposal

UAE makes the following specific proposal, but is open to other approaches that satisfactorily address the objective stated above.

- Assign 50% of Utah's share of system planning margin to temperature contingency.
  - Utah 2006 test year CP = 4,136 MW.
  - Utah share of planning margin = 15% x 4,136 MW = 620 MW.
  - Utah temperature-contingent generation = 50% x 620 MW = 310 MW.
- Adjust CP of temperature-sensitive classes in proportion to their share of temperature-related planning margin.
- Perform class COS analysis using current methodology, but with adjusted class CPs.

Reasonableness check:

- PacifiCorp estimates that each 1 degree increase in temperature above 90° increases Utah demand by 35 MW.
- The 310 MW share of the planning margin assigned to temperature-sensitive classes provides sufficient capacity to accommodate temperatures that are 9° above normal in summer.

Benefits of this approach

- Consistent with cost causation: Addresses the problem associated with the current practice of building and purchasing capacity to meet abnormal temperatures, but assuming normal temperature when allocating the costs of what gets built and purchased.

- Stability: Retains existing cost allocation methodology.

- Gradualism: Does not result in a significant decrease in the return index for any customer class.

Comments on Proposal #2

PacifiCorp's Comments

PacifiCorp disagrees with this proposal. There are a variety of reasons underpinning the need for the planning margin, therefore the cost of providing that margin should be the responsibility of all customers, not just those indicated in this proposal. A study on PacifiCorp's Planning Margin requirements can be found in Appendix N of the current Company IRP. That study lists several reasons for the planning margin requirement:

> "For a number of reasons including the random nature of generator outages, the utility's inability to store significant quantities of power, and uncertainty of future customer demand, a utility is required at all times to possess a greater amount of capability than its expected demands."

From the report we see that load uncertainty is only one of the reasons for the planning margin, and temperature is just one of the reasons for load uncertainty. While the report in Appendix N does indicate that temperature variation is a leading cause of load uncertainty, nowhere in the study does it suggest that temperature driven load uncertainty accounts for 50% of the planning margin requirement. Because of the variety of reasons underpinning the need for the planning margin, the cost of providing that margin should be the responsibility of all customers

UIEC Comments

In the context of embedded class cost of service studies, UIEC believes that the adjustments embodied in this proposal are consistent with cost-causation.
In the second bullet point of the Statement of the Issue, UIEC notes that PacifiCorp must plan for and acquire production capacity to meet peak load during period of increased temperature, not just abnormal temperature.

DPU Comments

- If warmer than expected summers and their associated loads constitute a "cause" behind the current level of the planning reserve margin, then those loads should bear a commensurate revenue requirement responsibility.
- The Task Force didn't receive sufficient information to "Identify what portion of the planning margin is attributable to temperature contingency." Valuable input would be a historical record of the amount of standby reserves that were actually utilized in each year to serve temperature-driven loads that exceeded the expected highs. This would be contrasted with how much of the reserves are used for dealing with unscheduled/contingency outages – the principal justification for the reserves.
- During episodes of hotter-than-expected weather, did contractually permitted industrial load interruptions constitute the reserves serving the inordinately high temperature-sensitive loads or did the availability of standby reserves reduce the need to interrupt those large industrial customers? If the latter, then, based on the beneficiary-pays principle, shouldn't the interruptible class pay for a portion of the costs of standby reserves that on a probabilistic basis are not used for unscheduled/ contingency outages.
- It would seem that standby reserve capacity should be cheaper, peaking capacity rather than average-cost capacity. So even if a portion were directly allocated to temperature sensitive classes, the allocation should be based on reserve system costs rather than system-average generation plant costs.

<u>DPU Recommendation:</u> While willing to take an active interest in whatever studies were conducted to "[i]dentify what portion of the planning margin is

attributable to temperature contingency" and to determine what might be the implications of the results of such studies, the Division lacks the resources to pursue such studies on its own initiative.

