Multi-State Process

PacifiCorp's Load Growth Report

October 20, 2005

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1. Executive Summary

1.1 Overview

The Multi-State Process[1] commenced in April 2002 and was a collaborative process with stakeholders from each of the six States PacifiCorp serves. The focus was to design, develop and implement a cost allocation methodology that would achieve a more permanent consensus on each State's responsibility for the costs and benefits of PacifiCorp's existing assets. Using a common cost allocation method provides PacifiCorp with the opportunity to recover the cost of investments deemed prudent, and provides States with the ability to independently implement State energy policy objectives.

A number of collaborative meetings and conferences occurred during 2002 and 2003, which resulted in the development of the "Protocol" cost allocation methodology proposal. The Protocol was filed with each of the State Commissions[2] in Utah, Oregon, Wyoming and Idaho in September 2003 and in Washington in December 2003. Following discussions with all parties, the proposal was further refined and re-submitted to each of the State Commissions as the "Revised Protocol."

Final ratification of the Revised Protocol was achieved in March 2005 with the State Commissions in Idaho, Oregon, Utah and Wyoming[3] issuing orders approving and accepting the use of the Revised Protocol cost allocation methodology. As part of the ongoing commitments of the Revised Protocol and the associated State Orders, additional analysis was required on the potential for inappropriate costs shifts to other States due to the fastest growing State's load growth.

This PacifiCorp Load Growth Report[4] is the culmination of the analysis and findings carried out from March 2005 to October 2005 by the Company, the Load Growth Workgroup (of interested parties from each State), and the MSP Standing Committee. The report encompasses discussion on the issue of load growth, the extent of any potential inappropriate cost shifts to other States and the development of possible mechanisms to address those potential cost shifts.

[1] MSP Regulatory Dockets are (1) Idaho – PAC-E-02-3, (2) Oregon – UM-1050, (3) Utah – 02-035-04, (4) Washington - UE 020319 or GRC 2003 UE 032065 and GRC 2005 UE 050684, and (5) Wyoming – 20000-EI-02-183.
[2] At the time of completing this Load Growth Report, neither the Protocol, nor Revised Protocol has been filed in the State of California. It is intended that the next general rate case to be filed in that State will be based on the Revised Protocol allocation methodology; however, the timeline associated with such a filing is not confirmed.
[3] The outcome of the GRC 2003 UE 032065 in Washington was the adoption of the Revised Protocol for reporting purposes only. To settle the issue of allocation methodology in that State, the Company's GRC 2005 UE 050684 has been filed recommending the Revised Protocol. The outcome of that proceeding is anticipated in April 2006.
[4] This PacifiCorp Load Growth Report is the product of PacifiCorp. During its drafting, it was circulated to the various members of the Load Growth Workgroup. The Load Growth Workgroup held a series of meetings and discussed the various issues related to the topic of load growth disparities among the States. The process that was conducted was a "collaborative" process, however, while MSP participants had the opportunity to present their viewpoints, PacifiCorp is the author of this report and this report contains the opinions of PacifiCorp.

1.2 PacifiCorp's Conclusion

The results of the analysis and studies carried out by the Company (and discussed with the Load Growth Workgroup) show that the Revised Protocol protects the slower growing States from potential inappropriate cost shifts due to the fastest growing State's load growth. The Company's analysis of Fiscal Years 2007 through 2020 reflected that Utah would be allocated 100%[5] of the incremental cost due to its load growth, As this is the case, it is not necessary to implement a Structural Protection Mechanism ("**SPM**") at this time.

1.3 PacifiCorp's Recommendation

As stated in the conclusion above, and as discussed throughout this report, the Company's current studies show that the Revised Protocol protects the slower growing States from potential inappropriate cost shifts due to the fastest growing State's load growth. Should future analysis suggest there maybe inappropriate cost shifts due to load growth and an SPM is needed to protect the slower growing States, the Company recommends one of the preferred Embedded Cost Differential ("**ECD**") SPMs described in **Sections 5.4.1** and **5.4.2,** or an alternative ECD-based approach, be reviewed and considered for further development in consultation with interested parties, taking into account the relevant factors identified in **Section 2.1.5**.

In furtherance of the work on an SPM, the MSP Standing Committee issued a directive[6] requesting that the Load Growth Workgroup continue this work, at least through December 2005. The Company is therefore coordinating with the MSP Standing Committee and Load Growth Workgroup participants to establish a timeline to finalize the development of a preferred SPM. It is believed that with further discussion and analysis, issues relating to SPMs and their proposed implementation can be resolved.

2. Introduction

2.1 Requirements Under Revised Protocol and MSP State Orders

The Revised Protocol requires the Company, in consultation with other participants, to update the Company's load growth studies, track key factors relevant to cost shifts, develop an SPM, and file a report on these issues with each of the State Commissions who ratified the Revised Protocol, no later than October 20, 2005.

Specifically, the Revised Protocol[7] states:-

> *"In concert with the 2004 IRP cycle, the Company and parties will analyze and quantify potential cost shifts related to faster-growing States (2). In addition, a multi-state workgroup*

[5] Based on a 14-Year NPV @ 8.4277% (Fiscal Years 2007 through 2020) March 2005 Forecast. The 9-Year NPV (Fiscal Years 2007 through 2015) calcul ates to 99%.
[6] MSP Standing Committee directive was advised to MSP Participants on September 23, 2005 via an email from the Committee's Chair (Terri Carlock).
[7] Revised Protocol Section IV.E

will track key factors including actual relative growth rates, forecast relative growth rates, costs of new Resources compared to costs of existing Resources, and other factors deemed relevant to this issue. No later than nine months after filing the 2004 IRP, the Company, in consultation with the MSP Standing Committee and other parties, will file a report with the Commissions regarding this issue. Included in this report will be a description of one or more options for a structural protection mechanism, detailed with sufficient specificity to allow timely implementation in the event that the studies show a material and sustained net harm to customers in any jurisdiction.

The MSP Standing Committee is charged with developing one or more ameliorative mechanisms that could be implemented in a timely manner in the event that the studies show a material and sustained net harm to particular States from the implementation of the IRP. The MSP Standing Committee should consider the impact of load growth in light of all other relevant factors. Potential mechanisms to be studied include tiered allocations, treatment of Seasonal Resources, a structural separation of the Company, temporary assignment of the costs of some new Resources to fast-growing States, and the inclusion of measures of recent load growth in the computation of allocation factors."

Footnote (2) from the Revised Protocol Section IV.E states as follows "This issue will be monitored through studies that compute the costs allocated to each State for two cases: (a) with currently projected load growth together with a least-cost, least-risk mix of Resource additions to meet that growth and (b) with the fastest-growing State growing at the average growth projected for the remaining States, again with a least-cost, least-risk mix of Resource additions".

As well as the language in the Revised Protocol, the State Orders of Oregon and Utah contain specific provisions relating to load growth issues.

The Oregon Order[8] requires the Company to include the Hybrid[9] as one of the potential SPMs. The Oregon Order states:-

"Section IV.E. of the Revised Protocol requires PacifiCorp, in consultation with the MSP Standing Committee and other parties, to file a report regarding load growth issues no later than nine months following the filing of PacifiCorp's 2004 Integrated Resource Plan (IRP). According to the Revised Protocol, this report will include a description of one or more options for structural protection against cost shifting. We direct PacifiCorp to include a fully developed Hybrid Method as one of [the] options for structural protection in this report. To accomplish this, PacifiCorp should work with parties from Oregon and those interested from other states. This Hybrid Method should be designed to meet the three original Commission goals in Order No. 02-193."

The above statement from the Oregon Order makes reference that the Hybrid should be designed to meet three goals of the Oregon Public Utility Commission.

These goals are:-

[8] Oregon Order No. 05-021, dated January 12, 2005, Commission Conditions Section, Page 12
[9] The Hybrid methodology is described in **Section 5.4.3** and the results of the Hybrid studies are included as **Appendix 12**.

1. Determine an allocation methodology that would allow PacifiCorp an opportunity to recover its prudently incurred costs associated with its investment in generation resources;

2. Insure that Oregon's share of PacifiCorp's costs is equitable in relation to other states; and

3. Meet the public interest standard in Oregon.

The Utah Order[10] requires the Company to raise matters relating to load growth to the Utah Public Service Commission before the Company takes a position in front of the MSP Standing Committee. The Utah Order states:-

> *"... [UPSC] will require the Company to file with us [UPSC] regarding the materiality of possible harm to other states from a fast growing jurisdiction before taking a position before the MSP Standing Committee."*

The Idaho[11] and Wyoming[12] State Orders did not contain explicit language relating to load growth issues other than that contained in the Revised Protocol.

In February 2005, interested parties were invited to work with the Company to address all of the above referenced requirements. An initial meeting was held on February 22, 2005 and three workgroups were formed:-

(a) Load Growth Workgroup,

(b) Seasonal Workgroup, and

(c) Hybrid Workgroup.

Work plans for each of the workgroups were developed and monthly meetings were established. Shortly thereafter, and in accordance with the requirements of the Revised Protocol, the Company initiated the formation of the MSP Standing Committee. More information on the workgroups and MSP Standing Committee is included in **Section 2.2**. In addition, the following sub-sections provide information on the specific requirements included in the language referenced above.

2.1.1 PacifiCorp's Studies to Measure Cost Shifts – The Revised Protocol requires participants to analyze and quantify potential inappropriate cost shifts due to the fastest growing State's load growth, in concert with the Company's IRP. The Revised Protocol also identifies the study design.[13]

[10] Utah Order dated December 14, 2004, Section VI. C, Page 38
[11] Idaho Order No. 29708 dated February 28, 2005
[12] Wyoming Order No. 7395 dated March 2, 2005
[13] Revised Protocol Section IV.E Footnote 2

The Company completed the required studies and presented the results at the Load Growth Workgroup meetings held from June 2005 through October 2005. More specific information about the Company's studies is included in **Section 3** and **Appendix 2**. The Company also completed a number of other studies related to potential load growth issues; a list of these studies is also included in **Appendix 2**.

2.1.2 Track Key Factors – The Revised Protocol[14] states:-

> *"a multi-state workgroup will track key factors including actual relative growth rates, forecast relative growth rates, costs of new Resources compared to costs of existing Resources, and other factors deemed relevant to this issue."*

In the Company's studies completed during 2003, 2004 and 2005 (prior to the ratification of the Revised Protocol in March 2005), and in all the Company's studies completed since, three primary elements have been found to increase the potential for inappropriate cost shifts due to the fastest growing State's load growth. These elements are:-

(a) differential load growth – one or more States growing faster than the average of the other States,

(b) addition of new resources – being added to the system at costs above the average of the system, and

(c) mismatch between load growth and new resource additions.

With these elements in mind, tracking factors have been identified as early indicators of potential inappropriate cost shifts due to the fastest growing State's load growth. The specifics of tracking factors are included in **Section 4**.

2.1.3 Develop Structural Protection Mechanisms ("**SPMs**") – The Revised Protocol[15] requires the Company to include, in its Load Growth Report, one or more SPM options that could be implemented in a timely manner should the study results show a potential for inappropriate cost shifts due to the fastest growing State's load growth. The options are required to be presented in sufficient detail to enable implementation in a timely manner. The Revised Protocol also requires that the SPMs will be developed in consultation with the MSP Standing Committee. Specifically, it states:-

[14] Revised Protocol Section IV.E Page 7
[15] Revised Protocol Section IV.E Page 8

> *". . . developing one or more ameliorative mechanisms that could be implemented in a timely manner in the event that the studies show material and sustained net harm to a particular State from implementation of the IRP."*

The Load Growth Workgroup put considerable effort into developing a number of potential SPMs, the details of which are included in **Section 5**.

2.1.4 Identify Process for Implementation of Structural Protection Mechanisms ("**SPMs**") – To meet the "timely implementation" requirement of an SPM, the Load Growth Workgroup decided it would be conducive to develop an implementation process specifying when and how to implement an SPM. Much time was spent considering the workgroup's differing views. Ideas ranged from a trigger point that would lead to the immediate implementation of an SPM to a trigger point that would necessitate further analysis before an SPM is considered appropriate for implementation. Although significant progress was made, at the conclusion of the Load Growth Workgroup meeting held September 13, 2005, the workgroup was unable to reach consensus on the specifications of the preferred SPM or how such an SPM would be implemented. At this time, the SPM and its implementation process remains a priority for the MSP Standing Committee to resolve (see also **Section 6)**. One of the key implementation challenges is that the Company's load growth studies are forward-looking, however, SPMs can only be applied to current test case periods.

On September 23, 2005, the MSP Standing Committee issued a directive[16] requesting that the Load Growth Workgroup continue this work, at least through December 2005. The Company is coordinating with the MSP Standing Committee and Load Growth Workgroup participants to establish a timeline to finalize the development of a preferred SPM. It is believed that with further discussion and analysis, issues relating to SPMs and their proposed implementation can be resolved.

2.1.5 Relevant Factors – The Revised Protocol[17] states:-

> *"The MSP Standing Committee should consider the impact of load growth in light of all relevant factors."*

This statement acknowledges that there may be other factors to consider in addition to the results of the Company's load growth studies when making a decision to implement an SPM. Below are some of the other relevant factors discussed. This list is only a guide and is not intended to be an exhaustive list; there may be other factors, not listed, which may also be deemed relevant (now or in the future):-

[16] MSP Standing Committee directive was advised to MSP Participants on September 23, 2005 via an email from the Committee's Chair (Terri Carlock).
[17] Revised Protocol Section IV.E Page 8

- benefit of operating and planning as an integrated system,
- structural protection provided by the hydro endowment ECD,
- structural protection provided by Seasonal Resources,
- impact of lost hydro generation, value of reserves and value of shaping, as referenced in **Section 3.5**,
- benefit of sharing costs with other States when loads are lost,
- impact of paying for retiring resources and expiring contracts on a system-wide basis,
- overall energy market conditions,
- planning and forecasting assumptions and expectations.

2.1.6 Consultation with MSP Standing Committee – Shortly after the ratification of the Revised Protocol, the MSP Standing Committee was formed. Its charge has been to develop potential ameliorative mechanisms to address potential inappropriate cost shifts due to the fastest growing State's load growth. In addition, the Company has a directive to consult with the MSP Standing Committee regarding the development and inclusion of SPMs in the Company's Load Growth Report. As the majority of the MSP Standing Committee members are also members of the Load Growth Workgroup, the efforts of both have been aligned such that the mechanisms developed in the workgroup forum and presented here, are offered as the same mechanisms developed by the MSP Standing Committee.

2.1.7 File a Load Growth Report – The Revised Protocol[18] states:-

> *"No later than nine months after filing the 2004 IRP, the Company, in consultation with the MSP Standing Committee and other parties, will file a report with the Commissions regarding this issue. Included in this report will be a description of one or more options for a structural protection mechanism, detailed with sufficient specificity to allow timely implementation in the event that the studies show a material and sustained net harm to customers in any jurisdiction."*

The Company's 2004 IRP Report was filed with the State Commissions on January 20, 2005. As such, the deadline for filing a Load Growth Report with the State Commissions was established as October 20, 2005 (nine months later).

[18] Revised Protocol Section IV.E Page 7

An outline of PacifiCorp's Load Growth Report was presented to the Load Growth Workgroup at its meeting in August 2005, and an initial draft of the report's content was presented in September 2005. A final draft was presented to the Load Growth Workgroup in October 2005; the same was also provided to the MSP Standing Committee members.

On October 20, 2005, this PacifiCorp Load Growth Report was filed with the State Commissions who ratified the Revised Protocol (Idaho, Oregon, Utah and Wyoming) and submitted, for informational purposes, to the State Commissions in Washington and California.

2.2 Process

2.2.1 Formation of the Load Growth Workgroup – At the February 22, 2005 meeting referenced in **Section 2.1**, the Company initiated the formation of the Load Growth Workgroup to specifically focus on issues related to load growth and to address specific requirements contained in the Revised Protocol. A work plan was prepared, monthly meetings were scheduled, and an issues list was developed. The participants agreed that the development of a Hybrid, as required by the Oregon Public Utility Commission's Order would be performed within the Hybrid Workgroup, but the development of the Hybrid as an SPM would be addressed by the Load Growth Workgroup (information regarding the Hybrid is included in **Section 5.4.3**).

2.2.2 Load Growth Workgroup Work Plan – At the March 30, 2005 meeting of the Load Growth Workgroup, the Company presented a proposed scope and work plan. The work plan covered five major tasks for the workgroup, summarized as:-

(a) Develop key tracking factors;

(b) File Load Growth Report by October 20, 2005;

(c) Compute the costs allocated to each State for two cases utilizing the Company's load growth studies defined within the Revised Protocol;

(d) Develop structural protection mechanisms; and

(e) Consider other relevant factors.

A copy of the original scope and work plan document is included as **Appendix 3**. The workgroup kept to schedule throughout the process and has met its deliverables accordingly.

2.2.3 Load Growth Workgroup Meetings - The Load Growth Workgroup held eight meetings during March 2005 through October 2005, culminating in the filing of this PacifiCorp Load Growth Report. Prior to each meeting, an agenda and meeting materials were prepared by the Company and provided to the participants. Meeting summaries briefly recording the progress of the workgroup were circulated to participants after each meeting. Below is a list of the meetings held, together with a brief description of the key topics covered:-

March 30, 2005

- Workgroup Guidelines
- Scope and Work Plan
- Initial Discussion on Key Tracking Factors
- Initial Discussion on Resource Additions for Average Growth Study
- Prioritization of Load Growth Issues List

May 4, 2005

- Discussion on Key Tracking Factors
- Initial Discussion on Structural Protection Mechanisms
- Identification of Analysis
- Review of Study Assumptions

June 1, 2005

- Discussion on Key Tracking Factors
- Structural Protection Mechanisms – Tiered Allocation Approaches
- Initial Discussion on Evaluation Criteria

June 29, 2005

- Analysis Assumptions and Results
- Structural Protection Mechanisms – Tiered Allocation and ECD Approaches
- Review of Load Growth Work Plan

August 10, 2005

- Analysis Assumptions and Results
- Structural Protection Mechanisms – Tiered Allocation, ECD and Lump Sum Approaches
- Draft Outline of Load Growth Report

August 23, 2005

- Structural Protection Mechanisms – Tiered Allocation, ECD and Lump Sum Approaches
- Preliminary Rankings of Structural Protection Mechanisms

- Draft Outline of Load Growth Report

September 13, 2005
- Structural Protection Mechanisms – ECD and Lump Sum Approaches
- Rankings of Structural Protection Mechanisms
- Draft Load Growth Report

October 11, 2005
- Final Review of PacifiCorp's Load Growth Report
- Analysis and Results
- MSP Standing Committee Directive

3. PacifiCorp's Load Growth Studies and Analysis

3.1 PacifiCorp's Load Growth Study Approach and Assumptions

As set out in the Revised Protocol (and as referenced in **Section 2.1**), two studies are identified to analyze load growth issues:-

- Study 1 - a study with currently projected load growth together with a least-cost, least-risk mix of resource additions[19] to meet load growth and,

- Study 2 - a study with the fastest growing State growing at the average growth projected for the other States, again with a least-cost, least-risk mix of resource additions.[20] Throughout the analysis leading up to this report, Utah was consistently identified as the fastest growing State.

In order to perform the required analysis, the Company completed a number of studies, a list of which is included as **Appendix 2**. For consistency purposes, the study assumptions in the Company's Generation and Regulation Initiatives Decision tool ("**GRID**") and Regulatory Forecast Model ("**RFM**") were updated to match the assumptions in the Company's 2004 IRP Report. Lists of the study assumptions are included as **Appendices 4** and **5**.

In Study 2, where the fastest growing State is adjusted to the average of the other States, Utah's compound annual peak load growth rate is reduced from 4.1% (forecast growth rate) to 1.5% (average growth rate of other States). The IRP Preferred Portfolio, from the Company's 2004 IRP Report, is then adjusted by removing planned resources, as needed, in order to maintain a consistent planning margin (no lower than a 15% planning margin). The adjusted portfolio was prepared by the Company's IRP Group and is included as **Appendix 6**.

