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April 1, 2016

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

RE: Docket No. UM 1050 – In the Matter of PACIFICORP Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol.

Attached for filing are staff's Opening Testimony (Exhibit 100) and Supporting exhibits (Exhibit 101 – 110) in UM 1050.

/s/ Kay Barnes

Kay Barnes
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PUBLIC UTILITY COMMISSION
OF OREGON

UM 1050

STAFF DIRECT TESTIMONY OF

LANCE KAUFMAN

In the Matter of
PACIFICORP, dba PACIFIC POWER,
Petition for Approval of the
2017 PacifiCorp Inter-Jurisdictional
Allocation Protocol.

April 1, 2016

CASE: UM 1050
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Direct Testimony

April 1, 2016

Q. Please state your name, occupation, and business address.

A. My name is Lance Kaufman. My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit staff/101.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to evaluate the 2017 Protocol.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

1. Staff/101, consisting of 1 page;
2. Staff/102, consisting of 7 pages;
3. Staff/103, consisting of 3 pages;
4. Staff/104, consisting of 1 page;
5. Staff/105, consisting of 2 pages;
6. Staff/106, consisting of 1 page;
7. Staff/107, consisting of 4 pages;
8. Staff/108, consisting of 2 pages;
9. Staff/109, consisting of 1 page; and
10. Staff/110, consisting of 1 page.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, HISTORY OF PACIFICORP MULTISTATE ALLOCATIONS

Q. Please describe PacifiCorp's background as a multi-state entity.

A. PacifiCorp provides electric distribution service to customers in six states, California, Oregon, Washington, Idaho, Utah, and Wyoming. PacifiCorp formed in 1910 as Pacific Power and Light (PPL), serving electric customers in Oregon and Washington.[1] In 1987 PacifiCorp acquired Utah Power and Light (UPL). At the time, PacifiCorp provided service as PPL in California, Idaho, Montana, Oregon, Washington, and Wyoming. Utah Power and Light provided service in Idaho, Utah, and Wyoming. Pacific Power and Light generation relied on a substantial amount of hydro facilities while Utah Power and Light had a relatively greater portion of generation and capacity from thermal resources.[2]

The Oregon Public Utility Commission (OPUC) approved the merger between PPL and UPL in Order No. 88-767. In this order, the Commission approved a stipulation regarding cost allocation guidelines. These guidelines direct parties to develop an agreement on how to allocate the benefits of the merger and they provide an allocation method in case no agreement is reached. The stipulation also states "Pacific agrees, however, that its shareholders will assume all risks that may result from less than full system cost recovery if interdivisional allocation methods differ among the merged company's jurisdictions."[3]

[1] *See* http://www.pacificorp.com/about/co.html accessed 3/2/2016.
[2] *See* Exhibit Staff/102 OPUC Order No 88-767 at Page 3.
[3] *See* Exhibit Staff/102 OPUC Order No 88-767 at Page 6.

PacifiCorp's jurisdictions have agreed to multiple cost allocation methodologies over the last 28 years. The initial effort to create a multistate agreement on cost allocations resulted in the Modified Accord. The Modified Accord recognized that, due to greater access to hydro power, PPL customers had lower generation costs on average than UPL customers. After the adoption of the Modified Accord, the Utah Commission changed their allocation methodology to reflect "Rolled In" costs. This reduced costs allocated to Utah customers.[4]

At PacifiCorp's request, the Commission opened Docket UM 1050 in 2002 to investigate multi-jurisdictional issues. As part of this docket, parties have re-negotiated the interstate cost allocations several times. The Commission ratified the Revised Protocol in 2005 and the 2010 Protocol in 2011. The stipulation adopting the 2010 Protocol states that parties will revert to the Revised Protocol for any rate cases filed after December 21, 2016. After several years of negotiations, parties have developed the 2017 Protocol. The 2017 Protocol is intended to be a short term agreement while parties evaluate the impact of recent changes in national environmental policy and regulation.

Q. Have all PacifiCorp jurisdictions agreed to follow the previous allocation protocols?

A. No, the Washington Utilities and Transportation Commission has not adopted previous allocation protocols. In addition the states that have adopted the protocols implement them in different ways.

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[4] *See* Exhibit 103 Utah Public Service Commission Docket No. 02-035-04 CCS Exhibit 1.3 at Page 2.

Q. Please provide more detail about how individual states implemented the 2010 Protocol.

A. The primary difference among participating states is the treatment of PPL's hydro endowment. PPL has historically had access to lower cost energy resources, including a substantial amount of hydropower. If the historically low cost of energy for PPL regions is not recognized, PPL customers may not receive an equitable share of the merger benefits. The cost difference between PPL and UPL resources is recognized in the 2010 Protocol though the Embedded Cost Differential (ECD). Staff describes the calculation of the ECD at page 5 of this testimony.

The participating states use a fixed ECD, Dynamic ECD, or no ECD. Appendix A of the 2017 Protocol defines these terms. PacifiCorp alleges that the differential treatment if ECD by the participating states has resulted in an allocation shortfall of several million dollars. The magnitude of the shortfall varies by year depending on the size of the ECD.

Q. What allocation method is Oregon currently committed to on a going forward basis?

A. Absent of any action by the OPUC, Oregon will revert to using the Revised Protocol in any general rate case filed after December 31, 2016.

ISSUE 2, CONTENT OF 2017 PROTOCOL

Q. What are the primary differences between the 2017 Protocol and the Revised Protocol.

A. There are three major differences between the 2017 Protocol and the Revised Protocol. These differences relate to the calculation of the ECD, the introduction of the Equalization Adjustment, and an agreement to not file a general rate case with rates effective before January 1, 2018.