FEA Comments
FEA agrees with the basic objective of UAE's proposed adjustment, but takes no position at this time on UAE's specific proposal.

AARP Comments
This proposal can be seen to be faulty by considering the end result of the process recommended here. It turns out that some classes (Industrial among potentially others) would be assigned costs for a reserve margin that are smaller than the costs that the customer class would be assigned if it were a stand-alone customer of the utility. In other words, the advantaged customer classes would be getting the assurance of continued secure service at less than the cost of that assurance.

CCS Comments
The Committee believes that this proposal deviates from fundamental principles of cost causation. The proposal is to allocate costs relating to planning margin on the basis of temperature-sensitive loads. However, planning margin is primarily tied to the possibility of losing generation resources rather than variations in temperature-sensitive loads. Some additional planning margin may be related to inaccuracies of forecasts of load growth—which is not the same as a margin for variations in temperature-sensitive loads.

Proposal #3
"Horizontal Analysis" Consideration should be given to analyzing the kinds of resources that can be associated with the different class load patterns.

Recommended by UIEC
Presented by Maurice Brubaker of Brubaker and Associates (BAI)

Mr. Brubaker did not present a specific cost allocation methodology but concluded his presentation by showing what he described as a "horizontal analysis" suggesting that consideration should be given to analyzing the kinds of resources that can be associated with the different class load patterns. For example, it may be that large, high load factor, customers are more appropriately served from base load resources, and classes with "peaking" load shapes are more appropriately served from cycling resources and purchased power. This type of analysis, whereby different load shapes would be "costed" using the set of resources most suitable for their load characteristics, may provide additional insights into costing approaches that will more accurately capture and reflect the impacts of seasonal and daily variations in load on PacifiCorp's cost of service.

Comments on Proposal #3

PacifiCorp's Comments
PacifiCorp is not opposed to exploring different classification and allocation procedures for different types of resources.

UIEC Comments
This is UIEC's proposal for further analysis designed to improve the understanding and tracking of cost-causation by looking at class annual load patterns (horizontal analysis) to distinguish the types of cost incurred to serve various load shapes, rather than allocating large groups of generation cost based on usage at particular times (vertical analysis). UIEC believes PacifiCorp should undertake further analysis along these lines.

DPU Comments
It would be interesting to see what the costs would be of serving each of the main customer classes on a stand-alone basis. If that is what Mr. Brubaker is talking about, the DPU would encourage pursuing such research. Given the system cost-reducing, diversity benefits of serving customers groups with different load configurations, total system costs would be expected to exceed the sum of all the groups' stand-alone costs. A reasonable cost allocation approach would be to have each group's share of system costs be set equal to a uniform percentage of its own stand-alone costs.

<u>DPU Recommendation:</u> While willing to take an active interest in whatever studies were conducted along these lines, the Division lacks the resources to pursue such studies on its own initiative.

FEA Comments

FEA agrees that PacifiCorp's approach to meeting seasonal peak requirements (for example, purchasing 6x16 liquated damages products for the summer) may create significant costing and pricing problems, especially for less-volatile, higher load factor loads. However, at this time, FEA is concerned about how accurately we can assign specific types of generation costs to specific types of customers defined by class load patterns. Current cost allocation methods try to achieve this objective indirectly, although some methods do a better job than others. FEA believes that this issue and UIEC's proposal require further analysis and evaluation.

AARP Comments

This is a promising approach at the conceptual level, essentially unbundling the cost allocation decision, permitting different allocation bases to be used for different classes of generating plant. Of course, there is likely to be much debate about the classification of specific units and purchases as well as about the appropriate allocation factor to be used for each class of plant.

CCS Comments

The Committee agrees that the general direction proposed by UIEC should be further analyzed. However, as stated throughout the body of this Report, there was insufficient time to fully address the issues before the Task Force—this was one such issue that requires a great deal more review. For example, if base load units are to be assigned to classes with flat load shapes, how does one treat sales for resale for those classes that do not offer any valley-time out of their load pattern (generation resources) to make these sales?

