ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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March 2, 2021

VIA ELECTRONIC FILING

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

Attention: Gary Widerburg
Commission Administrator

RE: Docket No. 20-035-04
In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations
RMP Reply Comments on Collaborative Stakeholder Process

In accordance with the Public Service Commission of Utah's ("Commission") December 30, 2020 Order in Rocky Mountain Power's 2020 general rate case, Docket No. 20-035-04, PacifiCorp ("RMP" or "the Company") hereby submits these reply comments on the scope and format of a Collaborative Stakeholder Process in response to the comments filed on February 16, 2021 by the Division of Public Utilities ("Division"), the Office of Consumer Services ("Office"), Utah Clean Energy ("UCE"), Western Resource Advocates ("WRA") and the Kroger Company ("Kroger").

Most of the parties who filed comments in this matter recognize the importance of keeping the collaborative stakeholder process from becoming an overly burdensome requirement on the participants' time and resources. The Company agrees and believes that the Commission should limit the scope and requirements of the process to ensure it is meaningful and efficient. The Company's reply comments briefly respond to the various recommendations by other parties in this matter.

Formal/Informal Process
The Division, the Office, UCE, and WRA each recommend that the collaborative stakeholder process be a formal docketed proceeding. The Company continues to support an informal collaborative process that is not docketed. As stated in the Company's initial comments, a final report could be filed in the general rate case, Docket No. 20-035-04 and/or a docket could be initiated if and when a consensus is reached. The Company believes an informal setting is the best forum for a free-flowing exchange of ideas. A more rigid process with frequent filings and technical conferences could quickly become time-consuming for all participants and administratively burdensome.

Initial Action
The Division, the Office, UCE and WRA each put forth a specific action to commence the collaborative process. The Division suggests that the Commission set a scheduling conference to

determine a date when parties can convene to discuss the scope of the collaborative. The Company believes that this would be duplicative of the process established by these comments on the collaborative and that an additional scheduling conference to determine a date to discuss the collaborative is not necessary.

The Office, UCE, and WRA each recommend the Company be required to make an initial filing containing various information related to the Advance Meter Infrastructure ("AMI") project listed in their comments. Rocky Mountain Power does not believe that making a formal filing aligns with the intent of a collaborative process. A requirement for formal filings, similar to that of a contested case proceeding, would dampen a potentially open atmosphere for engagement and discussion. This format would simply be a repeat of the general rate case that recently concluded and could easily become just as burdensome on the resources of the participants. Rather than having the Company make an initial filing, it would be better to simply discuss the various topics during several collaborative meetings with an open dialogue where questions can be asked, and ideas shared in real-time. Once parties have had time to discuss and work through issues in this forum, a formal filing could be made at a later time with agreed-upon solutions instead of filings espousing diverse parties' positions.

Scope/Topics

The Office, UCE, and WRA recommend the scope include, as a primary focus, but not necessarily limited to, discussion of grid modernization, AMI, and advanced rate design ("ARD"), including an ARD roadmap. As it articulated in the rate case, the Company continues to believe that requiring the Company to create an ARD roadmap is the wrong way to proceed. A very formal ARD would be more burdensome than having discussions at a collaborative session with the parties and could constrict discussions that take place. During a collaborative session, the relevant questions posed by the parties related to rate structures enabled by AMI can be answered by Company expert(s), or other parties' experts, with a more cooperative two-way exchange of ideas.

Based on the comments, the Company is also concerned that the scope of the collaborative stakeholder process could easily stray from the intended cost of service and pricing topics. Exploring future rate designs that AMI can enable, while perhaps the most often cited aspect of the collaborative by various parties, is not nor should not be the only topic of discussion. Cost of service methodology and retail rate unbundling are equally relevant and meritorious of discussion through this process. The context of the collaborative stakeholder process is the Company's general rate case. As such, discussions at each of the different collaborative sessions should be limited to the ratemaking issues of future rate designs and cost of service methodologies that could be incorporated into the Company's next general rate case. The broad range of topics covered under this scope will already be ambitious and should not be broadened further to include application of AMI to IRP, distribution system planning, or new potential non-rates-related customer service features enabled by AMI. If the scope were expanded to include such items, significant burden would be imposed upon all parties involved and a timely resolution before the Company's next rate case may not be possible.

The Commission supports the Company's proposed scope in its December 30, 2020 Order on page 62 where it states: "The purpose of this collaboration is to facilitate the exploration of improvements to current methods for assigning cost responsibility to the various customer classes and designing commensurate rates, including the unbundling of rate elements." The Company continues to recommend that the Commission adopt the schedule in the appendix to its initial comments, or something very similar, for this stakeholder process.

Kroger requests that the stakeholder process consider a multi-site commercial rate for schedule 6 customers. The Company believes that this topic is a good example of one that falls within the "discussion on additional cost of service topics as needed" that was included in the sample schedule in its comments.

<u>Length of Collaborative Stakeholder Process</u>
Rocky Mountain Power supports a maximum two-year process, which is long enough to provide ample opportunity for meaningful discussions while requiring parties to reach a conclusion. UCE recommends the collaborative stakeholder process continue until the next general rate case or 2024, whichever is earlier. The Company believes this timeframe is longer than necessary and would unduly burden the participants with several years of meetings.

<u>PSC involvement</u>
The Office, WRA, and UCE also recommend establishing a series of technical conferences with the Commission. The Company leaves it to the Commission's discretion and interest as to whether it wishes to convene technical conferences on this subject matter.

<u>Reporting</u>
The Office, UCE, and WRA recommend various frequencies of required reporting. The Company recommends that reporting be required no more frequently than annually with a final report due at the conclusion of the collaborative stakeholder process. A similar collaborative process took place in 2005 and discussed various cost of service and rate design subjects. The final report for this cost of service collaborative is provided as Appendix 1 to these reply comments. The Company envisions a similar final report being the end product for the collaborative stakeholder process presently under consideration.

<u>Ongoing Requirements</u>
The Office recommends the Commission consider requiring the Company to reconvene the collaborative stakeholder process prior to filing for any new rate design or pilot program to allow stakeholders a chance to provide input before filing. The Company disagrees with imposing this as a requirement on the Company as it is inconsistent with the statutory and administrative process for the Company to seek changes to its tariffs.

Thank you for your consideration of these comments. The Company is hopeful that these efforts will enable a thoughtful and useful process for all parties.

Sincerely,

Joelle Steward

Joelle Steward
Vice President, Regulation

CC: Service List - Docket No. 20-035-04

Appendix 1

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 and Rate Design Taskforce

Report to the

Utah Public Service Commission

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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
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Artie Powell	DPU
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Michael Reid	PacifiCorp
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Betsy Wolf	SLCAP
Gary Dodge	UAE
Kevin Higgins	UAE
Neal Townsend	UAE
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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

- <u>Consistent with cost causation</u>: 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.

- <u>Stability</u>: Retains existing cost allocation methodology.

- <u>Gradualism:</u> 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.

DPU Recommendation: 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.

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.

DPU Recommendation: 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

Appendix 1

Overview on cost of service principles and methodologies

COST OF SERVICE

OBJECTIVES & METHODOLOGY

Utah Cost of Service Taskforce

May 23, 2005

Dave Taylor

Cost of Service Objectives & Methodology

I. Conceptual Overview

II. Current PacifiCorp Methodology

   A. Functionalization

   B. Classification & Allocation

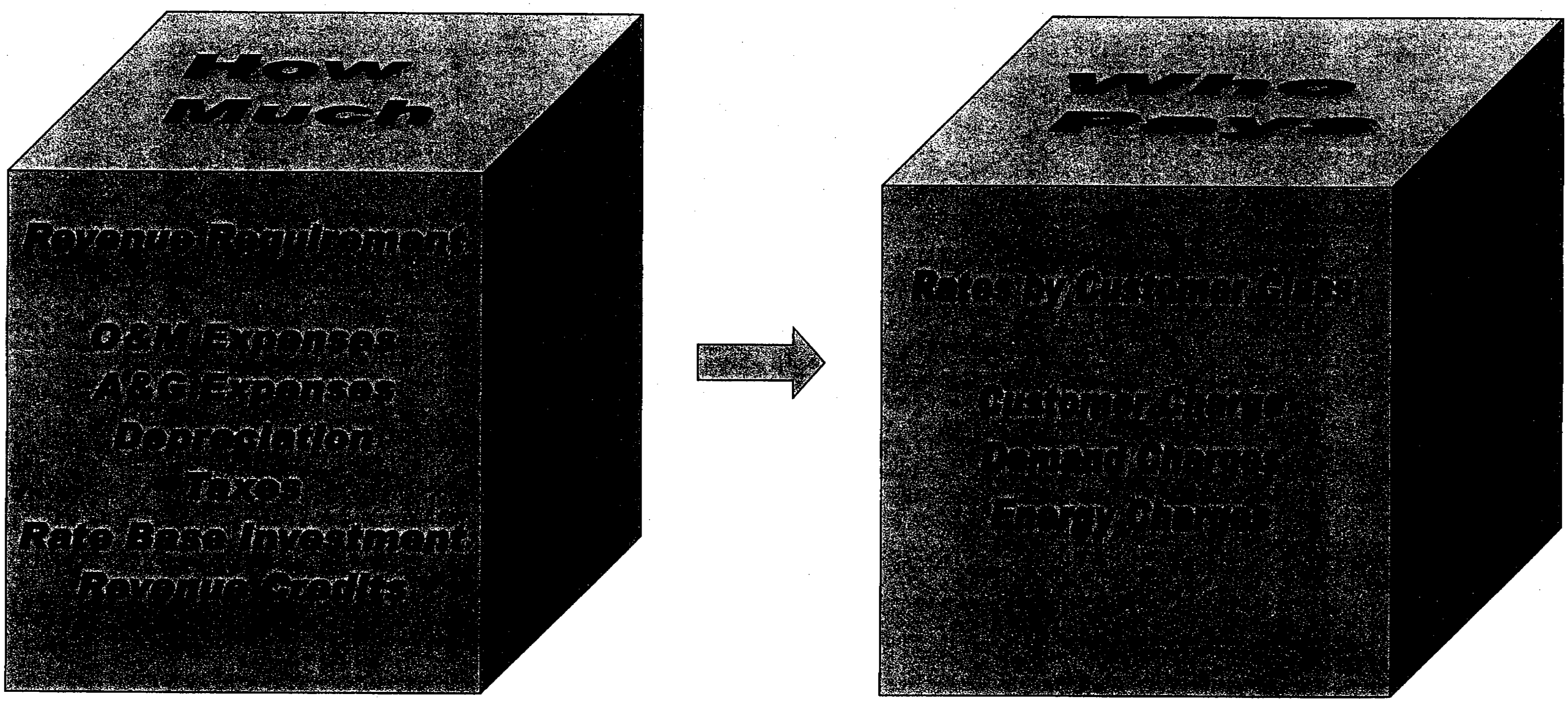
      1. Generation
      2. Transmission
      3. Distribution
      4. Customer Service, Billing & Collections

III. Cost of Service to Rate Design

Cost of Service Section I Conceptual Overview

Getting from "How Much" to "Who Pays"

Utility Rate Setting
Two Questions
How Much & Who Pays



PACIFICORP

Cost of Service

The Bridge between Revenue Requirement & Rates

PACIFICORP

Cost of Service

Dividing the Revenue Requirement

Cost of Service
A Three Step Process

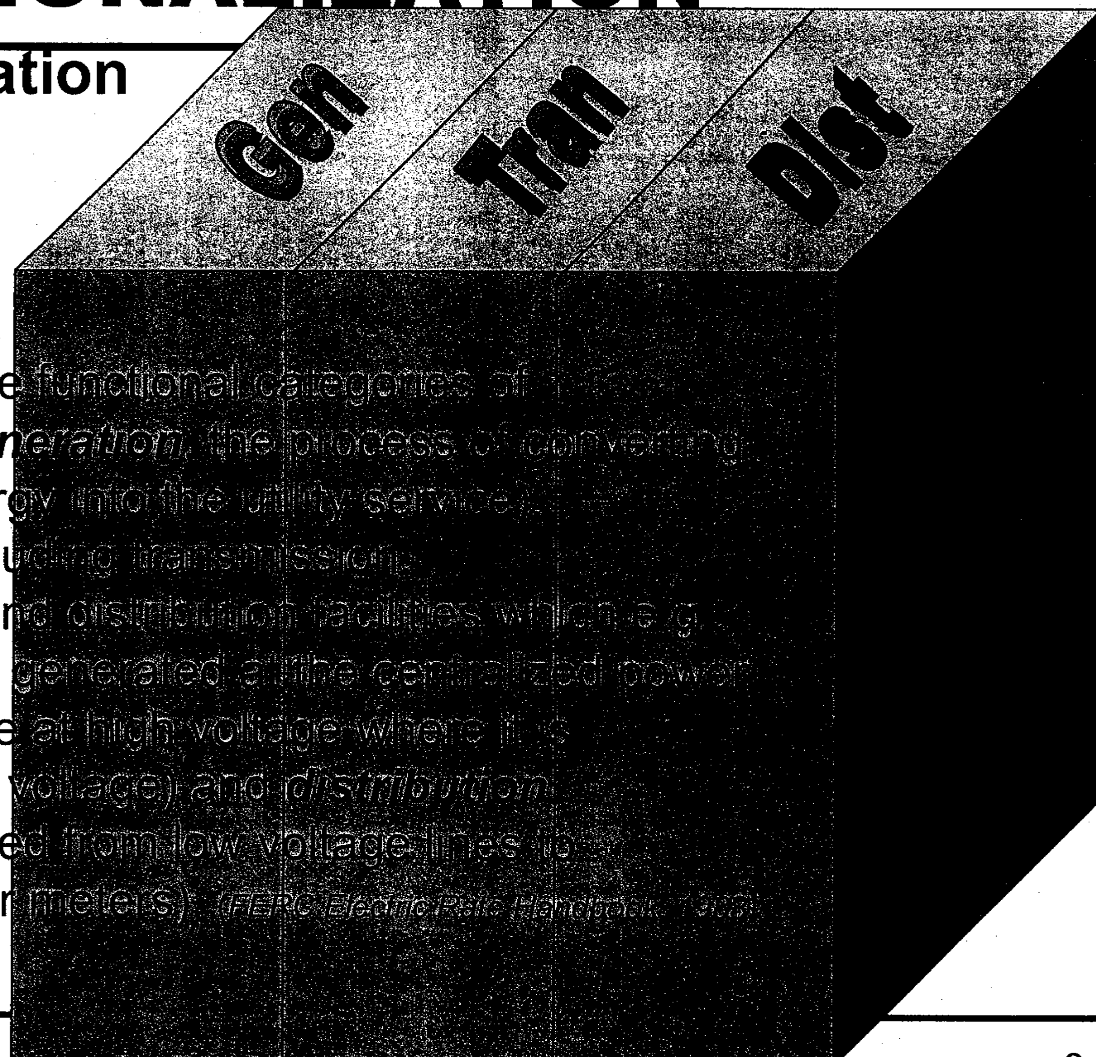
Functionalization

Classification

Allocation

FUNCTIONALIZATION

- **Functionalization**
- Classification
- Allocation



Assignment into the functional categories of ***production*** (or ***generation***, the process of converting other forms of energy into the utility service), ***transmission*** (including transmission, subtransmission, and distribution facilities which e.g. send the electricity generated at the centralized power station through wire at high voltage where it is transformed to low voltage) and *distribution* (electricity distributed from low voltage lines to individual ratepayer meters). *(FERC Electric Rate Handbook, [illegible])*

PACIFICORP

CLASSIFICATION

- Functionalization
- **Classification**
- Allocation

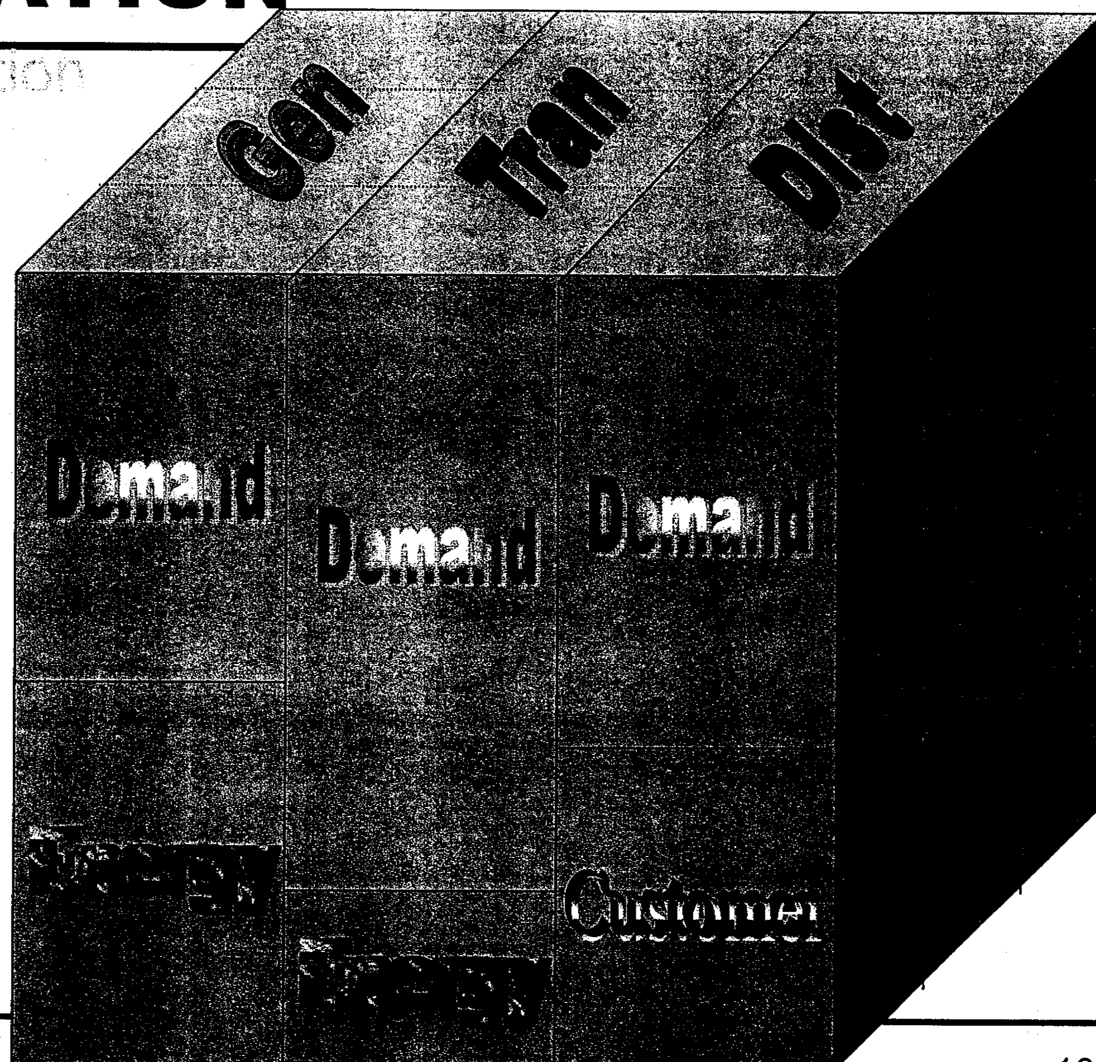
Assignment by energy usage, peak demand, and number of customers within the functional categories.

(FERC Electric Rate Handbook, 1983)

PACIFICORP

ALLOCATION

- Functionalization
- Classification
- **Allocation**



Assignment to stable customer groupings or classes consistent with Functionalization and Classification

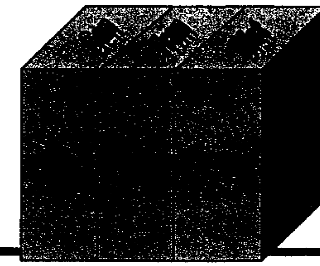
(FERC Electric Rate Handbook, 1983)

PACIFICORP

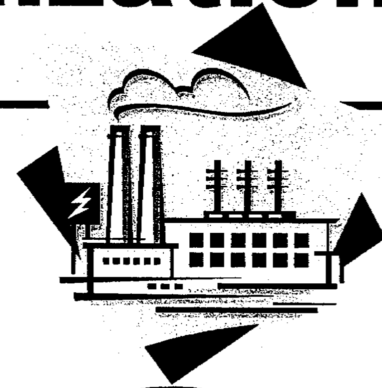
Cost of Service
Section II

Current PacifiCorp Methodology

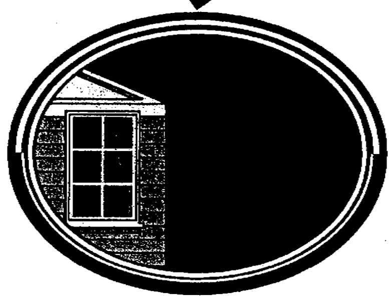
Functionalization



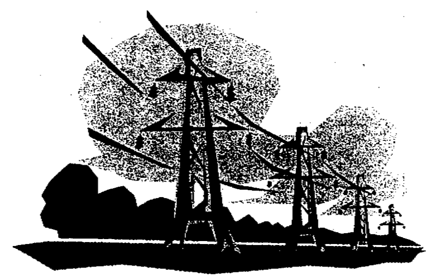
- Generation



- Transmission



- Distribution



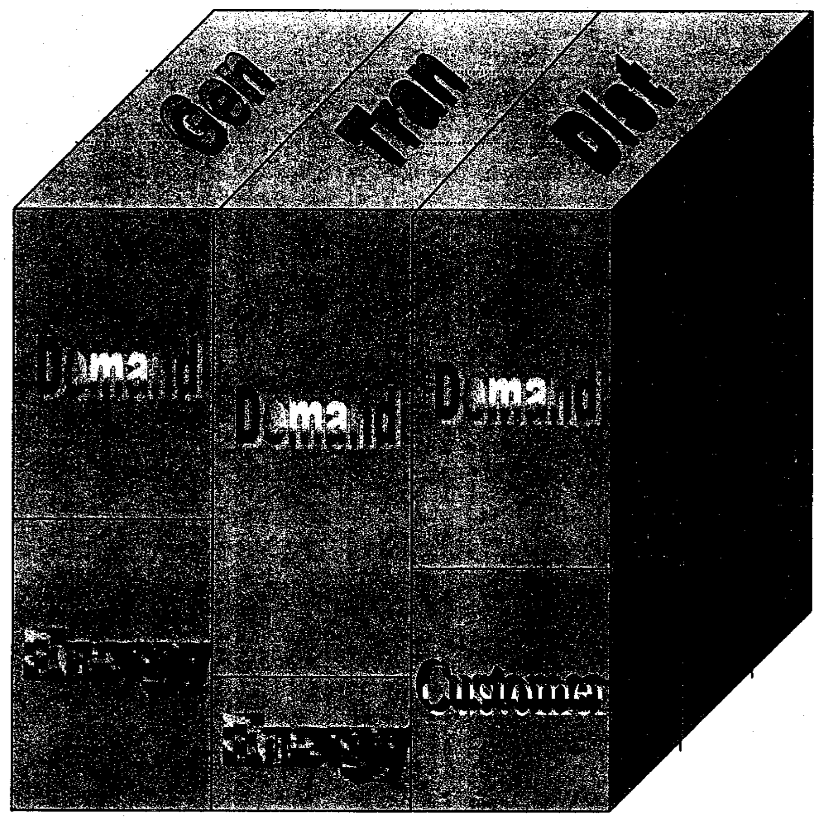
- Retail
(Customer Service &
Billing)

- Miscellaneous

Functionalization Procedures

- Direct Assign where Practical
  - 80% to 90% of costs can be direct assigned to one of the primary functions
- FUNC Factors
  - Composite more granular direct assignments
  - % of Direct Assigned Plant Investment by Function
  - % of Direct Assigned Labor by Function

Classification and Allocation



Generation
Current Utah Methodology

- Classification
  - Plant Investment & Other Fixed Costs
    - 75% Demand / 25% Energy
  - Fuel
    - 100% Energy
  - Firm Wholesale Purchases & Sales
    - 75% Demand / 25% Energy
  - Non-Firm Wholesale Purchases & Sales
    - 100% Energy
  - Total Generation Costs
    - Approximately 50% Demand / 50% Energy

Generation
Current Utah Methodology

- Allocation
  - Demand Related Costs
    - 12 CP
  - Energy Related Costs
    - Annual MWh

Generation

Methodology used in Other States

- Idaho & Wyoming
  - Same as Utah
- Oregon & California (Marginal Costs)
  - Demand – Fixed Costs of SCCT
    - Allocated on Average of 12 Monthly CP
  - Energy – Fuel and remaining Fixed Costs of CCCT
    - Allocated on Annual MWh
  - Total Generation Costs Approximately 25% Demand / 75% Energy
- Washington
  - Demand – ½ Fixed & Fuel Cost of SCCT running 200 Hours
    - Allocated on top 100 winter & 100 summer peak hours
  - Energy – All other costs
    - Allocated on Annual MWh
  - Total Generation Costs Approximately 13% Demand / 87% Energy

Transmission

Current Utah Methodology

- Classification
  - Plant Investment & Expenses
    - 75% Demand / 25% Energy
  - Firm Wheeling
    - 75% Demand / 25% Energy
  - Non-Firm Wheeling
    - 100% Energy
- Allocation
  - Demand - 12 CP
  - Energy - Annual MWh

Transmission

Methodology used in Other States

- Idaho & Wyoming
  - Same as Utah
- Oregon & California (Marginal Costs)
  - Backbone Transmission
    - Classified & Allocated Same as Generation
  - Local Transmission –
    - Classified 100% Demand
    - Allocated on Average of 12 Monthly CP
- Washington
  - Same as Generation

Distribution
Current Utah Methodology

- Classification
  - Meters & Service Drops – Customer Related
  - All Other Distribution Costs – Demand Related
- Allocation
  - Substation & Primary Lines
    - 12 Weighted Distribution Peaks
  - Line Transformers
    - Secondary Voltage Customers Only
    - Class Maximum Month Customer NCP Adjusted for Customer per Transformer Coincidence Factor
  - Secondary Lines
    - Only classes where more than one customer shares line transformer
    - Class Maximum Month Customer NCP Adjusted for Customer per Transformer Coincidence Factor
  - Meters & Services
    - Fully Installed Costs of New Meters and Services

Distribution

Methodology used in Other States

- Wyoming
  - Primary Lines
    - Large Industrial Customers broken our separately
    - All other Classes – 12 Distribution Peaks
- Washington
  - Primary Lines
    - Annual Schedule Peak (Class NCP)
- Oregon (Marginal Costs)
  - Distribution Feeders (Primary and Secondary)
    - Composite Feeder
    - Distance Based
    - Minimum System (Demand & Commitment)
  - Transformers
    - Zero Intercept Method

Retail Functions

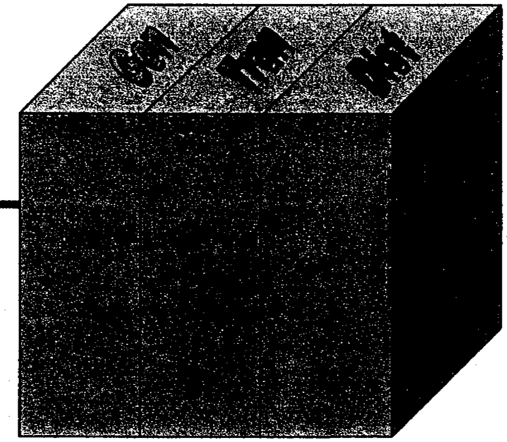
Customer Service – Billing - Collections

- Meter Reading
  - Typical Meter Reading Times by Class (Including Travel Time)
- Customer Service – Billing - Collections
  - Weighted Customers
    - Average per Customer Billing Costs (Including Manual Bills)
    - Average Write-off per Customer
    - Many activities have same weighting for all Customers

Cost of Service
Section III

Cost of Service
To
Rate Design

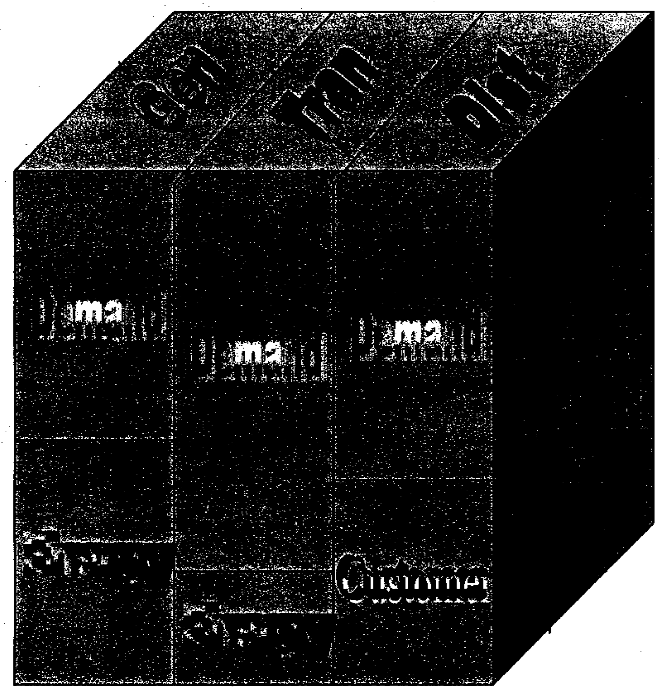
Cost of Service Summary



PacifiCorp
Cost Of Service By Rate Schedule
State of Utah
12 Months Ending March 2006
MSP
MSP Allocation Factors
8.15% = Target Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	1	Residential	441,366,225	8.30%	1.17	447,109,436	225,249,748	24,200,694	157,305,000	37,669,405	2,684,588	5,743,211	1.30%
2	6	General Service - Large	315,525,083	6.42%	0.90	336,956,586	219,070,471	24,669,124	88,927,487	1,957,891	2,331,612	21,431,503	6.79%
3	8	General Service - Over 1 MW	96,635,356	6.90%	0.97	101,563,045	69,938,974	7,481,461	23,261,771	143,056	737,784	4,927,689	5.10%
4	7,11,12,13	Street & Area Lighting	10,847,300	2.77%	0.39	12,386,007	1,836,157	131,741	10,038,227	339,601	40,281	1,538,707	14.19%
5	9	General Service - High Voltage	136,757,310	6.72%	0.94	143,321,419	125,725,649	14,441,890	1,075,534	839,233	1,239,114	6,564,109	4.80%
6	10	Irrigation	9,352,282	2.89%	0.41	11,063,981	7,197,833	743,384	2,894,508	155,278	72,978	1,711,699	18.30%
7	12	Traffic Signals	739,505	7.89%	1.11	755,321	389,811	39,100	204,430	117,339	4,642	15,816	2.14%
8	12	Outdoor Lighting	725,216	61.77%	8.67	335,155	228,508	15,016	71,734	16,290	3,606	(390,061)	-53.79%
9	21	Electric Furnace	241,825	11.04%	1.55	229,598	150,476	19,754	25,938	31,724	1,707	(12,227)	-5.06%
10	23	General Service - Small	80,575,401	7.32%	1.03	83,922,273	47,377,319	5,305,674	27,515,554	3,189,672	534,055	3,346,872	4.15%
11	25	Mobile Home Parks	658,771	7.65%	1.07	680,675	415,437	44,604	215,665	404	4,564	21,904	3.32%
12	SpC	Customer A	7,845,685	5.11%	0.72	8,529,757	7,609,707	777,706	60,192	8,252	73,899	684,072	8.72%
13	SpC	Customer B	16,333,550	6.58%	0.92	17,027,659	15,480,100	1,227,286	93,581	72,342	154,351	694,109	4.25%
14	SpC	Customer C	17,601,092	-0.66%	(0.09)	22,323,689	19,825,219	2,203,618	101,166	9,530	184,157	4,722,597	26.83%
15		Total Utah Jurisdiction	1,135,204,601	7.12%	1.00	1,186,204,601	740,495,410	81,301,052	311,790,786	44,550,016	8,067,337	51,000,000	4.49%

Unit Costs



Schedule No. 6

Demand per kW Month

Gen	$7.72
Tran	$1.33
Dist	$5.37

Energy per kWh

Gen	1.75 Cents
Tran	0.38 Cents
Misc	0.04 Cents

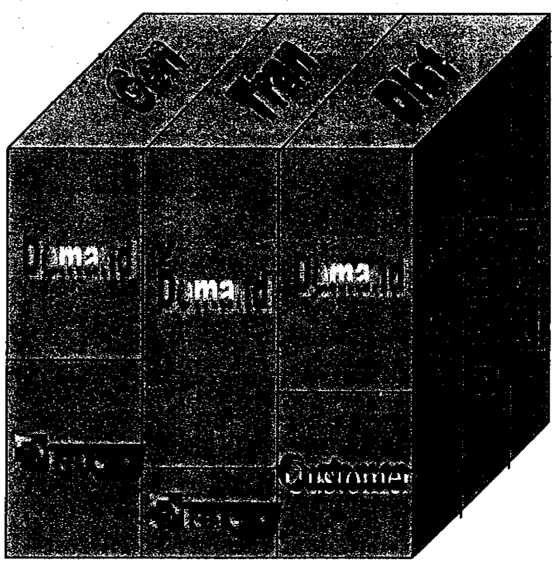
Customer per Month

Meter	$13.36
Service	$11.56
Retail	$11.60

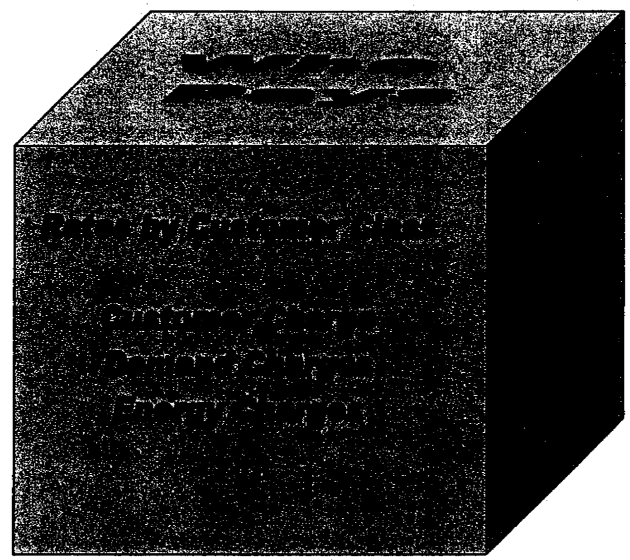
PACIFICORP

Cost of Service to Rate Design

How Costs are Allocated



How Bills are Paid



Appendix 2

Historical perspective on Utah cost allocation practices.

History of Utah PSC Decisions on Class Cost of Service Issues in PacifiCorp General Rate Cases

April 12, 1982:
PSC Order, Docket No. 79-035-12
Distribution costs to be classified as demand-related (p4)
Federal income tax exp to be allocated on rate base (p9)
Uncollectibles NOT to be treated as customer costs for rate design purposes (p9)
Company to report results of consultant's loss factor study (p11)
Minimum bill to include cost of meter & service drop and meter reading, billing and accounting (p14-15)

March 7, 1983:
PSC Order, Docket No. 81-035-13
Stated intent of order is to provide guidelines and policies for future cost of service studies (p3)
Adopted for future use DPU classification of distribution costs (mostly demand) & rejected use of minimum distribution system (p12)
Directed Company to develop with DPU allocation factor that reflects design characteristics of the distribution system (p13)
Coal mining operation costs classified as energy-related (p15)
Adopted for future cost of service studies the Stone & Webster Study method for developing loss factors (p16)
Found reasonable Dr. Compton's criteria (reserve margins, loss of load probability & probability of contribution to system peak) for determining which months to include in a coincident peak allocation factor (p22)
Adopts 8CP allocation method for production plant (p25)
Continues use of gradualism concept for rate spread increases (p29)
Adopts as a reasonable regulatory objective - each customer schedule over time be brought to within a range of plus or minus 10% of relevant cost of service study results. (p35).

January 30, 1984:
PSC Order, Docket No. 83-035-06
Company to conduct a study to determine the proper allocation of distribution substations and primary distribution lines (p14-15)

June 7, 1985:
PSC Order, Docket No. 84-035-01
Reaffirms 8CP allocation method (p10)
Distribution Study presented – PSC allows further consideration in future case (p10)

July 1, 1985:
PSC Order, Docket No. 84-035-01
No party opposed implementation of cost-based customer charges for non-residential schedules (p6)

Cites previous finding in MFS case (82-057-15) that a customer charge results in payment by each customer of those costs he imposes upon the system, which are independent of actual energy consumption (p11)
Finds that customer charge, as opposed to a minimum bill, allows customer costs to be recovered reasonably and properly (p12)
Imposes $1.00 residential customer charge (p12)

February 9, 1990:
PSC Order, Docket No. 89-035-10
Reaffirms 8CP allocation method (p26)
Adopts Distribution Study allocation methods for future cost of service studies (p28, 35)
Distribution (6 year) Study recommended allocation of substations & primary lines on 12 weighted coincident distribution peaks, line transformers & secondary lines on weighted annual NCP, and meters & service lines on weighted customers (p26)
A&G accounts 920 & 935 to be allocated on plant per DPU recommendation (p27)
Cites two past PSC policy guidelines (Docket No. 81-035-13) – 1-bring each class within a range of plus or minus 10% of cost of service, 2-objective of gradualism to avoid abrupt changes in rates (p31)
Approved $1.00 customer charge for residential rates 1 & 5 (p32)

April 10, 1992:
PSC Order, Docket No. 90-035-06
Finds residential customer-related costs are $2.15 per month (p45)
Keeps residential customer charge at $1.00 as PSC gives greater weight to an equal sharing of schedule revenue reduction than to recovery of all customer-related costs in a customer charge (p46)
Adopts DPU/Company proposed customer charges for rates 6,6A,6B,9,9A,9B & 23 (p50,51,53,57,58)
Load research is key to effective ratemaking (p60)
Finds that accurate estimates of class load and loads within classes are essential for cost allocation and rate design (p61)
Company should maintain adequate load research and data collections so that this regulatory body can make appropriate decisions on cost allocations, rate design and evaluation of DSM programs (p61-62)

March 4, 1999:
PSC Order, Docket No. 97-035-01 (available at www.psc.utah.gov)
Rejects Company's approach to functional unbundling (p76)
Adopts 12CP, 75% demand & 25% energy, for allocating production and transmission plant (p76, 78, 79)
Rejects Company loss factors since derived by an unapproved method (p76, 80)
Rejects Company labor-based approach to allocate A&G expenses (p76, 80, 81)
Accepts DPU proposal to allocate sales for resale revenues on a 65% demand & 35% energy basis (p77, 81, 82)
Reaffirms allocation of income taxes on rate base (p77, 82)
Accepts CCS proposal for weighting factors for accounts 902 & 903 (p77, 83, 84)

Establishes Allocation Task Force to study unresolved issues (p77)
Approves use of secondary loss factors for irrigation (p85)
No changes made to customer charges (p92)
Customer charges, by previous PSC decision, are the costs of meters, service drops, meter reading and billing and collecting (p101)
Retention of both the customer charge (residential) and the minimum bill at current levels promotes an equitable intra-class distribution of the rate decrease (p103)

May 24, 2000:
PSC Order, Docket No. 99-035-10 (available at www.psc.utah.gov)
The cost of service studies on this record are not completely reliable (p79)
Implemented lifeline rate with an $8 per month credit & $1.8 mill per year cap (p82)
Customers hate the residential customer charge (p88)
No changes made to residential customer charge (p89)
Set line extension allowance at $1100 for residential customers and two years of estimated revenues for non-residential customers (p84)

November 2, 2001:
PSC Order, Docket No. 01-035-01 (available at www.psc.utah.gov)
No COS issues litigated, PSC approved stipulated settlement

January 30, 2004:
PSC Order, Docket No. 03-2035-02 (available at www.psc.utah.gov)
No COS issues litigated, PSC approved stipulated settlement

February 25, 2005:
PSC Order, Docket No. 04-035-42 (available at www.psc.utah.gov)
No COS issues litigated, PSC approved stipulated settlement

Appendix 3

Seasonality in G&T Allocation

Summary of MEB's June 15, 2005 Presentation on Seasonality in Costs and Loads

On June 15, 2005, Maurice Brubaker made a presentation to explore "seasonality in costs and loads."

The analysis began with a review of PacifiCorp's monthly peaks and loads and how they have changed over the period 1994 through 2006. The presentation material demonstrated that, both on a Utah-state specific basis and a corporate-wide basis, summer peaks have grown significantly more than peaks in other months. Winter peaks have grown as well, but not nearly to the same extent. On a total company basis, over the period 1994 through 2006, summer peak loads have grown more than 25%, while winter peak loads have generally grown less than 12%.

Further analysis of PacifiCorp's operating profiles indicates that there is a significant difference in the seasonality of load of the various customer classes. The loads of Schedules 8, 9 and 23 are fairly constant across seasons, while the loads of residential customers and Schedule 6 customers exhibit much greater variations, with peaks occurring in the summer, followed by lesser peaks in the winter. On an hourly basis, across the 24-hours of a day and across the seven days of the week, there is much less variation in load by large industrial customers than by other customers, particularly residential and small commercial customers whose demands exhibit large swings.

This pattern is especially significant in the summertime because there are enormous swings from nighttime loads to daytime peaks. An example presented was that on the summer maximum weekday, the daily peak load on this highest day exceeded the minimum load reached during the preceding evening by approximately 72%. In other words, a nighttime low of 1,000 megawatts would be followed the next afternoon by a demand of over 1,700 megawatts. These kinds of load swings must be accommodated by a combination of PacifiCorp's high cost generators and purchased power.

Part of PacifiCorp's strategy of dealing with the "peakiness" and seasonality of its loads is to purchase 6x16 liquated damages products for the summer. This poses two problems. First, these products are typically purchased for an entire quarter. Thus, PacifiCorp has to forecast what it will need for the highest day, and purchase that amount of capacity for the entire summer period. As a result, there will be many days when PacifiCorp does not need all this capacity that it has purchased on a take-or-pay basis. The remedy is to sell this unneeded power off into the market at spot prices much lower than what PacifiCorp paid for it. These prices are low for the same reason PacifiCorp does not need the power – namely, that loads are not as high as during peak times and many suppliers have excess capacity. Thus, losses are typically incurred on this sale, adding further to the cost of serving this volatile load.

A similar phenomena exists with respect to the swing over the daily cycle. The 6x16's must be purchased to cover the absolute peak, but as the load pattern shows there are many hours on the shoulder periods even on high load days, where loads are not anywhere near that level – again requiring PacifiCorp to sell off these shoulders into the markets at spot prices that are much lower than the prices that PacifiCorp is paying for the power – further adding to the costs of serving this highly volatile load.

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.

Utah Cost of Service and Rate Design Task Force

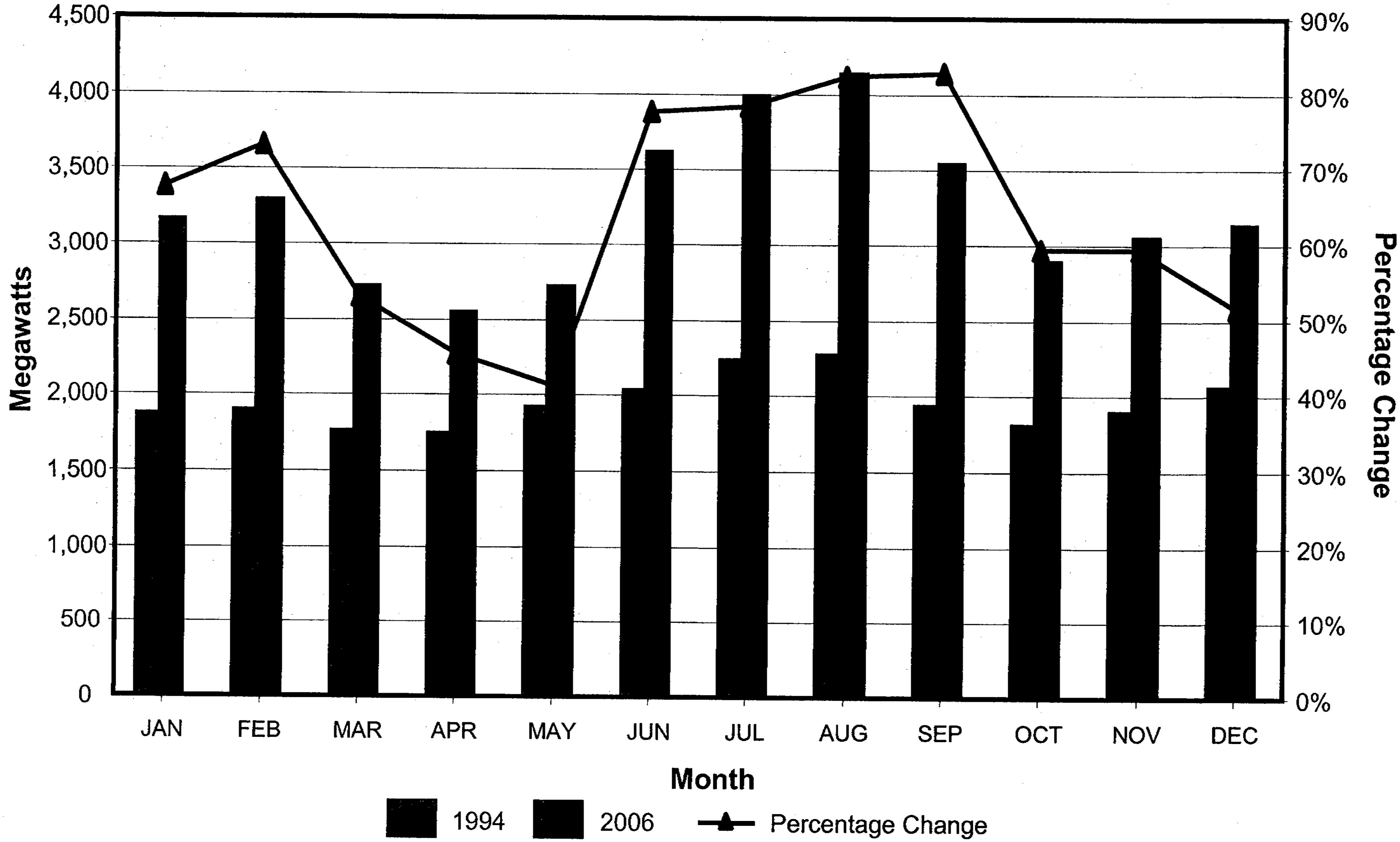
Seasonality in Costs and Loads

Maurice Brubaker

June 15, 2005
Salt Lake City, Utah

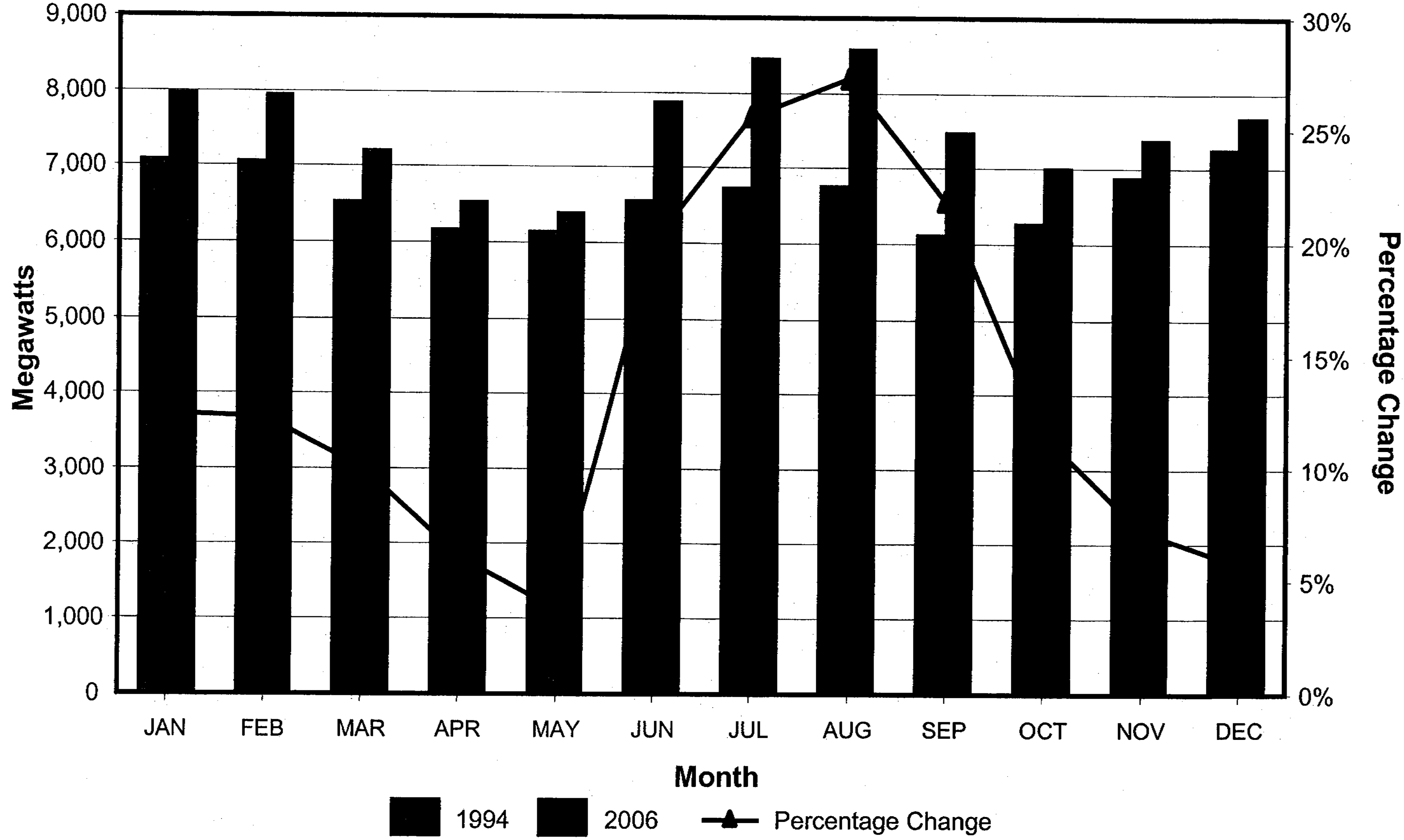
PacifiCorp-Utah

Comparison of Monthly Peaks
for Years 1994 and 2006



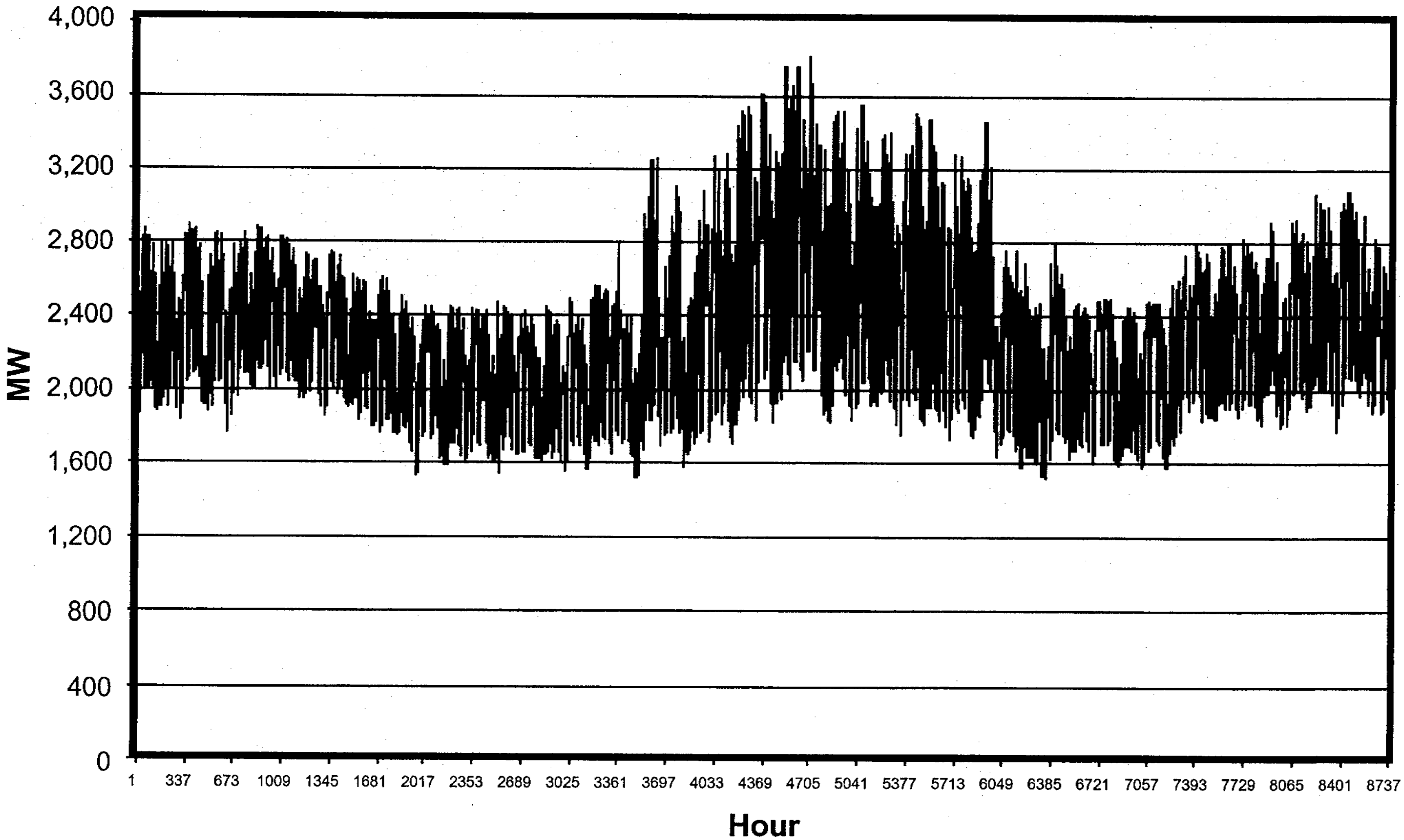
PacifiCorp

Comparison of Monthly Peaks for Years 1994 and 2006



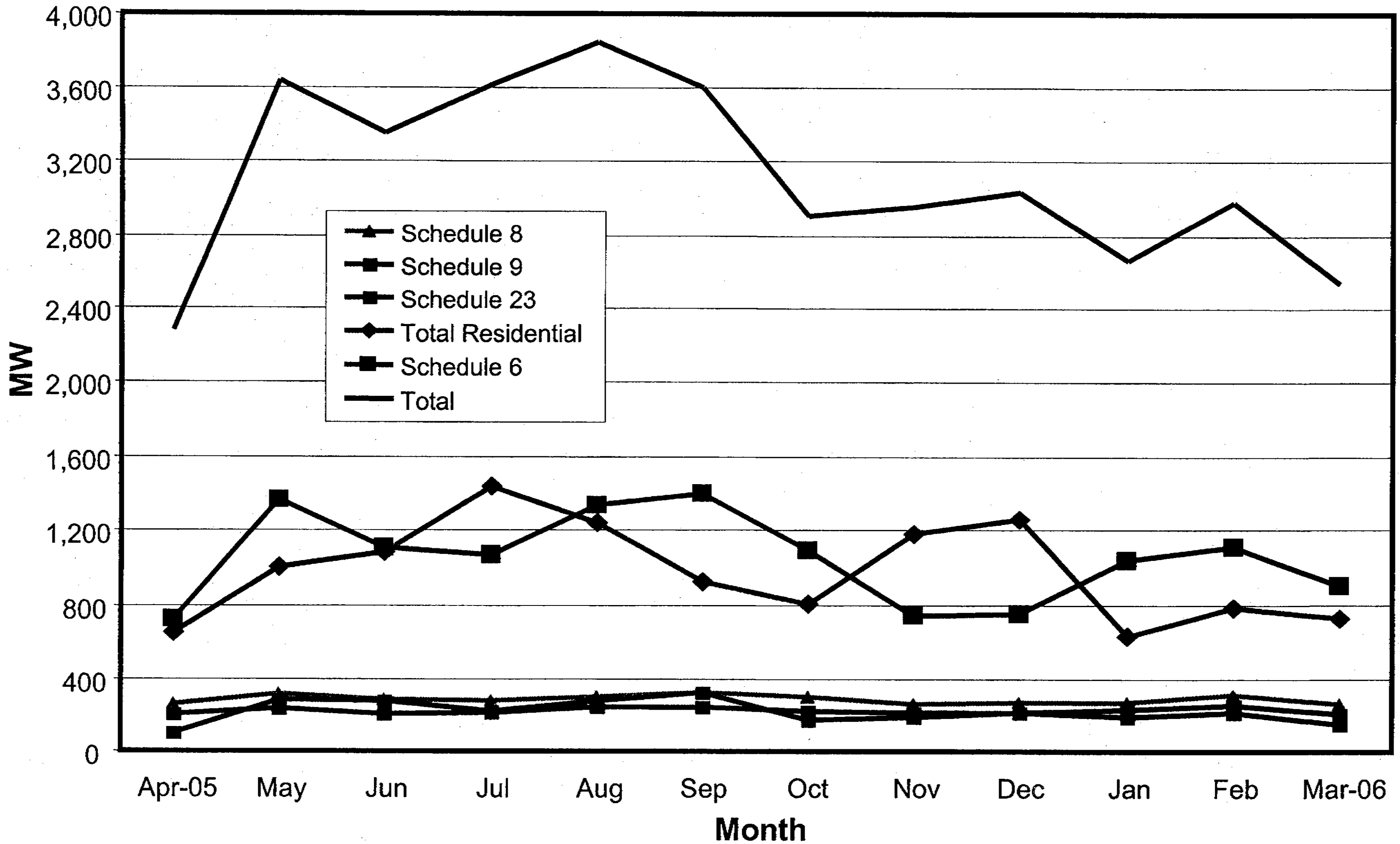
PacifiCorp

Hourly Load Data - Utah



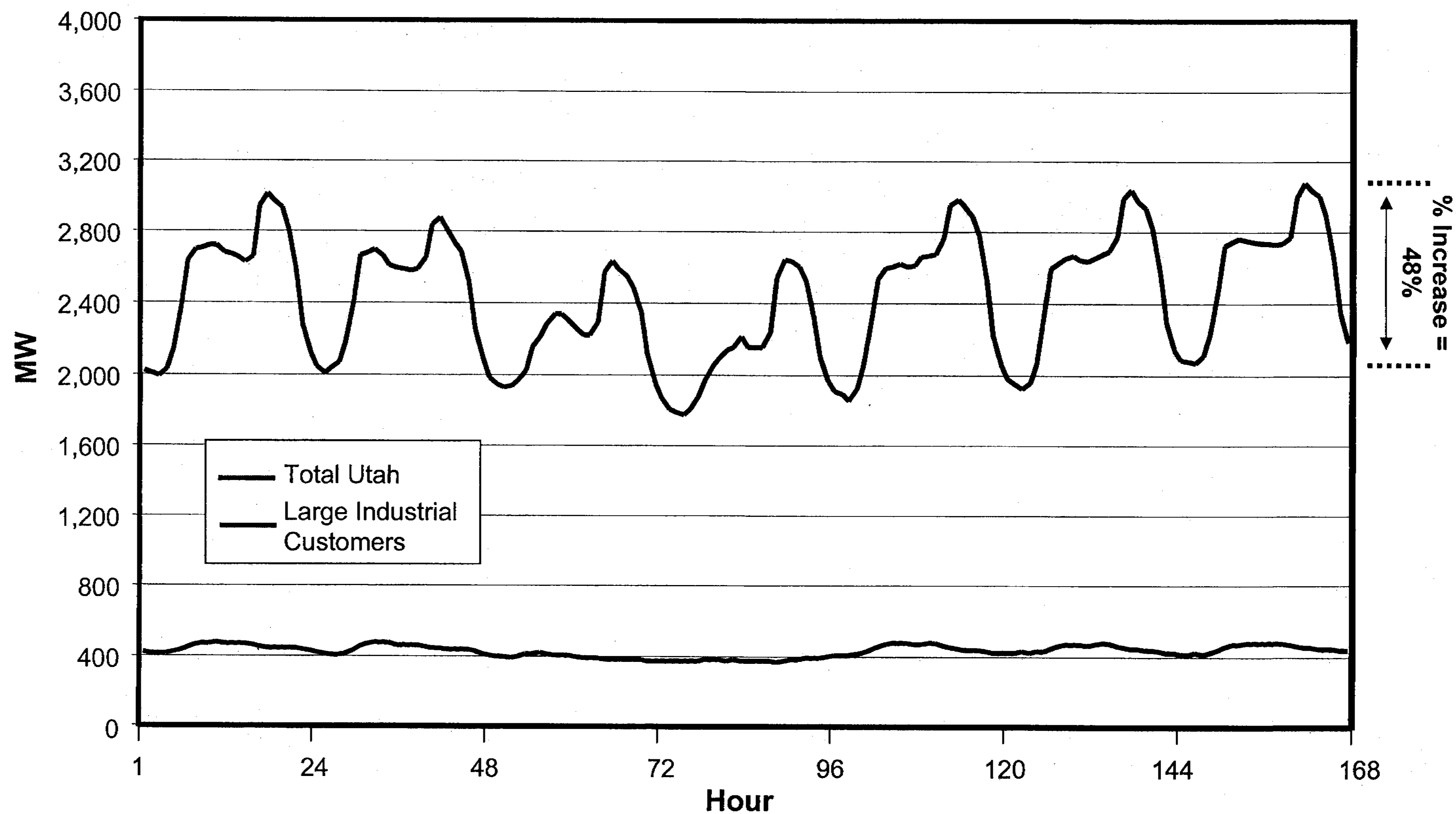
PacifiCorp-Utah

Contribution of Major Classes to Coincident Peak



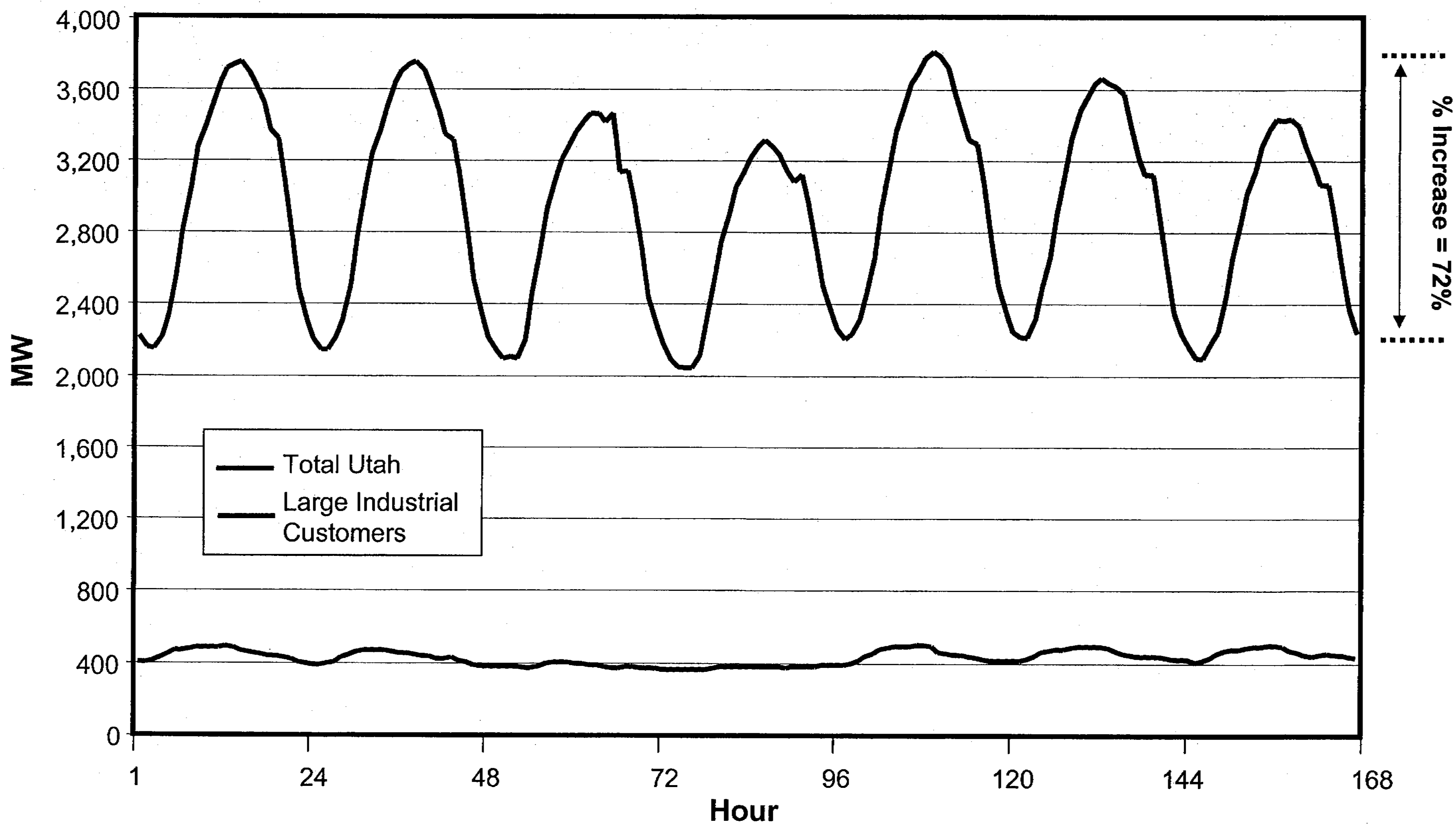
PacifiCorp-Utah

Hourly Load Data for Total Utah and Large Industrial Customers
Maximum Winter Week