Q. Please describe the calculation of ECD under the 2017 Protocol.

A. The ECD contains two components, a hydro cost differential and a Mid-Columbia contract differential. The hydro differential is calculated as the difference between the total dollars per megawatt cost of hydroelectric resources and the dollars per megawatt cost of all pre-2005 resources multiplied by the megawatt hours of hydro generation.

The Mid-Columbia differential is calculated as the difference between the total dollars per megawatt cost of Mid-Columbia Contracts and the pre-2005 resources multiplied by the Mid-Columbia megawatt hours.

Q. How does the Revised Protocol treatment of hydro and Mid-Columbia contracts differ from the 2017 protocol?

A. The Revised Protocol performs a similar calculation to adjust for the Pacific hydro endowment. However, the Revised Protocol evaluates the cost of hydro resources against all other resources, including those added after 2005. The revised protocol is forecasted to allocate fewer hydro endowment benefits to Oregon relative to the 2017 Protocol.

Q. What is the Equalization Adjustment?

A. The Equalization Adjustment is a $2.6 million annual charge to Oregon customers. This charge does not exist under the Revised Protocol and it does not replace any charges under the Revised Protocol.

Q. Please compare rate case restrictions under the 2017 Protocol to those under the Revised Protocol.

A. The 2017 Protocol restricts PacifiCorp from filing a rate case with rates effective before January 1, 2018. The Revised Protocol would not restrict future rate cases. The latest filing date that would result in an effective date before January 1, 2018 is February 28, 2017.

Q. Are there any other differences between the 2017 Protocol and the Revised Protocol that the Commission should be aware of?

A. Yes, in addition to the three substantive differences mentioned above, there are several minor differences in the two allocation mechanisms. The 2017 Protocol includes a financial commitment by PacifiCorp to continue evaluating the costs of alternate allocation mechanisms. The 2017 Protocol treats Qualified Facility contracts as system costs while the Revised Protocol directly assigns Qualified Facility contracts to the jurisdiction that approves them. Direct Assess loads are treated differently under the Revised Protocol relative to 2017 Protocol. The Revised Protocol allocates simple cycle combustion turbines in a manner more consistent with peaking resources while the 2017 Protocol treats these as general thermal generation units.

ISSUE 3, ANALYSIS OF 2017 PROTOCOL

Q. Do you support Oregon's use of the 2017 Protocol?

A. Yes. In the case that the 2017 Protocol is not adopted, Oregon will revert to the Revised Protocol. Staff's analysis tests the performance of the 2017 Protocol relative to the Revised Protocol. The 2017 Protocol will likely result in lower rates for Oregon customers than if Oregon were to default to the Revised Protocol. The 2017 Protocol benefits Oregon customers relative to the Revised Protocol in three main ways:

- Larger ECD
- Delay of general rate case
- Continued study of system costs.

These benefits must be weighed against the annual Oregon Equalization Adjustment.

Q. Please evaluate the ECD provided in the 2017 Protocol.

A. PacifiCorp forecasts that the ECD under the Revised Protocol would be less than that under the 2017 Protocol. Table 1 below summarizes the forecasted values. In each year 2017 Protocol provides substantial savings relative to the Revised Protocol. The values in this table include the different treatment of Qualified Facilities. The treatment of Qualified Facilities account for approximately $1.4 million to $3 million of the savings in Table 1.[5]

[5] *See* Exhibit 109 Response to OPUC to PAC DR 31

Table 1 ECD Estimate in Millions

	2017	2018	2019
2017 Protocol*	$8.7	$10.0	$9.2
Revised Protocol**	$6.3	$7.1	$5.9
2017 Protocol Savings	$2.4	$2.9	$3.3

* See Exhibit 110 OPUC to PAC DR 34
** See Exhibit 109 Respoonse to OPUC to PAC DR 31

Q. Please evaluate the rate case stay out provision in the 2017 Protocol.

A. The rate case stay out provision prevents PacifiCorp from filing a rate case before February 28, 2017. The value of this provision depends on when PacifiCorp would file a rate case earlier absent the provision, and what the final rate change would be. PacifiCorp has been experiencing rapidly escalating costs recently. From 1998 through 2015 PacifiCorp rates have increased at an average annual rate of 4.9 percent per year.[6] Since 2006 PacifiCorp has filed six general rate cases, resulting in an average rate increase of 3.3 percent per case. PacifiCorp's most recent rate case was filed on March 1, 2013, with rates effective January 1, 2014.[7]

Prices have held relatively stable since 2014. Capital costs have decreased 20 to 40 basis points since PacifiCorp's last rate case. PacifiCorp's rate base has remained relatively stable since the last rate case.

If PacifiCorp filed a rate case before March 1, 2017, I would expect that the rate increase would be relatively small given low inflation, stable rate base, and reduced cost of capital. The minimum rate increase resulting from a PacifiCorp general rate case was 0.6 percent in Docket No. UE 246. It is reasonable to

[6] *See* Exhibit 104 Response to OPUC to PAC DR 35
[7] *See* Exhibit 105 Response to ICNU to PAC DR 20 Part 6.

assume that the 2017 rate case stay-out clause delayed a relatively small rate increase for one year. The smallest general rate increase in the last ten years has been 0.6 percent.[8] Over one year a 0.6 percent increase in Oregon rates is equivalent to approximately equal to $7.3 million in revenue.[9] The 2017 Protocol would be in effect for two years, with a possibility of a third year.

Q. What is the forecasted net impact of adopting the 2017 Protocol relative to reverting to the Revised Protocol?

A. Table 2 below summarizes the yearly impact of the 2017 Protocol relative to reverting to the Revised Protocol. Oregon is forecasted to experience a substantial benefit in 2017 and a minor benefit in 2018 and 2019.