Proposal #4
Distribution Rate Design

Recommended by Division of Public Utilities (DPU)
Presented by George Compton of the DPU

Pricing and allocating distribution costs:

- The Division sees no compelling need at this time to alter the mechanism (i.e., class non-coincident peak demand) by which distribution system costs are allocated among customer classes.
- A very large portion of distribution costs (e.g., for poles, cross arms, insulators, rights-of-way, trenching, conduit, etc.) are principally geography/demographics-based rather than caused by the level of demand. Since only a portion of distribution costs are demand related, it is entirely arbitrary – as was done in the last general rate case – to place a disproportionate amount of the commercial schedules' rate increase into the demand element of its three-part rate design on the grounds that *none* of the distribution costs should ever be recovered by anything but the demand charge.
- Oregon regulation recognizes distance from substations (i.e., geography/ demographics) as a cost-causative factor in its allocations process.
- Compared to a time-of-day energy charge, the demand charge is a rather blunt instrument for getting customers to conserve on demand during peak load periods. In fact, once a customer has reached its own demand peak, the demand charge provides no incentive to cut back usage during subsequent hot-temperature, high load periods.
- As a NARUC white paper that was published in 2000 concluded regarding the pricing for the distribution system: "fairness, economic efficiency, competitive provision and innovation, and environmental protection….calls for usage-based pricing – primarily volumetric (energy-based) but, where appropriate, both demand- and energy-based." Expressly precluded would be distribution cost recovery solely through the demand and/or the customer charge.
- Given the fairness and conservation-based limits placed by this Commission on the scale and scope of the customer charge, the obvious locus for the recovery of at least of share of the non-demand costs of the distribution network lies in the energy charge.

DPU Recommendation: In its next rate case application, the Company's rate design proposal should move back towards (if not all the way to) the status quo ante mix of demand- and energy-related pricing for recovering the distribution system costs.

Comments on Proposal #4

PacifiCorp's Comments
PacifiCorp believes that distribution facilities are demand and customer related and that energy usage is not a cost driver for distribution related costs. PacifiCorp also believes that the goals of rate design, such as gradualism, continuity and minimizing customer impacts must also be recognized, and that it is not necessarily advisable to collect all demand related costs through demand charges.

FEA Comments
FEA disagrees that recovering distribution costs through energy charges is appropriate. If costing analyses indicate that a large portion of distribution costs is "geography/demographics-based," then such costs should be recovered through charges that are also "geography/demographics-based," which implies customer and demand charges differentiated by customer location, density, and other factors.

CCS Comments
The Committee generally agrees with the Divisions comments regarding distribution costs.

Kroger Comments
Proposal # 4 suggests that distribution costs should be placed into "both the demand and energy price elements" as a way to promote "rate continuity/stability, energy conservation, and customer equity". We disagree.

Distribution costs should not be placed in the energy component of rates. Distribution costs are either demand related or customer related. There is no energy component to distribution costs. The NARUC Cost Allocation Manual is very clear on this point.

The January 1992 NARUC Cost Allocation Manual discusses the allocation of distribution costs at pages 86-104. NARUC classifies every category of distribution plant to either demand or customer, or both. NARUC does not allocate any distribution plant to energy. At page 89 the NARUC Manual explains:

"Because there is no energy component of distribution-related costs, we need consider only the demand and customer components."

Adopting the suggestions contained in Proposal # 4 would cause Utah to utilize a cost allocation method for distribution costs that is contrary to accepted practice in the rest of the country.