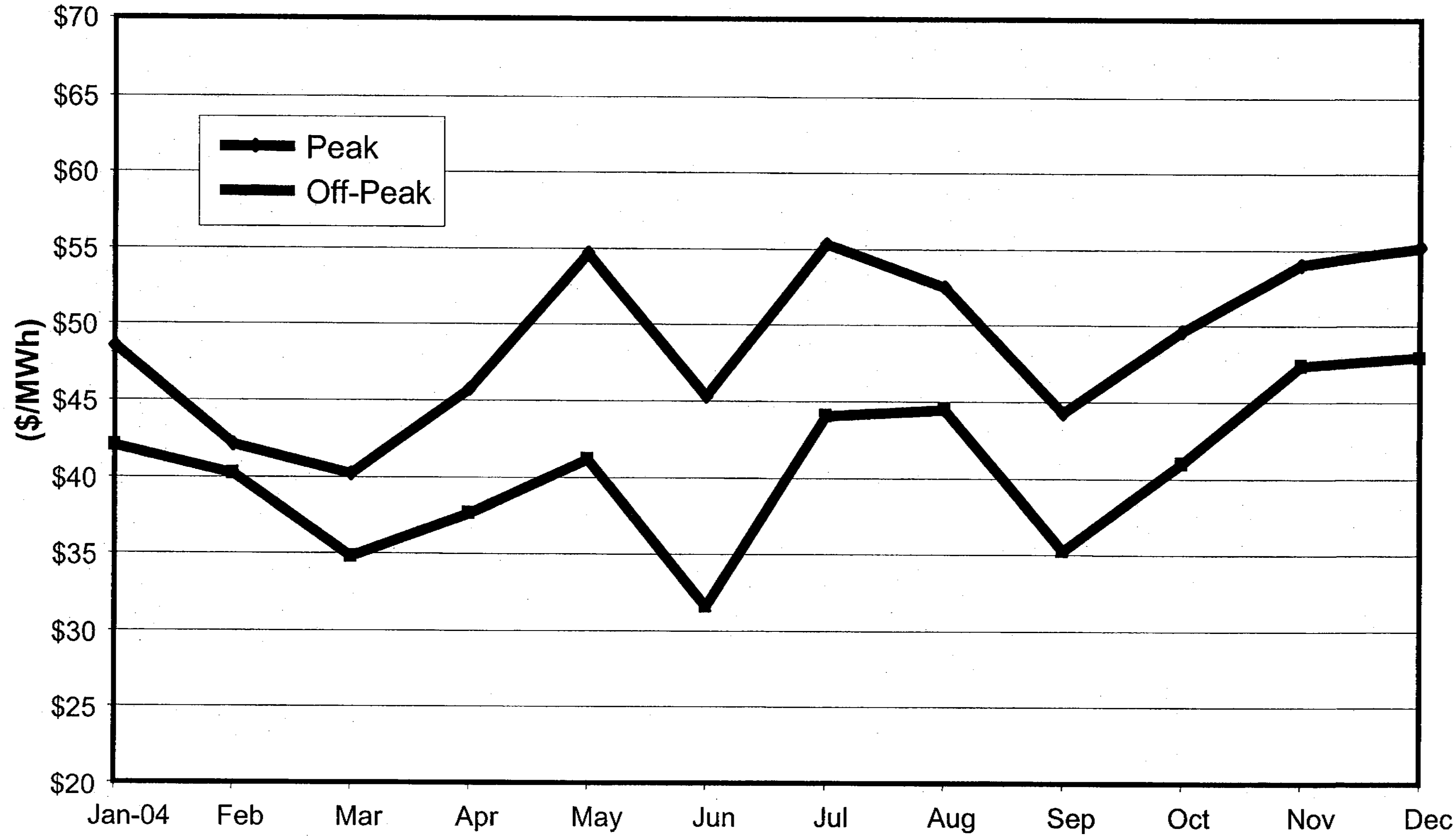
PacifiCorp-Utah

Hourly Load Data for Total Utah and Large Industrial Customers
Maximum Summer Week



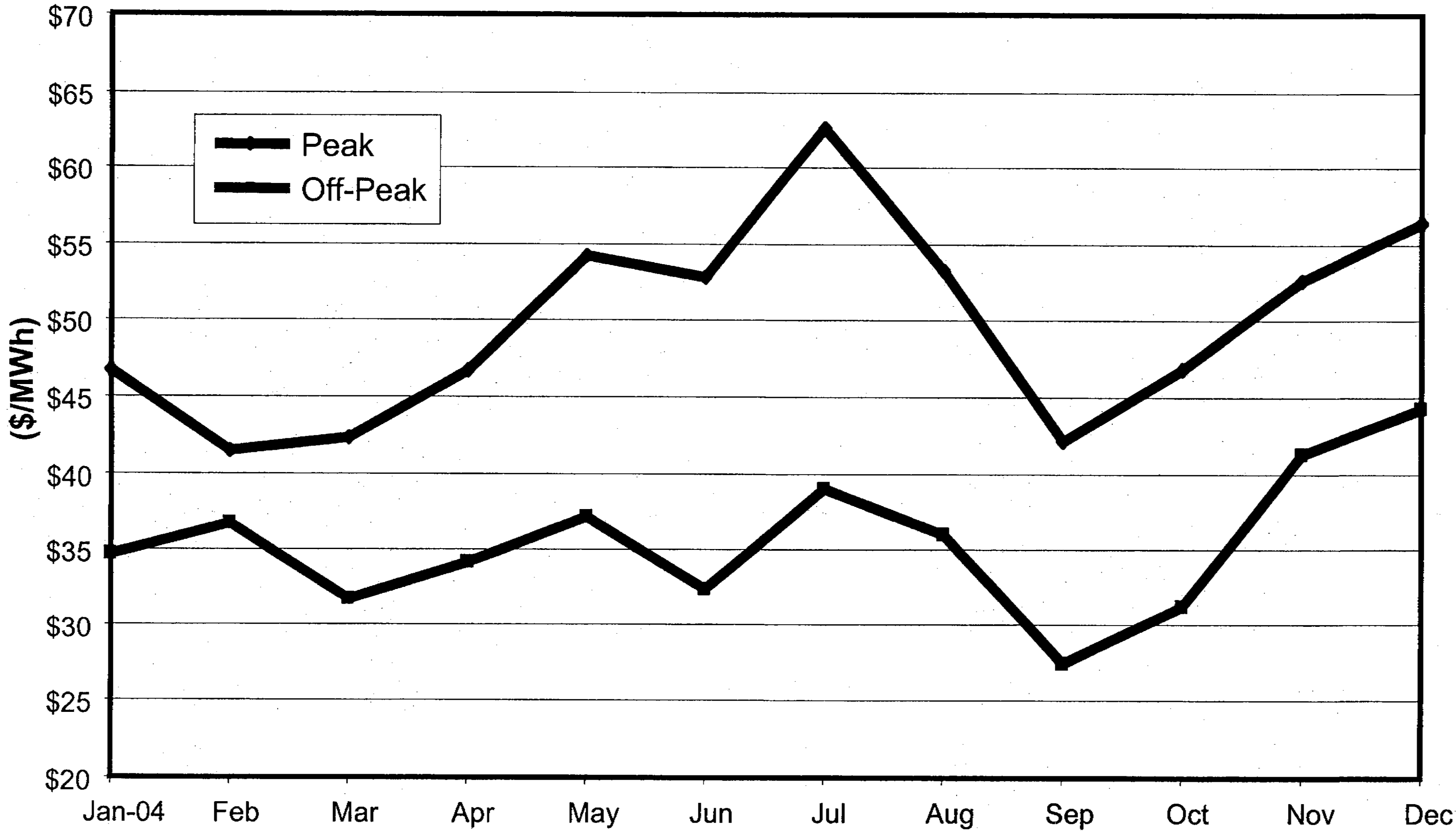
COB

Average Monthly On-Peak Prices
2004



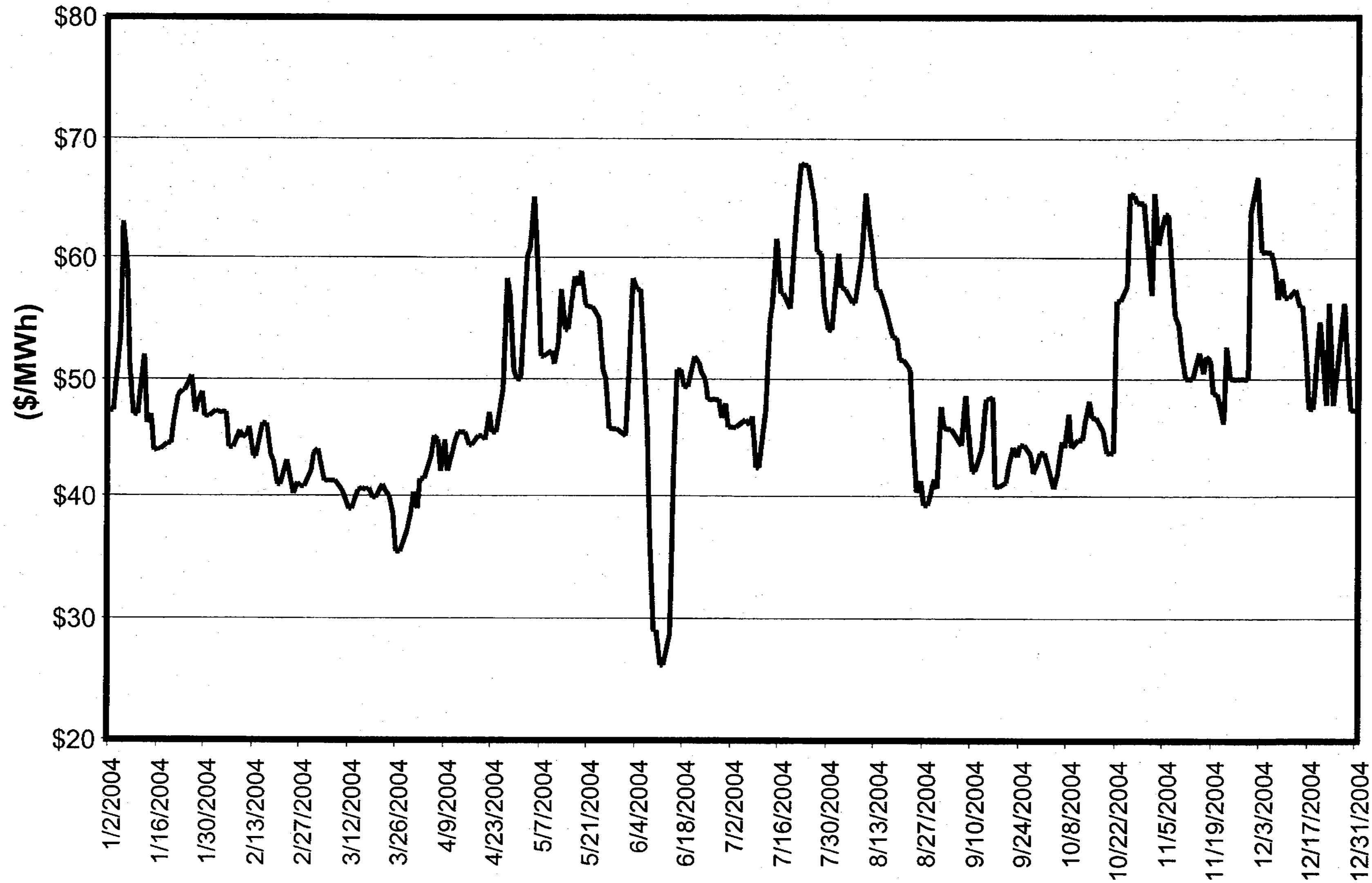
Palo Verde

Average Monthly On-Peak Prices
2004



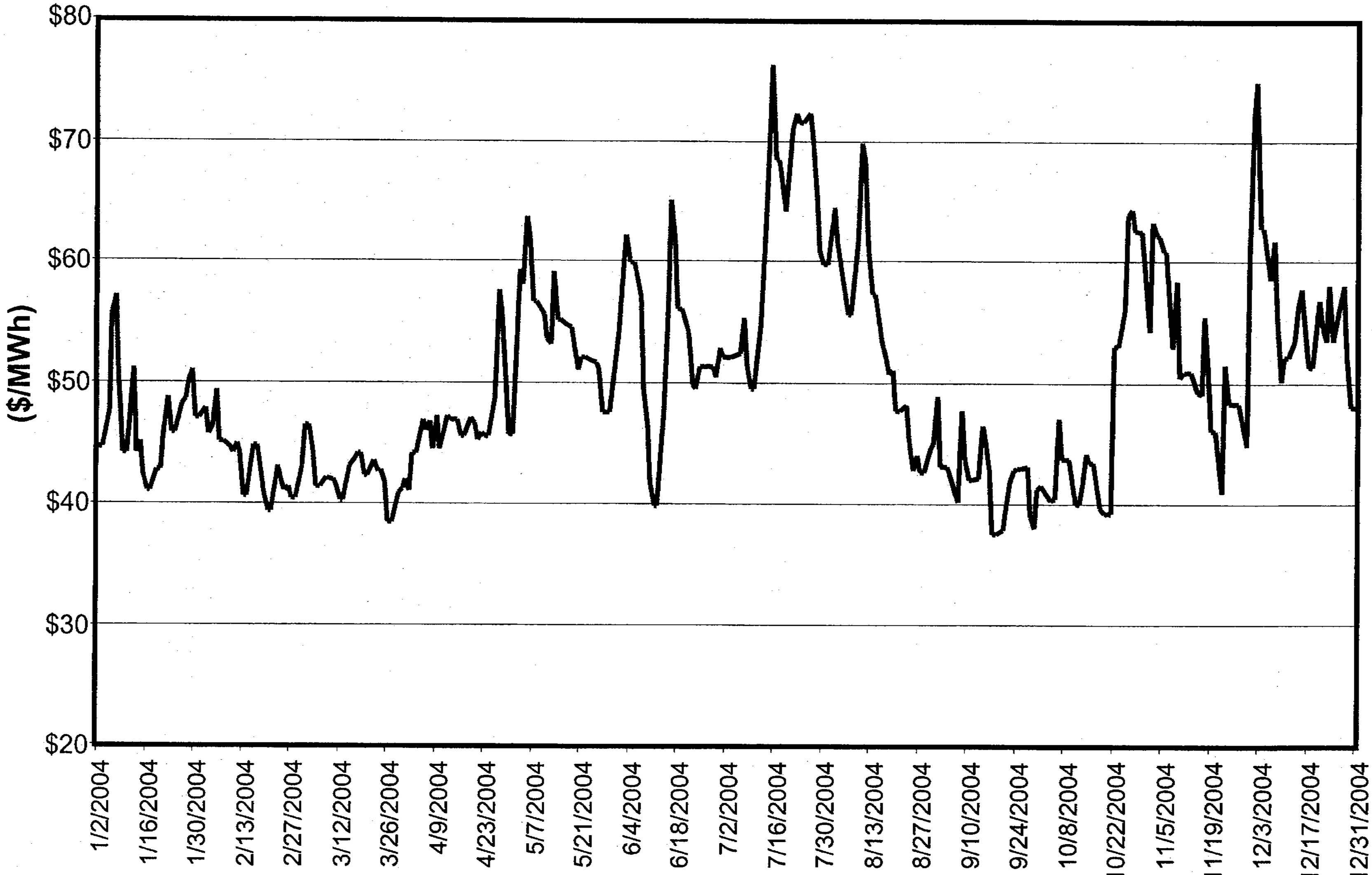
COB

Day Ahead On-Peak Prices
2004



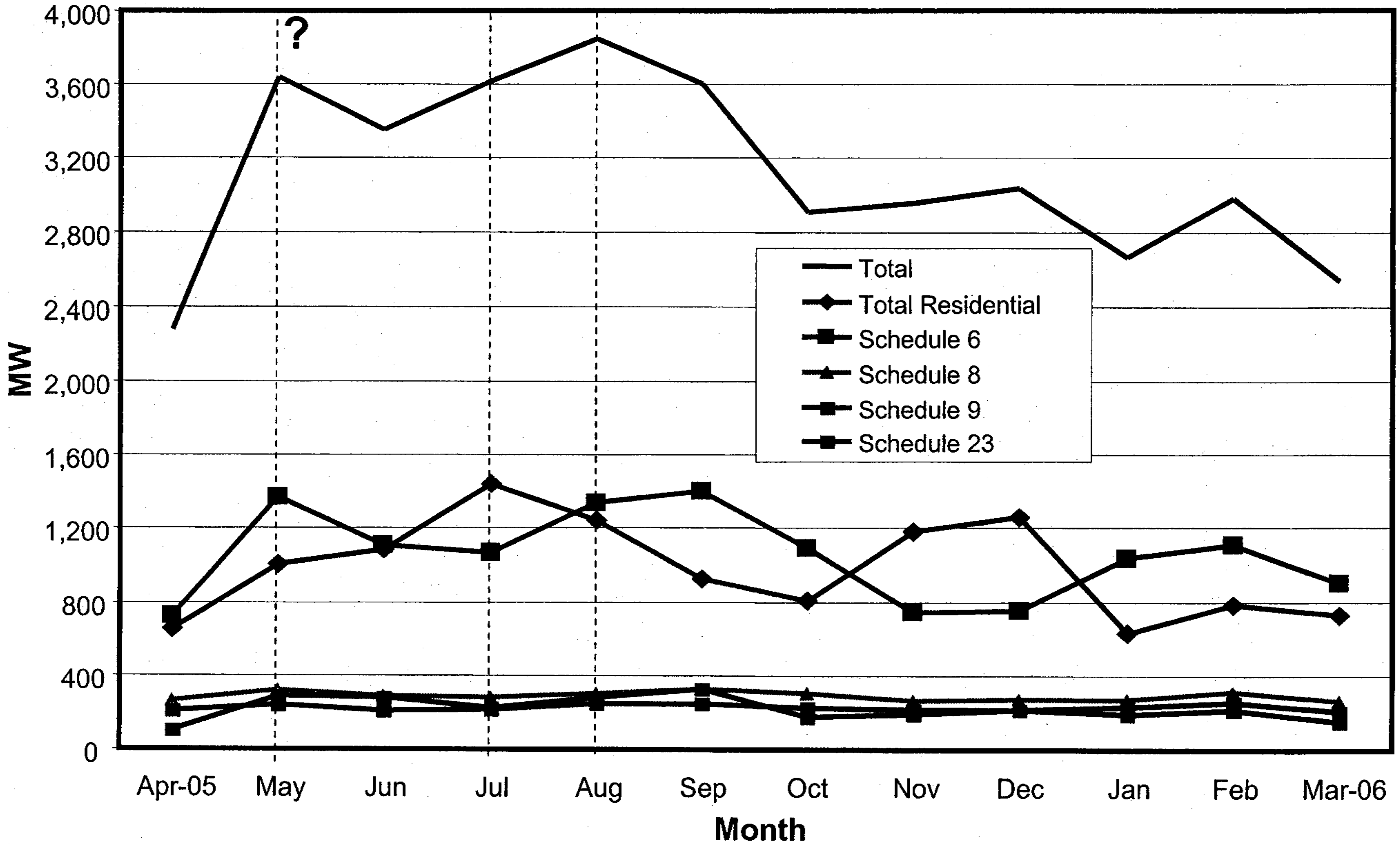
Palo Verde

Day Ahead On-Peak Prices
2004



PacifiCorp-Utah

Allocations Based on Peaks
(Vertical Slices)



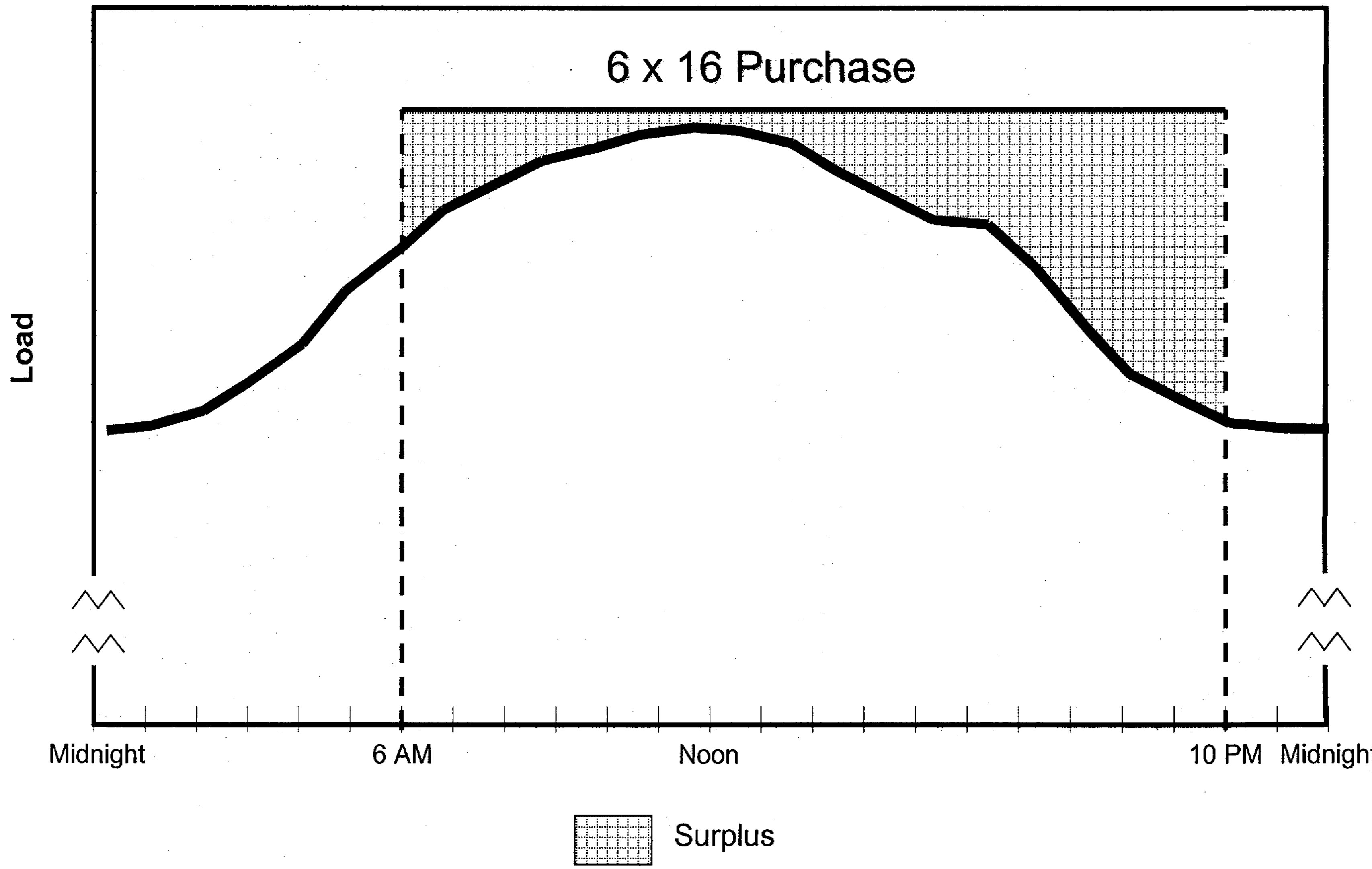
PacifiCorp-Utah

Resource Portfolio

- Base Load Coal
- Combined Cycle – Gas Fired
- Peaking Units – Gas Fired
- 24 x 7 x 52 Purchases
- Seasonal On-Peak Purchases
- Seasonal Off-Peak Purchases
- Hourly Purchases

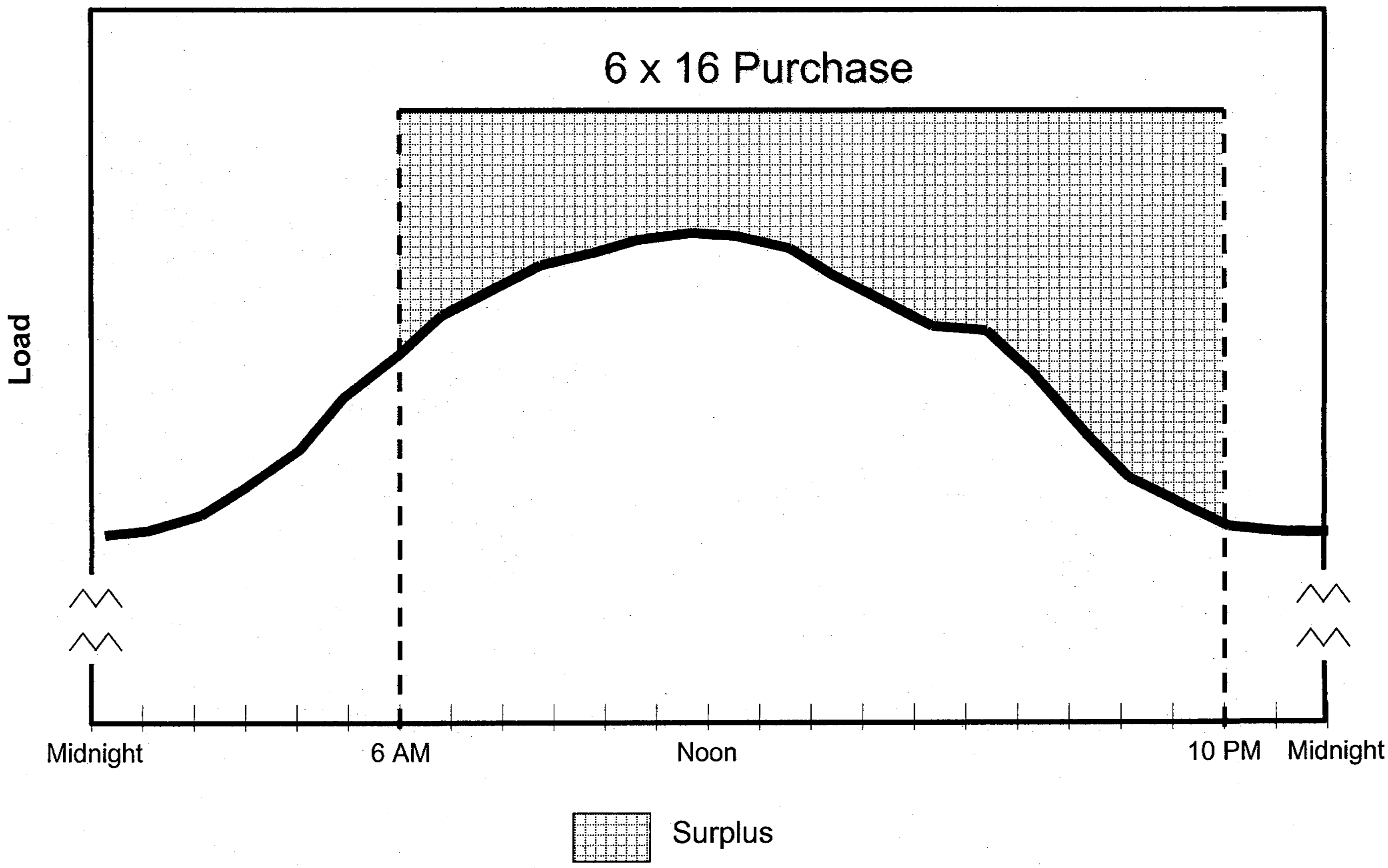
PacifiCorp-Utah

Block Purchases
Day 1



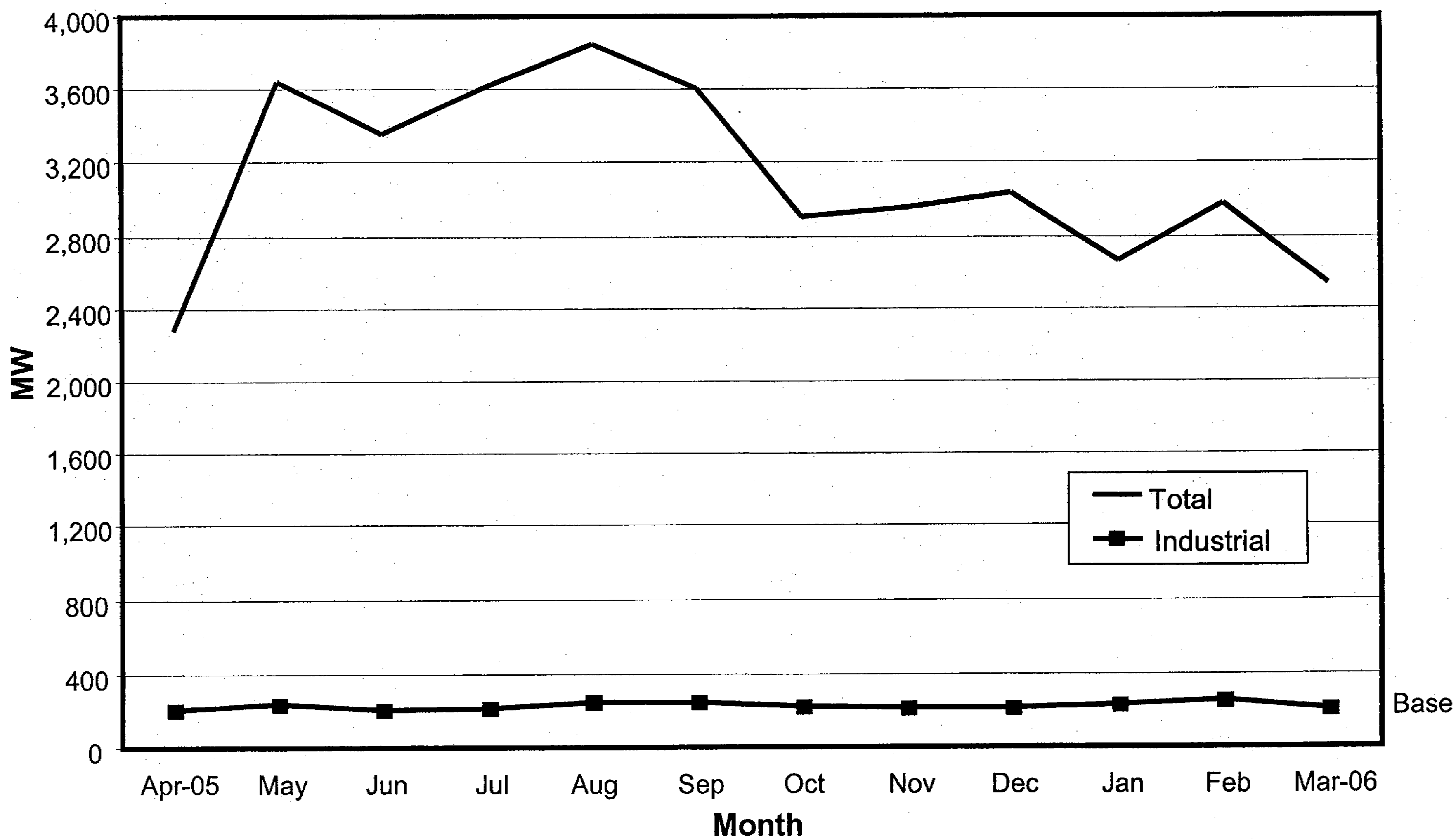
PacifiCorp-Utah

Block Purchases
Day 2



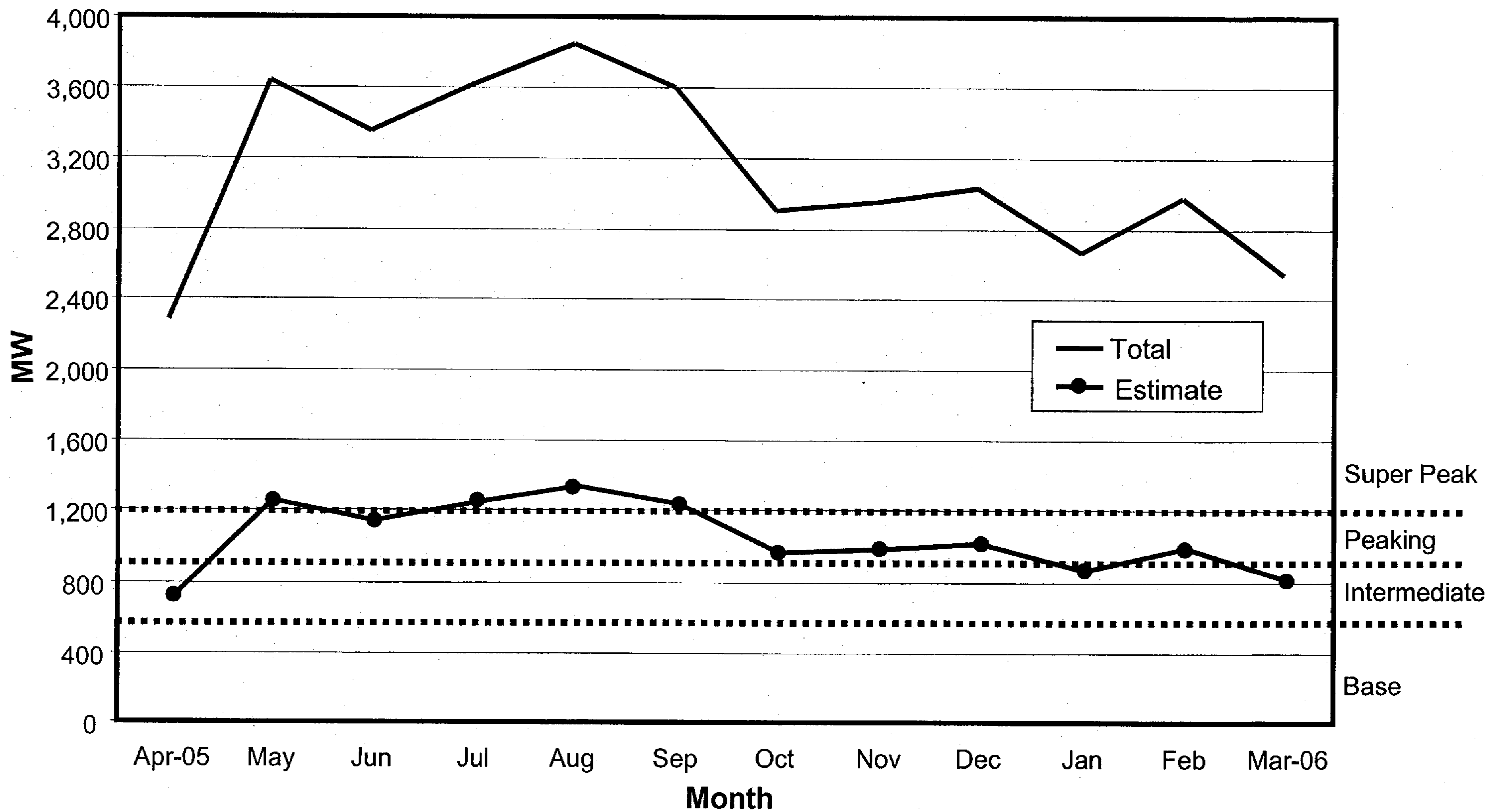
PacifiCorp-Utah

Horizontal Analysis - Industrial



PacifiCorp-Utah

Horizontal Analysis – Peaking Classes



Appendix 4

Review of MSP Classification and Allocation decision process

ROLLED-IN INTERJURISDICTIONAL ALLOCATION RESULTS BASED ON THE UNADJUSTED ACTUAL RESULTS OF OPERATIONS FOR THE PERIOD OCT. '01 THROUGH SEP. '02
Cost of Service = Revenue Requirement at an 11.5% Allowed Rate of Return on Common Equity

Energy	System	Pac Div	Ut Div	California	Oregon	Washington	Wyoming	Utah	Idaho	Wyoming	FERC
MWh	48,135,050	26,369,276	21,765,773	915,257	14,580,372	4,323,902	6,549,745	18,196,422	2,219,452	1,157,577	192,322
SE	**100.0000%**	**54.7819%**	**45.2181%**	**1.9014%**	**30.2906%**	**8.9828%**	**13.6070%**	**37.8029%**	**4.6109%**	**2.4049%**	**0.3995%**

System Generation Allocation Factor Based On 12 CP System Capacity Allocation Factor and Varying Proportions of Capacity and Energy

Demand/Energy	System	Pac Div	Ut Div	California	Oregon	Washington	Wyoming	Utah	Idaho	Wyoming	FERC
100% / 0%	100.0000%	52.2569%	47.7431%	1.8559%	29.9564%	8.8119%	11.6327%	41.0522%	4.3259%	1.9398%	0.4252%
Cost of Service	2,469,141,812	1,301,659,584	1,167,482,228	67,886,412	755,544,273	198,363,396	281,013,003	1,033,206,221	81,642,993	51,951,646	681,368
$COS / MWh	$51.30	$49.36	$53.64	$74.17	$51.82	$45.88	$42.90	$56.78	$36.79	$44.88	$3.54
87.5% / 12.5%	100.0000%	52.5725%	47.4275%	1.8616%	29.9982%	8.8332%	11.8795%	40.6460%	4.3615%	1.9979%	0.4220%
Cost of Service	2,469,136,262	1,305,713,162	1,163,423,100	67,959,551	756,080,398	198,638,042	284,182,670	1,028,008,870	82,089,889	52,684,024	640,316
$COS / MWh	$51.30	$49.52	$53.45	$74.25	$51.86	$45.94	$43.39	$56.50	$36.99	$45.51	$3.33
75% / 25%	**100.0000%**	**52.8882%**	**47.1118%**	**1.8673%**	**30.0400%**	**8.8546%**	**12.1263%**	**40.2398%**	**4.3971%**	**2.0561%**	**0.4188%**
Cost of Service	**2,469,130,711**	**1,309,766,739**	**1,159,363,972**	**68,032,691**	**756,616,532**	**198,912,690**	**287,352,326**	**1,022,811,880**	**82,536,614**	**53,416,213**	**599,265**
$COS / MWh	**$51.30**	**$49.67**	**$53.27**	**$74.33**	**$51.89**	**$46.00**	**$43.87**	**$56.21**	**$37.19**	**$46.14**	**$3.12**
62.5% / 37.5%	100.0000%	53.2038%	46.7962%	1.8730%	30.0817%	8.8760%	12.3731%	39.8337%	4.4328%	2.1142%	0.4156%
Cost of Service	2,469,125,160	1,313,820,315	1,155,304,845	68,105,830	757,152,674	199,187,339	290,521,971	1,017,615,256	82,983,165	54,148,209	558,216
$COS / MWh	$51.30	$49.82	$53.08	$74.41	$51.93	$46.07	$44.36	$55.92	$37.39	$46.78	$2.90
50% / 50%	100.0000%	53.5194%	46.4806%	1.8787%	30.1235%	8.8974%	12.6198%	39.4275%	4.4684%	2.1723%	0.4124%
Cost of Service	2,469,119,609	1,317,873,890	1,151,245,719	68,178,970	757,688,824	199,461,991	293,691,605	1,012,419,007	83,429,537	54,880,008	517,167
$COS / MWh	$51.30	$49.98	$52.89	$74.49	$51.97	$46.13	$44.84	$55.64	$37.59	$47.41	$2.69
37.5% / 62.5%	100.0000%	53.8350%	46.1650%	1.8844%	30.1653%	8.9187%	12.8666%	39.0213%	4.5040%	2.2305%	0.4092%
Cost of Service	2,469,114,058	1,321,927,466	1,147,186,593	68,252,110	758,224,982	199,736,644	296,861,229	1,007,223,141	83,875,727	55,611,605	476,119
$COS / MWh	$51.30	$50.13	$52.71	$74.57	$52.00	$46.19	$45.32	$55.35	$37.79	$48.04	$2.48
25% / 75%	100.0000%	54.1506%	45.8494%	1.8901%	30.2070%	8.9401%	13.1134%	38.6152%	4.5396%	2.2886%	0.4060%
Cost of Service	2,469,108,508	1,325,981,040	1,143,127,467	68,325,251	758,761,148	200,011,300	300,030,841	1,002,027,665	84,321,731	56,342,998	435,073
$COS / MWh	$51.30	$50.29	$52.52	$74.65	$52.04	$46.26	$45.81	$55.07	$37.99	$48.67	$2.26
12.5% / 87.5%	100.0000%	54.4662%	45.5338%	1.8957%	30.2488%	8.9615%	13.3602%	38.2090%	4.5753%	2.3467%	0.4028%
Cost of Service	2,469,102,957	1,330,034,614	1,139,068,343	68,398,392	759,297,322	200,285,957	303,200,444	996,832,588	84,767,546	57,074,181	394,028
$COS / MWh	$51.30	$50.44	$52.33	$74.73	$52.08	$46.32	$46.29	$54.78	$38.19	$49.30	$2.05
0% / 100%	100.0000%	54.7819%	45.2181%	1.9014%	30.2906%	8.9829%	13.6070%	37.8029%	4.6109%	2.4049%	0.3995%
Cost of Service	2,469,097,406	1,334,088,187	1,135,009,218	68,471,533	759,833,503	200,560,615	306,370,036	991,637,917	85,213,168	57,805,150	352,984
$COS / MWh	$51.30	$50.59	$52.15	$74.81	$52.11	$46.38	$46.78	$54.50	$38.39	$49.94	$1.84

ROLLED-IN INTERJURISDICTIONAL ALLOCATION RESULTS BASED ON THE UNADJUSTED ACTUAL RESULTS OF OPERATIONS FOR THE PERIOD OCT. '01 THROUGH SEP. '02
Cost of Service = Revenue Requirement at an 11.5% Allowed Rate of Return on Common Equity

Energy	System	Pac Div	Ut Div	California	Oregon	Washington	Wyoming	Utah	Idaho	Wyoming	FERC
MWh	48,135,050	26,369,276	21,765,773	915,257	14,580,372	4,323,902	6,549,745	18,196,422	2,219,452	1,157,577	192,322
SE	**100.0000%**	**54.7819%**	**45.2181%**	**1.9014%**	**30.2906%**	**8.9829%**	**13.6070%**	**37.8029%**	**4.6109%**	**2.4049%**	**0.3995%**

System Generation Allocation Factor Based On 11 CP System Capacity Allocation Factor and Varying Proportions of Capacity and Energy
Remove April

Demand/Energy	System	Pac Div	Ut Div	California	Oregon	Washington	Wyoming	Utah	Idaho	Wyoming	FERC
100% / 0%	100.0000%	51.9594%	48.0406%	1.8440%	29.7486%	8.8492%	11.5176%	41.4182%	4.2563%	1.9374%	0.4287%
Cost of Service	2,469,142,716	1,297,836,639	1,171,306,077	67,732,221	752,872,750	198,844,008	279,535,160	1,037,893,303	80,764,168	51,923,702	724,904
$COS / MWh	$51.30	$49.22	$53.81	$74.00	$51.64	$45.99	$42.68	$57.04	$36.39	$44.86	$3.77
87.5% / 12.5%	100.0000%	52.3122%	47.6878%	1.8511%	29.8164%	8.8659%	11.7788%	40.9663%	4.3006%	1.9958%	0.4250%
Cost of Service	2,469,137,052	1,302,368,085	1,166,768,967	67,824,633	753,742,813	199,058,574	282,889,564	1,032,109,780	81,321,110	52,659,668	678,409
$COS / MWh	$51.30	$49.39	$53.61	$74.10	$51.70	$46.04	$43.19	$56.72	$36.64	$45.49	$3.53
75% / 25%	100.0000%	52.6650%	47.3350%	1.8583%	29.8841%	8.8826%	12.0399%	40.5144%	4.3450%	2.0543%	0.4214%
Cost of Service	2,469,131,388	1,306,899,531	1,162,231,858	67,917,047	754,612,886	199,273,143	286,243,955	1,026,326,694	81,877,829	53,395,421	631,915
$COS / MWh	$51.30	$49.56	$53.40	$74.21	$51.76	$46.09	$43.70	$56.40	$36.89	$46.13	$3.29
62.5% / 37.5%	100.0000%	53.0178%	46.9822%	1.8655%	29.9519%	8.8993%	12.3011%	40.0625%	4.3893%	2.1127%	0.4177%
Cost of Service	2,469,125,725	1,311,430,975	1,157,694,749	68,009,460	755,482,967	199,487,715	289,598,333	1,020,544,053	82,434,320	54,130,954	585,422
$COS / MWh	$51.30	$49.73	$53.19	$74.31	$51.82	$46.14	$44.22	$56.08	$37.14	$46.76	$3.04
50% / 50%	100.0000%	53.3706%	46.6294%	1.8727%	30.0196%	8.9160%	12.5623%	39.6105%	4.4336%	2.1711%	0.4141%
Cost of Service	2,469,120,061	1,315,962,419	1,153,157,642	68,101,874	756,353,058	199,702,289	292,952,698	1,014,761,870	82,990,578	54,866,262	538,932
$COS / MWh	$51.30	$49.91	$52.98	$74.41	$51.87	$46.19	$44.73	$55.77	$37.39	$47.40	$2.80
37.5% / 62.5%	100.0000%	53.7234%	46.2766%	1.8799%	30.0873%	8.9327%	12.8235%	39.1586%	4.4779%	2.2296%	0.4105%
Cost of Service	2,469,114,397	1,320,493,862	1,148,620,535	68,194,288	757,223,156	199,916,867	296,307,051	1,008,980,154	83,546,597	55,601,342	492,442
$COS / MWh	$51.30	$50.08	$52.77	$74.51	$51.93	$46.24	$45.24	$55.45	$37.64	$48.03	$2.56
25% / 75%	100.0000%	54.0762%	45.9238%	1.8871%	30.1551%	8.9494%	13.0847%	38.7067%	4.5222%	2.2880%	0.4068%
Cost of Service	2,469,108,733	1,325,025,305	1,144,083,429	68,286,703	758,093,264	200,131,447	299,661,391	1,003,198,915	84,102,372	56,336,186	445,955
$COS / MWh	$51.30	$50.25	$52.56	$74.61	$51.99	$46.28	$45.75	$55.13	$37.89	$48.67	$2.32
12.5% / 87.5%	100.0000%	54.4291%	45.5709%	1.8943%	30.2228%	8.9661%	13.3458%	38.2548%	4.5666%	2.3464%	0.4032%
Cost of Service	2,469,103,070	1,329,556,746	1,139,546,323	68,379,118	758,963,380	200,346,030	303,015,719	997,418,166	84,657,898	57,070,791	399,469
$COS / MWh	$51.30	$50.42	$52.35	$74.71	$52.05	$46.33	$46.26	$54.81	$38.14	$49.30	$2.08
0% / 100%	100.0000%	54.7819%	45.2181%	1.9014%	30.2906%	8.9829%	13.6070%	37.8029%	4.6109%	2.4049%	0.3995%
Cost of Service	2,469,097,406	1,334,088,187	1,135,009,218	68,471,533	759,833,503	200,560,615	306,370,036	991,637,917	85,213,168	57,805,150	352,984
$COS / MWh	$51.30	$50.59	$52.15	$74.81	$52.11	$46.38	$46.78	$54.50	$38.39	$49.94	$1.84

ROLLED-IN INTERJURISDICTIONAL ALLOCATION RESULTS BASED ON THE UNADJUSTED ACTUAL RESULTS OF OPERATIONS FOR THE PERIOD OCT. '01 THROUGH SEP. '02
Cost of Service = Revenue Requirement at an 11.5% Allowed Rate of Return on Common Equity

Energy	System	Pac Div	Ut Div	California	Oregon	Washington	Wyoming	Utah	Idaho	Wyoming	FERC
MWh	48,135,050	26,369,276	21,765,773	915,257	14,580,372	4,323,902	6,549,745	18,196,422	2,219,452	1,157,577	192,322
SE	**100.0000%**	**54.7819%**	**45.2181%**	**1.9014%**	**30.2906%**	**8.9829%**	**13.6070%**	**37.8029%**	**4.6109%**	**2.4049%**	**0.3995%**

System Generation Allocation Factor Based On 10 CP System Capacity Allocation Factor and Varying Proportions of Capacity and Energy
Remove April & May

Demand/Energy	System	Pac Div	Ut Div	California	Oregon	Washington	Wyoming	Utah	Idaho	Wyoming	FERC
100% / 0%	100.0000%	52.2647%	47.7353%	1.8189%	30.0664%	8.9602%	11.4192%	41.3804%	3.9774%	1.9543%	0.4233%
Cost of Service	2,469,130,213	1,301,762,160	1,167,368,052	67,408,892	756,958,936	200,271,215	278,270,617	1,037,361,606	77,214,938	52,134,795	656,713
$COS / MWh	$51.30	$49.37	$53.63	$73.65	$51.92	$46.32	$42.49	$57.01	$34.79	$45.04	$3.41
87.5% / 12.5%	100.0000%	52.5793%	47.4207%	1.8292%	30.0945%	8.9630%	11.6927%	40.9332%	4.0566%	2.0106%	0.4203%
Cost of Service	2,469,126,112	1,305,802,916	1,163,323,196	67,541,722	757,318,225	200,307,379	281,783,089	1,031,644,452	78,215,739	52,844,261	618,745
$COS / MWh	$51.30	$49.52	$53.45	$73.80	$51.94	$46.33	$43.02	$56.69	$35.24	$45.65	$3.22
75% / 25%	100.0000%	52.8940%	47.1060%	1.8395%	30.1225%	8.9659%	11.9661%	40.4860%	4.1358%	2.0669%	0.4174%
Cost of Service	2,469,122,011	1,309,843,670	1,159,278,341	67,674,552	757,677,524	200,343,547	285,295,547	1,025,927,762	79,216,259	53,553,542	580,778
$COS / MWh	$51.30	$49.67	$53.26	$73.94	$51.97	$46.33	$43.56	$56.38	$35.69	$46.26	$3.02
62.5% / 37.5%	100.0000%	53.2086%	46.7914%	1.8498%	30.1505%	8.9687%	12.2396%	40.0388%	4.2149%	2.1232%	0.4144%
Cost of Service	2,469,117,910	1,313,884,424	1,155,233,486	67,807,382	758,036,832	200,379,718	288,807,993	1,020,211,546	80,216,494	54,262,635	542,811
$COS / MWh	$51.30	$49.83	$53.08	$74.09	$51.99	$46.34	$44.09	$56.07	$36.14	$46.88	$2.82
50% / 50%	100.0000%	53.5233%	46.4767%	1.8601%	30.1785%	8.9715%	12.5131%	39.5916%	4.2941%	2.1796%	0.4114%
Cost of Service	2,469,113,809	1,317,925,178	1,151,188,631	67,940,212	758,396,149	200,415,891	292,320,426	1,014,495,813	81,216,436	54,971,538	504,844
$COS / MWh	$51.30	$49.98	$52.89	$74.23	$52.01	$46.35	$44.63	$55.75	$36.59	$47.49	$2.62
37.5% / 62.5%	100.0000%	53.8379%	46.1621%	1.8705%	30.2065%	8.9744%	12.7866%	39.1444%	4.3733%	2.2359%	0.4085%
Cost of Service	2,469,109,708	1,321,965,931	1,147,143,777	68,073,042	758,755,474	200,452,068	295,832,846	1,008,780,573	82,216,081	55,680,244	466,879
$COS / MWh	$51.30	$50.13	$52.70	$74.38	$52.04	$46.36	$45.17	$55.44	$37.04	$48.10	$2.43
25% / 75%	100.0000%	54.1526%	45.8474%	1.8808%	30.2345%	8.9772%	13.0601%	38.6972%	4.4525%	2.2922%	0.4055%
Cost of Service	2,469,105,608	1,326,006,684	1,143,098,924	68,205,872	759,114,809	200,488,248	299,345,255	1,003,065,837	83,215,422	56,388,751	428,913
$COS / MWh	$51.30	$50.29	$52.52	$74.52	$52.06	$46.37	$45.70	$55.12	$37.49	$48.71	$2.23
12.5% / 87.5%	100.0000%	54.4672%	45.5328%	1.8911%	30.2625%	8.9800%	13.3335%	38.2500%	4.5317%	2.3485%	0.4025%
Cost of Service	2,469,101,507	1,330,047,436	1,139,054,071	68,338,703	759,474,152	200,524,430	302,857,651	997,351,615	84,214,453	57,097,054	390,948
$COS / MWh	$51.30	$50.44	$52.33	$74.67	$52.09	$46.38	$46.24	$54.81	$37.94	$49.32	$2.03
0% / 100%	100.0000%	54.7819%	45.2181%	1.9014%	30.2906%	8.9829%	13.6070%	37.8029%	4.6109%	2.4049%	0.3995%
Cost of Service	2,469,097,406	1,334,088,187	1,135,009,218	68,471,533	759,833,503	200,560,615	306,370,036	991,637,917	85,213,168	57,805,150	352,984
$COS / MWh	$51.30	$50.59	$52.15	$74.81	$52.11	$46.38	$46.78	$54.50	$38.39	$49.94	$1.84

ROLLED-IN INTERJURISDICTIONAL ALLOCATION RESULTS BASED ON THE UNADJUSTED ACTUAL RESULTS OF OPERATIONS FOR THE PERIOD OCT. '01 THROUGH SEP. '02
Cost of Service = Revenue Requirement at an 11.5% Allowed Rate of Return on Common Equity

Energy	System	Pac Div	Ut Div	California	Oregon	Washington	Wyoming	Utah	Idaho	Wyoming	FERC
MWh	48,135,050	26,369,276	21,765,773	915,257	14,580,372	4,323,902	6,549,745	18,196,422	2,219,452	1,157,577	192,322
SE	100.0000%	54.7819%	45.2181%	1.9014%	30.2906%	8.9829%	13.6070%	37.8029%	4.6109%	2.4049%	0.3995%

System Generation Allocation Factor Based On 9 CP System Capacity Allocation Factor and Varying Proportions of Capacity and Energy
Remove April, May & October

Demand/Energy	System	Pac Div	Ut Div	California	Oregon	Washington	Wyoming	Utah	Idaho	Wyoming	FERC
100% / 0%	100.0000%	52.6682%	47.3318%	1.8714%	30.3186%	9.1997%	11.2786%	41.1371%	3.8612%	1.9131%	0.4205%
Cost of Service	2,469,126,769	1,306,952,775	1,162,173,994	68,084,721	760,200,613	203,350,889	276,464,052	1,034,210,738	75,731,691	51,610,752	620,813
$COS / MWh	$51.30	$49.56	$53.39	$74.39	$52.14	$47.03	$42.21	$56.84	$34.12	$44.59	$3.23
87.5% / 12.5%	100.0000%	52.9324%	47.0676%	1.8751%	30.3151%	9.1726%	11.5696%	40.7203%	3.9549%	1.9746%	0.4179%
Cost of Service	2,469,123,099	1,310,344,703	1,158,778,396	68,133,072	760,154,697	203,002,092	280,202,342	1,028,887,599	76,917,821	52,385,643	587,333
$COS / MWh	$51.30	$49.69	$53.24	$74.44	$52.14	$46.95	$42.78	$56.54	$34.66	$45.25	$3.05
75% / 25%	100.0000%	53.1966%	46.8034%	1.8789%	30.3116%	9.1455%	11.8607%	40.3035%	4.0486%	2.0360%	0.4153%
Cost of Service	2,469,119,428	1,313,736,631	1,155,382,798	68,181,422	760,108,790	202,653,299	283,940,619	1,023,564,883	78,103,690	53,160,372	553,852
$COS / MWh	$51.30	$49.82	$53.08	$74.49	$52.13	$46.87	$43.35	$56.25	$35.19	$45.92	$2.88
62.5% / 37.5%	100.0000%	53.4608%	46.5392%	1.8826%	30.3081%	9.1184%	12.1517%	39.8867%	4.1423%	2.0975%	0.4126%
Cost of Service	2,469,115,758	1,317,128,558	1,151,987,200	68,229,774	760,062,890	202,304,509	287,678,885	1,018,242,600	79,289,294	53,934,934	520,373
$COS / MWh	$51.30	$49.95	$52.93	$74.55	$52.13	$46.79	$43.92	$55.96	$35.72	$46.59	$2.71
50% / 50%	100.0000%	53.7250%	46.2750%	1.8864%	30.3046%	9.0913%	12.4428%	39.4700%	4.2360%	2.1590%	0.4100%
Cost of Service	2,469,112,088	1,320,520,484	1,148,591,603	68,278,125	760,016,997	201,955,723	291,417,138	1,012,920,755	80,474,628	54,709,327	486,894
$COS / MWh	$51.30	$50.08	$52.77	$74.60	$52.13	$46.71	$44.49	$55.67	$36.26	$47.26	$2.53
37.5% / 62.5%	100.0000%	53.9892%	46.0108%	1.8902%	30.3011%	9.0642%	12.7338%	39.0532%	4.3297%	2.2204%	0.4074%
Cost of Service	2,469,108,417	1,323,912,411	1,145,196,006	68,326,476	759,971,113	201,606,941	295,155,380	1,007,599,356	81,659,687	55,483,548	453,415
$COS / MWh	$51.30	$50.21	$52.61	$74.65	$52.12	$46.63	$45.06	$55.37	$36.79	$47.93	$2.36
25% / 75%	100.0000%	54.2534%	45.7466%	1.8939%	30.2976%	9.0371%	13.0249%	38.6364%	4.4235%	2.2819%	0.4048%
Cost of Service	2,469,104,747	1,327,304,337	1,141,800,410	68,374,828	759,925,236	201,258,162	298,893,610	1,002,278,412	82,844,466	56,257,594	419,938
$COS / MWh	$51.30	$50.34	$52.46	$74.71	$52.12	$46.55	$45.63	$55.08	$37.33	$48.60	$2.18
12.5% / 87.5%	100.0000%	54.5177%	45.4823%	1.8977%	30.2941%	9.0100%	13.3160%	38.2196%	4.5172%	2.3434%	0.4022%
Cost of Service	2,469,101,076	1,330,696,262	1,138,404,814	68,423,180	759,879,366	200,909,387	302,631,829	996,957,929	84,028,962	57,031,463	386,460
$COS / MWh	$51.30	$50.46	$52.30	$74.76	$52.12	$46.46	$46.21	$54.79	$37.86	$49.27	$2.01
0% / 100%	100.0000%	54.7819%	45.2181%	1.9014%	30.2906%	8.9829%	13.6070%	37.8029%	4.6109%	2.4049%	0.3995%
Cost of Service	2,469,097,406	1,334,088,187	1,135,009,218	68,471,533	759,833,503	200,560,615	306,370,036	991,637,917	85,213,168	57,805,150	352,984
$COS / MWh	$51.30	$50.59	$52.15	$74.81	$52.11	$46.38	$46.78	$54.50	$38.39	$49.94	$1.84