Table 2 Net Impact of 2017 Protocol in Millions

	2017	2018	2019
ECD/QF Savings	$2.40	$2.90	$3.30
Stay-out Clause	$7.30		
Equalization Adjustment	($2.60)	($2.60)	($2.60)
Net Savings	$7.1	$0.3	$0.7

Q. No forecast is perfect. How sensitive is your support of the 2017 Protocol to forecast errors?

A. The Oregon savings generated by the 2017 Protocol is robust to deviations in actual ECD calculations. The EDC floor protects Oregon under the 2017 Protocol from significant decreases in the ECD. In the case of a substantially higher ECD than forecasted, the 2017 Protocol will harm Oregon relative to the

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[8] *See* Exhibit 105 Response to ICNU to PAC DR 20 Part 6.
[9] *See* Exhibit 106 Order No. 13-474 Page 1. This value is calculated as $56 million * 0.6 percent / 4.6 percent.

Revised Protocol. This is because the ECD is capped at $10.5 million. Staff is continuing to analyze the probability that the ECD will exceed the cap. However, the substantial savings of the Stay-out Clause provide Oregon with a large buffer against ECD forecast error. The ECD would have to increase by over 50 percent to an annual average of $13 million per year to substantially erode this buffer.[10]

Q. The 2017 Protocol includes an agreement that PacifiCorp will continue to study alternative inter-jurisdictional allocation methods. What value does this clause bring to Oregon customers?

A. This clause provides a financial incentive for PacifiCorp to perform several studies that OPUC Staff has requested. These studies are important for establishing a baseline for future negotiations. The original approval of the PacifiCorp merger was grounded in an understanding that the merger would result in net benefits, and that these benefits would be shared equitably among the Company's jurisdictions. Utah has consistently expressed a preference for Rolled In rates. However, it is not clear that Rolled In rates will provide an equitable division of the merger benefits. The studies requested by Staff will help to quantify the benefits of the merger, and identify the recipients of the benefits under various allocation methods.

Q. Are there any consequences if PacifiCorp does not complete these studies on or before the agreed upon date?

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[10] This estimate assumes that the historic correlation between the Revised Protocol ECD and the 2017 Protocol ECD continues.

A. Yes. PacifiCorp is required to complete these studies by March 31, 2017. Oregon customers will receive a monthly credit of $216,667 for each month after this date that PacifiCorp has failed to present the study results. This credit is equal to Oregon's monthly Equalization Adjustment.[11]

Q. The Equalization Adjustment appears to be related to an allocation shortfall. Please describe PacifiCorp's alleged allocation shortfall.

A. Bryce Dalley refers to an allocation shortfall in his testimony at PAC/100 Dalley/8 line 6 and Dalley/16 line 20. Mr. Dalley was primarily referring to an allocation shortfall resulting from inconsistent treatment of the Embedded Cost Differential.[12] In 2014 this shortfall was $9,671,323.

Q. Have you identified the cause for PacifiCorp's alleged allocation shortfall?

A. I have confirmed that the majority of this shortfall is due to Utah choosing to treat costs as Rolled In. While most states implement some variation of the ECD, Utah does not incorporate any form of ECD. PacifiCorp's testimony supporting the 2010 Protocol highlights an expectation by PacifiCorp that the Utah Commission would deviate from the 2010 Protocol in favor of Rolled In cost allocation:

"In Utah this cost allocation methodology produces results close to Rolled In so a side agreement between the Company and Utah parties will allow Utah to utilize Rolled In cost allocation methodology for its ratemaking purposes."

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[11] *See* PAC/101 Dalley/16 at lines 7 through 12.
[12] See Exhibit 107 Response to OPUC DR 41

If Utah were to comply with the 2010 Protocol (and the Revised Protocol) the allocation shortfall described by Dalley would be negligible.

Q. Does the Order approving PacifiCorp's merger with UPL identify who bears the costs associated with inconsistent implementation of the 2010 protocol?

A. The Order adopts the 1988 stipulation between parties. This stipulation states "Pacific agrees, however, that its shareholders will assume all risks that may result from less than full system cost recovery if interdivisional allocation methods differ among the merged company's jurisdictions."[13] This indicates that PacifiCorp has agreed that its shareholders will bear the cost of the allocation shortfall caused by Utah's decision not to recognize the West's hydro endowment.

Q. Do you believe that the Equalization Adjustment should be viewed as a partial remedy of the unequal treatment of the ECD?

A. No. PacifiCorp has not sufficiently demonstrated that the use of the Equalization Adjustment as an allocation mechanism is consistent with the 1988 Stipulation. Staff views the Equalization Adjustment as part of a one-time concession that was part of negotiations for a temporary allocation agreement. Staff does not anticipate that a long term allocation agreement will include such an adjustment.

[13] *See* Exhibit Staff/102 OPUC Order No 88-767 at Page 6.

Q. The 2017 Protocol treats Direct Access loads differently than the Revised Protocol. Can you outline the differences and explain why the 2017 Direct Access provisions are appropriate?

A. The Revised Protocol includes Direct Access loads in Oregon allocation factors for existing resources indefinitely.[14] The 2017 Protocol allows permanent Direct Access loads to be excluded from Oregon Allocations after a period of ten years. This reduces the long term burden that Oregon Direct Access customers will place on cost of service (COS) customers. Staff is continuing to confirm that the mechanisms in place under the 2017 Protocol will not burden Oregon COS customers during the period when Direct Access loads are included in Oregon Allocation Factors.[15]

Q. Does the 2017 Protocol specifically address the treatment of Direct Access loads in states other than Oregon?

A. The Protocol does not include any language identifying how Direct Access loads in other states will be incorporated in allocation factors. However, the 2017 Protocol does commit PacifiCorp to informing all parties should any states adopt or change Direct Access programs. Staff understanding is that the 2017 Protocol allows the OPUC to unilaterally choose to include or exclude any states Direct Access load.