Proposal #5
Residential Customer Charge

Recommended by Division of Public Utilities (DPU)
Presented by George Compton of the DPU

<u>The residential customer charge:</u>

- The Division does not take exception to how the Commission has demarcated the portion of the residential cost of service that would be appropriately recovered through a customer charge. (That portion consists of costs that each customer is solely responsible for. Such include the service drop, the meter, meter reading, and billing.) Our concern has to do with the failure to implement that finding in practice.
- Principles of cost causation, equity between large and small customers, and the avoidance of confusion due to the large disparity between PacifiCorp's and Questar's customer charge, all argue strongly for an increase in the former's residential customer charge.
- The very summer high tail block rate largely eliminates the historical conservation argument in favor of shifting the payment of customer costs over to the energy charge.
- In light of the very large and often burdensome increases experienced by large customers (a number of whom occupy the lower income strata who dwell in 1950s- and 1960s-vintage all-electric homes), an increase of $1 or $1.50 for all customers (including small customers, who have received a smaller overall increase from the energy charge) so as to mitigate the increases that would otherwise have gone to those same large customers seems most appropriate.

<u>DPU Recommendation:</u> The Company's next general rate case application should again sponsor a full, cost-based customer charge. The DPU can be expected to support a customer charge reflecting all of the costs which the Commission has previously designated as appropriately recovered through such a charge.

Comments on Proposal #5

PacifiCorp's Comments
PacifiCorp agrees that an increase to the customer charge is appropriate and necessary. The current residential customer charge is too low and does not reflect even the Utah Commission's narrowly defined calculation of a customer charge. The Utah residential customer charge is far below the Company's customer charges in other PacifiCorp states, i.e., Oregon ($7.00), Wyoming ($8.89), Washington ($4.75), California ($5.30), and the minimum monthly charge in Idaho ($9.78). PacifiCorp is unaware of any other electric utility that has a residential customer charge of less than one dollar.

CCS Comments

The Committee disagrees with the Division's position regarding the Residential Customer Charge. The Committee believes that a strict flow-though of allocated costs into the design of the residential rates is inappropriate and counter to general rate making principles of simplicity and (given the higher relative customer costs for residential customers) places too much emphasis upon a component over which the customer has no control.

Proposal #6
Residential Customer Charge

Recommended by the Committee of Consumer Services (CCS)
Presented by Tony Yankel, Consultant

Residential Customer Charge

- The customer charge is a rate design issue, not a cost allocation issue.
- Because the customer charge is a fixed charge, it provides customers a meaningless price signal. Could a customer decide to not take service to avoid it?
- Commission decisions in past orders support maintaining a low customers charge and placing the difference between the estimated customer charge level and the level approved for rates on the energy (usage) portion of residential customers' bills.

Comments on Proposal #6

PacifiCorp's Comments

PacifiCorp believes that an increase to the customer charge is appropriate and necessary. The current residential customer charge is too low and does not reflect even the Utah Commission's narrowly defined calculation of a customer charge. The Utah residential customer charge is far below the Company's customer charges in other PacifiCorp states, i.e., Oregon ($7.00), Wyoming ($8.89), Washington ($4.75), California ($5.30), and the minimum monthly charge in Idaho ($9.78). PacifiCorp is unaware of any other electric utility that has a residential customer charge of less than one dollar.

DPU Comments

- The Task Force's charter/scope expressly includes "rate design issues."
- The customer charge represents a bare minimum of the cost each customer causes/imposes on the system by virtue of being a customer. Yes, if the customer wants to avoid that charge/cost the choice is to terminate service.
- Judging from comments made from the bench in the most recent PacifiCorp general rate case hearing, the Commission would seem to welcome greater consistency between PacifiCorp and Questar Gas in how they charge for this Commission's own recognized customer costs. It is interesting that Questar has recently entertained an *elevation* in its customer charge in order to protect its fixed-cost coverage in the presence of declining usage.

<u>DPU Recommendation:</u> Same as our recommendation for Proposal No. 5.