ROLLED-IN INTERJURISDICTIONAL ALLOCATION RESULTS BASED ON THE UNADJUSTED ACTUAL RESULTS OF OPERATIONS FOR THE PERIOD OCT. '01 THROUGH SEP. '02
Cost of Service = Revenue Requirement at an 11.5% Allowed Rate of Return on Common Equity

Energy	System	Pac Div	Ut Div	California	Oregon	Washington	Wyoming	Utah	Idaho	Wyoming	FERC
MWh	48,135,050	26,369,276	21,765,773	915,257	14,580,372	4,323,902	6,549,745	18,196,422	2,219,452	1,157,577	192,322
SE	**100.0000%**	**54.7819%**	**45.2181%**	**1.9014%**	**30.2906%**	**8.9829%**	**13.6070%**	**37.8029%**	**4.6109%**	**2.4049%**	**0.3995%**

System Generation Allocation Factor Based On 8 CP System Capacity Allocation Factor and Varying Proportions of Capacity and Energy
Remove April, May, September & October

Demand/Energy	System	Pac Div	Ut Div	California	Oregon	Washington	Wyoming	Utah	Idaho	Wyoming	FERC
100% / 0%	100.0000%	53.3045%	46.6955%	1.9028%	30.9190%	9.3490%	11.1336%	40.7857%	3.5265%	1.9647%	0.4186%
Cost of Service	2,469,110,279	1,315,135,756	1,153,974,522	68,489,843	767,920,033	205,271,841	274,601,538	1,029,650,725	71,470,550	52,257,883	595,364
$COS / MWh	$51.30	$49.87	$53.02	$74.83	$52.67	$47.47	$41.93	$56.59	$32.20	$45.14	$3.10
87.5% / 12.5%	100.0000%	53.4892%	46.5108%	1.9027%	30.8405%	9.3033%	11.4428%	40.4128%	3.6620%	2.0197%	0.4162%
Cost of Service	2,469,108,669	1,317,504,811	1,151,603,858	68,487,554	766,909,195	204,682,928	278,572,634	1,024,897,895	73,189,245	52,951,656	565,063
$COS / MWh	$51.30	$49.96	$52.91	$74.83	$52.60	$47.34	$42.53	$56.32	$32.98	$45.74	$2.94
75% / 25%	100.0000%	53.6739%	46.3261%	1.9025%	30.7619%	9.2575%	11.7520%	40.0400%	3.7976%	2.0747%	0.4138%
Cost of Service	2,469,107,060	1,319,873,866	1,149,233,195	68,485,264	765,898,362	204,094,018	282,543,720	1,020,145,408	74,907,698	53,645,327	534,762
$COS / MWh	$51.30	$50.05	$52.80	$74.83	$52.53	$47.20	$43.14	$56.06	$33.75	$46.34	$2.78
62.5% / 37.5%	100.0000%	53.8585%	46.1415%	1.9023%	30.6834%	9.2117%	12.0611%	39.6671%	3.9331%	2.1298%	0.4114%
Cost of Service	2,469,105,451	1,322,242,920	1,146,862,531	68,482,975	764,887,537	203,505,111	286,514,797	1,015,393,268	76,625,906	54,338,895	504,463
$COS / MWh	$51.30	$50.14	$52.69	$74.82	$52.46	$47.07	$43.74	$55.80	$34.52	$46.94	$2.62
50% / 50%	100.0000%	54.0432%	45.9568%	1.9021%	30.6048%	9.1660%	12.3703%	39.2943%	4.0687%	2.1848%	0.4091%
Cost of Service	2,469,103,842	1,324,611,974	1,144,491,868	68,480,686	763,876,717	202,916,206	290,485,863	1,010,641,478	78,343,866	55,032,359	474,165
$COS / MWh	$51.30	$50.23	$52.58	$74.82	$52.39	$46.93	$44.35	$55.54	$35.30	$47.54	$2.47
37.5% / 62.5%	100.0000%	54.2279%	45.7721%	1.9020%	30.5262%	9.1202%	12.6795%	38.9214%	4.2042%	2.2398%	0.4067%
Cost of Service	2,469,102,233	1,326,981,028	1,142,121,206	68,478,397	762,865,904	202,327,305	294,456,921	1,005,890,044	80,061,575	55,725,718	443,868
$COS / MWh	$51.30	$50.32	$52.47	$74.82	$52.32	$46.79	$44.96	$55.28	$36.07	$48.14	$2.31
25% / 75%	100.0000%	54.4125%	45.5875%	1.9018%	30.4477%	9.0744%	12.9887%	38.5486%	4.3398%	2.2948%	0.4043%
Cost of Service	2,469,100,624	1,329,350,081	1,139,750,543	68,476,109	761,855,098	201,738,406	298,427,968	1,001,138,970	81,779,031	56,418,971	413,572
$COS / MWh	$51.30	$50.41	$52.36	$74.82	$52.25	$46.66	$45.56	$55.02	$36.85	$48.74	$2.15
12.5% / 87.5%	100.0000%	54.5972%	45.4028%	1.9016%	30.3691%	9.0286%	13.2978%	38.1757%	4.4753%	2.3498%	0.4019%
Cost of Service	2,469,099,015	1,331,719,134	1,137,379,881	68,473,821	760,844,297	201,149,509	302,399,007	996,388,259	83,496,229	57,112,115	383,277
$COS / MWh	$51.30	$50.50	$52.26	$74.81	$52.18	$46.52	$46.17	$54.76	$37.62	$49.34	$1.99
0% / 100%	100.0000%	54.7819%	45.2181%	1.9014%	30.2906%	8.9829%	13.6070%	37.8029%	4.6109%	2.4049%	0.3995%
Cost of Service	2,469,097,406	1,334,088,187	1,135,009,218	68,471,533	759,833,503	200,560,615	306,370,036	991,637,917	85,213,168	57,805,150	352,984
$COS / MWh	$51.30	$50.59	$52.15	$74.81	$52.11	$46.38	$46.78	$54.50	$38.39	$49.94	$1.84

ROLLED-IN INTERJURISDICTIONAL ALLOCATION RESULTS BASED ON THE UNADJUSTED ACTUAL RESULTS OF OPERATIONS FOR THE PERIOD OCT. '01 THROUGH SEP. '02
Cost of Service = Revenue Requirement at an 11.5% Allowed Rate of Return on Common Equity

Energy	System	Pac Div	Ut Div	California	Oregon	Washington	Wyoming	Utah	Idaho	Wyoming	FERC
MWh	48,135,050	26,369,276	21,765,773	915,257	14,580,372	4,323,902	6,549,745	18,196,422	2,219,452	1,157,577	192,322
SE	**100.0000%**	**54.7819%**	**45.2181%**	**1.9014%**	**30.2906%**	**8.9829%**	**13.6070%**	**37.8029%**	**4.6109%**	**2.4049%**	**0.3995%**

System Generation Allocation Factor Based On 7 CP System Capacity Allocation Factor and Varying Proportions of Capacity and Energy
Remove March, April, May, September & October

Demand/Energy	System	Pac Div	Ut Div	California	Oregon	Washington	Wyoming	Utah	Idaho	Wyoming	FERC
100% / 0%	100.0000%	52.9288%	47.0712%	1.9218%	30.5901%	9.3714%	11.0455%	41.4529%	3.2268%	1.9673%	0.4242%
Cost of Service	2,469,102,093	1,310,307,142	1,158,794,952	68,734,341	763,690,701	205,559,520	273,470,079	1,038,164,465	67,669,079	52,294,036	667,373
$COS / MWh	$51.30	$49.69	$53.24	$75.10	$52.38	$47.54	$41.75	$57.05	$30.49	$45.18	$3.47
87.5% / 12.5%	100.0000%	53.1604%	46.8396%	1.9193%	30.5526%	9.3228%	11.3657%	40.9966%	3.3998%	2.0220%	0.4211%
Cost of Service	2,469,101,507	1,313,279,774	1,155,821,734	68,701,488	763,208,525	204,934,643	277,582,616	1,032,346,821	69,863,455	52,983,390	628,067
$COS / MWh	$51.30	$49.80	$53.10	$75.06	$52.34	$47.40	$42.38	$56.73	$31.48	$45.77	$3.27
75% / 25%	100.0000%	53.3920%	46.6080%	1.9167%	30.5152%	9.2743%	11.6859%	40.5404%	3.5728%	2.0767%	0.4181%
Cost of Service	2,469,100,922	1,316,252,406	1,152,848,516	68,668,636	762,726,357	204,309,771	281,695,141	1,026,529,683	72,057,453	53,672,616	588,763
$COS / MWh	$51.30	$49.92	$52.97	$75.03	$52.31	$47.25	$43.01	$56.41	$32.47	$46.37	$3.06
62.5% / 37.5%	100.0000%	53.6237%	46.3763%	1.9142%	30.4777%	9.2257%	12.0061%	40.0841%	3.7458%	2.1314%	0.4150%
Cost of Service	2,469,100,336	1,319,225,037	1,149,875,299	68,635,784	762,244,197	203,684,902	285,807,654	1,020,713,059	74,251,067	54,361,711	549,462
$COS / MWh	$51.30	$50.03	$52.83	$74.99	$52.28	$47.11	$43.64	$56.09	$33.45	$46.96	$2.86
50% / 50%	100.0000%	53.8553%	46.1447%	1.9116%	30.4403%	9.1771%	12.3263%	39.6279%	3.9188%	2.1861%	0.4119%
Cost of Service	2,469,099,750	1,322,197,668	1,146,902,082	68,602,933	761,762,043	203,060,037	289,920,154	1,014,896,956	76,444,291	55,050,672	510,162
$COS / MWh	$51.30	$50.14	$52.69	$74.95	$52.25	$46.96	$44.26	$55.77	$34.44	$47.56	$2.65
37.5% / 62.5%	100.0000%	54.0870%	45.9130%	1.9091%	30.4029%	9.1286%	12.6464%	39.1716%	4.0918%	2.2408%	0.4088%
Cost of Service	2,469,099,164	1,325,170,298	1,143,928,865	68,570,082	761,279,898	202,435,176	294,032,643	1,009,081,382	78,637,119	55,739,499	470,864
$COS / MWh	$51.30	$50.25	$52.56	$74.92	$52.21	$46.82	$44.89	$55.45	$35.43	$48.15	$2.45
25% / 75%	100.0000%	54.3186%	45.6814%	1.9065%	30.3654%	9.0800%	12.9666%	38.7154%	4.2649%	2.2955%	0.4057%
Cost of Service	2,469,098,578	1,328,142,928	1,140,955,649	68,537,232	760,797,759	201,810,318	298,145,119	1,003,266,346	80,829,546	56,428,189	431,569
$COS / MWh	$51.30	$50.37	$52.42	$74.88	$52.18	$46.67	$45.52	$55.14	$36.42	$48.75	$2.24
12.5% / 87.5%	100.0000%	54.5502%	45.4498%	1.9040%	30.3280%	9.0314%	13.2868%	38.2591%	4.4379%	2.3502%	0.4026%
Cost of Service	2,469,097,992	1,331,115,558	1,137,982,434	68,504,382	760,315,628	201,185,465	302,257,583	997,451,854	83,021,564	57,116,740	392,275
$COS / MWh	$51.30	$50.48	$52.28	$74.85	$52.15	$46.53	$46.15	$54.82	$37.41	$49.34	$2.04
0% / 100%	100.0000%	54.7819%	45.2181%	1.9014%	30.2906%	8.9829%	13.6070%	37.8029%	4.6109%	2.4049%	0.3995%
Cost of Service	2,469,097,406	1,334,088,187	1,135,009,218	68,471,533	759,833,503	200,560,615	306,370,036	991,637,917	85,213,168	57,805,150	352,984
$COS / MWh	$51.30	$50.59	$52.15	$74.81	$52.11	$46.38	$46.78	$54.50	$38.39	$49.94	$1.84

ROLLED-IN INTERJURISDICTIONAL ALLOCATION RESULTS BASED ON THE UNADJUSTED ACTUAL RESULTS OF OPERATIONS FOR THE PERIOD OCT. '01 THROUGH SEP. '02
Cost of Service = Revenue Requirement at an 11.5% Allowed Rate of Return on Common Equity

Energy	System	Pac Div	Ut Div	California	Oregon	Washington	Wyoming	Utah	Idaho	Wyoming	FERC
MWh	48,135,050	26,369,276	21,765,773	915,257	14,580,372	4,323,802	6,549,745	18,196,422	2,219,452	1,157,577	192,322
SE	**100.0000%**	**54.7819%**	**45.2181%**	**1.9014%**	**30.2906%**	**8.9829%**	**13.6070%**	**37.8029%**	**4.6109%**	**2.4049%**	**0.3995%**

System Generation Allocation Factor Based On 6 CP System Capacity Allocation Factor and Varying Proportions of Capacity and Energy
Remove March, April, May, June, September & October

Demand/Energy	System	Pac Div	Ut Div	California	Oregon	Washington	Wyoming	Utah	Idaho	Wyoming	FERC
100% / 0%	100.0000%	53.5247%	46.4753%	1.9166%	31.2593%	9.4367%	10.9122%	41.4562%	2.5682%	2.0352%	0.4157%
Cost of Service	2,469,071,590	1,317,969,703	1,151,101,887	68,666,562	772,295,302	206,398,478	271,756,862	1,038,099,560	59,295,982	53,147,203	559,143
$COS / MWh	$51.29	$49.98	$52.89	$75.02	$52.97	$47.73	$41.49	$57.05	$26.72	$45.91	$2.91
87.5% / 12.5%	100.0000%	53.6818%	46.3182%	1.9147%	31.1382%	9.3799%	11.2490%	40.9995%	2.8235%	2.0814%	0.4137%
Cost of Service	2,469,074,817	1,319,984,515	1,149,090,303	68,642,182	770,737,555	205,668,736	276,083,541	1,032,290,284	62,536,939	53,729,710	533,370
$COS / MWh	$51.29	$50.06	$52.79	$75.00	$52.86	$47.57	$42.15	$56.73	$28.18	$46.42	$2.77
75% / 25%	100.0000%	53.8390%	46.1610%	1.9128%	31.0171%	9.3232%	11.5859%	40.5429%	3.0788%	2.1276%	0.4117%
Cost of Service	2,469,078,044	1,321,999,325	1,147,078,719	68,617,803	769,179,814	204,938,997	280,410,210	1,026,481,448	65,777,531	54,312,143	507,598
$COS / MWh	$51.29	$50.13	$52.70	$74.97	$52.75	$47.40	$42.81	$56.41	$29.64	$46.92	$2.64
62.5% / 37.5%	100.0000%	53.9961%	46.0039%	1.9109%	30.8960%	9.2665%	11.9227%	40.0862%	3.3342%	2.1738%	0.4097%
Cost of Service	2,469,081,271	1,324,014,136	1,145,067,135	68,593,424	767,622,080	204,209,261	284,736,871	1,020,673,056	69,017,752	54,894,501	481,827
$COS / MWh	$51.29	$50.21	$52.61	$74.94	$52.65	$47.23	$43.47	$56.09	$31.10	$47.42	$2.51
50% / 50%	100.0000%	54.1533%	45.8467%	1.9090%	30.7749%	9.2098%	12.2596%	39.6295%	3.5895%	2.2200%	0.4076%
Cost of Service	2,469,084,498	1,326,028,947	1,143,055,551	68,569,045	766,064,353	203,479,527	289,063,522	1,014,865,112	72,257,598	55,476,784	456,056
$COS / MWh	$51.29	$50.29	$52.52	$74.92	$52.54	$47.06	$44.13	$55.77	$32.56	$47.92	$2.37
37.5% / 62.5%	100.0000%	54.3104%	45.6896%	1.9071%	30.6538%	9.1530%	12.5965%	39.1729%	3.8449%	2.2662%	0.4056%
Cost of Service	2,469,087,725	1,328,043,757	1,141,043,968	68,544,667	764,506,631	202,749,795	293,390,164	1,009,057,622	75,497,067	56,058,992	430,287
$COS / MWh	$51.30	$50.36	$52.42	$74.89	$52.43	$46.89	$44.79	$55.45	$34.02	$48.43	$2.24
25% / 75%	100.0000%	54.4676%	45.5324%	1.9052%	30.5327%	9.0963%	12.9333%	38.7162%	4.1002%	2.3124%	0.4036%
Cost of Service	2,469,090,952	1,330,058,568	1,139,032,385	68,520,289	762,948,916	202,020,066	297,716,797	1,003,250,589	78,736,155	56,641,122	404,518
$COS / MWh	$51.30	$50.44	$52.33	$74.86	$52.33	$46.72	$45.45	$55.13	$35.48	$48.93	$2.10
12.5% / 87.5%	100.0000%	54.6247%	45.3753%	1.9033%	30.4116%	9.0396%	13.2702%	38.2595%	4.3555%	2.3586%	0.4016%
Cost of Service	2,469,094,179	1,332,073,378	1,137,020,801	68,495,911	761,391,206	201,290,339	302,043,421	997,444,019	81,974,856	57,223,175	378,751
$COS / MWh	$51.30	$50.52	$52.24	$74.84	$52.22	$46.55	$46.12	$54.82	$36.93	$49.43	$1.97
0% / 100%	100.0000%	54.7819%	45.2181%	1.9014%	30.2906%	8.9829%	13.6070%	37.8029%	4.6109%	2.4049%	0.3995%
Cost of Service	2,469,097,406	1,334,088,187	1,135,009,218	68,471,533	759,833,503	200,560,615	306,370,036	991,637,917	85,213,168	57,805,150	352,984
$COS / MWh	$51.30	$50.59	$52.15	$74.81	$52.11	$46.38	$46.78	$54.50	$38.39	$49.94	$1.84

ROLLED-IN INTERJURISDICTIONAL ALLOCATION RESULTS BASED ON THE UNADJUSTED ACTUAL RESULTS OF OPERATIONS FOR THE PERIOD OCT. '01 THROUGH SEP. '02
Cost of Service = Revenue Requirement at an 11.5% Allowed Rate of Return on Common Equity

Energy	System	Pac Div	Ut Div	California	Oregon	Washington	Wyoming	Utah	Idaho	Wyoming	FERC
MWh	48,135,050	26,369,276	21,765,773	915,257	14,580,372	4,323,902	6,549,745	18,196,422	2,219,452	1,157,577	192,322
SE	**100.0000%**	**54.7819%**	**45.2181%**	**1.9014%**	**30.2906%**	**8.9829%**	**13.6070%**	**37.8029%**	**4.6109%**	**2.4049%**	**0.3995%**

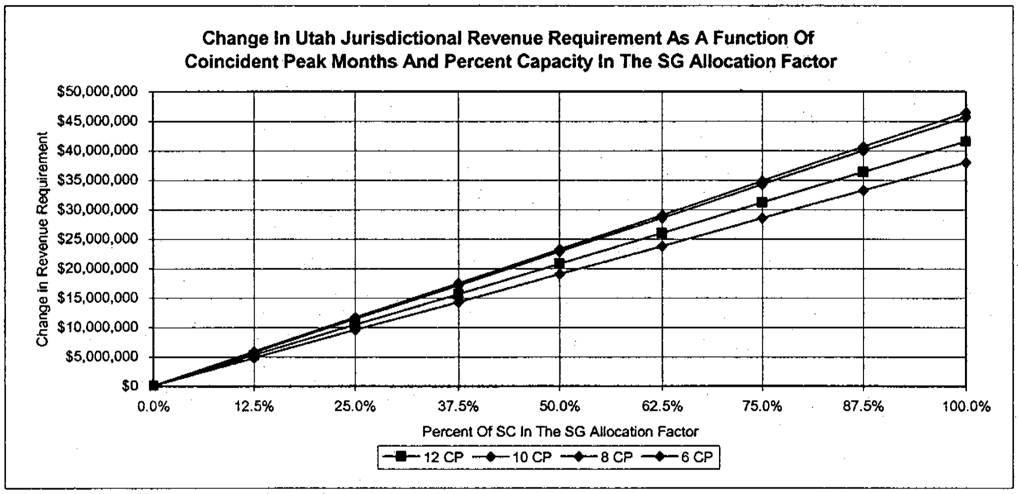
System Generation Allocation Factor Based On 5 CP System Capacity Allocation Factor and Varying Proportions of Capacity and Energy
Remove March, April, May, June, September, October, & November

Demand/Energy	System	Pac Div	Ut Div	California	Oregon	Washington	Wyoming	Utah	Idaho	Wyoming	FERC
100% / 0%	100.0000%	53.8126%	46.1874%	1.9827%	31.6859%	9.4794%	10.6646%	41.8432%	1.9442%	1.9808%	0.4193%
Cost of Service	2,469,049,576	1,321,675,395	1,147,374,181	69,518,332	777,779,809	206,948,565	268,576,189	1,042,945,335	51,369,024	52,456,811	603,012
$COS / MWh	$51.29	$50.12	$52.71	$75.96	$53.34	$47.86	$41.01	$57.32	$23.14	$45.32	$3.14
87.5% / 12.5%	100.0000%	53.9338%	46.0662%	1.9726%	31.5114%	9.4174%	11.0324%	41.3381%	2.2775%	2.0338%	0.4168%
Cost of Service	2,469,055,555	1,323,226,995	1,145,828,560	69,387,481	775,536,501	206,150,065	273,300,448	1,036,530,386	55,600,844	53,125,578	571,753
$COS / MWh	$51.29	$50.18	$52.64	$75.81	$53.19	$47.68	$41.73	$56.96	$25.05	$45.89	$2.97
75% / 25%	100.0000%	54.0549%	45.9451%	1.9624%	31.3370%	9.3553%	11.4002%	40.8331%	2.6109%	2.0868%	0.4143%
Cost of Service	2,469,061,534	1,324,778,594	1,144,282,940	69,256,630	773,293,198	205,351,566	278,024,699	1,030,115,866	59,832,297	53,794,281	540,496
$COS / MWh	$51.29	$50.24	$52.57	$75.67	$53.04	$47.49	$42.45	$56.61	$26.96	$46.47	$2.81
62.5% / 37.5%	100.0000%	54.1761%	45.8239%	1.9522%	31.1626%	9.2932%	11.7680%	40.3280%	2.9442%	2.1398%	0.4119%
Cost of Service	2,469,067,512	1,326,330,193	1,142,737,319	69,125,779	771,049,902	204,553,070	282,748,942	1,023,701,776	64,063,382	54,462,921	509,240
$COS / MWh	$51.29	$50.30	$52.50	$75.53	$52.88	$47.31	$43.17	$56.26	$28.86	$47.05	$2.65
50% / 50%	100.0000%	54.2972%	45.7028%	1.9421%	30.9882%	9.2311%	12.1358%	39.8230%	3.2775%	2.1928%	0.4094%
Cost of Service	2,469,073,491	1,327,881,793	1,141,191,699	68,994,929	768,806,611	203,754,575	287,473,177	1,017,288,121	68,294,095	55,131,496	477,986
$COS / MWh	$51.29	$50.36	$52.43	$75.38	$52.73	$47.12	$43.89	$55.91	$30.77	$47.63	$2.49
37.5% / 62.5%	100.0000%	54.4184%	45.5816%	1.9319%	30.8138%	9.1691%	12.5036%	39.3180%	3.6109%	2.2458%	0.4069%
Cost of Service	2,469,079,470	1,329,433,392	1,139,646,078	68,864,080	766,563,326	202,956,082	292,197,404	1,010,874,904	72,524,433	55,800,008	446,733
$COS / MWh	$51.29	$50.42	$52.36	$75.24	$52.58	$46.94	$44.61	$55.55	$32.68	$48.20	$2.32
25% / 75%	100.0000%	54.5395%	45.4605%	1.9218%	30.6394%	9.1070%	12.8714%	38.8129%	3.9442%	2.2988%	0.4045%
Cost of Service	2,469,085,449	1,330,984,990	1,138,100,458	68,733,230	764,320,046	202,157,591	296,921,623	1,004,462,129	76,754,393	56,468,454	415,482
$COS / MWh	$51.29	$50.47	$52.29	$75.10	$52.42	$46.75	$45.33	$55.20	$34.58	$48.78	$2.16
12.5% / 87.5%	100.0000%	54.6607%	45.3393%	1.9116%	30.4650%	9.0449%	13.2392%	38.3079%	4.2775%	2.3518%	0.4020%
Cost of Service	2,469,091,427	1,332,536,589	1,136,554,838	68,602,381	762,076,772	201,359,102	301,645,833	998,049,799	80,983,972	57,136,835	384,232
$COS / MWh	$51.30	$50.53	$52.22	$74.95	$52.27	$46.57	$46.05	$54.85	$36.49	$49.36	$2.00
0% / 100%	100.0000%	54.7819%	45.2181%	1.9014%	30.2906%	8.9829%	13.6070%	37.8029%	4.6109%	2.4049%	0.3995%
Cost of Service	2,469,097,406	1,334,088,187	1,135,009,218	68,471,533	759,833,503	200,560,615	306,370,036	991,637,917	85,213,168	57,805,150	352,984
$COS / MWh	$51.30	$50.59	$52.15	$74.81	$52.11	$46.38	$46.78	$54.50	$38.39	$49.94	$1.84

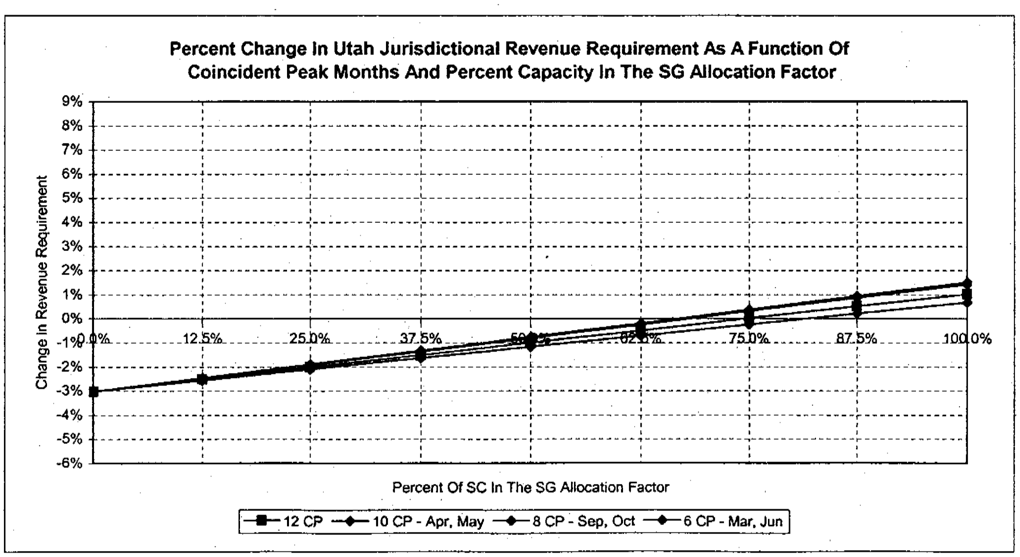
PRODUCTION COST SENSITIVITY

%SC	0.0%	12.5%	25.0%	37.5%	50.0%	62.5%	75.0%	87.5%	100.0%
12 - CP	991,637,917	996,832,588	1,002,027,665	1,007,223,141	1,012,419,007	1,017,615,256	**1,022,811,880**	1,028,008,870	1,033,206,221
11 - CP	991,637,917	997,418,166	1,003,198,915	1,008,980,154	1,014,761,870	1,020,544,053	1,026,326,694	1,032,109,780	1,037,893,303
10 - CP	991,637,917	997,351,615	1,003,065,837	1,008,780,573	1,014,495,813	1,020,211,546	1,025,927,762	1,031,644,452	1,037,361,606
9 - CP	991,637,917	996,957,929	1,002,278,412	1,007,599,356	1,012,920,755	1,018,242,600	1,023,564,883	1,028,887,599	1,034,210,738
8 - CP	991,637,917	996,388,259	1,001,138,970	1,005,890,044	1,010,641,478	1,015,393,268	1,020,145,408	1,024,897,895	1,029,650,725
7 - CP	991,637,917	997,451,854	1,003,266,346	1,009,081,382	1,014,896,956	1,020,713,059	1,026,529,683	1,032,346,821	1,038,164,465
6 - CP	991,637,917	997,444,019	1,003,250,589	1,009,057,622	1,014,865,112	1,020,673,056	1,026,481,448	1,032,290,284	1,038,099,560

%SC	0.0%	12.5%	25.0%	37.5%	50.0%	62.5%	75.0%	87.5%	100.0%
12 - CP	0	5,194,671	10,389,748	15,585,224	20,781,091	25,977,339	**31,173,963**	36,370,953	41,568,304
11 - CP	0	5,780,249	11,560,999	17,342,237	23,123,953	28,906,137	34,688,777	40,471,863	46,255,387
10 - CP	0	5,713,698	11,427,920	17,142,656	22,857,896	28,573,629	34,289,845	40,006,535	45,723,690
9 - CP	0	5,320,012	10,640,495	15,961,439	21,282,838	26,604,683	31,926,967	37,249,682	42,572,821
8 - CP	0	4,750,342	9,501,053	14,252,128	19,003,562	23,755,351	28,507,491	33,259,978	38,012,808
7 - CP	0	5,813,938	11,628,429	17,443,466	23,259,039	29,075,142	34,891,766	40,708,904	46,526,548
6 - CP	0	5,806,102	11,612,672	17,419,705	23,227,195	29,035,139	34,843,531	40,652,367	46,461,643



%SC	0.0%	12.5%	25.0%	37.5%	50.0%	62.5%	75.0%	87.5%	100.0%
12 - CP	-3.05%	-2.54%	-2.03%	-1.52%	-1.02%	-0.51%	**0.00%**	0.51%	1.02%
11 - CP	-3.05%	-2.48%	-1.92%	-1.35%	-0.79%	-0.22%	0.34%	0.91%	1.47%
10 - CP	-3.05%	-2.49%	-1.93%	-1.37%	-0.81%	-0.25%	0.30%	0.86%	1.42%
9 - CP	-3.05%	-2.53%	-2.01%	-1.49%	-0.97%	-0.45%	0.07%	0.59%	1.11%
8 - CP	-3.05%	-2.58%	-2.12%	-1.65%	-1.19%	-0.73%	-0.26%	0.20%	0.67%
7 - CP	-3.05%	-2.48%	-1.91%	-1.34%	-0.77%	-0.21%	0.36%	0.93%	1.50%
6 - CP	-3.05%	-2.48%	-1.91%	-1.34%	-0.78%	-0.21%	0.36%	0.93%	1.49%



Appendix 5

Classification and Allocation of G&T Costs

Classification and Allocation of Generation Fixed Costs
Discussion Paper
By: Dave Taylor
March 4, 2003

Introduction

One of the key questions to be resolved in the Multi State Process is that of classification and allocation of the fixed costs associated with generation resources. This is the case whether the final MSP resolution is based on a dynamic total system sharing of costs and resources as proposed by Utah, or whether the resolution is bases on a control area approach where resources are first directly assigned to the east and west control areas with a sharing of costs and resources separately in each control area. Even a direct assignment of resources to individual states requires a decision on classification and allocation to determine the shares of plants to assign to each state.

All parties to MSP agree that any classification and allocation of generation costs need to be based on principle of cost causation. Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For generation resources, cost causation attempts to determine what influences a utility's production plant investment decisions. In this process, classification relates to separating the portion of generation costs that are expended to meet the Company's peak demand requirements from the portion of generation costs that are expended to meet the Company's energy requirements. Allocation relates to the methods applied to apportion the demand and energy related components of generation costs between the states we serve. Often times the classification and allocation process get combined into a set of composite allocation factors that perform both steps of the process.

A wide variety of classification and allocation options are currently used by utilities across the country and Utah Power, Pacific Power and PacifiCorp have used several different methods in the past. Many of these methods, as well as a number of new alternatives have been discussed during MSP. Of the total system allocation options, the classification of plant between demand and energy components seems to have the largest impact on state revenue requirements. Larger energy classifications assign more costs to high load factor states while larger demand classifications assign more cost to lower load factor states. The choice of the 75% demand 25% energy classification for generation and transmission plant was the last allocation decision made by PITA after the merger.

Several states use the same classification and allocation procedures for both jurisdictional allocation and allocation of costs between customer classes. The classification of plant has even greater impacts on the allocation of costs between customer classes, which makes this an issue of great concern for the intervening industrial customers.

This paper reviews the methodologies used by PacifiCorp and its predecessors in the past, some of the methods used by other utilities, and those proposed by the participants in MSP.

Historical Perspective

Prior to the Utah Pacific merger, Pacific Power classified generation fixed costs as 50% demand related and 50% energy related. The demand component was allocated to states using an allocation factor based on the summation of each state's contribution to the system coincident peak for each of the 60 preceding months (60 CP). The energy component was allocated using each state's energy usage for the previous 24 months. This is shown in the example below:

PP&L Historical Generation Plant Jurisdictional Allocation Factor								
	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	MERGED TOTAL
Sum of 12 CP's								
1997	7,504	26,572	1,743	10,005	5,063	1,369	30,615	82,871
1998	8,099	27,733	1,815	9,977	5,112	1,791	31,936	86,463
1999	8,295	26,903	2,029	9,118	5,197	1,748	32,273	85,563
2000	8,135	27,679	1,719	9,567	5,146	1,760	34,786	88,791
2001	7,778	26,754	1,539	10,551	5,108	1,978	35,071	88,780
60 CP	39,811	135,640	8,845	49,218	25,626	8,646	164,680	432,468
60 CP Factor	9.2%	31.4%	2.0%	11.4%	5.9%	2.0%	38.1%	100.0%
Total Retail MWh								
2000	4,540,498	15,603,612	925,786	6,345,974	3,419,263	1,225,410	20,284,781	52,345,325
2001	4,413,518	15,025,360	865,652	7,083,751	3,406,870	1,366,799	20,070,975	52,232,925
24 Months of Energy	8,954,016	30,628,972	1,791,438	13,429,725	6,826,133	2,592,210	40,355,756	104,578,250
24 Months Energy Factor	8.6%	29.3%	1.7%	12.8%	6.5%	2.5%	38.6%	100.0%
Composite Factor								
Generation Plant Factor	8.9%	30.3%	1.9%	12.1%	6.2%	2.2%	38.3%	100.0%
Allocation Factor = 60 CP Factor X 50% + 24 Month Energy Factor X 50%								

Prior to the merger, Utah Power classified all generation fixed costs as 100% demand related and allocated those costs using each states contributions to the system coincident peak for the eight critical months of the test period (8 CP) with March, April, May, and October being excluded.

Old Utah Power Generation Allocation Factor 2001								
Month	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total System
January	723,744	2,739,428	142,784	888,677	370,179	175,778	2,652,253	7,692,843
February	687,411	2,689,629	146,431	901,580	341,777	175,579	2,652,713	7,595,120
March								
April								
May								
June	681,653	2,123,911	152,418	882,970	491,283	152,048	3,110,502	7,594,785
July	656,533	1,986,895	128,961	891,751	564,363	161,343	3,463,757	7,853,603
August	627,146	2,121,632	124,452	934,472	420,647	156,288	3,514,018	7,898,655
September	626,812	1,923,541	119,509	881,017	391,106	150,279	3,208,631	7,300,895
October								
November	670,076	2,169,395	118,765	897,491	410,725	170,314	2,981,676	7,418,442
December	691,537	2,346,343	131,577	900,452	422,902	178,549	3,017,000	7,688,360
8 CP	5,364,912	18,100,774	1,064,897	7,178,410	3,412,982	1,320,178	24,600,550	61,042,703
8 CP Factor	8.8%	29.7%	1.7%	11.8%	5.6%	2.2%	40.3%	100.0%

Since the merger PacifiCorp has classified generation fixed costs as 75% demand related and 25% energy related with the demand component being allocated using contributions to the system coincident peak all 12 months of the year. Because of the different cost basis of the Pacific Power and Utah Power fleet of plants, the investment in generation resources (Pre Merger Investment) that each company brought to the merger continued to be allocated separately to the Pacific Power and Utah Power states. All new investment in generation resources (Post Merger Investment) is allocated system wide. This is shown in the example below:

Current PacifiCorp Generation Plant Allocation Factor (Modified Accord)								
Pre Merger Investment								
	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	**TOTAL**
Sum of 12 CP's								
2001	7,778	26,754	1,539	10,551	5,108	1,978	35,071	88,780
Division Capacity Pacific (DC-P)	16.7%	57.4%	3.3%	22.6%				100.0%
Division Capacity Utah (DC-U)					12.1%	4.7%	83.2%	100.0%
Total Retail MWh								
2001	4,413,518	15,025,360	865,652	7,083,751	3,406,870	1,366,799	20,070,975	52,232,925
Division Energy Pacific (DE-P)	16.1%	54.9%	3.2%	25.9%				100.0%
Division Energy Utah (DE-U)					13.7%	5.5%	80.8%	100.0%
Composite Factor								
Division Generation Pacific (DG-P)	16.5%	56.8%	3.3%	23.4%	0.0%	0.0%	0.0%	100.0%
Division Generation Utah (DG-U)	0.0%	0.0%	0.0%	0.0%	12.5%	4.9%	82.6%	100.0%
Allocation Factor = 12 CP Factor X 75% + Energy Factor X 25%								
Post Merger Investment								
	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	**MERGED TOTAL**
Sum of 12 CP's								
2001	7,778	26,754	1,539	10,551	5,108	1,978	35,071	88,780
System Capacity (SC)	8.8%	30.1%	1.7%	11.9%	5.8%	2.2%	39.5%	100.0%
Total Retail MWh								
2001	4,413,518	15,025,360	865,652	7,083,751	3,406,870	1,366,799	20,070,975	52,232,925
System Energy Factor (SE)	8.4%	28.8%	1.7%	13.6%	6.5%	2.6%	38.4%	100.0%
Composite Factor								
System Generation Factor (SG)	8.7%	29.8%	1.7%	12.3%	5.9%	2.3%	39.2%	100.0%
Allocation Factor = 12 CP Factor X 75% + Energy Factor X 25%								

The choice of the 75% demand 25% energy classification for generation and transmission plant was the last allocation decision made by PITA after the merger. The PITA analysis indicated that a wide range of demand and energy classification could be supported on a technical basis. The demand energy classification was the swing issue employed to balance the sharing of merger benefits between all the states and 75% demand 25% energy was selected because it produced an overall cost allocation result that was acceptable to all the states.

Methods used by other Utilities

The Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners (NARUC) combines their discussion of classification and allocation alternatives for generation resources. The manual lists a range of alternatives, most of which are used by some utilities. While the Cost Allocation Manual was published as a guide for allocation of costs between customer classes, the cost causation principles discussed should also be applicable to jurisdictional allocation.

Cost Accounting Approach

The cost accounting approach identifies all production costs as either fixed or variable. The assumption is that plant capacity is built to meet peak demand and once it is built it is fixed. Therefore all fixed costs are considered demand related and variable costs are considered energy related. The demand related costs are allocated using class, or state, contributions to system peak (CP). The allocation can use the single system annual peak, or it can use the monthly system peak from more than one month of the year. The three common methods are the single peak, summer winter average peak, and the sum of all 12 CPs. The use of all twelve monthly CPs has been adopted by FERC and seems to be the most common among electric utilities.

100% Demand Factors

	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual CP			724,444	2,225,765	164,145	836,193	547,088	151,073	3,468,372	8,117,080
1 CP Factor	100%	0%	8.92%	27.42%	2.02%	10.30%	6.74%	1.86%	42.73%	100.00%
12 CP			8,067,405	27,115,372	1,746,245	9,824,030	5,190,516	1,812,264	34,259,181	88,015,012
12 CP Factor	100%	0%	9.17%	30.81%	1.98%	11.16%	5.90%	2.06%	38.92%	100.00%
Summer / Winter CP			1,443,622	4,672,892	309,461	1,689,646	957,261	322,124	6,509,073	15,904,079
Summer / Winter CP Factor	100%	0%	9.08%	29.38%	1.95%	10.62%	6.02%	2.03%	40.93%	100.00%

Peak and Average

The Peak and Average method considers that average demand (or annual energy usage / 8760) is a significant cost driver along with coincident peak demand. Under the peak and average method, the demand related classification of fixed costs is calculated by dividing the system annual CP by the sum of the annual CP and the average demand (CP / (CP + average demand)). The demand component is allocated using each state's contribution to the system single coincident peak. For PacifiCorp, this method classifies 60% of fixed generation costs as demand related compared to the 75% used today.

Peak & Average (1 CP)

	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual CP			724,444	2,225,765	164,145	836,193	547,088	151,073	3,468,372	8,117,080
Average MW (MWh / 8760)			516,055	1,744,790	112,149	746,574	386,399	143,767	2,276,339	5,926,074
Demand Component Demand Allocation Factor Single CP / (CP + (MWh/8760))	58%		8.92%	27.42%	2.02%	10.30%	6.74%	1.86%	42.73%	100.00%
Energy Component Average MW Component Allocation Factor (1 - Demand		42%	8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Total Allocation Factor	58%	42%	8.83%	28.27%	1.97%	11.27%	6.65%	2.10%	40.91%	100.00%

Average and Excess

The Average and Excess method also considers that average demand to be a significant cost driver, and that excess demand (individual class or state NCP less average demand) drives the demand component. Under the average and excess method, the energy related component of fixed costs is determined to be equal to the system annual load factor. The demand component is allocated using each state's excess demand, annual non-coincident peak (NCP) less average annual demand (annual MWh / 8760). For PacifiCorp, this method would classify 70% to 75% of fixed generation costs as energy related compared to the 25% used today. This method was proposed by Utah Power in the 1980s and rejected by the three state commissions in favor of the 8 CP method.

Average & Excess										
	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual NCP			782,957	2,639,481	188,904	897,121	671,089	184,209	3,502,529	8,866,290
Average MW (MWh / 8760)			516,055	1,744,790	112,149	746,574	386,399	143,767	2,276,339	5,926,074
Excess MW			266,902	894,690	76,755	150,547	284,690	40,443	1,226,189	2,940,216
Average MW Component Allocation Factor (System Annual		73%	8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Excess Demand Component Allocation Factor (1 - SALF)	27%		9.08%	30.43%	2.61%	5.12%	9.68%	1.38%	41.70%	100.00%
Total Allocation Factor	27%	73%	8.81%	29.71%	2.09%	10.58%	7.37%	2.14%	39.30%	100.00%

Equivalent Peaker Method

The premises of this methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and base load units because of the additional energy loads they must serve. Thus, the cost of peaking capacity is regarded as peak demand-related and classified as demand-related. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related. The demand related component is generally allocated using the single system peak or the loads during the narrow peak period. The Company currently uses the equivalent peaker method in its avoided cost and marginal cost studies. Based on information in the current IRP, this method would classify about 40% of generation fixed cost as demand related and 60% as energy related.

Equivalent Peaker 1 CP										
	D	E	PPL-WA	PPL-OR	PPL-CA	PPL-WY	UPL-ID	UPL-WY	UPL-UT	Total
Annual CP			724,444	2,225,765	164,145	836,193	547,088	151,073	3,468,372	8,117,080
1 CP Factor	38%		8.92%	27.42%	2.02%	10.30%	6.74%	1.86%	42.73%	100.00%
Annual Energy		62%	4,520,645,706	15,284,363,431	982,427,759	6,539,986,792	3,384,855,701	1,259,395,569	19,940,731,690	51,912,406,649
Energy Factor			8.71%	29.44%	1.89%	12.60%	6.52%	2.43%	38.41%	100.00%
Compopsite Factor	38%	62%	8.79%	28.67%	1.94%	11.73%	6.60%	2.21%	40.05%	100.00%

Base – Intermediate – Peak (BIP) Method

Under the BIP Method, base load plants are classified with a large energy component and allocated across all months of the year. Intermediate or Mid-range resources costs are assigned to individual months of the year based according to the operating hours in a given month and allocated using loads in each particular month. Peaking units are more heavily classified as demand related and allocated only to the months when the peaking resources are dispatched to meet retail load. The Oregon PUC Staff has proposed this method as one alternative in MSP.

Attachment 1 summarizes some of the available approaches for classification of generation fixed costs   Attachment 2 contains a summary of the methods used by a small sample of utilities. Attachment 3 shows examples of the allocation methods discussed in this paper applied to PacifiCorp loads.

Utah Allocation Factor Options
March 2006

Values

	Residential Schedule 1	General Large Dist. Schedule 6	General Large Dist. Schedule 8	General Transmission Schedule 9	Irrigation Schedule 10	General Small Dist. Schedule 23	Total
Annual Energy @ Input	6,743,555,490	6,228,648,828	2,005,307,137	4,070,828,033	221,371,385	1,328,102,477	22,263,546,269
Annual CP	1,243,431	1,342,622	303,739	575,289	63,754	275,768	3,925,489
Annual NCP (ICMD)	5,614,922	1,810,255	423,850	727,066	101,086	599,633	9,573,014
Annual Schedule Peak	1,733,165	1,429,517	336,448	599,994	86,608	345,185	4,810,952
12 CP	11,695,124	12,651,539	3,444,234	6,200,364	358,518	2,638,320	39,140,564
Summer / Winter CP	2,495,657	2,094,010	572,274	1,076,935	64,811	489,544	7,142,824
Summer 3 / Winter 3 CP	6,415,763	6,416,445	1,709,640	3,147,461	193,902	1,399,293	20,296,708

Load Factors

	Schedule 1	Schedule 6	Schedule 8	Schedule 9	Schedule 10	Schedule 23	Total
12 CP	79%	67%	80%	90%	85%	69%	78%
1 CP	62%	53%	75%	81%	40%	55%	65%
1 NCP (ICMD)	14%	39%	54%	64%	25%	25%	27%
Schedule Peak	44%	50%	68%	77%	29%	44%	53%

Allocation Factors

Energy Factor

	D	E	Schedule 1	Schedule 6	Schedule 8	Schedule 9	Schedule 10	Schedule 23	Total
Annual Energy			6,743,555,490	6,228,648,828	2,005,307,137	4,070,828,033	221,371,385	1,328,102,477	22,263,546,269
Energy Factor	0%	100%	30.3%	28.0%	9.0%	18.3%	1.0%	6.0%	100.0%

100% Demand Factors

	D	E	Schedule 1	Schedule 6	Schedule 8	Schedule 9	Schedule 10	Schedule 23	Total
Annual NCP			5,614,922	1,810,255	423,850	727,066	101,086	599,633	9,573,014
1 NCP Factor	100%	0%	58.7%	18.9%	4.4%	7.6%	1.1%	6.3%	100.0%
Annual CP			1,243,431	1,342,622	303,739	575,289	63,754	275,768	3,925,489
1 CP Factor	100%	0%	31.7%	34.2%	7.7%	14.7%	1.6%	7.0%	100.0%
12 CP			11,695,124	12,651,539	3,444,234	6,200,364	358,518	2,638,320	39,140,564
12 CP Factor	100%	0%	29.9%	32.3%	8.8%	15.8%	0.9%	6.7%	100.0%
Summer / Winter CP			2,495,657	2,094,010	572,274	1,076,935	64,811	489,544	7,142,824
Summer / Winter CP Factor	100%	0%	34.9%	29.3%	8.0%	15.1%	0.9%	6.9%	100.0%
Summer 3 / Winter 3 CP			6,415,763	6,416,445	1,709,640	3,147,461	193,902	1,399,293	20,296,708
Summer 3 / Winter 3 CP Factor	100%	0%	31.6%	31.6%	8.4%	15.5%	1.0%	6.9%	100.0%

Utah Allocation Factor Options
March 2006

Composite Demand / Energy Factors

12 CP Annual Energy Composite

	D	E	Schedule 1	Schedule 6	Schedule 8	Schedule 9	Schedule 10	Schedule 23	Total
12 CP			11,695,124	12,651,539	3,444,234	6,200,364	358,518	2,638,320	39,140,564
12 CP Factor			29.9%	32.3%	8.8%	15.8%	0.9%	6.7%	100.0%
Annual Energy			6,743,555,490	6,228,648,828	2,005,307,137	4,070,828,033	221,371,385	1,328,102,477	22,263,546,269
Energy Factor			30.3%	28.0%	9.0%	18.3%	1.0%	6.0%	100.0%
Composite Factor	75%	25%	29.98%	31.24%	8.85%	16.45%	0.94%	6.55%	100.00%
Composite Factor	50%	50%	30.08%	30.15%	8.90%	17.06%	0.96%	6.35%	100.00%
Composite Factor	25%	75%	30.19%	29.06%	8.96%	17.67%	0.97%	6.16%	100.00%

1 CP Annual Energy Composite

	D	E	Schedule 1	Schedule 6	Schedule 8	Schedule 9	Schedule 10	Schedule 23	Total
Annual CP			1,243,431	1,342,622	303,739	575,289	63,754	275,768	3,925,489
1 CP Factor			31.7%	34.2%	7.7%	14.7%	1.6%	7.0%	100.0%
Annual Energy			6,743,555,490	6,228,648,828	2,005,307,137	4,070,828,033	221,371,385	1,328,102,477	22,263,546,269
Energy Factor			30.3%	28.0%	9.0%	18.3%	1.0%	6.0%	100.0%
Composite Factor	75%	25%	31.33%	32.65%	8.05%	15.56%	1.47%	6.76%	100.00%
Composite Factor	50%	50%	30.98%	31.09%	8.37%	16.47%	1.31%	6.50%	100.00%
Composite Factor	25%	75%	30.64%	29.53%	8.69%	17.38%	1.15%	6.23%	100.00%

1 NCP Annual Energy Composite

	D	E	Schedule 1	Schedule 6	Schedule 8	Schedule 9	Schedule 10	Schedule 23	Total
Annual NCP			5,614,922	1,810,255	423,850	727,066	101,086	599,633	9,573,014
1 NCP Factor			58.7%	18.9%	4.4%	7.6%	1.1%	6.3%	100.0%
Annual Energy			6,743,555,490	6,228,648,828	2,005,307,137	4,070,828,033	221,371,385	1,328,102,477	22,263,546,269
Energy Factor			30.3%	28.0%	9.0%	18.3%	1.0%	6.0%	100.0%
Composite Factor	75%	25%	51.56%	21.18%	5.57%	10.27%	1.04%	6.19%	100.00%
Composite Factor	50%	50%	44.47%	23.44%	6.72%	12.94%	1.03%	6.11%	100.00%
Composite Factor	25%	75%	37.38%	25.71%	7.86%	15.61%	1.01%	6.04%	100.00%

Utah Allocation Factor Options
March 2006

Average & Excess

	D	E	Schedule 1	Schedule 6	Schedule 8	Schedule 9	Schedule 10	Schedule 23	Total
Using ICMD									
Annual NCP (ICMD)			5,614,922	1,810,255	423,850	727,066	101,086	599,633	9,573,014
Average MW (MWh / 8760)			769,812	711,033	228,916	464,706	25,271	151,610	2,541,501
Excess MW			4,845,110	1,099,222	194,934	262,360	75,816	448,023	7,031,513
Average MW Component Allocation Factor (System Annual Load Factor)		65%	30.3%	28.0%	9.0%	18.3%	1.0%	6.0%	100.0%
Excess Demand Component Allocation Factor (1 - SALF)	35%		68.9%	15.6%	2.8%	3.7%	1.1%	6.4%	100.0%
Total Allocation Factor	35%	65%	43.90%	23.62%	6.81%	13.15%	1.02%	6.11%	100.00%

	D	E	Schedule 1	Schedule 6	Schedule 8	Schedule 9	Schedule 10	Schedule 23	Total
Using Schedule Peaks									
Annual Schedule Peak			1,733,165	1,429,517	336,448	599,994	86,608	345,185	4,810,952
Average MW (MWh / 8760)			769,812	711,033	228,916	464,706	25,271	151,610	2,541,501
Excess MW			963,353	718,484	107,532	135,288	61,337	193,575	2,269,451
Average MW Component Allocation Factor (System Annual Load Factor)		65%	30.3%	28.0%	9.0%	18.3%	1.0%	6.0%	100.0%
Excess Demand Component Allocation Factor (1 - SALF)	35%		42.4%	31.7%	4.7%	6.0%	2.7%	8.5%	100.0%
Total Allocation Factor	35%	65%	34.58%	29.28%	7.50%	13.94%	1.60%	6.87%	100.00%

Utah Allocation Factor Options
March 2006

Peak & Average (1 CP)

	D	E	Schedule 1	Schedule 6	Schedule 8	Schedule 9	Schedule 10	Schedule 23	Total
Annual CP			1,243,431	1,342,622	303,739	575,289	63,754	275,768	3,925,489
Average MW (MWh / 8760)			769,812	711,033	228,916	464,706	25,271	151,610	2,541,501
Demand Component Demand Allocation Factor Single CP / (CP + (MWh/8760))	61%		31.68%	34.20%	7.74%	14.66%	1.62%	7.03%	100.00%
Energy Component Average MW Component Allocation Factor (1 - Demand Component)		39%	30.29%	27.98%	9.01%	18.28%	0.99%	5.97%	100.00%
Total Allocation Factor	61%	39%	31.13%	31.76%	8.24%	16.08%	1.38%	6.61%	100.00%

Peak & Average (12 CP)

	D	E	Schedule 1	Schedule 6	Schedule 8	Schedule 9	Schedule 10	Schedule 23	Total
Average of 12 CP			974,594	1,054,295	287,020	516,697	29,876	219,860	3,261,714
Average MW (MWh / 8760)			769,812	711,033	228,916	464,706	25,271	151,610	2,541,501
Demand Component Demand Allocation Factor Ave 12 CP / (Ave 12CP + (MWh/8760))	56%		29.88%	32.32%	8.80%	15.84%	0.92%	6.74%	100.00%
Energy Component Average MW Component Allocation Factor (1 - Demand Component)		44%	30.29%	27.98%	9.01%	18.28%	0.99%	5.97%	100.00%
Total Allocation Factor	56%	44%	30.06%	30.42%	8.89%	16.91%	0.95%	6.40%	100.00%

Utah Allocation Factor Options
March 2006

Equivalent Peaker 1 CP

	D	E	Schedule 1	Schedule 6	Schedule 8	Schedule 9	Schedule 10	Schedule 23	Total
Annual CP			1,243,431	1,342,622	303,739	575,289	63,754	275,768	3,925,489
1 CP Factor			31.7%	34.2%	7.7%	14.7%	1.6%	7.0%	100.0%
Annual Energy			6,743,555,490	6,228,648,828	2,005,307,137	4,070,828,033	221,371,385	1,328,102,477	22,263,546,269
Energy Factor			30.3%	28.0%	9.0%	18.3%	1.0%	6.0%	100.0%
Composite Factor	33%	67%	30.75%	30.04%	8.59%	17.08%	1.20%	6.32%	100.00%

Equivalent Peaker Summer Winter CP

	D	E	Schedule 1	Schedule 6	Schedule 8	Schedule 9	Schedule 10	Schedule 23	Total
Summer / Winter CP			2,495,657	2,094,010	572,274	1,076,935	64,811	489,544	7,142,824
Summer / Winter CP Factor			34.9%	29.3%	8.0%	15.1%	0.9%	6.9%	100.0%
Annual Energy			6,743,555,490	6,228,648,828	2,005,307,137	4,070,828,033	221,371,385	1,328,102,477	22,263,546,269
Energy Factor			30.3%	28.0%	9.0%	18.3%	1.0%	6.0%	100.0%
Composite Factor	33%	67%	31.83%	28.42%	8.68%	17.22%	0.97%	6.26%	100.00%

Utah Allocation Factor Options
March 2006

Summary of Calculated Allocation Factors

	D	E	Schedule 1	Schedule 6	Schedule 8	Schedule 9	Schedule 10	Schedule 23	Total
Energy Factor	0%	100%	30.3%	28.0%	9.0%	18.3%	1.0%	6.0%	100.0%
1 NCP Factor	100%	0%	58.7%	18.9%	4.4%	7.6%	1.1%	6.3%	100.0%
1 CP Factor	100%	0%	31.7%	34.2%	7.7%	14.7%	1.6%	7.0%	100.0%
12 CP Factor	100%	0%	29.9%	32.3%	8.8%	15.8%	0.9%	6.7%	100.0%
Summer / Winter CP Factor	100%	0%	34.9%	29.3%	8.0%	15.1%	0.9%	6.9%	100.0%
Summer 3 / Winter 3 CP Factor	100%	0%	31.6%	31.6%	8.4%	15.5%	1.0%	6.9%	100.0%
12 CP Annual Energy Composite									
Composite Factor	75%	25%	30.0%	31.2%	8.9%	16.5%	0.9%	6.5%	100.0%
Composite Factor	50%	50%	30.1%	30.2%	8.9%	17.1%	1.0%	6.4%	100.0%
Composite Factor	25%	75%	30.2%	29.1%	9.0%	17.7%	1.0%	6.2%	100.0%
1 CP Annual Energy Composite									
Composite Factor	75%	25%	31.3%	32.6%	8.1%	15.6%	1.5%	6.8%	100.0%
Composite Factor	50%	50%	31.0%	31.1%	8.4%	16.5%	1.3%	6.5%	100.0%
Composite Factor	25%	75%	30.6%	29.5%	8.7%	17.4%	1.2%	6.2%	100.0%
1 NCP Annual Energy Composite									
Composite Factor	75%	25%	51.6%	21.2%	5.6%	10.3%	1.0%	6.2%	100.0%
Composite Factor	50%	50%	44.5%	23.4%	6.7%	12.9%	1.0%	6.1%	100.0%
Composite Factor	25%	75%	37.4%	25.7%	7.9%	15.6%	1.0%	6.0%	100.0%
Average and Excess (ICMD)	35%	65%	43.9%	23.6%	6.8%	13.2%	1.0%	6.1%	100.0%
Average and Excess (Sch. Peaks)	35%	65%	34.6%	29.3%	7.5%	13.9%	1.6%	6.9%	100.0%
Peak & Avg (1 CP)	61%	39%	31.1%	31.8%	8.2%	16.1%	1.4%	6.6%	100.0%
Peak & Avg (12 CP)	56%	44%	30.1%	30.4%	8.9%	16.9%	1.0%	6.4%	100.0%
Equivalent Peaker 1 CP	33%	67%	30.7%	30.0%	8.6%	17.1%	1.2%	6.3%	100.0%
Equivalent Peaker Summer Winter CP	33%	67%	31.8%	28.4%	8.7%	17.2%	1.0%	6.3%	100.0%

PacifiCorp
2004 Integrated Resource Plan
Potential Resource Cost
Demand & Energy Related Components of Fixed & Variable Costs
Generation Costs Only

Equivalent Peaker Method

Description	Ttl Fixed $/kW-Yr	Convert to Mills: Expected Utilization	Convert to Mills: Ttl Fixed Mills/kWh	Total Variable Costs Mills/kWh	Total Resource Cost Mills/kWh
Simple Cycle Turbine					
Average IRP Costs	$ 59.61	$ 0.16	$ 42.53	$ 54.72	$ 97.25
Demand Related Costs	$ 59.61	16%	$ 42.53	$ -	$ 42.53
Energy Related Costs	$ -	16%	$ -	$ 54.72	$ 54.72
Demand Related %	100%		100%	0%	44%
Energy Related %	0%		0%	100%	56%
Combined Cycle Turbine					
[redacted]					
Base Load Coal					
Average IRP Costs	$ 180.30	$ 0.91	$ 22.62	$ 17.36	$ 39.98
Demand Related Costs	$ 59.61	91%	$ 7.48	$ -	$ 7.48
Energy Related Costs	$ 120.69	91%	$ 15.14	$ 17.36	$ 32.50
Demand Related %	33%		33%	0%	19%
Energy Related %	67%		67%	100%	81%

Other Options for Base Load Coal

Demand Related Costs	$ 180.30	91%	$ 22.62	$ -	$ 22.62
Energy Related Costs	$ -	91%	$ -	$ 17.36	$ 17.36
Demand Related %	100%		100%	0%	57%
Energy Related %	0%		0%	100%	43%

Demand Related Costs	$ 135.22	91%	$ 16.96	$ -	$ 16.96
Energy Related Costs	$ 45.07	91%	$ 5.65	$ 17.36	$ 23.01
Demand Related %	75%		75%	0%	42%
Energy Related %	25%		25%	100%	58%

Demand Related Costs	$ 90.15	91%	$ 11.31	$ -	$ 11.31
Energy Related Costs	$ 90.15	91%	$ 11.31	$ 17.36	$ 28.67
Demand Related %	50%		50%	0%	28%
Energy Related %	50%		50%	100%	72%

Demand Related Costs	$ 45.07	91%	$ 5.65	$ -	$ 5.65
Energy Related Costs	$ 135.22	91%	$ 16.96	$ 17.36	$ 34.32
Demand Related %	25%		25%	0%	14%
Energy Related %	75%		75%	100%	86%

Appendix 6

Planning Margin and Temperature Sensitive Loads

Temperature-Sensitive Loads and Class Cost Allocation

Presentation to
Utah Cost-of-Service Working Group

Kevin Higgins, Energy Strategies
July 13, 2005

Statement of the Issue

- System generation capacity is acquired to meet forecasted peak demand plus a 15% planning margin.
- The planning margin provides operating reserves to maintain reliability during system contingencies plus capacity to serve load during periods of abnormal temperature.