Utah recently enacted legislation to allow PacifiCorp's largest customer, Rio Tinto Kennecott, to transition to a Direct Access access customer. The load

[14] Revised Protocol at page 10 states: "Loads of customers permanently choosing Direct Access… will be included in Load-Based Dynamic Allocation Factors for all Existing Resources but will not be included in Load-Based Dynamic Allocation Factors for New Resources."
[15] *See* Exhibit 108 OPUC to PAC DR 44-46.

associated with this customer may exceed that of Oregon's Direct Access customers.

Q. How does the 2017 Protocol treat state specific initiatives such as renewable resource compliance and net metering?

A. The Revised Protocol and the 2017 Protocol treat renewable compliance in an identical manner. The above market costs are assigned on a situs basis. If these resources were to be acquired by PacifiCorp as part of a least cost plan, even if they contribute to compliance, they are treated as system resources. Staff understands this to mean that the above market costs of specific initiatives are situs assigned and the market costs are system assigned.

Q. You have raised some potential issues with the 2017 Protocol in this testimony. Please explain why you support the adoption of this agreement.

A. Despite the issues that Staff has raised, the 2017 Protocol provide a financial benefit to Oregon customers. Staff's primary concern relates to the equity of the Equalization Adjustment. Staff finds that the Equalization Adjustment is an acceptable short term concession in view of PacifiCorp's commitment to provide the type of cost studies that can identify an equitable allocation of the Pacific hydro endowment.

Q. Does this conclude your direct testimony?

A. Yes.

CASE: UM 1050
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

April 1, 2016

WITNESS QUALIFICATIONS STATEMENT

NAME: Lance Kaufman

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE., Suite 100
Salem, OR. 97301

EDUCATION: In 2013 I received a Doctorate degree in economics from the University of Oregon. In 2008 I received a Master of Science degree in Economics from the University of Oregon. In 2004 I received a Bachelor of Business Administration in Economics from the University of Alaska Anchorage.

EXPERIENCE: From March of 2013 to September of 2014 and from September of 2015 to the present I have been employed by the Oregon Public Utility Commission (OPUC). My current responsibilities include analysis of power costs, cost allocations, decoupling mechanisms, and sales forecasts. I have worked on Cost Allocations in the following OPUC dockets: UE 263, UG 246, and UM 1050.

From September 2014 to September 2015 I was employed by Regulatory Affairs Public Advocacy group of the Alaska Department of Law. I have worked on Cost Allocations in the following Alaska Regulatory Commission dockets: U-14-114/115/116/117/118, U-14-104/105/106/107, and U-14-102.

From 2008 to 2012 I was employed by the University of Oregon as an instructor. I taught undergraduate level courses in Microeconomics, Urban Economics, and Public Economics.

CASE: UM 1050
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Direct Testimony

April 1, 2016

ORDER NO. 88-767

ENTERED JULY 15 1988

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UF 4000

In the Matter of the Application of PACIFICORP and PC/UP&L MERGING CORP. for an Order Authorizing the Merger of PACIFICORP and UTAH POWER & LIGHT COMPANY into PC/UP&L MERGING CORP. (to be Renamed PACIFICORP upon Completion of the Merger), and Authorizing the Issuance of Securities, Assumption of Obligations, Adoption of Tariffs, and Transfer of Certificates of Public Convenience and Necessity, Allocated Territory, and Authorizations in Connection Therewith.	ORDER

On September 17, 1987, PacifiCorp, a Maine Corporation (PacifiCorp Maine), and PC/UP&L Merging Corp., an Oregon Corporation (PacifiCorp Oregon), filed an application with the Commission requesting approval of the following transactions:

1. The merger of PacifiCorp Maine and Utah Power and Light Company (Utah Power), with and into PacifiCorp Oregon, with PacifiCorp Oregon to be the surviving corporation, in accordance with an Agreement and Plan of Reorganization and Merger among PacifiCorp Maine, Utah Power and PacifiCorp Oregon, dated August 12, 1987 (Merger Agreement), pursuant to ORS 757.480;

2. The issuance by PacifiCorp Oregon of shares of its common and preferred stocks upon conversion of the outstanding shares of common and preferred stock of PacifiCorp Maine and Utah Power in accordance with the terms of the Merger Agreement, pursuant to ORS 757.410;

3. The assumption by PacifiCorp Oregon of all outstanding debt obligations of PacifiCorp Maine and Utah Power, pursuant to ORS 757.440, and the continuation or creation of liens in connection therewith, pursuant to ORS 757.480;

4. The transfer to PacifiCorp Oregon of all certificates of public convenience and necessity of PacifiCorp Maine, pursuant to ORS 758.015;

5. The transfer to PacifiCorp Oregon of all rights to allocated territory granted to PacifiCorp Maine, pursuant to ORS 758.460;

6. The adoption by PacifiCorp Oregon of all tariff schedules and service contracts of PacifiCorp Maine on file with the Commission and in effect at the time of the merger, pursuant to ORS 757.205;

7. The transfer to PacifiCorp Oregon of all Commission authorizations and approvals granted to PacifiCorp Maine for transactions with controlled corporations or affiliated interests, pursuant to ORS 757.490 and 757.495, and;

8. The transfer to PacifiCorp Oregon of all Commission authorizations and approvals for the issuance of securities by PacifiCorp Maine which have not been fully utilized, pursuant to ORS 757.410.

A prehearing conference was held in this matter on October 7, 1987 to identify parties and establish a procedural schedule. A settlement conference was convened February 13, 1988.

