



January 30, 2006

Judge Theodora Mace
Judge Ann Rendahl
Commissioner Philip Jones
Commissioner Patrick Oshie
Chairman Mark Sidran
Carole Washburn
Executive Secretary
Washington Utilities & Transportation Commission
1300 S. Evergreen Park Drive, SW
Olympia, WA 98504-7250

Re: Docket No. UE 050684
WUTC Bench Staff Data Requests 14-25

Please find enclosed one original and eighteen copies of PacifiCorp's 1st Supplemental response to WUTC Bench Data Requests (19). Provided on the enclosed CD is Attachment WUTC 19 1st Supplemental.

If you have any questions, please call Shay LaBray at (503) 813-6176.

Sincerely,

Shay LaBray
Regulation

Enclosure

cc: Donald T. Trotter/WUTC (3 copies)
Simon ffitich/Public Counsel
Steven Johnson/ATG
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WUTC Bench Data Request 19 1st Supplemental

WUTC Bench Data Request 19

Please provide a copy of the Hybrid proposal filed in Oregon in late 2005.

1st Supplemental Response to WUTC Bench Data Request 19

A copy of the Company's "Multi-State Process Hybrid Report to the Oregon Public Utility Commission" which was filed with the Oregon Commission on November 21, 2005 is provided as Attachment WUTC Bench Request 19 1st Supplemental on the enclosed CD.

Responder: Gregory N. Duvall
Witness: Gregory N. Duvall



Multi-State Process

Hybrid Report to the Oregon Public Utility Commission

November 21, 2005

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

Table of Contents

Section	Title	Page #
1	Executive Summary	Page 1
2	Background	Page 2
3	Oregon Public Utility Commission (“OPUC”) Order No. 05-021 / Docket UM-1050	Page 3
4	Hybrid Workgroup	Page 4
	4.1 Concerns of the July 2003 Hybrid Proposal	Page 4
	4.2 Formation of the Hybrid Workgroup	Page 7
	4.3 Hybrid Workgroup Work Plan	Page 8
	4.4 Hybrid Workgroup Meetings	Page 8
5	Hybrid	Page 9
	5.1 Components Unchanged from July 2003 Hybrid Proposal	Page 10
	5.2 Components Modified from the July 2003 Hybrid Proposal	Page 13
	5.3 New Components Incorporated into the Hybrid	Page 15
6	Hybrid Study Results	Page 16
7	Remaining Concerns of the Hybrid	Page 17
8	Conclusions	Page 18

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

List of Appendices

Appendix	Title	Page #
Appendix 1	Abbreviations and Definitions Used in this Report	Page 20
Appendix 2	List of MSP Participants / Hybrid Workgroup Participants	Page 22
Appendix 3	Hybrid Workgroup Scope and Work Plan	Page 23
Appendix 4	Hybrid Factors Applied to Allocation Components	Page 27
Appendix 5	Components of the Hybrid	Page 49
Appendix 6	Hybrid Issues List	Page 51
Appendix 7	Interchange Accounting Method	Page 54
Appendix 8	Cross Control Area Exchange Contracts	Page 55
Appendix 9	Method of Calculating the Operating Reserve Credit	Page 59
Appendix 10	Key Assumptions of PacifiCorp's Hybrid Studies	Page 62
Appendix 11	List of PacifiCorp's Hybrid Studies	Page 63
Appendix 12	Hybrid Results	Page 66
Appendix 13	Summary of Hybrid Case Results	Page 72

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

List of Tables

Table	Title	Page #
Table 1	July 2003 Hybrid Proposal and Updated July 2003 Hybrid Percentage Difference in NPV Revenue Requirement from Revised Protocol	Page 4
Table 2	Updated July 2003 Hybrid and Hybrid Percentage Difference in NPV Revenue Requirement from Revised Protocol	Page 7
Table 3	Hybrid (also known as Hybrid Case 3b1a) 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)	Page 17
Table 4	Resource Matrix for Hybrid Studies	Page 63
Table 5	Hybrid Case 1 and Updated July 2003 Hybrid Percentage Difference in NPV Revenue Requirement from Revised Protocol using June 2004 Forecast (Hybrid Workgroup Meeting – June 28, 2005)	Page 66
Table 6	Hybrid Case 1 Variations Percentage Difference in NPV Revenue Requirement from Revised Protocol using March 2005 Forecast (Hybrid Workgroup Meeting – July 18, 2005)	Page 67
Table 7	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)	Page 68
Table 8	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)	Page 69

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

Table	Title	Page #
Table 9	Hybrid 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)	Page 70
Table 10	Hybrid 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)	Page 71
Table 11	Summary of Hybrid Case Results Percentage Differences in NPV of Hybrid Method from Revised Protocol	Page 72

1. Executive Summary

This Hybrid Report is presented to the Commissioners of the Oregon Public Utility Commission (“**OPUC**”) in compliance with Order No. 05-021, and has been developed in consultation with Oregon parties. The Order required Oregon Parties (including PacifiCorp), to complete the Hybrid cost allocation methodology proposal which was designed and presented to participants of the Multi-State Process (“**MSP**”) which has been proceeding in Oregon under Docket UM-1050 since February 2002. That proposal, referred to in this Hybrid Report as the “**July 2003 Hybrid Proposal**”, was deemed unacceptable for use as a cost allocation methodology due to concerns over initial assignments of resources, inequity issues among the States, departure from an integrated system planning and operation approach, and unproven cost allocation methodologies surrounding “interchanges” between the control areas.

Since the OPUC issued its Order in January 2005, the Company and Oregon Parties (and other interested parties) have enhanced the July 2003 Hybrid Proposal by firstly updating the data assumptions to more current information. The updated study is referred to in this Hybrid Report as the “**Updated July 2003 Hybrid**”.

Following the update process, the Company and Oregon Parties (and other interested parties) worked closely on considering and determining modifications that could be incorporated into the Updated July 2003 Hybrid. The purpose of this exercise was to address the concerns that had been documented from the presentation of the Hybrid Proposal at the July 2003 MSP meeting in order to produce a methodology appropriate for reporting purposes.

At the conclusion of the deliberations, modifications were incorporated into the Hybrid in the following areas:-

- (1) Assignment of generation and power contracts,
- (2) Method for calculating the operating reserve credit, and
- (3) Operating reserve credit assignment to Wyoming.

Two new components were added:-

- (1) Allocation of Mid-Columbia contracts within the West Control Area, and
- (2) Situs allocation of Qualifying Facilities Contracts (“**QF Contracts**”).¹

This modified study is referred to in this Hybrid Report as the “**Hybrid**” and is now presented to the OPUC in compliance with Oregon Order No. 05-021, dated January 12, 2005. This

¹ Sections 5.2 and 5.3 contain detailed information about these modifications and additions.

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

methodology is considered complete for reporting purposes only. This Hybrid cost allocation methodology is not recommended for use as a rate making tool in any of the States in which the Company operates.

2. Background

The Multi-State Process² 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 common cost allocation methodology that would achieve a more permanent consensus on each State's responsibility for the costs and benefits of PacifiCorp's existing and future power resource assets. The purpose of implementing a common cost allocation method is to provide PacifiCorp with the opportunity to recover 100% of its prudently incurred costs, while providing each State the ability to independently implement its own energy policy objectives.

The Company facilitated a number of collaborative meetings during 2002 and 2003. At the July 2003 meeting, the Company presented to participants the July 2003 Hybrid Proposal cost allocation methodology (developed by the Company and other parties between October 2002 and June 2003) and Utah Parties presented the concepts of a **"Dynamic Alternative"** cost allocation methodology.³ Following the presentation of these two proposals, no acceptance of either proposal was achieved and an impasse was reached among the participants at the meeting. Honoring the collaborative nature of the forum and the significant effort of everyone to this point, the Company was requested to develop a proposal, utilizing the information learned over the course of the 2002-2003 MSP discussions.

In September 2003, the Company filed the **"Protocol"** cost allocation methodology proposal with the State Commissions of Idaho, Oregon, Utah and Wyoming (also filed with the State Commission of Washington in December 2003⁴). The Protocol proposal was subsequently refined and re-submitted to each of the State Commissions as the **"Revised Protocol."** The Revised Protocol was adopted as the cost allocation methodology in March 2005 by the State Commissions of Idaho, Oregon, Utah and Wyoming.⁵

In adopting the Revised Protocol, the Oregon Order No. 05-021 included specific directives relating to the July 2003 Hybrid Proposal. This Hybrid Report is a product of the work that has been performed by the Company and Oregon parties,⁶ (in collaboration with other interested parties), since the Oregon Order No. 05-021 was issued in January 2005.

² 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.

³ Refer to the Meeting Summary and Meeting Pack from the July 2003 MSP meeting for specific information on the Hybrid and Dynamic Alternative proposals.

⁴ At the time of completing this Hybrid Report, neither the Protocol nor Revised Protocol has been filed in the State of California. It is intended that the next rate case filed in that State will be based on the Revised Protocol allocation methodology. However, the timeline associated with such a filing is not confirmed.

⁵ 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.

⁶ A list of MSP participants from Oregon (and the States Idaho, Utah, Washington and Wyoming) who have either been involved in the Hybrid Workgroup and/or who have received material relating to the Hybrid Workgroup is provided in Appendix 2.

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

In overview, **Section 2** provides background to the MSP as well as general discussion on how the July 2003 Hybrid Proposal came about. **Section 3** provides specific details of what was requested by the Oregon Order No. 05-021. **Section 4** provides information on how the request was dealt with by the Company and Oregon parties (and other interested parties). **Section 5** provides specific information about the Hybrid, the components unchanged from the July 2003 Hybrid Proposal, the modifications that have been made and the new components that have been incorporated. **Section 6** provides study results using the Hybrid cost allocation methodology. **Section 7** describes the concerns that still exist with the concepts of the Hybrid, even though it is offered here for reporting purposes in Oregon. The last section of this report (**Section 8**) sets out the Company's conclusions, based on the work that has been performed to further develop the Hybrid, its analysis of the studies performed and the discussions held with Oregon parties (and other interested parties) during 2005.

3. Oregon Public Utility Commission ("OPUC") Order No. 05-021 / Docket UM-1050

The Oregon Order No. 05-021, ratifying the Revised Protocol for use in regulatory filings in Oregon, was issued on January 12, 2005. As well as ratifying the Revised Protocol, the Order included specific directives related to the July 2003 Hybrid Proposal and the desire of OPUC for the proposal to be developed for use as a reporting comparator to the Revised Protocol.

The Order⁷ states:-

"The Oregon parties are to devise a fully functional Hybrid Method no later than December 1, 2005."

and further states⁸:-

"PacifiCorp must file its annual reports and general rate case filings using both Modified Accord and the revised Hybrid Method as comparators beginning January 1, 2006, or once the Hybrid Method is completed, whichever occurs first."

During the development of the Hybrid, the Company and Oregon parties referred to OPUC's three original goals and requirements for the MSP in Order No. 02-193 (restated in Order No. 05-021⁹):-

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

⁷ OPUC Order No. 05-021 dated January 12, 2005, page 13 (items 2 and 3)

⁸ OPUC Order No. 05-021 also directed PacifiCorp to include a fully developed Hybrid as one of the options for structural protection to eliminate cost shifting among PacifiCorp customers in different States. The purpose of this report is to present the Hybrid cost allocation methodology and the work of the Hybrid Workgroup. The use of Hybrid as a structural protection mechanism is contained in PacifiCorp's Load Growth Report which was filed under OPUC Docket UM-1050 on October 20, 2005 (refer to Section 5.4 and Appendix 12).

⁹ OPUC Order No. 05-021 dated January 12, 2005, page 12 (Section entitled "Commission Conditions")

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

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."*

4. Hybrid Workgroup

4.1 Concerns of the July 2003 Hybrid Proposal

In order to commence development of the Hybrid, the Company and Oregon Parties (and other interested parties) first needed to update the original July 2003 Hybrid Proposal to more current information. The results of the update process are provided in **Table 1**, which reflect the net present value ("NPV") in revenue requirement over a 12-Year or 14-Year period, as a percentage difference from the Revised Protocol. The shaded rows highlight the results for the West Control Area, East Control Area and Oregon.

**Table 1
July 2003 Hybrid Proposal and Updated July 2003 Hybrid
Percentage Difference in NPV Revenue Requirement
from Revised Protocol**

State	July 2003 Hybrid Proposal (*)	Updated July 2003 Hybrid (*)	
	12-Year NPV @ 8.4277% Fiscal Years 2007-2018	12-Year NPV @ 8.4277% Fiscal Years 2007-2018	14-Year NPV @ 8.4277% Fiscal Years 2007-2020
California	-4.44%	-4.72%	-4.80%
Oregon	-1.21%	-3.08%	-3.21%
Washington	-1.10%	-2.35%	-2.58%
West Control Area	-1.39%	-3.03%	-3.18%
Utah	0.63%	1.56%	1.65%
Idaho	0.91%	1.02%	1.08%
Wyoming	1.45%	3.04%	3.00%
East Control Area	0.80%	1.77%	1.84%

(#) consistent with the Company's 2003 IRP Report

(*) also known as Hybrid Case 2, and consistent with the Company's 2004 IRP Report

As can be seen in the table above, updating the original July 2003 Hybrid Proposal with current data did not resolve any of the parties concerns, particularly with regard to the initial assignment of resources and the inequities among the States. As shown in the results above, the West Control Area moved from approximately 1.5%

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

below Revised Protocol (12-Year NPV) to approximately 3% below Revised Protocol (12-Year NPV). In comparison, the East Control Area moved from approximately 1% above Revised Protocol (12-Year NPV) to approximately 2% above Revised Protocol (12-Year NPV).