Statement of the Issue

- Some customer classes (e.g., 1, 6) are more temperature-sensitive than others (e.g., 9). Temperature-sensitive classes have a relatively greater need for the portion of the planning margin that provides a buffer against abnormal weather.
- In allocating class cost responsibility for generation plant, PacifiCorp utilizes weather-normalized load data.

Statement of the Issue

- Question: Does assuming a normal weather year inadvertently ignore cost responsibility for the capacity margin that is needed to maintain service during periods of abnormal temperature?

- Answer: Yes.

Proposed Solution

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

Why is this important?

Increased costs are being driven by growth in peak demand, much of which is temperature-related air conditioning load. Ignoring planning margin costs understates the costs imposed by this aspect of load growth.

Proposed Approach

- Identify what portion of the planning margin is attributable to weather contingency
- Assign an appropriate portion of planning margin costs to weather-sensitive classes 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

Application of Proposed Approach to Utah COS

- Assign 50% of planning margin to weather contingency
  [Note: Operating reserves = 7.0% of generation]
  - Utah 2006 TY CP = 4136 MW
  - 15% planning margin applicable to Utah = 620 MW
  - 50% of Utah planning margin = 310 MW

Is this a reasonable amount?

<u>Reality check</u>: PacifiCorp estimates that each 1 degree increase in temperature above 90° increases Utah demand by 35 MW.

310 MW provides sufficient capacity for 9° above normal in summer.

UAE's COS Analysis (04-035-42)

Determination of 15% of Utah Load at Time of PacifiCorp's Test Period System Peak

Month	Pac CAL	Pac ORE	Pac WASH	Pac MON	Pac WYO	Utah UTAH	Utah IDAHO	Utah WYO	Utah FERC	Total
Apr-05	135.9	2,070.4	600.2	0.0	768.9	2,548.4	379.4	155.1	26.0	6,684.4
May-05	120.5	1,775.9	534.4	0.0	743.6	2,718.6	434.5	145.5	32.0	6,504.9
Jun-05	144.9	1,937.7	666.0	0.0	815.4	3,615.6	619.1	157.1	37.0	7,992.9
Jul-05	149.8	2,082.9	764.4	0.0	806.9	3,986.6	610.8	148.3	35.0	8,584.7
Aug-05	148.0	2,101.4	781.1	0.0	809.7	4,135.5	550.4	144.2	37.0	8,707.2
Sep-05	120.4	1,872.0	638.4	0.0	807.2	3,536.5	429.9	146.8	37.0	7,588.2
Oct-05	129.4	2,120.8	649.6	0.0	763.4	2,894.7	386.6	150.7	29.0	7,124.2
Nov-05	137.0	2,270.1	651.9	0.0	818.2	3,044.8	402.8	161.1	30.0	7,515.7
Dec-05	149.0	2,393.6	682.8	0.0	825.2	3,136.5	422.2	156.8	29.0	7,795.1
Jan-06	144.4	2,664.4	736.5	0.0	820.9	3,163.3	378.2	155.5	25.0	8,088.3
Feb-06	141.9	2,539.8	701.6	0.0	816.1	3,291.6	390.5	162.8	25.0	8,069.3
Mar-06	146.2	2,432.2	671.0	0.0	806.8	2,712.3	391.0	161.3	28.0	7,348.8
Sum of 12 CPs	1,667.4	26,261.3	8,077.9	0.0	9,602.2	38,784.3	5,395.4	1,845.1	370.0	
12 CP Factor	1.8123%	28.5438%	8.7799%	0.0000%	10.4368%	42.1552%	5.8643%	2.0055%	0.4022%	100.00%

Annual System Peak (MW) 8,707.2

15% of Utah Load at time of Annual System Peak (MW) $\boxed{620.32}$

Data Source: Utah Results of Operations for March 2006 (JTW-1) - Tab 10 Allocation Factors

Application of Proposed Approach to Utah COS

- Allocate weather contingency generation to classes whose load is weather-normalized (1, 6, 8 & 23) based on index of temperature sensitivity.
  - Preferred index: Algorithm that predicts class demand as a function of temperature
  - Actual application: Class relative share of total kWh adjustment for weather
  - Shares:
    - 1 - 50.5%
    - 6 - 33.2%
    - 8 - 10.7%
    - 23 - 5.6%

Results of COS w/ Planning Margin Adjustment

Impact of Planning Margin Adjustment on Rate of Return Indices for Major Rate Schedules

(2004 Utah Rate Case)

Schedule	PacifiCorp Rolled-in	Rolled-in w/ Plan Margin Adjustment	PacifiCorp MSP	MSP w/ Plan Margin Adjustment
1 (Res.)	1.17	1.08	1.21	1.11
6 (GS - Large)	0.94	0.94	0.93	0.93
8 (GS>1 MW)	0.99	0.96	0.98	0.94
9 (GS - HV)	0.98	1.24	0.90	1.19
23 (GS - Sm)	1.09	1.11	1.11	1.13

Appendix 7

Distribution Cost Allocation and Pricing

DISTRIBUTION COSTS B ALLOCATION AND PRICING: A BRIEF WHITE PAPER PREPARED FOR THE UTAH COST-OF-SERVICE AND PRICING TASK FORCE

by George R. Compton
Utah Division of Public Utilities
July 13, 2005

I. Topics and organization of White Paper:

A. The issue as proposed in the 4/13/05 Cost of Service Task Force meeting

B. Orientation and issues driving the NARUC document, *Charging for Distribution Utility Services: Issues in Rate Design*[1]

C. Distribution system cost drivers

D. Cost allocation implications of the cost-causing elements of the distribution system

E. The wrongheadedness of the zero-intercept basis of distribution cost allocation and pricing

F. Pricing implications of the distribution cost drivers and the relationship between distribution cost allocation and pricing

G. The recommended pricing vehicle for recovering shared distribution system costs

II. The issue as proposed in the 4/13/05 Cost of Service Task Force meeting:
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?

III. Orientation and issues driving the NARUC document, *Charging for Distribution Utility Services: Issues in Rate Design*. This document will be quoted liberally in this

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[1] The National Association of Regulatory Utility Commissioners= document authored by Frederick Weston and the Regulatory Assistance Project, funded by The Energy Foundation, December 2000.

white paper. The following brief discussion will enable the readers to understand the issues forming the background for the NARUC document:

A. With the breaking up of vertically integrated utilities and the unbundling of distribution services there came a concern in some quarters that *distribution-only utilities* would attempt to recover their costs (which are almost entirely fixed) through customer charges that were pretty much uniform by customer class. To avoid that eventuality, the author sought to demonstrate how a customer=s amount of consumption contributed to the magnitude of the cost of a distribution system. Of the two primary measures of consumption, demand and energy, it is the former that correlates the most closely with distribution plant costs. The author also recognized geographic and demographic factors B not just demand -- as often contributing even more heavily to distribution costs. As the quotations will show, the NARUC document=s author, if anything, seems to favor energy charges over demand charges for the recovery of distribution costs.

IV. Distribution system cost drivers:

A. NARUC document quotes:

1. ADistribution investment can make up anywhere between ten and forty percent of a vertically-integrated utility=s costs, depending on the demographic, geographic, and other cost (in particular generation) characteristics of the company.@ [p.10]

2. AAnother dimension of cost, and perhaps most revealing, is the geographic. There are several aspects to it. First are the topographical and meteorological characteristics of the area over which the distribution system is laid. Elevations, plant life, weather, soil conditions, and so on all have effects on costs. So too demography, which is captured partly by demand and numbers of customers, *but also affecting costs is the density of customers in an area (sometimes expressed as customers per mile)* [emphasis added].@ [p.36]

3. AThe question is whether there is some amount of capacity in excess of the minimum needed to meet peak demand that can cost-effectively be installed. The additional capacity B larger substations, conductors,

transformers B will reduce energy losses; if the cost of energy saved is greater than that of the additional capacity, then the investment will be cost-effective and should be made. For the purposes of cost analysis and rate design, these kinds of distribution investments are rightly treated as energy-related.@ [p.32]

B. The cost-causing elements of non-customer-specific distribution costs (i.e., all distribution plant-related costs except for meters and service Adrops@) can be categorized as follows:

1. Customer demographics, e.g., density and average distance from the sub-stations. The more spread out are the customers, the greater will be the number of circuit miles to serve them and the greater will be the distribution system costs.

2. Infrastructure, i.e., rights-of-ways, power poles/conduit/trenches (with ancillary equipment) and their installation and maintenance costs. The as-installed cost per lineal foot or circuit-mile of right-of-way, and of pole lines, of conduit, and of trenches, and the relative contribution of those three primary structural elements to the total mix, establishes the average infrastructure unit-cost of the distribution system.

   a. Rights-of-way costs and infrastructure installation costs are a function of real estate costs and the physical topography (e.g., mountains or flat lands, swampy or dry, etc.).

   b. A distinguishing feature of the infrastructure is that in that it is overwhelmingly shared. As with streets, sewer systems, and other elements of a town or city=s civil infrastructure, most of the electric infrastructure can=t be identified with individual consumers but are utilized in some communal fashion.

3. Voltage/capacity. The higher the gauge of the wires used to serve the loads, the higher the cost of those wires. As with transmission lines, distribution line costs are directly proportional to the distance traversed. But while there is also a strong correlation between transmission unit costs and voltage levels (with the larger voltages requiring taller and more expensive towers), a single distribution pole line, for example, can serve

anywhere from one to hundreds of residential customers. In other words, there is a smaller correlation between costs and voltages or customers served with distribution systems than there is with transmission systems.

4. Conclusion: The three primary drivers of distribution costs are the customer demographics, unit infrastructure costs, and average voltage capability. The last item of the three is probably the least determining.
   a. Referring to the quoted observation that distribution costs can range from ten to forty percent of total costs, one might infer that the fourfold increase in the percentage share can=t be attributable to much greater customer-average kW demands, but rather to differences in geography and demographics. Example: My residential subdivision in Alpine consists of lots that average 3/4 acres. The infrastructure is trenches. The distribution cost savings had the Power Company built for half the average household kW loads, or the added costs had the Power Company built for twice the average household kW loads, would have been minimal. The greater drivers of the average-per-customer distribution costs in my neighborhood were the size of the lots and the decision to use trenches rather than power poles.

V. Cost allocation implications of the cost-causing elements of the distribution system

A. As just described, the primary distribution cost drivers are demographics, voltage demand or capacity requirements, and the supporting infrastructure (e.g., rights-of-way, and the purchase and installation of power poles, conduit and trenches). The first item has almost nothing to do with capacity, and the third item has little to do with capacity. With demand, or capacity, being only one B and perhaps the least consequential B of the three major cost-causing elements that drive distribution costs, one would not expect distribution costs to be allocated solely on the basis of demand.

B. On the basis of their lower neighborhood densities and greater average distances from the substations, one would expect that the residential class would receive a larger allocation of distribution costs relative to their loads/demands than would the commercial classes. Offsetting the density/distance factor with regard to residential costs versus commercial costs might be the fact that unit infrastructure costs are higher in urban centers (where the commercial customers are more heavily concentrated) than in the suburbs.

1. PacifiCorp-Oregon has recognized the differential in average distances from substations in establishing the classes= distribution cost allocations.
2. In the late 1970s in Utah, Mountain Bell=s rural customers paid Aurban zone@ monthly surcharges in recognition of the greater costs to extend their access Aloops@ outside the urban areas.[2]

C. The most plausible justification for the practice of allocating distribution costs among customer classes primarily on the basis of relative demand is its ease of administration. Oregon=s experience notwithstanding, easily quantifiable and unambiguous demographic measures by which distribution costs might be allocated are not always readily apparent.

VI. The wrongheadedness of the zero-intercept basis of distribution cost allocation and pricing

A. NARUC document quote: AThe zero-intercept method [also known as the minimum-system method] attempts to model a system that has no demand-serving capability whatsoever, but what remains is not necessarily a system whose costs are driven any more by the number of customers than it is by geographical considerations, whose causative properties are neither squarely demand- nor customer-related.@ [p.31]

B. Some time ago the industry=s costing/pricing analysts observed that even if the existing distribution system=s Awires@ actually contained no metal/conductivity (which would constitute the zero-intercept, where distribution costs are graphed as a function of voltage/capacity, starting with zero voltage and working up), there would still be a lot of costs involved B e.g., for rights-of-ways, power poles, cross-arms, insulators, etc. While the positive-cost, zero-intercept observation is

[2] The then-affiliate to AT&T, Mountain Bell, was one of Qwest=s predecessor companies.

entirely correct, many zero-intercept devotees got into trouble because they didn=t think beyond the conventional energy-demand-customer tri-part utility costing classifications. With no conductivity built into the system, it clearly would incorporate no demand or energy costs. The conclusion then reached was that this substantial residual share of distribution costs must B by elimination of the other two cost classifications B constitute customer costs.

C. The implication for cost allocations was that the distribution costs should be allocated in proportion to the customer count (i.e., if residential customers constitute 95% of the number of customers of a utility, that class should pay 95% of the non-customer-specific distribution costs). The implication for pricing was that the distribution costs B again as customer *costs* -- should be collected via flat-rate (i.e., without regard for individual consumption levels) customer *charges*. The latter would typically yield something in excess of $20 per month.

D. The erroneous assumption behind the zero-intercept pricing and costing policy conclusion is that there can only be the standard three cost classification categories B demand, energy, and customer. It is not unreasonable to regard Acustomer costs@ as applying narrowly to costs that can be identified with specific customers. (The Utah Commission did that in designating what costs are allowed to be recovered in the customer charge.[3]) Having ruled out demand and energy as cost bases of the minimum distribution system, and having limited the customer costs portion, the previous discussion should suggest powerfully a fourth cost basis for the zero-intercept, or minimum distribution system. It is Ademography/ infrastructure.@ I would suggest a particularly strong justification for placing the shared portion of the minimum system (which is almost all of it) in this fourth cost classification category.

1. The existence of a fourth *costing* category does not necessitate the creation of a fourth *pricing* category. Insofar as inter-class demographic/ infrastructure cost differences are recognized, such can be reflected in the pricing structure by augmenting any one, or a combination of two or three, of the standard basic rate elements B i.e., beyond the levels that would

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[3] Report and Order in Docket 84-035-01, dated July 1, 1985.

reflect unambiguous demand, energy, or customer costs.

VII. Pricing implications of the distribution cost drivers and the relationship between distribution cost allocation and pricing

A. NARUC document quote: AToo great a dependence on cost studies is to be captured by their underlying assumptions and methodological flaws. Utilities and commissions should be cautious before adopting a particular method on the basis of what may be a superficial appeal. More important, however, is the concern that a costing method, once adopted, becomes the predominant B and unchallenged B determinant of rate design.@ [Pp 6-7]

B. We have observed that the bulk of the costs for the minimum distribution system are for the shared infrastructure. The two primary mechanisms for recovering the costs of the shared infrastructure in the civic sector (e.g., highways, local streets and sewage systems) are direct or indirect user fees (e.g., gasoline taxes) and taxes, per se (e.g. property taxes). The latter reflects more the notion of ability-to-pay than benefits-received.

C. Paying for shared electrical distribution infrastructure via the customer charge has been largely, and appropriately, rejected by utility regulators. It would be the equivalent of a governmental head, or poll, tax B reflecting neither ability-to-pay nor benefits-received.

D. While tax subsidies based upon an ability to pay may underwrite a portion of the costs of municipal utility systems, recovering the costs of privately owned utilities on the basis of an ability to pay is not practically feasible, even if it were desirable. That leaves benefits-received B by way of usage fees B as the appropriate vehicle for recovering the utility=s shared infrastructure costs.

E. The single best measure of benefits received from an electric utility is energy consumption. At the least, it should be clear that if the shared infrastructure costs were recovered entirely on the basis of demand costs rather than on the basis of energy costs or a combination of energy and demand costs, that there would be a failure to fully connect revenues with benefits received.

1. Example: Consider two retail entities that are identical in every respect except that one operates 24-7 while the other operates for ten hours per

day, six days a week. Assume that the basic customer, energy, and demand charges cover the full plant and operating costs of generation and transmission as well as the explicit customer-, demand-, and energy-driven costs of the distribution system. Would it make sense for the two customers to pay the same amount towards the cost of the distribution Aminimum system@ when the 24-7 customer uses more than twice the amount of energy as the other customer? Such would be the case if the minimum system costs were collected entirely from the demand charge. The 24-7 customer is obviously receiving more benefits from the shared system. ***In a word, it is clear that if the benefits-received objective is to be achieved in this context, then a portion of the minimum system costs must be borne by the energy charge as well as by the demand charge.***

VIII. The recommended pricing vehicle for recovering shared distribution system costs.

A. NARUC document quotes:

1. AVolumetric, energy-based unit prices *for distribution services* [emphasis added]...are the preferred approach. This is particularly true for lower-volume consumers. Such rates promote long-run economic efficiency and are fair.... For larger[-]volume customers, a multi-part price structure that differentiates between demand-related and energy-related costs will work, to the extent that, as with energy-only pricing, customers pay only for what they use *and that, as their consumption changes, so do their bills* [emphasis added]. [p. 7]

2. AIt is not enough to assert a principle of economics to justify a particular rate design. Economic efficiency is an important consideration when structuring rates, but it is by no means the only one, or even the foremost. Fairness, rate stability, revenue stability, administrability, non-discrimination, and environmental protection are equally significant, and regulators often have to find ways to reconcile these sometimes competing goals.@ [p. 6]

B. The recently concluded PacifiCorp general rate case culminated in price increases that averaged approximately 4.4%. With two major exceptions, roughly that percentage was applied to all of the tariffed rate elements.[4] One of those exceptions was the residential customer charge, which remained at $0.98 per month. The other exception was the Schedule 6 (large commercial) energy charge, *which actually declined* -- but with a Acompensatory@[5] larger-than-average increase in that schedule=s demand charge. This exception allowed very high load-factor customers to experience a billing increase of between one and two percent while low load-factor customers experienced an increase that was above 5% (and as high as 6.5% in the summer).

1. The primary justification given for shifting partial distribution cost recovery away from the commercial class energy charge and placing it almost entirely on the demand charge was that distribution costs are allocated among customer classes on the basis of demand. A related justification was that PacifiCorp is more capacity constrained than energy constrained, and that the demand charge sends more of a capacity pricing signal than does the energy charge.

    a. Net revenue stability is a regulatory objective whose support for demand rather than energy charges was not brought up in the rate case=s pricing discussions. It=s my impression that monthly peak demands are more constant on a year-to-year basis than are

[4] The exceptions were requisites for the endorsements by two of the parties of the stipulation which settled the case.

[5] It was compensatory in the sense that the desired level of revenues from the rate schedule could be achieved despite the reduced energy charge. But the effect on individual customers within the schedule was rarely neutral. There were major winners and major losers, depending upon the customer=s load factor.

customers= energy usages. (The latter is affected by the weather and, in the industrial sector, by how long major electricity-consuming equipment is operated, not whether or not it is operated at all.) Accordingly, this objective will tend to encourage greater infrastructure cost recovery via the demand charges rather than the energy charges.

2. There are a number of arguments against the demand-to-energy, distribution cost recovery pricing shift.

   a. There is no immutable law of regulatory economics that says that there must be a one-to-one correspondence between costing and pricing structures. With the Utah residential price structure, for example, demand costs as well as most customer costs B along with the energy costs B are recovered via the cents-per-kWh energy charge(s).

   b. Because the Schedule 6 demand charge is not time-of-day based, and even if it were, because there is no demand charge incentive to reduce prospective peak period demands once the month=s peak had been reached, demand charges are regarded as relatively ineffectual in discouraging peak period consumption. The price signal effects of high energy charges are always in place.

   c. In the context of a general rate increase, to give some customers within a rates class a much larger increase than is placed upon others is considered a major breach of utility regulatory protocol. Referring back to the listed regulatory objectives regarding pricing, the described Arearranging@ of the demand and energy charges is a flagrant violation of the rate stability and gradualism goal. Allowing high load factor customers to pay little or nothing more for the distribution system than would customers with the same level of demand but with much lower consumption levels also violates the fairness objective. Finally, shifting the pricing away from the energy charge also subtracts from the environmental/

conservation objective.[6]

C. It is the Division=s recommendation that pursuant to the next general rate case that a zero-intercept, or minimum-system, study be conducted for the purpose of ascertaining what share of the distribution system costs are *not* demand related. That knowledge should illuminate our policy deliberations regarding what portion of the distribution system costs should be recovered through the demand charge and what portion should be recovered through the energy charge.

1. Partly to move us back closer to the status quo ante, it would be my personal recommendation to collect at least half of the costs that are not directly attributable to demand through the energy charge.
2. 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.

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[6] That objective has been employed as justification for using the energy charge to collect most of the narrowly defined residential customer costs.

Appendix 8

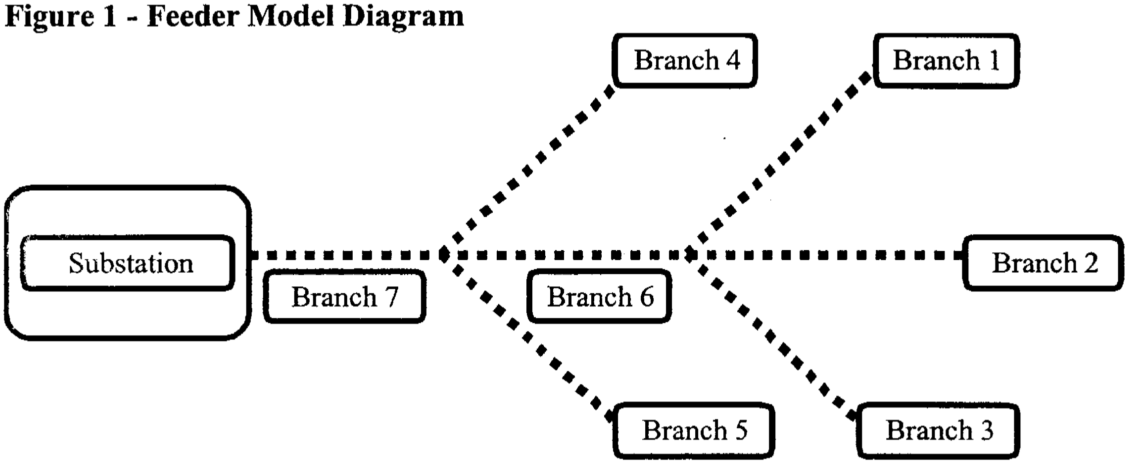
Oregon distance sensitive distribution allocation

PacifiCorp
State of Oregon
PacifiCorp Distribution Feeder Model

General Overview

The PacifiCorp Distribution Feeder Model is an Excel workbook that calculates the cost of building a hypothetical feeder (Figure 1, below) with seven branches of equal length using the composite line statistics for a chosen state or service area. A hypothetical feeder is used rather than a sampling of actual existing feeders. This is because the diverse characteristics of PacifiCorp's six state service area, consisting of over 2,000 distribution feeders, makes the selection of any single, or small number of typical feeders impractical. The fundamental concept of the hypothetical feeder is to create a model that reduces the elements of distribution cost assignment to a workable form.

Figure 1 - Feeder Model Diagram



The feeder model focuses on several key characteristics that influence distribution cost of service. Among these are customer density, customer size and usage characteristics, and perhaps most importantly, customer location on the feeder. Each customer is assigned cost responsibility for all distribution facilities between the customer's location and the substation (upstream facilities), but no facilities beyond the customer's service location (downstream facilities). The model performs three basic functions. First, it estimates the total cost to build the composite feeder using current construction costs and state specific characteristics. Second, it divides the cost of each branch of the feeder between demand and commitment related costs. Third, it assigns the various types of costs to customer classes.

Required Engineering & Statistical Data

Listed below are the basic statistics that we use to calculate the composite feeder for a given state:

1. Current One Mile Line Construction Cost Estimates for Each Conductor Size
2. Economic Conductor Loading for Each Conductor Size
3. Overhead and Underground Line Miles

4. Number of Poles
5. Number of Feeders -- distribution line points of origin radiating from a substation.
6. Actual Customer Distances from Distribution Substations
7. Number of Customers and Loads by Class
8. Percentages of Three-Phase and Single-Phase Customers by Class

One Mile Line Estimate

The model determines the cost of the feeder by using cost estimates to construct one mile of distribution facilities using each of the Company's single and three-phase wire sizes. These cost estimates are based on typical topography and equipment configuration for an average mile of line construction. Since the number of poles per mile varies between states, we use a factor to adjust the line cost estimate from the system wide average of 25 poles per mile to the state average poles per mile. For example, Oregon has an average of 24.83 poles per mile while Utah has 29.95 poles per mile. Figure 2 shows the feeder cost per mile calculation for Oregon.

Figure 2 – Adjusted Oregon Line Costs per Mile

Wire Sizes		Account 364 Pole Cost per Mile				Account 365	Total Line
		Pole Cost per Mile	Estimate Poles per Mile	Adjustment Factor	Adjusted Pole Cost	Conductor Cost per Mile	Construction Cost
1 Phase -1/0 ACSR		$ 25,110	25	0.978	$ 24,558	$ 9,832	$ 34,942
3 Phase - 1/0 ACSR 1\0 ACSR		$ 29,725	25	0.978	$ 29,071	$ 20,273	$ 49,998
3 Phase - 4/0 AAC & 4\0 AAC		$ 31,819	25	0.978	$ 31,119	$ 23,423	$ 55,242
3 Phase - 447 AAC & 4\0 AAC		$ 34,814	25	0.978	$ 34,048	$ 34,546	$ 69,360
3 Phase -795 AAC & 477 AAC		$ 37,334	25	0.978	$ 36,513	$ 74,083	$ 111,417

State	State Specific Account 364 Pole Statistics			Adjustment
	Poles	Pole Miles	Poles / Mile	Factor
California	54,923	2,320	23.67	0.932
Idaho	99,488	4,447	22.37	0.881
Oregon	353,613	14,239	24.83	0.978
Utah	357,900	11,951	29.95	1.179
Washington	96,084	3,584	26.81	1.056
Wyoming - East	126,080	5,975	21.10	0.831
Wyoming - West	22,888	1,233	18.56	0.731
Total	1,110,976	43,750	25.39	1.000

Customer Placement

One of the most significant cost drivers of marginal distribution costs is the distance between the customer and the substation. Costs increase as the distance from the substation increases.

The feeder model takes distance into account by assigning customers to the different branches of the feeder based upon actual customer locations. The actual customer distances are derived from PacifiCorp's outage management system (CADOPS). The system is able to accurately trace the flow of electricity from substation to customer as well as ascertain the exact distance it must travel.

Figure 3 shows the Customer Distribution on the Hypothetical Feeder Branch for Oregon.

Figure 3 Customer Distribution

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Feeder Branch							Branch
		1	2	3	4	5	6	7	Total
1	Residential	1.33%	1.33%	1.33%	3.07%	3.07%	3.07%	86.80%	100.00%
2	GS 0-15 kW (sec) (23)	1.77%	1.77%	1.77%	3.60%	3.60%	3.60%	83.90%	100.00%
3	GS >15 kW (sec) (23)	1.77%	1.77%	1.77%	3.60%	3.60%	3.60%	83.90%	100.00%
4	GS (pri) (23)	1.77%	1.77%	1.77%	3.60%	3.60%	3.60%	83.90%	100.00%
5	GS < 50 kW (sec) (28)	0.88%	0.88%	0.88%	2.28%	2.28%	2.28%	90.51%	100.00%
6	GS 51-100 kW (sec) (28)	0.88%	0.88%	0.88%	2.28%	2.28%	2.28%	90.51%	100.00%
7	GS > 100 kW (sec) (28)	0.88%	0.88%	0.88%	2.28%	2.28%	2.28%	90.51%	100.00%
8	GS (pri) (28)	0.88%	0.88%	0.88%	2.28%	2.28%	2.28%	90.51%	100.00%
9	GS 0-300 kW (sec) (30)	0.50%	0.50%	0.50%	2.32%	2.32%	2.32%	91.55%	100.00%
10	GS >300 kW (sec) (30)	0.50%	0.50%	0.50%	2.32%	2.32%	2.32%	91.55%	100.00%
11	GS (pri) (30)	0.50%	0.50%	0.50%	2.32%	2.32%	2.32%	91.55%	100.00%
12	Irrigation	3.68%	3.68%	3.68%	12.08%	12.08%	12.08%	52.73%	100.00%
15	Large GS 1 - 4 MW (sec)	-	-	-	1.81%	1.81%	1.81%	94.58%	100.00%
16	Large GS 1 - 4 MW (pri)	-	-	-	1.81%	1.81%	1.81%	94.58%	100.00%
15	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
16	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-

Customer Density

The next significant driver of distribution costs is customer density. The model uses state specific line and customer statistics to calculate the average number of customers by feeder branch. Total state distribution line miles and state customers, by class, are divided by the number of distribution feeders in the state to determine the average length of the composite feeder (line miles / number of feeders) and the number of customers on the feeder (customers / feeders). Figure 4 shows the average number of customers located on each of the seven feeder branches for Oregon.

Figure 4 – Oregon Average Customers by Hypothetical Feeder Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Feeder Branch							
		1	2	3	4	5	6	7	Total
	Average Customers								
1	Residential	10.17	10.17	10.17	23.49	23.49	23.49	664.01	765.00
2	GS 0-15 kW (sec) (23)	1.86	1.86	1.86	3.78	3.78	3.78	88.18	105.11
3	GS >15 kW (sec) (23)	0.16	0.16	0.16	0.33	0.33	0.33	7.61	9.07
4	GS (pri) (23)	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.05
5	GS < 50 kW (sec) (28)	0.06	0.06	0.06	0.17	0.17	0.17	6.56	7.24
6	GS 51-100 kW (sec) (28)	0.04	0.04	0.04	0.11	0.11	0.11	4.38	4.84
7	GS > 100 kW (sec) (28)	0.03	0.03	0.03	0.07	0.07	0.07	2.83	3.13
8	GS (pri) (28)	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.09
9	GS 0-300 kW (sec) (30)	0.00	0.00	0.00	0.01	0.01	0.01	0.43	0.47
10	GS >300 kW (sec) (30)	0.00	0.00	0.00	0.02	0.02	0.02	0.89	0.97
11	GS (pri) (30)	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08
12	Irrigation	0.41	0.41	0.41	1.35	1.35	1.35	5.90	11.20
15	Large GS 1 - 4 MW (sec)	-	-	-	0.00	0.00	0.00	0.22	0.23
16	Large GS 1 - 4 MW (pri)	-	-	-	0.00	0.00	0.00	0.09	0.10
17	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
18	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
19	Total	12.75	12.75	12.75	29.34	29.34	29.34	781.30	907.57

Load Accumulation

The kW load that a customer or class places on the system influences the size of the conductor necessary to serve the load. At each point on the feeder, the conductor must be sized to carry the entire downstream load. At the far ends of the outer branches, loads are minimal. As you move upstream closer to the substation, the load on the feeder becomes greater requiring larger conductor sizes. In the model, load can accumulate two ways. The first occurs as customers accumulate on a branch of the feeder. When enough customers, or load, accumulate it is necessary to increment up to the next wire size. Upstream from that point, customer segments increase in cost due to the increase in wire size. The second method of load accumulation is when several branches converge at a central point on the trunk of the feeder. The trunk branches must be of adequate size to carry the load of the customers on that branch plus all downstream branches.

Figure 5 shows the feeder kW loading on each of the feeder branches for Oregon. Loads are for customers located on that branch. Accumulated loads for branch 6 would be the combined loads of branches 1, 2, 3 and 6. Accumulated loads for branch 7 would be the combined loads of all branches.

Figure 5 – Oregon Feeder kW Load by Branch

	Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Hypothetical Feeder Branch							
		1	2	3	4	5	6	7	Total
	Feeder kW Loads								
1	Residential	22.2	22.2	22.2	51.4	51.4	51.4	1,452.1	1,673.0
2	GS 0-15 kW (sec) (23)	3.5	3.5	3.5	7.1	7.1	7.1	165.5	197.2
3	GS >15 kW (sec) (23)	2.8	2.8	2.8	5.6	5.6	5.6	130.7	155.8
4	GS (pri) (23)	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2
5	GS < 50 kW (sec) (28)	1.5	1.5	1.5	3.9	3.9	3.9	154.9	171.2
6	GS 51-100 kW (sec) (28)	1.5	1.5	1.5	4.0	4.0	4.0	158.0	174.6
7	GS > 100 kW (sec) (28)	2.1	2.1	2.1	5.3	5.3	5.3	212.0	234.3
8	GS (pri) (28)	0.1	0.1	0.1	0.1	0.1	0.1	5.3	5.8
9	GS 0-300 kW (sec) (30)	0.4	0.4	0.4	1.8	1.8	1.8	69.6	76.0
10	GS >300 kW (sec) (30)	1.5	1.5	1.5	7.0	7.0	7.0	277.9	303.5
11	GS (pri) (30)	0.1	0.1	0.1	0.6	0.6	0.6	23.5	25.7
12	Irrigation	1.3	1.3	1.3	4.4	4.4	4.4	19.1	36.3
13	Large GS 1 - 4 MW (sec)	-	-	-	3.8	3.8	3.8	200.6	212.1
14	Large GS 1 - 4 MW (pri)	-	-	-	2.0	2.0	2.0	102.7	108.6
15	Large GS + 4 MW (sec)	-	-	-	-	-	-	-	-
16	Large GS + 4 MW (pri)	-	-	-	-	-	-	-	-
17	Total	37.0	37.0	37.0	97.0	97.0	97.0	2,972.1	3,374.2

Feeder Model Cost Assignment

Line statistics for the PacifiCorp service area show that the distribution system is predominately overhead. To calculate the cost of branch construction, miles per branch is calculated by taking the distance per feeder (total line miles / total number of feeders) and dividing it by the number of branches per feeder (7 branches, see figure 1). Next, using an assumption from distribution engineers that the typical outer branches are 35% single phase, the feeder branch length is split between single and three-phase. The total branch construction cost can then be calculated by taking the single and three-phase distances per branch and multiplying them by the one mile construction costs for poles and conductors, as shown in figure 6.

Costs are split between demand and commitment by assuming that the cost of constructing the branch with the smallest single-phase conductor and smallest pole is the commitment related portion and all costs above this amount are demand related.

Branches 6 and 7 are 100% three-phase and are considered all demand. Figure 6 shows the feeder costs per mile, costs for each branch and miles per branch broken out by single and three-phase for Oregon.

Figure 6 – Adjusted Oregon Line Costs per Mile

Wire Sizes		Account 364 Pole Cost per Mile Pole Cost per Mile	Estimate Poles per Mile	Adjustment Factor	Adjusted Pole Cost	Account 365 Conductor Cost per Mile	Total Line Construction Cost
1 Phase -1/0 ACSR		$ 25,110	25	0.978	$ 24,558	$ 9,832	$ 34,942
3 Phase - 1/0 ACSR 1\0 ACSR		$ 29,725	25	0.978	$ 29,071	$ 20,273	$ 49,998
3 Phase - 4/0 AAC & 4\0 AAC		$ 31,819	25	0.978	$ 31,119	$ 23,423	$ 55,242
3 Phase - 447 AAC & 4\0 AAC		$ 34,814	25	0.978	$ 34,048	$ 34,546	$ 69,360
3 Phase -795 AAC & 477 AAC		$ 37,334	25	0.978	$ 36,513	$ 74,083	$ 111,417

	Costs for Branches 1,2,3,4,5			
Wire Size	1 Phase -1/0 A	3 Phase - 1/0 ACSR 1\0 /	Total	
Poles	$ 39,115	$ 85,994	$ 125,109	
Conductors	$ 15,660	$ 59,969	$ 75,629	
Total	$ 54,776	$ 145,963	$ 200,739	
	Costs for Branch 6		**Cost for Branch 7**	
Wire Size	3 Phase - 447 AAC & 4\0 AAC		3 Phase -795 AAC & 477 AAC	
Poles	$ 154,948		$ 166,164	
Conductors	$ 157,214		$ 337,142	
Total	$ 312,163		$ 503,306	

Miles per Branch	4.55
Single Phase Miles Per Branch	1.593
Three Phase Miles Per Branch	2.96

Customer Feeder Costs

After calculating the cost per mile for single and three-phase construction for all of the branches, we compile the data and create a hypothetical feeder model branch cost sheet, as shown in figure 7. Figure 7 includes the total cost per feeder branch in columns (A) and (B), and the allocation of total cost between commitment and demand in columns (C) through (F) for Oregon.

Figure 7 – Oregon Hypothetical Feeder Model Branch Costs

Conductors Type	(A)	(B)	(C)	(D)	(E)	(F)
	Total Cost		Commitment Cost		Demand Cost	
	Poles	Conductor	Poles	Conductor	Poles	Conductor
Branch 1						
1 Phase -1/0 ACSR	$ 39,115	$ 15,660	$ 39,115	$ 15,660	NA	NA
3 Phase - 1/0 ACSR 1\0 A	$ 85,994	$ 59,969	$ 72,643	$ 29,084	$ 13,351	$ 30,885
Total segment	$ 125,109	$ 75,629	$ 111,758	$ 44,744	$ 13,351	$ 30,885
Branch 2						
1 Phase -1/0 ACSR	$ 39,115	$ 15,660	$ 39,115	$ 15,660	NA	NA
3 Phase - 1/0 ACSR 1\0 A	$ 85,994	$ 59,969	$ 72,643	$ 29,084	$ 13,351	$ 30,885
Total Segments	$ 125,109	$ 75,629	$ 111,758	$ 44,744	$ 13,351	$ 30,885
Branch 3						
1 Phase -1/0 ACSR	$ 39,115	$ 15,660	$ 39,115	$ 15,660	NA	NA
3 Phase - 1/0 ACSR 1\0 A	$ 85,994	$ 59,969	$ 72,643	$ 29,084	$ 13,351	$ 30,885
Total Segments	$ 125,109	$ 75,629	$ 111,758	$ 44,744	$ 13,351	$ 30,885
Branch 4						
1 Phase -1/0 ACSR	$ 39,115	$ 15,660	$ 39,115	$ 15,660	NA	NA
3 Phase - 1/0 ACSR 1\0 A	$ 85,994	$ 59,969	$ 72,643	$ 29,084	$ 13,351	$ 30,885
Total Segments	$ 125,109	$ 75,629	$ 111,758	$ 44,744	$ 13,351	$ 30,885
Branch 5						
1 Phase -1/0 ACSR	$ 39,115	$ 15,660	$ 39,115	$ 15,660	NA	NA
3 Phase - 1/0 ACSR 1\0 A	$ 85,994	$ 59,969	$ 72,643	$ 29,084	$ 13,351	$ 30,885
Total Segments	$ 125,109	$ 75,629	$ 111,758	$ 44,744	$ 13,351	$ 30,885
Branch 6						
3 Phase - 447 AAC & 4\0 /	$ 154,948	$ 157,214	NA	NA	$ 154,948	$ 157,214
Total Segments	$ 154,948	$ 157,214	$ -	$ -	$ 154,948	$ 157,214
Branch 7						
3 Phase -795 AAC & 477 /	$ 166,164	$ 337,142	NA	NA	$ 166,164	$ 337,142
Total segment	$ 166,164	$ 337,142	$ -	$ -	$ 166,164	$ 337,142

Cost Sharing Calculation

As mentioned before, one of the critical factors of cost-responsibility is the location of a customer or class on the feeder branches. Customer classes that locate on all branches share cost responsibility for all branches of the feeder including the trunk. Large industrial customers, who locate on the trunk of the feeder, share cost responsibility for only the trunk. We determine cost responsibility by calculating the percentage of demand, or percentage of customers, by class, that shares a particular branch of the feeder. We then multiply the total branch costs by the share percentage and then total the branch costs by class. To calculate the total branch cost, we assign the applicable cost of branches 6 and 7 to customers on branches 1, 2, 3, 4 and 5. Demand costs calculated in an earlier step are allocated between customer classes at this point. Figure 8 shows this calculation along with the allocation of branch costs to the individual customer classes for Oregon. Demand costs are totaled for each customer class then divided by feeder kW to get demand cost in dollars per kW.

Figure 8 – Oregon Poles Demand Calculations, Branch 6 & 7 Cost Assignment

Line	Branch	1	2	3	4	5	6	7		
1	% Demand	17.79%	17.79%	17.79%	NA	NA	46.62%	NA	100.00%	
2	Branch 6 Cost	$ 27,569	$ 27,569	$ 27,569	NA	NA	$ 72,241	NA	$ 154,948	$ / kW
3	% Demand	1.10%	1.10%	1.10%	2.87%	2.87%	2.87%	88.08%	100.00%	
4	Branch 7 Cost	$ 1,823	$ 1,823	$ 1,823	$ 4,777	$ 4,777	$ 4,777	$ 146,364	$ 166,164	
5	Branch Demand Cost	$ 13,351	$ 13,351	$ 13,351	$ 13,351	$ 13,351	NA	NA		Average
6	Total	$ 42,743	$ 42,743	$ 42,743	$ 18,128	$ 18,128	$ 77,018	$ 146,364	$ 387,868	$ 114.95
7										
8									Total	Total
9	Class Cost per Branch(4)	1	2	3	4	5	6	7	Demand Cost	Per kW
10	Residential	$ 25,682	$ 25,682	$ 25,682	$ 9,601	$ 9,601	$ 40,788	$ 71,511	$ 208,546	$ 125
11	GS 0-15 kW (sec) (23)	$ 4,032	$ 4,032	$ 4,032	$ 1,326	$ 1,326	$ 5,633	$ 8,149	$ 28,531	$ 145
12	GS >15 kW (sec) (23)	$ 3,184	$ 3,184	$ 3,184	$ 1,047	$ 1,047	$ 4,449	$ 6,435	$ 22,531	$ 145
13	GS (pri) (23)	$ 5	$ 5	$ 5	$ 2	$ 2	$ 7	$ 10	$ 36	$ 145
14	GS < 50 kW (sec) (28)	$ 1,745	$ 1,745	$ 1,745	$ 729	$ 729	$ 3,099	$ 7,630	$ 17,423	$ 102
15	GS 51-100 kW (sec) (28)	$ 1,780	$ 1,780	$ 1,780	$ 744	$ 744	$ 3,161	$ 7,782	$ 17,771	$ 102
16	GS > 100 kW (sec) (28)	$ 2,389	$ 2,389	$ 2,389	$ 998	$ 998	$ 4,241	$ 10,442	$ 23,846	$ 102
17	GS (pri) (28)	$ 59	$ 59	$ 59	$ 25	$ 25	$ 105	$ 259	$ 591	$ 102
18	GS 0-300 kW (sec) (30)	$ 436	$ 436	$ 436	$ 329	$ 329	$ 1,400	$ 3,427	$ 6,794	$ 89
19	GS >300 kW (sec) (30)	$ 1,741	$ 1,741	$ 1,741	$ 1,315	$ 1,315	$ 5,588	$ 13,683	$ 27,125	$ 89
20	GS (pri) (30)	$ 147	$ 147	$ 147	$ 111	$ 111	$ 473	$ 1,158	$ 2,296	$ 89
21	Irrigation	$ 1,542	$ 1,542	$ 1,542	$ 818	$ 818	$ 3,477	$ 942	$ 10,680	$ 294
24	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 716	$ 716	$ 3,041	$ 9,878	$ 14,352	$ 68
25	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 366	$ 366	$ 1,557	$ 5,056	$ 7,346	$ 68
26	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Check Total	$ 42,743	$ 42,743	$ 42,743	$ 18,128	$ 18,128	$ 77,018	$ 146,364	$ 387,868	

Commitment costs are calculated using a similar method. Commitment costs calculated in an earlier step are allocated to classes using percent of customers on a given branch. Commitment dollars are totaled by customer class then divided by the number of customers in the class to get commitment costs in dollars per customer. Figure 9 shows these calculations for Oregon.

Figure 9–Oregon Poles Commitment Calculations, Branch 1,2,3,4 & 5 Cost Assignment

Line	Branch	1	2	3	4	5	6	7		
1	% customer	18.86%	18.86%	18.86%	NA	NA	43.41%	NA	100.00%	
2	Branch 6 Cost	$ -	$ -	$ -	NA	NA	$ -	NA	$ -	$ Per
3	% customer	1.40%	1.40%	1.40%	3.23%	3.23%	3.23%	86.09%	100.00%	Customer
4	Branch 7 Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Branch Commitment Cost	$ 111,758	$ 111,758	$ 111,758	$ 111,758	$ 111,758	NA	NA		average
6	Total	$ 111,758	$ 111,758	$ 111,758	$ 111,758	$ 111,758	$ -	$ -	$ 558,792	$ 615.70
7										
8									Total	$ Per
9									Commitment	Customer
10	Class Cost per Branch(2)	1	2	3	4	5	6	7	Cost	
11	Residential	$ 89,164	$ 89,164	$ 89,164	$ 89,473	$ 89,473	$ -	$ -	$ 446,439	$ 584
12	GS 0-15 kW (sec) (23)	$ 16,315	$ 16,315	$ 16,315	$ 14,400	$ 14,400	$ -	$ -	$ 77,745	$ 740
13	GS >15 kW (sec) (23)	$ 1,408	$ 1,408	$ 1,408	$ 1,243	$ 1,243	$ -	$ -	$ 6,710	$ 740
14	GS (pri) (23)	$ 7	$ 7	$ 7	$ 7	$ 7	$ -	$ -	$ 36	$ 740
15	GS < 50 kW (sec) (28)	$ 561	$ 561	$ 561	$ 629	$ 629	$ -	$ -	$ 2,941	$ 406
16	GS 51-100 kW (sec) (28)	$ 374	$ 374	$ 374	$ 420	$ 420	$ -	$ -	$ 1,963	$ 406
17	GS > 100 kW (sec) (28)	$ 242	$ 242	$ 242	$ 272	$ 272	$ -	$ -	$ 1,271	$ 406
18	GS (pri) (28)	$ 7	$ 7	$ 7	$ 8	$ 8	$ -	$ -	$ 35	$ 406
19	GS 0-300 kW (sec) (30)	$ 20	$ 20	$ 20	$ 41	$ 41	$ -	$ -	$ 144	$ 307
20	GS >300 kW (sec) (30)	$ 42	$ 42	$ 42	$ 86	$ 86	$ -	$ -	$ 298	$ 307
21	GS (pri) (30)	$ 4	$ 4	$ 4	$ 7	$ 7	$ -	$ -	$ 26	$ 307
22	Irrigation	$ 3,613	$ 3,613	$ 3,613	$ 5,150	$ 5,150	$ -	$ -	$ 21,139	$ 1,888
25	Large GS 1 - 4 MW (sec)	$ -	$ -	$ -	$ 16	$ 16	$ -	$ -	$ 32	$ 138
26	Large GS 1 - 4 MW (pri)	$ -	$ -	$ -	$ 7	$ 7	$ -	$ -	$ 13	$ 138
27	Large GS + 4 MW (sec)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Large GS + 4 MW (pri)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	Check Total	$ 111,758	$ 111,758	$ 111,758	$ 111,758	$ 111,758	$ -	$ -	$ 558,792	

Large Industrial Customers

Distribution studies have shown that very large industrial customers are not placed on a feeder in the same manner as residential or smaller commercial and industrial customers. Rather the customer is located very close to a substation (the average distance in Oregon is 2/3 of a mile) and has a dedicated feeder for their exclusive use. Since they have a dedicated feeder line, they do not share in the costs of other common distribution investments, but they are responsible for the entire cost of the dedicated feeder. Dividing the total cost of a 2/3 of a mile feeder by the customers kW gets the customers demand cost in dollars per kW. Table 10 shows this calculation for Oregon.

Table 10 – Oregon Dedicated Feeder Trunk Costs for Large Customers

	Voltage Delivery			
	Large GS + 4 MW (pri)		Large GS + 4 MW (sec)	
	Poles	Conductor	Poles	Conductor
1 Construction Cost Per Mile	$ 36,513	$ 74,083	$ 36,513	$ 74,083
2 Average Trunk Length	0.67 miles		0.67 miles	
3 Total Construction Cost	$ 24,463	$ 49,636	$ 24,463	$ 49,636
4 Customer Peak Demand	5,176 kW		3,254 kW	
5 Demand Cost $/kW	$4.73	$9.59	$7.52	$15.25

Summary

The final step in the feeder model is to bring the various results together in a single summary page. Table 11 shows the results calculated earlier in the study. Note that the $/customer and $/feeder kW is the distribution investment to serve that customer and not the price that the customer is expected to pay.

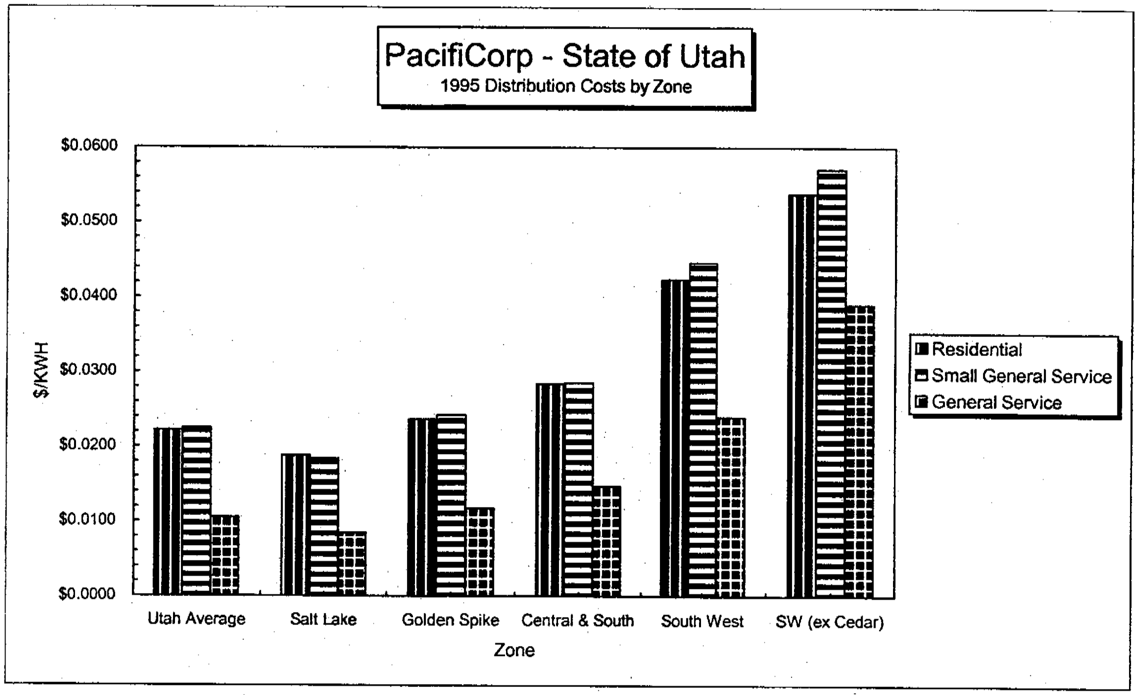
Table 11 – Oregon Summary of Results

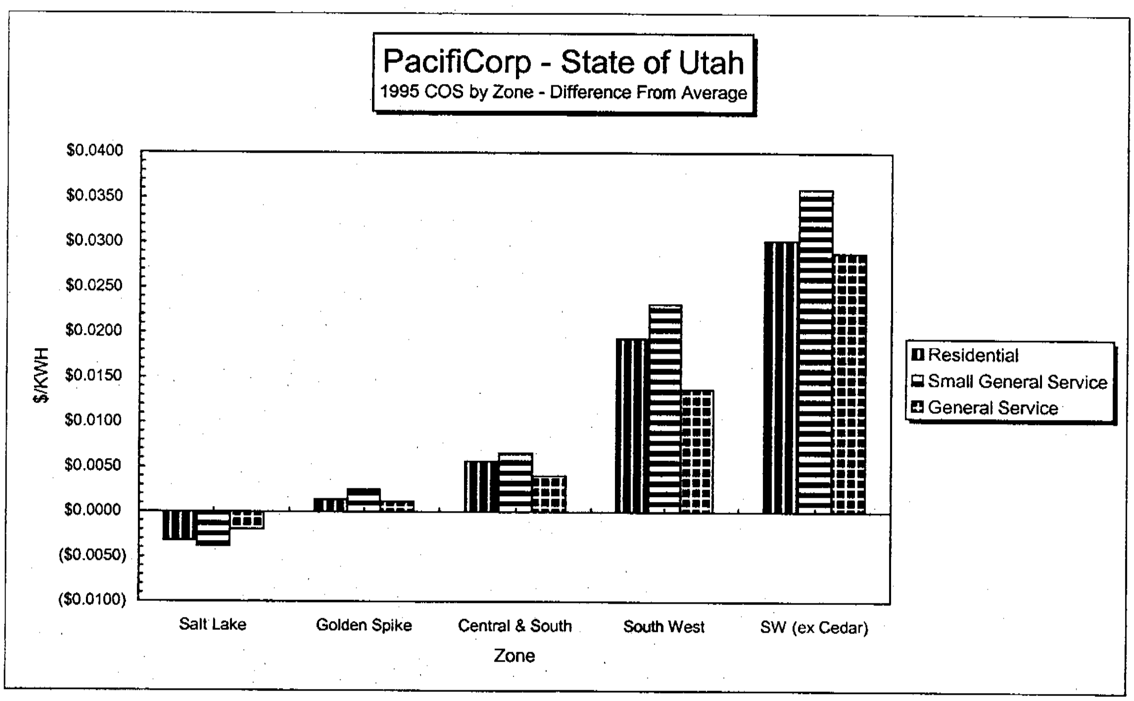
CLASS	COMMITMENT $/Customer Poles	COMMITMENT $/Customer Conductor	Demand $/feeder kW Poles	Demand $/feeder kW Conductor
Residential	$ 583.58	$ 233.65	$ 124.65	$ 206.09
GS 0-15 kW (sec) (23)	$ 739.67	$ 296.14	$ 144.65	$ 234.45
GS >15 kW (sec) (23)	$ 739.67	$ 296.14	$ 144.65	$ 234.45
GS (pri) (23)	$ 739.67	$ 296.14	$ 144.65	$ 234.45
GS < 50 kW (sec) (28)	$ 405.94	$ 162.52	$ 101.79	$ 173.78
GS 51-100 kW (sec) (28)	$ 405.94	$ 162.52	$ 101.79	$ 173.78
GS > 100 kW (sec) (28)	$ 405.94	$ 162.52	$ 101.79	$ 173.78
GS (pri) (28)	$ 405.94	$ 162.52	$ 101.79	$ 173.78
GS 0-300 kW (sec) (30)	$ 307.32	$ 123.04	$ 89.37	$ 155.90
GS >300 kW (sec) (30)	$ 307.32	$ 123.04	$ 89.37	$ 155.90
GS (pri) (30)	$ 307.32	$ 123.04	$ 89.37	$ 155.90
Irrigation	$ 1,888.05	$ 755.91	$ 294.49	$ 443.64
Large GS 1 - 4 MW (sec)	$ 137.59	$ 55.09	$ 67.67	$ 125.07
Large GS 1 - 4 MW (pri)	$ 137.59	$ 55.09	$ 67.67	$ 125.07
Total -	$ 615.70	$ 246.50	$ 114.95	$ 192.28
Large GS + 4 MW (sec)	$ -	$ -	$ 7.52	$ 15.25
Large GS + 4 MW (pri)	$ -	$ -	$ 4.73	$ 9.59

	COMMITMENT	Demand	Total
Poles	$ 558,792	$ 436,795	$ 995,587
Conductor	$ 223,721	$ 748,053	$ 971,774
Total	$ 782,512	$ 1,184,849	$ 1,967,361

Appendix 9

Utah Power 1995 Zonal Cost of Service Study


PacifiCorp - State of Utah
1995 Distribution Costs by Zone
$0.0600
$0.0500
$0.0400
$0.0300
$0.0200
$0.0100
$0.0000
$/KWH
Utah Average
Salt Lake
Golden Spike
Central & South
South West
SW (ex Cedar)
Zone
Residential
Small General Service
General Service


PacifiCorp - State of Utah
1995 COS by Zone - Difference From Average
$0.0400
$0.0350
$0.0300
$0.0250
$0.0200
$0.0150
$0.0100
$0.0050
$0.0000
($0.0050)
($0.0100)
$/KWH
Salt Lake
Golden Spike
Central & South
South West
SW (ex Cedar)
Zone
Residential
Small General Service
General Service

PacifiCorp
State of Utah
1995 Embedded Cost of Service
Comparison of Costs by Geographic Zone

Total Cost of Service
Per KWH

	Utah Average	Salt Lake	Golden Spike	Central & South	South West	SW (ex Cedar)
All Classes	$0.0556	$0.0535	$0.0566	$0.0576	$0.0690	$0.0735
Residential	$0.0673	$0.0642	$0.0687	$0.0730	$0.0867	$0.0976
Small General Service (Sch 23)	$0.0708	$0.0670	$0.0733	$0.0774	$0.0940	$0.1067
General Service (Sch 6)	$0.0558	$0.0538	$0.0570	$0.0598	$0.0695	$0.0846

Distribution Cost of Service
(Substation, Poles, Conductor, Meters, Services)
Per KWH

	Utah Average	Salt Lake	Golden Spike	Central & South	South West	SW (ex Cedar)
All Classes	$0.0170	$0.0136	$0.0189	$0.0230	$0.0361	$0.0496
Residential	$0.0222	$0.0188	$0.0236	$0.0284	$0.0424	$0.0538
Small General Service (Sch 23)	$0.0224	$0.0184	$0.0242	$0.0286	$0.0446	$0.0571
General Service (Sch 6)	$0.0105	$0.0085	$0.0118	$0.0147	$0.0240	$0.0390

Difference From State Average - Total Cost of Service
Per KWH

	Utah Average	Salt Lake	Golden Spike	Central & South	South West	SW (ex Cedar)
All Classes	$0.0000	($0.0020)	$0.0010	$0.0020	$0.0134	$0.0179
Residential	$0.0000	($0.0032)	$0.0014	$0.0057	$0.0193	$0.0302
Small General Service (Sch 23)	$0.0000	($0.0038)	$0.0025	$0.0066	$0.0232	$0.0360
General Service (Sch 6)	$0.0000	($0.0020)	$0.0012	$0.0040	$0.0137	$0.0288

Difference From State Average - Total Cost of Service
%

	Utah Average	Salt Lake	Golden Spike	Central & South	South West	SW (ex Cedar)
All Classes	0.00%	-3.64%	1.89%	3.62%	24.20%	32.19%
Residential	0.00%	-4.71%	2.06%	8.41%	28.68%	44.87%
Small General Service (Sch 23)	0.00%	-5.37%	3.53%	9.31%	32.73%	50.79%
General Service (Sch 6)	0.00%	-3.50%	2.10%	7.23%	24.56%	51.70%

Data

	Utah Total	Salt Lake	Golden Spike	Central & South	South West	SW (ex Cedar)
Revenue	$724,659,089	$429,248,271	$157,004,138	$97,329,913	$41,076,767	$12,888,564
Customers	555,812	326,152	127,505	69,137	33,018	11,293
GWH	13,083	7,767	2,840	1,747	729	213

