825 N.E. Multnomah St.
Portland, OR 97232

PACIFICORP
PACIFIC POWER UTAH POWER

November 21, 2005

VIA ELECTRONIC FILING

Oregon Public Utility Commission
550 Capitol Street NE, Suite 215
Salem, OR 97301-2551

Attention: Vikie Bailey-Goggins Administrator
Regulatory and Technical Support

Re: **Case No. UM-1050**
PacifiCorp's Petition to Initiate Investigation of Inter-Jurisdictional Issues
Submission of PacifiCorp's Hybrid Report - Compliance Filing

Enclosed for filing are an original and seven (7) copies of PacifiCorp's Hybrid Report associated with Case No. UM-1050. This report is filed in compliance with Commission Order No. 05-021.

This Hybrid Report is presented to the Oregon Commission 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**"). The Order also required the Company to file its annual reports and general rate case filings using the revised Hybrid as a comparator beginning January 1, 2006, or once the Hybrid is completed (whichever occurs first). Absent any further direction from the Oregon Commission, the Company will include the Hybrid as a comparator in future annual reports and general rate case filings.

It is respectfully requested that all formal correspondence and staff requests regarding this matter be addressed to:

By E-mail (preferred):	datarequest@pacificorp.com
By Fax:	(503) 813 6060
By Regular Mail:	Data Request Response Center PacifiCorp 825 NE Multnomah Street, Suite 800 Portland, OR, 97232

Informal inquiries may also be made to Greg Duvall (at 503 813 7069) or Sue Rolfe (at 503 813 6878).

Very truly yours,

D. Douglas Larson | p.r.

D. Douglas Larson
Vice President, Regulation

cc: Service List UM-1050

Enclosures

CERTIFICATE OF SERVICE

I hereby certify that on this 21st day of November, 2005 I caused to be served, via U.S. Mail, a true and correct copy of the PacifiCorp's Hybrid Report – Compliance Filing associated with Case No. UM-1050.

STEPHANIE S ANDRUS – **CONFIDENTIAL** DEPARTMENT OF JUSTICE REGULATED UTILITY & BUSINESS SECTION 1162 COURT ST NE SALEM OR 97301-4096 □elly□k□e.andrus@state.or.us	MELINDA J DAVISON – **CONFIDENTIAL** DAVISON VAN CLEVE PC 333 SW TAYLOR, STE. 400 PORTLAND OR 97204 mail@dvclaw.com
MICHAEL EARLY – **CONFIDENTIAL** INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES 333 SW TAYLOR STE 400 PORTLAND OR 97204 mearly@icnu.org	JASON EISDORFER – **CONFIDENTIAL** CITIZENS' UTILITY BOARD OF OREGON 610 SW BROADWAY STE 308 PORTLAND OR 97205 □elly@oregoncub.org
RANDALL J FALKENBERG – **CONFIDENTIAL** RFI CONSULTING INC PMB 362 8351 ROSWELL RD ATLANTA GA 30350 consultrfi@aol.com	PATRICK G HAGER PORTLAND GENERAL ELECTRIC 121 SW SALMON ST 1WTC0702 PORTLAND OR 97204 □elly□k.hager@pgn.com
ROBERT JENKS – **CONFIDENTIAL** CITIZENS' UTILITY BOARD OF OREGON 610 SW BROADWAY STE 308 PORTLAND OR 97205 bob@oregoncub.org	ANDREA L KELLY – **CONFIDENTIAL** PACIFICORP 825 NE MULTNOMAH ST STE 800 PORTLAND OR 97232 andrea.kelly@pacificorp.com
KATHERINE A MCDOWELL STOEL RIVES LLP 900 SW FIFTH AVE STE 1600 PORTLAND OR 97204-1268 kamcdowell@stoel.com	IRION SANGER – **CONFIDENTIAL** DAVISON VAN CLEVE 333 SW TAYLOR, STE 400 PORTLAND OR 97204 ias@dvclaw.com
V DENISE SAUNDERS PORTLAND GENERAL ELECTRIC 121 SW SALMON ST 1WTC1301 PORTLAND OR 97204 denise.saunders@pgn.com	STEVEN WEISS NORTHWEST ENERGY COALITION 4422 OREGON TRAIL CT NE SALEM OR 97305 weiss.steve@comcast.net

Peggy Ryan

Peggy Ryan
Supervisor Regulatory Administration

PACIFICORP
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Multi-State Process

Hybrid Report
to the Oregon Public Utility Commission

November 21, 2005

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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.

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 Process[2] 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 2003[4]). 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.

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[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.

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 Order[7] states:-

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

and further states[8]:-

> *"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. 05-021[9]):-

> *"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")

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

	July 2003 Hybrid Proposal (#)	Updated July 2003 Hybrid (*)	
State	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%

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.

> *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.

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 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:-

<u>March 29, 2005</u>
- Workgroup Guidelines
- Scope and Work Plan
- Prioritization of Hybrid Issues List

<u>April 18, 2005</u>
- Review of July 2003 Hybrid Proposal

<u>May 3, 2005</u>
- Hourly Interchange Logic
- ICNU Proposal Related to Development of a Hybrid Model
- Initial Assignment of Generation Resources and Contracts
- Identification of Analysis

<u>May 31, 2005</u>
- Analytical Results
- Assignment of Resources and Contracts
- Valuation of Reserves

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

- 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 meeting[14] 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.