After the update process, the Company and Oregon Parties (and other interested parties) revisited the concerns that had been raised about the July 2003 Hybrid Proposal when it was originally presented to the MSP participants. The main document utilized in considering the concerns of the July 2003 Hybrid Proposal was the Hybrid Issues List. This document lists the individual components of the proposal where there were areas of concern. A discussion of the issues list and how they were addressed in the Hybrid is included in **Section 5** and a copy of the Hybrid Issues List is included as **Appendix 6**.

However, a summary of the overall concerns can be gleaned from the "Joint Brief of Staff of the Public Utility Commission and the Citizen's Utility Board"¹⁰ that states:-

"..... the Hybrid model yields results that are likely unacceptable to other states. Accordingly, it is likely that adjustments would have to be made to the current version of the Hybrid model to obtain broader support for this method among the states."

"..... the Hybrid model has not been sufficiently refined to be used as a benchmark of rate impacts in Oregon or other states."

"..... the Hybrid has not yet been modified to ameliorate the negative impacts on other states. The likely result of such modifications would be to raise the allocations to Oregon and to reduce allocations to other states."

and the Company's "Brief of PacifiCorp"¹¹ that states:-

"While a Hybrid approach may resolve some MSP issues (such as cost shifts from faster Utah load growth) in ways that are appealing to Oregon parties, it has other attributes that have never been considered by this Commission [OPUC]. If considered, these factors might well cause the method to be found unacceptable to the Commission. For example, a region-based allocation of PacifiCorp's existing resources under a Hybrid approach leaves the Western region in a substantial "long" position and highly dependent on the vagaries of power market prices. Also, because of the "interchange methodology" embedded in the Hybrid proposal, which attempts to model and value 8,760 annual hourly transactions between the two regions, a Hybrid approach is hugely complex and potentially controversial."

"..... the results of a Hybrid allocation method are substantially dependent upon the initial assignment of existing resources between the two regions. A significant issue that has never been resolved is whether coal plants (Dave Johnston and Wyodak), that were part of the Pacific Power system, but are located in the Eastern control area, should be assigned to the Western or Eastern region. Similarly, it has never been resolved whether

¹⁰ Joint Brief of Staff of the Public Utility Commission and the Citizen's Utility Board, Docket UM-1050, dated September 7, 2004, Pages 27 to 28.

¹¹ Brief of PacifiCorp, Docket UM-1050, dated September 7, 2004, Pages 25 to 29.

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

load in eastern Wyoming, that was originally part of the Pacific Power system, should be included in the Western or Eastern region. " "..... even though the Hybrid method largely insulates Oregon consumers from the effects of Utah load growth, power costs to Oregon consumers grow at a faster rate under the Hybrid proposal than under the Rolled-In method. This is because under the Hybrid method, customers in the Eastern region do not contribute to the cost of hydro relicensing or to the cost of replacing expiring wholesale contracts and lost hydro generation in the west."

"The Hybrid approach includes an interchange methodology for hourly transactions between PacifiCorp's Eastern and Western control areas, which assumes current transmission limitations. An RTO would consolidate control areas, increase transfer capability and cause the interchange methodology to be moot."

"[Using the Hybrid as a bench mark] would unreasonably assume that the same resources are acquired under Hybrid and Revised Protocol methods."

With the update process complete, the Company and Oregon Parties (and other interested parties) worked closely on considering and determining modifications that could be incorporated into the Updated July 2003 Hybrid. The purpose of this exercise was to resolve some or all of the concerns that had been expressed regarding the Hybrid methodology following its presentation at the July 2003 MSP meeting. Addressing the concerns of the July 2003 Hybrid Proposal has been a crucial element of the Hybrid development in order to produce a methodology that could be used for reporting purposes, that is somewhat accepted in each of the States that PacifiCorp operates.

At the conclusion of the deliberations, modifications were incorporated into the Hybrid in the following areas:-

- (1) Assignment of generation and power contracts,
- (2) Method for calculating the operating reserve credit, and
- (3) Operating reserve credit assignment to Wyoming.

Two new components were added:-

- (1) Allocation of Mid-Columbia contracts within the West Control Area, and
- (2) Situs allocation of QF Contracts.¹²

Table 2 provides a comparison between the Updated July 2003 Hybrid and the Hybrid presented in this Hybrid Report for use as a reporting comparator. The shaded rows highlight the results for the West Control Area, East Control Area and

¹² Sections 5.2 and 5.3 contain detailed information about these modifications and additions.

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

Oregon. The shaded columns highlight the results that reflect the Hybrid presented in this Hybrid Report as a reporting comparator for use in Oregon.

**Table 2
Updated July 2003 Hybrid and Hybrid
Percentage Difference in NPV Revenue Requirement
from Revised Protocol**

State	Updated July 2003 Hybrid (*)	Hybrid (#)	
	14-Year NPV @ 8.4277% Fiscal Years 2007-2020	9-Year NPV @ 8.4277% Fiscal Years 2007-2015	14-Year NPV @ 8.4277% Fiscal Years 2007-2020
California	-4.80%	-0.15%	-0.21%
Oregon	-3.21%	0.03%	-0.09%
Washington	-2.58%	0.14%	-0.03%
West Control Area	-3.18%	0.04%	-0.08%
Utah	1.65%	-0.08%	0.04%
Idaho	1.08%	-0.69%	-0.68%
Wyoming	3.00%	0.54%	0.43%
East Control Area	1.84%	-0.02%	0.05%

(*) also known as Hybrid Case 2, and consistent with the Company's 2004 IRP Report

(#) also known as Hybrid Case 3b1a, and consistent with the Company's 2004 IRP Report

As can be seen in the table above, the modifications and added components brought the results, for all States, closer to the Revised Protocol. As shown in the results above, the West Control Area moved from approximately 3% below Revised Protocol (14-Year NPV) to less than 0.1% below Revised Protocol (14-Year NPV). In comparison, the East Control Area moved from approximately 2% above Revised Protocol (14-Year NPV) to less than 0.1% above Revised Protocol (14-Year NPV).

Section 5 provides a detailed description of the Hybrid, presented in this Hybrid Report as a reporting comparator for use in Oregon, and **Section 6** provides an explanation of the results of the Hybrid, with particular emphasis on the results for the West Control Area, East Control Area and Oregon. **Section 7** provides a discussion of the concerns that continue to exist with the Hybrid and its methodology.

4.2 Formation of the Hybrid Workgroup

In February 2005, the Company scheduled a meeting with Oregon parties (and other interested parties from the States of Idaho, Utah, Washington and Wyoming) to review Oregon Order No. 05-21 and discuss how to meet its conditions. At the

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

conclusion of the meeting, the Hybrid Workgroup was formed and a schedule of meetings established.

4.3 Hybrid Workgroup Work Plan

At the March 29, 2005 meeting of the Hybrid Workgroup, the Company presented a proposed scope and work plan. The work plan covered three major tasks for the workgroup, summarized as:-

- (a) Development of the Hybrid as an option for structural protection in PacifiCorp's Load Growth Report,¹³
- (b) Present the Hybrid to the OPUC before December 1, 2005, and
- (c) File the results of the Hybrid as a comparator in the Company's annual reports and general rate case filings from January 1, 2006 (or upon approval, whichever comes first).

A copy of the original scope and work plan document is included as **Appendix 3**.

4.4 Hybrid Workgroup Meetings

The Hybrid Workgroup held eight meetings from March 2005 through September 2005. Prior to each meeting, an agenda and meeting materials were prepared by the Company and provided to participants. Meeting summaries, briefly recording the progress of the workgroup, were circulated after each meeting. Below is a list of the meetings held, together with a brief description of the key topics covered:-

March 29, 2005

- Workgroup Guidelines
- Scope and Work Plan
- Prioritization of Hybrid Issues List

April 18, 2005

- Review of July 2003 Hybrid Proposal

May 3, 2005

- Hourly Interchange Logic
- ICNU Proposal Related to Development of a Hybrid Model
- Initial Assignment of Generation Resources and Contracts
- Identification of Analysis

May 31, 2005

- Analytical Results
- Assignment of Resources and Contracts
- Valuation of Reserves

¹³ PacifiCorp's Load Growth Report, dated October 20, 2005, Section 5.4.3

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

- Discussion of Transmission and Firm Wheeling
- Interchange Accounting Methodology and Pricing

June 28, 2005

- Analysis Assumptions and Results
- Assignment of Resources and Contracts
- Sensitivity Analysis

July 18, 2005

- Analysis Assumptions and Results
- Assignment of Resources and Contracts
- Intra-Control Area Equity Measures
- Resource Evaluations

August 24, 2005

- Resource Evaluations
- Assignment of Resources and Contracts
- Intra-Control Area Equity Measures
- Analysis Assumptions and Results

September 13, 2005

- Analysis Assumptions and Results

At the conclusion of the September 2005 meeting, the Hybrid was considered finished. The Company then focused its efforts on writing this Hybrid Report and meeting¹⁴ with Oregon parties to finalize the report.

5. Hybrid

What is the Hybrid? Hybrid is an accounting assignment of all loads and resources to the control area where they are physically located (with exceptions) combined with an interchange accounting methodology for determining the value of cross control area power transfers. The East Control Area contains loads for Idaho, Utah and Wyoming, while the West Control Area contains loads for California, Oregon and Washington. Dynamic allocations (that is, allocations that are based on changing loads) are used to allocate within each control area. State revenue requirements, under Hybrid, are calculated using several computer-based tools:-

- (1) Generation and Regulation Initiative Decision (“GRID”),
- (2) Interchange Accounting Model, and

¹⁴ The Oregon Parties meetings were held on November 2, 2005 and November 15, 2005.

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

- (3) regulatory / State allocation models.

Hourly results from GRID, an hourly production cost model, are run through the interchange model, which calculates each control area's share of system balancing and interchange. The output from the interchange model is summarized and run through the regulatory / State allocation models to calculate State-by-State revenue requirements. Refer to **Appendix 4** for the allocation factors applied to each component of revenue requirement under the Hybrid.

Components of the Hybrid Addressed by the Workgroup – Following the process of updating the July 2003 Hybrid Proposal to more current information, the workgroup's attention turned to summarizing the issues with the original proposal and identified the components on which to focus their efforts. The Hybrid Workgroup reviewed in detail each of the components identified. This report organizes the components into the following categories:

- Components Unchanged from the July 2003 Hybrid Proposal
- Components Modified from the July 2003 Hybrid Proposal
- New Components Incorporated into the Hybrid

Each component is discussed in further detail in **Sections 5.1** through **5.3** and **Appendix 5** provides a listing of the categorized components in tabular form for comparison purposes. A copy of the Hybrid Issues List is included as **Appendix 6**.

While the workgroup was able to address the above mentioned components, there are still philosophical concerns with the use of the Hybrid. These concerns are discussed further in **Section 7**.

5.1 Components Unchanged from the July 2003 Hybrid Proposal

The Hybrid Workgroup agreed that the following Hybrid components would remain consistent with the July 2003 Hybrid Proposal.

5.1.1 Interchange Accounting Method - The interchange accounting method is a process which values and allocates the costs and revenues associated with system balancing purchases / sales and interchange transactions deemed to be made between the two control areas. During the course of the MSP process, three methods of assigning system balancing and interchange quantities (MWhs) were considered:

- **Method 1** – Interchange first
- **Method 2** – Interchange after system balancing
- **Method 3** – Interchange equals the transfers between the control areas.

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

Studies showed the use of Method 3 resulted in the largest volume of interchange, while use of Method 2 resulted in the smallest amount of interchange. Method 2 estimates the volumes by netting each region's load, resources, assigned long-term and short-term wholesale transactions, and short-term non-firm balancing transactions. After accounting for system balancing transactions, the residual of transactions are deemed to be interchange transactions.

Method 2 was the preferred method used in the July 2003 Hybrid Proposal. The Hybrid Workgroup discussed the interchange accounting methodology and agreed that Method 2 would continue to be used as the preferred interchange accounting method in the Hybrid.

An outline of the specific steps used in Method 2 to calculate the amount of interchange is included as **Appendix 7**.

5.1.2 Interchange Pricing - Market prices are used to indicate the value of the "at arm's length" interchange transactions for both the buyer and the seller. Five methods of pricing interchange transactions were considered:

- **Seller's Maximum Price** – Using this method, all benefits go to the selling control area. The Buying control area is no worse off.
- **Buyer's Minimum Price** – With this method all benefits go to the buying control area. Selling control area is no worse off.
- **Average of Seller's Maximum Price and Buyer's Minimum Price** – In this method the benefits are shared between control areas. No control area is worse off.
- **Embedded Cost** – With this method the seller benefits if market price is below embedded cost. Buyer benefits if market price is above embedded cost.
- **Average of the Seller's Minimum Price and Buyer's Maximum Price** – This method recognizes the fact that in theory the seller would have exhausted its opportunities to sell in the highest priced market before turning to the lower priced market. Additionally, the buyer would have exhausted its opportunities to buy in the lower-priced market before turning to the higher priced market.