[19] Based in the Company's 2004 IRP Preferred Portfolio E with DSM (Original)
[20] Based on the Company's 2004 IRP Preferred Portfolio E with DSM (adjusted to maintain planning margin)

In the Company's studies, two scenarios were utilized:-

(1) the June 2004 or CG24 market and gas forecast (the "**June 2004 Forecast**")[21], and later

(2) the March 2005 or CG27 market and gas forecast (the "**March 2005 Forecast**").

The Load Growth Workgroup believed it was important to use a more recent natural gas and market price projection in the Company's studies performed, especially as the March 2005 prices exceeded those in June 2004 by approximately 40% for natural gas and 20% for market prices. Details of the June 2004 Forecast and the March 2005 Forecast is included as **Appendix 7**.

For comparison purposes, the Company's studies were run using each of the following allocation methodologies:-

(a) Revised Protocol,

(b) Rolled-In,

(c) Modified Accord, and

(d) Hybrid (information on the Hybrid is included in **Section 5.4.3).**

3.2 PacifiCorp's Load Growth Study Results

Under the Revised Protocol, the results of the Company's load growth studies show that between 100%[22] and 106%[23] of the incremental cost of load growth would be assigned to Utah (the fastest growing State). The Company's studies did not show that the slower growing States suffered any material and sustained harm from Utah's faster growth. Based on these results, the Company concludes the Revised Protocol provides adequate protection to slower growing States from potential inappropriate cost shifts due to the fastest growing State's load growth. The primary factors for the Revised Protocol providing this protection are:-

- dynamic allocation factors;
- the hydro endowment ECD;
- the treatment of Seasonal Resources.

[21] The use of the June 2004 Forecast is consistent with the assumptions used in the Company's 2004 IRP
[22] Based on a 14-Year NPV @ 8.4277% (Fiscal Years 2007 through 2020) March 2005 Forecast. The 9-Year NPV (Fiscal Years 2007 through 2015) calculates to 99%.
[23] Based on a 14-Year NPV @ 8.4277% (Fiscal Years 2007 through 2020) June 2004 Forecast. The 9-Year NPV (Fiscal Years 2007 through 2015) calculates to 105%.

More specifically:-

3.2.1 June 2004 Forecast Studies – Utilizing the June 2004 Forecast, the results of Study 2 (as referenced in **Section 3.1**) were compared with the results of the Study 1 (also referenced in **Section 3.1**). The Revised Protocol results demonstrate 106%[24] of the incremental costs related to load growth would be allocated to Utah, the fastest growing State.

3.2.2 March 2005 Forecast Studies – Utilizing the March 2005 Forecast, the results of Study 2 (as referenced in **Section 3.1**) were compared with the results of Study 1 (also referenced in **Section 3.1**). The Revised Protocol results demonstrate 100%[25] of the incremental costs related to load growth would be allocated to Utah, the fastest growing State.

Table 1 presents a summary of the results of the Company's studies by state, as referenced in **Sections 3.2.1** and **3.2.2**.

Table 1
Percentage of Load Growth Cost Allocated by State
(Revised Protocol)
(Adjusted to Maintain Consistent IRP Planning Margins)
(Load Growth Workgroup Meeting – August 10, 2005)

State	9 Year NPV (2007 – 2015) @ 8.4277%		14 Year NPV (2007 – 2020)@ 8.4277%	
	Costs June 2004 Forecast	**Costs March 2005 Forecast**	**Costs June 2004 Forecast**	**Costs March 2005 Forecast**
California	-0.3%	-0.1%	-0.3%	-0.1%
Oregon	-2.8%	0.0%	-3.6%	-0.8%
Washington	-1.2%	-0.2%	-1.3%	-0.4%
Utah	**104.8%**	**98.8%**	**105.9%**	**100.1%**
Idaho	0.4%	1.0%	0.1%	0.6%
Wyoming	-0.9%	0.6%	-0.8%	0.5%

In analyzing load growth issues, the Company also performed and presented a number of additional studies; a list of these studies is included as **Appendix 2**.

[24] Based on a 14-Year NPV @ 8.4277% (Fiscal Years 2007 through 2020) June 2004 Forecast. The 9-Year NPV (Fiscal Years 2007 through 2015) calculates to 105%.
[25] Based on a 14-Year NPV @ 8.4277% (Fiscal Years 2007 through 2020) March 2005 Forecast. The 9-Year NPV (Fiscal Years 2007 through 2015) calculates to 99%.

3.3 Comparison to PacifiCorp's Previous Load Growth Study Results

Following the 2003 MSP Filing[26], and at the request of Oregon[27] and Utah[28] parties, the Company completed a number of studies to analyze potential inappropriate cost shifts due to the fastest growing State's load growth. Most of the Company's studies assumed either a one-time increase in Utah loads or a continuing pattern of higher Utah load growth which were matched with different types of Resource additions. The Company performed additional studies assuming higher Oregon load growth and corresponding Resource additions.

In the Company's previous studies, the results showed that, under the Revised Protocol, the fastest growing State supported between 86%[29] and 127%[30] of the incremental cost of load growth. As indicated in **Section 3.2**, the Company's current load growth studies show between 100%[31] and 106%[32] of the incremental cost of load growth would be allocated to the fastest growing State.

The Company's current studies are believed to be an improvement on the previous studies for several reasons, including:-

(1) to ensure a better match of the loads and resources, the current studies were based on the Company's 2004 IRP with additions and deletions identified by the Company's IRP Group,

(2) in the Company's current studies, a consistent planning margin was maintained (no lower than 15%); previous studies were not modeled as precisely.

(3) in the Company's current studies, both plants and contracts are added/deleted; previous studies only added/deleted plants.

When comparing the Company's previous load growth studies to the Company's current load growth studies, the Company concludes that the results show the Revised Protocol provides adequate protection to slower growing States from potential inappropriate cost shifts due to the fastest growing State's load growth. The primary factors for the Revised Protocol providing this protection are:-

- dynamic allocation factors;
- the hydro endowment ECD;

[26] The 2003 MSP Filing was submitted to the States of Idaho, Oregon, Utah and Wyoming on September 30, 2003. Regulatory Dockets PAC-E-02-3 (Idaho), UM-1050 (Oregon), 02-035-04 (Utah) and 20000-EI-02-183 (Wyoming) refer.
[27] MSP Regulatory Docket UM-1050 / OPUC Staff Data Requests 59 and 60
[28] MSP Regulatory Docket 02-035-04 / DPU Data Request 7.3 and CCS Data Request 10.1
[29] Based on a 14-Year NPV (Fiscal Years 2005 through 2018)
[30] Based on a 14-Year NPV (Fiscal Years 2005 through 2018)
[31] Based on a 14-Year NPV (Fiscal Years 2007 through 2020) March 2005 Forecast
[32] Based on a 14-Year NPV (Fiscal Years 2007 through 2020) June 2004 Forecast

- the treatment of Seasonal Resources.

3.4 Additional Findings

In addition to the conclusions referenced in **Sections 3.2,** and **3.3**, the Company's findings of the principal drivers of the study outcomes are:-

(a) the greater the rate of growth of one State compared to other States, the greater the potential for inappropriate cost shifts to slower growing States,

(b) the higher the cost of new resource additions compared to existing resources, the greater the potential for inappropriate cost shifts to slower growing States, and

(c) the better the match between new resource additions and load patterns through an effective IRP process, the lower the potential for inappropriate cost shifts to slower growing States.

3.5 Other Analysis

During the Load Growth Workgroup meetings, the Company was directly approached by Oregon Commission Staff and requested to update analysis provided in previous data requests.[33] The analysis looked at the value of reserves, the value of shaping, and the value of lost hydro generation; elements not incorporated into the Revised Protocol. Oregon believes that without these elements integrated into the Revised Protocol, they are not receiving the full benefits of hydro within the hydro endowment. However, under the Revised Protocol's hydro endowment, Oregon is not bearing the cost for the replacement of lost hydro generation.[34] After reviewing the original and updated analysis, the Company concludes the value of reserves together with the value of shaping offset the value of lost hydro generation during the identified study period. The Company further concludes that the inclusion of these three elements in the Revised Protocol would not change the allocation of costs among the States. No further work has been performed on these elements and no further work has been requested.

4. Tracking Key Factors

4.1 Purpose of Tracking Key Factors

As referenced in **Section 2.1**, the Load Growth Workgroup was tasked with developing and tracking key relevant factors to act as early identifiers of potential inappropriate cost shifts due to the fastest growing State's load growth. As defined in

[33] MSP Docket UM-1050 OPUC Staff Data Requests 68, 70, 74, and 75
[34] Lost hydro generation from Hydro-Electric Resources and Mid-Columbia Contracts as a result of relicensing, contract renegotiation and plant retirements.

the Revised Protocol[35] and as further identified by Load Growth Workgroup participants, key factors for load growth and potential cost shifts include:-

(1) Historical Relative Load Growth Rates,

(2) Forecast Relative Load Growth Rates,

(3) Cost of New Resources Compared to Cost of Existing Resources,

(4) Market Prices,

(5) Forecast Demand Side Management Compared to Actual Demand Side Management ("**DSM**"), and

(6) Rate Design Changes.

More detail on these factors is included in **Section 4.2**.

4.2 Description and Source of Factors

4.2.1 Historical Relative Load Growth Rate – provides an historical view of the peak and energy growth in the PacifiCorp system, how each State's growth compares to the other States, and which State experienced the highest growth.

The purpose of this tracking factor is to identify disproportionate growth in one State as compared to the rest of the system as this could indicate a potential for inappropriate cost shifts due to the fastest growing State's load growth.

Historical peak and energy load data, along with the SG and SE factors, is included in the Company's Semi-Annual/Annual Filing.[36] In addition, the Company's historical peak and energy data is included in the Company's 2004 IRP Report.[37]

4.2.2 Forecast Relative Load Growth Rate – while historical relative load growth rate provides an overview of historical peak and energy growth, the forecasted relative load growth rate provides a projection of where system growth is expected to occur, including which State is expected to experience the highest growth in energy and peak demand.

[35] Revised Protocol Section IV.E Page 7
[36] Company's Semi-Annual/Annual Filing, "Allocation Factor" tab
[37] 2004 IRP Report, Technical Appendix I "Retail Load Forecasting"

The purpose of this tracking factor is to help identify forecasted growth in one State, exceeding the average of the other States, as this could indicate a potential for inappropriate cost shifts due to the fastest growing State's load growth. The Company's forecasted peak and energy load data is included in the Company's 2004 IRP Report.[38]

4.2.3 Cost of New Resources Compared to Cost of Existing Resources – the need for new resources can be driven by many factors including, among others, expiring purchase contracts, plant retirements, and load growth, with new and replacement resources typically more expensive than the existing resources.

The purpose of this tracking factor is to help identify when the differential between the cost of new resources and the cost of existing resources grows, as this may indicate an increase in the potential for inappropriate cost shifts due to the fastest growing State's load growth.

The actual cost of existing resources is reported in the Company's Semi-Annual/Annual Filing.[39] In addition, the Company's forecasted cost of new resources is included in the Company's 2004 IRP Report.[40]

4.2.4 Market Prices – as referenced in **Section 4.2.3**, there are several factors impacting the need for replacement resources. The need for replacement resources, along with an increasing demand for energy, may increase the Company's potential market exposure.

The purpose of this tracking factor is to help identify rising market prices during a time of load growth as this could increase the potential for inappropriate cost shifts due to the fastest growing State's load growth. The Company's forecasted market prices are included in the Company's 2004 IRP Report[41] and reflected in graph form in **Appendix 7**.

4.2.5 Forecast Demand Side Management Compared to Actual Demand Side Management ("**DSM**") – for many years, the Company has been operating several DSM programs in each of its six State service territories. There are four general classes of DSM[42] programs ranging from those aimed at conservation education to programs including resources able to be dispatched that the Company uses to proactively manage loads. Each program is designed to reduce energy and/or peak use.

[38] 2004 IRP Report, Technical Appendix I "Retail Load Forecasting"
[39] Company's Semi-Annual/Annual Filing, "Annual Embedded Costs – All Other"
[40] 2004 IRP Report, Technical Appendix C "Base Assumptions Table C.27 and C.28"
[41] 2004 IRP Report, Technical Appendix C "Base Assumptions Figure C.4"
[42] 2004 IRP Report, Chapter 2 Pg 30 to 32, Chapter 2 "Table 2.4 and 2.5", Technical Appendix C "Base Assumptions Tables C.10 to C.22" and Technical Appendix C Pg 62 to 64

Projected DSM programs and assumptions are included in the Company's 2004 IRP Report[43]; and under the Revised Protocol, the costs and benefits are situs assigned to the State sponsoring the DSM activity. PacifiCorp's DSM activities[44] are tracked by the Company's DSM Group, although no formal reporting is required at this time. Tracking these programs helps to identify actions being taken by each State to reduce load growth.

At the June 2005 meetings of the Load Growth Workgroup, the Company presented information about each State's DSM activities, including a summary which displayed DSM targets and accomplishments. This information shows that customers in Utah, the fastest growing State, are currently paying a 3% surcharge for DSM programs.

4.2.6 Rate Design Changes – There have been several recent rate design changes in Utah intended to address load growth. Some of the residential design changes include seasonal rates, inverted block rates, and time-of-use rates. Seasonal rates became effective in April 2004. Customers are charged a higher rate from May through September. Inverted block rates consist of a three-block design where customers using 1,000 kWh/month (or more) are charged 9.272 cents/kWh. Time-of-use rates are part of an experimental program introduced in April 2004. For small- and medium-service customers, there are seasonal rates and two optional time-of-use rates. Large industrial customers and general service customers also have seasonal rates and mandatory time-of-use rates.

As with the DSM programs referenced in **Section 4.2.5**, the purpose of this tracking factor is to help identify actions taken to reduce load growth.

5. Structural Protection Mechanisms ("SPMs")

5.1 General Discussion

The Revised Protocol[45] states:-,

> *"…the Company, in consultation with the MSP Standing Committee and other parties, will file a report with the Commissions regarding this issue [Load Growth]. Included in this report will be a description of one or more options for a structural protection mechanism, detailed with sufficient specificity to allow timely implementation in the event that the studies show a material and sustained net harm to customers in any jurisdiction."*

[43] 2004 IRP Report, Chapter 2 Pg 30 to 32, Chapter 2 "Table 2.4 and 2.5", Technical Appendix C "Base Assumptions Tables C.10 to C.22" and Technical Appendix C Pg 62 to 64
[44] DSM activity in Oregon is tracked by The Energy Trust of Oregon
[45] Revised Protocol Section IV.E

In accordance with this requirement, the Load Growth Workgroup developed and considered seven SPMs:-

(1) Embedded Cost Differential ("**ECD Alternative 1**") – see **Section 5.4.1** and **Appendices 8 and 11**,

(2) Embedded Cost Differential ("**ECD Alternative 2**") – see **Section 5.4.2** and **Appendices 9, 10** and **11**,

(3) Hybrid – see **Section 5.4.3** and **Appendix 12**,

(4) Tiered Allocations ("**Tiered Alternative 1**") – see **Section 5.4.4** and **Appendices 13** and **15**,

(5) Tiered Allocations ("**Tiered Alternative 2**") – see **Section 5.4.5** and **Appendices 14** and **15**,

(6) Structural Separation – see **Section 5.4.6** , and

(7) Seasonal Resources – see **Section 5.4.7**.

Each of the SPMs listed above were developed (to varying degrees), evaluated and ranked according to the criteria and process provided in **Section 5.2**. The key issues considered, when evaluating each of the proposals, included (1) the level of protection the SPM provided from inappropriate cost shifts due to load growth, (2) the level of complexity for understanding and communicating, (3) the ease in which the SPM can be implemented and administered, and (4) whether the SPM would lead to unintended consequences. Details of the ranking process and criteria are included in **Section 5.2**, the results of the ranking process are included in **Section 5.3** and a description of each SPM is included in **Section 5.4**.

5.2 Evaluation Criteria and Ranking Process

Following discussions at the March 2005 Load Growth Workgroup meeting, a sub-committee met in April 2005 to develop criteria for evaluating each potential SPM.

The draft evaluation criteria, developed by the sub-committee, was presented and discussed at the May 2005 and June 2005 meetings of the Load Growth Workgroup, with an additional meeting held in July 2005 to finalize the evaluation criteria. Preliminary rankings of each proposed SPM were initiated by the Company and provided to participants for discussion at the August 2005 Load Growth Workgroup meeting.

The final set of evaluation criteria, developed by the sub-committee and the Load Growth Workgroup, are provided below. A more detailed description of each is included as **Appendix 16**:-

A. Consistent with Revised Protocol

B. Degree of Protection from Load Growth

C. Equitable in Treatment Among the States

D. Does Not Create Unintended Consequences

E. Consistent with Utility System Least-Cost Planning

F. Consistent with Minimizing Total System Operating Costs

G. Aligns Assignment of Costs and Benefits of New Resources

H. Can be Implemented in a Timely Manner

I. Easy to Understand

J. Simple to Implement, Track and Maintain

5.3 Ranking of Structural Protection Mechanisms ("SPMs")

Table 2 provides an overview of the Company's ranking of each SPM, reflecting a "high" or "low" measure to indicate how well each SPM is anticipated to perform to the evaluation criteria, compared to each other. A detailed description of each SPM is included in **Section 5.4.**

Table 2
PacifiCorp's Ranking of Structural Protection Mechanisms

Model	Ranking to Evaluation Criteria	Load Growth Report Reference
Preferred SPM Proposals:-		
- ECD Alternative 1	High	Section 5.4.1
- ECD Alternative 2	High	Section 5.4.2
(Also refer to **Appendices 8**, **9**, **10**, **11** and **12**)		
Other SPM Proposals:-		
Hybrid	Low	Section 5.4.3
Tiered Alternative 1	Low	Section 5.4.4
Tiered Alternative 2	Low	Section 5.4.5
(Also refer to **Appendices 13, 14 and 15**)		
SPM Proposals Not Pursued:-		
- Structural Separation	Not Ranked	Section 5.4.6
- Seasonal Resources	Not Ranked	Section 5.4.7

5.4 Description of Structural Protection Mechanisms ("SPMs")

Preferred SPM Proposals

The following two ECD-based SPMs ranked "high" as they show the most promise for addressing potential cost shifts due to the fastest growing State's load growth. Although there is consensus among many of the workgroup participants that ECD-based SPMs are superior to other SPMs under consideration, neither of these approaches are agreed to or finalized in sufficient detail to allow timely implementation. Overall, the ECD-based SPMs appear more promising than other SPMs as they are designed specifically to target and remedy inappropriate cost shifts due to the fastest growing State's load growth in the event a material and sustained harm is determined, and their methodology is more consistent with the Revised Protocol. The Company therefore recommends either of these two SPMs, or an alternative ECD-based SPM, merit further review, development and consideration under the MSP Standing Committee Directive.[46]

[46] On September 23, 2005, the MSP Standing Committee issued a directive [46] requesting that the Load Growth Workgroup continue working to complete this work, at least through December 2005. The Company is coordinating with the MSP Standing Committee and Load Growth Workgroup participants to establish a timeline to finalize the development of a preferred SPM. It is believed that with further discussion and analysis, issues related to SPMs and their proposed implementation can be resolved.

5.4.1 Embedded Cost Differential Method ("**ECD Alternative 1**") - ECD Alternative 1 is based on the temporary assignment of new resources to the fastest growing State. The costs of all resources are allocated on system load based allocation factors. The ECD Alternative 1 provides a supplemental allocation of the amount by which the cost of the new resource(s) exceeds the average embedded cost of existing resources for a temporary two year period.

The Company provided an example of the estimated annual ECD Alternative 1 adjustment, beginning in Fiscal Year 2010 (when the first new IRP Resource is estimated to come on-line), through Fiscal Year 2017 (two years after the last new IRP Resource is estimated to come on-line). The results were shared with the Load Growth Workgroup in August 2005.

The Company's ranking of "high" reflects that this type of SPM is considered easy to comprehend, mechanically simple to implement, and is consistent with the basic concepts embodied in the Revised Protocol. However, the drawback is that it has not been shown to result in a sufficient redistribution of costs.

The paper that presented ECD Alternative 1 to Load Growth Workgroup participants is included as **Appendix 8**. Also, ECD Alternative 1 was qualitatively contrasted with ECD Alternative 2, the outcome of which is included as **Appendix 11**.