FEA Comments

FEA takes no position on specific residential customer charges. However, FEA believes that prices based on embedded costs should reflect reasonable approximations of the unit costs of serving various types of customers. Under this premise, setting the customer charge for any customer class should be primarily a costing issue. The Commission may choose to deviate from such costing results for a variety of factors, but such deviations should not obscure the need to determine customer costs as accurately as possible.

Proposal #7
Irrigation Load Research

Recommended by PacifiCorp
Presented by Rich Anderson of PacifiCorp

Company should conduct new irrigation load studies using a six strata sampling methodology. Upon complete installation of the new load study and a full test year of load data, the results of the cost of service study results for the irrigation class should be considered in the rate spread ordered in subsequent rate cases.

Utah Irrigation Sample Designs
Estimated cost for 6 Strata (143 meters) = $43,186

Comments on Proposal #7

DPU Comments
The DPU concurs in the recommendation to pursue this limited investigation.
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FEA Comments
FEA agrees with this proposal.

AARP Comments
It is reasonable to undertake the load research recommended here.

Proposal #8
System Generation Cost Causation and Allocation

Recommended by the Committee of Consumer Services (CCS)
Presented by Tony Yankel, Consultant for the CCS

Allocation and Cost Causation

- Allocation factors based upon retail load may not reflect overall system operations—system load and operation is different than retail load.
- PacifiCorp's generation is extremely flat when compared with retail and wholesale sales. Thus, an energy allocation factor appears to better reflect cost causation.
- Maximum generation did not occur at the time of the monthly coincident peak.
- Approximately 5% of the hourly generation was greater than during the time of the monthly coincident peak.
- Wholesale sales (loads) are approximately 40%-50% of PacifiCorp's overall business. Purchase power is used to meet system (retail + wholesale) requirements.
- A large portion of system resources are used to supply non-retail firm requirements.
- Wholesale sales have a similar pattern to that of Retail with little or no "valley filling".
- The difference between the level of retail load and generation is addressed in the wholesale market.
- If a class is allocated the same resources at peak as it uses during the rest of the time (flat load), it should have no stake in wholesale revenues.

Comments on Proposal #8

PacifiCorp's Comments

PacifiCorp believes the 75% demand / 25% energy classification coupled with the 12 CP allocation of generation fixed costs provides a reasonable balance between the dual capabilities of our generation fleet; peak coverage and base load energy production. PacifiCorp serves all of its customers, both retail and wholesale, from a common resource portfolio. It is therefore appropriate that revenue credits arising from wholesale sales be allocated to customer classes on the same basis as the cost of the generation resources.

UIEC Comments

UIEC is in general disagreement with the conclusions and recommendations presented. It does not appear that the declarations are supported by the facts. In particular, UIEC does not believe that the retail load shapes are flat, nor does it believe that an energy allocation factor would better reflect cost-causation. Even if retail load shapes were flat, there is no connection that gets one from there to the conclusion that an energy allocation factor would better reflect cost-causation. Bullet points 3 – 6 conflict with the evidence available and presented in other dockets. Also, the fact that a class has a flat load should not preclude it from being credited with a share of wholesale revenues when that class is being allocated a share of the cost of the generation and purchased power that enabled PacifiCorp to make the wholesale sales.

DPU Comments

- Independent of how successful the company is at valley-filling, it is the firm peaks that drive capacity costs. Accordingly, peak demands, not energy use (particularly annual energy use), should be the primary driver of capacity cost allocations.
- In a general rate case some twenty years ago the DPU advocated allocating revenues from valley filling to customer classes in proportion to the degree that each class's average consumption was below its peak rather than in proportion to their total energy use. (If average consumption equaled peak consumption there would be no valley to be filled in the first place.) That advocacy seems to be consistent with the implication of Mr. Yankel's last point.

<u>DPU Recommendation:</u> The DPU would be happy to join with the Committee consultant in an investigation of the most equitable means of compensating customer classes vis a vis the credits from valley-filling off-system sales.