In the July 2003 Hybrid Proposal, interchange was priced at the Average of the Seller's Maximum Price and Buyer's Minimum Price, as averaging the two represents a form of splitting the savings from the system as a whole. The Hybrid Workgroup discussed the issue of interchange pricing and

Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005

agreed that the Hybrid would continue to use the average of Seller's Maximum Price and Buyer's Minimum Price.

5.1.3 Allocation of Transmission and Firm Wheeling - Under Hybrid, the costs associated with transmission and firm wheeling are allocated on a rolled-in basis to all States using the average of the 12 monthly system coincident peak loads ("12CP"). This is consistent with the allocation used by the Federal Energy Regulatory Commission ("FERC") in setting transmission rates for all utilities, including PacifiCorp. Allocating transmission and firm wheeling in this manner is consistent with integrated system operations. During the course of the Hybrid Workgroup meetings, participants discussed this component and decided that, absent a compelling reason to change, the Hybrid would continue using a system-wide rolled-in approach.

5.1.4 Cross Control Area Exchanges – Exchange contracts have two components:-

- (1) a receipt, and
- (2) a delivery.

When a delivery takes place, the control area making the delivery incurs costs. The receipt offsets the costs. Some exchange contracts have both the receipt and delivery components in the same control area. Others have the receipt component in one control area and the delivery component in the other control area (referred to as Cross Control Area Exchange Contracts). The Company's existing Cross Control Area Exchange Contracts are:-

- (1) Bonneville Power Administration - South Idaho Exchange,
- (2) Redding Exchange,
- (3) Eugene Water and Electric Board Wind Energy Storage Services - Foote Creek I,
- (4) Bonneville Power Administration – Wind Energy Storage Services - Foote Creek II, and
- (5) Bonneville Power Administration – Generation Control & Storage Services - Foote Creek IV.

Refer to **Appendix 8** for a description of each of these Cross Control Area Exchange Contracts.

Under Hybrid, State allocations of system balancing purchases / sales are affected by the assignment of resources to each control area. When the

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

receipt and the delivery components are in different control areas, this creates a mismatch and results in higher costs for the control area with the delivery component and lower costs for the control area with the receipt component. Due to this mismatch, the Hybrid Workgroup agreed that the receipt and delivery components would both be assigned to the control area where the delivery component of the exchange takes place. This is consistent with the treatment of Cross Control Area Exchange Contracts in the July 2003 Hybrid Proposal.

5.2 Components Modified from the July 2003 Hybrid Proposal

The Hybrid Workgroup discussed the issues identified and modified the treatment of the following Hybrid components from the July 2003 Hybrid Proposal.

- 5.2.1 Assignment of Generation and Contracts - prior to the merger of Utah Power & Light ("UP&L") and Pacific Power & Light ("PP&L") in 1989 ("**1989 Merger**"), resources were planned and acquired according to each Company's needs. Since the 1989 Merger, the Company has planned and acquired resources on a system-wide integrated basis. This being the case, it was decided that a geographic assignment of resources, by control area, would be a good place to start assessing the initial position. However, a strict geographic assignment of loads and resources did not provide a load / resource balance between the control areas.

Participants spent a considerable amount of time reviewing the initial position, by control area, at the time of the peak, and the effect that the movement of various resources would have on each control area. Based on the analysis and studies performed, three exceptions to the control area assignment were incorporated into the Hybrid.

The first two exceptions affect existing resources. The APS Exchange Contract has been assigned to the West Control Area and 125 MW of Jim Bridger Units 1 to 4 has been assigned to the East Control Area. When looking at the initial position in the East Control Area versus the West Control Area, these changes shift additional energy and capacity to the East creating more equitable control area load / resource balances. Additionally, while assignment of the APS Exchange Contract to the West Control Area has no energy impact, it adds length to the East at the time of the system peak and recognizes the seasonal aspect of this resource, as is done in the Revised Protocol.

The third exception affects the assignment of future resources. The Company plans for and operates the system on an integrated system-wide basis.¹⁵ However, when viewed for Hybrid purposes, as two separate control areas, the resource additions may not match the individual needs of each

¹⁵ Refer to the Company's 2004 IRP Report

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

control area. From Fiscal Year 2006 through Fiscal Year 2016, the West Control Area peak load is projected to increase by approximately 485 MW. During this same period, there is projected to be approximately 1,540 MW of lost generation in the West Control Area due to expiring contracts and lost hydro generation. This creates a need for approximately 2,000 MW of new resources. The 2004 IRP Preferred Portfolio includes the addition of only one Westside CCCT in Fiscal Year 2013 and approximately 500 MW of market purchases for a total of approximately 1,136 MW of new generation. These additions are not sufficient to cover the West Control Area's resource needs. Resource needs exceed resource additions by more than 880 MW. In the Hybrid, the 2014 IRP CCCT¹⁶ that is planned to be built on the Eastside of PacifiCorp's integrated system, has been assigned to the West Control Area due to the projected shortfall of resources in the West Control Area.

Results in the East Control Area present a different picture. While the peak load in the East Control Area is expected to increase by more than 2,400 MW, only 200 MW will be lost due to retirements and contract expirations, and approximately 3,819 MW in new resources are projected to come on-line in the 2004 IRP Preferred Portfolio. This projects a surplus of more than 1,170 MW in the East Control Area. Due to the projected shortfall of resources in the West Control Area and the projected surplus in the East Control Area, in the Hybrid, the 2014 IRP CCCT¹⁷ that is planned to be built on the Eastside of PacifiCorp's integrated system has been assigned to the West Control Area.

- 5.2.2 Method for Calculating the Operating Reserve Credit - In the GRID model, the West Control Area provides 100 MW of spinning reserves, or regulating and frequency reserves through the dynamic overlay. In addition, the GRID model allows the West Control Area to provide 100 MW of non-spinning reserves to the East Control Area.¹⁸

In the July 2003 Hybrid Proposal, the West Control Area received an operating reserve credit for providing reserves to the East Control Area, and the East Control Area incurred an equal and opposite cost. The operating reserve credit was net of the former PP&L Wyoming share (refer to **Section 5.2.3**). The credit was calculated using "Method 1" where 100 MW of spinning reserves and 100 MW of supplemental reserve service (non-spinning reserves) were valued using the Open Access Transmission Tariff ("OATT") Spinning & Non-Spinning Price.

¹⁶ It should be noted that in the Company's 2005 IRP Update, the 2014 CCCT resource has been removed.

¹⁷ It should be noted that in the Company's 2005 IRP Update, the 2014 CCCT resource has been removed.

¹⁸ The amount of reserves modeled in GRID will change over time to reflect changes in operations of the system. The values cited here are those currently modeled in GRID.

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

During the Hybrid Workgroup meetings, the Company presented two methods for valuing operating reserves. The first was "Method 1", as previously discussed. The second, or "Method 2", valued 100 MW of regulating and frequency reserve service and 100 MW of supplemental reserve service (non-spinning reserves) using the OATT Regulating and Frequency & Non-Spinning Price. Prices for the spinning, regulating and frequency, and non-spinning reserve services are taken from PacifiCorp's open access transmission tariff, OV-11, which became effective in April 2004. The price of the reserve services in Schedule OV-11 are the same as the charges currently in effect with FERC for full requirements customers (Schedule 0V-6).

Following the Workgroup discussions, participants agreed that calculating the operating reserve credit using the average of Method 1 and Method 2 appeared to best reflect actual system operations and this method was adopted in the Hybrid.

- 5.2.3 Operating Reserve Credit to Wyoming - As previously discussed in **Section 5.2.2**, the West Control Area receives a credit for providing operating reserves to the East Control Area. Under the Hybrid, Wyoming load is included in the East Control Area; however, a portion of Wyoming includes former PP&L service territory and is entitled to receive a portion of the operating reserve credit. In the July 2003 Hybrid Proposal the former PP&L Wyoming portion of the operating reserve credit was shared among the States in the East Control Area. In the Hybrid presented in this report, the former PP&L Wyoming's "**DGP Factor**" share of the operating reserve credit is assigned directly to Wyoming as an Intra-Control Area Equity Measure, instead of being shared among the States in the East Control Area.

Refer to **Appendix 9** for the paper provided to the Hybrid Workgroup explaining the operating reserve calculation.

5.3 New Components Incorporated into the Hybrid

In an effort to ensure the OPUC's second goal¹⁹ that Oregon's share of PacifiCorp's costs is equitable in relation to other States, the Hybrid Workgroup considered additional Intra-Control Area Equity Measures to be incorporated into the Hybrid. The workgroup focused on this issue with a proposal for a Mid-Columbia Contracts embedded cost differential ("**ECD**") for the West Control Area and situs assignment of QF Contracts in both control areas. These equity adjustments, consistent with the Revised Protocol, were analyzed and incorporated into the Hybrid. These new components are discussed in **Sections 5.3.1** and **5.3.2** respectively.

- 5.3.1 Allocation of Mid-Columbia Contracts – The costs of the Mid-Columbia Contracts are, in the first instance, allocated to the West Control Area. Then,

¹⁹ The second goal was to "insure that Oregon's share of PacifiCorp's costs is equitable in relation to other states" (Oregon Order No. 02-193 (restated in Oregon Order No. 05-021)).

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

the total normalized costs of Mid-Columbia Contracts are compared against normalized costs of the remaining West Control Area generation portfolio on a \$/MWh basis and an adjustment to reflect the cost difference is applied. This adjustment is referred to as the Mid-Columbia Contracts ECD ("**Mid-C Contracts ECD**").

The Mid-C Contracts ECD is calculated as the Annual Mid-Columbia Contract Costs, less the Annual Embedded Costs – All Other (in the West Control Area), multiplied by the normalized MWh's of output from the Mid-Columbia Contracts. The adjustment is then allocated to the States in the West Control Area using the Mid-Columbia factor ("**MC Factor**") and the reciprocal amount (All Other less Mid-C) is allocated to all States in the West Control Area using the "**CAGW Factor**".

- 5.3.2 Allocation of QF Contracts – The costs of the QF Contracts are initially allocated on a control area basis. The costs are compared to other generation costs at a control area aggregate level and the Existing QF cost difference is calculated separately for each State in each control area. The Existing QF Contract costs in each State are compared against normalized costs of the remaining generation portfolio on a \$/MWh basis of the control area where they are located and an adjustment which reflects the cost difference is applied. This adjustment is referred to as "Existing QF Contracts Cost Differential Adjustment".

The Existing QF Contracts Cost Differential Adjustment is calculated as the Annual Existing QF Contracts Costs for a specific State, less the Annual Embedded Costs – All Other, multiplied by the normalized MWh's of output from that State's Existing QF Contracts. This adjustment is situs assigned to that State. The sum of this adjustment for all States is calculated and an adjustment for the reciprocal amounts (All Other less Total System QF) is allocated to all States using the "**CAGW Factor**" in the West Control Area and the "**CAGE Factor**" in the East Control Area.

6. Hybrid Study Results

The Company analyzed the proposed refinements to the Hybrid and presented its analysis to the Hybrid Workgroup at the meeting held on September 14, 2005. The State-by-State percentage differences in revenue requirement from Revised Protocol, on an NPV basis, are shown in **Table 3**. At the time of presenting these Hybrid results to the workgroup, the analysis was known as Hybrid Case 3b1a. The shaded rows highlight the results for the West Control Area, East Control Area and Oregon.

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

**Table 3
Hybrid
(also known as Hybrid Case 3b1a)
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)**

State	Includes Intra-Control Area Measures (*)	
	Hybrid	
	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 2007-2020
California	-0.15%	-0.21%
Oregon	0.03%	-0.09%
Washington	0.14%	-0.03%
West Control Area	0.05%	-0.08%
Idaho	-0.69%	-0.68%
Utah	-0.08%	0.04%
Wyoming	0.54%	0.43%
East Control Area	-0.02%	0.05%

(*) includes Intra-Control Area Equity Measures of (1) QFs situs assigned, (2) operating reserve credit situs assigned to Wyoming and (3) Mid-C Contracts ECD

The following appendices provide additional information relating to the Hybrid studies. **Appendix 10** provides a list of the key assumptions included in the Hybrid. **Appendix 11** provides the results of each of the Hybrid studies performed by the Company. **Appendix 12** provides the net effect of results on the Control Areas and, more specifically, Oregon.

7. Remaining Concerns of the Hybrid

The Hybrid Workgroup has invested a significant amount of time and effort to refine the July 2003 Hybrid Proposal into a Hybrid that could be used for reporting purposes. Despite the concerted efforts of the workgroup, many participants continue to express significant concerns about the Hybrid being used for anything other than comparison purposes. The main concerns are:-

- (1) The Hybrid may cause unintended consequences related to Integrated Resource Planning (“IRP”) and operation, the location of new resources and plant outage risk. The Company’s IRP efforts are done as an integrated system. The Hybrid hypothetically divides the Company into control areas and therefore system planning becomes challenging. For example, the IRP might show that to optimize the system,

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

a particular resource should be added in the East Control Area when a resource in the West Control Area retires.