5.4.2 Embedded Cost Differential ("**ECD Alternative 2**") - The approach of ECD Alternative 2 proposes a direct (and permanent) assignment of resources as a protection against load growth. The method also determines if the fastest growing State is covering its costs by conducting a load growth study using two 10-year GRID runs (5-historical and 5-forecast).

The 10-year NPV results of the two studies are compared to calculate what percentage increase in costs from higher load levels is allocated to the fastest growing State. The implementation of ECD Alternative 2 is a lump sum transfer payment approach calculated such that the fastest growing State bears 95% of the costs of a new resource(s) that are deemed to be required in order to meet the differential in load growth, and assuming pre-determined triggers are met. A key element of this SPM approach is the attaching of the ECD to specific resources, on a permanent basis.

The Load Growth Workgroup discussed the details of this proposal at its meeting in August 2005. Based on feedback and comments received, changes were incorporated and a revised proposal was considered.

The Company's ranking of "high" reflects that ECD Alternative 2 is considered arithmetically straight-forward and requires a relatively simple adjustment to the Revised Protocol. However, this proposal requires multiple GRID runs and a re-fit of existing resources to a hypothetical load level. Additionally, this method raises the potential to re-open decisions of previously settled rate cases with its 5-year historical analysis, and it might require dollar adjustments to be included into a general rate case for plants projected to come on line in the future, which may not, in real time, come on line at all. In response to this latter concern, discussions focused on limiting the forecast to the end of a rate case test period.

The paper that presented ECD Alternative 2 to Load Growth Workgroup participants is included as **Appendix 9**. Additionally, a Lump Sum Transfer Proposal, the mechanics of which are included into ECD Alternative 2, was originally presented as a separate SPM proposal. The paper that presented the Lump Sum Transfer approach to Load Growth Workgroup participants is included as **Appendix 10**. Also, ECD Alternative 2 was qualitatively contrasted with ECD Alternative 1, the outcome of which is included as **Appendix 11**.

Other SPM Proposals

The following three SPMs ranked "low", reflecting less promise for addressing potential load growth issues. These SPMs have also attracted little or no consensus as to their mechanics (other than Hybrid) among workgroup participants and the Company considers them complex and challenging to implement. As such, the Company does not consider these SPMs suitable options for implementation if and when any future load growth issues arise. This is also based on the conclusion that an ECD-based approach, like those described in **Section 5.4 1** and **Section 5.4.2,** appears to be more promising and mechanically more agreeable to workgroup participants.

5.4.3 Hybrid – This SPM approach is based on the Hybrid that has been under development within the Hybrid Workgroup since March 2005. In offering the details of this method as a potential SPM, it should be noted that the Hybrid is not an agreed or acceptable cost allocation methodology among any of the States in which the Company operates and has been solely developed for reporting purposes only, as specifically directed by the Oregon Public Utility Commission. The Oregon Order[47] specifically states:-

> *"… We direct PacifiCorp to include a fully developed Hybrid Method as one of [the] options for structural protection in this [Load Growth] report. To accomplish this, PacifiCorp should work with parties from Oregon and those interested from other states. This Hybrid Method should be designed to*

[47] Oregon Order No. 05-021, dated January 12, 2005, Commission Conditions Section, Page 12

meet the three original Commission goals in Order No. 02-193. Once completed, the participating Oregon parties are to present the Hybrid Method to the Commission no later than December 1, 2005.

Furthermore, while the Revised Protocol uses the Modified Accord as a comparator for the Revised Protocol, we want to also use the Hybrid Method as a comparator. Therefore, upon approval of the agreed-upon Hybrid Method, or January 1, 2006, whichever comes first, PacifiCorp must file its annual reports and general rate case filings comparing results under the Revised Protocol with both Modified Accord and Hybrid Method results."

The Hybrid is an accounting assignment of all loads and resources to the control area where they were physically located (with exceptions). The East Control Area contains loads for Idaho, Utah and Wyoming, while the West Control Area contains loads for California, Oregon and Washington. The East and West Control Areas are balanced using a complex interchange accounting methodology that assigns system balancing sales and purchases, on an hourly basis, using MWhs and market prices.[48]

Conceptually, the Hybrid provides a structural-type approach to separate the resources added to meet loads in each of the control areas, while retaining the primary hydro resources within the West Control Area. Exceptions to the direct control area assignments have been factored into the methodology to better balance the loads and resources in each control area and to reflect deliveries from certain exchanges.

Several studies were run by the Company to assess the Hybrid, including the potential of the Hybrid as an SPM to manage inappropriate cost shifts of the fastest growing State's load growth. **Table 3** presents the results of the Hybrid load growth study performed under the March 2005 Forecast. A list of all of the Company's Hybrid studies is included as **Appendix 12**.

[48] A detailed description of the Hybrid will be contained in the material that will be presented to the Oregon Public Utility Commissions, anticipated to be available by December 1, 2005.

Table 3
Percentage of Load Growth Cost Allocated by State
(Hybrid – Case 3b1a)
(with Intra-Control Area Equity Measures)
(Load Growth Workgroup Meeting – October 11, 2005)

State	Costs March 2005 Forecast 9 Year NPV (2007-2015)	Costs March 2005 Forecast 14 Year NPV (2007-2020)
California	0.3%	0.4%
Oregon	5.8%	7.1%
Washington	1.8%	2.3%
Utah	86.7%	86.6%
Idaho	1.5%	1.0%
Wyoming	3.8%	2.7%

The Company ranks the Hybrid "low". The ranking reflects (1) the Hybrid does not protect all States from inappropriate cost shifts due to the fastest growing State's load growth, (2) has little support of workgroup participants, (3) is a significant departure from the Revised Protocol, (4) has the potential for unintended consequences, and (5) has the potential to deviate from system-wide, integrated planning. On this basis, the Company would not recommend the Hybrid be considered as a potential SPM.

5.4.4 Tiered Allocation ("**Tiered Alternative 1**") – Tiered Alternative 1 allocates generation and purchase resources, and loads into two tiers. The existing resources acquired prior to a trigger date are placed in Tier 1 and allocated to the States based on loads at the trigger date. As the system grows, as contracts expire and as resources retire, new resources are acquired. These new resources are placed in Tier 2 and allocated to the States causing the incremental loads above Tier 1 loads. The effect of using this method segregates incremental system costs into Tier 2 loads. Over time, Tier 1 loads are shifted to Tier 2 as Tier 1 resources expire or retire. The fastest growing State is allocated a larger share of Tier 2 within their revenue requirement calculations. The overall effect of moving all resources into Tier 2 is to gradually move allocations back to a single tier. The Company has not performed any detailed analysis or specific modeling relating to Tiered Alternative 1.

The Load Growth Workgroup discussed and developed Tiered Alternative 1 at its meetings from May 2005 through August 2005. The paper presenting Tiered Alternative 1 included as **Appendix 13**. Also, Tiered Alternative 1 was qualitatively contrasted with Tiered Alternative 2, the outcome of which is provided as **Appendix 15**.

The Company ranks Tiered Alternative 1 "low". Specifically, it is not clear that Tier 2 would, in practice, capture only inappropriate cost shifts due to the fastest growing State's load growth and therefore it is not considered a reasonable approach for protecting States from such cost shifts. It is also considered complex to implement, track and maintain. On this basis, the Company would not recommend Tiered Alternative 1 be considered as a potential SPM.

5.4.5 Tiered Allocation ("**Tiered Alternative 2**") - This approach is based on assigning generation and purchase resources and loads into multiple tiers (or vintages) which segregates existing resources from new resources, with the fastest growing State being allocated a larger share of a new resource. The trigger dates occur once a new resource is added and as loads exceed resource capacity in the prior tier. The Company has not performed any detailed analysis or specific modeling relating to Tiered Alternative 2.

The Load Growth Workgroup discussed and developed the Tiered Alternative 2 at its meetings in June 2005 through August 2005. The initial paper presenting Tiered Alternative 2 included as **Appendix 14**. Also, Tiered Alternative 2 was qualitatively contrasted with Tiered Alternative 1, the outcome of which is provided as **Appendix 15**.

As with Tiered Alternative 1, the Company ranks Tiered Alternative 2 "low" in terms of its promise as an SPM. Specifically, it is not clear that multiple tiers would, in practice, only capture inappropriate cost shifts due to the fastest growing State's load growth and therefore it is not considered a reasonable approach for protecting States from such cost shifts. It is also considered complex to implement, track and maintain. On this basis, the Company would also not recommend Tiered Alternative 2 be considered as a potential SPM.

In summary, both of the tiered alternative proposals referenced in **Sections 5.4.4** and **5.4.5** are complex and represent a significant deviation from the Revised Protocol. The design of a tiered allocation proposal requires a number of decisions, including the number of tiers, timing of creating a tier, deciding which tier a resource is placed in, and deciding what happens to the tiers when loads increase or decrease and resources are acquired, expire or retire. It should also be noted that resource additions are not always driven by load growth, but may be caused by a need to replace expiring or retiring resources. The tiered-based proposals have the potential for unknown and unintended consequences, and workgroup participants have not expressed any interest in further developing a tiered-based SPM.

SPM Proposals Not Pursued

The last two SPMs have not been ranked and have not been fully developed (nor modeled) by the Load Growth Workgroup. The Company considers these SPMs to be overly complex, a significant deviation from the Revised Protocol and would not recommend any additional work be carried out on these SPM proposals.

5.4.6 Structural Separation - Structural separation of the Company's system was identified as an option for consideration as a SPM in the Revised Protocol. In particular, a number of possible scenarios have received initial consideration, such as a divisional separation (similar to a UP&L and PP&L type separation), a control area-based separation (similar to the Hybrid), an operating company separation and a physical separation (similar to the Company's Structural Realignment Proposal[49]). As well as requiring a structural separation approach to be considered as an SPM option, the Revised Protocol also contained a caveat that an SPM should be able to be implemented in a timely manner.

Recognizing that any potential structural separation would require significant time and attention to both develop and implement, the workgroup did not focus on developing a structural separation option as part of this effort. As such, no structural separation proposals exist for consideration at this time.

5.4.7 Seasonal Resources - Alternate treatment for Seasonal Resources was specifically identified in the Revised Protocol[50] to be considered as an SPM. Due to the work priorities of the Load Growth and Hybrid Workgroups, issues related to Seasonal Resources played a smaller part of the overall discussions. Ultimately, work on the alternate treatment of Seasonal Resources was suspended for two reasons – (1) the Company's updated studies utilizing Revised Protocol indicated that the impact of Seasonal Resources was relatively small in the context of the overall Revised Protocol, and (2) the participants most interested in Seasonal Resources were no longer available to dedicate efforts to explore alternatives.

At the June 2005 Seasonal Workgroup meeting, it was agreed to suspend further discussions on Seasonal Resources.

5.5 PacifiCorp's Structural Protection Mechanism ("SPM") Recommendation

The analysis and studies carried out by the Company, and discussed with participants of the Load Growth Workgroup, show that the Revised Protocol currently protects the slower growing States from potential inappropriate cost shifts due to the

[49] The Company's Structural Realignment Proposal was filed with each State Commission in 2000. Regulatory Dockets are (1) Idaho – PAC-E-00-6, (2) Oregon – UM-1001, (3) Utah – 00-035-15, (4) Washington – UE-001878, and (5) Wyoming – 20000-EA-00-161. This proposal was not filed in the State of California.
[50] Revised Protocol Section IV.A Page 3, Section IV.E Page 8 and Section XIII Page 13

fastest growing State's load growth. As this is the case, it is not necessary to implement an SPM at this time.

However, should future analysis suggest there is a potential for inappropriate cost shifts due to the fastest growing State's load growth, and an SPM is needed to protect the slower growing States, the Company recommends one of the preferred SPMs described in **Sections 5.4.1** and **5.4.2** or an alternative ECD-based approach be reviewed and considered for further development in consultation with interested parties, taking into account the relevant factors identified in **Section 2.1.5**.

6. Process for Implementing Recommended Structural Protection Mechanism ("SPM")

As previously noted in this report, the results of the Company's current load growth studies do not appear to indicate there is a potential for material and sustained harm resulting from inappropriate cost shifts due to the fastest growing State's load growth. Therefore, there is no need to implement a structural protection mechanism at this time.

However, the Revised Protocol does require at least one SPM be developed, with a process for implementing the SPM in a timely fashion, if analysis indicates that inappropriate cost shifts due to the fastest growing State's load growth will occur.

Much time was spent considering the workgroup participant's views on implementation the process. Ideas ranged from a trigger point that would lead to the immediate implementation of an SPM to a trigger point that would necessitate further analysis before an SPM is considered appropriate for implementation. Although significant progress was made, at the conclusion of the Load Growth Workgroup meeting held September 13, 2005, the workgroup participants were unable to reach consensus on the specifications of the preferred SPM or how such an SPM would be implemented. At this time, the SPM and its implementation process remains a priority for the MSP Standing Committee to resolve (see also **Section 2.1.4)**.

On September 23, 2005, the MSP Standing Committee issued a directive [51] requesting that the Load Growth Workgroup continue this work, at least through December 2005. The Company is coordinating with the MSP Standing Committee and Load Growth Workgroup participants to establish a timeline to finalize the development of a preferred SPM. It is believed that with further discussion and analysis, issues relating to SPMs and their proposed implementation can be resolved.

[51] MSP Standing Committee directive was advised to MSP Participants on September 23, 2005 via an email from the Committee's Chair (Terri Carlock).

7. PacifiCorp's Conclusions and Recommendation

Based on the results of the Company's current load growth studies, it is the Company's conclusion that it is not necessary to implement an SPM at this time.

If future analysis suggests there is a potential for inappropriate cost shifts due to the fastest growing State's load growth, the Company recommends that one of the preferred SPMs described in **Sections 5.4.1** and **5.4.2** or an alternative ECD-based approach be reviewed and considered for further development in consultation with interested parties, taking into account the relevant factors identified in **Section 2.1.5**.

Appendices

Appendix 1
Abbreviations and Definitions Used in this Report

"2004 IRP Report"	means the IRP report known as "PacifiCorp's IRP 2004" which was filed with each of the State Commissions on January 20 2005
"DSM"	means the Company's Demand Side Management programs
"ECD"	means Embedded Cost Differential
"GRID"	means the Company's Generation and Regulation Initiatives Decision tool; an hourly production cost dispatch model that simulates dispatch of PacifiCorp's resources to serve load obligations and utilized for forecasting (substantiating) net power costs for regulatory proceedings and other long-term power cost analysis and projection purposes
"IRP"	means the Company's Integrated Resource Plan program and published report
"IRP Preferred Portfolio"	means the 2004 IRP Report's IRP Preferred Portfolio E with DSM
"June 2004 Forecast"	means the June 2004 or CG24 market and gas forecast (consistent with the assumptions used in the Company's 2004 IRP)
"March 2005 Forecast"	means the March 2005 or CG27 market and gas forecast
"MSP"	means the Company's Multi-State Process collaborative inter-jurisdictional allocations project
"NPV"	means Net Present Value
"PP&L"	means Pacific Power and Light
"RFM"	means the Company's Regulatory Forecast Model, used to calculate state revenue requirements
"SE factors"	means the Company's System Energy allocation factors

"SG factors"	means the Company's System Generation allocation factors
"SPM"	means a Structural Protection Mechanism
"SPMs"	means Structural Protection Mechanisms, in the plural
"UP&L"	means Utah Power and Light

Appendix 2
List of PacifiCorp's Load Growth Studies

Below are the results of the load growth studies performed by the Company from June 2005 through October 2005. These studies are presented in chronological order, based on the date of the Load Growth Workgroup meeting at which they were presented. For study assumptions, refer to **Appendices 4** and **5**.

Load Growth Workgroup Meeting - June 29, 2005

The load growth study results shown in **Table 4** were presented to the Load Growth Workgroup meeting held on June 29, 2005. These studies were performed using both the June 2004 Forecast and March 2005 Forecast gas and market pricing data.

Table 4
Percentage of Load Growth Cost Allocated by State
(Revised Protocol)
(Load Growth Workgroup Meeting – June 29, 2005)

State	9 Year NPV (2007 – 2015) @ 8.4277%		14 Year NPV (2007 – 2020)@ 8.4277%	
	Costs June 2004 Forecast	Costs March 2005 Forecast	Costs June 2004 Forecast	Costs March 2005 Forecast
California	-0.2%	0.0%	-.3%	-0.1%
Oregon	-2.3%	0.6%	-3.2%	-0.4%
Washington	-1.1%	-0.2%	-1.2%	-0.3%
Utah	**103.9%**	**97.8%**	**105.3%**	**99.5%**
Idaho	0.4%	1.0%	0.1%	0.7%
Wyoming	-0.6%	0.9%	-0.7%	0.7%

Load Growth Workgroup Meeting – June 29, 2005

The load growth study results shown in **Table 5** were presented to the Load Growth Workgroup meeting held on June 29, 2005. These studies were performed by the Company at the request of the Utah Participants, and were only performed using the March 2005 Forecast gas and market pricing data. The 2004 IRP Portfolio Q was not the preferred portfolio and as such, the underlying assumptions of the Portfolio had not been fully developed to include elements like DSM. For this reason, this is the only study run with the 2004 IRP Portfolio Q.

Table 5
Percentage of Load Growth Cost Allocated by State
(Revised Protocol)
(Portfolio Q)
(Load Growth Workgroup Meeting – June 29, 2005)

State	Costs March 2005 Forecast 9 Year NPV (2007-2015)	Costs March 2005 Forecast 14 Year NPV (2007-2020)
California	0.2%	0.2%
Oregon	4.9%	4.9%
Washington	1.3%	1.4%
Utah	**89.2%**	**89.1%**
Idaho	1.8%	1.6%
Wyoming	2.6%	2.8%

Load Growth Workgroup Meeting – August 10, 2005

The load growth study results shown in **Table 6** were presented to the Load Growth Workgroup meeting held on August 10, 2005. These studies are the same as presented in **Table 4**, except that an adjustment was incorporated to maintain consistent IRP planning margins between Study 1 and Study 2 (see **Appendix 6**). These studies were also performed using both the June 2004 Forecast and March 2005 Forecast gas and market pricing data.

Table 6
Percentage of Load Growth Cost Allocated by State
(Revised Protocol)
(Adjusted to Maintain Consistent IRP Planning Margins)
(Load Growth Workgroup Meeting – August 10, 2005)

State	9 Year NPV (2007 – 2015) @ 8.4277%		14 Year NPV (2007 – 2020)@ 8.4277%	
	Costs June 2004 Forecast	Costs March 2005 Forecast	Costs June 2004 Forecast	Costs March 2005 Forecast
California	-0.3%	-0.1%	-0.3%	-0.1%
Oregon	-2.8%	0.0%	-3.6%	-0.8%
Washington	-1.2%	-0.2%	-1.3%	-0.4%
Utah	**104.8%**	**98.8%**	**105.9%**	**100.1%**
Idaho	0.4%	1.0%	0.1%	0.6%
Wyoming	-0.9%	0.6%	-0.8%	0.5%

Load Growth Workgroup Meeting – October 11, 2005

The load growth study results shown in **Table 7** were presented to the Load Growth Workgroup meeting held on October 11, 2005. This is Case 3b1a Hybrid (refer to **Section 5.4.3** and **Appendix 12**). These studies were performed using only the March 2005 Forecast gas and market pricing data, and incorporate the intra-control area equity measures of (1) QFs situs assigned, (2) hydro reserve credit situs assigned to Wyoming, and (3) a Mid-C ECD.