FEA Comments

FEA objects to the premise that "an energy allocation factor appears to better reflect cost causation." Nothing in this proposal refutes the key role that coincident peak demands play in how PacifiCorp plans, designs, and operates its system to serve both wholesale and retail loads.

UAE Comments

UAE offers the following observations regarding two of the bullets:
Second bullet: UAE strongly disagrees. Even if generation is relatively flat compared with retail and wholesale sales, it does not follow that an energy allocation better reflects cost causation. PacifiCorp retail demand requires capacity to serve load, and capacity is most appropriately classified as demand. Moreover, PacifiCorp's retail load – the subject of cost allocation – is far from flat. If an energy-based allocation method is to be considered, UAE recommends the "Average and Excess Demand" methodology as articulated in the NARUC Cost Allocation Manual. This method allocates a considerable portion of production cost on the basis of average demand, or energy, and is used in Colorado.

Ninth bullet: UAE strongly disagrees. There is no reasonable basis for denying a revenue credit to a class that is allocated a full share of production costs. Moreover, the rationale for this position implicitly assumes that a 1 CP method is used for allocating production costs, which is not the case in Utah. It is also inconsistent with the policy advocated in the second bullet, i.e., to allocate production costs using an energy basis. Thus, these bullets do not represent a single, consistent proposal.

Central Valley Water Comments

Central Valley Water Reclamation Facility's position is that we recognize that fixed costs must be covered, but the present approach is counter productive to DSM efforts. We will always be looking to better balance the costs by applying more to energy and less to demand.

Proposal #9
Seasonal Allocation of Generation Costs

Recommended by the PacifiCorp
Presented by Dave Taylor of PacifiCorp

Generation Fixed Costs

PacifiCorp recommends that the 75% demand 25% energy classification be retained for Generation fixed costs, but that the following modifications be made to the allocation of Generation fixed costs. PacifiCorp feels that these modifications represent a good start toward meeting the objective of reflecting seasonal load and cost differences in the cost of service study without causing significant cost shifts between customer classes.

Relative Monthly Peak Demand Weighted 12 CP Factor.

The 75% demand related component of fixed costs for all other Generation Resources allocated using a relative monthly peak demand weighted 12 CP allocation factor. The monthly weighting factor for each month is calculated as the system coincident retail peak for that month as % of annual system retail peak. For example, if the PacifiCorp retail system coincident peak in a given year occurs in July and is 8,000 MW, and the system retail coincident peak in April is 6,000 MW, then July class coincident peaks would be multiplied by 1.00 (8,000 / 8,000)) and class coincident peaks in April would be multiplied by .75 (6,000 / 8,000). The 12 weighted monthly peaks for each class would then be summed to calculate the allocation factor.

The 25% energy component of the factor would continue to use the annual energy usage by class.

Energy Costs

PacifiCorp recommends that fuel and other generation related net power cost components be allocated on a monthly basis. Class CP and energy loads are already included in the cost of service study and net power costs are also calculated and summarized by month in the NPC study for the test period. The allocation would work as follows:

The monthly value for each major component of system net power costs (Firm and Non-firm Wholesale sales, Firm and Non-Firm Purchases, and Fuel) is multiplied by the appropriate Utah interjurisdictional allocation factor (SE, SG, etc). Utah's share of this monthly amount is then allocated to customer classes using a factor based on that month's energy usage, or combined CP and energy in the case of firm purchases and sales. The process is repeated for each month of the test period and the monthly values summed for the year. The annual summation for each class would then be used to calculate the allocation factor for that component of NPC in the cost of service study.

PacifiCorp does not recommend that energy costs be allocated on an hourly basis.

Comments on Proposal #9

UIEC Comments

In the context of embedded class cost of service studies, UIEC believes that the recommendations in Proposal No. 9 would be a movement in the direction of better reflecting the seasonality of costs, but believes that it is only a small step. UIEC believes that the energy component of the factor and the energy costs should be approached with more granularity than proposed in Proposal No. 9.