Appendix 10

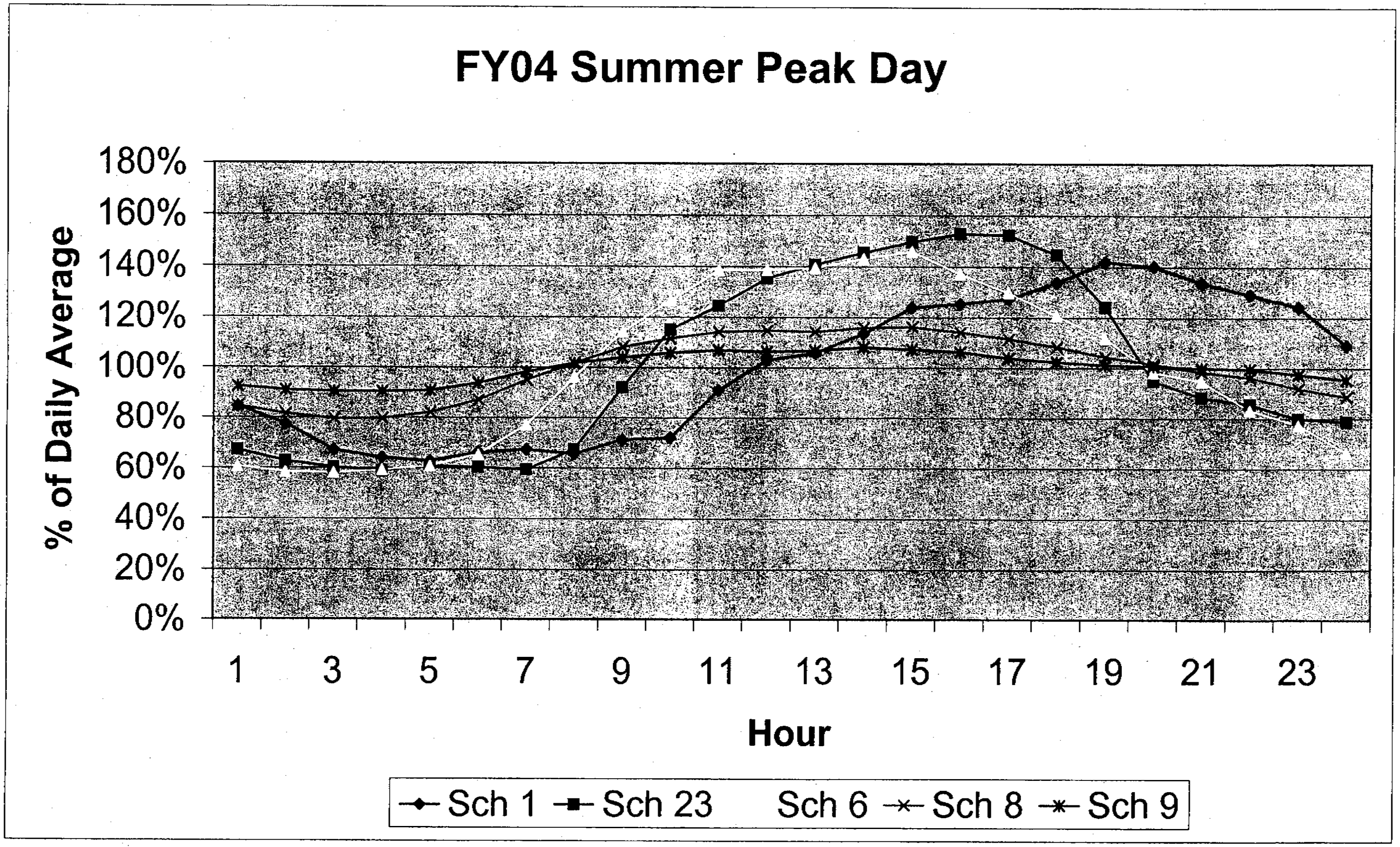
Follow up on Seasonality in G&T Allocation

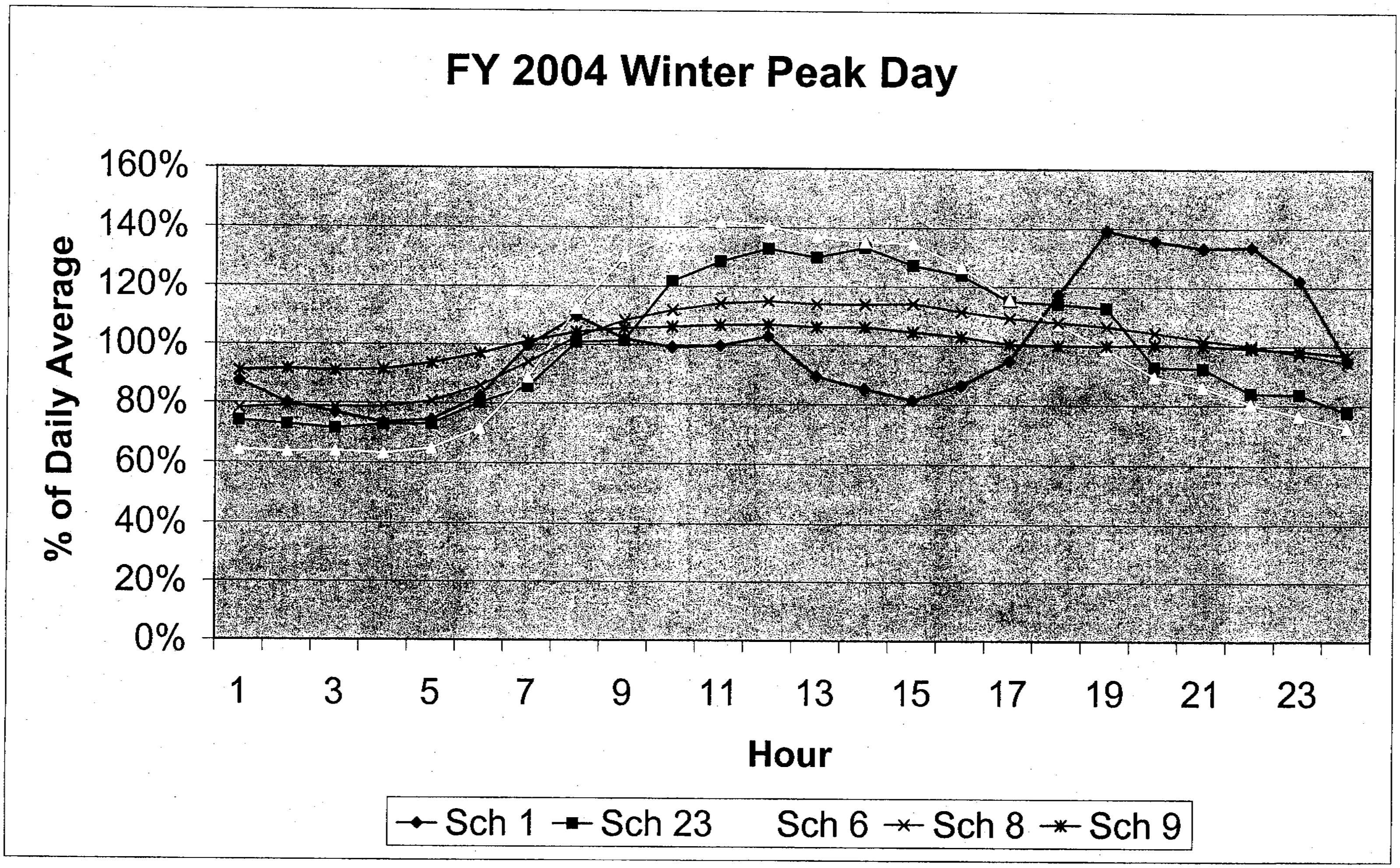
Utah Hourly Load Data
At Input
Apr03-Mar04

Date	**System Peak Hour Mtn Time**	**Schedule**	System Peak Hour Load	Minimum Hourly Load	Maximum Hourly Load	Daily Load Variation Min to Max	Min to Max Variation % of Max	Daily Load Variation Peak to Max	Peak to Max Variation % of Max
22-Jul-03	4PM	Sch 1	1,278,651	640,336	1,449,263	808,927	56%	170,612	12%
22-Jul-03	4PM	Sch 23	238,234	91,805	238,234	146,429	61%	0	0%
22-Jul-03	4PM	Sch 6	1,179,834	499,435	1,255,536	756,101	60%	75,702	6%
22-Jul-03	4PM	Sch 8	289,381	201,551	294,505	92,955	32%	5,124	2%
22-Jul-03	4PM	Sch 9	537,723	456,665	546,810	90,145	16%	9,086	2%

Date		**Schedule**	System Peak Hour Load	Minimum Hourly Load	Maximum Hourly Load	Daily Load Variation Min to Max	Min to Max Variation % of Max	Daily Load Variation Peak to Max	Peak to Max Variation % of Max
5-Jan-04	7PM	Sch 1	975,551	514,303	975,551	461,248	47%	0	0%
5-Jan-04	7PM	Sch 23	180,890	114,520	213,692	99,172	46%	32,802	15%
5-Jan-04	7PM	Sch 6	651,559	415,265	933,836	518,571	56%	282,277	30%
5-Jan-04	7PM	Sch 8	210,073	154,020	226,581	72,561	32%	16,508	7%
5-Jan-04	7PM	Sch 9	323,005	293,580	345,691	52,111	15%	22,686	7%

Date		**Schedule**	System Peak Hour Load	Minimum Hourly Load	Maximum Hourly Load	Daily Load Variation Min to Max	Min to Max Variation % of Max	Daily Load Variation Peak to Max	Peak to Max Variation % of Max
11-Feb-04	9AM	Sch 1	670,227	509,460	1,030,400	520,940	51%	360,173	35%
11-Feb-04	9AM	Sch 23	167,581	115,736	255,275	139,539	55%	87,695	34%
11-Feb-04	9AM	Sch 6	896,549	448,178	985,480	537,302	55%	88,932	9%
11-Feb-04	9AM	Sch 8	241,942	189,825	248,522	58,697	24%	6,580	3%
11-Feb-04	9AM	Sch 9	361,437	312,037	362,525	50,489	14%	1,088	0%


FY04 Summer Peak Day
180%
160%
140%
120%
100%
80%
60%
40%
20%
0%
% of Daily Average
1
3
5
7
9
11
13
15
17
19
21
23
Hour
Sch 1
Sch 23
Sch 6
Sch 8
Sch 9


FY 2004 Winter Peak Day
160%
140%
120%
100%
80%
60%
40%
20%
0%
% of Daily Average
1
3
5
7
9
11
13
15
17
19
21
23
Hour
Sch 1
Sch 23
Sch 6
Sch 8
Sch 9

Utah Hourly Load Data
At Input
Apr03-Mar04

Date	Schedule	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00	Average Daily Load
22-Jul-03	Sch 1	861,898	789,960	685,506	654,366	640,336	676,027	687,399	669,333	725,742	734,387	927,914	1,049,902	1,081,224	1,158,099	1,264,166	[redacted]	1,299,325	1,366,581	1,449,263	1,430,865	1,365,871	1,318,140	1,268,059	1,111,938	1,020,815
22-Jul-03	Sch 23	104,714	97,753	93,815	91,805	94,919	93,913	92,514	104,892	143,424	179,266	194,058	211,008	219,231	226,773	233,221	[redacted]	237,246	225,766	193,551	147,820	137,496	133,353	124,301	122,694	155,907
22-Jul-03	Sch 6	521,304	502,407	499,435	508,752	523,147	562,259	662,551	827,434	982,211	1,089,550	1,192,056	1,192,817	1,200,260	1,231,201	1,255,536	[redacted]	1,117,170	1,039,164	961,800	844,582	813,710	716,426	665,015	571,165	860,825
22-Jul-03	Sch 8	214,303	206,520	201,551	201,935	206,001	220,479	240,773	257,864	274,117	282,436	289,148	290,564	289,567	293,699	294,505	[redacted]	282,537	274,897	264,695	257,551	248,981	243,486	232,397	224,155	253,481
22-Jul-03	Sch 9	467,080	459,627	456,665	457,114	458,841	473,790	496,811	514,009	525,794	535,435	540,697	537,582	539,952	546,810	542,903	[redacted]	525,390	517,711	511,845	509,240	505,021	503,267	492,458	482,063	505,743
Percent of Average Load																										
22-Jul-03	Sch 1	84%	77%	67%	64%	63%	66%	67%	66%	71%	72%	91%	103%	106%	113%	124%	125%	127%	134%	142%	140%	134%	129%	124%	109%	
22-Jul-03	Sch 23	67%	63%	60%	59%	61%	60%	59%	67%	92%	115%	124%	135%	141%	145%	150%	153%	152%	145%	124%	95%	88%	86%	80%	79%	
22-Jul-03	Sch 6	61%	58%	58%	59%	61%	65%	77%	96%	114%	127%	138%	139%	139%	143%	146%	137%	130%	121%	112%	98%	95%	83%	77%	66%	
22-Jul-03	Sch 8	85%	81%	80%	80%	82%	87%	95%	102%	108%	111%	114%	115%	114%	116%	116%	114%	111%	108%	104%	102%	98%	96%	92%	88%	
22-Jul-03	Sch 9	92%	91%	90%	90%	91%	94%	98%	102%	104%	106%	107%	106%	107%	108%	107%	106%	104%	102%	101%	101%	100%	100%	97%	95%	

Date	Schedule	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00	
5-Jan-04	Sch 1	612,302	560,071	538,207	514,303	521,151	576,798	698,862	768,224	715,072	695,570	699,563	721,129	626,897	596,684	570,422	605,625	664,724	822,428	[redacted]	951,320	934,443	936,853	857,231	665,260	701,187
5-Jan-04	Sch 23	116,704	116,664	114,520	116,458	117,061	128,462	137,176	161,569	162,623	195,307	205,991	212,965	208,399	213,692	204,107	198,814	184,392	182,968	[redacted]	148,871	148,052	134,741	134,062	124,507	160,459
5-Jan-04	Sch 6	422,862	419,332	421,046	415,265	427,365	470,566	584,437	738,270	856,417	900,286	933,836	924,546	901,035	889,012	886,209	833,821	760,252	706,021	[redacted]	588,905	566,247	529,554	502,337	476,510	658,571
5-Jan-04	Sch 8	154,020	155,782	154,976	155,046	158,937	169,310	185,218	202,282	213,495	220,271	225,026	226,581	224,546	224,509	225,071	219,872	215,405	212,624	[redacted]	206,040	201,152	197,381	191,551	186,164	197,306
5-Jan-04	Sch 9	293,661	295,887	293,580	295,176	302,147	312,930	326,761	336,716	341,132	342,985	345,070	345,691	342,898	342,837	337,666	332,530	324,733	323,461	[redacted]	324,239	323,029	320,660	317,444	313,021	323,220
Percent of Average Load																										
5-Jan-04	Sch 1	87%	80%	77%	73%	74%	82%	100%	110%	102%	99%	100%	103%	89%	85%	81%	86%	95%	117%	139%	136%	133%	134%	122%	95%	
5-Jan-04	Sch 23	74%	73%	71%	73%	73%	80%	85%	101%	101%	122%	128%	133%	130%	133%	127%	124%	115%	114%	113%	93%	92%	84%	84%	78%	
5-Jan-04	Sch 6	64%	64%	64%	63%	65%	71%	89%	112%	130%	137%	142%	140%	137%	135%	135%	127%	115%	107%	99%	89%	86%	80%	76%	72%	
5-Jan-04	Sch 8	78%	79%	79%	79%	81%	86%	94%	103%	108%	112%	114%	115%	114%	114%	114%	111%	109%	108%	106%	104%	102%	100%	97%	94%	
5-Jan-04	Sch 9	91%	92%	91%	91%	93%	97%	101%	104%	106%	106%	107%	107%	106%	106%	104%	103%	100%	100%	100%	100%	100%	99%	98%	97%	

Date	Schedule	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	0:00	
11-Feb-04	Sch 1	634,534	525,472	535,909	509,460	529,076	557,282	686,055	801,570	[redacted]	609,925	606,547	564,748	566,900	570,415	585,811	578,131	648,741	753,266	917,508	1,030,400	952,933	957,034	788,748	701,381	678,503
11-Feb-04	Sch 23	119,005	118,221	115,736	119,974	128,287	137,730	148,205	131,120	[redacted]	211,583	224,401	237,683	242,053	255,275	233,690	220,640	214,679	185,965	192,413	184,885	170,768	155,186	142,752	138,922	174,781
11-Feb-04	Sch 6	471,562	453,269	448,178	456,551	471,531	515,476	617,720	770,154	[redacted]	949,055	985,480	977,394	970,434	948,405	926,600	911,103	786,709	716,954	891,329	659,935	631,528	579,429	549,168	513,774	704,095
11-Feb-04	Sch 8	201,156	194,440	191,472	189,825	193,376	202,561	218,470	234,340	[redacted]	246,725	248,522	247,584	247,709	247,790	246,339	240,489	234,385	231,136	230,884	227,069	222,006	216,247	210,814	203,703	223,708
11-Feb-04	Sch 9	324,417	322,787	312,037	322,327	322,247	331,706	349,520	360,192	[redacted]	355,314	356,717	357,437	358,478	362,525	361,748	351,651	344,470	340,762	345,737	344,329	337,181	332,924	329,857	327,636	342,226
Percent of Average Load																										
11-Feb-04	Sch 1	94%	77%	79%	75%	78%	82%	101%	118%	99%	90%	89%	83%	84%	84%	86%	85%	96%	111%	135%	152%	140%	141%	116%	103%	
11-Feb-04	Sch 23	68%	68%	66%	69%	73%	79%	84%	75%	96%	121%	128%	136%	138%	146%	134%	126%	123%	106%	110%	106%	98%	89%	82%	79%	
11-Feb-04	Sch 6	67%	64%	64%	65%	67%	73%	88%	109%	127%	135%	140%	139%	138%	135%	132%	129%	112%	102%	98%	94%	90%	82%	78%	73%	
11-Feb-04	Sch 8	90%	87%	86%	85%	86%	91%	98%	105%	108%	110%	111%	111%	111%	111%	110%	108%	105%	103%	103%	102%	99%	97%	94%	91%	
11-Feb-04	Sch 9	95%	94%	91%	94%	94%	97%	102%	105%	106%	104%	104%	104%	105%	106%	106%	103%	101%	100%	101%	101%	99%	97%	96%	96%	

Appendix 11

How to treat MSP Rate Mitigation Cap

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

Presentation to
Utah Cost-of-Service Working Group

Kevin Higgins, Energy Strategies
August 25, 2005

Initial Recommendations to Audience

Choose One:

- Drink coffee <u>now</u>
- Feign cell phone call and hurry to hallway
- Initiate good daydream, but nod intermittently to reassure speaker

Why does this matter?

- Class cost of service is based on a specific set of jurisdictional costs
- The revised MSP 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
- <u>Issue 1</u>: What set of jurisdictional costs should be used for Utah class cost allocation?
- <u>Issue 2:</u> If “Rolled-in + 1.x%” is the basis for jurisdictional costs, how should these costs be incorporated into the class COS analysis?

2nd Recommendation to audience

- Go back two slides and re-evaluate your options

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

- Options
  - Rolled-in
  - “Rolled in + 1.x%” = “Constrained” MSP
  - MSP (unconstrained)
- What variants did PacifiCorp present in the last rate case?
  - Rolled-in
  - Rolled-in + 1.5%
  - “Constrained” MSP revenue requirements paired with “unconstrained” MSP relative returns

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

- Proposal
  - If jurisdictional allocation is based on MSP, use MSP for Utah COS
    - Ensure that jurisdictional allocation of non-generation costs is the same between Rolled-in and MSP
  - If jurisdictional allocation is based on "Rolled-in + 1.x%", for Utah COS use either:
    - Rolled-in, or
    - "Constrained" MSP

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

- In presenting "constrained MSP" results in the last Utah rate case, how did PacifiCorp approach this question?
  - (A) Relative return indices for classes were based on "unconstrained" MSP results
  - (B) To meet "Rolled-in + 1.5%" jurisdictional cost constraint, target rate of return was reduced for each function (e.g., generation, distribution, transmission) in performing class cost allocation

    (In other words, the MSP rate mitigation cap was treated as lowering the target return for all functions)
  - (C) Lower income tax consequence of MSP spread to all functions

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

- Critique of PacifiCorp's approach in last rate case
  - (A) Relative return indices for classes based on "unconstrained" MSP results

    <u>Problem</u>: "Unconstrained" MSP allocates more generation costs to Utah than "constrained" MSP – causing a higher cost allocation to "generation-heavy" classes than is justified by "constrained" MSP allocation to Utah

PacifiCorp Rolled-In COS Results

(Docket 04-035-42)

PacifiCorp
Cost Of Service By Rate Schedule
State of Utah
12 Months Ending March 2006
Rolled In
BaseCase Allocation Factors
8.73% = Target Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	1	Residential	440,028,733	8.08%	1.17	461,679,091	223,609,390	29,101,710	167,551,929	38,628,239	2,787,823	21,650,358	4.92%
2	6	General Service - Large	321,430,640	6.50%	0.94	353,036,713	221,975,113	30,242,435	96,414,636	1,936,995	2,467,534	31,606,073	9.83%
3	8	General Service - Over 1 MW	90,729,497	6.86%	0.99	98,221,970	65,718,870	8,475,798	23,202,439	105,767	719,096	7,492,473	8.26%
4	7,11,12,13	Street & Area Lighting	10,847,300	2.03%	0.29	12,890,773	1,907,384	161,958	10,417,650	361,517	42,267	2,043,473	18.84%
5	9	General Service - High Voltage	136,758,294	6.79%	0.98	146,628,090	126,096,672	17,260,708	1,138,089	849,336	1,283,284	9,869,796	7.22%
6	10	Irrigation	9,352,282	3.31%	0.48	11,287,616	7,067,045	896,566	3,084,815	163,533	75,658	1,935,334	20.69%
7	12	Traffic Signals	739,505	7.44%	1.08	783,035	392,252	47,248	217,444	121,264	4,827	43,530	5.89%
8	12	Outdoor Lighting	725,216	59.86%	8.66	353,127	236,992	18,817	76,677	16,877	3,764	(372,089)	-51.31%
9	21	Electric Furnace	241,825	10.57%	1.53	237,970	151,961	23,545	27,400	33,294	1,770	(3,855)	-1.59%
10	23	General Service - Small	80,869,735	7.50%	1.09	86,349,690	46,939,642	6,368,018	29,284,940	3,201,473	555,617	5,479,955	6.78%
11	25	Mobile Home Parks	658,771	7.67%	1.11	701,783	413,532	53,693	230,511	(692)	4,739	43,012	6.53%
12	SpC	Customer A	7,755,432	4.66%	0.67	8,734,533	7,645,632	940,138	63,102	9,422	76,240	979,101	12.62%
13	SpC	Customer B	13,349,697	-6.63%	(0.96)	19,669,887	17,542,223	1,876,696	100,943	(11,374)	161,399	6,320,190	47.34%
14	SpC	Customer C	17,601,092	-0.46%	(0.07)	22,814,664	19,861,490	2,644,725	105,808	12,156	190,484	5,213,572	29.62%
15		Total Utah Jurisdiction	1,131,088,019	6.91%	1.00	1,223,388,943	739,558,198	98,112,054	331,916,383	45,427,805	8,374,502	92,300,924	8.16%

Corrections:
1. Schedule 8 revenues adjusted to full amount.
2. Account 908S functionalized to Retail (CUST).

UAE Reconstruction of PacifiCorp Unconstrained MSP COS Results

(Docket 04-035-42)

PacifiCorp
Cost Of Service By Rate Schedule
State of Utah
12 Months Ending March 2006
MSP
MSP Allocation Factors
8.73% = Target Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	1	Residential	440,028,733	7.61%	1.21	471,990,385	233,432,479	29,497,380	167,857,943	38,670,772	2,531,811	31,961,652	7.26%
2	6	General Service - Large	321,430,640	5.86%	0.93	362,652,230	232,326,793	30,652,316	96,590,015	1,937,560	1,145,547	41,221,590	12.82%
3	8	General Service - Over 1 MW	90,729,497	6.19%	0.98	100,843,982	68,567,753	8,592,413	23,243,696	105,198	334,923	10,114,485	11.15%
4	7,11,12,13	Street & Area Lighting	10,847,300	2.21%	0.35	12,946,837	1,941,224	164,213	10,425,800	362,300	53,301	2,099,537	19.36%
5	9	General Service - High Voltage	136,758,294	5.68%	0.90	151,441,511	131,391,029	17,496,120	1,142,208	850,077	562,077	14,683,217	10.74%
6	10	Irrigation	9,352,282	2.72%	0.43	11,551,916	7,350,307	908,627	3,090,323	163,880	38,779	2,199,634	23.52%
7	12	Traffic Signals	739,505	7.01%	1.11	797,712	404,623	47,906	217,825	121,407	5,951	58,207	7.87%
8	12	Outdoor Lighting	725,216	59.01%	9.38	359,547	243,513	19,114	76,835	16,898	3,188	(365,669)	-50.42%
9	21	Electric Furnace	241,825	10.20%	1.62	242,144	156,715	23,861	27,447	33,349	772	319	0.13%
10	23	General Service - Small	80,869,735	6.96%	1.11	88,497,701	49,128,574	6,454,047	29,337,863	3,203,340	373,876	7,627,966	9.43%
11	25	Mobile Home Parks	658,771	7.11%	1.13	720,117	433,096	54,427	230,973	(719)	2,340	61,346	9.31%
12	SpC	Customer A	7,755,432	3.55%	0.56	9,017,322	7,958,388	953,303	63,354	9,460	32,817	1,261,890	16.27%
13	SpC	Customer B	13,349,697	-7.21%	(1.15)	20,094,787	18,032,667	1,904,205	101,826	(13,491)	69,580	6,745,090	50.53%
14	SpC	Customer C	17,601,092	-1.58%	(0.25)	23,578,247	20,703,505	2,681,083	106,412	12,239	75,007	5,977,155	33.96%
15		Total Utah Jurisdiction	1,131,088,019	6.29%	1.00	1,254,734,437	772,070,666	99,449,014	332,512,520	45,472,269	5,229,968	123,646,418	10.93%

Rate of Return Index Comparison
PacifiCorp Rolled-In vs. Unconstrained MSP COS Results
(Docket 04-035-42)

PacifiCorp
Cost Of Service By Rate Schedule
State of Utah
12 Months Ending March 2006
Rolled In vs MSP
8.73% = Target Return on Rate Base

	A	B	D	E		
			Rolled In COS		MSP Unconstrained COS	
Line No.	Schedule No.	Description	Return on Rate Base	Rate of Return Index	Return on Rate Base	Rate of Return Index
1	1	Residential	8.08%	1.17	7.61%	1.21
2	6	General Service - Large	6.50%	0.94	5.86%	0.93
3	8	General Service - Over 1 MW	6.86%	0.99	6.19%	0.98
4	7,11,12,13	Street & Area Lighting	2.03%	0.29	2.21%	0.35
5	9	General Service - High Voltage	6.79%	0.98	5.68%	0.90
6	10	Irrigation	3.31%	0.48	2.72%	0.43
7	12	Traffic Signals	7.44%	1.08	7.01%	1.11
8	12	Outdoor Lighting	59.86%	8.66	59.01%	9.38
9	21	Electric Furnace	10.57%	1.53	10.20%	1.62
10	23	General Service - Small	7.50%	1.09	6.96%	1.11
11	25	Mobile Home Parks	7.67%	1.11	7.11%	1.13
12	SpC	Customer A	4.66%	0.67	3.55%	0.56
13	SpC	Customer B	-6.63%	(0.96)	-7.21%	(1.15)
14	SpC	Customer C	-0.46%	(0.07)	-1.58%	(0.25)
15		Total Utah Jurisdiction	6.91%	1.00	6.29%	1.00

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

- Critique of PacifiCorp's approach in last rate case (cont'd)
  - (B) To meet "Rolled-in + 1.5%" jurisdictional cost constraint, target rate of return was reduced for each function (e.g., generation, distribution, transmission) in performing class allocation

    Problem: Reducing target rate of return for each function causes changes in jurisdictional allocations for functions (such as distribution) that should be otherwise unaffected by MSP.
    - For example, this approach lowered the distribution cost allocated to Utah under constrained MSP relative to Rolled-in – even though MSP did not affect distribution costs

PacifiCorp Rolled-In vs Constrained MSP Results

(Docket 04-035-42)

PacifiCorp
Cost Of Service By Rate Schedule
State of Utah
12 Months Ending March 2006
Rolled In
BaseCase Allocation Factors
8.73% = Target Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
15		Total Utah Jurisdiction	1,131,088,019	6.91%	1.00	1,223,388,943	739,558,198	98,112,054	331,916,383	43,610,885	10,191,423	92,300,924	8.16%

PacifiCorp
Cost Of Service By Rate Schedule
State of Utah
12 Months Ending March 2006
MSP
MSP Allocation Factors
8.48% = Target Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
15		Total Utah Jurisdiction	1,131,088,019	6.29%	1.00	1,242,110,503	766,971,894	96,944,639	327,608,027	45,388,170	5,197,774	111,022,484	9.82%

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

- Critique of PacifiCorp’s approach in last rate case (cont’d)
  - (C) Lower income tax consequence of MSP spread to all functions

  Problem: The lower income tax consequence of MSP should be allocated only to generation, as that is the only jurisdictional cost that is increased under MSP

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. Target returns for, and allocation of, non-generation function costs (and income taxes) to Utah remain equal 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.

UAE Recommended Constrained MSP Results

(Docket 04-035-42)

PacifiCorp
Cost Of Service By Rate Schedule
State of Utah
12 Months Ending March 2006
MSP
MSP Allocation Factors
8.73% = Target Return on Rate Base

	A	B	C	D	E	F	G	H	I	J	K	L	M
Line No.	Schedule No.	Description	Annual Revenue	Return on Rate Base	Rate of Return Index	Total Cost of Service	Generation Cost of Service	Transmission Cost of Service	Distribution Cost of Service	Retail Cost of Service	Misc Cost of Service	Increase (Decrease) to = ROR	Percentage Change from Current Revenues
1	1	Residential	440,028,733	7.73%	1.18	468,046,287	229,997,556	29,096,671	167,534,437	38,629,608	2,788,016	28,017,554	6.51%
2	6	General Service - Large	321,430,640	6.13%	0.94	358,730,028	227,681,892	30,236,464	96,407,105	1,936,908	2,467,659	37,299,388	11.59%
3	8	General Service - Over 1 MW	90,729,497	6.50%	0.99	99,746,912	67,246,325	8,474,600	23,201,167	105,734	719,086	9,017,415	9.87%
4	7,11,12,13	Street & Area Lighting	10,847,300	1.99%	0.30	12,916,877	1,935,215	161,985	10,415,863	361,542	42,273	2,069,577	19.51%
5	9	General Service - High Voltage	136,758,294	6.28%	0.96	149,467,980	128,935,449	17,258,355	1,141,579	849,415	1,283,183	12,709,686	8.96%
6	10	Irrigation	9,352,282	2.97%	0.45	11,433,709	7,214,096	896,151	3,084,233	163,526	75,703	2,081,427	22.27%
7	12	Traffic Signals	739,505	7.18%	1.10	791,318	400,554	47,244	217,424	121,269	4,827	51,813	7.08%
8	12	Outdoor Lighting	725,216	59.21%	9.06	356,899	240,756	18,825	76,678	16,878	3,764	(368,317)	-50.79%
9	21	Electric Furnace	241,825	10.65%	1.63	239,183	153,171	23,542	27,404	33,296	1,770	(2,642)	-1.26%
10	23	General Service - Small	80,869,735	7.14%	1.09	87,656,277	48,250,417	6,366,736	29,282,000	3,201,463	555,661	6,786,542	8.47%
11	25	Mobile Home Parks	658,771	7.30%	1.12	713,010	424,787	53,685	230,492	(693)	4,739	54,239	8.31%
12	SpC	Customer A	7,755,432	4.17%	0.64	8,899,908	7,810,878	940,047	63,323	9,427	76,233	1,144,476	14.39%
13	SpC	Customer B	13,349,697	-6.58%	(1.01)	19,856,852	17,728,173	1,876,993	101,817	(11,458)	161,328	6,507,155	48.26%
14	SpC	Customer C	17,601,092	-0.96%	(0.15)	23,261,940	20,308,513	2,644,387	106,407	12,170	190,463	5,660,848	31.74%
15		Total Utah Jurisdiction	1,131,088,019	6.54%	1.00	1,242,117,181	758,327,780	98,095,684	331,889,927	45,429,085	8,374,704	111,029,162	9.82%

Corrections:

1. Schedule 8 revenues adjusted to full amount.
2. Account 454S functionalized to Production (P).
3. State and Federal taxes for T, D, R& M constrained to rolled-in amounts; balance of tax change to P.
4. T, D, R & M return on rate base constrained to roll-in amount; G return on rate base adjusted to necessary level to produce overall return.
5. Generation expense constrained to produce capped MSP revenue increase.

Appendix 12

Utah Irrigation Load Research

LOAD RESEARCH

Irrigation Load Study

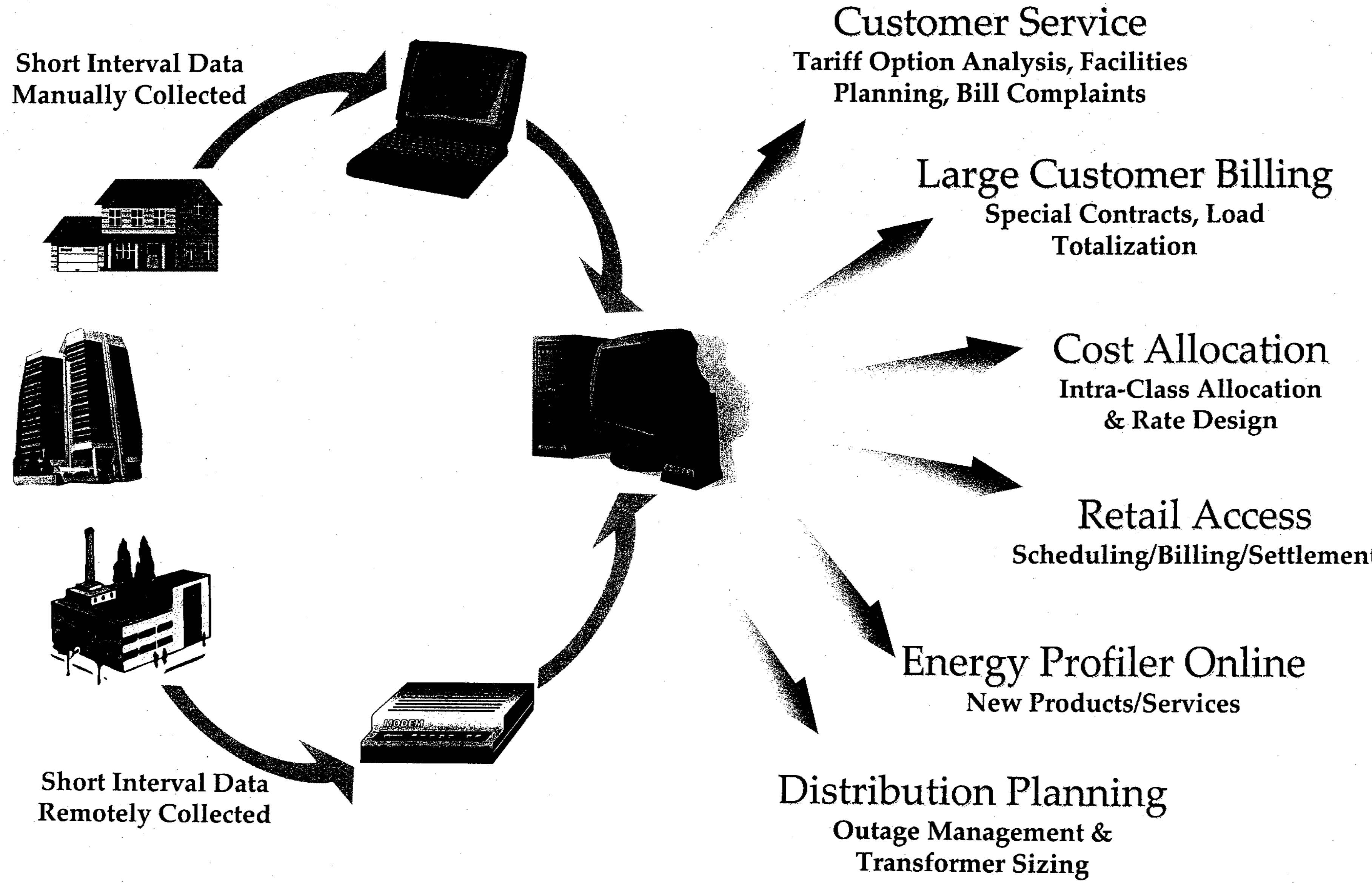
Utah Cost of Service Task Force

August 25, 2005

What is Load Research?

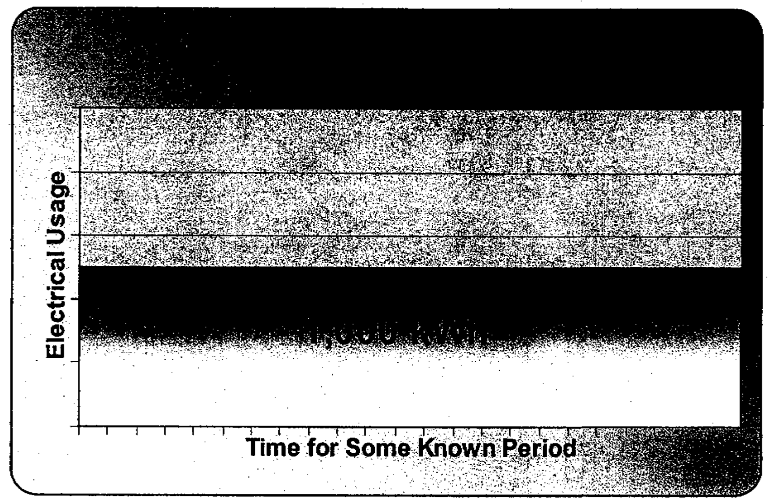
- The study of how and when our customers use energy so that PacifiCorp can most effectively:
  - Allocate Fixed Costs per Regulatory Mandates
  - Design or Maximize Customer Rates
  - Forecast Loads
  - Service Customer Data Requests
  - Size Distribution Circuits
  - Provide Customer Service

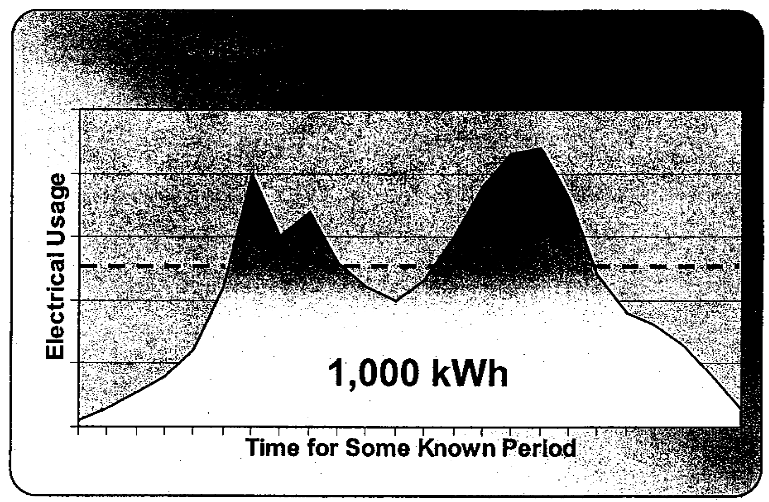
Load Research Data Process



Load Shape Analysis

- Electric usage varies over time and by customer type
- PacifiCorp is obligated to provide electricity (load) when the customer demands (kW) and for the length of time that the customer needs it (kWh).
- Load research (interval) data provides an important data input into planning, regulatory and financial decision making processes… $$$$$$

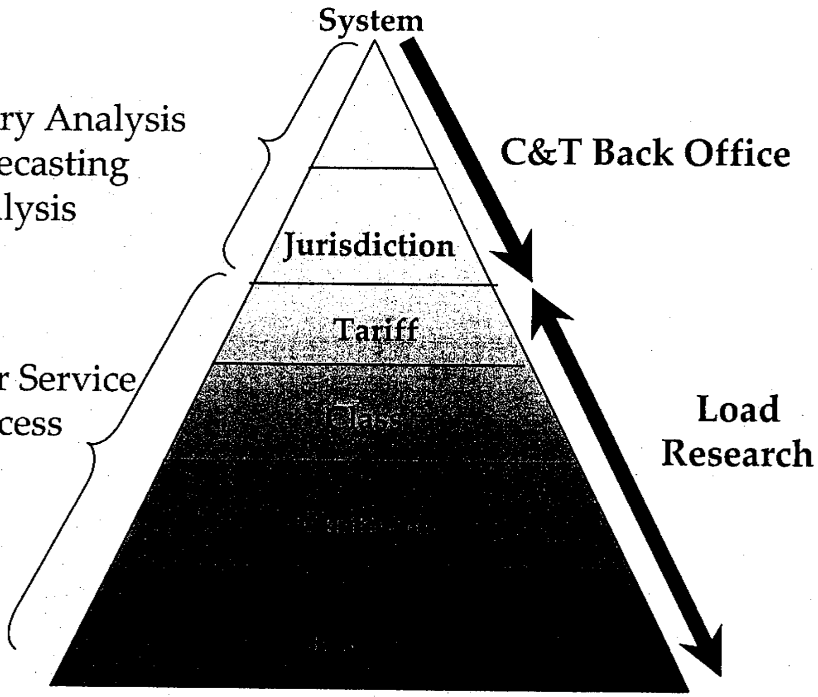


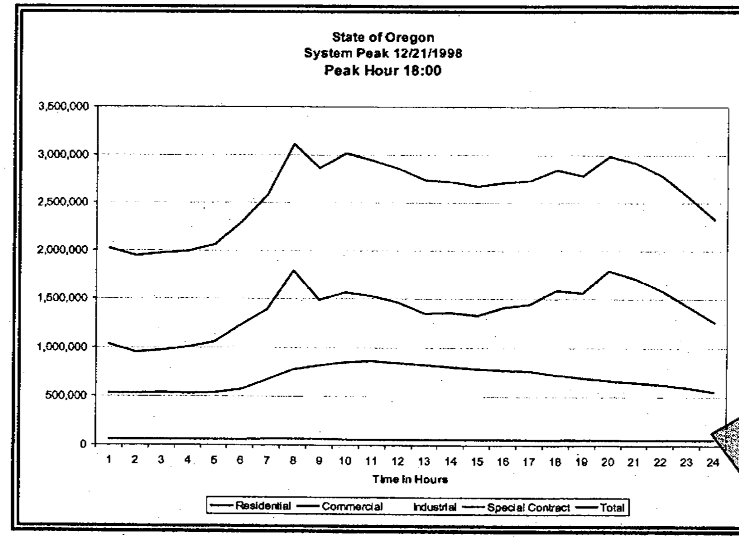


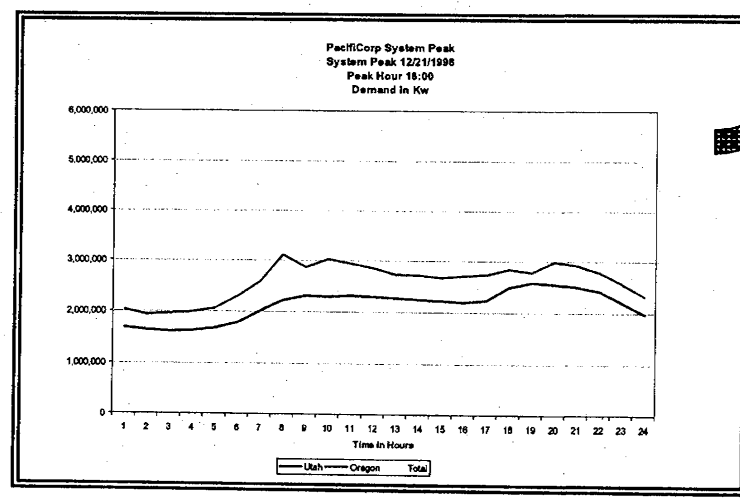
Regulatory Support

Regulatory Analysis
Peak Forecasting
Loss Analysis

Customer Service
Retail Access
Billing
EPO





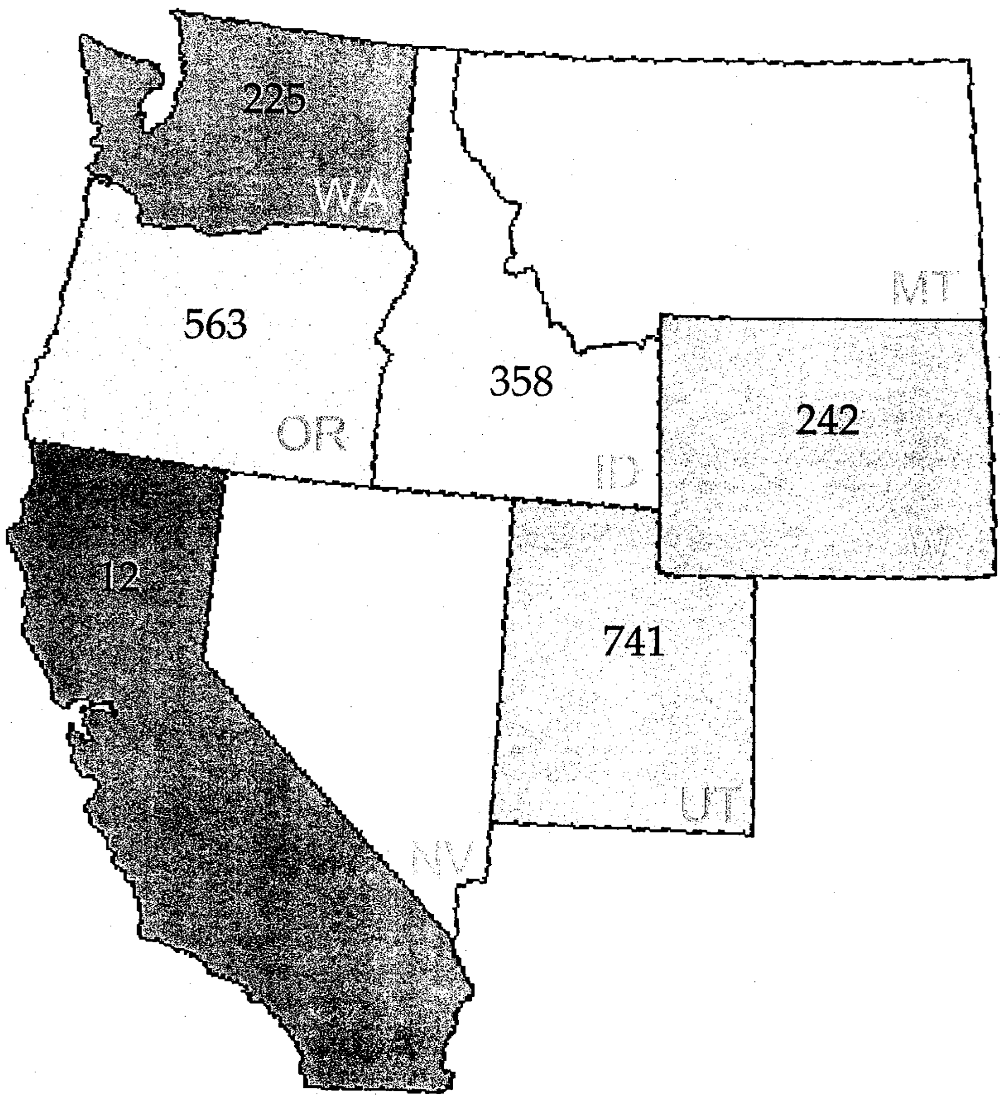


Load Research Meters

State	Class	# Recorders
Utah	Residential	169
	Rate 023	63
	Rate 006	142
	Rate 008	190
	Rate 009	20
	Large Load	157
		741
Idaho	Rate 001	52
	Rate 036	45
	Rate 006	89
	Rate 008	4
	Rate 009	12
	Rate 023	56
	Irrigation	88
	Large Load	12
		358

State	Class	# Recorders
Oregon	Residential	91
	Rate 025	85
	Large Load	387
		563
Washington	Residential	53
	General Service	61
	Large Load	111
		225
Wyoming	Residential	44
	General Service	96
	Large Load	102
		242
Other (DSM, FinAnswer, etc.)		75
Total		2,204

Load Research Meters



■ Load Research Meters

Irrigation Load Study - Issues

- 1991-1993 3-year average for current reporting.
- Issues
  - Crop rotation
  - Weather impacts
    - Growing season
    - Access to water
  - Smaller family owned farms (vs. Corporations in Idaho)
- Options
  - Conduct new load studies
  - Use Idaho Data
  - Use system average costing/pricing

Sample Design

Bill Frequency Analysis Summary

Utah Irrigation Schedule 010
Five Strata

Range			Customer Count f	Interval Factor (1K) μ	μf	$\sqrt{\mu f}$	cum $\sqrt{\mu f}$	
0	to	25	1066	1.0	1,066.0	32.6	32.6	1,066
26	to	50	423	1.0	406.1	20.2	52.8	423
51	to	75	204	1.0	195.8	14.0	66.8	
76	to	100	140	1.0	134.4	11.6	78.4	344
101	to	125	99	1.0	95.0	9.7	88.1	99
126	to	150	57	1.0	54.7	7.4	95.5	
151	to	175	49	1.0	47.0	6.9	102.4	
176	to	200	27	1.0	25.9	5.1	107.5	
201	to	225	25	1.0	24.0	4.9	112.4	
226	to	250	11	1.0	10.6	3.2	115.6	
251	to	275	3	1.0	2.9	1.7	117.3	
276	to	300	1	1.0	1.0	1.0	118.3	
301	to	325	4	1.0	3.8	2.0	120.3	
326	to	350	5	1.0	4.8	2.2	122.5	
351	to	375	1	1.0	1.0	1.0	123.4	
376	to	400	2	1.0	1.9	1.4	124.8	
401	to	450	1	2.0	2.0	1.4	126.2	
451	to	475	1	1.0	1.0	1.0	127.2	
476	to	550	1	3.0	3.0	1.7	128.9	
551	to	600	1	2.0	2.0	1.4	130.3	
601	to	800	2	8.0	15.9	4.0	134.3	
801	to	1,000	1	8.0	8.0	2.8	137.1	
1,001	to	2,000	1	40.0	40.0	6.3	143.5	
2,001	to	2,750	1	30.0	30.0	5.5	148.9	194
		Total N	2,126					2,126

BOUNDARIES INDICATED FOR STRATA:

	3	4	5	6
1	49.6	37.2	29.8	24.8
2	99.3	74.5	59.6	49.6
3		111.7	89.4	74.5
4			119.1	99.3
5				124.1

SAMPLING STATISTI	Avg. kWh[2]	Mean kW[2]	Res. Variance[2]
1	0	3.503	5.571
2	0	23.371	14.814
3	0	39.910	25.513
4	0	35.208	40.642
5	0	189.051	187.652

[1] Billing records for the twelve months ended June 2005
[2] Load Research estimates based on Idaho Schedule 010 sample data

Utah Irrigation Sample Designs

3 Strata – 235 recorders

4 Strata – 203 recorders

5 Strata – 175 recorders

6 Strata – 169 recorders

Sample Design - Stratification

UTAH SCHEDULE 010 LOAD STUDY DESIGN OPTION FOR 2005
THREE STRATA, MEAN-PER-UNIT DESIGN

		a	b	c	d	e	f	g	h	i	j
		Sample Mean kW	Sample Mean kWh	2004 Pop N	Variance of Mean	Standard Deviation	Wtd. Devtns. c*e	Proprtn. row f/ sum f	Optimal Allocation g*h total	Optimal with Attrition	Final with Attrition
STRATUM 1	0 - 50 kW	7.4760	0	1,489	125.6417	11.2090	16690	0.2130	45	45	50
STRATUM 2	51- 100 kW	39.9100	0	344	650.9132	25.5130	8776	0.1120	23	23	26
STRATUM 3	GT- 100 kW	162.2950	0	293	32590.7198	180.5290	52895	0.6750	142	142	159
EST POP MEAN (wtd by N)		34.0608	0	2,126			78362	1.0000	210	210	235
										Sample Estimate	**Adj Sample Estimate**
										210	**235**

RELATIVE PRECISION OF SAMPLE KW ESTIMATE

	TOTAL KW Optimal n (col. h)	TOTAL KW Adjusted n (col. i)	MEAN KW Adj. n
Variance 1	6,139,641	6,139,641	1.358365
contribute 2	3,267,111	3,267,111	0.722832
by strata: 3	10,226,321	10,226,321	2.262522
Total Variance	19,633,072	19,633,072	4.343719
Standard Error	4430.922259	4430.922259	2.0841591
Desired Conf. Level	90%	90%	90%
(z two tailed)	1.645	1.645	1.645
Conf. Interval	7288.867115	7288.867115	3.4284417
MPU Est of kW	72413.239	72413.239	34.0608
Relative Conf. Int.	10.07%	10.07%	10.07%

Sample Design - Stratification

UTAH SCHEDULE 010 LOAD STUDY DESIGN OPTION FOR 2005
FOUR STRATA, MEAN-PER-UNIT DESIGN

		a	b	c	d	e	f	g	h	i	j
		Sample Mean kW	Sample Mean kWh	2004 Pop N	Variance of Mean	Standard Deviation	Wtd. Devtns. c*e	Proprtn. row f/ sum f	Optimal Allocation g*h total	Optimal with Attrition	Final with Attrition
STRATUM 1	0 - 50 kW	7.4760	0	1,489	125.6417	11.2090	16690	0.2593	47	47	53
STRATUM 2	51 - 75 kW	25.5910	0	204	327.8634	18.1070	3694	0.0574	10	10	11
STRATUM 3	76 - 125 kW	48.9570	0	239	1008.1260	31.7510	7588	0.1179	21	21	24
STRATUM 4	GT- 125 kW	189.0510	0	194	35213.2731	187.6520	36404	0.5655	103	103	115
EST POP MEAN (wtd by N)		30.4464	0	2,126			64377	1.0000	182	181	203

Sample Estimate	**Adj Sample Estimate**
182	**203**

RELATIVE PRECISION OF SAMPLE KW ESTIMATE

	TOTAL KW Optimal n (col. h)	TOTAL KW Adjusted n (col. i)	MEAN KW Adj. n
Variance 1	5,864,566	5,864,566	1.297506
contribute 2	1,441,725	1,441,725	0.318974
by strata: 3	2,626,269	2,626,269	0.581049
4	6,094,658	6,094,658	1.348413
Total Variance	16,027,218	16,027,218	3.545942
Standard Error	4003.40078	4003.40078	1.88306716
Desired Conf. Level	90%	90%	90%
(z two tailed)	1.645	1.645	1.645
Conf. Interval	6585.594284	6585.594284	3.09764548
MPU Est of kW	64728.945	64728.945	30.4464
Relative Conf. Int.	10.17%	10.17%	10.17%

Sample Design - Stratification

UTAH SCHEDULE 010 LOAD STUDY DESIGN OPTION FOR 2005
FIVE STRATA, MEAN-PER-UNIT DESIGN

		a	b	c	d	e	f	g	h	i	j
		Sample Mean kW	Sample Mean kWh	2004 Pop N	Variance of Mean	Standard Deviation	Wtd. Devtns. c*e	Proprtn. row f/ sum f	Optimal Allocation g*h total	Optimal with Attrition	Final with Attrition
STRATUM 1	0 - 25 kW	3.5030	0	1,066	31.0360	5.5710	5939	0.0967	15	15	17
STRATUM 2	26 - 50 kW	23.3710	0	423	219.4546	14.8140	6266	0.1020	16	16	18
STRATUM 3	51 - 100 kW	39.9100	0	344	650.9132	25.5130	8776	0.1429	22	22	25
STRATUM 4	101 - 125 kW	35.2080	0	99	1651.7722	40.6420	4024	0.0655	10	10	11
STRATUM 5	GT- 125 kW	189.0510	0	194	35213.2731	187.6520	36404	0.5928	93	93	104
EST POP MEAN (wtd by N)		31.7548	0	2,126			61410	1.0000	156	156	175

Sample Estimate	Adj Sample Estimate
156	**175**

RELATIVE PRECISION OF SAMPLE KW ESTIMATE

		TOTAL KW Optimal n (col. h)	TOTAL KW Adjusted n (col. i)	MEAN KW Adj. n
Variance	1	2,483,695	2,483,695	0.549505
contribute	2	2,518,768	2,518,768	0.557265
by strata:	3	3,433,350	3,433,350	0.759612
	4	1,617,085	1,617,085	0.357772
	5	7,499,662	7,499,662	1.659263
Total Variance		17,552,559	17,552,559	3.883416
Standard Error		4189.577478	4189.577478	1.970638512
Desired Conf. Level		90%	90%	90%
(z two tailed)		1.645	1.645	1.645
Conf. Interval		6891.854951	6891.854951	3.241700353
MPU Est of kW		67510.657	67510.657	31.7548
Relative Conf. Int.		10.21%	10.21%	10.21%

Sample Design - Stratification

UTAH SCHEDULE 010 LOAD STUDY DESIGN OPTION FOR 2005
SIX STRATA, MEAN-PER-UNIT DESIGN

		a	b	c	d	e	f	g	h	i	j
		Sample Mean kW	Sample Mean kWh	2004 Pop N	Variance of Mean	Standard Deviation	Wtd. Devtns. c*e	Proprtn. row f/ sum f	Optimal Allocation g*h total	Optimal with Attrition	Final with Attrition
STRATUM 1	0 - 25 kW	3.5030	0	1,066	31.0360	5.5710	5939	0.1003	15	15	17
STRATUM 2	26 - 50 kW	23.3710	0	423	219.4546	14.8140	6266	0.1058	16	16	18
STRATUM 3	51 - 75 kW	25.5910	0	204	327.8634	18.1070	3694	0.0624	9	10	11
STRATUM 4	76 - 100 kW	59.9560	0	140	437.1026	20.9070	2927	0.0494	7	10	11
STRATUM 5	101 - 125 kW	35.2080	0	99	1651.772164	40.6420	4024	0.0680	10	10	11
STRATUM 6	GT- 125 kW	189.0510	0	194	35118.76	187.4000	36356	0.6141	90	90	101
EST POP MEAN (wtd by N)		31.7009	0	2,126			59205	1.0000	146	151	169

Sample Estimate	Adj Sample Estimate
146	169

RELATIVE PRECISION OF SAMPLE KW ESTIMATE

		TOTAL KW Optimal n (col. h)	TOTAL KW Adjusted n (col. i)	MEAN KW Adj. n
Variance	1	2,483,695	2,483,695	0.549505
contribute	2	2,518,768	2,518,768	0.557265
by strata:	3	1,630,301	1,441,725	0.318974
	4	1,356,475	883,919	0.195563
	5	1,617,085	1,617,085	0.357772
	6	7,961,305	7,961,305	1.761399
Total Variance		17,567,629	16,906,496	3.740478
Standard Error		4191.375492	4111.750948	1.9340315
Desired Conf. Level		90%	90%	90%
(z two tailed)		1.645	1.645	1.645
Conf. Interval		6894.812684	6763.830309	3.1814818
MPU Est of kW		67396.021	67396.021	31.7009
Relative Conf. Int.		10.23%	10.04%	10.04%

Sample Design

Bill Frequency Analysis Summary

Utah Irrigation Schedule 010
Six Strata

Range			Customer Count f	Interval Factor (1K) μ	μf	$\sqrt{\mu f}$	cum $\sqrt{\mu f}$	
0	to	25	1066	1.0	1,066.0	32.6	32.6	1,066
26	to	50	423	1.0	406.1	20.2	52.8	423
51	to	75	204	1.0	195.8	14.0	66.8	204
76	to	100	140	1.0	134.4	11.6	78.4	140
101	to	125	99	1.0	95.0	9.7	88.1	
126	to	150	57	1.0	54.7	7.4	95.5	
151	to	175	49	1.0	47.0	6.9	102.4	
176	to	200	27	1.0	25.9	5.1	107.5	
201	to	225	25	1.0	24.0	4.9	112.4	
226	to	250	11	1.0	10.6	3.2	115.6	268
251	to	275	3	1.0	2.9	1.7	117.3	
276	to	300	1	1.0	1.0	1.0	118.3	
301	to	325	4	1.0	3.8	2.0	120.3	
326	to	350	5	1.0	4.8	2.2	122.5	
351	to	375	1	1.0	1.0	1.0	123.4	
376	to	400	2	1.0	1.9	1.4	124.8	
401	to	450	1	2.0	2.0	1.4	126.2	
451	to	475	1	1.0	1.0	1.0	127.2	
476	to	550	1	3.0	3.0	1.7	128.9	
551	to	600	1	2.0	2.0	1.4	130.3	
601	to	800	2	8.0	15.9	4.0	134.3	
801	to	1,000	1	8.0	8.0	2.8	137.1	
1,001	to	2,000	1	40.0	40.0	6.3	143.5	
2,001	to	2,750	1	30.0	30.0	5.5	148.9	25
		Total N	2,126					2,126

BOUNDARIES INDICATED FOR STRATA:

	3	4	5	6
1	49.6	37.2	29.8	24.8
2	99.8	74.5	59.6	49.6
3		111.7	89.4	74.5
4			119.1	99.3
5				124.1

SAMPLING STATISTI	Avg. kWh[2]	Mean kW[2]	Res. Variance[2]
1	0	3.503	5.571
2	0	23.371	14.814
3	0	25.591	18.107
4	0	59.956	20.907
5	0	95.052	67.321
6	0	404.370	257.663

[1] Billing records for the twelve months ended June 2005
[2] Load Research estimates based on Idaho Schedule 010 sample data

Sample Design - Stratification

UTAH SCHEDULE 010 LOAD STUDY DESIGN OPTION FOR 2005
SIX STRATA, MEAN-PER-UNIT DESIGN

		a	b	c	d	e	f	g	h	i	j
		Sample Mean kW	Sample Mean kWh	2004 Pop N	Variance of Mean	Standard Deviation	Wtd. Devtns. c*e	Proprtn. row f/ sum f	Optimal Allocation g*h total	Optimal with Attrition	Final with Attrition
STRATUM 1	0 - 25 kW	3.5030	0	1,066	31.0360	5.5710	5939	0.1371	15	15	17
STRATUM 2	26 - 50 kW	23.3710	0	423	219.4546	14.8140	6266	0.1447	15	15	17
STRATUM 3	51 - 75 kW	25.5910	0	204	327.8634	18.1070	3694	0.0853	9	10	11
STRATUM 4	76 - 100 kW	59.9560	0	140	437.1026	20.9070	2927	0.0676	7	10	11
STRATUM 5	101 - 250 kW	95.0520	0	268	4532.117041	67.3210	18042	0.4166	44	44	49
STRATUM 6	GT- 250 kW	404.3700	0	25	66390.22157	257.6630	6442	0.1487	16	16	18
EST POP MEAN (wtd by N)		29.5474	0	2,126			43309	1.0000	106	110	123

Sample Estimate	Adj Sample Estimate
106	123

RELATIVE PRECISION OF SAMPLE KW ESTIMATE

		TOTAL KW Optimal n (col. h)	TOTAL KW Adjusted n (col. i)	MEAN KW Adj. n	Weighted St.Dev	Weighted Variance
Variance	1	2,483,695	2,483,695	0.549505	2.793361	15.56182
contribute	2	2,705,311	2,705,311	0.598537	2.94747	43.66383
by strata:	3	1,630,301	1,441,725	0.318974	1.737454	31.46009
	4	1,356,475	883,919	0.195563	1.376754	28.78381
	5	6,327,257	6,327,257	1.399874	8.486373	571.3111
	6	995,853	995,853	0.220328	3.029904	780.694
Total Variance		15,498,892	14,837,759	3.282780	20.37132	1471.475
Standard Error		3936.863223	3851.981227	1.8118444	V =	3.22631
Desired Conf. Level		90%	90%	90%		
(z two tailed)		1.645	1.645	1.645		
Conf. Interval		6476.140001	6336.509119	2.9804841		
MPU Est of kW		62817.721	62817.721	29.5474		
Relative Conf. Int.		10.31%	10.09%	10.09%		

Utah Irrigation Sample Designs

3 Strata – 235 recorders + 24 (10%) = $78,218

4 Strata – 203 recorders + 20 = $67,346

5 Strata – 175 recorders + 18 = $58,286

6 Strata – 169 recorders + 17 = $56,172

6 Strata (adjusted) – 123 + 20 = $43,186

Data acquisition merged with FieldNet Pro operations for summer months only.