Table 7
Percentage of Load Growth Cost Allocated by State
(Hybrid – Case 3b1a)
(with Intra-Control Area Equity Measures)
(Load Growth Workgroup Meeting – October 11, 2005)

State	Costs March 2005 Forecast 9 Year NPV (2007-2015)	Costs March 2005 Forecast 14 Year NPV (2007-2020)
California	0.3%	0.4%
Oregon	5.8%	7.1%
Washington	1.8%	2.3%
Utah	**86.7%**	**86.6%**
Idaho	1.5%	1.0%
Wyoming	3.8%	2.7%

Appendix 3
Load Growth Workgroup Scope and Work Plan
Load Growth Workgroup Meeting – March 30, 2005

SCOPE	DUE DATE
A multi-state workgroup will track key factors including actual relative growth rates, forecast relative growth rates, cost of new Resources compared to costs of existing Resources, and other factors deemed relevant to this issue.	May 31, 2005
PacifiCorp must file a report with the Commissions regarding potential cost shifts related to faster growing states. (See Section IV.E. of the Revised Protocol)	October 20, 2005
PacifiCorp will consult with Standing Committee and other parties.	Ongoing
Studies will compute the costs allocated to each State for two cases: (a) with currently projected load growth together with a least-cost, least-risk mix of Resources additions to meet the growth and (b) with the fastest-growing State growing at the average growth projected for the remaining States, again with a least-cost, least-risk mix of Resource additions.	October 20, 2005
The report will include a description of one or more options for a structural protection mechanism, detailed with sufficient specificity to allow timely implementation in the event that the studies show a material and sustained net harm to customers in any jurisdiction. This supports the Standing Committee charge to develop one or more ameliorative mechanisms. (see below)	October 20, 2005
The report should include information on other relevant factors to support the Standing Committee charge. (see below)	October 20, 2005

STANDING COMMITTEE CHARGE	DUE DATE
The MSP Standing Committee is charged with developing one or more ameliorative mechanisms that could be implemented in a timely manner in the event that the studies show a material and sustained net harm to particular States from the implementation of the IRP.	TBD
The MSP Standing Committee should consider the impact of load growth in light of other relevant factors.	TBD

WORK PLAN

Meeting 1 (end of March)

Process Issues

- Discuss Guidelines for the Workgroup
- Discuss Reporting from the Workgroup
- Discuss Overall Scope and Work Plan
- Discuss Logistics for future meetings

Technical Issues

- Discuss tracking of key factors
- Discuss Resource additions for average growth study
- Prioritize Issues
- Define deliverables for Meeting 2 (Note: This could be analysis or written documents from both the Company and other parties)
  - Key factors
  - Study work
  - Structural Protection / ameliorative mechanisms
  - Other relevant factors

Meeting 2 (end of April)

Process Issues

- Review Work Plan
- Discuss Reports (as needed)
- Discuss Logistics for future meetings

Technical Issues

- Review deliverables
  - Review key factor tracking
  - Review assumptions for updated study
  - Review write-ups on ameliorative mechanisms
  - Review write-ups on Other relevant factors
- Define preferred / potential solution for issues reviewed
- Define deliverables for Meeting 3
  - Key factors
  - Study work
  - Structural Protection / ameliorative mechanisms
  - Other relevant factors

Meeting 3 (end of May)

Process Issues

- Review Work Plan
- Approve final key factor tracking
- Discuss Reports (as needed)
- Discuss Logistics for future meetings

Technical Issues

- Review deliverables
  - Finalize key factor tracking
  - Define study scenarios for updated study
  - Review write-ups on ameliorative mechanisms
  - Review write-ups on Other relevant factors
- Define preferred / potential solution for issues reviewed
- Define deliverables for Meeting 4
  - Study work
  - Structural Protection / ameliorative mechanisms
  - Other relevant factors

Meeting 4 (end of June)

Process Issues

- Review Work Plan
- Discuss Reports (as needed)
- Discuss Logistics for future meetings

Technical Issues

- Review deliverables
  - Review write-up on tracking key factors
  - Present results of updated studies
  - Review write-ups on ameliorative mechanisms
  - Review write-ups on Other relevant factors
- Define preferred / potential solution for issues reviewed
- Define deliverables for Meeting 5
  - Study work
  - Structural Protection / ameliorative mechanisms
  - Other relevant factors

Meeting 5 (end of July)

Process Issues

- Review Work Plan
- Discuss Reports (as needed)
- Discuss Logistics for future meetings

Technical Issues

- Review deliverables
  - Present follow-on work on updated studies

  - Review write-up on updated studies
  - Review write-ups on ameliorative mechanisms
  - Review write-ups on Other relevant factors
- Define preferred / potential solution for issues reviewed
- Define deliverables for Meeting 6
  - Study work
  - Structural Protection / ameliorative mechanisms
  - Other relevant factors

Meeting 6 (end of August)

Process Issues
- Review Work Plan
- Discuss Reports (as needed)
- Discuss Logistics for future meetings

Technical Issues
- Review deliverables
  - Review draft report
- Define deliverables for Meeting 7
  - Comments from workgroup participants

Meeting 7 (Middle of September)

Process Issues
- Review Work Plan
- Discuss Reports (as needed)
- Discuss Logistics for future meetings

Technical Issues
- Review comments from workgroup participants

Meeting 8 (Middle of October)

Process Issues
- Review Work Plan
- Discuss Reports (as needed)
- Discuss Logistics for future meetings

Technical Issues
- Review Final Report

Appendix 4
Key Assumptions of PacifiCorp's Load Growth Studies
(Base Case Using June 2004 Forecast and March 2005 Forecast)

- 2004 IRP Preferred Portfolio
- Forecasted study period FY2007 to FY2020
- March 2004 load forecast
- June 2004 Forecast, subsequently updated to the March 2005 Forecast for market and gas prices
- Recent forecast of clean air improvements to existing thermal generation
- Recent forecast of relicensing hydro facilities
- CO_2 tax timing and cost assumptions consistent with IRP ($8/ton in 2008 dollars)
- IRP Preferred Portfolio Resource Additions (under a 15% planning margin):
  - FY2010 – 525MW Utah (Brownfield) Dry Cool CCCT with duct firing
  - FY2012 – 575MW Utah (Brownfield) Coal
  - FY2013 – 586MW West Main Dry Cool CCCT with duct firing
  - FY2014 – 560MW Utah Wet Cool CCCT with duct firing
  - FY2015 – 383MW Wyoming (Brownfield) Coal

Appendix 5
Key Assumptions of PacifiCorp's Load Growth Studies (Base Case Using June 2004 Forecast and March 2005 Forecast) (With Utah Growing at the Average of the Other States)

- 2004 IRP Preferred Portfolio
- Forecasted study period FY2007 to FY2020
- March 2004 load forecast
- June 2004 Forecast, subsequently updated to the March 2005 Forecast for market and gas prices
- Recent forecast of clean air improvements to existing thermal generation
- Recent forecast of relicensing hydro facilities
- CO_2 tax timing and cost assumptions consistent with IRP ($8/ton in 2008 dollars)
- IRP Preferred Portfolio E: 1,485MW of new resources removed by 2015 while loads decreased 1,271MW
    - Remove East Mona Front Office transactions 50MW in 2008, 175MW in 2009, 50MW in 2010, then 200MW afterwards
    - Lower the Four Corners Front Office transactions 175MW in 2008, 225MW in 2012, 400MW in 2013, 75MW in 2014, 200MW in 2015
    - Lower the West Main Front Office transactions by 200MW in 2009
    - Remove 525MW Dry Cool CCCT in 2010 located at Utah- S. Mona
    - Remove 560MW Wet Cool CCCT in 2014 located at Utah- N. Salt Lake Valley
- The study adjusted the Front Office transactions in 25MW increments in calculating the planning margin.

Appendix 6
Preferred Portfolio E with DSM and Preferred Portfolio E with DSM Adjusted to Maintain Consistent IRP Planning Margins

Preferred Portfolio E with DSM - Original (2004 IRP, Executive Summary, page 9)
(Load Growth Workgroup Meeting - August 10, 2005)

East

Type	Location	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Brownfield Coal	Utah-S Hunter 4	0	0	0	0	0	0	575	575	575	575
Greenfield Coal	WY	0	0	0	0	0	0	0	0	0	383
Dry Cool CCCT	Utah-S Mona	0	0	0	0	525	525	525	525	525	525
Wet Cool CCCT	Utah-N Salt Lake Valley	0	0	0	0	0	0	0	0	560	560
East Market	Mona	50	0	50	200	200	200	200	200	200	200
East Market	4-Corners	50	400	400	500	500	500	500	500	500	500
QF East	QF Utah-N	100	100	100	100	100	100	100	100	100	100
Transfer	To East	454	454	454	454	454	454	454	454	454	454
Comm Cool Control	East	0	0	0	0	0	0	0	0	44	44
Irrigation Control	East	0	0	0	44	44	44	44	44	44	44

West

Type	Location	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Dry Cool CCCT	WMAIN (1500') Medford	0	0	0	0	0	0	0	586	586	586
West Market	WMAIN	200	150	200	400	400	400	500	500	500	500
Transfer	From West	-454	-454	-454	-454	-454	-454	-454	-454	-454	-454
AC Control	West	0	0	0	0	0	0	0	0	45	45
Irrigation Control	West	0	0	0	44	44	44	44	44	44	44
	Total MW	**400**	**650**	**750**	**1288**	**1813**	**1813**	**2488**	**3074**	**3723**	**4106**
	PM	**15.0%**	**15.0%**	**15.0%**	**15.0%**	**17.0%**	**15.0%**	**17.0%**	**15.0%**	**17.0%**	**15.0%**

Preferred Portfolio E with DSM - Adjusted to Maintain Planning Margin 1/

East

Type	Location	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Brownfield Coal	Utah-S Hunter 4	0	0	0	0	0	0	575	575	575	575
Greenfield Coal	WY	0	0	0	0	0	0	0	0	0	383
Dry Cool CCCT	Utah-S Mona	0	0	0	0	0	0	0	0	0	0
Wet Cool CCCT	Utah-N Salt Lake Valley	0	0	0	0	0	0	0	0	0	0
East Market	Mona	50	0	**0**	**25**	**150**	0	0	0	0	0
East Market	4-Corners	50	400	**225**	500	500	500	**275**	**100**	**425**	**300**
QF East	QF Utah-N	100	100	100	100	100	100	100	100	100	100
Transfer	To East	454	454	454	454	454	454	454	454	454	454
Comm Cool Control	East	0	0	0	0	0	0	0	0	44	44
Irrigation Control	East	0	0	0	44	44	44	44	44	44	44

West

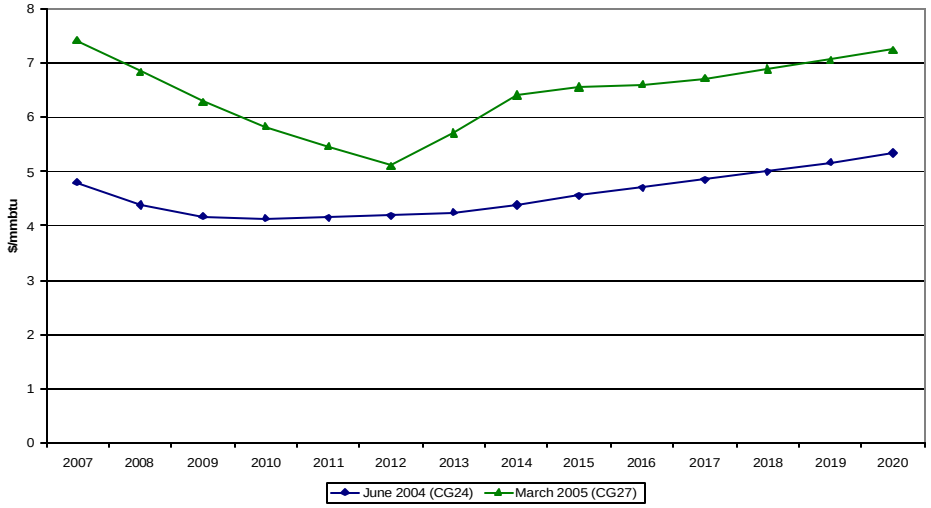
Type	Location	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Dry Cool CCCT	WMAIN (1500') Medford	0	0	0	0	0	0	0	586	586	586
West Market	WMAIN	200	150	200	200	400	400	500	500	500	500
Differences in Load	From West	-454	-454	-454	-454	-454	-454	-454	-454	-454	-454
AC Control	West	0	0	0	0	0	0	0	0	45	45
Irrigation Control	West	0	0	0	44	44	44	44	44	44	44
	Total MW	**400**	**650**	**525**	**913**	**1238**	**1088**	**1538**	**1949**	**2363**	**2621**
	PM	**15.0%**	**15.1%**	**15.2%**	**15.1%**	**17.0%**	**15.0%**	**17.1%**	**15.1%**	**17.0%**	**15.1%**

Differences in MW's	-	-	**225**	**375**	**575**	**725**	**950**	**1,125**	**1,360**	**1,485**
Differences in East Load	-	-	**191**	**319**	**477**	**644**	**795**	**968**	**1,111**	**1,271**

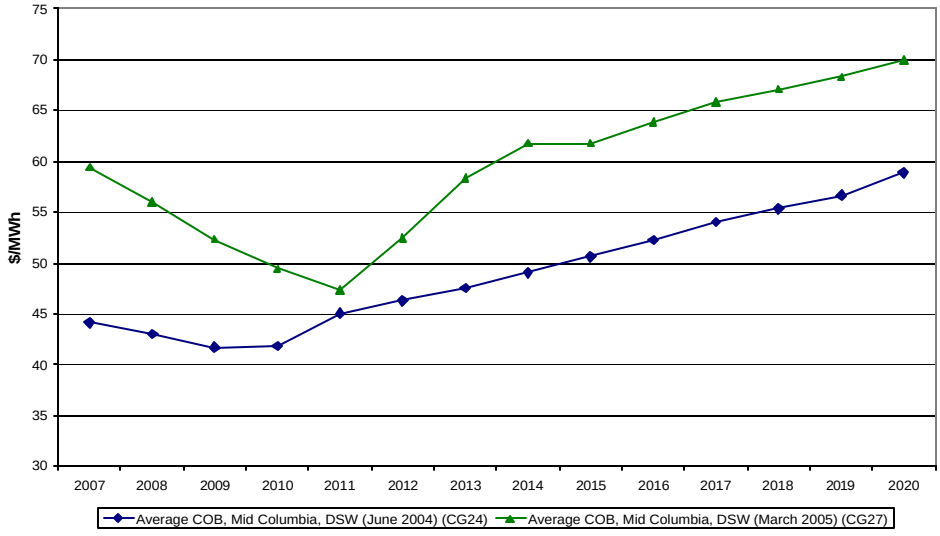
1/ Planning Margin on adjusted Case (Utah Load Growth) set equal Base Case by adjusting FOT in 25 MW increments

Appendix 7
Comparison of March 2005 Forecast (or CG 27) and June 2004 Forecast (or CG24) of Market and Natural Gas Prices

Average (East & West) Fiscal Year Natural Gas Price Comparison
March 2005 Forecast (or CG27) and June 2004 Forecast (or CG24)



Average Fiscal Year Market Price Comparison
March 2005 Forecast (or CG27) and June 2004 Forecast (or CG24)



Appendix 8
ECD Alternative 1 Paper

MSP Revised Protocol
(Load Growth Workgroup Meeting – August 10, 2005)

New Resource ECD

As part of the Load Growth Workgroup various proposals for a structural mechanism to ensure that all states pay their full share of the cost of meeting load growth have been discussed. In this paper (together with Attachment 1) PacifiCorp sets forth a proposed New Resource Embedded Cost Differential calculation as a structural protection mechanism that addresses the drivers of cost shifts associated with load growth and at the same time is relatively simple to implement.

New Resource ECD

The New Resource ECD operates very much like the Hydro, Mid-C and Existing QF ECD calculations in the current Revised Protocol. In the ECD calculation, a new resource category would be created. This category would contain the costs of each newly constructed owned resource for a period of two years. As with other ECD adjustments, the amount by which the cost of the new resource exceeds the cost of the "All Other Resources" would be allocated to states using a forward looking SG factor calculated with projected loads from a future period. Projected loads two years beyond the test period would be used during the first year of the ECD assignment and one year beyond the test period during the second year. The inverse amount would then be allocated back to states using the SG factor from the test period. There may be times when there are both first and second year resources in the New Resource category. Because a different allocation factor is applied during the first and second years a resource is included in the New Resource ECD, a separate calculation would be made for each resource.

Drivers of Cost Shifts

Potential cost shifts associated with load growth occurs when two conditions (drivers) exist simultaneously. The first condition is differential load growth rates among the states; one or more states growing significantly faster than the other states. The second condition is that the costs of new resources are greater than the average embedded costs of the existing resource portfolio. The New Resource ECD incorporates both of these drivers. The forward looking allocation factors address differential load growth and the Total Company New Resource Embedded Cost Differential addresses the higher cost of the new resource.

Why is only the cost difference between new and existing resources rather than the total cost of new resources allocated on the forward looking factor?

The costs of all resources continue to be allocated on system load based allocation factors. As one state grows faster than the other states, that state is allocated a larger portion of the cost of all resources. The faster growing state will already be allocated an increased share, a share that reflects differential load growth, of the average embedded cost of the portfolio. The New Resource ECD only needs to provide a supplemental allocation of the amount by which the new resource costs exceed average embedded costs.

Why is the New Resource only included in the ECD for the first two years?

The Company's studies on the impact of differential load growth show that the largest potential for cost shifts occur during the first two years after a new resource come on line. This is driven by front revenue requirement loading of owned resources. The impact of front end loading is mostly offset by the third year as the allocation of all generation, transmission and common overhead costs to the faster growing state has increased enough to absorb the incremental costs difference.

Summary New Resource Embedded Cost Differential adjustment

- Create New Resource ECD category
- Compare cost of new resource ($/MWH) to cost of Annual Embedded Cost – All Other
- Newly constructed resources included in ECD for two years
- Separate calculation for each new resource
- First year ECD allocated using SG factor calculated with projected loads two years beyond test year
- Second ECD allocated using SG factor calculated with projected loads one years beyond test year
- Inverse amount allocated with test year SG factor

PacifiCorp
New Resource ECD (Attachment 1)
(Load Growth Workgroup Meeting - August 10, 2005)

			Total	California	Oregon	Washington	Wyoming	Utah	Idaho
2010	**ECD Adjustment**								
	New Resource Year 1 Alternate	SG-FY12	55,433,142	950,869	14,321,956	4,425,975	6,491,420	26,308,402	2,934,519
	New Resource Year 1 Current	SG-FY10	(55,433,142)	(966,188)	(14,767,204)	(4,476,756)	(6,744,029)	(25,485,048)	(2,993,917)
	New Resource Year 2 Alternate	SG-FY11	0	0	0	0	0	0	0
	New Resource Year 2 Current	SG-FY10	0	0	0	0	0	0	0
	Total Net ECD Adustment		0	(15,319)	(445,248)	(50,782)	(252,608)	823,354	(59,398)
2011	**ECD Adjustment**								
	New Resource Year 1 Alternate	SG-FY13	-	-	-	-	-	-	-
	New Resource Year 1 Current	SG-FY11	-	-	-	-	-	-	-
	New Resource Year 2 Alternate	SG-FY12	51,156,512	877,510	13,217,027	4,084,514	5,990,612	24,278,727	2,708,123
	New Resource Year 2 Current	SG-FY11	(51,156,512)	(885,451)	(13,479,581)	(4,118,276)	(6,034,322)	(23,910,775)	(2,728,108)
	Total Net ECD Adustment		-	(7,941)	(262,554)	(33,762)	(43,711)	367,952	(19,985)
2012	**ECD Adjustment**								
	New Resource Year 1 Alternate	SG-FY14	26,547,065	445,256	6,778,350	2,089,069	3,075,947	12,799,737	1,358,706
	New Resource Year 1 Current	SG-FY12	(26,547,065)	(455,374)	(6,858,819)	(2,119,610)	(3,108,757)	(12,599,158)	(1,405,348)
	New Resource Year 2 Alternate	SG-FY13	-						
	New Resource Year 2 Current	SG-FY12	-						
	Total Net ECD Adustment		-	(10,117)	(80,470)	(30,541)	(32,810)	200,580	(46,642)
2013	**ECD Adjustment**								
	New Resource Year 1 Alternate	SG-FY15	50,397,609	836,958	12,797,304	3,940,341	5,745,149	24,523,499	2,554,359
	New Resource Year 1 Current	SG-FY13	(50,397,609)	(853,033)	(12,915,899)	(3,988,708)	(5,888,047)	(24,146,068)	(2,605,855)
	New Resource Year 2 Alternate	SG-FY14	8,463,150	141,947	2,160,924	665,991	980,606	4,080,530	433,153
	New Resource Year 2 Current	SG-FY13	(8,463,150)	(143,248)	(2,168,936)	(669,814)	(988,766)	(4,054,792)	(437,595)
	Total Net ECD Adustment		-	(17,376)	(126,606)	(52,191)	(151,058)	403,170	(55,938)
2014	**ECD Adjustment**								
	New Resource Year 1 Alternate	SG-FY16	46,724,459	769,723	11,793,556	3,641,898	5,189,281	22,990,930	2,339,071
	New Resource Year 1 Current	SG-FY14	(46,724,459)	(783,679)	(11,930,310)	(3,676,889)	(5,413,855)	(22,528,320)	(2,391,406)
	New Resource Year 2 Alternate	SG-FY15	48,325,058	802,539	12,271,028	3,778,298	5,508,885	23,514,995	2,449,313
	New Resource Year 2 Current	SG-FY14	(48,325,058)	(810,524)	(12,338,996)	(3,802,845)	(5,599,313)	(23,300,053)	(2,473,326)
	Total Net ECD Adustment		-	(21,941)	(204,723)	(59,538)	(315,002)	677,552	(76,348)
2015	**ECD Adjustment**								
	New Resource Year 1 Alternate	SG-FY17	63,051,950	1,031,328	15,681,826	4,881,894	6,964,918	31,357,113	3,134,870
	New Resource Year 1 Current	SG-FY15	(63,051,950)	(1,047,109)	(16,010,581)	(4,929,721)	(7,187,699)	(30,681,107)	(3,195,733)
	New Resource Year 2 Alternate	SG-FY16	47,715,942	786,056	12,043,812	3,719,178	5,299,397	23,478,793	2,388,705
	New Resource Year 2 Current	SG-FY15	(47,715,942)	(792,423)	(12,116,357)	(3,730,674)	(5,439,448)	(23,218,599)	(2,418,441)
	Total Net ECD Adustment		-	(22,148)	(401,299)	(59,323)	(362,833)	936,200	(90,598)
2016	**ECD Adjustment**								
	New Resource Year 1 Alternate	SG-FY18	-						
	New Resource Year 1 Current	SG-FY16	-						
	New Resource Year 2 Alternate	SG-FY17	55,454,984	907,066.24	13,792,363.72	4,293,687.74	6,125,732.86	27,578,975.92	2,757,157.94
	New Resource Year 2 Current	SG-FY16	(55,454,984)	(913,546.74)	(13,997,196.78)	(4,322,391.46)	(6,158,904.96)	(27,286,815.21)	(2,776,129.25)
	Total Net ECD Adustment		-	(6,481)	(204,833)	(28,704)	(33,172)	292,161	(18,971)