DPU Comments

- There is no scientific basis at this time for nay-saying Mr. Taylor's admittedly unscientific proposal, which posseses the advantage of being intuitively superior to the status quo (which ignores the obvious cost basis in seasonality).
- The UIEC testimony in the prior general rate case as well as elements of the earlier DPU MSP discourse, lend credence to applying Mr. Taylor's weights to just the five months with the greatest peak loads (two are in summer and three in winter) rather than to all twelve months. That would be superior to a simple (i.e., equally weighted) 5CP, since the two summer months are each more stressful than the three winter months and accordingly should receive heavier weights.
- But if there were to be such a move beyond Mr. Taylor's proposal (as suggested by UIEC and UAE), serious consideration should be given to reclassifying baseload plant as 50% energy-related rather than 25% energy-related. The former figure better reflects the amount of additional capital costs that are incurred with baseload plants over peaking plants for the purpose of avoiding fuel costs.

<u>DPU Recommendation:</u> The Company's next general rate case application should present the weighted 12CP substitute for the simple 12CP generation fixed cost allocator as its base case and defend it as such. Absent compelling contrary evidence brought to bear by some other party, the DPU can be expected to support this weighted 12CP alternative.

FEA Comments
FEA commends PacifiCorp's attempt to develop a relatively simple, straightforward approach to address complex seasonal costing issues. In particular, FEA believes that PacifiCorp's proposal reflects one reasonable approach to address the issue of costs driven by summer peak load growth. FEA would like to analyze and evaluate PacifiCorp's proposal further, and therefore must take no position on the proposal at this time.

UAE Comments
UAE believes this approach provides a small improvement in allocating costs, but does not go far enough in distinguishing the differences among the months (e.g., Probability of Contribution to Peak would be a better measure). UAE also believes this approach can be used in conjunction with the adjustments to the CP of weather-sensitive classes as outlined in Proposal #2 of this report.

AARP Comments
Conceptually, this approach to the demand allocator seems to make sense, although it will be important to review how various customer classes are affected by the change. As a general matter, allocation of demand or energy costs using seasonal and/or time-of-day differentiation of total (average) costs will likely make little difference to the class cost allocation.

CCS Comments
This is a very important issue, but one that was first presented at the very last meeting of the Task Force. Far more effort and review must be put into the development of seasonal or time-differentiated cost allocations before a consensus can be developed. Additionally, the establishment of any type of proposal that allocates costs differently than comes to Utah from the IJA (other than stipulated agreements) presents a disconnect between cost causation (the IJA) and what Utah may think of as theoretical cost drivers. The Committee is not averse to reviewing seasonal and time differentiated allocators, but there was simply insufficient review of this issue during the time allotted for this Task Force.

Central Valley Water Comments
Central Valley also believes that the company will need to provide information that tells end-users how well the costs are matching seasonal and time of day usage.

Appendices

Appendix 1

Overview on cost of service principles and methodologies

Appendix 2

Historical perspective on Utah cost allocation practices.

Appendix 3

Seasonality in G&T Allocation

Appendix 4

Review of MSP Classification and Allocation decision process

Appendix 5

Classification and Allocation of G&T Costs

Appendix 6

Planning Margin and Temperature Sensitive Loads

Appendix 7

Distribution Cost Allocation and Pricing

Appendix 8

Oregon distance sensitive distribution allocation

Appendix 9

Utah Power 1995 Zonal Cost of Service Study

Appendix 10

Follow up on Seasonality in G&T Allocation

Appendix 11

How to treat MSP Rate Mitigation Cap

Appendix 12

Utah Irrigation Load Research

Appendix 13

Retail Load Patterns vs Total System Load Patterns.

Appendix 14

Allocation options that reflect seasonal and time of day differences