A public hearing was held on April 13-14, 1988, in Salem, Oregon, before Commissioners Ron Eachus, Myron Katz, and Nancy Ryles, and Hearings Officer Samuel Petrillo. Post hearing briefs were filed on May 17, and May 27, 1988.

Parties

The Applicants in this proceeding are PacifiCorp (PacifiCorp Maine or Pacific) and PC/UP&L Merging Corp. (PacifiCorp Oregon) (jointly, Applicants). In addition to the Applicants, the parties to this proceeding are the Public Power Council (PPC), the Bonneville Power Administration (BPA), the Citizens Utility Board (CUB), the Utility Reform Project (URP), Austin Collins, the Pacific Northwest Generating Company (PNGC), and the Commission Staff (Staff). Testimony was presented at the hearing by the Applicants, PPC, BPA, and Staff. URP, PNGC, and Austin Collins did not participate in the hearing or briefing of this case.

PacifiCorp

PacifiCorp Maine is a diversified corporation whose operations include electric utility service, telecommunications, mining, leasing of capital and business equipment, lending against receivables and inventories, and providing equity investments in leveraged lease transactions.

PacifiCorp conducts its electric utility business under the assumed business name "Pacific Power & Light Company" (Pacific, or PP&L). It provides electric service to more than 670,000 retail customers in California, Idaho, Montana, Oregon, Washington, and Wyoming. PP&L serves approximately 396,400 retail customers in Oregon. Its Oregon retail electric operating revenues for the 12 months ending December 31, 1986, were $526,838,000.

Pacific's electric generating resources consist primarily of coal-fired generation and, to a lesser extent, hydroelectric facilities and power supplies purchased from other utilities. Its total resource capability of 5,859 megawatts (mw) includes 3,073 mw from coal-fired resources, 868 mw of system hydro, 1,027 mw of BPA peaking capability, 583 mw of purchased hydro resources, and 308 mw of other resources. During 1986, Pacific met 59.2 percent of its total energy requirements from its thermal resources, 15.3 percent from firm purchases, 14.5 percent from hydro resources, and 11 percent from other resources.

Utah Power

Utah Power provides retail electric service to approximately 510,000 customers in Idaho, Utah, and Wyoming. It does not provide electric service in Oregon.

Utah Power's total resource capacity is 2,946 mw. Approximately 91.5 percent of that capacity is from coal-fired generation, with the remainder from system hydro and other resources. In 1986, Utah Power derived 72.1 percent of its total energy requirements from its thermal facilities, 5.2 percent from its hydro facilities, 0.2 percent from firm purchases, and 22.5 percent from other resources.

Merger Agreement

On August 12, 1987, PacifiCorp Maine, Utah Power, and PC/UP&L Merging Corp. (PacifiCorp Oregon) entered into an Agreement and Plan of Reorganization and Merger (Merger Agreement). The Merger Agreement calls for Utah Power and

PacifiCorp Maine to merge with and into PacifiCorp Oregon, a new Oregon corporation which will be named PacifiCorp contemporaneously with the merger. Under the terms of the Merger Agreement, Utah Power and PacifiCorp Maine will cease to exist on the effective date of the merger, and PacifiCorp

Oregon will succeed to all rights and properties and all debts, liabilities, and obligations of PacifiCorp Maine and Utah Power.

The outstanding shares of common and preferred stock of PacifiCorp Maine will be converted into shares of the new corporation on a one-for-one basis. The common stock of Utah Power will be converted into shares of the new corporation based on a formula derived from the PacifiCorp Maine closing price during a 10-day computation period following final regulatory approval. Except for shares owned by dissenters, outstanding Utah Power preferred stock will be converted to preferred stock of the new corporation. The Applicants contemplate that the transaction will qualify as a tax-free reorganization under the Internal Revenue Code.

If the merger is approved, PacifiCorp Oregon will operate two electrical divisions--one doing business as Pacific Power & Light Company (Pacific Power division) and the other as Utah Power & Light Company (Utah Power division). Pacific Power will continue to serve customers within its existing territory, as will the Utah division. Each division will operate as a separate "profit center" and will have a separate board of directors. The organization and function of each board will be similar to PP&L's existing board of directors.

Although the two divisions will maintain their separate retail identities, the power supply and transmission systems of the Utah Power and Pacific Power divisions will be planned and operated on a single-utility basis. A plan has been developed to further integrate the transmission facilities linking the Pacific Power and Utah Power divisions. Likewise, arrangements will be established to coordinate the dispatch of power to ensure that the merged systems operate efficiently. The specific merger benefits anticipated by the Applicants are discussed below.

Stipulation

On March 3, 1988, the Staff and Applicants entered into a stipulation recommending approval of the application subject to a number of conditions regarding reporting requirements, allocation of merger costs and benefits, future rate cases, and specific approval requests.

a) Reporting Requirements

The reporting requirements of the stipulation require that Pacific shall file semiannual reports demonstrating the effects of the merger, including:

1. Consolidated operating merger benefits achieved;

2. Oregon allocated merger operating benefits achieved;

3. Current bond ratings and an explanation of any change;

4. Description of Pacific's preferred stock and debt series before and after the merger; and

5. Descriptions of all major post-merger additions to generation and system transmission plant and related system facilities, including costs.

The semiannual reports required by the stipulation must be supported by detailed workpapers and shall be submitted in conjunction with the semiannual regulatory results of operations currently received by the Commission. In addition, Pacific must also file monthly and quarterly operating results, construction budgets, and operating budgets used to monitor operating results and plans, irrespective of the stipulation requirements.