Appendix 9
ECD Alternative 2 Paper

Straw Proposal for Direct Resource Assignment (Revised)
Marc Hellman, Public Utility Commission of Oregon
(Load Growth Workgroup Meeting – August 23, 2005)

This straw proposal presents a structural protection for cost shifts. The proposal uses concepts embodied in the Revised Protocol relating to the treatment of hydroelectric resources. A key component of this proposal is the use of comparative grid runs, each with the same ten- year period. For any study conducted up to December 31, 2009, the time period of cost-shift analysis is January 1, 2005 through December 31, 2014. Studies conducted subsequent to December 31, 2009, will continue to use a ten-year period, comprised of the most recent five-year history along with a projected five-year term. The analysis will use the actual costs of new resources as available.

For the ten-year period, two Grid runs would be used. The first would be based on Grid and the Revised Protocol for the relevant time period as defined above, using IRP identified resources as needed for the projected future five-year period. The first Grid run would also include the new resources and contracts acquired during the historic five-year period, of the ten year period. The second modeling exercise would have two complementary adjustments. First, the highest growth state (in terms of aMW) would have its loads revised to equal the average growth rate (in percentage terms) of the remaining states. For the start of the ten-year period, the highest growth state would begin with the actual loads for the initial year of the study period. The subsequent nine years would be adjusted so that high growth state loads grow at the average percentage growth rate equal to that of the remaining jurisdictional states. Resources, including purchases, would be adjusted downwards, consistent with the IRPs and knowledge available at the time, over the ten-year period to reflect the revised load levels. So adjustments would be made to resources and contracts for both the five-year historic as well as the five-year projected period of the ten-year analysis. Only new resources and longer-term purchases added over the unadjusted study ten-year period may be dropped from the analysis should the adjusted load levels no longer warrant the power purchase or new resource coming on line as scheduled. New resources, as the last sentence suggests, could have on-line dates changed so that they remain in the analysis, but coming on line later in the study period.

The two studies would be compared to calculate what percentage of the increase in costs from the higher load levels was being allocated to the highest growing state. If the highest growing state is being allocated under Revised Protocol a net 90 per cent or more of the 10-year present-valued costs of new resources needed to serve the additional loads within the study, then the structural protection mechanism would not be implemented.

However, if the highest growth state is allocated under the Revised Protocol less than a net 90 per cent of the costs of new resources, for each of any two consecutive years of study (not an average of the two years), then this structural protection would be implemented. The net 90 per cent

calculation represents offsetting the ten-year present value estimate by the cumulative percentage that the preceding five years of studies resulted in the high growth state bearing more than 110% of cost of new resources. By two consecutive years, it is meant that if the 10-year study conducted in 2007, and the 10-year study conducted a year later in 2008 both result in less than a net 90 percent of the costs of new resources being assigned under Revised Protocol to the highest cost state, then the structural protection mechanism would be implemented.

In addition, if the highest growth state is allocated under the Revised Protocol less than a net 80 per cent of the costs of new resources for any single study, then this structural protection would be implemented.

The "netting" process steps are as follows:

1. Check to see if any of the preceding five years of results yielded the high growth state bearing more than 110% of costs of new resources and purchases. If no, no netting is required. If yes, go to Step 2.
2. Calculate the cumulative excess above 110% for any of the preceding five years of study that have the high growth state bearing more than 110% of costs of new resources and purchases.
3. Review the % cost burden borne by Utah for the current year study and last year's study. If either year has a % level lower than 80%, use any excess cumulative % to bring the below-80% level up to 80%.
4. If any excess cumulative % remains after step 3, review cost burden % to see if either the prior year or the current year study is below 90% and the remaining excess cumulative percentage could bring that value up to 90%. If yes, then take that action.

The examples below might help illustrate the trigger proposal:

Example # 1					
	Year				Action
10-Year Present Value	2005	2006	2007	2008	No Trigger
	102%	89%	93%	83%	

Example # 2					
	Year				Action
10-Year Present Value	2005	2006	2007		Triggered in 2007
	102%	89%	87%		

Example # 3					
	Year				Action
10-Year Present Value	2005	2006	2007	2008	Trigger in 2008
	102%	89%	93%	77%	

Example # 4					
	Year				Action
10-Year Present Value	2005	2006	2007	2008	No Trigger Adjusted 2006 = 90% Adjusted 2007 = 88%
	112%	89%	87%	93%	
Calculation—Use the "excess" 2% (112 – 110) to bring the 89% to 90%, then any remaining excess is applied to 2007.					

Example # 5					
	Year				Action
10-Year Present Value	2005	2006	2007		Triggered in 2007 Adjusted 2006 = 80% Adjusted 2007 = 87%
	102%	75%	82%		
Calculation—Use the "excess" 10% (120 – 110) to bring the 75% to 80%, then any remaining excess is applied to 2007. The 75% value for 2006 would also have been raised in that year due to the 120% value for the 2005 study.					

Once the trigger thresholds are met establishing the implementation of the structural protection mechanism, the resources that came on line during the ten-year study period would be ranked for possible use in the structural protection mechanism. New resources that are renewable or hydroelectric-based would be excluded from the candidates considered for disparate treatment. (See Revised Protocol, Section IV.C.2) The remaining new resources would be ranked fist by identifying the resources added within the five-year historic period, with the highest cost per aMW being first and lowest cost per aMW last. Next transfer payments would be established similar to the treatment of hydroelectric resources. In conceptual terms the fastest growing state bears the differential in cost between the resource added during the study period and the average cost of the remaining PacifiCorp thermal resources.

The objective is to establish a set of transfer payments such that 95 per cent of the costs of new resources needed to meet the differential in load growth are assigned to the highest growth state. Again, the difference in costs of the new resource would be compared to all other thermal resources, with the higher than average costs being assign to the highest growth state to the extent necessary to achieve the 95 per cent target. If assigning all of the capacity of the highest cost resource differential is insufficient with respect to the highest new thermal resource, then the next highest cost resource would be used for transfer payment purposes. These steps would be repeated until the 95 percent target is met. Once the 95 per cent target is met, the Revised Protocol with the structural protection transfer payments would be used for PacifiCorp general rate filings on a going forward basis until the trigger is triggered again.

Transfer payments would not include costs of resources or purchases projected to come on line in the future five-year period because they are not yet used and useful, and as such would not be included in rates.

Appendix 10
Lump Sum Transfer Paper

Load Growth Lump Sum Transfer ECD Adjustment
(Load Growth Workgroup – August 10, 2005)

One approach to ensuring that a faster growing state picks up an adequate level of the cost of load growth is to make a lump sum revenue requirement transfer from slower growing states to the faster growing state. Such an approach would only be implemented when analysis suggests that a faster growing state is not covering the cost of its load growth. A Lump Sum ECD Adjustment is one approach to make such a lump sum transfer. For discussion purposes an example Lump Sum ECD Adjustment is shown.

This example is based on the FY 2010, CG27 load growth study (the year where Utah picks up the lowest percentage of the cost of load growth). An $11 million lump sum transfer, the amount needed to bring Utah up to 90% of the cost of load growth that year, is direct assigned to Utah. An equal credit is allocated back to the other states using a modified SG factor (the proportional SG factors of all states except Utah).

PacifiCorp
FY 2010 Lump Sum ECD Adjustment
Lump Sum Transfer to bring Growth State to 90% of Cost of Incremental Load Growth

	FY 2010 MSP Factors		Total	California	Oregon	Washington	Wyoming	Utah	Idaho
1		SG	100.0000%	1.7430%	26.6397%	8.0760%	12.1661%	45.9744%	5.4010%
2		SG-Less UT	100.0000%	3.2262%	49.3093%	14.9484%	22.5191%	0.0000%	9.9970%
	Lump Sum ECD Adjustment	Factor							
3	Assignment to Growth State	Situs	11,220,400					11,220,400	
4	Adjustment to non Growth States	SG-Less UT	(11,220,400)	(361,993)	(5,532,704)	(1,677,269)	(2,526,728)	0	(1,121,706)
	Total		0	(361,993)	(5,532,704)	(1,677,269)	(2,526,728)	11,220,400	(1,121,706)

FY2010 - Comparison of Utah growing at system average vs Utah growing as projected (Revised Protocol - CG27)

5	Cost of Incremental Load Growth	$147,006,000
6	90% of Incremental Cost	$132,305,400
7	Utah Incremental Revenue Requirement	$121,085,000
8	Lump Sum Transfer (line 6 less line 7)	$11,220,400

Appendix 11
Structural Protection Mechanisms
ECD Alternative 1 Compared to ECD Alternative 2

	ECD Alternative 1	**ECD Alternative 2**
Author	PacifiCorp	Marc Hellman, Oregon PUC Staff
Load Growth Workgroup Meeting	August 10, 2005	August 23, 2005
Proposal	New Resource ECD and Process for Implementing SPMs on Revised Protocol	Straw Proposal for Direct Resource Assignment
LG Study Period	Minimum 10-Year forward looking forecast that captures IRP planned resource additions	5 Year Historical/ 5 Year Forward Start with calendar 2005, replace forecast with actual until 5 years of actuals are included. Studies conducted after calendar 2009 will roll forward annually maintaining 5 years historical & 5 years forecast
Commencement Year of LG Study Period	2nd year of IRP Study period	Calendar 2005 to start
LG Study	Load Growth Study defined by Revised Protocol page 7 footnote 2. Requires comparative GRID & RFM runs. Average load growth study defers or removes IRP planned resources to maintain IRP planning margin	Same as Company Study except for study period (see above). Average load growth study defers or removes IRP newly acquired resources and IRP planned resources to maintain IRP planning margin
LG Study Updates	Biennial (every two years) - following IRP cycle, and upon request by MSP Standing Committee after it has reviewed the key tracking factors. Follows acknowledgement of the Company's IRP	Annually – recognizing in the years where IRP is not published update is limited (excludes loads and new resources forecast updates)

	ECD Alternative 1	**ECD Alternative 2**
Trigger	Qualitative Trigger - Fast Growing State Pays 85% or higher on a NPV basis, no material harm & no action required. Fast Growing State pays less than 85% ▪ MSP Standing Committee to define action	Quantitative Trigger -Fast Growing State Pays 90-110% on a NPV basis, no material harm & no action required. Trigger occurs: ▪ Below 90% for two consecutive years ▪ Any year below 80% Allows netting when load growth study is above 110%.
Resource Cost Adjustment (ECD)	Newly constructed cost of owned resources included in rates.	Newly constructed cost of owned and purchased resources, ranked from highest cost (first) to lowest cost (last) per aMW. Transfer payment is determined by starting with highest cost company acquired resource during historical 5 year period. Exclude renewable or hydro-electric resources given disparate treatment.
SPM Allocation	New resource costs built and in operation in excess of the all other resource cost. Projected loads two years beyond the test period during 1st year of new resource addition, and projected loads one year beyond test period during second year. Inverse SG factor for test period.	Objective to create transfer payments so 95% of unpaid load growth on a NPC basis is assigned to highest growth state. Start with assigning highest cost new resources (over last 5 years historical) until transfer payment threshold is met to ECD. Approach similar to QF existing methodology in ECD. Inverse SG factor without high growth state for test period.
SPM Implementation	MSP Standing Committee decides one of three actions. 1) Do nothing 2) Recommend PacifiCorp, in each of its subsequent general rate case filings, include structural protection mechanism 3) consider changes to the Revised Protocol	Implement immediately and automatically upon trigger, SPM transfer payment in next general rate filing
SPM Duration	Temporary assignment of 2 years for GRC within period	Permanent assignment using a transfer payment

Appendix 12
List of PacifiCorp's Hybrid Studies and Results

Hybrid Studies

A number of Hybrid studies were modeled before Case 3b1a was confirmed as the basis for the presentation to the Oregon Public Utility Commission. **Table 8** is a Resource Matrix providing a list of the studies performed and presented to the Hybrid Workgroup.

Table 8
Resource Matrix for Hybrid Studies

Hybrid Case Number	Hybrid Workgroup Meeting (except where indicated)	APS (480 MW)	Cholla (380 MW Nameplate)	Jim Bridger Units 1 – 4 (1412 MW Nameplate)	IRP Jim Bridger Unit 5 (383 MW Nameplate)	IRP 2014 CCCT (560 MW Nameplate)	IRP 2010 CCCT (525 MW Nameplate)
1	2004 Forecast – June 28, 2005 2005 Forecast – July 18, 2005	West	West	All units in West	East	East	East
1 (Load Growth Study)	2004 Forecast – June 28, 2005	West	West	All units in West	East	Removed from the East Control Area	Removed from the East Control Area
Existing Resource Sensitivities							
1a	August 24, 2005	West	West	380 MW allocated to the East and remainder is allocated to the West	East	East	East
1b	August 24, 2005	West	West	Equally split between East and West	East	East	East
2[(1)]	June 28, 2005	East	East	All units in West	East	East	East
3	July 18, 2005	West	East	All units in West	East	East	East
New Resource Sensitivities							
3a	August 24, 2005	West	East	All units in West	West	East	East
3b	August 24, 2005	West	East	All units in West	East	West	East

Hybrid Case Number	Hybrid Workgroup Meeting (except where indicated)	APS (480 MW)	Cholla (380 MW Nameplate)	Jim Bridger Units 1 – 4 (1412 MW Nameplate)	IRP Jim Bridger Unit 5 (383 MW Nameplate)	IRP 2014 CCCT (560 MW Nameplate)	IRP 2010 CCCT (525 MW Nameplate)
3b1a	**September 14, 2005**	**West**	**East**	**125 MW allocated to the East and remainder is allocated to the West**	**East**	**West**	**East**
3b1a (Load Growth Study)	October 11, 2005 (Load Growth Workgroup Meeting)	West	East	125 MW allocated to the East and remainder is allocated to the West	East	Removed from the West Control Area	Removed from the East Control Area
3c	September 14, 2005	West	Equally split between East and West	190 MW allocated to the East and remainder is allocated to the West	East	West	East
Test Case (3b1)	September 14, 2005	West	East	100 MW allocated to the East and remainder is allocated to the West	East	West	East
Test Case (3b2)	September 14, 2005	West	East	200 MW allocated to the East and remainder is allocated to the West	East	West	East
Test Case (3b3)	September 14, 2005	West	East	300 MW allocated to the East and remainder is allocated to the West	East	West	East

[(1)]Study was run using only the 2004 Forecast

Below are the results of the Hybrid studies performed by the Company from June 2005 through October 2005. These studies are presented in chronological order, based on the date of the Hybrid Workgroup meeting at which they were presented. For study assumptions, refer to **Appendices 4** and **5**.

Hybrid Workgroup Meeting - June 28, 2005

The Hybrid study results shown in **Table 9** were presented to the Hybrid Workgroup meeting held on June 28, 2005. The studies were performed using the June 2004 Forecast gas and market pricing data.

Table 9
Hybrid Cases 1 and 2
Percentage Difference in NPV Revenue Requirement
from Revised Protocol using June 2004 Forecast
(Hybrid Workgroup Meeting – June 28, 2005)

State	Hybrid Case 1 "Base Case"		Hybrid Case 2	
	9-Year NPV 2007-2015	14-Year NPV 2007-2020	9-Year NPV 2007-2015	14-Year NPV 2007-2020
California	-3.33%	-3.79%	-4.16%	-4.80%
Oregon	-1.23%	-1.86%	-2.43%	-3.21%
Washington	-0.09%	-1.04%	-1.36%	-2.58%
West Control Area	-1.13%	-1.81%	-2.25%	-3.18%
Idaho	0.17%	0.55%	0.60%	1.08%
Utah	0.29%	0.76%	1.06%	1.65%
Wyoming	2.46%	2.51%	2.83%	3.00%
East Control Area	0.67%	1.05%	1.34%	1.84%

Hybrid Workgroup Meeting – July 18, 2005

The Hybrid study results shown in **Table 10** were presented to the Hybrid Workgroup meeting held on July 18, 2005. The studies were performed using the March 2005 Forecast gas and market pricing data and incorporate the intra-control area equity measures of (1) QFs situs assigned, and (2) hydro reserve credit situs assigned to Wyoming.

Table 10
Hybrid Case 1 Variations
Percentage Difference in NPV Revenue Requirement
from Revised Protocol using March 2005 Forecast
with Intra-Control Area Equity Measures
(Hybrid Workgroup Meeting – July 18, 2005)

					Includes Intra-Control Area Equity Measures			
State	**Hybrid Case 1**		**Results with APS West / Cholla in East**		**Results with APS in West / Cholla in East, QFs situs assigned**		**Results with APS in West / Cholla in East, QFs situs assigned and hydro reserve credit situs to Wyoming**	
	9-Year NPV 2007-2015	**14-Year NPV 2007-2020**	**9-Year NPV 2007-2015**	**14-Year NPV 2007-2020**	**9-Year NPV 2007-2015**	**14-Year NPV 2007-2020**	**9-Year NPV 2007-2015**	**14-Year NPV 2007-2020**
California	-4.62%	-4.70%	-3.87%	-4.25%	-2.61%	-2.86%	-2.61%	-2.86%
Oregon	-2.92%	-3.08%	-1.88%	-2.44%	-1.59%	-2.24%	-1.59%	-2.24%
Washington	-1.97%	-2.41%	-1.00%	-1.87%	-2.43%	-3.02%	-2.43%	-3.02%
West Control Area	-2.83%	-3.04%	-1.83%	-2.44%	-1.83%	-2.44%	-1.83%	-2.44%
Idaho	1.33%	1.37%	0.38%	0.68%	0.36%	0.59%	0.50%	0.72%
Utah	1.14%	1.31%	0.71%	1.12%	0.82%	1.21%	0.96%	1.34%
Wyoming	4.06%	3.78%	2.95%	2.94%	2.52%	2.57%	1.86%	1.96%
East Control Area	1.68%	1.75%	1.08%	1.40%	1.08%	1.40%	1.08%	1.40%

Hybrid Workgroup Meeting – August 24, 2005

The Hybrid study results shown in **Tables 11 and 12** were presented to the Hybrid Workgroup meeting held on August 24, 2005. The studies were performed using the March 2005 Forecast gas and market pricing data and incorporate the intra-control area equity measures of (1) QFs situs assigned, (2) hydro reserve credit situs assigned to Wyoming, and (3) Mid-C.