- (2) The Hybrid increases regulatory complexity by introducing complicated hourly interchange accounting and pricing calculations.
- (3) Moving from system-wide resources to control area resources limits the diversity of resources available to a control area. PacifiCorp's system is operated on a system basis, however under Hybrid, resources are assigned to a control area. A major change in costs at one plant may have a greater impact on individual States within the control area than an individual State's allocation on a system-wide basis.
- (4) The Hybrid does not protect Idaho and Wyoming from Utah's load growth.
- (5) The Hybrid does not meet the first goal²⁰ of the OPUC because use of the Hybrid is not supported by all States and would therefore not allow PacifiCorp the opportunity to recover 100% of its prudently incurred costs.

8. Conclusions

The Company formed the Hybrid Workgroup with Oregon parties (and other interested parties) from the States in which PacifiCorp serves at the request of the OPUC. The workgroup considered, and where possible, addressed unresolved issues from the July 2003 Hybrid Proposal, updated the data to more current assumptions, included three modifications and incorporated two new components. In compliance with Oregon Order No. 05-021, the Hybrid is deemed complete for reporting purposes in Oregon, however, it is not recommended as a cost allocation methodology for rate making purposes.

²⁰ "Determine an allocation methodology that would allow PacifiCorp an opportunity to recover its prudently incurred costs associated with its investment in generation resources". OPUC Order No. 05-021 dated January 12, 2005, page 12 (Section entitled "Commission Conditions")

Appendices

Appendix 1 Abbreviations and Definitions Used in this Report

"12CP"	means 12 monthly system coincident peak loads
"1989 Merger"	means the merger of Utah Power & Light and Pacific Power & Light in 1989
"CAGE Factor"	means the Company's Control Area Generation East Factor
"CAGW Factor"	means the Company's Control Area Generation West Factor
"DPG Factor"	means the Company's Divisional Pacific Generation Factor
"Dynamic Alternative"	means the cost allocation proposal presented to the MSP collaborative forum by Utah Parties in July 2003
"ECD"	means Embedded Cost Differential
"FERC"	means the Federal Energy Regulatory Commission
"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
"Hybrid"	means the Hybrid that has been developed within the Hybrid Workgroup which is presented in this report to the Oregon Public Utility Commission as a reporting comparator
"IRP"	means the Company's Integrated Resource Plan program and published report
"Mid-C Contracts ECD"	means Mid-Columbia Contracts ECD
"July 2003 Hybrid Proposal"	means the Hybrid Proposal presented to participants at the July 2003 meeting of the collaborative MSP
"MC Factor"	means the Company's Mid-C Factor
"MSP"	means the Company's Multi-State Process collaborative inter-jurisdictional allocations project

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

“NPV”	means Net Present Value
“OATT”	means Open Access Transmission Tariff
“OPUC”	means the Oregon Public Utility Commission
“PP&L”	means Pacific Power and Light
“Protocol”	means the cost allocation proposal filed by the Company with the State Commissions of Idaho, Oregon, Utah, Washington and Wyoming during the last quarter of calendar year 2003.
“QF Contracts”	means Qualifying Facilities Contracts
“Revised Protocol”	means the cost allocation methodology adopted by the State Commissions of Idaho, Oregon, Utah and Wyoming in March 2005.
“SPM”	means Structural Protection Mechanism
“UP&L”	means Utah Power and Light
“Updated July 2003 Hybrid”	means the July 2003 Hybrid updated to current data for the purposes of considering and determining the starting point of the Hybrid Workgroup’s development of a Hybrid for reporting purposes

**Appendix 2
List of MSP Participants / Hybrid Workgroup Participants**

The following is a list of MSP participants who have either been involved in the Hybrid Workgroup and/or who have received material relating to the Hybrid Workgroup.

Oregon

OPUC Staff - Marc Hellman^(*) and Bill Wordley^(*)
ICNU - Irion Sanger^(*), Randall Falkenberg^(*) and Melinda Davison
CUB - Lowrey Brown, Bob Jenks and Jason Eisdorfer

Idaho

IPUC Staff - Terri Carlock^(*) and David Schunke
AARP - Ron Binz, AARP
Monsanto - Jim Smith

Utah

UPSC Commission Advisory Staff - Lowell Alt^(*), Jim Logan^(*) and Becky Wilson^(*)
DPU - George Compton^(*), Andrea Coon, Mike Ginsberg, John Gothard^(*) and Chris Luras^(*)
UAE Intervention Group - Gary Dodge^(*), Justin Farr^(*), Kelly Francone, Neal Townsend^(*) and Kevin Higgins
CCS - Dan Gimble, Nancy Kelly^(*) and Cheryl Murray^(*)
USEA - Craig Paulson
SLCAP - Besty Wolf

Washington

WUTC Staff - Roger Braden and Alan Buckley
Public Counsel - Steven Johnson^(*)

Wyoming

WPSC Staff - Don Biedermann^(*) and Ruth Hobbs
WOCA - Denise Parrish^(*) and Ivan Williams
WIEC - Tom O'Donnell, WIEC

^(*) denotes those who attended one or more Hybrid Workgroup meeting

**Appendix 3
Hybrid Workgroup Scope and Work Plan
(Hybrid Workgroup Meeting – March 29, 2005)**

SCOPE	DUE DATE
PacifiCorp must include a Hybrid Method as one option for structural protection in the report regarding load growth. The Hybrid Method should be designed to: 1. 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.	October 20, 2005
PacifiCorp should work with parties from Oregon and those interested from other States.	Ongoing
The participating Oregon parties must present the Hybrid Method to the Oregon Commission.	December 1, 2005
PacifiCorp must file the results of the Hybrid Method as a comparator in its annual reports and general rate case filings.	January 1, 2006 or upon approval, whichever comes first

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

- Prioritize Issues
- Define deliverables for Meeting 2 (Note: This could be analysis or written documents from both the Company and other parties)
 - Assignment of Generation
 - Interchange Method
 - Interchange Pricing
 - Transmission and Firm Wheeling
 - Resource Planning and Investment

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

Meeting 2 (end of April)

Process Issues

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

Technical Issues

- Review deliverables
- Define preferred / potential solution for issues reviewed
- Define deliverables for Meeting 3
 - Assignment of Generation
 - Interchange Method
 - Interchange Pricing
 - Transmission and Firm Wheeling
 - Resource Planning and Investment

Meeting 3 (end of May)

Process Issues

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

Technical Issues

- Review deliverables
- Define preferred / potential solution for issues reviewed
- Define deliverables for Meeting 4
 - Assignment of Generation
 - Interchange Method
 - Interchange Pricing
 - Transmission and Firm Wheeling
 - Resource Planning and Investment

Meeting 4 (end of June)

Process Issues

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

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

Technical Issues

- Review deliverables
- Define preferred / potential solution for issues reviewed
- Define deliverables for Meeting 5
 - Assignment of Generation
 - Interchange Method
 - Interchange Pricing
 - Transmission and Firm Wheeling
 - Resource Planning and Investment

Meeting 5 (end of July)

Process Issues

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

Technical Issues

- Review deliverables
- Define preferred / potential solution for issues reviewed
- Narrow issues
- Identify and specify potential Hybrid Model solution(s)
 - Identify deliverables for Meeting 6 focused on potential Hybrid Model solution(s)

Meeting 6 (end of August)

Process Issues

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

Technical Issues

- Review deliverables
- Narrow potential solution(s) (prefer no more than 2 candidate solutions)
- Define / specify stress tests for potential Hybrid Model solution(s)
 - Identify deliverables for Meeting 7 focused on refined potential Hybrid Model solution(s)

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

Meeting 7 (Middle of September)

Process Issues

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

Technical Issues

- Review Hybrid Model solution(s)
- Select final Hybrid Model solution
- Review outline of write-up to include in load growth report

Meeting 8 (Middle of October)

Process Issues

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

Technical Issues

- Make final review of Hybrid Model write-up
- Outline December 1 filing / presentation with Oregon Commission

Meeting 9 (Not Scheduled)

Process Issues

- Discuss Reports (as needed)
- Discuss Logistics for Commission filing / presentation

Technical Issues

- Final review of Oregon filing / presentation

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

**Appendix 4
Hybrid Factors Applied to Allocation Components**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
SALES TO ULTIMATE CUSTOMERS		
440	Residential Sales Direct assigned - Jurisdiction	S
442	Commercial & Industrial Sales Direct assigned - Jurisdiction	S
444	Public Street & Highway Lighting Direct assigned - Jurisdiction	S
445	Other Sales to Public Authority Direct assigned - Jurisdiction	S
448	Interdepartmental Direct assigned - Jurisdiction	S
447	Sales for Resale Direct assigned - Jurisdiction Non-Firm Non-Firm Firm - West Control Area Firm - East Control Area	S CAEW CAEE CAGW CAGE
449	Provision for Rate Refund Direct assigned - Jurisdiction West Control Area East Control Area	S CAGW CAGE
OTHER ELECTRIC OPERATING REVENUES		
450	Forfeited Discounts & Interest Direct assigned - Jurisdiction	S

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
451	Miscellaneous Electric Revenue	
	Direct assigned - Jurisdiction	S
	Other - Common	SO
454	Rent of Electric Property	
	Direct assigned - Jurisdiction	S
	Common	SG
	Other	SO
456	Other Electric Revenue	
	Direct assigned - Jurisdiction	S
	Wheeling Non-firm, Other	SE
	Common	SO
	Wheeling - Firm, Other	SG
MISCELLANEOUS REVENUES		
41160	Gain on Sale of Utility Plant - CR	
	Direct assigned - Jurisdiction	S
	Transmission	SCT
	Production - West Control Area	CAGW
	Production - East Control Area	CAGE
	General Office	SO
41170	Loss on Sale of Utility Plant	
	Direct assigned - Jurisdiction	S
	Transmission	SCT
	Production - West Control Area	CAGW
	Production - East Control Area	CAGE
	General Office	SO
4118	Gain from Emission Allowances	
	SO2 Emission Allowance sales – West Control Area	CAEW
	SO2 Emission Allowance sales – East Control Area	CAEE
41181	Gain from Disposition of NOX Credits	
	NOX Emission Allowance sales - West Control Area	CAEW

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
	NOX Emission Allowance sales – East Control Area	CAEE
421	(Gain) / Loss on Sale of Utility Plant	
	Direct assigned - Jurisdiction	S
	Transmission	SCT
	Production - West Control Area	CAGW
	Production - East Control Area	CAGE
	General Office	SO
MISCELLANEOUS EXPENSES		
4311	Interest on Customer Deposits	
	Utah Customer Service Deposits	S
STEAM POWER GENERATION		
500, 502, 504-514	Operation Supervision & Engineering	
	West Control Area	CAGW
	East Control Area	CAGE
501	Fuel Related	
	West Control Area	CAEW
	East Control Area	CAEE
502	Steam Expenses	
	West Control Area	CAGW
	East Control Area	CAGE
503	Steam From Other Sources	
	Steam Royalties - West Control Area	CAEW
	Steam Royalties - East Control Area	CAEE
NUCLEAR POWER GENERATION		
517 - 532	Nuclear Power O&M	
	Nuclear Plants - West Control Area	CAGW
	Nuclear Plants - East Control Area	CAGE

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
HYDRAULIC POWER GENERATION		
535 - 545	Hydro O&M	
	Hydro - West Control Area	CAGW
	Hydro - East Control Area	CAGE
OTHER POWER GENERATION		
546, 548-554	Operation Super & Engineering	
	Other Production Plant - West Control Area	CAGW
	Other Production Plant - East Control Area	CAGE
547	Fuel	
	Other Fuel Expense - West Control Area	CAEW
	Other Fuel Expense - East Control Area	CAEE
OTHER POWER SUPPLY		
555	Purchased Power	
	Direct assigned - Jurisdiction	S
	Firm - West Control Area	CAGW
	Firm - East Control Area	CAGE
	Non-firm - West Control Area	CAEW
	Non-firm - East Control Area	CAEE
556 - 557	System Control & Load Dispatch	
	Other Expenses	SG
	Intra Control Area Equity Embedded Cost Differentials	
	Mid-Columbia Contract Embedded Cost Differential (Mid C less All Other - West Control Area)	MC
	Mid-Columbia Contract Embedded Cost Differential (All Other - West Control Area less Mid C)	CAGW
	Existing QF Contracts Embedded Cost Differential (QF less - All Other Control Area)	S
	Existing QF Contracts Embedded Cost Differential (All Other West Control Area less QF)	CAGW
	Existing QF Contracts Embedded Cost Differential (All Other East Control Area less QF)	CAGE

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
TRANSMISSION EXPENSE		
560-564, 566-573	Transmission O&M	
	Transmission Plant	SCT
565	Transmission of Electricity by Others	
	Firm Wheeling	SCT
	Non-Firm Wheeling - West Control Area	CAEW
	Non-Firm Wheeling - East Control Area	CAEE
DISTRIBUTION EXPENSE		
580 - 598	Distribution O&M	
	Direct assigned - Jurisdiction	S
	Other Distribution	SNPD
CUSTOMER ACCOUNTS EXPENSE		
901 - 905	Customer Accounts O&M	
	Direct assigned - Jurisdiction	S
	Total System Customer Related	CN
CUSTOMER SERVICE EXPENSE		
907 - 910	Customer Service O&M	
	Direct assigned - Jurisdiction	S
	Total System Customer Related	CN
SALES EXPENSE		
911 - 916	Sales Expense O&M	
	Direct assigned - Jurisdiction	S
	Total System Customer Related	CN
ADMINISTRATIVE & GEN EXPENSE		
920-935	Administrative & General Expense	