The stipulation further provides that Pacific shall also submit reports demonstrating the effects of the merger in all general rate applications and show cause actions initiated by the Commission.

b) <u>Allocation guidelines</u>

The stipulation provides that, within six weeks after the merger has been approved by all authorities, the merged company will initiate a meeting of an allocation committee consisting of representatives from all appropriate regulatory jurisdictions. The function of the committee will be to develop methods for allocating joint costs and benefits of the merger between the Pacific Power and Utah Power divisions. Allocations within each division will be governed by that division's existing jurisdictional allocation methods.

Until final methods for the allocation of merger costs and benefits are developed and adopted, the stipulation provides that certain general guidelines will apply with respect to Pacific's Oregon customers. These guidelines are:

1. Pre-merger generation and transmission facilities of Pacific and Utah Power will remain the responsibilities of the Pacific and Utah Power divisions, respectively.

2. Post-merger additions to generation and system transmission plant and related system facilities due to the merger will be allocated on an equitable basis that is based on sound economic principles and is mutually agreeable to Staff and Pacific.

3. Net power cost changes due to the merger will be allocated on the basis described in paragraph 2 above and shall embody the principle of Pacific's existing allocation Notes 1 and 1A. Net power cost changes will be determined based on the results of three power cost studies: one showing net power costs for Pacific Power separately as if the merger had not occurred; a second showing net power cost for Utah Power separately as if the merger had not occurred; and a third showing net power costs of the merged company.

4. Other cost changes due to the merger will be allocated using equitable allocation methods that (i) embody the principle that incurred costs and benefits follow the cause of such costs and benefits and (ii) are mutually agreeable to Staff and Pacific. In general, costs that can be directly assigned to an operating division will be so assigned.

If Staff and Pacific are unable to reach agreement on an allocation issue, the method of allocation will be determined by the Commission based on the guidelines in the stipulation. Pacific agrees, however, that its shareholders will assume all risks that may result from less than full system cost recovery if interdivisional allocation methods differ among the merged company's jurisdictions.

c) Future Rate Cases

With regard to future rate cases, the stipulation provides that: (i) pre-merger Utah Power rate base assets will be excluded from Pacific's Oregon rate base; (ii) the Staff may propose adjustments to Pacific's embedded debt and preferred stock costs; and (iii) the calculation of post-merger common equity costs will be determined under a method that relies upon the use of comparable companies.

Pacific further agrees that, by the end of the second quarter of calendar year 1989, it will file a general rate case incorporating the estimated merger benefits shown on Exhibit 1 of the stipulation. The filing will include Oregon's allocated share of estimated system merger benefits totaling $59 million. Assuming that final allocation methods attribute approximately 58 percent of system merger benefits to the Pacific division, and 50 percent of the Pacific division merger benefits to Oregon, the general rate filing will include $17 million in cost savings due to the merger.

In addition, the stipulation provides that Pacific shall not "effect any overall increase in electric rates in Oregon prior to the end of calendar year 1992." While Pacific may propose rate spread/rate design changes during that time frame, such proposals would first have to approved by this Commission.

Lastly, Pacific has agreed to hold Oregon customers harmless if the merger results in greater net costs to serve Oregon customers than if the merger had not occurred. Pacific witness Reed testified that this commitment is not limited in duration and shall apply both before and after application of the residential exchange credit from BPA.

d) Specific Approvals

With respect to the specific approvals requested by Pacific in its application, the stipulation provides:

(1) Pacific will demonstrate, when necessary, the need for any existing certificates of public convenience and necessity;

(2) Tariffs will not be changed between the time of Commission approval and closing of the merger except as specifically approved by the Commission;

(3) The terms and conditions of affiliated interest and controlled corporation contract approvals will be unchanged in all material respects at the time of the merger, except as specifically approved by the Commission;

(4) Information regarding the shares of PacifiCorp Oregon common stock to be issued upon consummation of the merger will be unchanged in all material respects at the time of the merger, and if the issuance of additional shares is required, the Applicants will promptly amend their application;

(5) Pacific will file with this Commission the Forms 10-K, 10-Q, and 8-K submitted to the Securities and Exchange Commission for Pacific and Utah Power prior to the date an order is issued in this application. Thereafter, Pacific will report any material changes in merger-related contingent liabilities to the Commission;

(6) The Applicants accept all terms and conditions attached to existing authorizations for the issuance of securities.

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STAFF EXHIBIT 103

Exhibits in Support
Of Direct Testimony

April 1, 2016

MULTISTATE DIALOGUE ON

PACIFICORP INTERSTATE ALLOCATION OF COSTS AND REVENUES

Draft goal statement and process alternative for Commissions

Problem Statement

The current allocation of PacifiCorp's costs and revenues among the affected states does not currently provide PacifiCorp an opportunity to recover all of its costs. With this in mind, and with the knowledge that each states may choose different market-structure policies, the states of Oregon, Utah, Washington, Wyoming, and Idaho are willing to attempt a resolution among the states regarding the allocation of PacifiCorp's costs and revenues. We direct our respective staffs and interested parties to achieve a resolution, using a public process, whereby PacifiCorp has the opportunity to recover all of its costs and, the issues on the following two pages are addressed. We leave open the issue of whether the resolution reached is in the public interest in each of our states.

Process

We understand that each state has different statutes and regulations to which it must abide. Generally, we envision that the staffs of each state commission or advocacy agency, along with interested participants or parties, would jointly hold multi-day workshops and settlement conferences with a goal of reaching a global resolution. Once such resolution is reached, each state would proceed with the necessary legal mechanism to review the resolution. This could occur state by state, or could occur with joint hearings by several or all of the states.