Table 11
Hybrid Cases 1a and 1b
Percentage Difference in NPV Revenue Requirement
from Revised Protocol using March 2005 Forecast
with Intra-Control Area Equity Measures
(Hybrid Workgroup Meeting – August 24, 2005)

	Includes Intra-Control Area Equity Measures			
State	**Hybrid Case 1a**		**Hybrid Case 1b**	
	9-Year NPV 2007-2015	**14-Year NPV 2007-2020**	**9-Year NPV 2007-2015**	**14-Year NPV 2007-2020**
California	1.25%	1.07%	4.54%	4.23%
Oregon	1.90%	1.62%	6.25%	5.86%
Washington	2.19%	1.82%	6.88%	6.33%
West Control Area	1.92%	1.63%	6.27%	5.86%
Idaho	-1.74%	-1.62%	-4.64%	-4.34%
Utah	-1.20%	-0.95%	-3.58%	-3.20%
Wyoming	-0.57%	-0.57%	-3.80%	-3.61%
East Control Area	-1.14%	-0.93%	-3.71%	-3.36%

Table 12
Hybrid Cases 3, 3a, and 3b
Percentage Difference in NPV Revenue Requirement
from Revised Protocol using March 2005 Forecast
with Intra-Control Area Equity Measures
(Hybrid Workgroup Meeting – August 24, 2005)

	Includes Intra-Control Area Equity Measures					
State	**Hybrid Case 3**		**Hybrid Case 3a**		**Hybrid Case 3b**	
	9-Year NPV 2007-2015	**14-Year NPV 2007-2020**	**9-Year NPV 2007-2015**	**14-Year NPV 2007-2020**	**9-Year NPV 2007-2015**	**14-Year NPV 2007-2020**
California	-1.54%	-1.95%	-1.35%	-1.52%	-1.09%	-1.14%
Oregon	-1.84%	-2.45%	-1.58%	-1.89%	-1.22%	-1.35%
Washington	-1.87%	-2.55%	-1.57%	-1.89%	-1.19%	-1.35%
West Control Area	-1.83%	-2.44%	-1.56%	-1.87%	-1.21%	-1.34%
Idaho	0.50%	0.72%	0.39%	0.52%	0.17%	0.16%
Utah	0.96%	1.34%	0.79%	0.96%	0.58%	0.69%
Wyoming	1.86%	1.96%	1.75%	1.79%	1.51%	1.37%
East Control Area	1.08%	1.40%	0.92%	1.07%	0.71%	0.77%

Hybrid Workgroup Meeting – September 14, 2005

The Hybrid study results shown in **Tables 13** and **14** were presented to the Hybrid Workgroup meeting held on August 24, 2005. The studies were performed using the March 2005 Forecast gas and market pricing data and incorporate the intra-control area equity measures of (1) QFs situs assigned, (2) hydro reserve credit situs assigned to Wyoming, and (3) Mid-C.

Table 13
Case 3b Variations
Percentage Difference in NPV Revenue Requirement
from Revised Protocol using March 2005 Forecast
with Intra-Control Area Equity Measures
(Hybrid Workgroup Meeting – September 14, 2005)

	Includes Intra-Control Area Equity Measures							
State	Hybrid Case 3b1		Hybrid Case 3b1a		Hybrid Case 3b2		Hybrid Case 3b3	
	9-Year NPV 2007-2015	14-Year NPV 2007-2020	9-Year NPV 2007-2015	14-Year NPV 2007-2020	9-Year NPV 2007-2015	14-Year NPV 2007-2020	9-Year NPV 2007-2015	14-Year NPV 2007-2020
California	-0.39%	-0.43%	-0.15%	-0.21%	0.57%	0.47%	1.54%	1.38%
Oregon	-0.29%	-0.39%	0.03%	-0.09%	0.98%	0.82%	2.26%	2.04%
Washington	-0.20%	-0.35%	0.14%	-0.03%	1.16%	0.93%	2.54%	2.22%
West Control Area	-0.28%	-0.38%	0.05%	-0.08%	0.99%	0.82%	2.28%	2.04%
Idaho	-0.48%	-0.48%	-0.69%	-0.68%	-1.33%	-1.27%	-2.20%	-2.06%
Utah	0.09%	0.20%	-0.08%	0.04%	-0.60%	-0.44%	-1.30%	-1.08%
Wyoming	0.77%	0.65%	0.54%	0.43%	-0.18%	-0.23%	-1.14%	-1.12%
East Control Area	0.16%	0.22%	-0.02%	0.05%	-0.59%	-0.47%	-1.35%	-1.17%

Table 14
Case 3c
Percentage Difference in NPV Revenue Requirement
from Revised Protocol using March 2005 Forecast
with Intra-Control Area Equity Measures
(Hybrid Workgroup Meeting – September 14, 2005)

	Includes Intra-Control Area Equity Measures	
State	Hybrid Case 3c	
	9-Year NPV 2007-2015	14-Year NPV 2007-2020
California	0.07%	0.14%
Oregon	0.33%	0.38%
Washington	0.49%	0.51%
West Control Area	0.35%	0.39%
Idaho	-0.77%	-0.84%
Utah	-0.31%	-0.28%
Wyoming	0.49%	0.29%
East Control Area	-0.21%	-0.23%

Appendix 13
Tiered Alternative 1 Paper

Straw Proposal for Tiered Allocations
(Second Revision)
Marc Hellman, Public Utility Commission of Oregon
Load Growth Workgroup Meeting – June 29, 2005

This straw proposal presents a structural protection from cost shifts. The proposal is based upon a two tiers of resources framework with corresponding load demarcation. All new resources would begin to be allocated to the second tier when it is determined[52] that the least-cost plans identify resource additions, or group of resource additions, to come on-line within 36 months, to meet disparate load growth, will cause a cost shift among the states for which offsetting considerations are not sufficient to mitigate the cost shift. Allocations for changes in Tier 1 resources are made on a fixed set of allocation factors established at the trigger date.[53] Reductions in Tier 1 loads are handled slightly differently. (See Scenario 1) Common costs are allocated based on total loads.

A. Base Tier[54]
   1. Existing resources and contracts as of a trigger date and includes:
      a) Refurbishment of Tier 1 resources
      b) Relicensing of Tier 1 resources
      c) Contract renewal of Tier 1 resources for which renewal rights are specified by contract which is being renewed. (Holder of contract has renewal rights different than what would be available to an independent third party.)
      d) Net of existing wholesale sales commitments executed prior to trigger date

[52] This paper does not have a definitive suggestion as to whom or how this determination is made. One option would be that any state could make the determination independently. Presumably the state would try to convince the other states to agree with this finding. The Revised Protocol identifies the consequences should Oregon depart from the Revised Protocol and PacifiCorp's obligations assuming Oregon does not depart from the Revised Protocol. An alternative for how the cost shift determination could be made is through the Standing Committee. However, it is clear that no state is delegating to the standing Committee the state's obligation to ensure fair and reasonable rates. This "determination" matter need not be resolved at this time. The Revised Protocol directs the development of a structural protection mechanism but does not prescribe the considerations for when it would be adopted.

[53] If a state has load loss causing the state loads to fall below the Tier 1 trigger date levels, any benefits/costs of the remaining Tier 1 resources would be allocated to all the states proportionally to their respective Tier 1 trigger date levels with the exception of using the state's reduced load levels. The trigger date is the date by which a state finds cost shifts would occur and hence is never retroactive, and can start at the date of the order or some future date as established through that commission's order.

[54] The structural protection is prospective in nature. The proposal is not based on the concept that cost shifts have occurred. All four states adopting the Revised Protocol have essentially concluded that at the time of adoption, and studies analyzing its reasonableness, the allocations based upon the Revised Protocol are reasonable. The trigger date can be based on resources currently under construction and not on line as of early 2005, when the Revised Protocol was adopted.

(1) Base Tier net position (Tier 1 resources net of firm long-term wholesale sales) can increase or decrease

2. No replacement of Tier 1 except as provided above
3. Resource/costs allocated using Revised Protocol Methodology
4. Base factors are those calculated as of the trigger date.
    a) Establish state load levels as of trigger date and allocation at a level of loads that equals available resources
        (1) Calculate pro rata reductions in loads to establish Tier 1 loads and resources.
        (2) For changes in Tier 1 Resources, first step is to use pro rata changes using trigger date load ratio/factors.
        (3) If state loads fall below original Tier 1 allocations, any remaining Tier 1 resources are allocated pro rata across states using adjusted state trigger-date factors. In this case the benefits of the excess Tier 1 resources (cost versus market) are what are allocated. Such state can grow back into its original Tier 1 allocation, with corresponding reversal of increases in Tier 1 allocations for other states.
5. Calculate remaining resource needs for each state
6. Power cost runs are based on Tier 1 loads and resources
7. To the extent reserves are needed, purchase at market prices

B. Second Tier (only two tiers are proposed)
    1. All new resources, purchase contracts and wholesale sales on and after the trigger date
    2. Tier 2 cost and allocations is given by the following: Tier 2 allocations = Total Company Grid run - Grid run on Tier 1
        a) The costs identified as Tier 2 costs are allocated using the Tier 2 load based factors.
    3. Calculate remaining resource needs for each state. (Remaining resource needs of each state equals total state loads minus allocated Tier 1 resources.)
    4. Power cost runs are based on net remaining loads and Tier 2 resources
    5. To the extent reserves are needed, purchase at market

C. Changes in loads
    1. Loads assigned to Tier 2 for any state cannot decrease except when Tier 2 resources decrease.
        a) Reductions in load are assigned unadjusted shares of Tier 2 and any offsetting sales for resale revenues
    2. Reductions in Tier 1 loads are handled consistent with Revised Protocol. Reductions caused by factors other than direct access result in a reduction in allocation of Tier 1 resources. Tier 1 resources are reallocated to other states. However, Tier 1 resource allocations can be restored if loads return to pre-trigger date levels.

3. Calculate remaining resource needs for each state

D. Other

a) Short-term and new long-term sales for resale are assumed to be provided by Tier 2 resources up to the energy generating capability of Tier 2 resources. Exception is sale of power matching a Tier 1 load reduction.

Appendix

Option Selections

The following lists the options selected from the PacifiCorp paper provided in the Appendix.

1.a.) Tier 1 Design:	Option 1
1.b.) Growth Costs:	Option 1
1.c.) Multiple Tiers:	Option 1
2) Selection of Base Year:	Option 3
3.a.) Wholesale Sales:	Option 1
3.b.) Long Term Wholesale Purchases:	Option 1
3.c.) Treatment of Load Decrements:	Not applicable
4.a.) Reductions in Load:	Option 1
4.b.) One state grows then loses load	Option 1
4.c.) Gain or loss of Service Territory	Option 1
4.d.) Sale of Generation	Option 1
4.e.) Direct Access	Treat consistent with Revised Protocol
5.a.) Replacement power	Option 1
5.b.) Generation Changes	Option 1

5.c.) Lost Hydro Generation	Same as 5.b
5.d.) Planning Reserves	New Proposal closest to Option 2

Base Case

Tier 1 Resources equals	1000	Tier 1 Allocations
Tier 1 Loads as of Trigger Date		
Utah	425	0.425
Wyoming	150	0.150
Idaho	100	0.100
Washington	75	0.075
Oregon	250	0.250
Tier 2 Resources equals	100	Tier 2 Allocations
Tier 2 loads		
Utah	75	0.75
Oregon	25	0.25

The following examples are designed to provide how factors would be derived for both Tier 1 and Tier 2 costs. Tier 1 costs are identified by means of the resources existing prior to the trigger date. Tier 2 costs are total company costs minus Tier 1 costs. General allocators are based on total loads.

Scenario 1 = Idaho Tier 1 loads decrease by 25 mW

Tier 1 Resources equals	1000		Tier 1 Allocations
Tier 1 Loads as of Trigger Date with Adjustment			
Utah	425		0.425
Wyoming	150		0.150
Idaho	75	(100 – 25)	0.100
Washington	75		0.075
Oregon	250		0.250

Excess 25 MW gets valued at market and margins are distributed pro rata to the adjusted Tier 1 allocations.

Adjusted Tier 1 allocations for distribution of margins

	Adjustment	Factor
Utah	.425*1.000/0.975	0.436
Wyoming	150*1.000/0.975	0.154
Idaho	75*1.000/0.975	0.077
Washington	75*1.000/0.975	0.077
Oregon	250*1.000/0.975	0.256

Adjusted Tier 1 allocations for 975 mw of Tier 1 Resources

	Load	Factor
Utah	425	0.436
Wyoming	150	0.154
Idaho	75	0.077
Washington	75	0.077
Oregon	25	0.256

Tier 2 Resources equals	100	Tier 2 Allocations
Tier 2 loads		
Utah	75	0.75
Oregon	25	0.25

Scenario 2 = Tier 1 Resources reduced by 100 mW

Tier 1 Resources equals	1000	Tier 1 Allocations
Tier 1 Loads as of Trigger Date		
Utah	425	0.425
Wyoming	150	0.150
Idaho	100	0.100
Washington	75	0.075
Oregon	250	0.250

Tier 1 loads shifted into Tier 2

	Adjustment	Load Shifted

Utah	425*100/1000	42.5
Wyoming	150*100/1000	15.0
Idaho	100*100/1000	10.0
Washington	75*100/1000	7.5
Oregon	250*100/1000	25.0

Tier 2 Resources equals	200 (100 + 100)	Tier 2 Allocations
Tier 2 loads		
Utah	75+42.5 = 117.5	0.5875
Oregon	25+25 = 50.0	0.25
Idaho	0+10 = 10.0	0.05
Washington	0+7.5 = 7.5	0.0375
Wyoming	0+15 = 15	0.075

Scenario 3 = Utah Tier 2 loads decrease by 25 mW

Tier 1 Resources equals	1000	Tier 1 Allocations
Tier 1 Loads as of Trigger Date		
Utah	425	0.425
Wyoming	150	0.150
Idaho	100	0.100
Washington	75	0.075
Oregon	250	0.250

Tier 2 Resources equals	100	Tier 2 Allocations
Tier 2 loads		
Utah	50 (75 - 25)	0.75*
Oregon	25	0.25

* 25 mW of Tier 2 resources are sold on market for a term of one year with 100% sales for resale allocated to Utah.

Scenario 4 = Tier 2 Resources Increase by 100 mW with loads increasing 50 mW

Tier 1 Resources equals	1000	Tier 1 Allocations
Tier 1 Loads as of Trigger Date		
Utah	425	0.425
Wyoming	150	0.150
Idaho	100	0.100
Washington	75	0.075
Oregon	250	0.250
Tier 2 Resources equals	200	Tier 2 Allocations
Tier 2 loads		
Utah	120 (75 + 45)	0.80 (120/150)
Oregon	30 (25 + 5)	0.20 (30/150)

* The excess 50 aMW is marketed in the wholesale market and the revenues from such a sale are allocated to Utah and Oregon on an 80/20 basis. The full costs of the excess 50 aMW are allocated to the Tier 2 loads using the 80/20 factors in this illustrative example.

Tiered Allocation
Issues and Options for Resolution
(Load Growth Workgroup Meeting – June 29, 2005)

PacifiCorp Discussion Paper
April 20, 2004

Initial studies of tiered allocation identified a large number of issues that must be resolved before a tiered allocation method could be put in place. Each issue appears solvable and in most cases more than one solution is possible. This paper summarizes the options identified so far.

1) Overall Design Issues

1.a.) Tier 1 Design
Fundamental to the design of tiered allocations is the identification of loads and resources to be included in Tier 1 over time. The initial design of a tiered allocation method started Tier 1 loads and resources at FY 2002 levels. All growth in resources and loads were added to Tier 2. Over time, a number of Tier 1 resources expire or retire. It is desirable to keep Tier 1 loads and resources relatively in balance because the load/resource balance will affect the assignment of system balancing sales and purchases to Tier 1. The initial concept was to reduce Tier 1 loads to keep them relatively in balance with resources as the later expired or retired over time. This would represent a gradual move toward Rolled-In allocation as Tier 1 loads and resources decline.

Another possible design of a tiered allocation method would replenish Tier 1 resources as they expire. This would keep Tier 1 loads and resources near their initial values. It would also increase the mix of Tier 2 costs in Tier 1. This tiered allocation method requires calculation of Tier 1 and Tier 2 before adjustments, determination of the size of the Tier 1 adjustment, then adjustment of both loads and resources for Tier 1 and Tier 2. Fundamentally, the design of the tiered allocation method will reflect whether parties believe that the tiers should diminish over time or persist.

Option 1: Reduce Tier 1 loads as Tier 1 resources expire. Over time, Tier 1 goes away.
Option 2: Replenish expiring Tier 1 resources, maintaining the size of Tier 1 over time. For issues related to replenishment of resources, see the "Replacement Power" section on page 5 of this paper.

1.b.) Growth Costs

Tiered allocation methods are intended to cause fast growing states would pay for their own load growth. Costs associated with growth can be difficult to quantify and assign to Tier 2 within a single company system. Identifying the addition of new generation resources is easy but each new resource may contribute to factors other than growth. In addition, other system costs needed to support needed to support new resources are more difficult to quantify. Examples include transmission and overheads. A central design question for tiered allocation is whether Tier 2 has adequately captured all costs of load growth.

Option 1: Apply tiered allocation method only to direct new resource costs.
Option 2: Identify additional categories of costs related to growth.
Option 3: Determine the growth-related portion of new resources, existing resources and overheads and assign only growth-related costs to Tier 2.

1.c.) Multiple Tiers

The design of a tiered allocation method could come under considerable pressure if load growth patterns were to change in the future. Utah loads are presently growing faster loads in other states. Present tiered allocation designs place relatively more Utah load in Tier 2 than other state loads. Suppose the growth patterns of Utah and Oregon were to reverse in future years and the Company began acquiring resources in the West. The principles of tiered allocation would suggest that Utah should not be responsible for the costs of those Western resources just because they happened to have grown in prior years. A third tier may be needed to reflect this new era. Indeed, it would be possible to argue that *every* resource is the product of a unique pattern of growth.

Option 1: Agree in advance that no additional tiers will be created.
Option 2: Create additional tiers under specified circumstances.
Option 3: Allocate resources added in each year based on growth formulas specific to that year (i.e. a new tier each year.)

2) Selection of Base Year

The base year divides Tier 1 from Tier 2. Selection of the base year is a fundamental design step for tiered allocation. Since growth and resource acquisition are more-or-less continuous processes, parties may differ in their choice of one base year over another. For initial studies of tiered allocation, FY 2002 was chosen because energy loads and resources were roughly in balance in that year. This base year also places in Tier 2 the newer resources that Oregon parties believed were associated with the type of growth to be captured by Tier 2.

Option 1: Move base year to FY 2005. Moving the base year to 2005 would have the effect of including Gadsby CT's and West Valley in Tier 1. The change would not eliminate the problem of decreasing loads discussed in the Section 4.a. of this paper.
Option 2: Leave base year in FY 2002
Option 3: Pick a different year.

3) Loads To Be Included

3.a.) Wholesale Sales
When wholesale sales contracts expire, existing resources can serve more retail load. The initial tiered allocation studies were based on retail loads. Studies increased the size of Tier 1 loads when existing wholesale sales contracts expired, consistent with the treatment of expiring long-term purchases. Increasing Tier 1 loads in this way contributed to the problem of negative Tier 2 loads in the initial studies. Alternatively, expiring wholesale sales contracts are one way that the Company plans to serve new retail loads. New resource additions in the Integrated Resource Plan assume that certain wholesale sales contracts will expire. Focusing on these considerations, one could decide not to increase Tier 1 loads as wholesale sales contracts expire.

Option 1: Increase adjusted Tier 1 loads as long-term wholesale sales contracts expire
Option 2: Do not increase adjusted Tier 1 loads as long-term wholesale sales contracts expire.
Option 3: Use loads that include long-term wholesale sales for Tier 1 modeling and allocation factors.