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
	Direct assigned - Jurisdiction	S
	Customer Related	CN
	General	SO
	FERC Regulatory Expense	SG
DEPRECIATION EXPENSE		
403SP	Steam Depreciation	
	Steam Plants - West Control Area	CAGW
	Steam Plants - East Control Area	CAGE
403NP	Nuclear Depreciation	
	Nuclear Plant - West Control Area	CAGW
	Nuclear Plant - East Control Area	CAGE
403HP	Hydro Depreciation	
	Hydro - West Control Area	CAGW
	Hydro - East Control Area	CAGE
403OP	Other Production Depreciation	
	Other Production Plant - West Control Area	CAGW
	Other Production Plant - East Control Area	CAGE
403TP	Transmission Depreciation	
	Transmission Plant	SCT
403	Distribution Depreciation	
	Direct assigned - Jurisdiction	
	Land & Land Rights	S
	Structures	S
	Station Equipment	S
	Poles & Towers	S
	OH Conductors	S
	UG Conduit	S
	UG Conductor	S
	Line Trans	S
	Services	S
	Meters	S

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
	Inst Cust Prem	S
	Leased Property	S
	Street Lighting	S
403GP	General Depreciation	
	Distribution	S
	Production Plant - West Control Area	CAGW
	Production Plant - East Control Area	CAGE
	Hydro - West Control Area	CAGW
	Hydro - East Control Area	CAGE
	Transmission	SCT
	Customer Related	CN
	General SO	SO
403MP	Mining Depreciation	
	Remaining Mining Plant - East Control Area	CAEW
	Remaining Mining Plant - West Control Area	CAEE
AMORTIZATION EXPENSE		
404GP	Amortization of LT Plant - Capital Lease Gen	
	Direct assigned - Jurisdiction	S
	General	SO
	Customer Related	CN
404SP	Amortization of LT Plant - Cap Lease Steam	
	Steam Production Plant - West Control Area	CAGW
	Steam Production Plant - East Control Area	CAGE
404IP	Amortization of LT Plant - Intangible Plant	
	Distribution	S
	Production, Transmission	SCT
	Production - West Control Area	CAGW
	Production - East Control Area	CAGE
	General	SO
	Customer Related	CN

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
404MP	Amortization of LT Plant - Mining Plant	
	Mining Plant - West Control Area	CAEW
	Mining Plant - East Control Area	CAEE
404HP	Amortization of Other Electric Plant	
	Hydro - West Control Area	CAGW
	Hydro - East Control Area	CAGE
405	Amortization of Other Electric Plant	
	Direct assigned - Jurisdiction	S
406	Amortization of Plant Acquisition Adjustment	
	Direct assigned - Jurisdiction	S
	Production Plant - West Control Area	CAGW
	Production Plant - East Control Area	CAGE
407	Amortization of Property Losses, Unrec Plant, etc	
	Direct assigned - Jurisdiction	S
	Transmission	SCT
	Trojan	TROJP
TAXES OTHER THAN INCOME		
408	Taxes Other Than Income	
	Direct assigned - Jurisdiction	S
	Property	GPS
	General Payroll Taxes	SO
	Miscellaneous Energy	SE
	Miscellaneous Production	SG
DEFERRED ITC		
41140	Deferred Investment Tax Credit - Fed	
	ITC	DGU
41141	Deferred Investment Tax Credit - Idaho	

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
	ITC	DGU
INTEREST EXPENSE		
427	Interest on Long-Term Debt	
	Direct assigned - Jurisdiction	S
	Interest Expense	SNP
428	Amortization of Debt Disc & Exp	
	Interest Expense	SNP
429	Amortization of Premium on Debt	
	Interest Expense	SNP
431	Other Interest Expense	
	Interest Expense	SNP
432	AFUDC - Borrowed	
	AFUDC	SNP
INTEREST & DIVIDENDS		
419	Interest & Dividends	
	Interest & Dividends	SNP
DEFERRED INCOME TAXES		
41010	Deferred Income Tax - Federal-DR	
	Direct assigned - Jurisdiction	S
	Electric Plant in Service	DITEXP
	Hydro - West Control Area	DGP
	Production, Transmission	SG
	Customer Related	CN
	General	SO
	Property Tax related	GPS
	Miscellaneous	SNP
	Bad Debt	BADDEBT
	Cholla Transaction Costs	SGCT
	Trojan	TROJD

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
	Distribution	SNPD
	Mining Plant	SE
41020	Deferred Income Tax -- Non Utility -DR	
	Direct assigned - Jurisdiction	S
	Electric Plant in Service	DITEXP
	Hydro - West Control Area	DGP
	Production, Transmission	SG
	Customer Related	CN
	General	SO
	Property Tax related	GPS
	Miscellaneous	SNP
	Bad Debt	BADDEBT
	Cholla Transaction Costs	SGCT
	Trojan	TROJP
	Distribution	SNPD
	Mining Plant	SE
41110	Deferred Income Tax - Federal-CR	
	Direct assigned - Jurisdiction	S
	Electric Plant in Service	DITEXP
	Hydro - West Control Area	DGP
	Production, Transmission	SG
	Customer Related	CN
	General	SO
	Property Tax related	GPS
	Miscellaneous	SNP
	Bad Debt	BADDEBT
	Cholla Transaction Costs	SGCT
	Trojan	TROJD
	Distribution	SNPD
	Mining Plant	SE
41120	Deferred Income Tax -- Non Utility -CR	
	Direct assigned - Jurisdiction	S
	Electric Plant in Service	DITEXP
	Hydro - West Control Area	DGP

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
	Production, Transmission	SG
	Customer Related	CN
	General	SO
	Property Tax related	GPS
	Miscellaneous	SNP
	Bad Debt	BADDEBT
	Cholla Transaction Costs	SGCT
	Trojan	TROJP
	Distribution	SNPD
	Mining Plant	SE
 SCHEDULE - M ADDITIONS		
SCHMAF	Additions - Flow Through	
	Direct assigned - Jurisdiction	S
SCHMAP	Additions - Permanent	
	Mining related	SE
	Miscellaneous	SNP
	General	SO
SCHMAT	Additions - Temporary	
	Direct assigned - Jurisdiction	S
	Contributions in aid of construction	CIAC
	Miscellaneous	SNP
	Trojan	TROJD
	Hydro - West Control Area	SG
	Mining Plant	SE
	Production, Transmission	SG
	Property Tax	GPS
	General	SO
	Depreciation	SCHMDEXP
	Distribution	SNPD
	Customer Related	CN
	Cholla Transaction Costs	SGCT
	Bad Debt	BADDEBT

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
SCHEDULE - M DEDUCTIONS		
SCHMDF	Deductions - Flow Through	
	Direct assigned - Jurisdiction	S
	Production, Transmission	SG
	Hydro - West Control Area	DGP
SCHMDP	Deductions - Permanent	
	Direct assigned - Jurisdiction	S
	Mining Related	SE
	Miscellaneous	SNP
	General	SO
SCHMDT	Deductions - Temporary	
	Direct assigned - Jurisdiction	S
	Bad Debt	BADDEBT
	Miscellaneous	SNP
	Mining related	SE
	Production, Transmission	SG
	Property Tax	GPS
	General	SO
	Depreciation	TAXDEPR
	Distribution	SNPD
STATE INCOME TAXES		
40911	State Income Taxes	
	Income Before Taxes	IBT
40910	FIT True-up	S
40910	Wyoming Wind Tax Credit	CAEE
STEAM PRODUCTION PLANT		
310 - 316		
	Steam Plants - West Control Area	CAGW
	Steam Plants - East Control Area	CAGE

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
NUCLEAR PRODUCTION PLANT		
320-325	Nuclear Plant - West Control Area	CAGW
	Nuclear Plant - East Control Area	CAGE
HYDRAULIC PLANT		
330-336	Hydro - West Control Area	CAGW
	Hydro - East Control Area	CAGE
OTHER PRODUCTION PLANT		
340-346	Other Production Plant - West Control Area	CAGW
	Other Production Plant - East Control Area	CAGE
TRANSMISSION PLANT		
350-359	Transmission Plant	SCT
DISTRIBUTION PLANT		
360-373	Direct assigned - Jurisdiction	S
GENERAL PLANT		
389 - 398	Distribution	S
	Production Plant - West Control Area	CAGW
	Production Plant - East Control Area	CAGE
	Hydro - West Control Area	CAGW
	Hydro - East Control Area	CAGE
	Transmission	SCT
	Customer Related	CN

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
	General SO	SO
399	Coal Mine	
	Mining Plant - West Control Area	CAEW
	Mining Plant - East Control Area	CAEE
399L	WIDCO Capital Lease	
	WIDCO Capital Lease	SE
1011390	General Capital Leases	
	Direct assigned - Jurisdiction	S
	General	SO
GP	Unclassified Gen Plant - Acct 300	
	Distribution	S
	Production Plant West Control Area	CAGW
	Production Plant East Control Area	CAGE
	Hydro - West Control Area	CAGW
	Hydro - East Control Area	CAGE
	Transmission	SCT
	Customer Related	CN
	General	SO
INTANGIBLE PLANT		
301	Organization	
	Direct assigned - Jurisdiction	S
302	Franchise & Consent	
	Direct assigned - Jurisdiction	S
	Production - West Control Area	CAGW
	Production - East Control Area	CAGE
	Transmission	SCT
303	Miscellaneous Intangible Plant	
	Distribution	S
	Production Plant - West Control Area	CAGW

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
	Production Plant - East Control Area	CAGE
	Hydro - West Control Area	CAGW
	Hydro - East Control Area	CAGE
	Mining - West Control Area	CAEW
	Mining - East Control Area	CAEE
	Transmission	SCT
	Customer Related	CN
	General	SO
303	Less Non-Utility Plant	
	Direct assigned - Jurisdiction	S
RATE BASE ADDITIONS		
105	Plant Held For Future Use	
	Direct assigned - Jurisdiction	S
	Production Plant - West Control Area	CAGW
	Production Plant - East Control Area	CAGE
	Transmission	SCT
	Mining Plant - West Control Area	CAEW
	Mining Plant - East Control Area	CAEE
114	Electric Plant Acquisition Adjustments	
	Direct assigned - Jurisdiction	S
	Production Plant - West Control Area	CAGW
	Production Plant - East Control Area	CAGE
115	Accumulated Provision for Asset Acquisition Adjustments	
	Direct assigned - Jurisdiction	S
	Production Plant - West Control Area	CAGW
	Production Plant - East Control Area	CAGE
120	Nuclear Fuel	
	Nuclear Plant - West Control Area	CAGW
	Nuclear Plant - East Control Area	CAGE
124	Weatherization	
	Direct assigned - Jurisdiction	S

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
	General	SO
182W	Weatherization Direct assigned - Jurisdiction	S
186W	Weatherization Direct assigned - Jurisdiction	S
151	Fuel Stock Steam Production Plant	SE
152	Fuel Stock - Undistributed Steam Production Plant	SE
25316	DG&T Working Capital Deposit Mining Plant	SE
25317	DG&T Working Capital Deposit Mining Plant	SE
25319	Provo Working Capital Deposit Mining Plant	SE
154	Materials and Supplies Direct assigned - Jurisdiction Transmission Mining General Production - Common Hydro Distribution	S SCT SE SO SNPPS SNPPH SNPD
163	Stores Expense Undistributed General	SO
25318	Provo Working Capital Deposit Provo Working Capital Deposit	SNPPS

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
165	Prepayments	
	Direct assigned - Jurisdiction	S
	Property Tax	GPS
	Production	SG
	Transmission	SCT
	Mining	SE
	General	SO
182M	Miscellaneous Regulatory Assets	
	Direct assigned - Jurisdiction	S
	Production	SG
	Transmission	SCT
	Cholla Transaction Costs	SGCT
	Mining	SE
	General	SO
186M	Miscellaneous Deferred Debits	
	Direct assigned - Jurisdiction	S
	Production	SG
	Transmission	SCT
	General	SO
	Mining	SE
	Production - Common	SG
WORKING CAPITAL		
CWC	Cash Working Capital	
	Direct assigned - Jurisdiction	S
OWC	Other Working Capital	
131	Cash	SNP
135	Working Funds	SG
143	Other Accounts Receivable	SO
232	Accounts Payable	SO
232	Accounts Payable	SE
253	Deferred Hedge	SE