(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.

<u>Components of the Hybrid Addressed by the Workgroup</u> – 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 <u>Interchange Accounting Method</u> - 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.

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 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 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

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 CCCT[16] 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 CCCT[17] 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.

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 goal[19] 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)).

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.

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,

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 goal[20] 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

"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

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

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)

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

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	S
		Non-Firm	CAEW
		Non-Firm	CAEE
		Firm - West Control Area	CAGW
		Firm - East Control Area	CAGE
449	Provision for Rate Refund		
		Direct assigned - Jurisdiction	S
		West Control Area	CAGW
		East Control Area	CAGE
OTHER ELECTRIC OPERATING REVENUES			
450	Forfeited Discounts & Interest		
		Direct assigned - Jurisdiction	S

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

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

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

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		

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

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

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		

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

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

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

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

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

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

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

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	S
		Transmission	SCT
		Mining	SE
		General	SO
		Production - Common	SNPPS
		Hydro	SNPPH
		Distribution	SNPD
163	Stores Expense Undistributed		
		General	SO
25318	Provo Working Capital Deposit		
		Provo Working Capital Deposit	SNPPS

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

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

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

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		

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

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

	July 2003 Hybrid Proposal	**Hybrid[21]**	**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, ie., transmission investments, plant siting etc., that might be different under a hybrid methodology

- 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?

  - 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 though 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 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 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 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 0V-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.

Formula to calculate spinning and non-spinning reserve service:-

Definitions:-

Spin Demand = MW capacity for spinning reserves
Non-spin Demand = MW capacity for non-spinning reserves
PDWA = Pacific Division Wyoming Adjustment (1 – 2004 DGP) = 0.76037
HY = Hour in Year
Spin TED = Spin Thermal Energy delivered
Non-Spin TED = Non-spin Thermal Energy delivered
SRR = 3.5% (i.e. 50% of the operating reserve requirement or spinning portion)
NSRR = 3.5% (i.e. 50% of the operating reserve requirement or non-spinning portion)
OV11 Price = $0.373/MWh

Formula:-

Spin TED = (Spin Demand * (PDWA) * HY) / SRR
Non-spin TED = (Non-Spin demand * (PDWA) * HY) / NSRR

Spin Reserve Charge $ =Spin TED * OV11 Price
Non-Spinning reserves Charge $ =Non-spin TED * OV11 Price

Calculation of the operating reserve credit for Hybrid:-

- 100 MW spinning reserves = $7,098,535 ((100 MW (1-0.239632) x 8760)/0.035 x $0.373 MWh)
- 100 MW non-spinning reserves = $7,098,535 ((100 MW (1-0.239632) x 8760)/0.035 x $0.373 MWh)

  Total charge $14,197,070

Under the Hybrid (using Method 2 to calculate the operating reserve credit), the East Control Area would incur a $14.2 million increase in revenue requirement while the West Control Area would receive $14.2 million reduction in revenue requirement using Method 1.

Method 2

- **Regulating and Frequency Reserve Service (100 MW)** – This service is necessary to provide for the continuous balancing of hourly scheduled resources with actual real time load and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). Regulating and frequency 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 must offer this service when the transmission service is used to serve load within its control area. Charges developed for the OV-11 and approved by FERC are as follows:

  I. **Regulation and Frequency Response Service = $0.16/MWh**

- **Supplemental Reserve Service (100 MW non-spinning reserves)** – Same as Method 1

II. Calculation of the operating reserve credit for Hybrid:-

- 100 MW regulating & frequency reserves = $3,044,948 ((100 MW (1-0.239632) x 8760)/0.035 x $0.16 MWh)
- 100 MW non-spinning reserves = $7,098,535 ((100 MW (1-0.239632) x 8760)/0.035 x $0.373 MWh)
  Total charge $10,143,483

Under the Hybrid (using Method 2 to calculate the operating reserve credit), the East Control Area would incur a $10.1 million increase in revenue requirement while the West Control Area would receive $10.1 million reduction in revenue requirement.

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
- CO_2 tax timing and cost assumptions consistent with IRP ($8/ton in 2008 dollars)
- IRP Preferred Portfolio Resource Additions (under a 15% planning margin):-
  - 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

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

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**

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

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)

					Includes Intra-Control Area Equity Measures			
State	Hybrid Case 1 March 2005 Forecast		Results with APS West / Cholla in East		Results with APS in West / Cholla in East, QFs situs assigned (*)		Results with APS in West / Cholla in East, QFs situs assigned and operating reserve credit situs to Wyom ing (#)	
	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

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)

	Includes Intra-Control Area Equity Measures (*)			
State	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

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

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)

	Includes Intra-Control Area Equity Measures (*)							
State	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

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)

	Includes Intra-Control Area Equity Measures (*)	
State	**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

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[3]	1[1]	1a	1b	2[2]	3	3a	3b	3c	3b1	3b2	3b3
	September 14th	July 18th	August 24th		June 28th	August 24th			September 14th			
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%**	**-1.62%**	**-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%**

	Hybrid 3b1a[3]	1[1]	1a	1b	2[2]	3	3a	3b	3c	3b1	3b2	3b3
	September 14th	July 18th	August 24th		June 28th	August 24th			September 14th			
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%**	**1.62%**	**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	**-0.08%**	**-3.04%**	**1.63%**	**5.86%**	**-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%**

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