Notwithstanding the various state statutes, a few general procedural understandings are necessary:

1. The state commissions may decide to hold a joint public meeting whereby we formally direct our staffs to seek global resolution assuming the problem statement holds.
2. At some point, each state will conduct a contested case or similar proceeding consistent with its Administrative Procedures Act to review the resolution. Each state will determine whether a new docket is appropriate, or whether this matter will be held within its current PacifiCorp restructuring docket.
3. Any state may petition to intervene in another state's proceedings. To ensure broad discussions and reaching resolution, the state staffs should not oppose such intervention
4. Due to the numbers of potential parties in this process, PacifiCorp or the states will share the cost of using a facilitator to convene and manage the multi-state workshop and settlement conference process.
5. The facilitator will explore with the parties mechanisms to assure adequate participation by **customer** groups.
6. All workshops and settlement conferences will be open to the public. These meetings will likely take place over groups of days.

Multistate Allocation Issues Faced by PacifiCorp

PacifiCorp faces a number of issues related to the interstate allocation of its costs. In each case, these issues could cause the states' shares of PacifiCorp's costs to add to less than the total. In several cases, PacifiCorp has already experienced allocation shortfalls. Additional issues indicate that this problem may well become more significant in the future.

Actual Allocation Shortfalls

- Adoption of "rolled-in" methodology by Utah. At the time of the merger between Utah Power and Pacific Power, a taskforce of staffs of the Commissions regulating PacifiCorp developed several different methods of allocating PacifiCorp's costs. The group ultimately adopted the "modified accord" allocation method. In recent years, the Utah Commission has adopted the "rolled in" allocation methodology, which allocates a lower share of PacifiCorp's power costs to Utah.
- Sale of Centralia. In 2000, PacifiCorp sold its Centralia generating station at a price higher than the plant's net book value. All of the state commissions regulating PacifiCorp held hearings to approve the sale and determine the appropriate ratemaking treatment. In total, the various state commissions ordered that more than 100% of the gain on Centralia be returned to ratepayers, causing PacifiCorp to incur a loss on an otherwise profitable sale.
- Allocation of special contracts. The "modified accord" allocation method provides that the costs and revenues from certain interruptible retail special contracts be allocated across PacifiCorp's system like power supply costs. In PacifiCorp's most recent rate case, the Oregon staff and other parties proposed that costs and revenues from these contracts be assigned "situs" to the states in which the customers are located. Since none of the relevant special contracts are with Oregon customers, this reduces costs that are allocated to Oregon and creates an allocation shortfall.
- Responsibility for load growth. In Oregon docket UE 116, the Commission approved a stipulation regarding deferral of excess power costs. That stipulation calculates the amount of Oregon power costs based on actual Oregon loads rather than factors specified in the "modified accord" allocation method. Since Oregon is growing more slowly than PacifiCorp's system as a whole, this results in an allocation of less power cost to Oregon and creates an allocation shortfall.
- SG allocation factor. In a previous rate case, the Utah PSC determined that one of the allocation factors shared by the "modified accord" and "rolled in" allocation methods was inappropriate and ordered that rates be calculated on a different number. The Commission's preferred allocation factor allocated fewer costs to Utah.
- Customer accounting and customer service. The "modified accord" method allocates the costs of customer accounting and customer service to the various states based on the number of customers in each state. In a previous rate case, the Utah PSC ordered that these costs be allocated on a different basis, which resulted in fewer costs being allocated to Utah.

Potential Allocation Shortfalls

- Direct access. Ultimate implementation of Oregon's direct access initiative requires PacifiCorp to identify and value a fixed slice of resources serving Oregon load. This "fixed slice" approach is inconsistent with the "modified accord" allocation method, which allocates power costs dynamically, using shares of energy and contribution to peak demand in each year.
- Significant load changes. PacifiCorp faces a variety of situations that could lead to loss of significant amounts of load. These include municipalization, direct access, and sale of service territory. The various states have very different views regarding the implications of these developments. If PacifiCorp were to sell its California service territory, for instance, it seems unlikely that all states will agree to pay their shares of the fixed costs of generation presently used to serve California customers. Equally, there are circumstances in which a state's load could grow significantly and disputes are likely regarding these. Examples include a new large single load or an acquisition of new service territory.
- New generation. States have divergent policy goals regarding new generation. Some states support integrated resource planning. Some states, like Oregon, have given policy support to supplying new load from market sources. There has been substantial policy support in Washington State for a renewable portfolio standard. Other states have not indicated a willingness to pay more than traditional cost-effective amounts. Parties in slow growing states have indicated that they would not support recovery of the costs of even cost-effective new generation if the need for that generation was prompted by another state. Additionally, states are likely to disagree regarding the types of generation to be built, appropriate reserve margins, and approaches to controlling air emissions from PacifiCorp's existing plants.
- Multiple cost allocation methodologies. In addition to the adoption of "rolled in" allocation by Utah, other states have indicated that they might consider alternatives. The Idaho staff is presently supporting "rolled in" allocation. The Washington staff has indicated a desire to revisit the use of "modified accord," favoring the use of prior allocation methods.
- Treatment of wholesale sales and purchases. Some jurisdictions have proposed that wholesale sales and purchases be allocated in a manner different than the "modified accord" method. For example, one state has proposed the establishment of a separate FERC jurisdiction. In addition, states have considered a "situs" assignment of the costs of QF contracts.
- State taxes. As other allocation issues are raised, states are likely to want to revisit the system-wide allocation of state-specific taxes.

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STAFF EXHIBIT 104

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April 1, 2016

OPUC Data Request 35

From 1998 through 2015, what has been the average percentage change in PacifiCorp overall Oregon retail rates?

Response to OPUC Data Request 35

The average annual percentage change in PacifiCorp's overall Oregon retail rates from 1998 through 2015 is 4.9 percent.