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
25330	Other Deferred Credits - Miscellaneous	SE
MISCELLANEOUS RATE BASE		
18221	Unrec Plant & Reg Study Costs	
	Direct assigned - Jurisdiction	S
18222	Nuclear Plant - Trojan	
	Trojan Plant	TROJP
	Trojan Plant	TROJD
141	Impact Housing - Notes Receivable	
	Employee Loans - Hunter Plant	CAGE
RATE BASE DEDUCTIONS		
235	Customer Service Deposits	
	Direct assigned - Jurisdiction	S
2281	Provision for Property Insurance	SO
2282	Provision for Injuries & Damages	SO
2283	Provision for Pensions and Benefits	SO
22842	Accumulated Miscellaneous Operations Provision-Trojan	
	Trojan Plant	TROJD
252	Customer Advances for Construction	
	Direct assigned - Jurisdiction	S
	Production	SG
	Transmission	SCT
	Customer Related	CN
25399	Other Deferred Credits	
	Direct assigned - Jurisdiction	S
	Production	SG

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
	Transmission	SCT
	Mining	SE
190	Accumulated Deferred Income Taxes	
	Direct assigned - Jurisdiction	S
	Bad Debt	BADDEBT
	Production, Transmission	SG
	Mining	SE
	General	SO
	Miscellaneous	SNP
	Trojan	TROJD
	Pacific Pre-Merger Hydro	DGP
	Distribution	SNPD
281	Accumulated Deferred Income Taxes	
	Production, Transmission	DGP
282	Accumulated Deferred Income Taxes	
	Direct assigned - Jurisdiction	S
	Depreciation	DITBAL
	Pacific Pre-Merger Hydro	DGP
	Production, Transmission	SG
	Customer Related	CN
	General	SO
	Mining	SE
283	Accumulated Deferred Income Taxes	
	Direct assigned - Jurisdiction	S
	Production, Transmission	SG
	Mining	SE
	General	SO
	Property Tax related	GPS
	Miscellaneous	SNP
	Trojan	TROJD
	Distribution	SNPD
	Cholla Transaction Costs	SGCT

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
255	Accumulated Investment Tax Credit	
	Direct assigned - Jurisdiction	S
	Investment Tax Credits	ITC84
	Investment Tax Credits	ITC85
	Investment Tax Credits	ITC86
	Investment Tax Credits	ITC88
	Investment Tax Credits	ITC89
	Investment Tax Credits	ITC90
	Investment Tax Credits	DGU
PRODUCTION PLANT ACCUM DEPRECIATION		
108SP	Steam Prod Plant Accumulated Depreciation	
	Steam Plants - West Control Area	CAGW
	Steam Plants - East Control Area	CAGE
108NP	Nuclear Prod Plant Accumulated Depreciation	
	Nuclear Plant - West Control Area	CAGW
	Nuclear Plant - East Control Area	CAGE
108HP	Hydraulic Prod Plant Accumulated Depreciation	
	Hydro - West Control Area	CAGW
	Hydro - East Control Area	CAGE
108OP	Other Production Plant - Accumulated Depreciation	
	Other Production Plant - West Control Area	CAGW
	Other Production Plant - East Control Area	CAGE
TRANS PLANT ACCUM DEPR		
108TP	Transmission Plant Accumulated Depreciation	
	Transmission Plant	SCT
DISTRIBUTION PLANT ACCUMULATED DEPRECIATION		
108360 - 108373	Distribution Plant Accumulated Depreciation	

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
	Direct assigned - Jurisdiction	S
108D00	Unclassified Dist Plant - Acct 300 Direct assigned - Jurisdiction	S
108DS	Unclassified Dist Sub Plant - Acct 300 Direct assigned - Jurisdiction	S
108DP	Unclassified Dist Sub Plant - Acct 300 Direct assigned - Jurisdiction	S
GENERAL PLANT ACCUMULATED DEPRECIATION		
108GP	General Plant Accumulated Depreciation	
	Distribution	S
	Generation - West Control Area	CAGW
	Generation - East Control Area	CAGE
	Mining - East Control Area	CAEE
	Transmission	SCT
	Customer Related	CN
	General SO	SO
108MP	Mining Plant Accumulated Depreciation	
	Mining Plant - West Control Area	CAEW
	Mining Plant - East Control Area	CAEE
108MP	Less Centralia Situs Depreciation	
	Direct assigned - Jurisdiction	S
1081390	Accumulated Depreciation - Capital Lease	
	General	SO
1081399	Accumulated Depreciation - Capital Lease	
	Direct assigned - Jurisdiction	S

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

FERC ACCT	DESCRIPTION	HYBRID ALLOCATION FACTOR
ACCUMULATED PROVISION FOR AMORTIZATION		
111SP	Accumulated Provision for Amortization - Steam Remaining Steam Plants	SG
111GP	Accumulated Provision for Amortization - General Distribution Remaining Steam Plants Hydro - West Control Area Hydro - East Control Area Transmission Customer Related General SO	S SG CAGW CAGE SCT CN SO
111HP	Accumulated Provision for Amortization - Hydro Hydro - West Control Area Hydro - East Control Area	CAGW CAGE
111IP	Accumulated Provision for Amortization - Intangible Plant Distribution Hydro - West Control Area Generation - West Control Area Generation - East Control Area Transmission General Mining - East Control Area Customer Related	S CAGW CAGW CAGE SCT SO CAEE CN
111IP	Less Non-Utility Plant Direct assigned - Jurisdiction	S
111399	Accumulated Provision for Amortization - Mining Mining Plant - East Control Area	CAEE

Appendix 5 Components of the Hybrid

The shaded column highlights the components that form the Hybrid presented in this report as complete for use in the State of Oregon as a reporting comparator.

	July 2003 Hybrid Proposal	Hybrid ²¹	Hybrid Report Section
COMPONENTS UNCHANGED FROM JULY 2003 HYBRID PROPOSAL			
Interchange Model	Method 2 – interchange after system balancing	Unchanged	Section 5.1.1
Interchange Pricing	Average of the Seller's Maximum Price and the Buyer's Minimum Price (Method 2 Pricing)	Unchanged	Section 5.1.2
Allocation of Transmission and Firm Wheeling	Rolled-In cost allocation approach	Unchanged	Section 5.1.3
Cross Control Area Exchanges	Assigned to the control area where delivery takes place	Unchanged	Section 5.1.4
COMPONENTS MODIFIED FROM THE JULY 2003 HYBRID PROPOSAL			
Assignment of Generation and Contracts	Assigned to the control Area where located	Assigned to the control area where located, except:-	Section 5.2.1

²¹ Also known as Case 3b1a through the development stage of the Hybrid

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

	July 2003 Hybrid Proposal	Hybrid²¹	Hybrid Report Section
		<u>Assigned to East</u> 125 MW of Bridger Units 1-4 <u>Assigned to West</u> APS Exchange 2014 IRP CCCT	
Method for Calculating the Operating Reserve Credit	Method 1	Average of Method 1 and Method 2	Section 5.2.2
Operating Reserve Credit to Wyoming	Allocated among the East Control Area's States	Situs Assigned to Wyoming	Section 5.2.3
NEW COMPONENTS INCORPORATED INTO THE HYBRID			
Allocation of Mid-Columbia Contracts	Allocated among the West Control Area's States	Mid-Columbia Contracts ECD	Section 5.3.1
Allocation of QF Contracts	Allocated to control area	Situs	Section 5.3.2

**Appendix 6
Hybrid Issues List
(Hybrid Workgroup Meeting – March 29, 2005)**

Assignment of Existing Generation and Contracts

- What is the goal of the initial assignment of generation?
 - Equal surplus or deficit for East and West?
 - Consider HLH and LLH balances?
 - What is the initial point in time?
 - Other?
- What are the rules for initial assignment of generation between the East and West?
 - By control area?
 - How should resources be assigned if they are located in one area but are acquired to serve the other area?
 - Exchanges by point of delivery?
 - Winter resources to the West (Cholla / APS)?
 - Should fuel diversity be considered?
 - Should asset diversity be considered (PPA vs. owned)?
 - Should embedded cost be considered?
 - How would additional transmission, combining the control areas, affect the assignment?
- Once initial assignment is made, is there a need to adjust for historical entitlement?
 - Dave Johnston / Wyodak?
 - Wyoming share of West hydro?
 - Post merger investments in pre-merger plant?
 - Other?
- How are adjustments made?
 - Move resources?
 - Value of operation reserves
 - Create swaps?
 - Create risk pools?
- How is the assignment of generation done on a going forward basis?
 - How would the hybrid method treat cross-area assignments of resources?
 - Are all new resources assigned to control area of interconnection?
 - Are resources moved to match changes in system operation (Colstrip)?
 - If RTO consolidates control areas, then what?

Resource Planning and Investment

- Evaluate the impact that the designed method has on resource planning and investment going forward, i.e., transmission investments, plant siting etc., that might be different under a hybrid methodology

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

- Evaluate the impact of new technologies
- Under the hybrid method, how could costs be allocated to ensure that cost-effective contracting and other management decisions would proceed without disadvantaging either control area?

Transmission and Firm Wheeling

- How should the costs and benefits of transmission and firm wheeling be allocated?
 - Rolled-In?
 - By Region?
- How should the costs of non-firm transmission be allocated?
- Is the allocation of transmission consistent with the access to markets assumed in the interchange accounting method?
- How should the role of transmission in generation integration and balancing be taken into account in the allocation of transmission costs?
- How should new transmission investment associated with interconnecting and transferring power from new generation be allocated?
- Are there transmission impacts associated with cross control area exchanges?

Interchange Method

- Is there a better method than Method 2?
 - Develop a production-cost model with interchange-accounting logic to identify directly the internal and external transactions?
- Should the GRID model be used to estimate system balancing?
- Should the method include prior concessions?
 - Should East receive reserve credit for Wyoming share of hydro?
 - Should exchange contract return power receive priority to highest priced market?
- What should the method assume about each control area's access to markets for balancing?
- How should the method adapt to new topologies (AMPS line change affects hybrid logic)?
- How should the method adapt to changes in number of market hubs (integral to hybrid logic)?

Interchange Pricing

- Is there a better method than Method 3?
 - Capacity equalization and variable cost?
 - Portion at embedded cost?
 - Should the pricing formula reflect PacifiCorp internal costs, including running costs, as well as market prices?
 - Market averages per region?
 - Should market price be based on markets *connected* to the control area or markets with which control area is *conducting* system balancing, on an hour-by-hour basis?

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

- Should market price be based on the best price, the best incrementally available price, the average price or something else?
- Should interchange price always be set at a market price, or should it also reflect the marginal, incremental, or decremental costs of internal generation that supports interchange
- Are corrective adjustments needed to address potential for free-riding, such as capacity equalization or surcharge on energy over a certain level?
- What should the interchange pricing method assume about each control area's access to markets?
- Should the computation of interchange pricing include separate prices in additional market areas and sub-areas (e.g., Ault Colorado and three Desert Southwest market areas—Four Corners, Palo Verde and Mead)?
- How should interchange pricing take into account transmission constraints?
- Should interchange price include the variable costs of non-firm transmission?
- Should interchange price include non-firm wheeling costs?
- Risk sharing agreements?
 - What data source can be used for deriving valid estimates of hourly market prices? Under the Hybrid approach, how sensitive is the allocation to the estimates of market price?
 - If interchange is sensitive to the market prices assumed, how will differences among the States be resolved?
 - How will consistency between market price estimates and other production-costing model inputs (such as fuel prices, loads, and resource additions) be maintained?
 - How will consistency between market price estimates and assumed water conditions be maintained?

Appendix 7
Interchange Accounting Method
(Hybrid Workgroup Meeting – May 3, 2005)

Steps	Action
Step 1	Compute the hourly load / resource balance (position) by control area (East and West) from the GRID output. This initial balance includes loads, long-term and short-term firm sales / purchases, thermal resources, hydro resources and emergency purchases. System balancing purchases / sales are excluded.
Step 2	Move half (100 MW) of the SCE sale from the East to West. This is necessary because the GRID run has the entire SCE sale in the east (SP-15 bubble), whereas the Hybrid requires the sale to be split 50:50 between East and West.
Step 3	Assign the cost and energy of SP-15 purchases equally to the East and West to be consistent with the SCE sale assignment.
Step 4	Move the receipt (IN) portion of Cross-Control Area Exchanges to the other control area to the extent that the control area with the delivery (OUT) is short. Refer to Section 5.1.4 for further discussion.
Step 5	Sell any receipts (IN) not transferred in Step 4 at the highest market price.
Step 6	Balance using market purchases / sales in own control area.
Step 7	Balance using market purchases / sales in other control area.
Step 8	Share excess system balancing purchases / sales (if any).
Step 9	Interchange between East and West Control Areas – amount of remaining short position filled by other control area's long position. Interchange priced at the Average of Seller's Maximum Price and Buyer's Minimum Price.

Appendix 8 Cross Control Area Exchange Contracts (Hybrid Workgroup Meeting – May 3, 2005)

Background

Exchange contracts have two delivery point components: a receipt (IN) and a delivery (OUT). When the delivery takes place, the control area making the delivery incurs costs. The receipts are meant to offset these costs. Some exchange contracts have both the IN and OUT components in the same control area. Others have the IN component in one control area and the OUT component in the other control area. We have referred to these latter exchanges as Cross Control Area Exchange Contracts. This group includes Bonneville Power Administration (“BPA”) South Idaho Exchange, Redding Exchange, and the Foote Creek I, II, and IV Exchange Contracts. Each Cross Control Area Exchange Contracts is described in detail below.