Sample Expansion

The expansion of sample data using mean-per-unit procedures are simple and straight forward. The estimate of the population mean ($\hat{Y}$) is derived by multiplying the sample mean ($\ddot{y}$) against the total number of customers in the target group (N), as indicated below:

$$\hat{Y} = N\ddot{y} = N \sum^{n} y_i/n$$

If the sample mean ($\ddot{y}$)is derived from a stratified sample, the population mean ($\hat{Y}$) is derived by performing the above outlined procedure on the individual strata basis (h) and summing the strata totals to derive the estimate for the total population, as outlined below:

$$\hat{Y} = \sum N_h \ddot{y}_h = N \sum^{n} y_{hi}/n_h$$

Sample Design

Random Sample Selection

Wyoming Small General Service Sample Parameters
Secondary Voltage Level

Active Customers with kWh Meters
March 2004 History

Stratum	1	2	3	4	5
Sampling Frame	9,239	6,933	1,537	450	137
Sample	10	16	15	10	10
Interval	923.90	433.31	102.47	45.00	13.70
Random Starts					
Primary					
Random No.[1]	0.58586	0.09998	0.14346	0.74103	0.24200
Start	541	43	15	33	3
Alternate 1					
Random No.[1]	0.87308	0.07351	0.96423	0.26432	0.66432
Start	807	32	99	12	9
Alternate 2					
Random No.[1]	0.26422	0.94305	0.77341	0.56170	0.55293
Start	244	409	79	25	8
Alternate 3					
Random No.[1]	0.88640	0.12908	0.30134	0.49127	0.49618
Start	819	56	31	22	7
Alternate 4					
Random No.[1]	0.78171	0.81263	0.64270	0.82765	0.46473
Start	722	352	66	37	6

(1) Random numbers from Probability and Statistics in Engineering and Management Science, Hines & Montgomery, 2nd Ed, Pg. 628, beginning at row 19, col 4.

Appendix 13

Retail Load Patterns vs Total System Load Patterns.

Utah
Cost of Service and Rate Design Task Force

Committee of Consumer Services

Tony Yankel

August 25, 2005

OVERVIEW

- System vs. Jurisdictional cost allocation
  - Retail load pattern
  - Generation pattern
  - Long-term Firm Wholesale pattern
  - Short-term Firm Wholesale pattern
  - Economy Wholesale pattern
  - Cost allocation implications
- Customer Charge

System vs. Jurisdictional Costs

- Costs come from system load, not isolated jurisdictional loads.
- Costs come from the way system costs are allocated to the jurisdiction.
- The appropriate starting place for defining costs is to look at the system load and allocation factors.

Retail Load Pattern

(MW x 1,000)

July 2003 Retail Load

	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		
	7/1	7/2	7/3	7/4	7/5	7/6	7/7	7/8	7/9	7/10	7/11	7/12	7/13	7/14	7/15	7/16	7/17	7/18	7/19	7/20	7/21	7/22	7/23	7/24	7/25	7/26	7/27	7/28	7/29	7/30	7/31	Ave.	6x16
Temp	96	94	93	92	94	95	96	87	94	103	102	105	99	98	105	102	102	100	100	100	101	104	104	101	94	91	94	95	99	101	97	98	
1	5.6	5.4	5.4	5.2	5.0	5.2	5.4	5.7	5.5	5.7	5.8	5.7	5.6	5.5	5.7	5.9	5.9	5.9	5.9	5.8	5.8	6.1	6.1	6.1	5.8	5.4	5.3	5.6	5.9	6.0	6.0	5.7	6.0
2	5.3	5.3	5.2	5.0	4.9	5.0	5.2	5.5	5.3	5.4	5.6	5.5	5.4	5.3	5.6	5.7	5.7	5.7	5.6	5.6	5.6	5.9	5.9	5.8	5.6	5.2	5.1	5.4	5.7	5.7	5.8	5.5	5.7
3	5.2	5.1	5.1	4.9	4.8	4.9	5.1	5.4	5.1	5.3	5.5	5.3	5.2	5.1	5.5	5.6	5.6	5.5	5.5	5.4	5.5	5.7	5.7	5.6	5.5	5.1	5.0	5.3	5.5	5.5	5.6	5.3	5.6
4	5.2	5.1	5.1	4.8	4.7	4.8	5.1	5.4	5.1	5.3	5.4	5.2	5.1	5.1	5.4	5.5	5.5	5.5	5.3	5.3	5.4	5.6	5.6	5.5	5.4	5.0	4.9	5.2	5.4	5.5	5.5	5.3	5.5
5	5.3	5.2	5.2	4.8	4.7	4.8	5.2	5.4	5.2	5.3	5.5	5.2	5.1	5.3	5.5	5.6	5.6	5.6	5.3	5.3	5.5	5.7	5.7	5.5	5.5	5.1	4.9	5.4	5.5	5.6	5.6	5.3	5.6
6	5.5	5.4	5.3	4.8	4.6	4.8	5.5	5.7	5.4	5.5	5.6	5.2	5.1	5.5	5.8	5.8	5.8	5.8	5.3	5.2	5.8	6.0	6.0	5.8	5.7	5.1	4.9	5.6	5.8	5.8	5.9	5.5	5.8
7	6.0	5.9	5.8	5.0	4.8	4.8	6.0	6.1	5.9	5.9	6.1	5.4	5.2	6.0	6.2	6.3	6.3	6.2	5.5	5.3	6.3	6.4	6.4	6.1	6.1	5.3	5.0	6.0	6.2	6.2	6.2	5.8	6.2
8	6.5	6.4	6.3	5.3	5.2	5.2	6.5	6.5	6.4	6.5	6.6	5.9	5.6	6.6	6.8	6.8	6.9	6.8	6.0	5.7	6.9	7.0	7.0	6.6	6.6	5.7	5.4	6.6	6.8	6.8	6.7	6.3	6.8
9	6.9	6.8	6.6	5.6	5.6	5.5	7.0	6.9	6.7	6.9	7.1	6.4	6.0	7.0	7.2	7.2	7.3	7.3	6.5	6.1	7.4	7.5	7.4	7.0	7.1	6.2	5.8	7.0	7.0	7.2	7.2	6.8	7.2
10	7.2	7.0	6.9	5.9	6.0	5.8	7.3	7.2	7.0	7.2	7.5	6.7	6.4	7.4	7.6	7.6	7.7	7.7	6.9	6.5	7.8	7.9	7.8	7.4	7.5	6.6	6.2	7.4	7.6	7.6	7.6	7.1	7.6
11	7.3	7.2	7.1	6.1	6.2	6.1	7.5	7.3	7.2	7.5	7.6	7.1	6.7	7.6	7.9	7.8	7.9	8.0	7.2	6.7	8.1	8.2	8.1	7.7	7.8	6.8	6.5	7.8	7.9	8.0	7.9	7.4	7.9
12	7.4	7.3	7.2	6.3	6.4	6.3	7.7	7.4	7.4	7.7	7.8	7.3	6.9	7.8	8.1	7.9	8.0	8.2	7.4	7.0	8.4	8.4	8.3	7.9	7.8	7.0	6.7	7.9	8.2	8.2	8.1	7.6	8.0
13	7.5	7.4	7.3	6.4	6.5	6.5	7.9	7.6	7.5	7.9	8.1	7.4	7.0	8.0	8.3	8.0	8.2	8.3	7.5	7.2	8.5	8.6	8.5	8.0	8.0	7.1	6.9	8.2	8.4	8.5	8.3	7.7	8.2
14	7.6	7.3	7.4	6.5	6.7	6.7	8.0	7.6	7.7	8.1	8.2	7.5	7.1	8.1	8.4	8.1	8.3	8.4	7.6	7.4	8.7	8.7	8.6	8.1	8.0	7.1	7.1	8.3	8.5	8.6	8.3	7.8	8.3
15	7.6	7.5	7.4	6.5	6.7	6.8	8.1	7.6	7.8	8.3	8.3	7.6	7.2	8.2	8.4	8.2	8.4	8.4	7.7	7.5	8.8	[redacted]	8.7	8.1	8.0	7.2	7.2	8.4	8.6	8.7	8.4	7.9	8.4
16	7.6	7.6	7.4	6.6	6.9	7.0	8.1	7.6	8.0	8.3	8.4	7.7	7.2	8.3	8.4	8.2	8.4	8.4	7.8	7.6	8.8	8.9	8.7	8.1	8.0	7.3	7.4	8.5	8.7	8.7	8.4	8.0	8.4
17	7.6	7.6	7.4	6.7	7.0	7.1	8.1	7.6	8.0	8.3	8.3	7.7	7.3	8.3	8.4	8.2	8.3	8.3	7.8	7.7	8.8	8.8	8.6	8.0	7.9	7.4	7.4	8.4	8.6	8.7	8.4	8.0	8.4
18	7.5	7.4	7.3	6.6	7.0	7.1	8.0	7.5	7.9	8.2	8.2	7.7	7.3	8.2	8.2	8.1	8.1	8.1	7.8	7.7	8.6	8.7	8.5	7.9	7.7	7.3	7.4	8.3	8.5	8.5	8.2	7.9	8.3
19	7.3	7.4	7.1	6.5	6.9	7.0	7.8	7.4	7.8	8.1	7.9	7.4	7.1	8.0	8.0	7.9	7.9	7.9	7.6	7.6	8.5	8.5	8.2	7.7	7.5	7.2	7.3	8.2	8.4	8.4	8.0	7.7	8.1
20	7.1	7.2	6.9	6.3	6.7	6.9	7.5	7.1	7.6	7.9	7.7	7.3	7.0	7.8	7.8	7.7	7.8	7.7	7.5	7.4	8.3	8.3	8.1	7.5	7.3	7.0	7.2	8.0	8.2	8.2	7.8	7.5	7.9
21	7.0	7.1	6.8	6.0	6.6	6.8	7.5	7.0	7.5	7.7	7.5	7.2	6.9	7.6	7.7	7.7	7.7	7.6	7.4	7.4	8.2	8.2	7.9	7.4	7.0	6.9	7.1	7.9	8.0	8.0	7.7	7.4	7.8
22	6.9	6.8	6.6	5.8	6.4	6.6	7.2	6.8	7.2	7.3	7.2	6.9	6.7	7.3	7.4	7.3	7.4	7.3	7.2	7.1	7.8	7.8	7.6	7.2	6.7	6.6	6.9	7.6	7.7	7.6	7.3	7.1	7.5
23	6.3	6.3	6.1	5.6	6.0	6.2	6.6	6.3	6.6	6.8	6.7	6.5	6.2	6.7	6.9	6.7	6.8	6.8	6.7	6.5	7.1	7.2	7.0	6.6	6.2	6.1	6.4	6.8	7.0	7.0	6.8	6.6	6.9
24	5.8	5.8	5.6	5.4	5.5	5.7	6.0	5.8	6.0	6.2	6.2	6.0	5.7	6.1	6.3	6.2	6.3	6.3	6.2	6.1	6.6	6.5	6.4	6.2	5.8	5.6	5.9	6.3	6.4	6.4	6.3	6.0	6.4
Ave.	6.6	6.6	6.4	5.8	5.9	6.0	6.8	6.7	6.7	7.0	7.0	6.6	6.3	6.9	7.1	7.1	7.1	7.2	6.7	6.5	7.4	7.5	7.4	7.0	6.8	6.3	6.2	7.1	7.3	7.3	7.2	6.8	7.2
	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		

Retail Load Pattern

(Percentage of Peak)

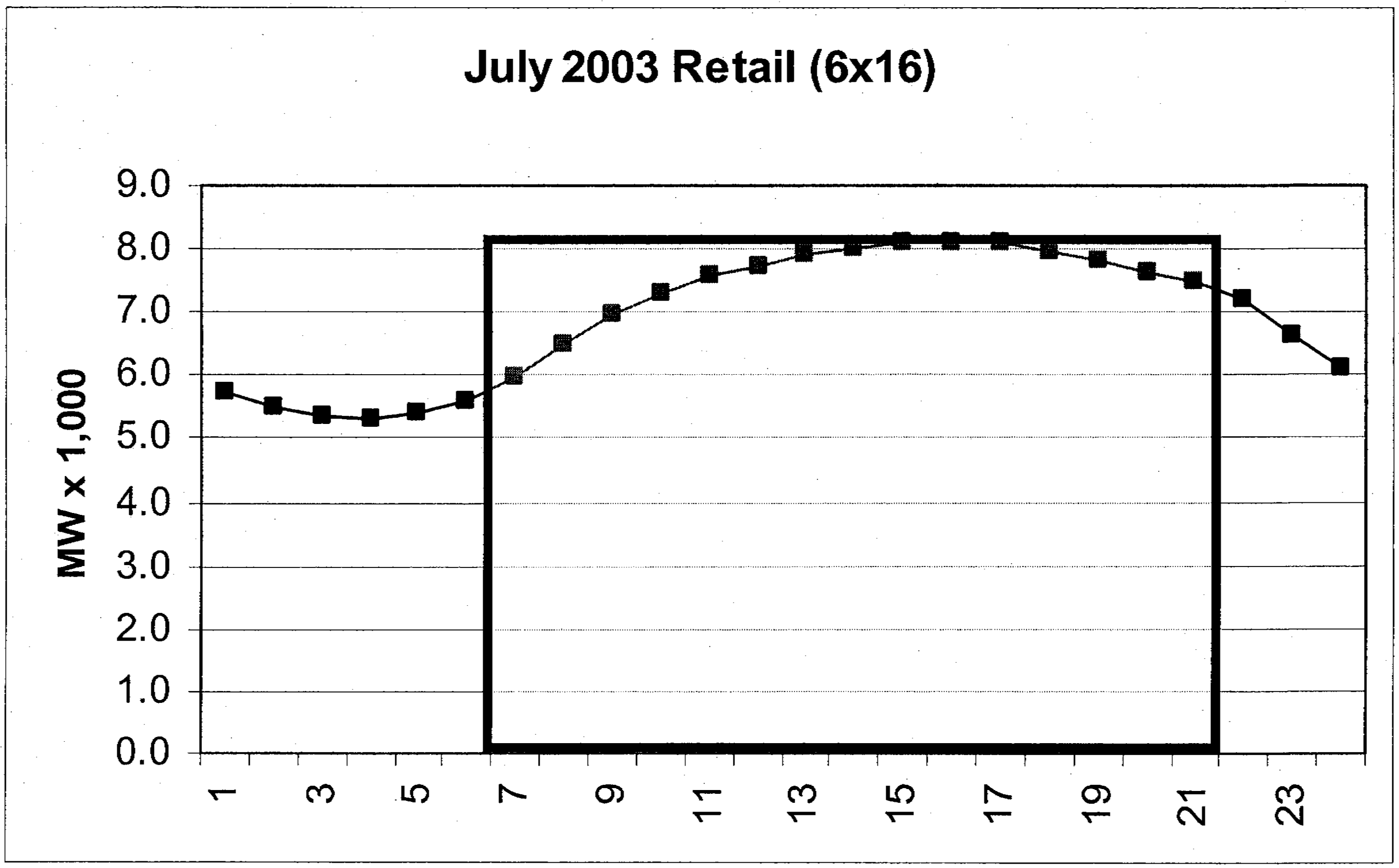
July 2003 Retail Load

	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		
	7/1	7/2	7/3	7/4	7/5	7/6	7/7	7/8	7/9	7/10	7/11	7/12	7/13	7/14	7/15	7/16	7/17	7/18	7/19	7/20	7/21	7/22	7/23	7/24	7/25	7/26	7/27	7/28	7/29	7/30	7/31	Ave.	6x16
1	63	61	61	59	57	58	61	65	61	64	66	64	63	61	65	67	66	66	66	65	65	69	68	68	65	61	60	63	66	68	68	64	67
2	60	59	59	56	55	56	59	62	59	61	63	62	60	59	63	64	64	64	63	63	63	66	66	65	63	58	57	61	64	64	65	61	64
3	59	58	57	55	54	55	58	61	58	60	61	60	59	58	61	63	63	62	61	61	61	65	64	63	61	57	56	60	62	62	63	60	63
4	58	57	57	54	53	54	57	60	57	59	61	59	58	58	61	62	62	61	60	60	61	63	63	62	61	57	55	59	61	62	62	59	62
5	59	59	58	54	53	54	59	61	59	60	61	59	58	59	62	63	63	63	60	60	62	65	65	62	62	57	55	60	62	63	64	60	63
6	62	61	60	54	52	53	61	64	61	62	63	58	57	62	65	66	66	65	60	59	65	67	67	65	64	58	55	63	65	66	66	62	65
7	67	66	65	56	54	54	67	69	66	67	69	61	59	67	70	70	70	70	62	60	71	72	72	68	68	59	56	68	70	70	70	66	70
8	73	72	70	60	59	58	73	74	72	73	74	66	63	74	76	76	77	77	67	64	77	79	78	74	75	64	61	74	76	76	76	71	76
9	78	76	75	64	63	61	78	78	76	77	80	72	67	79	81	81	82	82	73	69	83	84	84	79	80	69	65	79	79	81	81	76	81
10	81	79	78	67	67	65	82	81	79	81	84	76	72	83	86	85	86	86	78	73	88	88	88	84	85	74	70	84	85	86	85	80	86
11	82	81	80	69	70	69	85	82	81	84	86	80	75	86	89	87	89	90	81	75	91	92	91	86	87	77	73	87	89	90	89	83	88
12	84	82	81	71	72	71	87	83	83	87	88	82	78	88	91	88	90	92	84	78	94	95	93	88	88	78	76	89	92	92	91	85	91
13	84	83	82	72	74	73	89	85	85	89	91	84	79	90	93	90	92	93	85	81	96	97	96	90	90	80	78	92	95	95	93	87	92
14	85	82	83	73	75	75	90	85	86	91	92	84	80	91	94	91	93	95	86	83	98	98	97	91	90	80	80	94	96	97	94	88	94
15	86	84	84	74	75	77	91	85	88	93	94	86	80	92	95	92	94	95	87	84	99	[redacted]	98	91	90	81	81	95	97	98	95	89	95
16	86	85	84	75	77	79	91	85	90	94	94	86	81	93	95	93	94	94	88	85	99	100	98	91	90	82	83	95	98	98	95	90	95
17	86	85	83	75	79	79	91	85	90	94	94	87	82	93	94	92	93	93	88	86	99	99	97	90	89	83	84	95	97	98	94	90	95
18	84	84	82	75	78	80	90	84	89	92	92	86	82	92	92	91	91	91	88	86	97	98	95	89	87	83	83	94	96	96	92	88	93
19	82	83	80	74	77	79	87	83	88	91	89	84	80	90	90	89	89	89	86	85	95	95	93	86	84	81	82	92	95	95	90	87	91
20	80	81	78	71	75	77	85	80	85	88	87	82	79	87	88	87	87	87	84	83	93	93	91	85	82	78	81	90	92	92	88	84	89
21	79	80	76	68	74	77	84	79	84	86	85	81	78	86	87	86	87	86	83	83	92	92	89	83	79	77	80	89	91	91	86	83	88
22	77	77	74	66	72	75	80	77	81	83	81	78	76	82	84	82	83	82	81	80	88	88	85	81	75	74	77	85	86	86	83	80	84
23	71	71	69	63	67	70	74	71	74	77	76	73	69	76	77	75	77	76	75	73	80	81	78	75	70	69	72	77	78	78	76	74	78
24	65	65	63	60	62	64	68	65	68	70	69	67	65	69	71	70	71	70	70	68	74	74	73	69	65	63	66	71	72	72	71	68	71
Ave.	75	74	72	65	66	67	77	75	76	78	79	74	71	78	80	80	80	80	76	74	83	84	83	79	77	71	70	80	82	82	81	76	81
	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		

Retail usage patterns Observations

- Load profile is relatively flat.
- The non-6x16 usage (Sundays and nights) is lower, but not significantly lower than 6x16.
- The 6x16 pattern is relatively flat for the monthly average as well as the peak day.

Average July 2003 6x16 Load



Average July 2003 6x16 Load
Observations

- The average July 6x16 Retail load shows and expected pattern of lower load at the ends of the period and high in the middle.
- The peak 6x16 Retail load is 2,200 Mw's or 1/3rd greater than the load at 7:00 and 900 Mw's greater than at 22:00.
- How are resources combined to meet Retail load?

Generation Pattern
(MW x 1,000)

July 2003 Generation

	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		
	7/1	7/2	7/3	7/4	7/5	7/6	7/7	7/8	7/9	7/10	7/11	7/12	7/13	7/14	7/15	7/16	7/17	7/18	7/19	7/20	7/21	7/22	7/23	7/24	7/25	7/26	7/27	7/28	7/29	7/30	7/31	Ave.	6x16
Temp	96	94	93	92	94	95	96	87	94	103	102	105	99	98	105	102	102	100	100	100	101	104	104	101	94	91	94	95	99	101	97	98	
1	6.2	6.1	5.8	5.7	5.8	5.8	5.8	6.1	6.0	5.9	5.9	5.8	5.9	6.3	6.1	6.1	5.9	6.1	6.4	6.2	6.4	6.5	6.1	6.1	6.0	5.4	5.0	6.1	5.9	6.1	6.1	6.0	6.3
2	6.2	6.1	5.8	5.6	5.7	5.6	5.6	6.0	5.9	5.9	5.9	5.6	5.7	6.3	6.1	6.2	6.0	6.1	6.3	6.0	6.2	6.4	5.9	5.9	6.0	5.2	5.0	6.0	5.9	6.0	6.0	5.9	6.2
3	6.2	6.2	5.7	5.5	5.6	5.6	5.6	6.0	5.8	5.9	5.9	5.5	5.7	6.1	6.1	6.2	6.1	6.0	6.3	6.0	6.0	6.4	5.8	5.9	5.9	5.2	5.0	5.9	5.9	5.8	6.0	5.9	6.2
4	6.2	6.0	5.6	5.4	5.4	5.7	5.7	6.0	5.8	5.9	5.9	5.5	5.9	6.2	5.9	6.1	6.1	6.1	6.3	6.1	6.1	6.2	5.8	5.8	5.8	5.2	4.9	5.8	5.9	5.9	6.0	5.8	6.1
5	6.3	6.0	5.6	5.6	5.3	5.6	5.7	6.1	5.9	5.9	5.9	5.6	6.0	6.3	6.1	6.0	6.1	6.2	6.2	6.1	6.1	6.4	5.9	5.7	5.8	5.2	5.0	5.8	5.7	5.9	6.0	5.9	6.1
6	6.4	5.9	5.6	5.6	5.0	5.6	5.8	6.1	5.9	6.0	6.0	5.4	5.8	6.3	6.1	5.9	6.2	6.3	6.0	6.1	6.1	6.4	5.9	5.7	5.8	5.1	5.0	5.8	5.6	5.8	5.9	5.8	6.1
7	6.4	5.8	5.6	5.6	5.0	5.5	5.6	6.1	5.8	5.9	6.0	5.3	5.7	6.2	6.0	5.6	6.0	6.2	5.6	6.0	5.9	6.3	5.7	5.6	5.8	5.0	4.9	5.8	5.4	5.7	5.5	5.7	6.0
8	6.4	5.9	5.8	5.9	5.7	5.7	5.9	6.1	6.1	6.0	6.0	5.8	6.1	6.3	6.1	5.9	6.3	6.2	6.1	6.3	6.1	6.4	5.8	5.7	6.1	5.3	5.3	6.0	5.9	5.9	5.8	6.0	6.2
9	6.4	6.0	5.9	6.2	5.9	5.9	6.1	6.2	6.1	6.1	6.0	6.0	6.3	6.3	6.2	6.1	6.4	6.4	6.4	6.5	6.4	6.6	6.0	5.8	6.3	5.5	5.5	6.0	6.1	6.1	5.9	6.1	6.4
10	6.5	6.0	5.9	6.2	6.1	6.1	6.4	6.4	6.3	6.2	6.0	6.2	6.4	6.5	6.5	6.3	6.6	6.6	6.5	6.6	6.7	6.8	6.1	5.9	6.5	5.6	6.0	6.2	6.3	6.2	6.1	6.3	6.5
11	6.5	6.2	6.1	6.3	6.2	6.2	6.5	6.4	6.4	6.5	5.9	6.5	6.5	6.7	6.7	6.5	6.8	6.7	6.6	6.7	6.8	6.9	6.2	6.2	6.6	5.6	6.3	6.4	6.5	6.3	6.2	6.4	6.7
12	6.7	6.4	6.1	6.5	6.3	6.3	6.6	6.4	6.5	6.5	6.0	6.6	6.7	6.8	6.7	6.6	6.8	6.9	6.7	6.8	6.8	6.9	6.2	6.2	6.3	5.7	6.4	6.4	6.5	6.4	6.2	6.5	6.7
13	6.8	6.4	6.2	6.6	6.3	6.5	6.6	6.3	6.5	6.6	6.0	6.6	6.7	7.0	6.8	6.6	6.8	6.8	6.7	6.9	6.9	6.9	6.3	6.2	6.3	5.8	6.5	6.5	6.6	6.5	6.2	6.5	6.8
14	7.0	6.3	6.3	6.6	6.4	6.5	6.8	6.2	6.6	6.8	6.1	6.6	6.8	6.9	6.9	6.6	6.8	6.9	6.8	7.0	6.8	6.9	6.4	6.2	6.1	5.8	6.5	6.5	6.7	6.6	6.2	6.6	6.8
15	7.0	6.4	6.4	6.6	6.4	6.6	6.8	6.3	6.6	6.7	6.0	6.7	6.9	7.0	6.9	6.6	6.8	6.9	6.8	7.0	6.9	[redacted]	6.4	6.2	6.0	5.8	6.6	6.4	6.8	6.7	6.3	6.6	6.8
16	7.0	6.5	6.5	6.7	6.5	6.6	6.7	6.4	6.7	6.8	6.1	6.7	6.9	7.1	6.9	6.7	6.9	6.9	6.8	7.1	7.0	6.9	6.4	6.2	6.1	5.8	6.7	6.2	6.8	6.8	6.4	6.6	6.9
17	7.0	6.6	6.5	6.8	6.6	6.7	6.8	6.5	6.6	6.7	6.2	6.7	6.9	7.1	6.9	6.6	6.8	6.9	6.8	7.1	7.0	6.9	6.3	6.3	6.1	5.8	6.7	6.2	6.8	6.8	6.3	6.6	6.9
18	6.9	6.5	6.5	6.8	6.6	6.7	6.8	6.5	6.6	6.7	6.1	6.7	6.8	7.0	6.8	6.7	6.8	6.9	6.8	7.1	6.9	6.9	6.3	6.4	6.1	5.6	6.6	6.2	6.8	6.7	6.4	6.6	6.8
19	6.8	6.5	6.4	6.8	6.7	6.6	6.8	6.4	6.6	6.7	6.2	6.7	6.7	7.0	6.8	6.6	6.8	6.7	6.7	7.0	6.9	6.8	6.2	6.2	6.1	5.5	6.5	6.2	6.6	6.7	6.4	6.6	6.8
20	6.7	6.2	6.2	6.6	6.6	6.5	6.7	6.4	6.5	6.5	6.1	6.7	6.8	6.8	6.8	6.6	6.8	6.7	6.7	6.9	6.9	6.8	6.2	6.3	6.0	5.4	6.5	6.2	6.5	6.6	6.5	6.5	6.7
21	6.6	6.3	6.0	6.3	6.4	6.4	6.7	6.5	6.5	6.5	6.2	6.7	6.8	6.7	6.7	6.6	6.8	6.8	6.7	6.8	6.8	6.8	6.2	6.4	6.0	5.5	6.5	6.2	6.4	6.6	6.5	6.5	6.7
22	6.5	6.1	6.0	6.1	6.2	6.4	6.7	6.4	6.4	6.4	6.1	6.7	6.7	6.6	6.7	6.4	6.6	6.7	6.7	6.7	6.7	6.7	6.2	6.4	6.0	5.5	6.5	6.2	6.4	6.5	6.4	6.4	6.6
23	6.4	6.0	6.0	6.0	6.0	6.2	6.5	6.2	6.3	6.3	6.1	6.6	6.5	6.4	6.6	6.4	6.5	6.7	6.4	6.4	6.7	6.6	6.2	6.3	5.9	5.4	6.3	6.2	6.4	6.3	6.3	6.3	6.5
24	6.2	5.9	5.9	6.0	5.9	6.0	6.3	6.0	6.0	6.0	5.9	6.3	6.3	6.3	6.3	6.2	6.4	6.5	6.4	6.3	6.6	6.3	6.2	6.0	5.7	5.2	6.1	5.9	6.3	6.2	6.2	6.1	6.4
Ave	6.5	6.2	6.0	6.2	6.0	6.1	6.3	6.2	6.3	6.3	6.0	6.2	6.4	6.6	6.5	6.3	6.5	6.5	6.5	6.6	6.6	6.7	6.1	6.1	6.1	5.5	5.9	6.1	6.3	6.3	6.2	6.3	6.5
	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		

Generation Pattern
(Percentage)

	July 2003 Generation																																
	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		
	7/1	7/2	7/3	7/4	7/5	7/6	7/7	7/8	7/9	7/10	7/11	7/12	7/13	7/14	7/15	7/16	7/17	7/18	7/19	7/20	7/21	7/22	7/23	7/24	7/25	7/26	7/27	7/28	7/29	7/30	7/31	Ave.	6x16
Temp	96	94	93	92	94	95	96	87	94	103	102	105	99	98	105	102	102	100	100	100	101	104	104	101	94	91	94	95	99	101	97	98	
1	90	88	84	83	84	84	84	88	87	86	85	84	85	91	88	89	86	89	92	90	92	94	89	88	87	79	72	88	86	89	88	87	91
2	90	88	84	82	82	82	82	87	86	86	86	82	83	91	88	90	87	88	92	87	90	93	85	86	87	75	73	87	85	87	87	85	90
3	90	89	82	80	81	82	81	87	84	85	85	80	82	89	88	90	88	88	92	87	87	92	84	86	85	76	73	85	85	85	87	85	89
4	90	88	81	78	78	82	83	87	83	85	85	80	85	89	86	89	88	88	91	88	88	90	83	84	84	75	71	83	86	85	87	84	89
5	92	87	82	82	76	81	83	88	85	85	85	81	87	91	88	88	88	89	91	88	89	92	85	83	84	75	72	84	83	86	86	85	89
6	92	86	81	82	73	81	84	89	86	86	86	79	84	91	89	85	90	91	88	88	88	94	85	82	84	74	72	84	81	85	85	84	89
7	92	84	81	81	73	80	82	89	85	85	86	77	82	91	88	81	87	89	81	88	85	92	83	81	84	72	71	84	78	83	80	83	87
8	93	86	84	86	83	83	85	89	89	87	87	84	88	92	89	85	91	90	88	92	89	93	84	83	88	76	77	86	86	85	84	86	90
9	93	87	85	90	86	86	89	89	89	89	87	87	91	91	90	88	93	93	92	94	93	96	87	83	92	80	79	87	88	88	86	88	92
10	94	87	85	90	89	88	93	93	91	90	87	90	93	94	94	91	96	95	95	96	97	98	88	86	94	81	86	90	92	90	88	91	95
11	95	90	88	91	90	90	95	93	92	94	86	94	95	97	96	94	98	98	95	97	98	100	90	90	95	82	92	92	94	92	89	93	97
12	98	93	89	94	92	91	95	92	94	95	88	96	97	99	97	95	99	99	97	99	99	100	90	90	92	82	93	93	95	93	90	94	98
13	99	93	89	96	91	94	96	92	95	96	88	96	97	101	99	95	99	99	98	100	100	100	91	90	91	84	94	95	96	94	90	95	98
14	101	91	91	95	93	95	98	90	95	98	88	96	98	100	100	96	99	100	98	102	99	100	92	90	89	84	94	95	97	96	91	95	99
15	101	93	92	96	93	95	98	91	96	98	87	97	100	101	100	96	99	101	98	102	100	[redacted]	93	90	87	84	95	92	98	97	91	95	99
16	101	95	94	98	94	96	97	93	96	98	88	97	100	103	100	97	99	99	98	103	101	100	93	89	88	84	98	90	99	98	93	96	99
17	101	95	94	99	95	97	98	94	96	97	90	97	100	103	100	96	99	101	98	103	101	100	92	91	88	84	97	90	98	98	91	96	99
18	101	94	94	99	96	97	98	94	96	97	89	97	99	101	99	96	98	100	98	103	100	100	91	92	88	82	96	90	98	98	93	96	99
19	98	94	94	98	97	96	98	93	95	96	90	97	98	102	98	96	98	98	97	102	100	99	91	91	88	80	95	90	96	97	92	95	99
20	97	91	90	96	96	94	97	93	95	95	89	97	99	99	99	96	99	97	97	100	100	99	90	92	87	79	94	90	94	96	94	94	98
21	96	91	88	92	93	93	97	94	94	94	89	97	98	98	98	95	99	98	97	99	99	99	90	93	87	80	94	90	93	96	94	94	98
22	94	89	87	88	90	93	97	93	93	93	88	97	97	95	97	93	96	97	97	97	97	98	90	92	86	80	94	90	93	94	93	93	96
23	92	87	87	87	87	90	94	90	91	91	89	96	94	93	96	93	95	97	93	93	97	95	90	91	86	79	91	89	92	91	92	91	95
24	90	85	85	87	85	87	91	87	88	87	86	91	92	91	91	89	92	95	93	92	95	91	89	87	83	75	89	86	91	89	90	89	92
Ave.	95	90	87	90	87	89	92	91	91	91	87	90	93	96	94	92	94	95	94	95	95	96	89	88	88	79	86	89	91	91	89	91	94
	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		

Generation Pattern
Observations

- Generation is very flat, even with the use of Peaking resources.
- 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.

Retail Load less Generation

(MW x 1,000)

(Red values are negative)

July 2003 Retail less Generation

	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		
	7/1	7/2	7/3	7/4	7/5	7/6	7/7	7/8	7/9	7/10	7/11	7/12	7/13	7/14	7/15	7/16	7/17	7/18	7/19	7/20	7/21	7/22	7/23	7/24	7/25	7/26	7/27	7/28	7/29	7/30	7/31	Ave.	6x16
Temp	96	94	93	92	94	95	96	87	94	103	102	105	99	98	105	102	102	100	100	100	101	104	104	101	94	91	94	95	99	101	97	98	102
1	0.7	0.6	0.4	0.5	0.8	0.6	0.4	0.4	0.5	0.3	0.0	0.0	0.3	0.8	0.3	0.2	0.0	0.2	0.5	0.4	0.6	0.4	0.1	0.0	0.2	0.0	0.3	0.5	0.0	0.1	0.1	0.3	0.3
2	0.9	0.8	0.5	0.6	0.8	0.7	0.4	0.5	0.6	0.5	0.3	0.1	0.4	1.0	0.5	0.5	0.3	0.4	0.7	0.4	0.6	0.5	0.0	0.1	0.4	0.0	0.1	0.6	0.2	0.3	0.2	0.5	0.5
3	1.0	1.0	0.6	0.6	0.8	0.8	0.5	0.5	0.6	0.6	0.4	0.2	0.4	1.0	0.6	0.6	0.5	0.5	0.9	0.6	0.6	0.6	0.1	0.3	0.4	0.2	0.0	0.6	0.4	0.3	0.4	0.5	0.6
4	1.0	0.9	0.5	0.6	0.7	0.9	0.6	0.6	0.6	0.6	0.5	0.3	0.7	1.0	0.5	0.6	0.6	0.6	1.0	0.8	0.7	0.6	0.1	0.3	0.4	0.2	0.0	0.5	0.5	0.3	0.4	0.6	0.6
5	1.0	0.8	0.5	0.8	0.6	0.8	0.5	0.7	0.6	0.6	0.4	0.4	0.9	1.0	0.6	0.4	0.4	0.6	0.9	0.8	0.6	0.6	0.1	0.2	0.3	0.1	0.1	0.5	0.2	0.3	0.3	0.5	0.5
6	0.9	0.5	0.3	0.8	0.4	0.8	0.3	0.4	0.5	0.4	0.3	0.3	0.7	0.8	0.4	0.1	0.3	0.4	0.7	0.9	0.3	0.5	0.1	0.1	0.1	0.0	0.1	0.2	0.2	0.0	0.0	0.4	0.3
7	0.4	0.1	0.2	0.6	0.2	0.7	0.3	0.0	0.0	0.1	0.1	0.1	0.5	0.3	0.1	0.7	0.2	0.1	0.1	0.7	0.4	0.1	0.7	0.5	0.2	0.3	0.1	0.2	0.8	0.5	0.7	0.1	0.2
8	0.1	0.5	0.5	0.6	0.5	0.6	0.6	0.4	0.3	0.5	0.6	0.1	0.5	0.2	0.7	0.9	0.6	0.6	0.1	0.6	0.8	0.6	1.2	0.9	0.6	0.4	0.1	0.6	0.8	0.9	1.0	0.4	0.5
9	0.5	0.8	0.8	0.5	0.4	0.4	0.8	0.7	0.6	0.8	1.1	0.4	0.3	0.7	1.1	1.1	0.9	0.9	0.1	0.4	1.0	0.9	1.5	1.3	0.8	0.7	0.3	1.0	0.9	1.2	1.3	0.6	0.9
10	0.7	1.0	1.0	0.2	0.1	0.3	0.9	0.8	0.7	1.0	1.5	0.6	0.1	0.9	1.2	1.3	1.0	1.1	0.4	0.1	1.1	1.1	1.7	1.5	1.0	1.0	0.3	1.2	1.2	1.4	1.5	0.8	1.1
11	0.7	1.0	1.0	0.2	0.0	0.1	1.0	0.9	0.8	1.0	1.7	0.6	0.1	1.0	1.3	1.3	1.1	1.2	0.6	0.0	1.3	1.3	1.9	1.5	1.2	1.2	0.2	1.4	1.5	1.7	1.7	1.0	1.2
12	0.7	0.9	1.1	0.2	0.1	0.0	1.1	1.1	0.9	1.1	1.8	0.7	0.2	1.0	1.4	1.3	1.2	1.3	0.7	0.1	1.5	1.5	2.1	1.7	1.5	1.3	0.3	1.5	1.6	1.8	1.9	1.1	1.3
13	0.7	1.0	1.1	0.2	0.3	0.1	1.3	1.2	1.0	1.2	2.0	0.8	0.3	1.0	1.4	1.4	1.4	1.4	0.8	0.3	1.6	1.7	2.2	1.8	1.7	1.3	0.4	1.7	1.8	1.9	2.0	1.2	1.4
14	0.6	1.0	1.1	0.1	0.3	0.1	1.2	1.4	1.1	1.3	2.1	0.9	0.3	1.2	1.5	1.5	1.5	1.5	0.9	0.3	1.8	1.8	2.3	1.9	1.8	1.4	0.6	1.8	1.8	2.0	2.1	1.3	1.5
15	0.7	1.1	1.1	0.1	0.3	0.2	1.3	1.3	1.2	1.5	2.3	0.9	0.3	1.2	1.5	1.6	1.5	1.5	0.9	0.4	1.9	[redacted]	2.3	1.9	2.0	1.5	0.6	2.1	1.9	2.0	2.1	1.3	1.6
16	0.6	1.0	1.0	0.1	0.4	0.4	1.4	1.2	1.3	1.6	2.3	1.0	0.3	1.1	1.6	1.6	1.5	1.5	1.0	0.5	1.8	2.0	2.3	1.9	1.9	1.5	0.6	2.3	1.9	2.0	2.0	1.3	1.6
17	0.6	1.0	0.9	0.2	0.4	0.3	1.3	1.1	1.4	1.6	2.1	1.1	0.4	1.2	1.5	1.6	1.5	1.4	1.0	0.5	1.8	1.9	2.3	1.7	1.8	1.6	0.7	2.2	1.8	2.0	2.1	1.3	1.6
18	0.5	1.0	0.8	0.2	0.3	0.4	1.2	1.0	1.3	1.5	2.0	1.0	0.5	1.2	1.4	1.4	1.4	1.2	1.0	0.6	1.7	1.8	2.2	1.5	1.6	1.7	0.8	2.1	1.7	1.8	1.8	1.2	1.4
19	0.5	0.9	0.7	0.2	0.2	0.4	1.0	0.9	1.2	1.4	1.8	0.8	0.4	1.0	1.2	1.3	1.2	1.2	0.9	0.6	1.6	1.6	2.0	1.4	1.4	1.7	0.8	2.0	1.8	1.7	1.6	1.1	1.3
20	0.4	0.9	0.7	0.4	0.1	0.4	0.8	0.8	1.1	1.3	1.6	0.6	0.2	0.9	1.0	1.1	0.9	1.1	0.8	0.5	1.4	1.5	1.9	1.2	1.2	1.5	0.7	1.8	1.7	1.5	1.3	1.0	1.2
21	0.4	0.8	0.7	0.3	0.2	0.4	0.7	0.6	1.0	1.2	1.4	0.5	0.1	0.9	1.0	1.1	0.9	0.9	0.7	0.6	1.4	1.4	1.7	1.0	1.0	1.4	0.6	1.7	1.6	1.4	1.2	0.9	1.1
22	0.4	0.7	0.6	0.3	0.2	0.3	0.5	0.4	0.8	1.0	1.2	0.3	0.0	0.7	0.8	0.9	0.8	0.7	0.5	0.4	1.1	1.1	1.4	0.8	0.7	1.1	0.4	1.3	1.2	1.2	0.9	0.7	0.8
23	0.1	0.3	0.1	0.4	0.1	0.0	0.1	0.1	0.3	0.6	0.6	0.1	0.3	0.3	0.3	0.3	0.3	0.1	0.3	0.1	0.4	0.6	0.7	0.4	0.3	0.7	0.1	0.7	0.6	0.7	0.4	0.3	0.4
24	0.4	0.1	0.3	0.6	0.3	0.3	0.3	0.2	0.0	0.2	0.2	0.3	0.6	0.2	0.0	0.0	0.1	0.3	0.2	0.3	0.0	0.3	0.3	0.1	0.0	0.4	0.2	0.4	0.2	0.3	0.0	0.1	0.0
Ave.	0.1	0.4	0.4	0.4	0.1	0.2	0.5	0.4	0.5	0.7	1.0	0.3	0.1	0.4	0.7	0.8	0.7	0.6	0.2	0.0	0.8	0.8	1.3	0.9	0.8	0.8	0.3	1.0	1.0	1.0	1.0	0.5	0.7
	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		

Retail Load less Generation

Observations

- For Retail load, the Company is generally an importer of power during HLH and and exporter during LLH.
- Daytime on Sundays is like any other HLH—Retail greater than Generation.
- During HLH, retail load can be 20-30% greater than generation.
- What are wholesale transactions like?

LTF Purchases (MW)

July 2003 LTF Input (MW)

	T 7/1	W 7/2	Th 7/3	F 7/4	S 7/5	S 7/6	M 7/7	T 7/8	W 7/9	Th 7/10	F 7/11	S 7/12	S 7/13	M 7/14	T 7/15	W 7/16	Th 7/17	F 7/18	S 7/19	S 7/20	M 7/21	T 7/22	W 7/23	Th 7/24	F 7/25	S 7/26	S 7/27	M 7/28	T 7/29	W 7/30	Th 7/31	Ave.	6x16
1	459	454	434	424	423	428	425	445	428	423	423	424	444	440	267	466	470	427	420	425	225	439	430	424	456	421	424	424	427	424	429	422	437
2	460	454	435	425	424	428	426	490	578	422	424	425	444	435	236	435	470	427	421	428	274	439	430	425	425	422	425	425	427	425	429	427	443
3	460	454	460	425	424	428	426	535	578	422	431	425	444	435	236	435	470	426	420	427	425	439	430	425	425	422	425	425	427	425	429	434	452
4	460	454	460	425	423	478	426	545	578	422	431	425	433	444	236	435	470	426	420	425	425	439	430	425	425	421	425	425	427	425	429	436	453
5	475	454	454	424	423	497	426	535	578	422	424	424	433	435	236	484	469	426	420	425	425	439	430	425	425	421	425	425	427	425	429	437	454
6	475	453	449	424	423	502	425	570	628	572	623	524	427	440	235	584	469	424	420	425	425	438	430	424	524	421	424	424	426	424	429	461	483
7	462	457	468	422	463	492	465	462	431	428	438	458	427	440	257	459	539	465	479	419	472	466	493	496	473	486	419	473	479	479	471	456	478
8	441	447	487	422	445	428	451	452	442	429	438	458	428	484	251	455	540	454	472	419	454	477	486	470	491	473	419	463	462	485	461	451	475
9	473	455	450	422	445	428	440	431	442	429	438	445	458	316	279	485	540	448	461	419	459	472	485	466	489	467	419	452	492	483	483	447	469
10	464	430	437	423	435	421	429	429	442	430	463	436	458	271	267	472	540	445	460	421	445	458	485	466	476	489	419	476	482	486	474	443	463
11	546	552	530	515	528	443	521	532	548	521	605	463	458	363	359	459	572	470	451	251	441	457	482	468	472	487	419	482	476	447	469	477	508
12	547	551	530	537	553	443	553	532	549	553	605	460	459	355	357	555	664	559	481	251	463	454	554	552	563	482	419	564	563	551	551	510	548
13	546	547	560	536	517	443	552	532	549	603	605	459	459	355	351	610	718	612	569	343	555	543	552	605	562	573	511	559	557	606	605	539	576
14	546	546	554	536	515	535	550	531	549	603	605	459	460	355	347	610	718	609	564	343	609	602	550	603	560	574	511	612	606	607	603	547	583
15	548	546	552	536	536	535	551	535	549	603	605	458	460	355	349	608	718	609	577	343	609	[redacted]	550	602	553	571	511	609	604	603	602	548	584
16	548	546	506	536	544	535	550	535	550	603	605	458	460	405	394	603	718	609	574	401	608	601	610	602	555	571	569	608	607	603	604	555	589
17	548	526	547	536	544	541	549	535	551	603	605	458	460	404	422	607	718	612	572	401	608	603	610	611	552	570	569	608	607	595	604	557	591
18	548	530	526	536	536	534	549	548	551	603	605	458	414	405	471	610	718	613	557	401	608	601	611	611	552	565	569	609	605	584	604	556	591
19	456	454	438	444	444	534	464	456	459	511	513	426	414	312	389	610	717	615	472	401	593	601	558	613	550	476	569	610	613	608	610	514	543
20	474	464	458	422	422	442	464	439	459	461	438	427	306	263	386	529	686	594	466	401	609	614	466	521	465	467	569	510	525	490	490	475	503
21	445	432	439	422	421	442	465	439	459	429	438	427	261	270	431	469	632	524	357	251	432	464	478	465	473	469	419	452	432	431	432	432	464
22	448	453	444	422	426	442	435	440	442	429	438	427	261	238	474	472	540	438	443	219	440	460	458	471	448	454	419	424	438	442	433	426	458
23	466	461	446	424	423	442	425	441	428	423	424	454	229	223	467	466	502	423	452	234	471	464	462	456	424	421	421	419	459	465	424	424	456
24	434	429	435	424	423	428	425	445	428	423	456	453	428	223	467	466	428	423	420	234	437	439	462	424	424	421	423	424	427	440	474	422	446
Ave	489	481	479	461	465	470	475	493	508	490	503	447	414	361	340	516	584	503	473	363	480	500	497	502	490	481	463	496	500	498	499	475	502

LTF Sales (MW)

(Red values are leaving the system)

July 2003 LTF Output (MW)

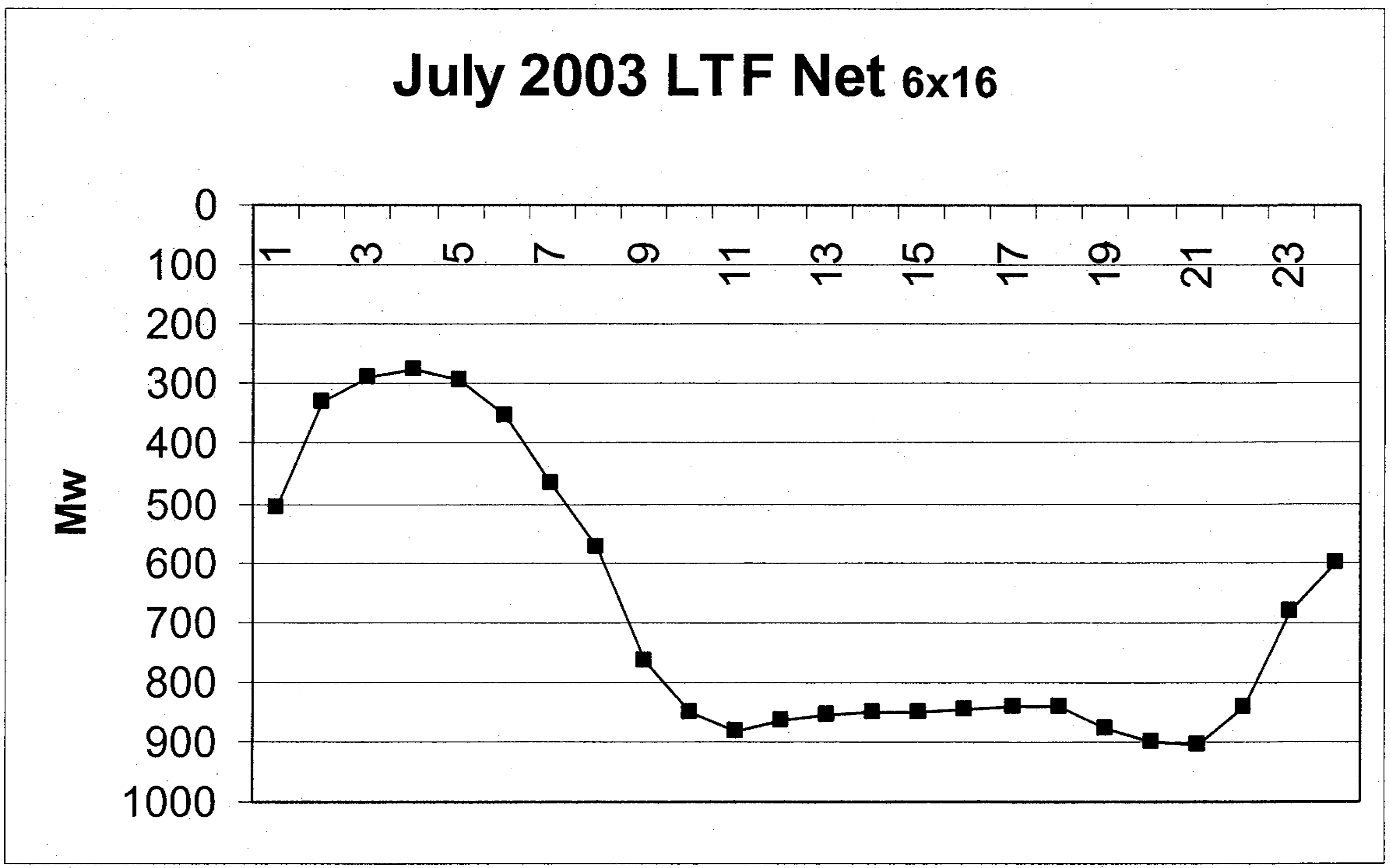
	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		
	7/1	7/2	7/3	7/4	7/5	7/6	7/7	7/8	7/9	7/10	7/11	7/12	7/13	7/14	7/15	7/16	7/17	7/18	7/19	7/20	7/21	7/22	7/23	7/24	7/25	7/26	7/27	7/28	7/29	7/30	7/31	Ave.	6x16
1	847	763	762	803	771	836	754	734	921	800	901	882	684	668	984	903	1010	959	887	835	818	1046	1092	1099	1103	899	954	873	1071	985	1054	893	943
2	819	676	726	785	707	762	685	704	713	640	764	742	664	614	726	824	820	741	745	812	805	728	751	766	767	760	923	732	772	783	817	751	773
3	801	657	670	735	701	692	707	687	697	645	683	686	680	640	650	839	767	621	740	773	739	722	716	732	738	731	878	737	683	805	708	718	740
4	803	654	647	736	730	640	756	699	699	679	653	678	711	673	621	764	744	597	686	858	713	789	700	729	714	659	855	742	618	792	660	710	728
5	783	725	655	761	760	669	715	723	708	690	681	708	711	719	671	849	814	607	668	792	790	734	708	747	719	654	882	750	663	796	683	727	749
6	777	763	721	724	743	696	800	791	825	854	787	751	742	730	756	918	907	704	698	796	904	762	815	852	753	816	926	817	802	900	931	799	835
7	1156	845	838	833	878	737	892	849	887	889	1019	947	824	1021	820	957	971	810	897	868	932	920	853	914	866	823	726	878	875	879	1035	892	946
8	1125	1036	1082	1036	897	662	954	936	898	1109	1007	908	910	1265	1229	1112	1237	913	919	858	974	929	939	1047	888	815	716	1009	951	1035	1012	981	1049
9	1267	1358	1367	1111	971	724	974	1061	1080	1200	1231	1157	1133	1378	1268	1197	1291	1188	1036	1085	1151	1204	1208	1204	1167	992	1041	1204	1188	1309	1213	1160	1235
10	1267	1326	1284	1073	995	866	1114	1581	1247	1241	1290	1111	1074	1388	1296	1247	1342	1263	1131	1141	1162	1255	1307	1296	1317	1077	1164	1273	1298	1377	1352	1231	1313
11	1370	1328	1322	1136	1113	886	1315	1537	1339	1358	1406	1199	1184	1392	1366	1336	1477	1357	1208	1141	1336	1379	1358	1357	1382	1203	1230	1277	1332	1376	1357	1302	1391
12	1346	1352	1344	1187	1156	902	1384	1527	1370	1473	1458	1249	1202	1408	1382	1382	1476	1357	1199	1172	1348	1380	1337	1363	1382	1236	1204	1327	1357	1378	1384	1323	1414
13	1383	1377	1371	1272	1156	980	1389	1534	1372	1474	1500	1255	1234	1399	1382	1382	1488	1357	1301	1216	1382	1379	1338	1371	1378	1310	1259	1379	1357	1378	1387	1346	1431
14	1383	1384	1371	1274	1156	1055	1399	1529	1373	1475	1466	1258	1263	1394	1382	1382	1485	1357	1303	1215	1387	1381	1358	1378	1373	1315	1261	1377	1382	1378	1395	1351	1433
15	1383	1384	1378	1272	1164	1088	1395	1527	1373	1479	1503	1257	1257	1382	1382	1382	1487	1357	1304	1240	1382	[redacted]	1361	1385	1371	1321	1261	1378	1378	1381	1387	1354	1434
16	1383	1389	1392	1274	1161	1089	1398	1519	1365	1472	1470	1268	1264	1385	1382	1382	1500	1357	1307	1253	1384	1381	1356	1386	1372	1319	1262	1380	1378	1378	1389	1355	1434
17	1388	1385	1382	1279	1162	1090	1395	1494	1362	1499	1461	1270	1267	1389	1382	1382	1495	1357	1307	1255	1389	1380	1356	1379	1370	1319	1264	1384	1378	1378	1387	1354	1433
18	1382	1381	1382	1280	1184	1086	1393	1474	1364	1499	1509	1272	1263	1382	1385	1382	1489	1357	1307	1255	1387	1382	1356	1371	1368	1320	1256	1386	1378	1378	1393	1355	1434
19	1376	1309	1378	1270	1184	1048	1395	1471	1354	1466	1352	1198	1260	1379	1385	1382	1542	1357	1307	1183	1314	1383	1357	1374	1367	1275	1248	1382	1378	1378	1442	1339	1419
20	1277	1191	1327	1184	1185	1087	1384	1463	1354	1466	1335	1194	1231	1377	1382	1382	1559	1284	1330	1183	1313	1381	1352	1363	1366	1254	1244	1377	1408	1378	1432	1324	1405
21	1280	1225	1285	1118	1180	1018	1335	1378	1274	1392	1294	1142	1231	1353	1347	1357	1489	1287	1244	1185	1262	1376	1343	1360	1377	1225	1246	1375	1319	1376	1372	1292	1370
22	1201	1202	1196	1116	1061	936	1235	1329	1221	1371	1283	1118	1183	1237	1332	1288	1358	1262	1212	1177	1262	1291	1266	1230	1286	1175	1170	1301	1208	1261	1291	1228	1299
23	937	1030	1033	989	863	858	864	1105	1006	1155	1126	1079	1132	1113	1218	1165	1194	1138	1083	1109	1104	1150	1141	1149	1152	1115	1131	1198	1106	1103	1099	1085	1137
24	914	844	818	799	828	756	820	864	970	862	892	894	913	921	1164	1022	1200	1111	895	1073	1100	1088	1087	1134	1129	1221	1063	1183	1067	1125	1093	995	1050
ave.	1152	1108	1114	1044	988	882	1102	1188	1116	1175	1170	1051	1042	1150	1162	1176	1256	1112	1071	1061	1139	1158	1144	1166	1154	1076	1090	1155	1139	1179	1178	1119	1183

Net LTF (MW)
(Red values are leaving the system)

July 2003 LTF Net (MW)

	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		
	7/1	7/2	7/3	7/4	7/5	7/6	7/7	7/8	7/9	7/10	7/11	7/12	7/13	7/14	7/15	7/16	7/17	7/18	7/19	7/20	7/21	7/22	7/23	7/24	7/25	7/26	7/27	7/28	7/29	7/30	7/31	Ave.	6x16
1	388	309	328	379	348	408	329	289	493	377	478	458	240	228	717	437	540	532	467	410	593	607	662	675	647	478	530	449	644	561	625	472	506
2	359	222	291	360	283	334	259	214	135	218	340	317	220	179	490	389	350	314	324	384	531	289	321	341	342	338	498	307	345	358	388	324	330
3	341	203	210	310	277	264	281	152	119	223	252	261	236	205	414	404	297	195	320	346	314	283	286	307	313	309	453	312	256	380	279	284	288
4	343	200	187	311	307	162	330	154	121	257	222	253	278	229	385	329	274	171	266	433	288	350	270	304	289	238	430	317	191	367	231	274	275
5	308	271	201	337	337	172	289	188	130	268	257	284	278	284	435	365	345	181	248	367	365	295	278	322	294	233	457	325	236	371	254	290	295
6	302	310	272	300	320	194	375	221	197	282	164	227	315	290	521	334	438	280	278	371	479	324	385	428	229	395	502	393	376	476	502	338	352
7	694	388	370	411	415	245	427	387	456	461	581	489	397	581	563	498	432	345	418	449	460	454	360	418	393	337	307	405	396	400	564	436	468
8	684	589	595	614	452	234	503	484	456	680	569	450	482	781	978	657	697	459	447	439	520	452	453	577	397	342	297	546	489	550	551	530	574
9	794	903	917	689	526	296	534	630	638	771	793	712	675	1062	989	712	751	740	575	666	692	732	723	738	678	525	622	752	696	826	730	712	766
10	803	896	847	650	560	445	685	1152	805	811	827	675	616	1117	1029	775	802	818	671	720	717	797	822	830	841	588	745	797	816	891	878	788	850
11	824	776	792	621	585	443	794	1005	791	837	801	736	726	1029	1007	877	905	887	757	890	895	922	876	889	910	716	811	795	856	929	888	825	883
12	799	801	814	650	603	459	831	995	821	920	853	789	743	1053	1025	827	812	798	718	921	885	926	783	811	819	754	785	763	794	827	833	813	866
13	837	830	811	736	639	537	837	1002	823	871	895	796	775	1044	1031	772	770	745	732	873	827	836	786	766	816	737	748	820	800	772	782	808	855
14	837	838	817	738	641	520	849	998	824	872	861	799	803	1039	1035	772	767	748	739	872	778	779	808	775	813	741	750	765	776	771	792	804	849
15	835	838	826	736	628	553	844	992	824	876	898	799	797	1027	1033	774	769	748	727	897	773	[redacted]	811	783	818	750	750	769	774	778	785	806	850
16	835	843	886	738	617	554	848	984	815	869	865	810	804	980	988	779	782	748	733	852	776	780	746	784	817	748	693	772	771	775	785	799	845
17	840	859	835	743	618	549	846	959	811	896	856	812	807	985	960	775	777	745	735	854	781	777	746	768	818	749	695	776	771	783	783	797	842
18	834	851	856	744	648	552	844	926	813	896	904	814	849	977	914	772	771	744	750	854	779	781	745	760	816	755	687	777	773	794	789	799	843
19	920	855	940	826	740	514	931	1015	895	955	839	772	846	1067	996	772	825	742	835	782	721	782	799	761	817	799	679	772	765	770	832	825	877
20	803	727	869	762	763	645	920	1024	895	1005	897	767	925	1114	996	853	873	690	864	782	704	767	886	842	901	787	675	867	883	888	942	849	901
21	835	793	846	696	759	576	870	939	815	963	856	715	970	1083	916	888	857	763	887	934	830	912	865	895	904	756	827	923	887	945	940	860	906
22	753	749	752	694	635	494	800	889	779	942	845	691	922	999	858	816	818	824	769	958	822	831	808	759	838	721	751	877	770	819	858	801	841
23	471	569	587	565	440	416	439	664	578	732	702	625	903	890	751	699	692	715	631	875	633	686	679	693	728	694	710	779	647	638	675	661	681
24	480	415	383	375	405	328	395	419	542	439	436	441	485	698	697	556	772	688	475	839	663	649	625	710	705	800	640	759	640	685	619	573	604
ave.	663	626	635	583	523	412	628	695	607	684	666	604	629	789	822	660	672	609	599	699	659	658	647	664	664	595	627	659	640	681	679	644	681

Net LTF 6x16



July 2003 LTF Net 6x16
Mw
0
100
200
300
400
500
600
700
800
900
1000
1
3
5
7
9
11
13
15
17
19
21
23

Net LTF
Observations

- PacifiCorp was a net exporter of LTF during every hour of July 2003.
- Net LTF transactions add another 10% (8-900 Mw) to the 6x16 System load.
- On average, LTF is more "peaky" than retail load—requiring more HLH input than that required for Retail alone.