3.b.) Long-Term Wholesale Purchases
The initial tiered allocation studies reduced the size of Tier 1 as long-term purchase contracts expired. The treatment maintains a reasonable match between base period loads and resources. See also Section 1.a. of this paper on "Tier 1 Design."

Option 1: Reduce Tier 1 loads as long-term purchase contracts expire.
Option 2: Do not reduce Tier 1 loads as long-term purchase contracts expire. Replace expiring contracts with an average of Tier 2 resources.
Option 3: Similar to Option 2 but replace expiring contracts with specific replacement resources.

3.c.) Treatment of Load Decrements

The initial tiered allocation studies used decremented loads to allocate West Hydro, Mid-C contracts, and QFs. The studies used no decrements assigned to Tier 2 because new QF contracts were not assumed. The combination of load decrements and tiered allocation is much more computationally complex than either method alone. Load decrements may be redundant with tiered allocation since both are aimed, at least to some degree, at removing load growth impacts. In addition, Utah parties have raised concerns regarding the load decrement approach.

Option 1: Apply the load decrements approach with tiered allocation.
Option 2: Use other methods of calculating a hydro endowment with tiered allocation.

4) Changes in Load Over Time

4.a.) Reductions in Load
State loads can fall as well as rise. The initial design for tiered allocations makes no special provision for that fact. Wyoming loads, in particular, fall below their FY 2002 levels during the forecast. When a state's load falls below the Tier 1 amount, its calculated Tier 2 loads would be negative under the initial design. In effect, the state buys power at Tier 1 costs and sells it at higher Tier 2 costs, creating benefits for that state. Negative loads reverse the signs of many computations and this can make interpretation of results difficult. If a tiered allocation method reduced a state's Tier 1 allocation if loads fall below the base level, parties would have to agree on changes to the allocation of Tier 1 resources and on whether the state's Tier 1 allocation could increase again once loads started to grow.

Option 1: Tier 1 load is the lower of the adjusted base period Tier 1 load or the actual load. When actual load is less than adjusted Tier 1 load there would be no Tier 2 allocations. Reductions in Tier 1 load are permanent.
Option 2: Similar to Option 1 except that reductions in Tier 1 load are temporary so that a state could grow again and remain in Tier 1.
Option 3: No adjustment for negative loads in a tier.

4.b.) One state grows then loses load
A state that is growing and loses a material portion of its load, such as could occur in areas that currently serve industrial loads, may create unintended revenue requirement impacts to other states. The design of tiers should consider whether the load being lost is from Tier 1 or Tier 2. The allocation effect of losing loads will be more pronounced in Tier 2 than under Rolled-In because of the smaller base of Tier 2 loads. The loss of load in Tier 2 may magnify any imbalance between Tier 2 retail loads and resources. A key concern in developing tiered allocations is the risk sharing issue.

Option 1: No adjustments for large load losses
Option 2: Adjustment to Tier 1 or Tier 2 depending on when and where load was originally assigned
Option 3: Reset Tier 1 and Tier 2 prices. This option would require specification of when and how the tiers are reset.
Option 4: Add additional tiers

4.c.) Gain or Loss of Service Area
The design of tiered allocations should consider the impact of gaining or losing service territory, either within an existing state or in a new state. Generally, MSP parties have favored treating allocation issues associated with acquisition of service territory as special cases. This discussion focuses on loss of service territory.

Loss of service territory could potentially impact both Tier 1 and Tier 2 loads. A power sales contract may be associated with the loss of service area. This power sales contract would need to be split into Tier 1 and Tier 2 resources.

Option 1: Adjust Tier 1 and Tier 2 loads to reflect the sale, net of obligations under any power sales contract.
Option 2: Treat lost load and power supply obligations in different ways.
Option 3: Do not adjust Tier 1 loads in response to loss of service territory.

4.d.) Sales of Generation
The design of tiered allocations should consider the impact of sold generation. The sold generation resource would be removed from the tier originally assigned and the loads in that tier adjusted. How would the gain on the sale be allocated to the states? If a purchased contract is secured as part of the sold generation, to what tier should this purchase contract be applied?

Option 1: Remove sold generation from original tier assigned, apply purchase contract & gain on sale to the same tier
Option 2: Remove sold generation from original tier assigned, apply purchase contract & gain on sale to an alternative tier
Option 3: Remove sold generation from original tier assigned, apply purchase contract & gain on sale to both Tier 1 and Tier 2

4.e.) Direct Access
A tiered allocation method should account for load that permanently elects direct access. (Load that elects direct access service with a right to return to cost-based service would continue to be reflected in a jurisdiction's loads and would not be removed from any tier.) One may adopt the view that most permanent direct access load would have been served in the base period and would, therefore, be part of Tier 1. In this view, Tier 1 loads would be reduced by the amount of permanent direct access load. This would have the effect of altering the Tier 1 allocations of other states. Additionally, if the state in which the departing direct access customer was located had a positive Tier 2 allocation at the time of departure, a Tier 2 load adjustment may also be appropriate. Generally, MSP participants have adopted the principle that implementation of direct access should not affect other states. Transition adjustments associated with the direct access load would reflect the change in system cost associated with the loss of this load.

Option 1: Reduce Tier 1 load by the amount of load that permanently elects direct access service.

Option 2: Do not reduce Tier 1 load in response to direct access.
Option 3: Similar to Option 1 but split load reduction between Tier 1 and Tier 2.

5) Resource Issues

5.a.) Replacement Power
In some cases an expiring or retiring resource may be explicitly replaced by another resource. For instance, contracts may be replaced according to specific renewal provisions or a generating resource may be replaced by another built on the same site. Parties have discussed solutions to the Tier 1 design issue discussed in the first section of this paper that give special consideration to costs of replacement resources. When an expiring Tier 1 resource is explicitly replaced by another, the costs of the replacement resource could be assigned to Tier 1. This would slow the decline in the size of Tier 1 compared to the case where no resources are added.

Special treatment of replacement resources would require parties to agree on design choices. For instance, do such replacements include generating plant shut-down, expiring contracts, or both? Do replacements include contracts entered into when the renewal provisions of the expiring contract were vague and the new contract differs from the old? The Integrated Resource Plan does not provide guidance since it does not distinguish between new resources intended to replace expiring resources and resources to meet new growth. Initial studies indicate that the definition and treatment of replacement power has an important effect on the assignment of costs to the tiers.

Option 1: Reduce Tier 1 loads as Tier 1 resources expire. Over time, Tier 1 goes away.
Option 2: Replenish expiring Tier 1 resources with specific identified replacements, where they can be identified.
Option 3: Replenish expiring Tier 1 resources with Tier 2 resources at the average cost of Tier 2 resources.

5.b.) Generation Changes: Overhauls, Re-powering and Capacity Increases
The initial study treated the re-power of Gadsby plant as a Tier 2 resource and not as a replacement of a Tier 1 resource. No special treatment was given to overhauls which increased generating plant capacity. Modeling becomes substantially more complex if the fixed costs of a resource are split between the tiers.

Option 1: Treat overhauls and re-powering as replacements of or changes to Tier 1 resources.
Option 2: Treat generation changes as Tier 2 resources. Split resources where needed. Include the fixed and variable costs associated with overhauls and re-powering in Tier 2.
Option 3: Adjust Tier 1 loads to reflect generation changes.
Option 4: Do not adjust Tier 1 load.

5.c.) Lost Hydro Generation

The initial study treated the lost hydro generation as a reduction to a Tier 1 resource. This issue is similar to the Generation Changes issue discussed in the preceding section of this paper.

5.d.) Planning Reserves

The initial study did not attempt to segregate planning reserves between the tiers. The resources in Tier 2 are built with a reflection of planning reserves, so the output of a base load plant may not be fully dispatched due to fuel and market prices. This is a similar issue where SCCT plants are being added to address peak loads, but they dispatch at low capacity factors.

An alternative view does not recognize that planning reserves are included in or adjusted for in Tier 2 resources.

Option 1: No adjustment for planning reserves in Tier 2
Option 2: Adjust Tier 2 to recognize planning reserves; include a corresponding adjustment in Tier 1.

Appendix 14
Tiered Alternative 2 Paper

ILLUSTRATIONS OF A MODIFIED TIERING/VINTAGING ALLOCATIONS MECHANISM FOR MITIGATING THE BURDEN OF GROWTH COSTS ON NON-GROWING JURISDICTIONS: A STRAWMAN FRAMEWORK

by George Compton

(Load Growth Workgroup – June 29, 2005)

I. *Exhibit 1*

A. The problem: Growth costs are incurred to meet annual and seasonal peak loads, yet most of PacifiCorp's generation fixed costs are allocated on the basis of all twelve monthly peaks. A future departure from the 12CP approach may or may not be called for on cost-causation grounds. A mechanism is required for synchronizing growth costs and the cost allocations methodology that is now in effect.

B. Discussion: When growth loads are being distinguished from prior loads, the allocations problem seems to be more tractable when apportionments of capacity (rather than costs) are being kept track of. The simplest combination of system capacity sizing and capacity allocations would be to use the single annual peak.[55] But the Revised Protocol uses a combination of a 12CP allocator and seasonal allocations which employ a monthly energy component. Obviously the average of the 12 coincident peaks will lie below the annual coincident peak, which more than anything else dictates the requisite system capacity level. To place the capacity allocation on the same level of the overall capacity requirement, it is necessary to inflate the average 12CP figure commensurately so as to yield "composite loads" that are the working equivalent of annual peak loads.

C. Suggested resolution: The last column of the exhibit inflates each jurisdiction's 12CP monthly average figure by a uniform percentage amount so that the sum of the new figures equates to the annual peak (which appears in month 7 in this example). Those adjusted averages are what will subsequently be used to allocate the capacity costs.[56]

[55] Example: If a system's capacity was 1000MWs and Jurisdiction A's annual coincident peak load (including reserve requirement) was 400MWs, then in a simple 1CP world that jurisdiction would be allocated 40% of the demand, or capacity, costs.

[56] One might object to the fact that HiGro's allocation of 427 is beneath its load (450) at the time of the annual system peak (in July) while the other two jurisdictions' allocation figures (206 and 90) exceeds their annual coincident peak loads. The apparent break received by HiGro under the 12CP approach is justified insofar as the winter peak (in months 1 and 12) is also cost sensitive (as manifest by its being almost as great as the summer peak). HiGro's allocation figure exceeds its winter figure while the allocation amounts of the other two jurisdictions are below their winter peak figures.

II. *Exhibit 2*
- A. The problem: Should the loads used to establish the Tier 1 allocations be those of the trigger year (from when subsequent growth is recognized in future-tier allocations) or some average of that and prior years' loads?
- B. Discussion: Rather than deciding this issue arbitrarily, it is useful to compare the trigger- and pre-trigger-years' loads with the amount of capacity residing in the first tier. Different answers to the problem suggest themselves depending on that comparison.
- C. Suggested resolution: Where the base tier's capacity is less than the trigger year's peak load, it is reasonable to use an average of past loads going back in time as far as to yield an average that will approximate the tier 1 capacity. Where the tier 1 capacity exceeds the trigger year peak load, it is reasonable to base the initial allocation on the trigger year's loads themselves (assuming that such represent the highest recent load level). Exhibit 2 illustrates those two types of resolutions and their respective contexts.

III. *Exhibit 3*
- A. Block 1: This is merely a duplication of Base Case B from the previous exhibit.
- B. Block 2:
  1. Problem: How should the Tier 1 resources be allocated in the years between the trigger year and the introduction of large new production resource(s) that constitutes the Tier 2[57]? Note: It may not appear important to allocate Tier 1 resources when the concern is the post-Tier 1 growth. But it is difficult to know how much of a jurisdiction's load is being served from Tier 2 (and subsequent tiers') resources unless it is know how much is being served out of Tier 1. (This also helps to explain the practice of placing the allocations – at least preliminarily – in terms of capacity magnitudes rather than costs.)
  2. Suggestion as illustrated in this block: Until which time a new tier is introduced, it would seem appropriate to allocate the Tier 1 resources in the same manner as was used in the trigger year. This approach seems suitable whether the loads are beneath or in excess of the Tier 1 capacity.
- C. Block 3:
  1. Problem: How should the Tier 1 resources be allocated in the year in which the second tier is introduced?
  2. Discussion and Resolution: It would seem intrinsic to the notion of a trigger year that a jurisdiction's Tier 1 allocation for purposes of establishing its Tier 2 (or growth) allocation should not be lower than what it would be if based on the trigger year's loads (or the average of the "basis" years' loads). Where the Tier 1 capacity exceeded the aggregate load, the "surplus" might be

[57] One would think that a mere increase in front-office acquisitions would not warrant creating a new cost allocations tier. Instead, it would seem to require the addition of a new generation plant or comparable, long-termed production resource.

allocated to all the jurisdictions in proportion to their growths between the trigger year and the first Tier 2 year. The block illustrates that approach.

D. Block 4:
   1. Problem: How to allocate a new tier's resources, given a recognition of the fact that growth may not account initially for the entire magnitude of those resources?
   2. Discussion: Resources large enough to constitute the beginnings of a new tier possess the distinguishing characteristic of "lumpiness," i.e., their magnitude may not mesh exactly with the growth that has occurred since the prior tier's trigger period. Two methods of dealing with this matter suggest themselves. One is to assign the entire new resource to the growth jurisdictions and credit them with the off-system sales that are enabled by the lumpiness surplus. The downside of this approach is that it adds to the direct growth burdens the onus of a somewhat arbitrary portfolio expansion plan and the risk, in a normalized, future test-year context, that the Company's modelers can adequately project the added non-jurisdictional sales enabled by temporarily surplus production capacity. The other method is to allocate the surplus capacity to all the jurisdictions in proportion to their total loads – so as to reflect their shares of benefits to whatever added surplus sales margins are ultimately captured in the net power cost results.[58]
   3. Resolution: Block 4 illustrates the second approach that was just discussed.

IV. *Exhibit 4*
   A. Block 1. This block merely applies to the second Tier 2 year the methodology employed in the first (as illustrated in Block 4 of Exhibit 3).
   B. Block 2.
      1. Problem: How should the Tier 1 resources be re-allocated to reflect the retirement of some of them? Of particular interest is the case where one of those retired resources had benefits that were differentially dedicated among the jurisdictions.
      2. Discussion: One basis for system capacity expansion is the need to replace production resources as they are retired or otherwise discontinued. "Growth" can be defined as the difference between current demand and some prior capacity allocation. Accordingly, increased demand and a reduced allocation of earlier tier resources are algebraically equivalent. This invokes a requirement to differentially re-allocate Tier 1 resources insofar as a retired resource provided benefits differentially to jurisdictions.
      3. Resolution: Block 2 illustrates the re-allocation of Tier 1 resources where a portion of the retired resources had dedicated beneficiaries and another portion's benefits were shared among all the jurisdictions.

[58] Recall that this proposed multi-tier methodology only differentially allocates the demand portion of the new production costs, and not the added energy costs. The latter would presumably be allocated according to the standard Revised Protocol techniques.

C. Block 3. This block allocates the entire amount of the Tier 2 resource to the jurisdictions in proportion to their load growth beyond their Tier 1 allocations.

D. Block 4.

1. Problem: How should the tiers' resources be re-allocated in the presence of a substantial reduction in the loads of some of the jurisdictions?
2. Discussion and Resolution: As a rule of thumb it would seem that a reduction in demand would be reflected in a reduction in the allocation of the most recent tier's capacity. Beyond that, if a jurisdiction's demand falls below its Tier 1 allocation, then that allocation should be reduced to the new demand level, with the newly created excess within that tier re-allocated to the other jurisdictions.[59] Block 4 shows the consequences of two jurisdictions having a lower demand than in the previous year. The reduction experienced by the jurisdiction that had not grown earlier (i.e., "NoGro") caused it to lose a portion of its Tier 1 allocation. That portion was redistributed to the other two jurisdictions. The other declining jurisdiction's load loss was reflected in the reduction of its Tier 2 allocation. The faster growing jurisdiction (i.e., "HiGro") picked up the entire surplus that would have otherwise been created in the Tier 2 resources.

E. A discussion of why a load-losing jurisdiction should be able to receive a smaller allocation of growth-tier resources, even if the load loss produces a production resource surplus:

1. The primary ongoing MSP growth concern is to require a growing jurisdiction to itself bear the costs of growth, not to insulate the jurisdictions from the risks of other jurisdictions' declining demands. It is one thing to bear growth costs when, at the same time, sales are increasing (thereby bearing most of the incremental costs). It is another to have increased costs in the presence of diminished sales.
2. The issue may be moot. As long as the overall system is growing, when the system is running short the capacity freed up by one jurisdiction's occasional load reduction will be utilized by the rest of the growing system – thereby reducing the need for market purchases and allowing savings from the postponement of new plant additions. In other words, one jurisdiction's load reduction may not be accompanied by additional market sales (but rather by reduced purchases), and even if there temporarily is spare capacity the reduction of one jurisdiction's load will enable the growing jurisdictions to benefit from greater utilization of existing capacity rather than having to bear the cost of new capacity.
3. Estimating the incremental off-system market sales made possible by a reduction in a jurisdiction's load involves multiple GRID runs and is heavily assumption driven, with price estimates based upon hourly regional supply and demand projections. The benefits of not allowing allocations to ratchet down and attributing the enabled market sales to the load-losing jurisdictions do not appear to justify the added regulatory complexity and uncertainty involved in making "what-if" projections of such market sales absent versus given the released production capacity.

[59] An exception to this rule would apply under Direct Access, where the jurisdiction that loses a designated load would still receive its allocation – and have the benefit of the added off-system sales enabled therefrom.

F. Block 5. This illustrates the allocations of Tier 3 resources being performed in the same manner as the Tier 2 resources were allocated in Block 4 of Exhibit 3.

G. A discussion of why there should be more than one growth tier:

1. Primary justification: The cost consequences of growth are partly a function of the timing of a jurisdiction's growth. Not taking such into consideration can cause a jurisdiction to pay costs that are well in excess of what it caused.
2. Illustration of the problem of having just one growth tier: Say that one jurisdiction experiences considerable growth in year 1, causing a new plant of commensurate capability to be built and entered as the sole item in Tier 2. Assume no more growth occurs until year 15, when a different jurisdiction experiences the same amount of growth, which causes the addition of a new plant into Tier 2 of the same size as the first. With only one growth tier, and which is simply allocated in proportion to post- trigger-year growth, both jurisdictions would pay the same amount in year 16 even though most of the growth costs in that year (given the fifteen years of depreciation of the first growth plant) are due to the second plant, which was caused to be built by the second jurisdiction. If a second growth tier were added, then the cost of the second new plant would be borne solely by the later-growing jurisdiction – whose growth caused it to be built.
3. Complexity? Obviously having several tiers or vintages makes for greater complexity than having just two. But the algorithm for allocating within and between the tiers can be relatively straightforward, as has been illustrated in this paper. As far as a multiplicity of GRID runs being required, I think not. In fact, I don't see the need for any additional runs being run beyond what would otherwise be needed to estimate the effects of a large load loss owing to direct access in Oregon (i.e., with that State capturing the benefits of the additional off-system sales or reduced purchase costs made possible thereby).
4. A related issue: When all the new plants are placed into a single costing tier, there is a diluted potential for the somewhat arbitrary timing of the installation of an expensive coal baseload plant versus a CCCT of SCCT to have an unwarranted impact on a jurisdiction whose growth spurt just happened to coincide with the installation of such a plant. But with each new plant constituting a new tier, such a consequence would be inevitable if the full fixed costs of such plants are what are allocated. To avoid that problem, it is proposed that only the demand portion of new plants be allocated according to vintage. (That portion is approximately half of the fixed costs of a coal plant.) The balance of those costs, i.e., the energy portion, would be allocated as part of the net power costs, which would be spread across all sales in the current manner.