Under the Hybrid, State allocations of system balancing purchases and sales are affected by the assignment of resources to each control area. When the IN and the OUT components are in different control areas, this creates a mismatch and results in higher costs for the control area with the OUT component and lower costs for the control area with the IN component. To alleviate this mismatch, the IN and OUT components are both assigned to the control area where the delivery (OUT) component of the exchange takes place.

BPA South Idaho Exchange Agreement

This agreement was signed February 10, 1989, as a result of the 1989 Merger. Without the merger, this agreement would not have been possible.

Terms of the Agreement: From February 1989 until counterparty termination

Exchange of Energy: BPA has customers in South Idaho that are interconnected with PacifiCorp's system. PacifiCorp has resources in its East Control Area and delivers energy to meet BPA's customer needs in the City of Idaho Falls, Soda Springs, and several small cooperatives. In exchange PacifiCorp receives like energy plus 2% losses from BPA on the West Side at existing points of interconnection between the parties. Prior to this agreement BPA wheeled the power through Idaho Power's control area. BPA's agreement with Idaho Power expired at about the time of the PP&L / UP&L merger.

Transmission Service: BPA reduces PacifiCorp's West Side transmission expense based on a ratcheted 11-month demand that PacifiCorp provides on the East Side for BPA. This is booked as Other Revenue. For calendar year 2001 PacifiCorp received \$5.1 million in credit for deliveries made to BPA in South Idaho.

Storage Service: BPA has rights to generation in South Idaho at the Palisades project and at Idaho Falls. This generation is within PacifiCorp's East Control Area and at times is in excess of BPA's

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

customer requirements. PacifiCorp stores excess energy in its system during the summer when it is above BPA's customer requirements and returns the energy in the winter at an agreed time. PacifiCorp receives a storage charge of \$8/MWh for this service.

Treatment in GRID: West – includes the receipt (IN) of energy from BPA. East – includes the delivery (OUT) of energy to BPA customers.

Treatment in the 2003 Hybrid Interchange Model: Adjust the initial position of the East Control Area to include both the BPA South Idaho Exchange IN and OUT in the East Control Area, since the point of delivery is in the East Control Area.

Redding Exchange

Terms of the Agreement: PacifiCorp and Redding exchange capacity and energy during the exchange period, December 1, 2000 through November 30, 2015.

Point of Delivery: Deliveries from PacifiCorp to Redding: COB

Point of Receipt: PacifiCorp's choice of PV, Westwing, Monekopi, or San Juan.

Receipt by PacifiCorp: Maximum Receipt - Redding makes available its maximum share of capacity and energy from San Juan Unit 4 (21.5 MW). **Minimum Receipt –** During each hour, the lesser of Redding's share of the output or 9 MW/hour. During each year, PacifiCorp has to take delivery of 130,000 MWh.

Delivery to Redding: PacifiCorp is required to make available 50 MW of capacity. Minimum monthly deliveries of 16,250 MWh. Maximum deliveries of 50 MW in each hour and 27,500 MWh in each month. In each season, energy equal to the amount of energy scheduled from San Juan to PacifiCorp during the relevant contract year. Seasonal energy shall not exceed Redding's annual minimum delivery obligations.

Treatment in GRID: West – includes the delivery (OUT) of energy. East – includes the receipt (IN) of energy.

Treatment in the 2003 Hybrid Interchange Model: Adjust the initial position of the West Control Area to include both the Redding Exchange IN and OUT in the West Control Area since the Company delivers energy to Redding in the West Control Area.

Eugene Water and Electric Board ("EWEB") – Foote Creek I Wind Energy Storage

Terms of the Agreement: July 21 1997 to April 21, 2029

Points of Delivery / Receipt: PacifiCorp receives the energy at PacifiCorp's Miners Substation in Wyoming and delivers it to EWEB at the Currin Tap in Oregon or other points as mutually agreed

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

upon. PacifiCorp provides generation control and storage services to convert output of the Foote Creek I project into firm dependable power. EWEB has an ownership interest in the Wyoming project of 8.78%. PacifiCorp takes EWEB's stored share of the actual output of the project into its East Control Area and schedules the energy to EWEB 168 hours after generation. In addition to transmission and storage fees EWEB reimburses PacifiCorp for transmission losses that PacifiCorp incurs on its system.

Treatment in GRID: West – includes the delivery (OUT) of energy to EWEB. East – includes the receipt (IN) of energy from Foote Creek I.

Treatment in the 2003 Hybrid Interchange Model: Adjust the initial position of the West Control Area to include both the EWEB Foote Creek I Exchange IN and OUT in the West Control Area since the Company delivers power to EWEB in the West Control Area.

BPA - Wind Energy Storage Services for Foote Creek II

Terms of the Agreement: May 28, 1999 through June 28, 2014. BPA has the right to extend the term in five-year increments for up to an additional ten years.

Points of Delivery / Receipt: PacifiCorp receives the energy at Miners Substation in Wyoming and delivers to interconnections with BPA within PacifiCorp's West Control Area; Alvey, Hot Springs, and Malin Substations. PacifiCorp provides storage and transmission services to BPA for power generated by Foote Creek II. BPA entered into a power purchase agreement with Foote Creek, LLC to purchase the output of three 600KW wind turbines. PacifiCorp takes the energy from the Foote Creek II project and integrates it into its system providing load control and load following services for the project output. PacifiCorp delivers stored energy to BPA 168 hours after receipt of the energy. PacifiCorp is not obligated to accept capacity in excess of 3 MW. BPA reimburses PacifiCorp for transmission and substation losses that PacifiCorp incurs on its system. In addition to a storage charge, PacifiCorp charges BPA a use of facilities fee plus a transmission charge.

Treatment in GRID: West – includes the delivery (OUT) of energy to BPA. East – includes the receipt (IN) of energy from Foote Creek II.

Treatment in the 2003 Hybrid Interchange Model: Adjust the initial position of the West Control Area to include the Foote Creek II BPA / BPA Exchange IN and OUT in the West Control Area since the Company delivers power to BPA in the West Control Area.

BPA - Generation Control & Storage Services for Foote Creek IV

Terms of the Agreement: July 20, 2000 to August 2, 2020

Point of Receipt / Delivery: PacifiCorp receives the energy at Miners Substation in Wyoming and delivers to interconnections with BPA within PacifiCorp's West Control Area; Alvey, Hot Springs, and Malin Substations. BPA contracted to purchase the entire output from the Foote Creek IV wind project which is interconnected with PacifiCorp in Wyoming. PacifiCorp provides generation control

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

and storage service to convert the power of the wind plant into power that can be scheduled. In addition to recovery of losses on its system, PacifiCorp charges BPA for generation control, storage, and use of transmission facilities.

Treatment in GRID: West – includes the delivery (OUT) of energy to BPA. East – includes the receipt (IN) of energy from Foote Creek IV.

Treatment in the 2003 Hybrid Interchange Model: Adjust the initial position of the West Control Area to include the Foote Creek IV BPA / BPA Exchange IN and OUT in the West Control Area since the Company delivers power to BPA in the West Control Area.

Appendix 9 Method of Calculating the Operating Reserve Credit (Hybrid Workgroup Meeting – May 31, 2005)

Background

The Company has made the operating reserve valuation computation using two methods.

In GRID, the West Control Area provides 100 MW of spinning reserves (Method 1) or regulating and frequency reserves (Method 2) through the dynamic overlay. In addition, the GRID model allows the West Control Area to provide 100 MW of non-spinning reserves (Method 1 and Method 2) to the East Control Area. The Company's net power costs are reduced by operating in this manner as it enables more of the total system operating reserve requirement to be carried on hydro facilities.

Under the Hybrid, the West Control Area receives an operating reserve credit for providing operating reserves to the East Control Area and the East Control Area incurs an equal and opposite cost. The operating reserve credit is net of the former PP&L Wyoming Divisional generation factor. Prices for the spinning, regulating and frequency and non-spinning reserve services are taken from PacifiCorp's open access transmission tariff, OV-11, which became effective April 26, 2004. The price of the reserve services in OV-11 are the same as the charges currently in effect with FERC for our full requirements customers (schedule OV-6).

Method 1

- **Spinning Reserve Service** – spinning reserves are provided immediately in the event of a system contingency. spinning reserve service is provided by generation units controlled by automatic generation control that are on-line and loaded at less than maximum output. The transmission provider will provide capacity immediately upon an outage until the earlier of restoration of such resource or the end of ten full minutes after the occurrence of such outage. Charges developed for the OV-11 and approved by FERC are as follows:
 - Hydro energy delivered = \$0.266/MWh (based on \$7.77/KW month x 1000 x 2.5%/730 hrs)
 - Thermal or other energy delivered = 0.373/MWh (based on \$7.77/KW month x 1000 x 3.5%/730 hrs)
 - In case of an outage of a generating resource, energy scheduled is charged at \$17.42/MWh
 - (The 2.5% and 3.5% are the spinning reserve requirements per NERC or 50% of the operating reserve requirement)
- **Supplemental Reserve Service (100 MW non-spinning reserves)** – This service is provided in the case of a system emergency, however it is not available immediately to serve load but rather in a short period of time. This is provided by generating units that are on-line but unloaded, by quick start generation or by interruptible load. This service covers load from 10 minutes after the outage until the earlier of the restoration of the resource or the end of the first full hour immediately following such outage.

Appendix 10 Key Assumptions of PacifiCorp's Hybrid Studies

- 2004 IRP Preferred Portfolio
- Forecasted study period Fiscal Year 2007 to Fiscal Year 2020
- 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
- CO₂ tax timing and cost assumptions consistent with IRP (\$8/ton in 2008 dollars)
- IRP Preferred Portfolio Resource Additions (under a 15% planning margin): -
 - Fiscal Year 2010 – 525 MW Utah (Brownfield) Dry Cool CCCT with duct firing
 - Fiscal Year 2012 – 575 MW Utah (Brownfield) Coal
 - Fiscal Year 2013 – 586 MW West Main Dry Cool CCCT with duct firing
 - Fiscal Year 2014 – 560 MW Utah Wet Cool CCCT with duct firing
 - Fiscal Year 2015 – 383 MW Wyoming (Brownfield) Coal

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

**Appendix 11
List of PacifiCorp's Hybrid Studies**

Table 4 below provides a list of the studies performed and presented to the Hybrid Workgroup from June 2005 through October 2005 and relied upon for the discussion and conclusions presented in this Hybrid Report. The list also includes to two Hybrid load growth studies (Hybrid Case 1 Load Growth and Hybrid Case 3b1a Load Growth) that were performed by the Company. These studies are referenced in PacifiCorp's Load Growth Report filed with OPUC on October 20, 2005. The shaded row highlights the components that form the Hybrid presented in this report as complete for use in the State of Oregon as a reporting comparator. For study assumptions, refer to **Appendix 10**. Refer also to **Sections 5, 6** and **Appendices 12** and **13**.

**Table 4
Resource Matrix for Hybrid Studies**

Hybrid Case Number	Hybrid Workgroup Meeting (except where indicated)	APS (480 MW)	Cholla (380 MW Nameplate)	Intra-Control Area Equity Measures	Jim Bridger Units 1 – 4 (1,412 MW Nameplate)	IRP Jim Bridger Unit 5 (383 MW Nameplate)	IRP 2014 CCCT (560 MW Nameplate)
Hybrid Case 1	June 28, 2005 (2004 Forecast)	West	West	Not included	All units in West	East	East
Hybrid Case 1	July 18, 2005 (2005 Forecast)	West	West	QFs Situs and operating reserve credit to Wyoming	All units in West	East	East
Hybrid Case 1 (Load Growth)	June 28, 2005 (2004 Forecast)	West	West	Not Included	All units in West	East	Removed
Hybrid Case 1a	August 24, 2005	West	West	QFs Situs, operating reserve credit to Wyoming and Mid-C Contracts ECD	380 MW allocated East; remainder West	East	East
Hybrid Case 1b	August 24, 2005	West	West	QFs Situs, operating reserve credit to Wyoming and Mid-C Contracts ECD	Equally split between East and West	East	East

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

Hybrid Case Number	Hybrid Workgroup Meeting (except where indicated)	APS (480 MW)	Cholla (380 MW Nameplate)	Intra-Control Area Equity Measures	Jim Bridger Units 1 – 4 (1,412 MW Nameplate)	IRP Jim Bridger Unit 5 (383 MW Nameplate)	IRP 2014 CCCT (560 MW Nameplate)
Hybrid Case 2 (also known as Updated July 2003 Hybrid)	June 28, 2005 (2004 Forecast)	East	East	Not Included	All units in West	East	East
Hybrid Case 3	July 18, 2005	West	East	QFs Situs, operating reserve credit to Wyoming and Mid-C Contracts ECD	All units in West	East	East

New Resource Sensitivities							
Hybrid Case 3a	August 24, 2005	West	East	QFs Situs, operating reserve credit to Wyoming and Mid-C Contracts ECD	All units in West	West	East
Hybrid Case 3b	August 24, 2005	West	East	QFs Situs, operating reserve credit to Wyoming and Mid-C Contracts ECD	All units in West	East	West
Hybrid (also known as Hybrid Case 3b1a)	September 14, 2005	West	East	QFs Situs, operating reserve credit to Wyoming and Mid-C Contracts ECD	125 MW allocated East; remainder West	East	West

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

Hybrid Case Number	Hybrid Workgroup Meeting (except where indicated)	APS (480 MW)	Cholla (380 MW Nameplate)	Intra-Control Area Equity Measures	Jim Bridger Units 1 – 4 (1,412 MW Nameplate)	IRP Jim Bridger Unit 5 (383 MW Nameplate)	IRP 2014 CCCT (560 MW Nameplate)
Hybrid Case 3b1a (Load Growth)	October 11, 2005 (Load Growth Workgroup Meeting)	West	East	QFs Situs, operating reserve credit to Wyoming and Mid-C Contracts ECD	125 MW allocated East; remainder West	East	Removed
Hybrid Case 3c	September 14, 2005	West	Equally split between East and West	QFs Situs, operating reserve credit to Wyoming and Mid-C Contracts ECD	190 MW allocated East; remainder West	East	West
Test Hybrid Case (3b1)	September 14, 2005	West	East	QFs Situs, operating reserve credit to Wyoming and Mid-C Contracts ECD	100 MW allocated East; remainder West	East	West
Test Hybrid Case (3b2)	September 14, 2005	West	East	QFs Situs, operating reserve credit to Wyoming and Mid-C Contracts ECD	200 MW allocated East; remainder West	East	West
Test Hybrid Case (3b3)	September 14, 2005	West	East	QFs Situs, operating reserve credit to Wyoming and Mid-C Contracts ECD	300 MW allocated East; remainder West	East	West

Appendix 12 Hybrid Results

Hybrid Results

The tables below provide 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 10** and **11**. Refer also to **Sections 5, 6** and **Appendix 13**.