Retail plus LTF less Generation (Mw)

July 2003 Retail plus LTF less Generation

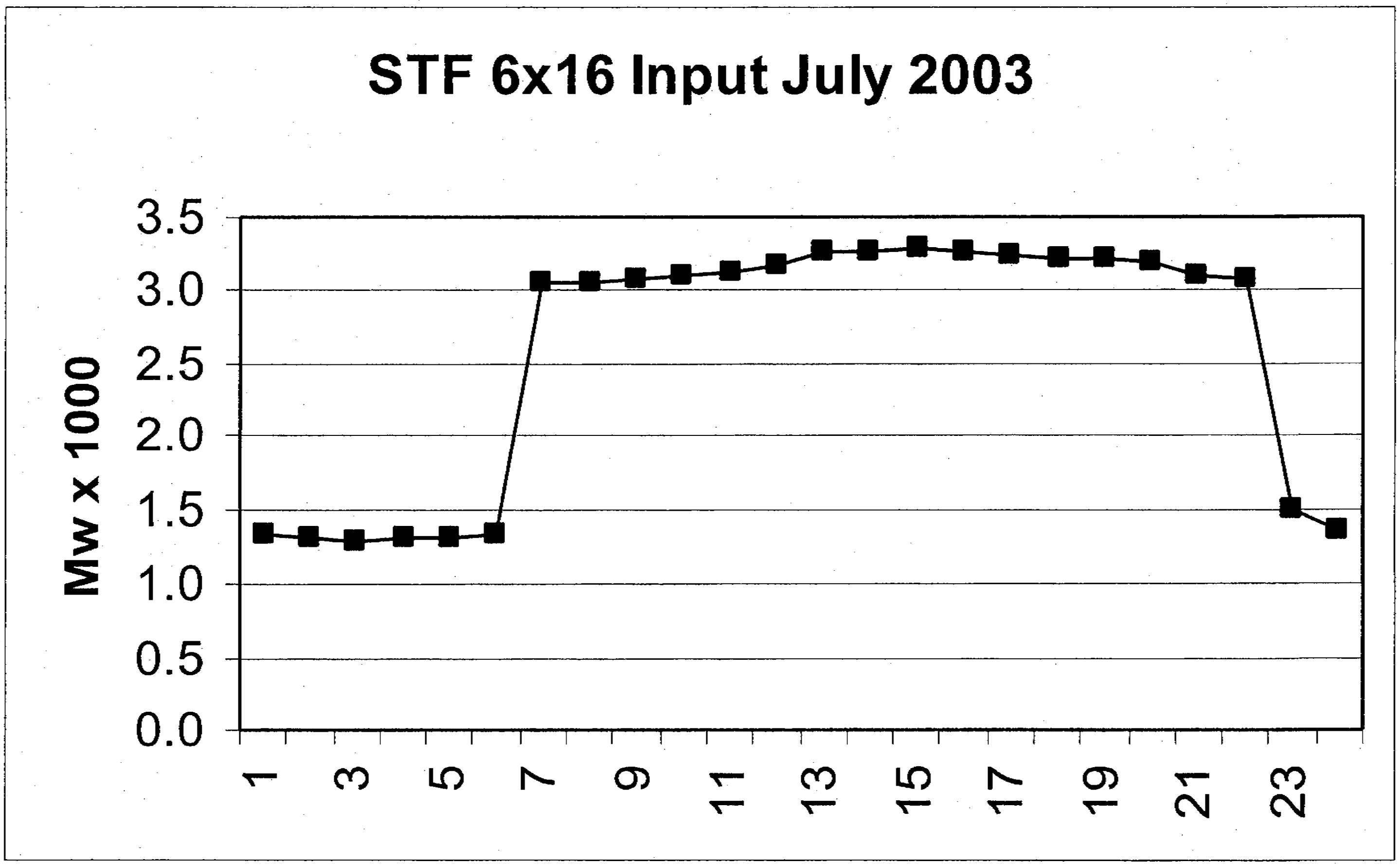
	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		
	7/1	7/2	7/3	7/4	7/5	7/6	7/7	7/8	7/9	7/10	7/11	7/12	7/13	7/14	7/15	7/16	7/17	7/18	7/19	7/20	7/21	7/22	7/23	7/24	7/25	7/26	7/27	7/28	7/29	7/30	7/31	Ave.	6x16
1	173	119	392	337	1	249	337	374	378	538	861	843	419	144	638	689	967	742	426	456	228	688	1042	1096	894	887	1280	350	1043	892	977	586	617
2	44	116	190	153	115	98	268	246	91	164	476	594	297	417	203	353	476	368	40	399	208	182	737	645	334	720	992	129	545	498	580	300	294
3	153	365	107	119	101	80	228	140	63	72	254	476	243	356	3	221	267	121	119	148	169	107	602	476	333	562	836	166	291	516	318	183	176
4	231	282	110	164	41	242	162	69	51	53	155	393	38	335	106	166	174	36	283	88	48	201	591	436	344	505	849	232	163	469	218	140	141
5	267	39	160	74	176	162	213	72	83	131	256	303	144	259	67	436	365	34	250	39	221	97	590	510	421	545	809	300	467	488	377	192	220
6	109	285	454	97	316	128	489	360	331	413	479	493	21	37	373	866	579	271	3	94	637	303	933	961	630	810	873	612	1010	903	944	448	532
7	772	908	1007	195	654	47	1224	861	890	960	1146	1030	358	767	960	1617	1205	884	821	132	1344	1024	1554	1391	1112	1139	790	1109	1675	1376	1744	990	1167
8	1222	1501	1559	429	412	98	1593	1344	1164	1591	1636	994	413	1510	1895	2027	1821	1481	829	239	1745	1543	2094	1918	1452	1249	855	1612	1768	1936	1969	1352	1595
9	1755	2148	2148	573	616	281	1822	1808	1649	1966	2304	1511	798	2103	2325	2328	2224	2078	1150	666	2124	2080	2662	2493	1933	1652	1328	2242	2129	2459	2546	1803	2090
10	1986	2346	2310	834	853	573	1966	2365	1995	2259	2763	1665	990	2257	2467	2549	2364	2339	1501	1010	2233	2347	3031	2814	2326	2027	1436	2510	2537	2785	2866	2074	2378
11	2113	2330	2358	980	1121	778	2301	2438	2178	2398	3098	1820	1326	2370	2630	2629	2607	2595	1815	1166	2657	2645	3262	2852	2570	2373	1416	2674	2787	3056	3056	2271	2589
12	2019	2247	2404	980	1240	947	2530	2579	2238	2622	3262	1951	1416	2390	2794	2666	2665	2678	1946	1308	2883	2874	3399	3014	2872	2512	1504	2876	3006	3171	3299	2397	2726
13	2043	2353	2485	1058	1408	1040	2656	2781	2388	2720	3518	2075	1569	2417	2830	2832	2858	2790	2105	1505	3004	3053	3563	3164	3073	2611	1703	3053	3145	3325	3427	2534	2867
14	1993	2428	2456	1164	1411	1176	2648	2884	2463	2819	3608	2152	1601	2565	2858	2851	2977	2869	2180	1544	3218	3193	3637	3259	3201	2678	1866	3195	3213	3336	3481	2610	2943
15	2037	2444	2440	1169	1428	1337	2714	2854	2583	3008	3802	2192	1534	2619	2929	2954	3008	2856	2244	1689	3278	[redacted]	3638	3269	3363	2776	1909	3459	3254	3370	3529	2679	3017
16	2031	2397	2350	1165	1568	1474	2824	2679	2698	3027	3724	2272	1554	2515	2938	2959	3021	2857	2328	1720	3211	3344	3676	3315	3278	2863	1878	3672	3282	3365	3436	2691	3025
17	2030	2379	2272	1125	1606	1437	2684	2600	2719	3107	3604	2335	1652	2564	2889	3006	3003	2709	2351	1803	3199	3302	3656	3100	3196	2885	1986	3617	3226	3334	3459	2672	2993
18	1925	2332	2155	1085	1511	1467	2583	2463	2656	3006	3534	2232	1718	2575	2754	2821	2841	2596	2317	1859	3102	3187	3528	2916	3018	3023	2062	3515	3128	3190	3183	2590	2884
19	1891	2206	2041	1032	1382	1476	2375	2383	2604	2893	3122	1972	1672	2347	2616	2663	2695	2561	2206	1745	2876	3022	3362	2802	2744	2958	2021	3411	3153	3078	3041	2463	2736
20	1701	2110	2006	830	1265	1497	2199	2215	2428	2779	2912	1771	1426	2294	2428	2514	2494	2344	2122	1666	2729	2841	3231	2562	2596	2789	1948	3187	3114	2895	2771	2312	2572
21	1715	2013	2014	788	1339	1421	2071	1932	2275	2612	2660	1624	1373	2235	2352	2458	2379	2147	1925	1738	2614	2751	3062	2360	2390	2591	1887	3056	2943	2823	2550	2197	2436
22	1565	1898	1809	857	1258	1202	1713	1731	2048	2334	2447	1372	1230	1950	2089	2174	2147	1925	1718	1582	2396	2386	2632	2016	2008	2227	1594	2647	2440	2430	2206	1936	2143
23	863	1330	1142	548	808	857	937	1194	1304	1710	1705	966	822	1392	1491	1461	1501	1241	1366	1227	1534	1757	1885	1503	1423	1798	1191	1891	1701	1805	1539	1351	1490
24	492	754	553	176	481	461	561	653	942	1078	1113	577	333	770	1181	1071	1114	827	672	781	1117	1346	1368	1269	1156	1670	815	1552	1231	1396	1130	924	1043
ave.	1230	1489	1538	650	862	721	1629	1626	1592	1844	2185	1401	941	1504	1826	1930	1906	1720	1309	1017	1949	1985	2406	2089	1944	1910	1409	2128	2135	2204	2194	1654	1861

STF Purchase (MW x 1,000)

	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		
	7/1	7/2	7/3	7/4	7/5	7/6	7/7	7/8	7/9	7/10	7/11	7/12	7/13	7/14	7/15	7/16	7/17	7/18	7/19	7/20	7/21	7/22	7/23	7/24	7/25	7/26	7/27	7/28	7/29	7/30	7/31	Ave	6x16
1	1.2	1.0	1.1	1.1	1.1	1.1	1.1	1.0	1.0	1.2	1.1	1.1	1.8	1.8	1.2	1.4	1.2	1.1	1.1	1.3	1.3	1.2	1.2	1.6	1.7	1.6	1.6	1.5	1.4	1.4	1.5	1.3	1.3
2	1.2	1.0	1.0	1.1	1.1	1.1	1.1	1.0	1.0	1.2	1.1	1.1	1.8	1.8	1.2	1.3	1.2	1.1	1.1	1.3	1.3	1.1	1.2	1.6	1.6	1.6	1.5	1.5	1.2	1.4	1.4	1.3	1.3
3	1.2	1.0	1.0	1.1	1.1	1.1	1.1	1.0	1.0	1.2	1.1	1.1	1.8	1.8	1.1	1.2	1.2	1.1	1.1	1.3	1.3	1.1	1.2	1.6	1.6	1.6	1.5	1.5	1.2	1.4	1.4	1.3	1.3
4	1.2	1.0	1.0	1.1	1.1	1.1	1.2	1.0	1.0	1.2	1.1	1.1	1.8	1.8	1.1	1.2	1.2	1.1	1.1	1.4	1.3	1.1	1.3	1.6	1.6	1.6	1.5	1.5	1.2	1.4	1.4	1.3	1.3
5	1.2	1.0	1.0	1.1	1.1	1.2	1.1	1.0	1.0	1.2	1.1	1.1	1.8	1.8	1.1	1.2	1.2	1.1	1.1	1.4	1.3	1.1	1.2	1.6	1.6	1.6	1.5	1.5	1.2	1.4	1.4	1.3	1.3
6	1.2	1.0	1.1	1.2	1.2	1.3	1.1	1.0	1.0	1.2	1.1	1.1	1.8	1.8	1.3	1.2	1.2	1.1	1.4	1.4	1.3	1.1	1.3	1.6	1.6	1.6	1.6	1.6	1.2	1.4	1.4	1.3	1.3
7	2.3	2.6	2.6	1.8	2.4	1.8	2.8	2.9	3.1	3.0	2.7	2.7	2.7	2.8	2.8	3.2	2.9	2.7	2.7	2.3	2.9	2.9	3.0	3.1	3.3	3.3	2.2	3.4	3.6	3.2	3.4	2.8	3.1
8	2.3	2.6	2.6	1.8	2.4	1.8	2.9	2.9	3.1	3.0	2.7	2.7	2.7	2.8	2.8	3.2	2.9	2.8	2.7	2.1	3.0	2.9	3.0	3.1	3.3	3.3	2.2	3.4	3.6	3.2	3.3	2.8	3.1
9	2.3	2.6	2.6	1.8	2.4	1.8	2.8	2.9	3.1	3.0	2.7	2.7	2.7	2.8	3.0	3.2	2.9	2.7	2.7	2.1	2.9	2.9	3.0	3.3	3.3	3.3	2.2	3.4	3.6	3.2	3.3	2.8	3.1
10	2.3	2.6	2.6	1.8	2.4	1.8	2.8	2.9	3.1	3.0	3.0	2.7	2.8	2.8	3.2	3.2	2.9	2.7	2.8	2.1	2.9	2.9	3.0	3.3	3.5	3.3	2.2	3.5	3.6	3.2	3.4	2.8	3.1
11	2.3	2.6	2.6	1.8	2.4	1.8	3.0	3.1	3.1	3.0	3.4	2.7	2.8	2.8	3.4	3.2	2.9	2.7	2.7	2.2	3.0	2.9	3.0	3.1	3.3	3.3	2.2	3.4	3.6	3.2	3.3	2.9	3.1
12	2.3	2.6	2.7	1.8	2.4	1.8	2.9	3.1	3.1	3.1	3.7	2.7	2.8	2.9	3.6	3.2	2.9	2.7	2.7	2.2	3.0	2.9	3.0	3.2	3.3	3.5	2.2	3.5	3.6	3.2	3.7	2.9	3.2
13	2.4	2.8	2.8	1.8	2.5	1.9	3.0	3.2	3.3	3.1	3.8	2.9	2.8	3.2	3.3	3.3	2.9	3.0	2.8	2.3	3.0	3.0	3.1	3.3	3.5	3.4	2.6	3.5	3.6	3.2	3.6	3.0	3.3
14	2.4	2.8	2.8	1.9	2.5	2.0	3.1	3.0	3.3	3.1	3.6	2.9	2.8	3.1	3.3	3.3	2.9	2.8	2.8	2.3	3.0	3.0	3.1	3.4	3.5	3.5	2.6	3.6	3.6	3.3	3.6	3.0	3.3
15	2.4	2.8	2.8	1.9	2.5	1.9	3.1	3.0	3.3	3.2	3.5	2.9	2.8	3.2	3.5	3.3	2.9	2.8	2.8	2.4	3.0	[redacted]	3.1	3.3	3.7	3.5	2.6	3.7	3.8	3.4	3.6	3.0	3.3
16	2.4	2.8	2.8	1.9	2.5	1.9	3.2	3.0	3.3	3.2	3.3	2.9	2.8	3.2	3.2	3.3	2.9	2.9	2.8	2.4	3.1	3.0	3.1	3.3	3.7	3.4	2.6	3.5	3.7	3.4	3.7	3.0	3.3
17	2.4	2.8	2.8	1.9	2.5	1.9	3.1	3.0	3.3	3.2	3.2	2.9	2.8	3.0	3.2	3.3	2.9	2.9	2.8	2.7	3.0	3.0	3.2	3.3	3.6	3.4	2.6	3.5	3.7	3.3	3.7	3.0	3.2
18	2.4	2.8	2.8	1.9	2.5	1.9	3.3	3.0	3.3	3.2	3.2	2.9	2.8	2.9	3.1	3.3	2.9	2.9	2.8	2.7	3.0	3.0	3.1	3.3	3.5	3.5	2.6	3.5	3.6	3.3	3.6	3.0	3.2
19	2.4	2.8	2.8	1.8	2.4	1.9	3.0	3.0	3.3	3.2	3.1	2.9	2.8	2.9	3.2	3.3	2.9	2.9	2.8	2.6	3.0	3.0	3.1	3.3	3.4	3.4	2.6	3.5	3.6	3.3	3.6	3.0	3.2
20	2.3	2.8	2.8	1.8	2.4	1.8	2.9	3.0	3.3	3.2	3.1	2.9	2.8	3.1	2.9	3.3	2.9	2.8	2.8	2.5	3.0	3.0	3.1	3.2	3.3	3.3	2.6	3.5	3.6	3.4	3.3	2.9	3.2
21	2.3	2.7	2.7	1.8	2.4	1.8	2.8	2.9	3.1	3.1	3.0	2.7	2.8	2.9	2.9	3.3	2.9	2.7	2.7	2.3	3.2	3.2	3.0	3.1	3.3	3.3	2.5	3.6	3.6	3.2	3.3	2.9	3.1
22	2.3	2.6	2.7	1.8	2.4	1.8	2.8	2.9	3.1	3.0	2.8	2.7	2.8	2.9	2.8	3.3	3.0	2.7	2.8	2.1	2.9	3.0	3.0	3.1	3.3	3.3	2.2	3.6	3.6	3.2	3.3	2.8	3.1
23	1.2	1.1	1.0	1.2	1.2	1.1	1.2	1.0	1.5	1.3	1.5	1.2	1.8	1.9	1.2	1.3	1.3	1.3	1.4	1.3	1.5	1.5	1.7	1.8	1.8	1.8	1.6	1.7	1.3	1.7	1.8	1.4	1.5
24	1.2	1.1	1.0	1.1	1.2	1.1	1.2	1.0	1.1	1.2	1.1	1.1	1.8	1.8	1.2	1.2	1.2	1.2	1.2	1.3	1.4	1.3	1.4	1.6	1.6	1.7	1.5	1.5	1.2	1.6	1.5	1.3	1.3
Ave	2.0	2.2	2.2	1.6	2.0	1.6	2.4	2.3	2.5	2.5	2.5	2.2	2.5	2.6	2.5	2.6	2.3	2.3	2.2	2.0	2.4	2.4	2.5	2.7	2.8	2.8	2.1	2.9	2.8	2.7	2.8	2.4	2.6

Table title: July 2003 STF Input

STF Purchases 6x16



STF Purchases 6x16
Observations

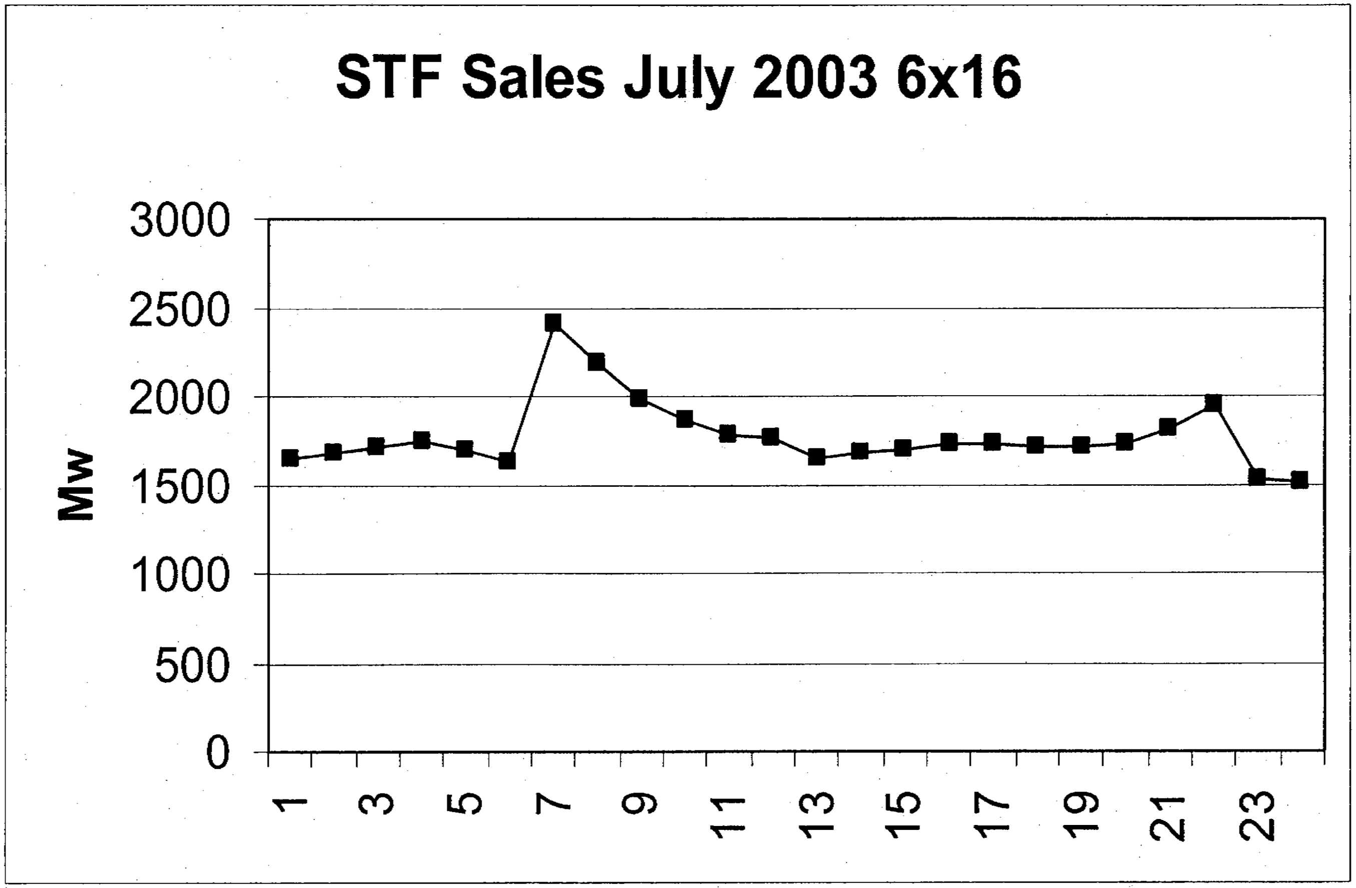
- STF Purchases are 2.5 times greater during HLH than LLH with a well defined line of demarcation.
- STF Purchases are significant in size with the HLH purchases being 40% of the Retail load and 45% of system generation.
- STF Purchases are 25% of Retail load during LLH and 22% of system generation.
- PacifiCorp has more generation than Retail load during LLH, but it purchases 1,300 Mw's of STF.

STF Sales (MW x 1,000)
(Red values leaving the system)

July 2003 STF Output

	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		
	7/1	7/2	7/3	7/4	7/5	7/6	7/7	7/8	7/9	7/10	7/11	7/12	7/13	7/14	7/15	7/16	7/17	7/18	7/19	7/20	7/21	7/22	7/23	7/24	7/25	7/26	7/27	7/28	7/29	7/30	7/31	Ave	6x16
1	1.7	2.1	2.0	1.8	1.6	1.4	1.4	1.4	1.7	1.4	1.4	1.7	2.3	2.8	1.8	1.3	1.3	1.3	1.6	1.6	1.3	1.4	1.3	1.4	1.7	1.6	1.2	1.5	1.4	1.5	1.6	1.6	1.6
2	1.9	2.2	1.6	1.8	1.6	1.5	1.4	1.4	1.7	1.4	1.5	1.6	2.0	2.7	1.8	1.6	1.4	1.4	1.6	1.6	1.3	1.4	1.3	1.7	1.9	1.6	1.2	1.7	1.3	1.5	1.5	1.6	1.7
3	1.9	2.0	1.8	1.7	1.7	1.5	1.4	1.6	1.8	1.5	1.6	1.5	2.2	2.7	1.6	1.6	1.5	1.3	1.6	1.7	1.5	1.4	1.4	1.7	2.0	1.8	1.2	1.7	1.2	1.6	1.4	1.6	1.7
4	1.7	2.0	1.6	1.7	1.7	1.6	1.4	1.5	1.8	1.5	1.7	1.6	2.4	2.7	1.5	1.6	1.6	1.5	1.8	1.7	1.7	1.4	1.5	1.8	2.0	1.8	1.2	1.7	1.2	1.5	1.5	1.7	1.7
5	1.8	1.9	1.6	1.7	1.7	1.6	1.3	1.5	1.8	1.4	1.6	1.4	2.3	2.6	1.6	1.5	1.5	1.6	1.8	1.7	1.7	1.5	1.3	1.8	2.0	1.8	1.2	1.6	1.2	1.6	1.5	1.6	1.7
6	1.8	1.9	1.7	1.7	1.5	1.6	1.2	1.4	1.8	1.5	1.5	1.4	2.3	2.7	1.6	1.4	1.5	1.6	1.8	2.1	1.4	1.3	1.3	1.5	1.6	1.7	1.2	1.7	1.2	1.5	1.4	1.6	1.6
7	2.0	2.4	2.1	1.8	2.2	1.8	1.9	2.5	2.5	2.3	2.1	2.9	2.6	2.8	2.1	2.2	2.2	2.1	2.2	2.2	1.9	2.3	2.2	2.7	2.9	2.6	1.4	2.6	2.2	2.2	2.0	2.3	2.4
8	1.8	2.2	2.1	1.8	2.2	1.9	2.2	2.1	2.2	2.3	2.3	2.2	2.4	2.1	1.9	1.8	2.4	1.8	2.3	2.3	1.7	2.2	1.8	1.9	2.5	2.6	1.4	2.4	2.3	1.7	2.0	2.1	2.2
9	1.5	1.9	1.9	2.1	2.3	2.0	1.9	1.8	2.1	2.1	1.8	1.7	2.0	1.8	1.9	1.9	2.0	1.9	2.0	2.1	1.6	2.1	2.0	1.8	1.9	2.2	1.4	1.8	2.2	1.6	2.0	1.9	2.0
10	1.5	1.9	1.9	1.9	2.2	2.1	2.0	1.8	2.0	1.8	1.8	1.7	2.0	1.8	1.8	1.9	1.8	2.0	2.0	1.9	1.5	1.8	1.4	1.6	1.9	1.7	1.4	1.5	2.0	1.6	1.9	1.8	1.9
11	1.5	2.0	1.6	1.9	2.2	1.8	1.8	1.6	1.8	1.7	1.7	1.7	1.9	1.7	1.8	1.8	1.5	1.8	1.8	1.6	1.5	1.6	1.4	1.6	1.8	1.6	1.4	1.6	1.8	1.6	1.9	1.7	1.8
12	1.6	1.8	1.6	1.8	2.4	1.7	1.8	1.5	1.8	1.8	1.7	1.7	1.7	1.8	1.8	1.9	1.4	1.8	1.5	1.6	1.4	1.4	1.4	1.6	1.8	1.6	1.4	1.6	1.9	1.5	1.9	1.7	1.8
13	1.6	1.8	1.7	1.9	2.4	1.7	1.6	1.4	1.6	1.7	1.6	1.6	1.7	1.7	1.6	1.7	1.4	1.5	1.3	1.9	1.3	1.4	1.3	1.4	1.6	1.5	1.5	1.4	1.8	1.3	1.7	1.6	1.6
14	1.7	1.8	1.8	1.9	2.4	1.7	1.6	1.5	1.8	1.7	1.5	1.7	1.7	1.7	1.7	2.0	1.4	1.4	1.3	1.7	1.3	1.4	1.3	1.4	1.6	1.5	1.5	1.5	2.0	1.4	1.7	1.6	1.7
15	1.7	1.8	2.0	1.9	2.4	1.6	1.6	1.5	1.8	1.6	1.5	1.7	1.7	1.8	1.7	2.0	1.5	1.2	1.3	1.6	1.4	[redacted]	1.3	1.4	1.6	1.5	1.5	1.5	2.0	1.4	1.7	1.6	1.7
16	1.9	1.9	1.9	1.8	2.5	1.7	1.6	1.7	2.0	1.6	1.5	1.7	1.9	1.7	1.8	2.0	1.6	1.3	1.3	1.6	1.3	1.4	1.3	1.4	1.6	1.5	1.5	1.6	1.9	1.5	1.7	1.7	1.7
17	1.9	1.8	2.1	1.8	2.5	1.7	1.6	1.7	2.0	1.6	1.5	1.7	1.8	1.7	1.7	2.0	1.6	1.2	1.2	1.6	1.3	1.4	1.3	1.4	1.5	1.5	1.6	1.6	2.0	1.5	1.8	1.7	1.7
18	1.9	1.8	1.9	2.0	2.4	1.6	1.7	1.6	2.0	1.6	1.5	1.8	1.8	1.6	1.7	2.0	1.7	1.4	1.2	1.7	1.3	1.4	1.3	1.4	1.5	1.5	1.5	1.8	1.8	1.4	1.7	1.7	1.7
19	1.8	1.9	1.8	2.0	2.2	1.6	1.7	1.4	2.0	1.6	1.6	1.8	1.7	1.7	1.7	1.9	2.0	1.4	1.3	1.7	1.4	1.4	1.3	1.6	1.5	1.5	1.5	1.7	1.7	1.6	1.7	1.7	1.7
20	1.9	2.1	1.7	1.6	2.1	1.6	1.6	1.5	2.1	1.6	1.6	1.9	1.9	1.7	1.7	1.9	2.0	1.4	1.2	1.5	1.4	1.3	1.4	1.7	1.7	1.5	1.5	1.5	1.7	1.5	1.7	1.7	1.7
21	1.8	1.9	1.9	1.5	2.1	1.6	1.7	1.6	2.1	1.6	1.8	2.0	2.1	1.7	1.8	1.9	2.0	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.7	1.6	1.4	1.6	2.0	1.5	1.8	1.7	1.8
22	1.9	1.9	2.1	1.5	2.0	1.7	1.9	1.9	2.2	1.7	1.9	2.1	2.0	1.8	1.9	1.9	2.1	1.6	1.9	1.5	1.5	1.9	1.5	1.8	1.9	1.8	1.5	1.8	2.2	1.5	2.0	1.8	1.9
23	2.2	1.5	1.6	1.4	1.9	1.6	1.5	1.5	1.7	1.3	1.4	1.9	1.6	1.7	1.4	1.3	1.3	1.4	1.5	1.3	1.2	1.2	1.3	1.4	1.3	1.3	1.2	1.2	1.2	1.5	1.4	1.5	1.5
24	2.0	1.8	1.9	1.7	1.8	1.6	1.5	1.4	1.6	1.3	1.4	1.6	1.9	1.6	1.4	1.3	1.3	1.3	1.4	1.2	1.3	1.2	1.3	1.5	1.3	1.3	1.2	1.2	1.2	1.5	1.4	1.5	1.5
Ave	1.8	1.9	1.8	1.8	2.1	1.7	1.6	1.6	1.9	1.6	1.7	1.8	2.0	2.0	1.7	1.8	1.7	1.5	1.6	1.7	1.4	1.5	1.4	1.6	1.8	1.7	1.4	1.7	1.7	1.5	1.7	1.7	1.8

STF Sales 6x16



STF Sales 6x16
Observations

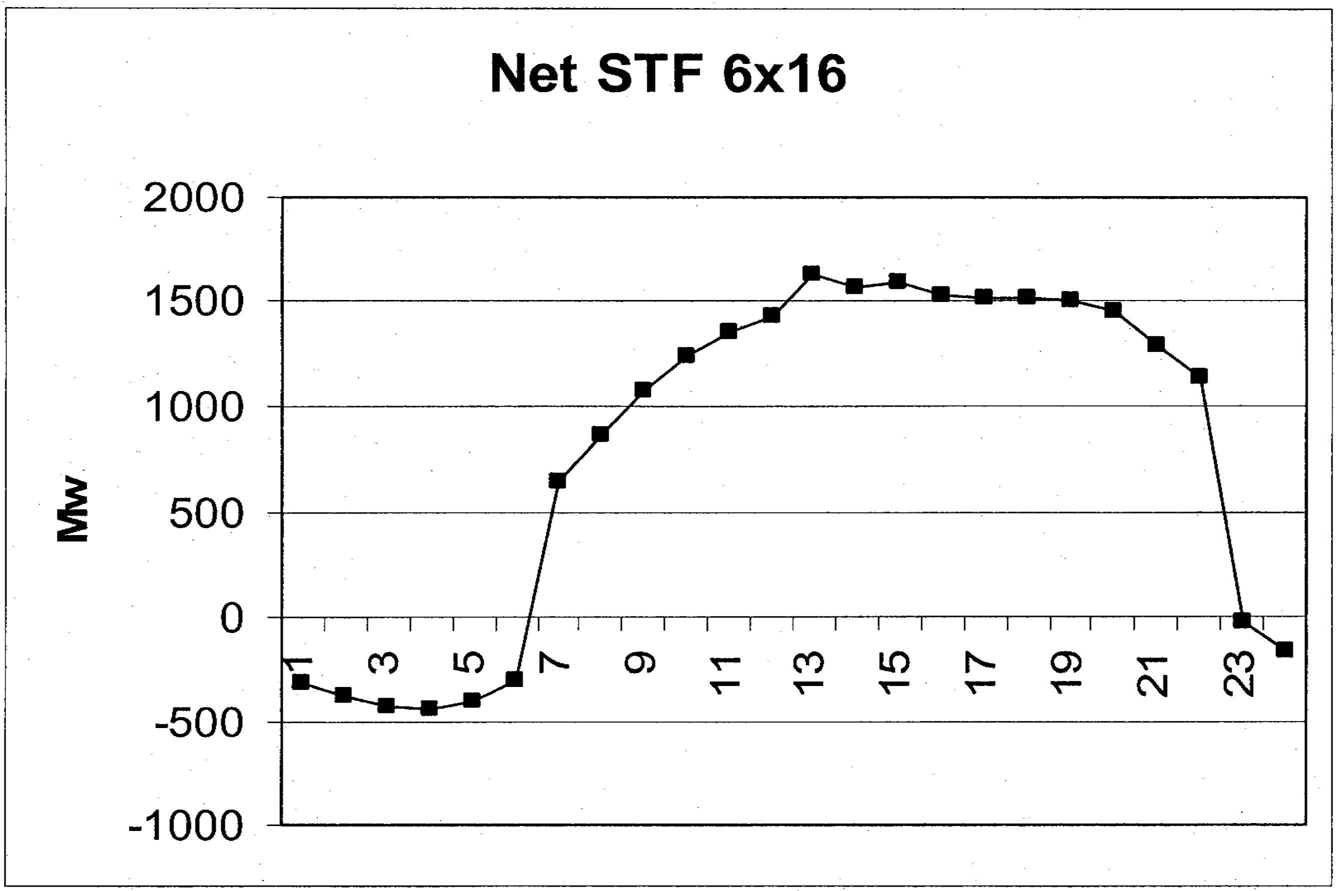
- STF Sales are relatively flat at 1,700 Mw.
- STF Sales increase by 700 Mw at the beginning of the HLH.
- The increase in STF Sales at 7:00 a.m. is only about 1/3rd of the difference between Retail load at peak and at 7:00 a.m. (2,200 Mw).

STF Net (MW x 1,000)
(Red values leave the system)

July 2003 STF Net

	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		
	7/1	7/2	7/3	7/4	7/5	7/6	7/7	7/8	7/9	7/10	7/11	7/12	7/13	7/14	7/15	7/16	7/17	7/18	7/19	7/20	7/21	7/22	7/23	7/24	7/25	7/26	7/27	7/28	7/29	7/30	7/31	Ave.	6x16
Temp	96	94	93	92	94	95	96	87	94	103	102	105	99	98	105	102	102	100	100	100	101	104	104	101	94	91	94	95	99	101	97	98	
1	0.5	1.1	0.9	0.7	0.5	0.3	0.2	0.4	0.6	0.2	0.3	0.6	0.6	1.0	0.5	0.1	0.1	0.2	0.5	0.3	0.1	0.2	0.1	0.2	0.0	0.0	0.4	0.0	0.1	0.1	0.1	0.3	0.3
2	0.8	1.2	0.6	0.6	0.5	0.4	0.3	0.4	0.7	0.2	0.4	0.6	0.2	1.0	0.6	0.3	0.2	0.2	0.4	0.3	0.0	0.2	0.1	0.1	0.3	0.0	0.4	0.2	0.1	0.1	0.1	0.3	0.4
3	0.7	1.0	0.9	0.6	0.6	0.4	0.2	0.6	0.8	0.3	0.5	0.5	0.4	0.9	0.5	0.4	0.3	0.2	0.5	0.4	0.2	0.2	0.2	0.2	0.4	0.2	0.4	0.1	0.0	0.2	0.0	0.4	0.4
4	0.6	1.0	0.7	0.6	0.6	0.5	0.2	0.5	0.8	0.3	0.6	0.5	0.6	0.9	0.4	0.4	0.4	0.4	0.7	0.3	0.4	0.2	0.2	0.3	0.4	0.2	0.4	0.1	0.0	0.1	0.1	0.4	0.4
5	0.6	0.9	0.7	0.5	0.5	0.4	0.2	0.5	0.8	0.2	0.5	0.4	0.6	0.8	0.5	0.3	0.3	0.5	0.7	0.3	0.4	0.4	0.1	0.2	0.3	0.2	0.4	0.0	0.0	0.1	0.1	0.4	0.4
6	0.6	0.9	0.6	0.5	0.3	0.3	0.0	0.4	0.8	0.3	0.4	0.3	0.6	1.0	0.3	0.2	0.3	0.4	0.5	0.7	0.1	0.1	0.0	0.0	0.0	0.0	0.4	0.1	0.0	0.1	0.0	0.3	0.3
7	0.3	0.2	0.6	0.0	0.2	0.0	0.8	0.4	0.6	0.7	0.6	0.1	0.2	0.0	0.7	1.0	0.7	0.6	0.5	0.0	1.0	0.6	0.7	0.5	0.3	0.6	0.8	0.8	1.3	1.0	1.3	0.6	0.6
8	0.6	0.5	0.6	0.0	0.2	0.1	0.7	0.8	0.9	0.7	0.4	0.4	0.4	0.8	0.8	1.4	0.5	1.0	0.4	0.1	1.3	0.7	1.2	1.2	0.8	0.7	0.8	1.1	1.3	1.5	1.4	0.7	0.9
9	0.8	0.7	0.7	0.3	0.1	0.2	0.9	1.1	1.0	0.9	0.9	1.0	0.8	1.0	1.1	1.3	0.9	0.8	0.8	0.0	1.2	0.8	1.0	1.5	1.4	1.1	0.8	1.7	1.3	1.6	1.3	0.9	1.1
10	0.8	0.7	0.8	0.1	0.2	0.2	0.8	1.1	1.1	1.2	1.2	1.0	0.8	1.1	1.4	1.3	1.1	0.7	0.8	0.2	1.4	1.1	1.6	1.7	1.6	1.6	0.8	1.9	1.6	1.6	1.4	1.0	1.2
11	0.8	0.6	1.0	0.1	0.2	0.0	1.2	1.4	1.3	1.3	1.7	1.0	0.9	1.2	1.6	1.4	1.4	1.0	0.9	0.6	1.5	1.3	1.6	1.5	1.5	1.6	0.8	1.9	1.8	1.6	1.5	1.2	1.4
12	0.8	0.9	1.1	0.0	0.1	0.1	1.1	1.5	1.3	1.3	2.0	1.0	1.1	1.1	1.9	1.3	1.5	0.9	1.2	0.6	1.6	1.5	1.6	1.6	1.5	1.8	0.8	1.9	1.6	1.7	1.8	1.2	1.4
13	0.8	1.1	1.2	0.0	0.2	0.2	1.4	1.7	1.6	1.4	2.2	1.3	1.1	1.5	1.7	1.5	1.6	1.4	1.5	0.4	1.7	1.6	1.8	1.9	2.0	1.9	1.1	2.1	1.8	1.9	1.9	1.4	1.6
14	0.7	1.0	1.1	0.1	0.1	0.3	1.4	1.5	1.4	1.4	2.1	1.2	1.1	1.5	1.5	1.3	1.5	1.4	1.5	0.7	1.7	1.6	1.8	2.0	2.0	2.0	1.1	2.0	1.6	1.9	2.0	1.4	1.6
15	0.7	1.0	0.9	0.1	0.1	0.3	1.4	1.5	1.4	1.6	2.0	1.2	1.1	1.4	1.8	1.3	1.4	1.6	1.5	0.8	1.7	[redacted]	1.8	1.9	2.1	2.0	1.1	2.2	1.7	2.0	1.9	1.4	1.6
16	0.5	1.0	0.9	0.0	0.0	0.3	1.6	1.4	1.3	1.6	1.7	1.2	1.0	1.5	1.4	1.3	1.3	1.7	1.5	0.8	1.8	1.6	1.8	1.8	2.1	1.9	1.1	1.9	1.7	1.9	2.0	1.3	1.5
17	0.5	1.0	0.8	0.1	0.0	0.2	1.5	1.4	1.2	1.6	1.7	1.2	1.0	1.3	1.5	1.3	1.3	1.7	1.6	1.1	1.7	1.6	1.9	1.8	2.1	1.9	1.0	1.9	1.7	1.8	1.9	1.3	1.5
18	0.5	1.1	1.0	0.1	0.1	0.3	1.6	1.4	1.2	1.6	1.6	1.1	1.0	1.3	1.4	1.3	1.3	1.5	1.6	1.0	1.7	1.6	1.8	1.8	2.0	2.1	1.1	1.7	1.8	1.9	1.9	1.3	1.5
19	0.6	1.0	1.1	0.2	0.2	0.3	1.4	1.6	1.3	1.6	1.6	1.2	1.1	1.2	1.5	1.4	0.9	1.5	1.5	0.9	1.6	1.6	1.8	1.7	1.9	1.9	1.1	1.8	1.9	1.8	1.9	1.3	1.5
20	0.4	0.7	1.1	0.2	0.3	0.2	1.3	1.5	1.2	1.6	1.5	1.0	0.9	1.4	1.3	1.4	1.0	1.4	1.6	0.9	1.5	1.7	1.7	1.5	1.6	1.9	1.1	2.0	1.9	1.9	1.7	1.3	1.5
21	0.5	0.7	0.8	0.3	0.3	0.2	1.1	1.3	1.0	1.5	1.2	0.7	0.7	1.2	1.1	1.3	0.9	1.2	1.2	0.7	1.6	1.7	1.6	1.5	1.6	1.7	1.1	2.0	1.6	1.7	1.5	1.1	1.3
22	0.4	0.8	0.5	0.3	0.4	0.1	0.9	1.0	0.9	1.3	1.0	0.6	0.8	1.1	1.0	1.3	1.0	1.1	0.9	0.6	1.4	1.1	1.5	1.3	1.3	1.5	0.7	1.8	1.4	1.7	1.3	1.0	1.1
23	1.1	0.4	0.7	0.3	0.8	0.4	0.2	0.5	0.2	0.1	0.1	0.7	0.2	0.2	0.1	0.0	0.0	0.1	0.0	0.0	0.3	0.2	0.4	0.4	0.5	0.4	0.4	0.5	0.2	0.2	0.4	0.0	0.0
24	0.9	0.7	0.9	0.5	0.6	0.5	0.2	0.4	0.5	0.0	0.4	0.5	0.1	0.2	0.2	0.0	0.1	0.2	0.3	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.4	0.4	0.0	0.1	0.1	0.2	0.2
ave.	0.2	0.2	0.3	0.2	0.1	0.1	0.7	0.7	0.6	0.8	0.8	0.5	0.5	0.6	0.8	0.8	0.7	0.7	0.7	0.3	1.0	0.9	1.0	1.0	1.1	1.1	0.8	1.2	1.1	1.1	1.1	0.7	0.8
	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		

STF Net (MW)



Net STF 6x16
Mw
2000
1500
1000
500
0
-500
-1000
1
3
5
7
9
11
13
15
17
19
21
23

STF Net
Observations

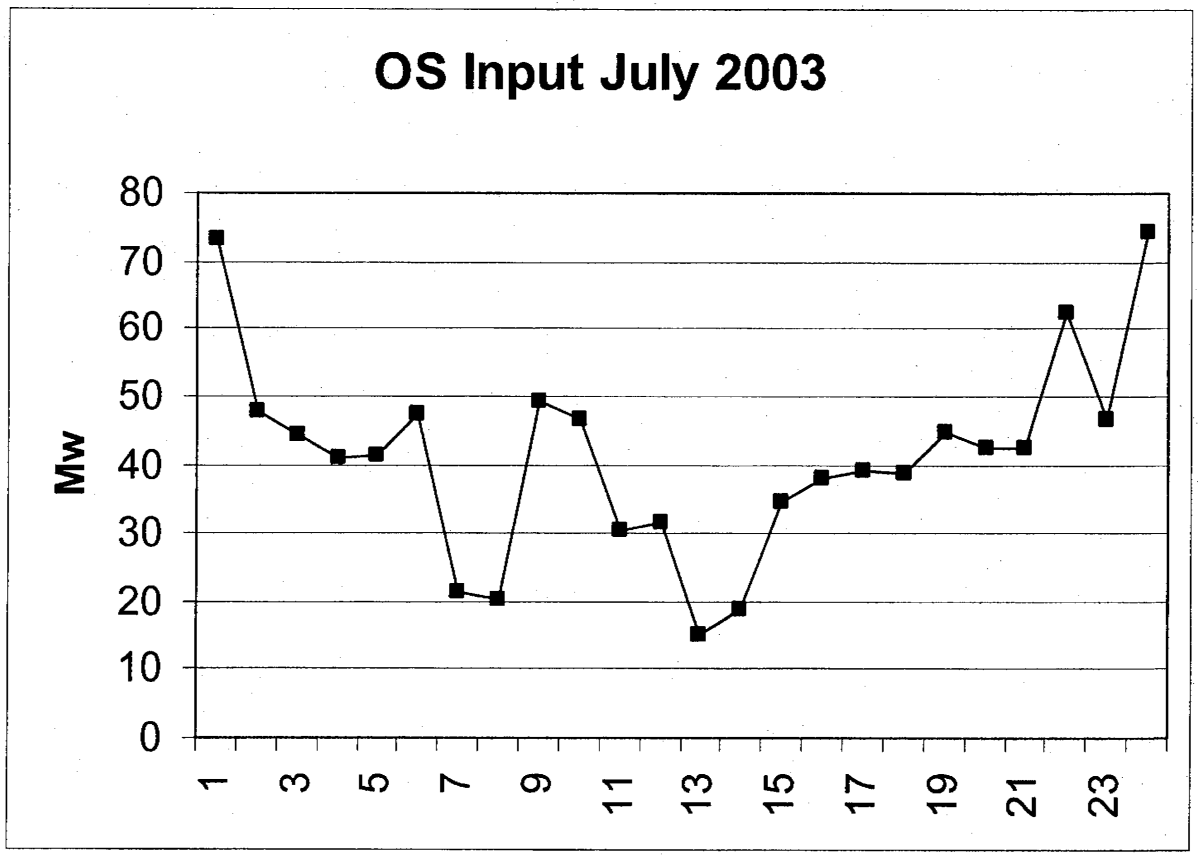
- Net STF is negative during LLH and somewhat shaped during HLH.
- Net STF is significant and follows the shape of the Retail plus LTF requirements. However, it is not of sufficient magnitude to fully make up the difference between Retail plus LTF requirements and Generation.

OS Purchases (Mw)

July 2003 OS Input (MW)

	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		
	7/1	7/2	7/3	7/4	7/5	7/6	7/7	7/8	7/9	7/10	7/11	7/12	7/13	7/14	7/15	7/16	7/17	7/18	7/19	7/20	7/21	7/22	7/23	7/24	7/25	7/26	7/27	7/28	7/29	7/30	7/31	Ave.	6x16
1	210	25	115							75	100	90	205	110	177	13			10	75		15	67	292	134	170	225			125	100	117	73
2		25	140								68	150	130	75	85					175		29	173	180		70				100	100	107	48
3			215							20		125	69		121					150		45	255	75		50				100	100	110	44
4			215									75	5		149					60			280	50		50				100	100	108	41
5			215										3		163								289	115		50				100	100	129	41
6			95												20								209	509	150					100	100	169	47
7																							50	247	142					100		135	22
8								28		50							15			60			161	50	30		75	100	65		10	59	20
9	75		100	150		100		100		75	50				100	100				80			165	190	100	100	299	75				116	49
10	50		100	100	160	100		100			109	40			100	75	80			45	22		55	150	50	70	320					96	46
11	20		50		100					36	50				100	84			25	100			25	65	50	140	360	20				82	31
12					140		63	100		15	105			65	100		20			60			15	60	50	60	140					71	32
13					75			100			45			50								30	20		50	10	135					57	15
14								50		20	115			50								17			140		160	30			50	70	19
15	12							50		20	320			50			40	25				[redacted]			165		40	35			140	75	35
16											295			100											165	100	30	36	110		140	122	38
17											240			75									50		140	100	35	135	100		140	113	39
18											240			100					65	50			50		75	150	25	165	110		12	95	39
19	50				50	50				95				100			45	20	150	50		46	85	10		143	60	180	130		15	75	45
20					28					96				50					75				80		134	270		20	185	121		106	42
21					23					47	54					25			100				180		151	244		20	100	117		96	42
22	50			39					130	100	67	60				50			130	125		27	135	104	140	290	45	35		244		104	62
23	50	30							45							78			25	100	39	112	120	100	109	145	25	45	60	175	30	76	47
24	75	90							75	100		150			25	75			75	75	112	78	220	255	92	193			40	200		114	74
ave.	66	43	138	96	82	83	63	75	83	58	133	99	82	75	104	63	40	23	73	86	58	41	128	153	109	127	132	69	100	132	81	87	41
	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		

OS Purchases (Mw) 6x16



OS Purchases

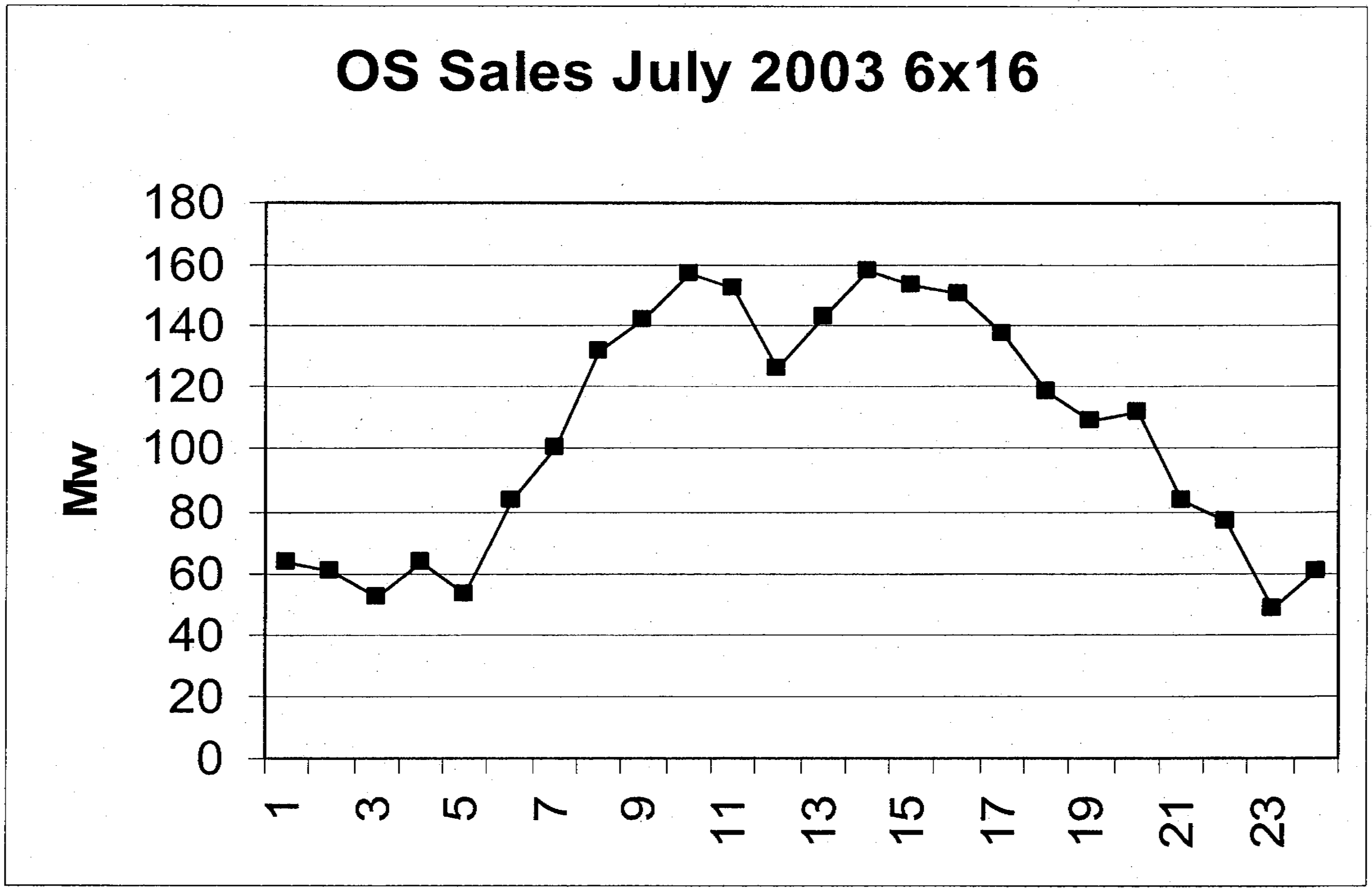
- OS purchases are random as would be expected.
- OS purchases are insignificant when compared to Retail load that is in the 6-8,000 Mw range.

OS Sales (Mw)
(Red values leave the system)

July 2003 OS Output (MW)

	T 7/1	W 7/2	Th 7/3	F 7/4	S 7/5	S 7/6	M 7/7	T 7/8	W 7/9	Th 7/10	F 7/11	S 7/12	S 7/13	M 7/14	T 7/15	W 7/16	Th 7/17	F 7/18	S 7/19	S 7/20	M 7/21	T 7/22	W 7/23	Th 7/24	F 7/25	S 7/26	S 7/27	M 7/28	T 7/29	W 7/30	Th 7/31	Ave.	6x16
1	200	30	25	187	338	80	75		75	95	95		230	200	60						100	15	15			38		225				116	63
2			25	230	290	80	80			50	10		255	250	150			10	50		75	30		110	60	50		200	75			109	61
3			35	185	155	228	50			125	40		200	200	100			62	75			50	140	60				50	75		75	106	52
4			30	100	65	313	50			100	90		235	175	200			110	150			50	140	40				75	235		75	124	63
5			25	130	65	265	75		10	25	40		160	175	100			45	150			125	140					116	165		75	105	53
6	75		25	165		250	75		40	135	10		85		150	118	242	185	150		100	125	140	150				181	100		75	123	83
7	125		100	45		295	125	125	155	200			85	175	170	138	125	210	225		154	113						160	125	75		146	100
8	250	140	100	70	295	175	175	125	315	175	40	175	210	150	135	223	100	90	175	25	250	60			60		75	75	75	30	75	137	132
9	100	120	110	55	75	90	270	105	475	275	35	175	210	275	165	55		75	100		259	80	50		185		75	75	150	170	165	147	142
10	30	195	179	385	25	180	345	139	510	300	10	275	210	180	10	80	430	85	125	35	207	95	50	20	70		75	119	246	107	110	161	158
11	50	215	220	530	210	160	377	74	420	336		245	225	357	15	35	415	85		75	180	70			20		75		241	175	85	196	153
12	140	125	239	455	195	170	332	110	415	210	15	70	218	211	20	40	248	30		200	210	90					75	50	291	120		171	126
13	175	125	289	295	160	319	225	90	446	320	15	65	200	220	20	75	206	114	150	177	264	76			50		75	50	150	252	30	165	143
14	175	80	335	367	125	407	303	95	436	175	15	115	225	305	100	151	213	290	200	270	298						75	110	168	200	65	204	158
15	175	95	379	488	125	373	262	100	471	168	10	146	315	270	135	81	112	275	140	255	218	[redacted]					75	140	250	240	30	198	153
16	86	90	345	481	125	289	267	120	446	185	10	190	383	345	105	89	107	280	100	250	126	17	2					104	312	230	95	192	151
17	120	60	350	507	215	295	256	110	356	100		185	377	350	95	91	87	110	165	335	124	18		10		19		125	353	125		190	137
18	155	50	335	299	282	200	170	40	266	85		240	332	350	85	20		75	40	360	137	59				50	25	124	270	125		167	118
19	135	125	255	330	180	145	65	30	261	90		155	300	330	75			50	115	285	220	61		10		50	25	104	250	165		152	109
20	35	115	210	295	195	5	121	60	276	65		50	355	280	25	30	50	75	125	160	210	50		100		50	25	269	250	150		134	112
21	10	55	143	145	30	28	25	25	286	40	50	50	395	225	65	15	90		125	120	200	25			50	50	25	170	250	95		103	83
22			142	265	15	35	25	63	196	20	120	350	315	50	43		85		50	120	267				50	50	25	160	75	150		116	76
23			115	175		20		20	75	60		260	225	215	30	118				120	200	30	40							25	20	103	48
24	65	25	205	165	28	67	80	80	100	50	30	350	240	105						120	220	75	100				75					115	61
ave.	117	103	176	265	152	186	166	84	287	141	37	182	249	234	89	85	179	119	127	182	191	60	82	63	68	45	57	128	196	143	75	138	106
	7/1	7/2	7/3	7/4	7/5	7/6	7/7	7/8	7/9	7/10	7/11	7/12	7/13	7/14	7/15	7/16	7/17	7/18	7/19	7/20	7/21	7/22	7/23	7/24	7/25	7/26	7/27	7/28	7/29	7/30	7/31		

OS Sales (Mw) 6x16



OS Sales
Observations

- OS Sales (although larger than OS Purchases) are insignificant when compared to Retail load that is in the 6-8,000 Mw range.
- There is more OS sales during daylight hours than at night.