Exhibit 1

Simplified Scenario Analysis of Strawman Skeleton
Proposal for Modified Tier Allocations
by George R. Compton, UDPU
(Load Growth Workgroup - June 29, 2005)
A PRELIMINARY CONSIDERATION

COMMENT: Both Marc's and my tiering proposals place loads, resources, and allocations on the same numeric terms -- ostensibly annual coincident peak megawatts. However, the current allocations practice is to use the twelve monthly coincident peaks rather than the annual peak. One method -- illustrated below -- for placing the twelve monthly peaks on the same terms as the total load that matches with total resources (and making the simplifying assumption that resources are acquired primarily to meet the annual peak) is to ratio up the average monthly peaks by a uniform amount sufficient to bring the final total load figure up to the same level as the annual coincident peak. The pros and cons of this approach are discussed briefly in the text accompanying these worksheets.

YEAR 0 LOADS ANALYSIS

	MONTH AND LOADS														
	1	2	3	4	5	6	7	8	9	10	11	12	SUM	MONTHS' AVERAGE	ADJUSTED AVERAGE
JURISDICTION															
HiGro	389	385	375	355	369	405	425	415	375	335	355	389	4572	381	401.9
LoGro	214	211	207	180	175	180	194	195	190	185	200	214	2345	195	206.1
NoGro	91	90	85	85	85	80	79	80	82	85	90	92	1024	85	90.0
SUM	694	686	667	620	629	665	698	690	647	605	645	695	7941	662	698.0

Exhibit 2

Simplified Scenario Analysis of Strawman Skeleton
Proposal for Modified Tier Allocations
(Refined Initial Proposal)
by George R. Compton, UDPU
(Load Growth Workgroup - June 29, 2005)

Initial Tier 1 Allocation

COMMENT: Whether the initial Tier 1 allocation is based upon the trigger-year loads or some average of prior year loads will depend on whether the trigger year loads are less than or greater than the Tier 1 cacacity.

"PEAK" LOAD HISTORY

	BASIS YEAR					
JURISDICTION	-4	-3	-2	-1	0	AVERAGE
HiGro	198	300	350	375	401.9	325
LoGro	184	190	195	200	206.1	195
NoGro	90	90	90	90	90.0	90
SUM	472	580	635	665	698.0	610

NOTE: In every instance, the loads and resources are exclusive of QFs, which are situs. Also, the loads include the suggested 15% planning margin.

Assume the "trigger" occurs at the end of year 0.

BASE CASE A: Tier 1 Capacity Less Than Five Basis Years' Average Total Load

TIER 1 CAPACITY 600

JURISDICTION	5-YEAR AVERAGE	AVG. SHARE	CAPACITY ALLOCATION
HiGro	325	53%	320
LoGro	195	32%	192
NoGro	90	15%	89
SUM	610	100%	600

Proposal: Use the basis years' average to establish the allocations.

BASE CASE B: Tier 1 Capacity Greater Than Trigger Year's and Basis Years' Average Load

TIER 1 CAPACITY 750

JURISDICTION	YEAR 0	YEAR 0 SHARE	CAPACITY ALLOCATION
HiGro	401.9	58%	431.8
LoGro	206.1	30%	221.5
NoGro	90.0	13%	96.7
SUM	698.0	100%	750.0

Proposal: Use the trigger year's loads to establish the allocations.

Exhibit 3

Simplified Scenario Analysis of Strawman Skeleton
Proposal for Modified Tier Allocations
(Refined Initial Proposal)
by George R. Compton, UDPU
(Load Growth Workgroup - June 29, 2005)

The Evolving Tier 1 Allocation and Initial Tier 2 Allocation

INITIAL (i.e., year 0, or trigger-year) TIER 1 ALLOCATION

BASE CASE B: Tier 1 Capacity Greater Than Trigger Year's Total

TIER 1 CAPACITY 750

JURISDICTION	Trigger year (0) "peak" loads	Load Share	Capacity Allocation
HiGro	401.9	58%	432
LoGro	206.1	30%	221
NoGro	90.0	13%	97
SUM	698.0	100%	750

POST TRIGGER-YEAR LOADS AND TIER 1 ALLOCATIONS

Proposal: Prior to the initial Tier 2 year, allocate Tier 1 capacity in proportion to each year's "peak" loads.

	YEAR								
	1			2			3		
JURISDICTION	"Peak" Loads	Load Share	Capacity Allocation	"Peak" Loads	Load Share	Capacity Allocation	"Peak" Loads	Load Share	Capacity Allocation
HiGro	425	59%	440	450	60%	447	475	61%	454
LoGro	210	29%	217	215	28%	214	220	28%	210
NoGro	90	12%	93	90	12%	89	90	11%	86
SUM	725	100%	750	755	100%	750	785	100%	750

NOTE: Shortfall in years when aggregate peak load exceeds capacity is assumed to be met with balancing purchases included in Net Power Costs.
NOTE: The indicated 3rd year may be a "future" test year.

ADJUSTED TIER 1 ALLOCATION OWING TO A NEW (i.e., Tier 2) RESOURCE THAT ARRIVES IN YEAR 4

Proposal (given Base Case B): Each jurisdiction receives an allocation of Tier 1 resources that is at least equal to its trigger-year (i.e., year 0) load. The surplus Tier 1 capacity relative to the trigger-year load is allocated in proportion to growth between the trigger-year and the new resource (i.e., Tier 2) year.

TIER 1 CAPACITY: 750

NOTE: The total prior Tier 1 surplus capacity was 750 - 698 = 52

JURISDICTION	Year 0 "peak" loads	Year 4 "peak" loads	Growth since trigger year	Allocation of Tier 1 trigger-year surplus	New Tier 1 capacity allocation	Adjusted Tier 1 Share
HiGro	401.9	510.0	108.1	44.3	446.1	59%
LoGro	206.1	225.0	18.9	7.7	213.9	29%
NoGro	90.0	90.0	0.0	0.0	90.0	12%
SUM	698.0	825.0	127.0	52.00	750.0	100%

TIER 2 ALLOCATION FOR ITS INITIAL YEAR (i.e., year 4)

Proposal: After having "filled" the Tier 1 capability, first allocate the Tier 2 capacity in proportion to the year 4 "peak" loads that are beyond the Adjusted Tier 1 allocation, and then allocate the "unused" Tier 2 quantity in proportion to the year 4 "peak" loads per se.

TIER 2 CAPACITY: 130
TIER 1 plus 2 CAPACITY: 880

JURISDICTION	New Tier 1 capacity allocation	Terminal, or Year 4, "peak" loads	Growth over Tier 1 allocation	Preliminary Tier 2 allocation	Year 4 load shares	Residual Tier 2 allocation	Total Tier 2 capacity allocation	Total Tier 2 Shares	TOTAL TIER 1 PLUS 2 ALLOCATION
HiGro	446.1	510.0	63.9	63.9	61.8%	34.0	97.9	75%	544.0
LoGro	213.9	225.0	11.1	11.1	27.3%	15.0	26.1	20%	240.0
NoGro	90.0	90.0	0.0	0.0	10.9%	6.0	6.0	5%	96.0
SUM	750.0	825.0	75.0	75.0	100.0%	55.0	130.0	100%	880.0

Exhibit 4

Simplified Scenario Analysis of Strawman Skeleton
Proposal for Modified Tier Allocations
(Refined Initial Proposal)
by George R. Compton, UDPU

(Load Growth Workgroup - June 29, 2005)

Teir 3 Allocations and Later-Year Tiers 1 & 2 Re-allocations

TIER 2 ALLOCATION FOR ITS SECOND YEAR (i.e., year 5)

Proposal: Allocate the Tier 2 capacity in proportion to the Terminal Figure's growth beyond the Tier 1 allocation.

TIER 2 CAPACITY: 130
TIER 1 plus 2 CAPACITY: 880

JURISDICTION	Tier 1 capacity allocation	Year 5 "peak" loads	Growth over Tier 1 allocation	Preliminary Tier 2 allocation	Year 5 load shares	Residual Tier 2 allocation	Total Tier 2 capacity allocation	Total Tier 2 Shares	TOTAL TIER 1 PLUS 2 ALLOCATION
HiGro	446.1	530.0	83.9	83.9	62.0%	15.5	99.4	76.4%	545.5
LoGro	213.9	235.0	21.1	21.1	27.5%	6.9	28.0	21.6%	241.9
NoGro	90.0	90.0	0.0	0.0	10.5%	2.6	2.6	2.0%	92.6
SUM	750.0	855.0	105.0	105.0	100.0%	25.0	130.0	100.0%	880.0

YEAR 6 TIER 1 RE-ALLOCATION DUE TO RESOURCE DECREMENTS

Prior Tier 1 Capacity 750
New Tier 1 Capacity 730
Dedicated Decrement: 5 from LoGro
Shared Decrement 15

JURISDICTION	Previous, i.e, year 4, capacity allocation	Dedicted Capacity Decrement	Preliminary Capacity Allocation	Shared Capacity Decrement	New Tier 1 Capacity Allocation
HiGro	446.1	0	446.1	-8.9	437.2
LoGro	213.9	-5	208.9	-4.3	204.5
NoGro	90.0	0	90.0	-1.8	88.2
SUM	750.0	-5	745.0	-15.0	730.0

TIER 2 ALLOCATION FOR ITS THIRD YEAR (i.e., year 6)

Proposal: Allocate the Tier 2 capacity in proportion to the Terminal Figure's growth beyond the Tier 1 allocation.

TIER 1 CAPACITY: 730
TIER 2 CAPACITY: 130
TIER 1 plus 2 CAPACITY: 860

JURISDICTION	New Tier 1 capacity allocation	Year 6 "peak" loads	Growth over Tier 1 allocation	Total growth shares	Total Tier 2 capacity allocation	Total Tier 2 Shares	TOTAL TIER 1 PLUS 2 ALLOCATION
HiGro	437.2	550.0	112.8	70.5%	91.6	70.5%	528.8
LoGro	204.5	250.0	45.5	28.4%	36.9	28.4%	241.5
NoGro	88.2	90.0	1.8	1.1%	1.5	1.1%	89.7
SUM	730.0	890.0	160.0	100.0%	130.0	100.0%	860.0

NOTE: Shortfall in years when aggregate peak load exceeds capacity is assumed to be met with balancing purchases included in the Net Power Costs.

YEAR 7 TIER 1 and 2 RE-ALLOCATION DUE TO CHANGING LOADS

Proposal: Make the Tier 1 allocation consistent with the reduced load of NoGro, which was previously receiving a minimal Tier 2 allocation. LoGro's recent negative growth is reflected in a reduced Tier 2 allocation.

TIER 1 CAPACITY: 730
TIER 2 CAPACITY: 130
TIER 1 plus 2 CAPACITY: 860

JURISDICTION	New (i.e., yr. 7) "Peak" Loads	Prior Tier 1 Capacity Allocation	New Tier 1 Capacity Allocation	Growth from New Tier 1 Allocation	Total growth shares	New Tier 2 Allocation	TOTAL TIER 1 PLUS 2 ALLOCATION
HiGro	570	437.2	439.4	130.6	84.2%	109.5	548.9
NegGro (LoGro)	230	204.5	205.6	24.4	15.8%	20.5	226.1

Appendix 15
Structural Protection Mechanisms
Tiered Alternative 1 Compared to Tiered Alternative 2

	Tiered Alternative 1	**Tiered Alternative 2**
Author	Marc Hellman, Oregon PUC Staff.	George Compton DPU
Load Growth Workgroup Meeting	June 29, 2005	June 1, 2005 and June 29, 2005
Proposal	June 2005 Straw Proposal for Tiered Allocation (Second Revision)	Elements of a Modified Tiering / Vintaging Allocation Mechanism for Mitigating the Burden of Growth Costs on Non-Growing Jurisdictions: A Strawman Framework. Illustrations of a Modified Tiering / Vintaging Allocation Mechanism for Mitigating the Burden of Growth Costs on Non-Growing Jurisdictions: A Strawman Framework
Method	Tiering	Vintaging
Method Overview	The proposal is based on two Tiers of resources and the segregation of corresponding loads at the "trigger date". All new resources and loads increases will be added to the second Tier after the trigger date. The jurisdictional allocations of resources within the Tier are based on the associated jurisdictional loads assigned to the Tier. The Tiers increase or decrease for changes to resources, and some changes to loads.	The proposal is based on vintaging resources into multiple Tiers and the segregation of corresponding loads at the "trigger dates". The proposal would track the peak loads against the resource capacity (see Stock of Resources) in creating the jurisdictional allocation factors. Resources within Tiers are allocated on associated loads or resource capacity for that Tier. Any unused resource capacity is segregated and system allocated, after the first Tier is filled. This reflects unused resource capacity being sold to the market. Costs are segregated into Tier 1 for existing owned resources and contracts at trigger date, additional Tiers for each new resources added, and production costs reflecting short term market purchases. Costs of short term purchases are system allocated.
Creation of Tier	Determination is made that new	All new resources (see Stock of

	Tiered Alternative 1	**Tiered Alternative 2**
(Trigger Date)	resources coming on-line within 36 months to meet disparate load growth will cause a cost shift among the states without offsetting considerations. The trigger date establishes resources to be included in Tier 1.	Resource) will be allocated to a new Tier once a new resource is added and loads exceed capacity in the prior Tier (also suggested using calendar 2004 date or fiscal year 2005 as starting point). The trigger dates establishes which Tier resources are assigned.
Number of Tiers	Two	Unlimited
Tier 1	The base Tier includes resources and contracts at the trigger date and includes the refurbishment, relicensing, and contract renewal of these base resources net of existing wholesale sales commitment.	The base Tier includes resources and contracts at the trigger date
Jurisdictional Allocation Factors	Created on jurisdictional loads associated with each Tier, 1 and 2. Tier 2 loads calculated as system loads less Tier 1. See "Reduction in Loads" and "Retired or Expired Resources" below. Follows Revised Protocol for allocation purposes.	For Base Tier, the proposal uses the loads to create the allocation factor until the loads exceeds the capacity, then the loads are scaled down to the resource capacity for allocation purposes. ▪ For Initial Tier use 5 year average of loads when loads are lower than capacity, other wise use capacity when capacity is lower than loads For other Tiers, the growth in peak loads between this Tier and the prior Tier is calculated to create an allocation factor. ▪ When capacity of the new resource exceeds loads delta, allocate used portion of resource capacity to serve loads on the load delta factors. The unused capacity of the new resource is allocated on the system loads so all jurisdictions share in the cost (reflects excess capacity is sold at the market). ▪ When the resource capacity is less than the load deltas, allocate the capacity on the load delta's. Seasonal allocation must be a

	Tiered Alternative 1	Tiered Alternative 2
		consideration in this proposal.
Increase in Loads	Assigned to Tier 2	Assigned to current Tier until new resource addition, then excess over resource capacity in current Tier is assigned to new Tier
Reduction in Loads	Reduction in Tier 1 loads are handled consistent with Revised Protocol. Load reduction, other than Direct Access, result in reduction in allocation of Tier 1 resources for that state. Other states reallocated larger share of existing resources. Tier 1 resource allocation can be restored if loads return to trigger levels. Loads assigned to Tier 2 for any state can not decrease except when Tier 2 resources decrease. The state losing loads receives the same allocation of resource cost but is assigned a short term market sales in proportion to the lost load.	If one or more jurisdictions has experienced a load reduction for the Tier 1 loads, reallocate the Tier 1 existing resources using the lower Tier 1 loads. Same effect as Tiered - Alternative 1. Other load reductions assigned to last Tier and then work backwards if needed.
Resources Acquired	Assigned to Tier 2	Assign to New Tier
Retired or Expired Resources **(Generation / Long Term Contract Purchases/ Lost Hydro Generation)**	Tier 1 resource reductions are pro-rata reduction to state jurisdictional loads. A corresponding increase occurs in Tier 2 loads and short term resources. Reduction in long-term wholesale sales would have opposite effect of increasing Tier 1 state loads. Reduction in Tier 2 resources removed from Tier 2, no change to allocation factors.	The load for each jurisdiction, related to the Tier where the retired resource resides, would be reduced by each jurisdiction's allocated share of the capacity of the retired resource. If other than last Tier, a corresponding increase in the last Tiers loads occurs.
Power Cost Model Runs	Requires two GRID runs – one for Tier 1 study, another for System Study (Tier 2 calculated as System less Tier 1). Alternative Tier 2 GRID run then adjust so Tier 1 plus Tier 2 equal System.	Not specified - required GRID System Study at minimum
Resource Definition	Owned Generation and Long Term Contracts	The proposal suggested "Stock of Resources" are company owned and contracts with a life of at least 10-years. Production resources (includes shorter term market purchases), excludes "Stock of Resources", allocated as system resources
Other Elements of Proposal	Resources built in excess of loads	The paper proposes a basis of

	Tiered Alternative 1	**Tiered Alternative 2**
	allocated on Tier 2 allocation factors. Gain or loss on Service Territory - Adjust Tier 1 and Tier 2 loads to reflect the sale, net of obligations, under any power sales contract. Sale of Generation – Remove sold generation from original Tier assigned, apply purchase contract and gain on sale to same Tier. Direct Access – Treat consistent with Revised Protocol. Short term and new long term sales for resale are assumed provided by Tier 2 resources up to generating capability of Tier 2 resources. Power sales matching Tier 1 load reduction is an exception. The paper proposes common costs are allocated on system loads.	allocation and classification different than that used in the Revised Protocol that is unresolved and lacks quantification. ▪ Proposal System Capacity 4 Coincidental Peak (CP) versus 12 CP in Revised Protocol ▪ Proposal SG factor 50% Demand/ 50% energy weighting versus 75% Demand / 25% Energy in Revised Protocol
Issues	This proposal is administratively complex. Unknown and potential for unintended consequences. Assumptions require modeling judgments. For each Tier, proposal requires more definition on calculation of remaining resource needs for each state. Unclear how to incorporate reserves required to be purchased at market. Unclear methodology to measure short term market sales in proportion to lost load under Tier 2.	This proposal is administratively complex in the requirement to track the loads against the system capacity and represents a deviation from Revised Protocol that uses loads to create the allocation factors. Unknown and potential for unintended consequences. Assumptions require modeling judgments. Unclear how long-term wholesale sales capacity is accounted for in adjusting the resource capacity. Unclear how the proposal addresses segregating the cost/ revenue requirement to vintage the resources. Unclear in proposal what occurs when the loads and capacity do not match for the existing Tier and a new resource is added. Proposal should consider the implication of reserves in building of resource capacity in relation to the proposal.

Appendix 16
Structural Protection Mechanisms
Ranking Criteria

To assess the viability of the SPMs being developed by the Load Growth Workgroup, a ranking evaluation criteria was developed by a sub-group that met on July 14, 2005. That SPM Ranking Criteria is summarized in **Section 5.2**, and provided in more detail below:-

A. Consistent with Revised Protocol

- Makes small incremental modifications to the Revised Protocol
- Promotes the stability or integrity of the Revised Protocol
- Employs principles of the Revised Protocol

B. Degree of Protection from Load Growth

- Overall, to what degree does the mechanism provide protection from cost shifts (revenue requirement impacts) associated with differential load growth
- Includes consideration of other load growth impacts, including the increased assignment of common and other costs to States with higher load growth

C. Is Equitable in Treatment among the States

- Does not unduly burden single State or group of States
- Does not develop systemic bias to single State or group of States

D. Does Not Create Unintended Consequences

- Does not modify items that can negatively impact other allocations/assignments
- Does not create unwanted incentives

E. Consistent with Utility System Least-Cost Planning

- Mechanism does not conflict with IRP, system-wide planning to minimize total system costs
- Mechanism provides the utility with the incentive to identify system, least-cost resource alternatives including DSM options

F. Consistent with Minimizing Total System Operating Costs

- Mechanism promotes day-to-day operation of the system that achieves lowest total system-wide operating costs
- Alternatively, mechanism does not provide perverse incentives to deviate from system, least-cost operations

G. Aligns Assignment of Costs and Benefits of New Resources

- Closely aligns revenue requirement impact of new resources with the benefits of and need for new resources

H. Can be Implemented in a Timely Manner

- Timeframe for implementation of the mechanism is consistent with requirements of Revised Protocol
- Mechanism can be quickly implemented to offset demonstrated impacts from cost shifts

I. Easy to Understand

- Mechanism is easy to explain and for easy non-regulatory people to understand

J. Simple to Implement, Track and Maintain

- Mechanism does not add additional modeling/processing during regulatory cycles as compared to Revised Protocol. Applies to implementation of the mechanism as well as on-going filing, reporting and analysis/auditing of results