Hybrid Workgroup Meeting - June 28, 2005

The Hybrid study results shown in **Table 5** 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. Hybrid Case 1 has APS, Cholla and all Jim Bridger Units 1 to 4 assigned to the West Control Area, with IRP Jim Bridger Unit 5 and IRP 2014 CCCT assigned to the East Control Area. In comparison, Hybrid Case 2 has Jim Bridger Units 1 to 4 assigned to the West Control Area, with APS, Cholla, IRP Jim Bridger Unit 5 and IRP 2014 CCCT assigned to the East Control Area. These studies were performed prior to any discussions regarding the modifications to the Hybrid (other than the movement of APS / Cholla from East to West) and the incorporation of Intra-Control Area Equity Measures. The shaded columns highlight the results that reflect the Updated July 2003 Hybrid (also known as Hybrid Case 2).

Table 5
Hybrid Case 1 and Updated July 2003 Hybrid
Percentage Difference in NPV Revenue Requirement
from Revised Protocol using June 2004 Forecast
(Hybrid Workgroup Meeting – June 28, 2005)

State	Hybrid Case 1 June 2004 Forecast		Updated July 2003 Hybrid (*) June 2004 Forecast	
	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 2007-2020	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 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%

(*) also known as Hybrid Case 2

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

Hybrid Workgroup Meeting – July 18, 2005

The Hybrid study results shown in **Table 6** 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, are an update to the Hybrid Case 1 analysis presented at the June 28, 2005 Hybrid Workgroup meeting, and incorporate the Intra-Control Area Equity Measures of (1) QFs situs assigned, and (2) operating reserve credit situs assigned to Wyoming. In summary, this Hybrid Case 1 has APS, Cholla and all Jim Bridger Units 1 to 4 assigned to the West Control Area, with IRP Jim Bridger Unit 5 and IRP 2014 CCCT assigned to the East Control Area. The shaded rows highlight the results for the West Control Area, East Control Area and Oregon.

**Table 6
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)**

State	Hybrid Case 1 March 2005 Forecast		Results with APS West / Cholla in East		Includes Intra-Control Area Equity Measures			
	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 2007-2020	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 2007-2020	Results with APS in West / Cholla in East, QFs situs assigned (*)		Results with APS in West / Cholla in East, QFs situs assigned and operating reserve credit situs to Wyoming (#)	
	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 2007-2020	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 2007-2020	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 2007-2020	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 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%

(*) includes Intra-Control Area Equity Measure of (1) QFs situs assigned

(#) includes Intra-Control Area Equity Measures of (1) QFs situs assigned, and (2) operating reserve credit situs assigned to Wyoming

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

Hybrid Workgroup Meeting – August 24, 2005

The Hybrid study results shown in **Tables 7 and 8** 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) operating reserve credit situs assigned to Wyoming, and (3) Mid-C ECD. The Hybrid Case 1a and 1b studies incorporated analysis to determine the amount of Jim Bridger Units 1 to 4 to be assigned to the West and East Control Areas. Hybrid Case 1a has APS, Cholla and 1,032 MW of Jim Bridger Units 1 to 4 assigned to the West Control Area, with 380 MW of Jim Bridger Units 1 to 4, IRP Jim Bridger Unit 5 and IRP 2014 CCCT assigned to the East Control Area. The shaded rows highlight the results for the West Control Area, East Control Area and Oregon.

**Table 7
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)**

State	Includes Intra-Control Area Equity Measures (*)			
	Hybrid Case 1a		Hybrid Case 1b	
	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 2007-2020	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 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%

(*) includes Intra-Control Area Equity Measures of (1) QFs situs assigned, (2) operating reserve credit situs assigned to Wyoming, and (3) Mid-C ECD

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

The Hybrid Cases 3, 3a and 3b incorporated analysis to determine the potential split of APS and Cholla, and then built on the assignments of IRP Jim Bridger Unit 5 and IRP 2014 CCCT on the East or West Control Areas. Hybrid Case 3 has APS and Jim Bridger Units 1 to 4 assigned to the West Control Area, with Cholla, IRP Jim Bridger Unit 5 and IRP 2014 CCCT assigned to the East Control Area. Hybrid Case 3a has APS, Jim Bridger Units 1 to 4 and IRP Jim Bridger Unit 5 assigned to the West Control Area, with Cholla and IRP 2014 CCCT assigned to the East Control Area. Hybrid Case 3b has APS, Jim Bridger Units 1 to 4 and IRP 2014 CCCT assigned to the West Control Area, with Cholla and IRP Jim Bridger Unit 5 assigned to the East Control Area. The shaded rows highlight the results for the West Control Area, East Control Area and Oregon.

**Table 8
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 Fiscal Years 2007-2015	14-Year NPV Fiscal Years 2007-2020	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 2007-2020	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 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%

(*) includes Intra-Control Area Equity Measures of (1) QFs situs assigned, (2) operating reserve credit situs assigned to Wyoming, and (3) Mid-C ECD

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

Hybrid Workgroup Meeting – September 14, 2005

The Hybrid study results shown in **Tables 9** and **10** 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) operating reserve credit situs assigned to Wyoming, and (3) Mid-C ECD. The Hybrid Case 3b Variations incorporated analysis to determine the amount of Jim Bridger Units 1 to 4 assignments to each control area. Hybrid Case 3b1 has APS, 1,312 MW Jim Bridger Units 1 to 4 and IRP 2014 CCCT assigned to the West Control Area, with Cholla, 100 MW Jim Bridger Units 1 to 4 and IRP Jim Bridger Unit 5 assigned to the East Control Area. Hybrid Case 3b2 has APS, 1,212 MW Jim Bridger Units 1 to 4 and IRP 2014 CCCT assigned to the West Control Area, with Cholla, 200 MW Jim Bridger Units 1 to 4 and IRP Jim Bridger Unit 5 assigned to the East Control Area. Hybrid Case 3b3 has APS, 1,112 MW Jim Bridger Units 1 to 4 and IRP 2014 CCCT assigned to the West Control Area, with Cholla, 300 MW Jim Bridger Units 1 to 4 and IRP Jim Bridger Unit 5 assigned to the East Control Area. The shaded rows highlight the results for the West Control Area, East Control Area and Oregon.

**Table 9
Hybrid 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)**

State	Includes Intra-Control Area Equity Measures (*)							
	Hybrid Case 3b1		Hybrid Case 3b1a		Hybrid Case 3b2		Hybrid Case 3b3	
	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 2007-2020	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 2007-2020	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 2007-2020	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 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%

(*) includes Intra-Control Area Equity Measures of (1) QFs situs assigned, (2) operating reserve credit situs assigned to Wyoming and (3) Mid-C ECD

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

The Hybrid Case 3c built on the analysis of variation Hybrid Cases 3b with MW splits of Jim Bridger Units 1 to 4 between the East and West Control Areas, and also split Cholla between the two control areas on a 50:50 basis. In summary, Hybrid Case 3c has APS, 50% Cholla, 1,222 MW Jim Bridger Units 1 to 4 and IRP 2014 CCCT assigned to the West Control Area, with 50% Cholla, 190 MW Jim Bridger Units 1 to 4 and IRP Jim Bridger Unit 5 assigned to the East Control Area. The shaded rows highlight the results for the West Control Area, East Control Area and Oregon.

**Table 10
Hybrid 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)**

State	Includes Intra-Control Area Equity Measures (*)	
	Hybrid Case 3c	
	9-Year NPV Fiscal Years 2007-2015	14-Year NPV Fiscal Years 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%

(*) includes Intra-Control Area Equity Measures of (1) QFs situs assigned, (2) operating reserve credit situs assigned to Wyoming and (3) Mid-C ECD

**Multi-State Process
Hybrid Report to the Oregon Public Utility Commission
November 21, 2005**

**Appendix 13
Summary of Hybrid Case Results**

**Table 11
Summary of Hybrid Case Results
Percentage Differences in NPV of Hybrid Method from Revised Protocol**

	Hybrid 3b1a ^{2b}											
	1 ^{1b}	1a	1b	2 ^{2b}	3	3a	3b	3c	3b1	3b2	3b3	
	September 14 ^a	July 18 ^a	August 24 ^a		June 28 ^a	August 24 ^a		September 14 ^a				
2007-2015 NPV @ 8.4277%												
Total Company	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
California	-0.15%	-4.62%	1.25%	4.54%	-4.16%	-1.54%	-1.35%	-1.09%	-0.29%	-1.13%	-0.37%	0.39%
Oregon	0.03%	-2.92%	1.90%	6.25%	-2.34%	-1.84%	-1.58%	-1.22%	-0.56%	-1.66%	-0.60%	0.47%
Washington	0.14%	-1.97%	2.19%	6.88%	-1.36%	-1.87%	-1.57%	-1.19%	-0.40%	-1.62%	-0.54%	0.55%
West Total	0.04%	-2.83%	1.92%	6.27%	-2.25%	-1.83%	-1.56%	-1.21%	-0.51%	-1.82%	-0.57%	0.48%
Utah	-0.08%	1.14%	-1.20%	-3.58%	1.06%	0.96%	0.79%	0.58%	0.33%	0.96%	0.43%	-0.11%
Idaho	-0.69%	1.33%	-1.74%	-4.64%	0.60%	0.50%	0.39%	0.17%	-0.69%	-0.17%	-0.81%	-1.45%
Wyoming	0.54%	4.06%	-0.57%	-3.80%	2.83%	1.86%	1.75%	1.51%	0.50%	1.04%	0.32%	-0.41%
East Total	-0.02%	1.68%	-1.14%	-3.71%	1.34%	1.08%	0.92%	0.71%	0.28%	0.88%	0.31%	-0.26%
2007-2020 NPV @ 8.4277%												
Total Company	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
California	-0.21%	-4.70%	1.07%	4.23%	-4.80%	-1.95%	-1.52%	-1.14%	-0.01%	-0.83%	-0.07%	0.68%
Oregon	-0.09%	-3.08%	1.82%	5.86%	-3.21%	-2.45%	-1.89%	-1.35%	0.53%	-0.59%	0.44%	1.46%
Washington	-0.03%	-2.41%	1.82%	6.33%	-2.58%	-2.55%	-1.89%	-1.35%	0.52%	-0.69%	0.37%	1.44%
West Total	-0.06%	-3.04%	1.83%	5.89%	-3.18%	-2.44%	-1.87%	-1.34%	0.49%	-0.62%	0.40%	1.42%
Utah	0.04%	1.31%	-0.95%	-3.20%	1.65%	1.34%	0.96%	0.69%	-0.26%	0.37%	-0.15%	-0.67%
Idaho	-0.68%	1.37%	-1.62%	-4.34%	1.08%	0.72%	0.52%	0.16%	-0.88%	-0.34%	-0.97%	-1.60%
Wyoming	0.43%	3.78%	-0.57%	-3.61%	3.00%	1.96%	1.79%	1.37%	-0.02%	0.54%	-0.18%	-0.89%
East Total	0.05%	1.75%	-0.93%	-3.36%	1.84%	1.40%	-1.07%	0.77%	-0.27%	0.35%	-0.22%	-0.78%

¹Hybrid Case 1 excluded the intra-control area adjustments (DFS Status, Hydro Reserve to WY, Mid-C ECD)
²Hybrid Case 2 was run in CG24 only, and excluded the intra-control area adjustments (DFS Status, Hydro Reserve to WY, Mid-C ECD)
³Hybrid Case 3 includes the intra-control area adjustments (DFS Status, Hydro Reserve to WY, Mid-C ECD)