OS Net (MW x 1,000) 6x16

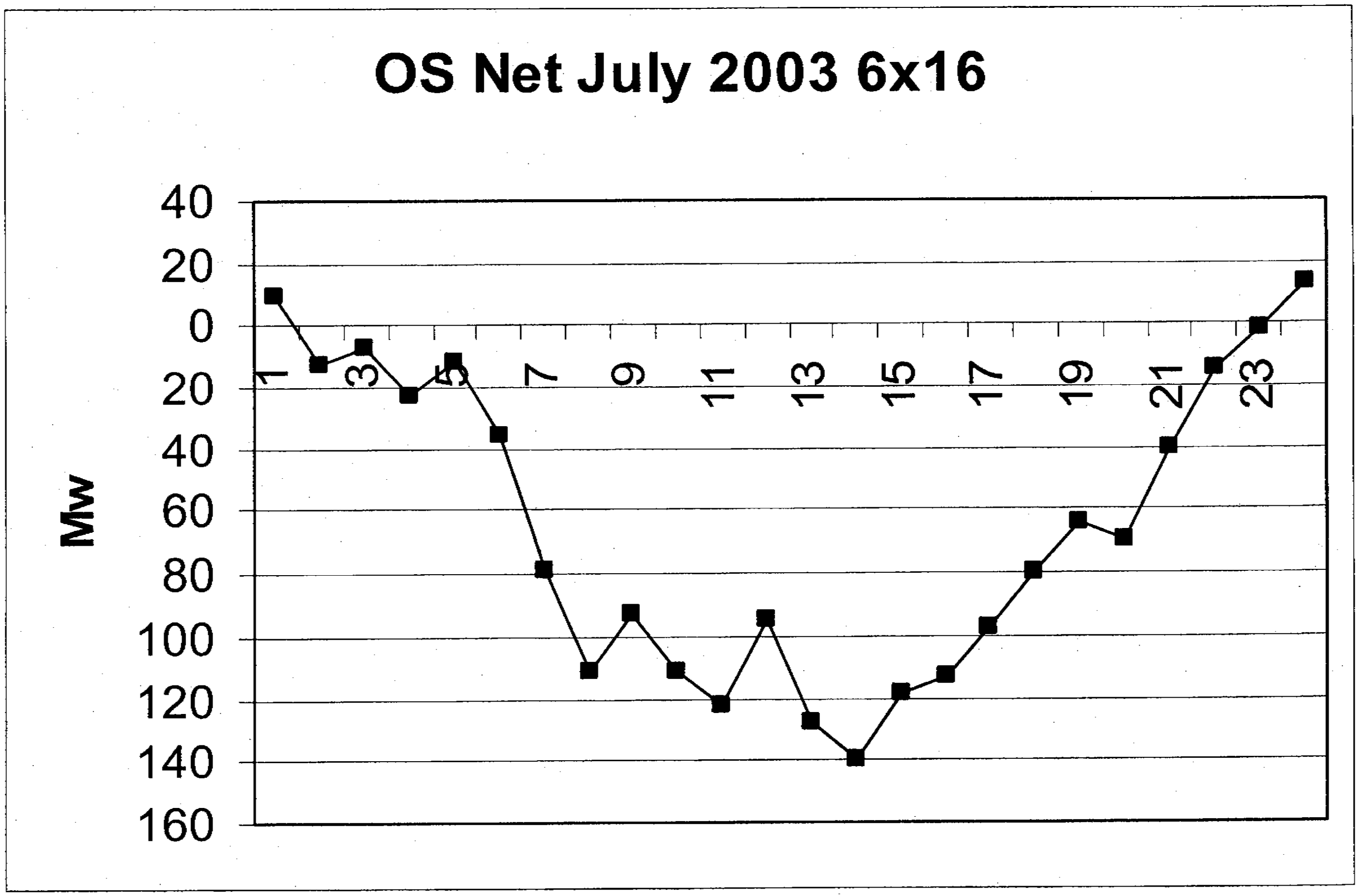
(Red values leave the system)

July 2003 OS Net (MW)

	T 7/1	W 7/2	Th 7/3	F 7/4	S 7/5	S 7/6	M 7/7	T 7/8	W 7/9	Th 7/10	F 7/11	S 7/12	S 7/13	M 7/14	T 7/15	W 7/16
1	10	5	90	187	338	80	75		75	20	5	90	25	90	117	13
2		25	115	230	290	80	80			50	58	150	125	175	65	
3			180	185	155	228	50			105	40	125	131	200	21	
4			185	100	65	313	50			100	90	75	230	175	51	
5			190	130	65	265	75		10	25	40		157	175	63	
6	75		70	165		250	75		40	135	10		85	0	130	118
7	125		100	45		295	125	125	155	200			85	175	170	138
8	250	140	100	70	295	175	175	97	315	125	40	175	210	150	135	223
9	25	120	10	95	75	10	270	5	475	200	15	175	210	275	65	45
10	20	195	79	285	135	80	345	39	510	300	99	235	210	180	90	5
11	30	215	170	530	110	160	377	74	420	300	50	245	225	357	85	49
12	140	125	239	455	55	170	269	10	415	195	90	70	218	146	80	40
13	175	125	289	295	85	319	225	10	446	320	30	65	200	170	20	75
14	175	80	335	367	125	407	303	45	436	155	100	115	225	255	100	151
15	163	95	379	488	125	373	262	50	471	148	310	146	315	220	135	81
16	86	90	345	481	125	289	267	120	446	185	285	190	383	245	105	89
17	120	60	350	507	215	295	256	110	356	100	240	185	377	275	95	91
18	155	50	335	299	282	200	170	40	266	85	240	240	332	250	85	20
19	85	125	255	330	130	95	65	30	261	5		155	300	230	75	
20	35	115	210	295	167	5	121	60	276	31		50	355	230	25	30
21	10	55	143	145	7	28	25	25	286	7	4	50	395	225	65	10
22	50		142	226	15	35	25	63	66	80	53	290	315	50	43	50
23	50	30	115	175		20		20	30	60		260	225	215	30	40
24	10	65	205	165	28	67	80	80	25	50	30	200	240	105	25	75
ave.	63	61	124	253	109	176	157	41	241	110	51	100	232	190	38	36
	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W

	Th 7/17	F 7/18	S 7/19	S 7/20	M 7/21	T 7/22	W 7/23	Th 7/24	F 7/25	S 7/26	S 7/27	M 7/28	T 7/29	W 7/30	Th 7/31	Ave.	6x16
1			10	75	100		52	292	134	132	225	225		125	100	8	10
2		10	50	175	75	1	173	70	60	20		200	75	100	100	19	13
3		62	75	150		5	115	15		50		50	75	100	25	19	7
4		110	150	60		50	140	10		50		75	235	100	25	37	23
5		45	150			125	149	115		50		116	165	100	25	27	12
6	242	185	150		100	125	69	359	150			181	100	100	25	45	36
7	125	210	225		154	113	50	247	142			160	125	25		77	78
8	85	90	175	35	250	60	161	50	30			25	10	30	65	103	111
9		75	100	80	259	80	115	190	85	100	224		150	170	165	68	93
10	350	85	125	10	185	95	5	130	20	70	245	119	246	107	110	100	111
11	415	85	25	25	180	70	25	65	30	140	285	20	241	175	85	118	122
12	228	30	0	140	210	90	15	60	50	60	65	50	291	120		106	95
13	206	114	150	177	264	46	20			10	60	50	150	252	30	133	127
14	213	290	200	270	298	17			140		85	80	168	200	15	151	139
15	72	250	140	255	218	[redacted]			165		35	105	250	240	110	143	119
16	107	280	100	250	126	17	2		165	100	30	68	202	230	45	136	113
17	87	110	165	335	124	18	50	10	140	81	35	10	253	125	140	127	98
18		75	25	310	137	59	50		75	100		41	160	125	12	101	80
19	45	30	35	235	220	15	85			93	35	76	120	165	15	82	64
20	50	75	50	160	210	50	80	100	134	220	25	249	65	29		83	69
21	90		25	120	200	25	180		101	194	25	150	150	22		56	41
22	85		80	5	267	27	135	104	90	240	20	125	75	94		29	14
23			25	20	161	82	80	100	109	145	25	45	60	150	10	15	2
24			75	45	108	3	120	255	92	193	75		40	200		8	14
ave.	96	92	73	71	160	38	78	81	63	85	49	74	134	36	7	74	64
	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		

OS Net July 2003 (net sales)



OS Net
Observations

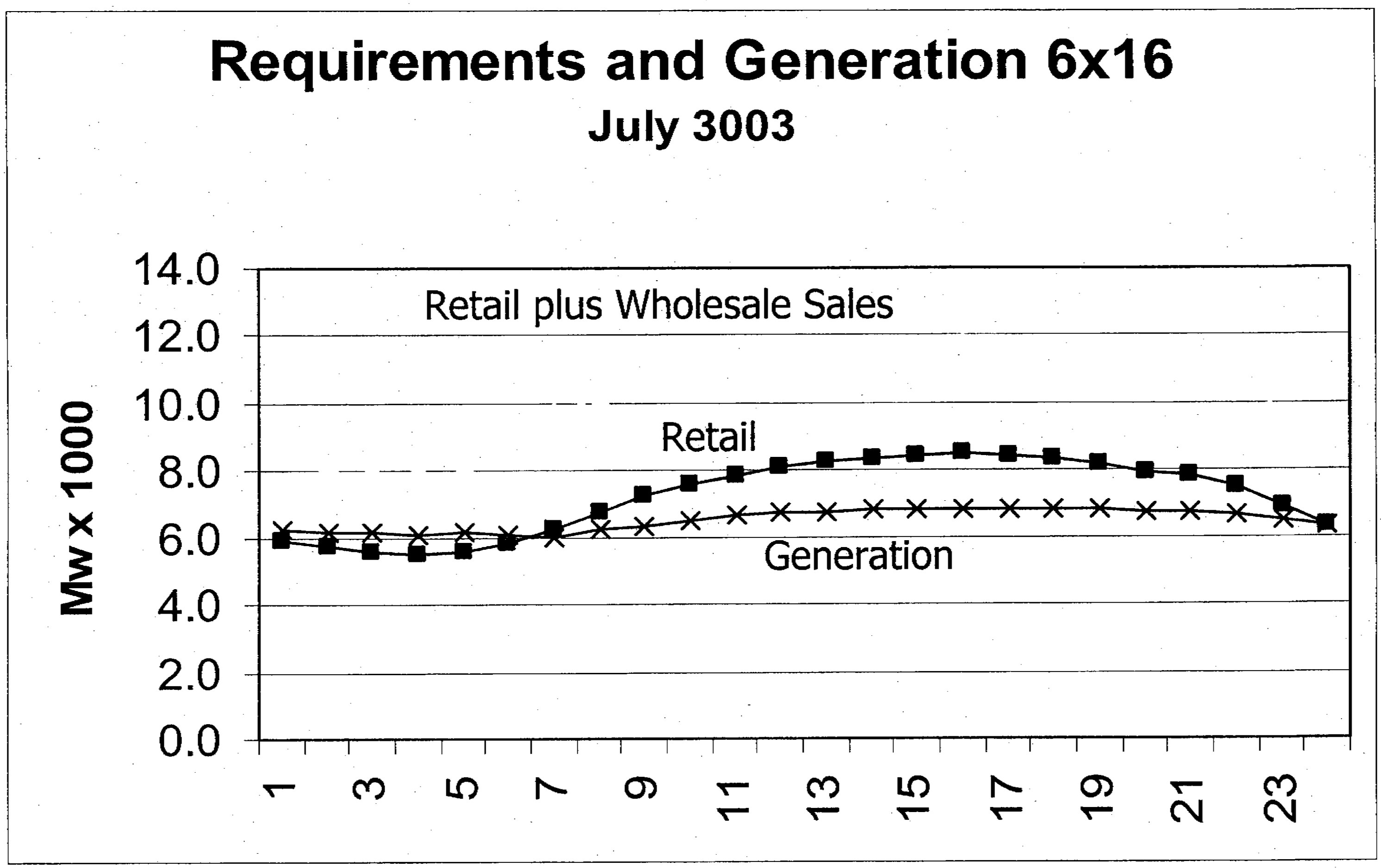
- Net OS activity is insignificant when compared to Retail load that is in the 6-8,000 Mw range.
- The Net OS activity results in increased sales during the peak hours.

Sum of LF, SF, and OS Sales
(Red means leaving the system)
(Mw x 1,000)

July 2003 Sum LF, SF, OS

	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		
	7/1	7/2	7/3	7/4	7/5	7/6	7/7	7/8	7/9	7/10	7/11	7/12	7/13	7/14	7/15	7/16	7/17	7/18	7/19	7/20	7/21	7/22	7/23	7/24	7/25	7/26	7/27	7/28	7/29	7/30	7/31	Ave.	6x16
Temp	96	94	93	92	94	95	96	87	94	103	102	105	99	98	105	102	102	100	100	100	101	104	104	101	94	91	94	95	99	101	97	98	
1	0.9	1.5	1.1	1.3	1.1	0.8	0.6	0.7	1.2	0.6	0.8	1.0	0.8	1.3	1.1	0.3	0.6	0.7	0.9	0.6	0.8	0.8	0.7	0.2	0.5	0.3	0.1	0.6	0.6	0.5	0.6	0.8	0.8
2	1.1	1.4	0.8	1.2	1.0	0.8	0.6	0.7	0.8	0.5	0.7	0.7	0.6	1.3	1.1	0.7	0.5	0.6	0.8	0.5	0.6	0.5	0.2	0.4	0.7	0.3	0.1	0.7	0.5	0.4	0.4	0.7	0.7
3	1.1	1.2	0.9	1.1	1.0	0.9	0.5	0.7	0.9	0.6	0.8	0.6	0.8	1.3	0.9	0.8	0.6	0.4	0.9	0.6	0.6	0.5	0.4	0.5	0.7	0.4	0.1	0.5	0.4	0.4	0.3	0.7	0.7
4	0.9	1.2	0.7	1.0	0.9	0.9	0.6	0.7	0.9	0.6	0.9	0.7	1.1	1.3	0.8	0.7	0.7	0.7	1.1	0.7	0.7	0.6	0.4	0.6	0.7	0.4	0.1	0.5	0.4	0.4	0.3	0.7	0.7
5	0.9	1.2	0.7	1.0	0.9	0.9	0.6	0.7	0.9	0.5	0.8	0.7	1.0	1.3	0.9	0.7	0.6	0.7	1.1	0.7	0.8	0.8	0.2	0.4	0.6	0.3	0.1	0.5	0.4	0.4	0.4	0.7	0.7
6	1.0	1.2	0.8	1.0	0.6	0.8	0.5	0.6	1.0	0.7	0.6	0.6	1.0	1.2	1.0	0.6	1.0	0.9	0.9	1.1	0.7	0.6	0.3	0.0	0.1	0.4	0.1	0.7	0.5	0.4	0.5	0.7	0.7
7	0.5	0.2	0.1	0.4	0.2	0.5	0.3	0.1	0.0	0.0	0.0	0.6	0.3	0.7	0.0	0.4	0.1	0.1	0.1	0.4	0.4	0.0	0.4	0.3	0.1	0.3	0.5	0.3	0.8	0.7	0.8	0.0	0.1
8	0.4	0.3	0.1	0.7	0.6	0.5	0.0	0.2	0.1	0.1	0.2	0.2	0.3	0.2	0.3	0.5	0.3	0.5	0.2	0.6	0.5	0.2	0.9	0.6	0.4	0.3	0.5	0.5	0.8	0.9	0.7	0.1	0.2
9	0.1	0.3	0.2	0.9	0.5	0.5	0.1	0.4	0.1	0.0	0.1	0.1	0.1	0.3	0.1	0.6	0.1	0.0	0.1	0.6	0.3	0.0	0.4	1.0	0.6	0.6	0.4	0.9	0.5	0.6	0.4	0.1	0.2
10	0.0	0.4	0.1	1.0	0.2	0.8	0.2	0.1	0.2	0.1	0.5	0.1	0.0	0.2	0.5	0.6	0.1	0.2	0.0	0.5	0.5	0.2	0.8	1.0	0.8	1.1	0.3	1.0	0.5	0.6	0.5	0.2	0.3
11	0.0	0.3	0.0	1.2	0.5	0.6	0.1	0.3	0.1	0.2	0.9	0.0	0.0	0.2	0.7	0.6	0.1	0.0	0.2	0.3	0.4	0.3	0.7	0.7	0.6	1.1	0.3	1.1	0.7	0.5	0.5	0.2	0.3
12	0.2	0.0	0.0	1.1	0.6	0.6	0.0	0.5	0.1	0.1	1.2	0.2	0.1	0.1	0.9	0.4	0.4	0.1	0.5	0.5	0.5	0.5	0.9	0.8	0.7	1.1	0.1	1.1	0.5	0.8	1.0	0.3	0.5
13	0.2	0.1	0.1	1.1	0.6	0.6	0.3	0.7	0.4	0.2	1.4	0.5	0.1	0.3	0.6	0.7	0.6	0.5	0.6	0.6	0.6	0.8	1.0	1.1	1.2	1.2	0.4	1.2	0.9	0.9	1.1	0.5	0.6
14	0.3	0.1	0.1	1.2	0.7	0.6	0.3	0.5	0.2	0.3	1.3	0.3	0.1	0.2	0.4	0.3	0.5	0.4	0.6	0.5	0.6	[redacted]	1.0	1.2	1.3	1.3	0.5	1.2	0.7	1.0	1.2	0.4	0.6
15	0.3	0.1	0.3	1.3	0.7	0.6	0.3	0.4	0.2	0.6	1.4	0.3	0.0	0.2	0.6	0.4	0.6	0.6	0.7	0.4	0.7	0.8	1.0	1.1	1.5	1.3	0.3	1.3	0.7	1.0	1.2	0.4	0.6
16	0.4	0.0	0.3	1.2	0.8	0.6	0.5	0.2	0.0	0.6	1.2	0.2	0.2	0.3	0.3	0.4	0.4	0.6	0.7	0.3	0.9	0.8	1.1	1.1	1.5	1.2	0.5	1.1	0.8	0.9	1.2	0.4	0.6
17	0.4	0.1	0.4	1.2	0.8	0.6	0.4	0.3	0.1	0.6	1.0	0.2	0.2	0.1	0.4	0.4	0.4	0.8	0.7	0.1	0.8	0.9	1.2	1.0	1.4	1.2	0.4	1.1	0.7	0.9	1.2	0.4	0.6
18	0.5	0.2	0.2	1.1	0.8	0.5	0.6	0.4	0.2	0.6	1.0	0.1	0.2	0.1	0.4	0.5	0.5	0.7	0.8	0.1	0.8	0.8	1.1	1.1	1.3	1.4	0.4	1.0	0.9	1.0	1.1	0.4	0.6
19	0.4	0.0	0.1	1.3	0.6	0.4	0.4	0.5	0.1	0.7	0.7	0.2	0.0	0.1	0.4	0.6	0.1	0.8	0.7	0.2	0.6	0.8	1.1	1.0	1.1	1.2	0.4	1.1	1.1	0.8	1.1	0.4	0.6
20	0.4	0.1	0.0	0.8	0.6	0.4	0.2	0.4	0.0	0.6	0.6	0.2	0.3	0.1	0.2	0.5	0.1	0.7	0.7	0.0	0.6	0.9	0.9	0.6	0.8	1.3	0.4	0.9	1.0	1.0	0.7	0.3	0.5
21	0.4	0.1	0.2	0.6	0.4	0.4	0.2	0.3	0.1	0.5	0.3	0.1	0.7	0.1	0.1	0.5	0.0	0.4	0.3	0.3	0.6	0.8	0.9	0.6	0.8	1.1	0.2	0.9	0.6	0.8	0.5	0.2	0.4
22	0.3	0.0	0.4	0.6	0.3	0.4	0.1	0.1	0.0	0.5	0.1	0.3	0.4	0.1	0.1	0.6	0.1	0.3	0.2	0.3	0.3	0.3	0.9	0.6	0.6	1.0	0.0	0.8	0.5	1.0	0.5	0.2	0.3
23	1.5	1.0	1.4	1.0	1.2	0.9	0.7	1.1	0.8	0.7	0.6	1.6	1.0	0.9	0.9	0.8	0.7	0.8	0.6	0.9	0.5	0.4	0.2	0.2	0.1	0.1	0.3	0.2	0.4	0.3	0.3	0.7	0.7
24	1.3	1.0	1.5	1.1	1.0	0.9	0.7	0.9	1.1	0.4	0.8	1.2	0.9	0.6	0.9	0.5	0.8	0.8	0.7	0.8	0.6	0.6	0.4	0.4	0.3	0.3	0.4	0.4	0.6	0.4	0.5	0.7	0.8
Ave.	0.6	0.4	0.4	1.0	0.7	0.6	0.1	0.0	0.3	0.0	0.2	0.2	0.4	0.4	0.1	0.1	0.1	0.0	0.0	0.5	0.2	0.2	0.5	0.5	0.5	0.6	0.2	0.5	0.3	0.4	0.4	0.0	0.0
	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th	F	S	S	M	T	W	Th		

Retail, Wholesale Sales and Generation 6x16



Retail, Wholesale, Generation
Observations

- Wholesale sales run 40-50% that of Retail.
- A large portion of system resources are required/used to supply non-Retail firm requirements.
- Wholesale sales have a similar pattern to that of Retail with little or no "valley filling".

Retail, Wholesale, Generation
Observations (Cont.)

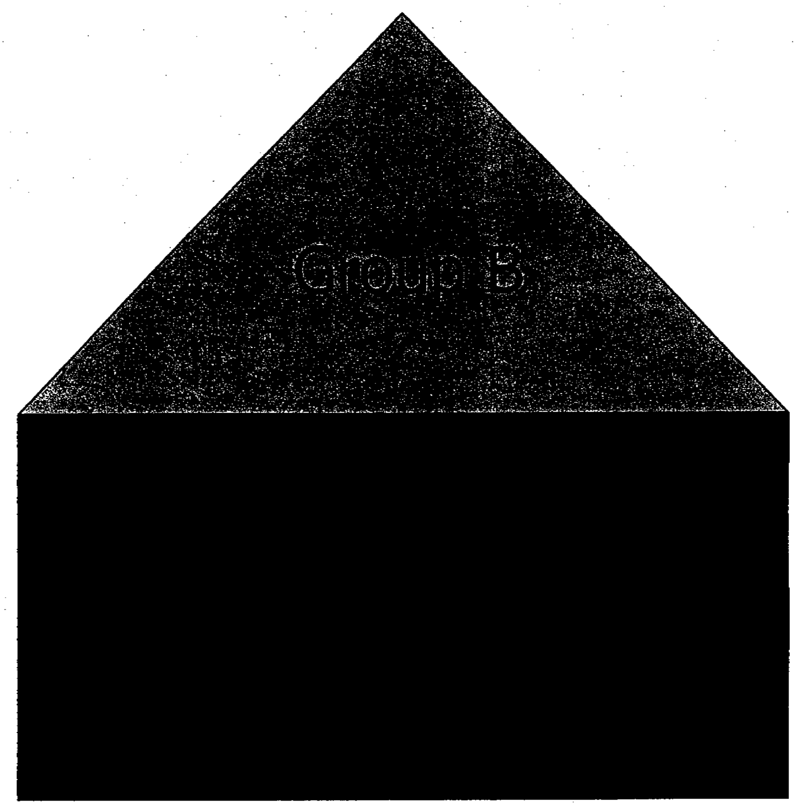
- Generation is extremely flat when compared with Retail or Wholesale sales.
- Generation is insufficient to serve Retail during HLH and during all hours of the combined Retail, LF, SF, OS sales.
- The System is operated to meet far more than the Retail requirements.

Allocation and Cost Causation

- Allocation factors based upon Retail load may not reflect overall system operations.
- Generation is run fairly flat, so these costs should be heavily spread on the basis of energy.
- Purchase power is used to meet System requirements, not just Retail.

Inadequacy of CP Allocation

- Assume Group A and B have the same demand at peak.
- A CP method would equally allocate fixed costs to each group.
- However, Wholesale revenue would only be generated by Group B as Group A would have no resources to offer for off-system sales.



Normalized Net Wholesale

March 2005 Semi-Annual Report

$16,738,686	Apr-05
$21,902,156	May-05
$1,772,583	Jun-05
-$9,341,247	Jul-05
$5,328,503	Aug-05
$5,550,536	Sep-05
$13,115,474	Oct-05
$20,665,108	Nov-05
$15,040,524	Dec-05
$23,346,664	Jan-06
$18,680,249	Feb-06
$38,843,886	Mar-06

Conclusions Regarding Resource Costs

- PacifiCorp's generation is used flat-out with an energy allocation factor looking like it would be representative of costs.
- Total Retail load is not flat, but it is for some customer groups.
- The difference in Retail load and Generation is addressed in the Wholesale market.
- If a group is allocated the same resources at peak as it uses during the rest of the time (flat load), it has no stake in Wholesale revenues.

Customer Charge

- Yes, some Costs are allocated on the basis of the number of Customers or Weighted Customers.
- However, the Customer Charge is a rate design issue, not a cost allocation issue.
- There are a number of customer groups allocated demand costs, that have a zero demand charge. (Rate design vs. Cost Allocation)

Benefits of a Low Customer Charge

- Conservation: More emphasis is placed upon the energy charge—the charge the customers have control over.
- Customer understanding: Residential customers are not charged for entering a grocery store, why pay one to the utility?
- Low bill for low usage: The proportion of the bill for low usage customers is far more related to the amount of usage.

Benefits of a High Customer Charge

- Utility has a higher fixed income.
- Utility revenue is less dependant upon temperature sensitive load or conservation measures.
- From a rate analyst point of view, revenue collection would be more in line with cost allocation methods.

Price Signals Associated with the Customer Charge

- By itself, it gives a meaningless price signal. Could a customer decide to not take service to avoid it?
- To a rate analyst, it means establishing a closer link between cost allocation and rate design. However, a customer is not a rate analyst.
- It is a charge that simply puts a utility in a bad light with its customers.

Appendix 14

Allocation options that reflect seasonal and time of day differences

COST OF SERVICE

Seasonal & Time of Day Allocation Options

Utah Cost of Service Taskforce

August 25, 2005

Dave Taylor

Cost of Service
Seasonal & Time of Day Allocation Options

I. Objective

II. Options

  I. Monthly Weighting in Annual Allocation

  II. Monthly Allocation

  III. Hourly Allocation

III. Impact on Class COS Results

IV. Possible Action

Seasonal & Time of Day Allocations Objective

- To explore:
  - If PacifiCorp experiences seasonal and time-of-day cost differences
  - Options to reflect those differences in the Cost of Service Study.
- To provide cost of service support for the seasonal and time-of-day price differences reflected in current tariffs.

Seasonal Allocations
Option 1 : Weighted Monthly Values

- Annual Allocation Factors developed with weighted monthly values
- Traditional Weighting
  - All monthly values weighted the same
    - 12CP
  - Monthly values weighted either 1 or 0
    - 8 CP
    - 4 CP
- Relative Monthly Weighting
  - Weighting Factor is calculated as each monthly value as % of annual maximum value

Seasonal Allocations
Option 1 : Relative Monthly Weighting

- Annual Allocation Factors developed with weighted monthly values
- Monthly weighting factor is calculated as each monthly value as % of annual maximum value
- Monthly loads (CP or Energy) multiplied by weighting factor then 12 monthly weighted values summed
- Potential Monthly Demand Weighting
  - Relative Monthly Peak Demand
  - Probability of Contribution to System Peak
  - Cost to Achieve 15% Reserve Margin
- Potential Monthly Energy Weighting
  - Total Power Costs per MWH
  - Net Power Costs per MWH

Seasonal Allocations
Option 1: Relative Monthly Weighting

- Example

Utah COS
Peak and Energy Weighting Options
FY 2006

	Peak Weighting Factors			Energy Weighting Factors	
Months/Year	System Firm Peak Demand MW (A)	Probability of Contribution to Peak (MSP Study) (B)	Cost to Bring Reserve Margin To 15% (MSP Study) (C)	Total Power Costs $/MWH (D)	Net Power Costs $/MWH (E)
FY 2006					
April	6,684	0%	$3,858,825	$19.48	$11.33
May	6,505	3%	$5,060,796	$19.47	$12.22
June	7,993	24%	$8,025,632	$21.59	$14.23
July	8,585	39%	$10,791,962	$24.50	$17.88
August	8,707	42%	$11,608,762	$25.60	$18.65
September	7,588	17%	$8,315,857	$23.92	$15.85
October	7,124	2%	$1,845,878	$20.71	$12.02
November	7,516	19%	$4,496,249	$19.88	$10.85
December	7,705	40%	$5,672,891	$19.03	$10.99
January	7,990	43%	$4,926,358	$18.36	$11.21
February	8,069	37%	$5,720,773	$19.22	$12.42
March	7,349	10%	$6,624,384	$20.28	$12.11

Monthly Value as % of Maximum Value

	Peak Weighting Factors			Energy Weighting Factors	
Months/Year	System Firm Peak Demand (A)	Probability of Contribution to Peak (MSP Study) (B)	Cost to Bring Reserve Margin To 15% (MSP Study) (C)	Total Power Costs $/MWH (D)	Net Power Costs $/MWH (E)
FY 2006					
April	77%	0%	33%	76%	61%
May	75%	8%	44%	76%	66%
June	92%	57%	69%	84%	76%
July	99%	92%	93%	96%	96%
August	100%	98%	100%	100%	100%
September	87%	39%	72%	93%	85%
October	82%	5%	16%	81%	64%
November	86%	45%	39%	78%	58%
December	88%	94%	49%	74%	59%
January	92%	100%	42%	72%	60%
February	93%	86%	49%	75%	67%
March	84%	24%	57%	79%	65%

PacifiCorp
Presentation to Utah Cost of Service Taskforce
August 25, 2005

Monthly Weighting Example

PacifiCorp
KW Loads Coincident To System Peak
12 Months Ending March 2006
Coincident Peaks @ Input

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
Month :		Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Sum Of	
Peak Date:	COS	7	26	30	21	2	1	31	29	13	10	2	2	12	Allocation
Peak Time:	Sch	08:00	15:00	16:00	16:00	16:00	15:00	09:00	20:00	20:00	10:00	10:00	09:00	CPs	Factor
Class							Monthly CP KW								
Residential	Sch 1	655,670	999,230	1,080,882	1,436,725	1,243,431	919,874	803,876	1,179,928	1,252,226	626,671	775,827	720,783	11,695,124	30.0585%
GS Dist - Large	Sch 6	711,106	1,344,579	1,086,914	1,047,798	1,314,900	1,372,050	1,066,502	729,142	735,874	1,016,693	1,081,783	882,977	12,390,318	31.8452%
GS Dist - > 1MW	Sch 8	276,642	340,492	303,715	294,017	323,032	346,094	318,045	281,606	285,592	285,551	326,328	281,899	3,663,013	9.4146%
ST Lighting	Sch 7,11,12	-	-	-	-	-	-	-	17,767	15,882	-	-	-	33,648	0.0865%
GS Trans	Sch 9	478,928	549,746	495,575	517,351	575,289	555,841	493,595	513,597	501,646	508,967	548,633	461,195	6,200,364	15.9360%
Irrigation	Sch 10	22,448	71,037	71,685	55,539	63,754	37,161	20,792	8,840	1,056	971	897	4,337	358,518	0.9215%
Traffic Signals	Sch 12	1,436	1,267	1,419	1,212	1,882	1,480	1,572	1,744	1,417	1,528	1,673	1,490	18,120	0.0466%
Outdoor Lighting	Sch 12	-	-	-	-	-	-	-	2,410	2,295	-	-	-	4,705	0.0121%
Electirc Furnace	Sch 21	2,175	957	269	55	202	465	265	149	105	2,079	2,320	1,433	10,475	0.0269%
GS Dist - Small	Sch 23	106,895	284,020	280,402	225,077	275,768	326,677	175,758	192,156	213,776	189,842	214,428	153,520	2,638,320	6.7809%
Residential - Mobile Home	Sch 25	1,309	1,875	1,968	2,523	2,026	1,875	1,190	2,208	2,413	1,158	1,672	1,523	21,739	0.0559%
Cust A	Cust A	30,839	30,841	30,788	30,853	30,835	30,639	30,825	30,761	30,848	30,848	30,538	30,282	368,898	0.9481%
Cust B	Cust B	63,683	70,814	-	-	-	-	77,623	104,129	-	-	84,632	86,260	487,140	1.2520%
Cust C	Cust C	83,693	85,939	85,928	85,696	85,941	85,664	82,571	84,598	85,047	85,029	82,915	84,510	1,017,530	2.6152%
Total Utah		2,434,825	3,780,798	3,439,546	3,696,846	3,917,060	3,677,819	3,072,615	3,149,033	3,128,178	2,749,336	3,151,647	2,710,209	38,907,912	100.0000%
Monthly % of Total		6.26%	9.72%	8.84%	9.50%	10.07%	9.45%	7.90%	8.09%	8.04%	7.07%	8.10%	6.97%	100.00%	

Weighted by Relative System Monthly Peak

Relative System Monthly Peak (% of Peak Month)															
Monthly Weighting Factor		76.77%	74.71%	91.80%	98.59%	100.00%	87.15%	81.82%	86.32%	88.49%	91.76%	92.67%	84.40%		Allocation Factor
Class							Weighted Monthly CP KW								
Residential	Sch 1	503,344	746,491	992,202	1,416,502	1,243,431	801,652	657,730	1,018,467	1,108,150	575,043	718,984	608,333	10,390,330	30.2490%
GS Dist - Large	Sch 6	545,901	1,004,490	997,739	1,033,050	1,314,900	1,195,716	872,610	629,367	651,208	932,932	1,002,524	745,223	10,925,657	31.8074%
GS Dist - > 1MW	Sch 8	212,372	254,370	278,797	289,879	323,032	301,614	260,224	243,071	252,733	262,026	302,419	237,920	3,218,456	9.3698%
ST Lighting	Sch 7,11,12	-	-	-	-	-	-	-	15,335	14,054	-	-	-	29,390	0.0856%
GS Trans	Sch 9	367,662	410,697	454,916	510,069	575,289	484,405	403,859	443,316	443,929	467,036	508,436	389,244	5,458,858	15.8922%
Irrigation	Sch 10	17,233	53,070	65,804	54,758	63,754	32,385	17,012	7,630	935	891	831	3,660	317,962	0.9257%
Traffic Signals	Sch 12	1,103	947	1,302	1,195	1,882	1,290	1,286	1,505	1,254	1,402	1,550	1,257	15,974	0.0465%
Outdoor Lighting	Sch 12	-	-	-	-	-	-	-	2,080	2,031	-	-	-	4,111	0.0120%
Electirc Furnace	Sch 21	1,670	715	247	54	202	405	217	129	93	1,908	2,150	1,210	8,999	0.0262%
GS Dist - Small	Sch 23	82,061	212,182	257,397	221,909	275,768	284,693	143,805	165,862	189,180	174,202	198,718	129,569	2,335,344	6.7988%
Residential - Mobile Home	Sch 25	1,005	1,401	1,806	2,487	2,026	1,634	974	1,906	2,135	1,063	1,550	1,286	19,271	0.0561%
Cust A	Cust A	23,674	23,040	28,262	30,418	30,835	26,701	25,221	26,552	27,299	28,307	28,300	25,558	324,169	0.9437%
Cust B	Cust B	48,888	52,903	-	-	-	-	63,511	89,880	-	-	78,431	72,802	406,415	1.1832%
Cust C	Cust C	64,249	64,202	78,878	84,490	85,941	74,654	67,559	73,021	75,262	78,023	76,840	71,325	894,446	2.6040%
Total Utah		1,869,162	2,824,507	3,157,351	3,644,811	3,917,060	3,205,149	2,514,007	2,718,121	2,768,263	2,522,831	2,920,734	2,287,387	34,349,384	100.0000%

Seasonal Allocations
Option 2 : Monthly Allocations

- Separate Allocation Factor calculated for Each Month
- Only applicable to Net Power Costs
  - Monthly allocation of Composite NCP
  - Monthly allocation for each NPC Component
- Energy Component only or Demand and Energy Component of NPC?

Seasonal Allocations
Option 2 : Monthly Allocations

- Example

PacifiCo
Presentation to Utah Cost of Service Taskforce
August 25, 2005

PacifiCorp
12 Months Ending March 2006
Allocation of Net Power Costs Components

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Month :		Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Total
Generation Energy Related NPC		12,744,623	14,445,137	17,603,698	23,042,099	23,209,355	18,874,215	16,941,961	15,162,794	16,646,449	15,814,459	15,822,967	15,594,132	205,901,889
Class							Monthly MWH							Annual MWH
Residential	Sch 1	425,805	413,912	552,250	780,512	795,779	578,672	439,651	457,359	576,183	666,456	563,681	493,296	6,743,555
GS Dist - Large	Sch 6	445,776	470,724	530,781	583,328	598,434	522,284	499,479	481,309	512,939	508,378	478,783	468,769	6,100,985
GS Dist - > 1MW	Sch 8	156,160	165,681	186,593	204,657	209,422	182,033	174,367	167,739	178,317	177,079	167,072	163,832	2,132,953
ST Lighting	Sch 7,11,12	7,623	7,997	6,755	7,931	7,576	7,862	7,001	7,319	7,882	7,032	7,998	7,709	90,685
GS Trans	Sch 9	334,156	321,303	341,608	348,219	360,119	354,070	337,399	353,800	318,861	344,367	348,327	308,601	4,070,828
Irrigation	Sch 10	4,851	38,858	45,194	50,692	42,226	28,085	4,322	4,050	2,027	157	318	591	221,371
Traffic Signals	Sch 12	1,121	1,080	1,062	1,054	1,147	1,143	1,050	1,084	1,048	1,092	1,114	1,015	13,012
Outdoor Lighting	Sch 12	972	936	921	913	994	991	910	939	908	947	965	880	11,275
Electirc Furnace	Sch 21	278	282	261	261	264	239	263	266	330	286	239	324	3,293
GS Dist - Small	Sch 23	94,102	95,385	108,930	125,589	129,587	122,721	111,637	98,026	112,997	116,376	111,165	101,587	1,328,102
Residential - Mobile Home	Sch 25	867	816	996	1,135	1,357	917	990	898	1,178	1,302	1,068	1,038	12,562
Cust A	Cust A	20,366	21,736	21,409	21,633	21,789	22,147	21,294	21,269	20,743	20,328	20,983	16,911	250,609
Cust B	Cust B	55,192	59,345	54,749	53,105	55,792	55,718	57,493	60,826	49,671	54,265	65,172	57,892	679,220
Cust C	Cust C	43,407	53,892	52,491	49,401	53,797	55,365	41,988	56,150	53,626	54,249	57,443	47,907	619,716
Total Utah		1,590,677	1,651,947	1,904,001	2,228,428	2,278,281	1,932,249	1,697,843	1,711,035	1,836,710	1,952,316	1,824,328	1,670,352	22,278,168

Class							Monthly Energy Factor						
Residential	Sch 1	26.7688%	25.0560%	29.0047%	35.0252%	34.9289%	29.9481%	25.8946%	26.7299%	31.3704%	34.1367%	30.8980%	29.5325%
GS Dist - Large	Sch 6	28.0243%	28.4951%	27.8771%	26.1766%	26.2669%	27.0299%	29.4184%	28.1297%	27.9270%	26.0398%	26.2444%	28.0641%
GS Dist - > 1MW	Sch 8	9.8172%	10.0294%	9.8001%	9.1839%	9.1921%	9.4208%	10.2699%	9.8034%	9.7085%	9.0702%	9.1580%	9.8082%
ST Lighting	Sch 7,11,12	0.4793%	0.4841%	0.3548%	0.3559%	0.3325%	0.4069%	0.4123%	0.4278%	0.4291%	0.3602%	0.4384%	0.4615%
GS Trans	Sch 9	21.0071%	19.4499%	17.9416%	15.6262%	15.8066%	18.3242%	19.8722%	20.6775%	17.3604%	17.6389%	19.0935%	18.4752%
Irrigation	Sch 10	0.3049%	2.3523%	2.3736%	2.2748%	1.8534%	1.4535%	0.2546%	0.2367%	0.1103%	0.0080%	0.0174%	0.0354%
Traffic Signals	Sch 12	0.0705%	0.0654%	0.0558%	0.0473%	0.0504%	0.0592%	0.0618%	0.0633%	0.0571%	0.0560%	0.0611%	0.0608%
Outdoor Lighting	Sch 12	0.0611%	0.0567%	0.0484%	0.0410%	0.0436%	0.0513%	0.0536%	0.0549%	0.0495%	0.0485%	0.0529%	0.0527%
Electirc Furnace	Sch 21	0.0175%	0.0171%	0.0137%	0.0117%	0.0116%	0.0124%	0.0155%	0.0155%	0.0180%	0.0147%	0.0131%	0.0194%
GS Dist - Small	Sch 23	5.9159%	5.7741%	5.7211%	5.6358%	5.6879%	6.3512%	6.5752%	5.7291%	6.1521%	5.9609%	6.0935%	6.0818%
Residential - Mobile Home	Sch 25	0.0545%	0.0494%	0.0523%	0.0509%	0.0596%	0.0475%	0.0583%	0.0525%	0.0641%	0.0667%	0.0585%	0.0621%
Cust A	Cust A	1.2803%	1.3158%	1.1244%	0.9708%	0.9564%	1.1462%	1.2542%	1.2431%	1.1294%	1.0412%	1.1502%	1.0124%
Cust B	Cust B	3.4697%	3.5924%	2.8755%	2.3831%	2.4489%	2.8836%	3.3862%	3.5549%	2.7044%	2.7795%	3.5724%	3.4659%
Cust C	Cust C	2.7289%	3.2623%	2.7569%	2.2168%	2.3613%	2.8653%	2.4730%	3.2816%	2.9197%	2.7787%	3.1487%	2.8681%
Total Utah		100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

Total NPC Energy Allocated Costs

Month :		Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Total Monthly Allocation
Class														
Residential	Sch 1	3,411,582	3,619,378	5,105,906	8,070,545	8,106,772	5,652,473	4,387,061	4,053,005	5,222,054	5,398,532	4,888,981	4,605,331	62,521,621
GS Dist - Large	Sch 6	3,571,593	4,116,161	4,907,407	6,031,647	6,096,376	5,101,673	4,984,055	4,265,249	4,648,861	4,118,047	4,152,638	4,376,355	56,370,064
GS Dist - > 1MW	Sch 8	1,251,168	1,448,763	1,725,174	2,116,167	2,133,425	1,778,103	1,739,926	1,486,465	1,616,118	1,434,404	1,449,068	1,529,510	19,708,290
ST Lighting	Sch 7,11,12	61,079	69,932	62,453	82,002	77,174	76,800	69,856	64,863	71,436	56,965	69,366	71,972	833,896
GS Trans	Sch 9	2,677,281	2,809,571	3,158,379	3,600,605	3,668,611	3,458,555	3,366,745	3,135,294	2,889,894	2,789,495	3,021,151	2,881,045	37,456,624
Irrigation	Sch 10	38,863	339,789	417,849	524,156	430,167	274,339	43,130	35,892	18,367	1,269	2,759	5,519	2,132,099
Traffic Signals	Sch 12	8,983	9,445	9,823	10,895	11,688	11,168	10,478	9,603	9,502	8,849	9,660	9,477	119,571
Outdoor Lighting	Sch 12	7,784	8,185	8,513	9,441	10,128	9,678	9,080	8,322	8,234	7,668	8,371	8,213	103,616
Electirc Furnace	Sch 21	2,226	2,470	2,412	2,695	2,694	2,333	2,628	2,357	2,990	2,318	2,074	3,022	30,219
GS Dist - Small	Sch 23	753,954	834,072	1,007,128	1,298,601	1,320,127	1,198,740	1,113,972	868,686	1,024,113	942,690	964,170	948,399	12,274,653
Residential - Mobile Home	Sch 25	6,950	7,133	9,206	11,738	13,823	8,960	9,876	7,962	10,672	10,549	9,262	9,690	115,821
Cust A	Cust A	163,174	190,062	197,943	223,688	221,968	216,336	212,486	188,483	188,002	164,667	181,991	157,877	2,306,677
Cust B	Cust B	442,203	518,927	506,191	549,111	568,364	544,253	573,695	539,025	450,181	439,566	565,253	540,471	6,237,241
Cust C	Cust C	347,782	471,248	485,313	510,807	548,040	540,805	418,974	497,589	486,026	439,440	498,223	447,250	5,691,497
Total Utah		12,744,623	14,445,137	17,603,698	23,042,099	23,209,355	18,874,215	16,941,961	15,162,794	16,646,449	15,814,459	15,822,967	15,594,132	205,901,889

Seasonal & Time of Day Allocations
Option 3 : Hourly Allocations

- Options:
  - Separate Allocation Factor calculated for Each Hour
  - Aggregated Allocation Factor for TOD Time Periods
- Only applicable to Net Power Costs
  - Hourly allocation of Composite NCP
  - Hourly allocation for each NPC Component
- Energy Component only

Seasonal & Time of Day Allocations
Option 3 : Hourly Allocations

- Example

PacifiCorp
Presentation to Utah Cost of Service Taskforce
August 25, 2005

PacifiCorp
Summary of Class Energy by Time Period
12 Months Ending March 2006
Hourly Energy @ Input

		FY06 MWH Forecast			
		Summer	Winter	S & W	
Class		On Peak	On Peak	Off Peak	Total
Residential	Sch 1	854,818	1,828,198	4,060,540	6,743,555
GS Dist - Large	Sch 6	807,032	1,991,130	3,302,823	6,100,985
GS Dist - > 1MW	Sch 8	247,141	651,681	1,234,131	2,132,953
ST Lighting	Sch 7,11,12	4,632	15,773	70,280	90,685
GS Trans	Sch 9	483,991	1,037,182	2,549,655	4,070,828
Irrigation	Sch 10	39,977	24,034	157,361	221,371
Traffic Signals	Sch 12	1,222	3,555	8,235	13,012
Outdoor Lighting	Sch 12		6,520	4,755	11,275
Electirc Furnace	Sch 21	278	1,735	1,280	3,293
GS Dist - Small	Sch 23	172,688	454,541	700,873	1,328,102
Residential - Mobile Home	Sch 25	1,592	3,406	7,564	12,562
Cust A	Cust A	29,377	62,693	158,540	250,609
Cust B	Cust B	62,887	192,539	423,794	679,220
Cust C	Cust C	72,645	155,029	392,043	619,716
Total Utah		2,778,281	6,428,016	13,071,871	22,278,168
BAI Study			$/MWH		
Average Energy Costs		$25.81	$20.26	$18.83	
Residential	Sch 1	$22,062,850	$37,039,292	$76,459,960	$135,562,102
GS Dist - Large	Sch 6	$20,829,508	$40,340,290	$62,192,149	$123,361,947
GS Dist - > 1MW	Sch 8	$6,378,714	$13,203,052	$23,238,680	$42,820,446
ST Lighting	Sch 7,11,12	$119,549	$319,571	$1,323,371	$1,762,491
GS Trans	Sch 9	$12,491,818	$21,013,308	$48,009,996	$81,515,122
Irrigation	Sch 10	$1,031,798	$486,926	$2,963,105	$4,481,829
Traffic Signals	Sch 12	$31,547	$72,016	$155,059	$258,622
Outdoor Lighting	Sch 12	$0	$132,105	$89,532	$221,638
Electirc Furnace	Sch 21	$7,176	$35,161	$24,099	$66,437
GS Dist - Small	Sch 23	$4,457,078	$9,209,010	$13,197,438	$26,863,526
Residential - Mobile Home	Sch 25	$41,099	$68,997	$142,431	$252,527
Cust A	Cust A	$758,222	$1,270,153	$2,985,303	$5,013,678
Cust B	Cust B	$1,623,103	$3,900,843	$7,980,040	$13,503,986
Cust C	Cust C	$1,874,959	$3,140,882	$7,382,167	$12,398,008
Total Utah		$71,707,421	$130,231,608	$246,143,330	$448,082,359

COST OF SERVICE

Seasonal & Time of Day Allocation Options

Impact on COS Results

Pa[illegible]rp
Presentation to Utah Cost of Service Taskforce
August 25, 2005

12 Months Ending Mar[illegible]
Comparison of Allocation Factor Options
Weighted vs Non-Weighted Demand Factors

Allocation Options

Class	Factor Weighting	Demand Factor: 12 CP Un-Weighted	Demand Factor: 12 CP Relative Monthly System Peak	Demand Factor: 12 CP Probability Contribution To System Peak	Demand Factor: 12 CP Bring Reserve Margin To 15%	Demand Related Generation COS Allocation: 12 CP Un-Weighted	Demand Related Generation COS Allocation: 12 CP Relative Monthly System Peak	Demand Related Generation COS Allocation: 12 CP Probability Contribution To System Peak	Demand Related Generation COS Allocation: 12 CP Bring Reserve Margin To 15%
Residential	Sch 1	30.06%	30.25%	31.59%	30.88%	$116,017,981	$116,753,203	$121,914,671	$119,198,120
GS Dist - Large	Sch 6	31.85%	31.81%	31.29%	31.92%	$122,914,444	$122,768,518	$120,777,382	$123,185,365
GS Dist - > 1MW	Sch 8	9.41%	9.37%	9.13%	9.12%	$36,337,825	$36,164,881	$35,229,214	$35,208,982
ST Lighting	Sch 7,11,12	0.09%	0.09%	0.11%	0.07%	$333,796	$330,244	$411,850	$253,122
GS Trans	Sch 9	15.94%	15.89%	15.78%	15.53%	$61,508,852	$61,339,638	$60,918,808	$59,951,413
Irrigation	Sch 10	0.92%	0.93%	0.85%	1.08%	$3,556,569	$3,572,853	$3,279,250	$4,158,782
Traffic Signals	Sch 12	0.05%	0.05%	0.05%	0.04%	$179,755	$179,494	$178,524	$173,229
Outdoor Lighting	Sch 12	0.01%	0.01%	0.02%	0.01%	$46,673	$46,195	$58,233	$35,524
Electirc Furnace	Sch 21	0.03%	0.03%	0.02%	0.02%	$103,914	$101,124	$94,227	$84,835
GS Dist - Small	Sch 23	6.78%	6.80%	6.93%	6.96%	$26,172,665	$26,241,605	$26,746,656	$26,845,332
Residential - Mobile Home	Sch 25	0.06%	0.06%	0.06%	0.06%	$215,658	$216,548	$225,399	$220,157
Cust A	Cust A	0.95%	0.94%	0.92%	0.91%	$3,659,541	$3,642,591	$3,569,812	$3,522,383
Cust B	Cust B	1.25%	1.18%	0.70%	0.88%	$4,832,529	$4,566,770	$2,701,120	$3,382,113
Cust C	Cust C	2.62%	2.60%	2.56%	2.53%	$10,094,100	$10,050,640	$9,869,159	$9,754,945
Total Utah		100.00%	100.00%	100.00%	100.00%	$385,974,304	$385,974,304	$385,974,304	$385,974,304
$ / CP KW Mo. Summer (May - September)						$9.92	$10.17	$10.55	$13.09
$ /CP KW Mo. Winter (October - April)						$9.92	$9.70	$9.35	$7.05

Difference From Un-Weighted Annual Allocation Factors

Class	Factor Weighting	Demand Factor: 12 CP Un-Weighted	Demand Factor: 12 CP Relative Monthly System Peak	Demand Factor: 12 CP Probability Contribution To System Peak	Demand Factor: 12 CP Bring Reserve Margin To 15%	Demand Related Generation COS Allocation: 12 CP Un-Weighted	Demand Related Generation COS Allocation: 12 CP Relative Monthly System Peak	Demand Related Generation COS Allocation: 12 CP Probability Contribution To System Peak	Demand Related Generation COS Allocation: 12 CP Bring Reserve Margin To 15%
Residential	Sch 1	0.00%	0.19%	1.53%	0.82%	$0	$735,222	$5,896,689	$3,180,139
GS Dist - Large	Sch 6	0.00%	-0.04%	-0.55%	0.07%	$0	($145,926)	($2,137,061)	$270,921
GS Dist - > 1MW	Sch 8	0.00%	-0.04%	-0.29%	-0.29%	$0	($172,943)	($1,108,611)	($1,128,842)
ST Lighting	Sch 7,11,12	0.00%	0.00%	0.02%	-0.02%	$0	($3,552)	$78,054	($80,674)
GS Trans	Sch 9	0.00%	-0.04%	-0.15%	-0.40%	$0	($169,214)	($590,045)	($1,557,440)
Irrigation	Sch 10	0.00%	0.00%	-0.07%	0.16%	$0	$16,284	($277,319)	$602,213
Traffic Signals	Sch 12	0.00%	0.00%	0.00%	0.00%	$0	($261)	($1,231)	($6,526)
Outdoor Lighting	Sch 12	0.00%	0.00%	0.00%	0.00%	$0	($478)	$11,560	($11,149)
Electirc Furnace	Sch 21	0.00%	0.00%	0.00%	0.00%	$0	($2,791)	($9,688)	($19,079)
GS Dist - Small	Sch 23	0.00%	0.02%	0.15%	0.17%	$0	$68,940	$573,991	$672,668
Residential - Mobile Home	Sch 25	0.00%	0.00%	0.00%	0.00%	$0	$890	$9,741	$4,499
Cust A	Cust A	0.00%	0.00%	-0.02%	-0.04%	$0	($16,950)	($89,730)	($137,158)
Cust B	Cust B	0.00%	-0.07%	-0.55%	-0.38%	$0	($265,760)	($2,131,410)	($1,450,416)
Cust C	Cust C	0.00%	-0.01%	-0.06%	-0.09%	$0	($43,460)	($224,941)	($339,155)
Total Utah		0%	0%	0%	0%	$0	$0	($0)	$0
[illegible] / CP KW Mo. Summer (May - September)						$0.00	$0.25	$0.63	$3,[illegible]
[illegible]CP KW Mo. Winter (October - April)						$0.00	($0.22)	($0.57)	($2[illegible]

Pa[illegible]rp
Presentation to Uta[illegible] of Service Taskforce
Augus[illegible]25, 2005

12 Months Ending March 2006
Comparison of Allocation Factor Options
Weighted vs Non-Weighted Energy Factors

Allocation Options

Class	Weighting	Energy Factor: Un-Weighted	Energy Factor: Monthly Total Power Costs $/MWH	Energy Factor: Monthly Net Power Costs $/MWH	Energy Factor: Energy NPC Monthly Factors	Energy Factor: On & Off Peak Marginal Costs Costs $/MWH	Energy Factor: On & Off Peak Average Costs Costs $/MWH	Total Energy Related Generation COS Allocation: Un-Weighted	Total Energy Related Generation COS Allocation: Monthly Total Power Costs $/MWH	Total Energy Related Generation COS Allocation: Monthly Net Power Costs $/MWH	Total Energy Related Generation COS Allocation: Energy NPC Monthly Factors	Total Energy Related Generation COS Allocation: On & Off Peak Average Costs Costs $/MWH	Total Energy Related Generation COS Allocation: On & Off Peak Marginal Costs Costs $/MWH
Residential	Sch 1	30.27%	30.46%	30.69%	30.36%	30.20%	30.25%	$107,312,809	$107,974,508	$108,792,185	$107,649,494	$107,256,234	$107,079,311
GS Dist - Large	Sch 6	27.39%	27.34%	27.27%	27.38%	27.67%	27.53%	$97,087,333	$96,925,874	$96,680,310	$97,057,766	$97,603,516	$98,091,959
GS Dist - > 1MW	Sch 8	9.57%	9.56%	9.54%	9.57%	9.56%	9.56%	$33,942,500	$33,889,988	$33,809,310	$33,933,661	$33,879,378	$33,905,879
ST Lighting	Sch 7,11,12	0.41%	0.40%	0.40%	0.40%	0.38%	0.39%	$1,443,110	$1,430,674	$1,419,108	$1,435,800	$1,394,476	$1,363,639
GS Trans	Sch 9	18.27%	18.15%	18.02%	18.19%	18.11%	18.19%	$64,780,662	$64,346,254	$63,878,768	$64,492,675	$64,494,463	$64,211,030
Irrigation	Sch 10	0.99%	1.07%	1.14%	1.04%	0.99%	1.00%	$3,522,769	$3,791,419	$4,039,006	$3,671,041	$3,546,006	$3,500,815
Traffic Signals	Sch 12	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	$207,058	$205,394	$203,725	$205,878	$204,621	$203,505
Outdoor Lighting	Sch 12	0.05%	0.05%	0.05%	0.05%	0.05%	0.05%	$179,428	$177,986	$176,540	$178,405	$175,359	$178,312
Electirc Furnace	Sch 21	0.01%	0.01%	0.01%	0.01%	0.02%	0.01%	$52,409	$51,678	$50,992	$52,032	$52,564	$53,669
GS Dist - Small	Sch 23	5.96%	5.95%	5.94%	5.96%	6.03%	6.00%	$21,134,609	$21,104,528	$21,060,713	$21,134,451	$21,254,323	$21,391,429
Residential - Mobile Home	Sch 25	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	$199,904	$198,925	$198,410	$199,419	$199,799	$199,469
Cust A	Cust A	1.12%	1.12%	1.11%	1.12%	1.11%	1.12%	$3,988,045	$3,961,565	$3,933,836	$3,971,628	$3,966,803	$3,946,543
Cust B	Cust B	3.05%	3.02%	2.98%	3.03%	3.00%	3.01%	$10,808,686	$10,690,881	$10,580,236	$10,739,258	$10,684,304	$10,636,386
Cust C	Cust C	2.78%	2.76%	2.74%	2.76%	2.75%	2.77%	$9,861,785	$9,771,433	$9,697,969	$9,799,598	$9,809,258	$9,759,159
Total Utah		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	$354,521,105	$354,521,105	$354,521,105	$354,521,105	$354,521,105	$354,521,105
$ / KWH Summer (May - September)								$0.0159	$0.0175	$0.0188	$0.0167	$0.0204	$0.0216
$ /KWH Winter (October - April)								$0.0159	$0.0147	$0.0136	$0.0152	$0.0160	$0.0170
$ /KWH Off Peak												$0.0149	$0.0142

Difference From Un-Weighted Annual Allocation Factors

Class	Weighting	Energy Factor: Un-Weighted	Energy Factor: Monthly Total Power Costs $/MWH	Energy Factor: Monthly Net Power Costs $/MWH	Energy Factor: Energy NPC Monthly Factors	Energy Factor: On & Off Peak Marginal Costs Costs $/MWH	Energy Factor: On & Off Peak Average Costs Costs $/MWH	Total Energy Related Generation COS Allocation: Un-Weighted	Total Energy Related Generation COS Allocation: Monthly Total Power Costs $/MWH	Total Energy Related Generation COS Allocation: Monthly Net Power Costs $/MWH	Total Energy Related Generation COS Allocation: Energy NPC Monthly Factors	Total Energy Related Generation COS Allocation: On & Off Peak Average Costs Costs $/MWH	Total Energy Related Generation COS Allocation: On & Off Peak Marginal Costs Costs $/MWH
Residential	Sch 1	0.00%	0.19%	0.42%	0.09%	-0.07%	-0.02%	$0	$661,699	$1,479,376	$336,685	($56,575)	($233,497)
GS Dist - Large	Sch 6	0.00%	-0.05%	-0.11%	-0.01%	0.28%	0.15%	$0	($161,460)	($407,024)	($29,568)	$516,183	$1,004,626
GS Dist - > 1MW	Sch 8	0.00%	-0.01%	-0.04%	0.00%	-0.01%	-0.02%	$0	($52,512)	($133,190)	($8,839)	($63,121)	($36,621)
ST Lighting	Sch 7,11,12	0.00%	0.00%	-0.01%	0.00%	-0.02%	-0.01%	$0	($12,436)	($24,003)	($7,310)	($48,634)	($79,471)
GS Trans	Sch 9	0.00%	-0.12%	-0.25%	-0.08%	-0.16%	-0.08%	$0	($434,408)	($901,894)	($287,987)	($286,199)	($569,632)
Irrigation	Sch 10	0.00%	0.08%	0.15%	0.04%	-0.01%	0.01%	$0	$268,650	$516,237	$148,272	$23,238	($21,953)
Traffic Signals	Sch 12	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	($1,663)	($3,333)	($1,180)	($2,437)	($3,553)
Outdoor Lighting	Sch 12	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	($1,441)	($2,888)	($1,023)	($4,069)	($1,116)
Electirc Furnace	Sch 21	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	($730)	($1,416)	($377)	$156	$1,260
GS Dist - Small	Sch 23	0.00%	-0.01%	-0.02%	0.00%	0.07%	0.03%	$0	($30,081)	($73,896)	($158)	$119,714	$256,820
Residential - Mobile Home	Sch 25	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	$0	($979)	($1,494)	($485)	($105)	($435)
Cust A	Cust A	0.00%	-0.01%	-0.02%	0.00%	-0.01%	-0.01%	$0	($26,480)	($54,209)	($16,417)	($21,241)	($41,501)
Cust B	Cust B	0.00%	-0.03%	-0.06%	-0.02%	-0.05%	-0.04%	$0	($117,805)	($228,450)	($69,428)	($124,382)	($172,300)
Cust C	Cust C	0.00%	-0.03%	-0.05%	-0.02%	-0.03%	-0.01%	$0	($90,352)	($163,816)	($62,186)	($52,527)	($102,626)
Total Utah		0%	0%	0%	0%	0%	0%	$0	($0)	($0)	($0)	($0)	($0)
$ / KWH Summer (May - September)								$0.0000	$0.0015	$0.0029	$0.0008	$0.0045	$0.0057
$ /KWH Winter (October - April)								$0.0000	($0.0013)	($0.0024)	($0.0007)	$0.0001	$0.0011
$ /KWH Off Peak												($0.0010)	($0.0018)

Seasonal & Time of Day Allocations Impact on Results

- Energy options have impact on Seasonal and TOD differences but very little difference in Class cost responsibility.
- Some Demand options have larger impacts
- Most COS differences less than currently reflected in tariffs

COST OF SERVICE

Seasonal & Time of Day Allocation Options

Possible Action

Seasonal & Time of Day Allocations Possible Action

- None
- Implement Seasonal and TOD Allocations in COS
- No change to allocation, reflect Seasonal and TOD Marginal Cost differences in Tariffs

CERTIFICATE OF SERVICE

Docket No. 20-035-04

I hereby certify that on March 2, 2021, a true and correct copy of the foregoing was served by electronic mail to the following:

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