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STAFF EXHIBIT 105

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April 1, 2016

ICNU Data Request 20.6

Please refer to PAC/101, Dalley/16:12-20. For each of the past 10 years, 2006-2015, inclusive, please identify percentage annual rate increases attributable to:

(a) general rate case increases; and

(b) non-general rate case increases, including but not limited to any increases attributable to deferral amortizations, single-issue rate cases, or rate adjustment mechanisms.

Response to ICNU Data Request 20.6

Please see Attachment ICNU 20.6. General rate case increases are shown on separate lines.

OR UM 1050
ICNU 20.6

Staff/105
Kaufman/2

Oregon Docket/Advice No.	Filing	Rate Effective Date	Net Change Overall %
UE 170	TAM	1/06	0.4
06-002	Cancel Y2K Surcharge	2/06	(0.0)
UE 170/06-011	Klamath Basin Irrigation Year 1	4/06	0.2
06-008, 06-010	SB1149 Phase VI plus Shopping Incen. Surcharge	5/06	0.3
UE 170	GRC reconsideration	7/06	0.8
06-015	BPA Credit Reduction	10/06	0.9
UE 179, 06-016	GRC	1/07	3.8
UE 179, 06-016	TAM and Transaction and Def. Tax Adj.	1/07	1.8
07-004	Misc. Deferred Accounts Credit Elimination	2/07	0.2
07-005	SB1149 Phase VII	3/07	0.2
07-010, 07-013	Intervenor Funding and BPA Credit Suspension	6/07	6.5
07-015	Cancel Trail Mine Surcharge	8/07	(0.3)
UE 191	TAM	1/08	2.5
07-022, 07-026	ECC and Transaction and Def. Tax Adj. Elimination	1/08	0.7
08-004	Klamath Irrigation Year 3 and Large SB1149 Adj. Elim.	4/08	(0.8)
UE 177, 08-008	Income Tax Adjustment and Intervenor Funding	6/08	2.9
08-011	BPA Credit Return	11/08	(2.2)
08-016	Residential & Small SB1149 Adj. Elimination	11/08	(0.2)
UE 199, UE 200, 08-019, 08-017, 08-018	TAM, RAC, Renew Def, Ind. Evaluator, Property Sales	1/09	4.8
09-001	RAC Revision	1/09	0.6
09-004, 09-005	Intervenor Funding and Shopping Incen. Surcharge	2/09	(0.2)
09-006	Klamath Irrigation Year 4	4/09	0.0
UE 177	Income Tax Adjustment	06/09	(0.8)
09-013	BPA Credit Increase	10/09	(0.7)
UE 207, 09-015, 09-017	TAM, RAC Deferral, ECC	1/10	1.0
UE 210	GRC	2/10	4.8
UE 219	Klamath Dam Removal Surcharges	3/10	1.7
10-004	Shoping Incentive Surcharge Cancellation	3/10	(0.0)
09-018	ECC	4/10	0.1
10-006	RAC Deferral	4/10	0.1
10-011	Income Tax Adjustment	6/10	(1.5)
10-015, 10-014	Prop. Sales and Trans. Plan-Oregon Cancellation	8/10	(0.1)
UE 217	GRC	1/11	7.9
UE 216, 10-015, 10-021	TAM, Property Sales, RAC Deferral	1/11	5.9
11-010	Independent Evaluator	5/11	(0.1)
11-009	Income Tax Adjustment	6/11	1.0
11-014	BPA Credit Change	10/11	0.5
11-017	RAC Deferral	11/11	(0.4)
UE 227, 11-019, 11-020, 11-021	TAM, OSIP, ECC, 2010 Protocol Adj.	1/12	4.5
12-006	Klamath Irrigation Year 7	4/12	0.0
12-009	MEHC CIC Adj Cancelation	5/12	(0.2)
12-010	Income Tax Adjustment Cancelation	5/12	(1.3)
12-015	Grid West Adjustment Cancelation	11/12	0.0
UE 246	GRC	1/13	0.6
UE 245, 12-020	TAM, ECC	1/13	0.3
12-019, 13-001	OSIP, 2010 Protocol Cancelation	2/13	0.3
13-008	Property Sales	4/13	0.3
13-011	Transmission Investment Adj.	6/13	0.9
13-010	Klamath Dam Removal Surcharges	6/13	0.1
13-016	BPA Credit Change	10/13	(0.2)
13-017	Distribution Safety Surcharge	11/13	0.1
UE 263	GRC	1/14	2.0
UE 264	TAM	1/14	(0.2)
13-022	Cancel UE 246 Gen. Credit	1/14	1.5
13-019, 13-025	OSIP, RAC Deferral	2/14	0.2
14-008	Generation Investment Adjustment	6/14	1.8
14-009	ECC	7/14	(0.1)
UE 287, 14-012, 14-014	TAM, OSIP, ECC	1/15	0.2
15-001	RAC Deferral	2/15	(0.0)
15-002	Distribution Safety Surcharge Cancellation	3/15	(0.1)
15-009	Deer Creek Mine Transaction	6/15	0.2
15-011	BPA Credit Change	10/15	(1.6)
UE 296, 15-016	TAM, Intervenor Funding	1/16	0.9

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PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 106

Exhibits in Support
Of Direct Testimony

April 1, 2016

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 263

In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision.	ORDER

DISPOSITION: STIPULATION ADOPTED

I. SUMMARY

In this order, we adopt the stipulation of the parties, attached as Appendix A, regarding PacifiCorp, dba Pacific Power's proposed rate increase, including an overall revenue requirement increase of $23.7 million, or an overall rate increase of 1.9 percent, effective January 1, 2014. We order Pacific Power to file new tariffs reflecting the modifications and conditions set forth in the stipulation.

II. INTRODUCTION

Pacific Power is a public utility providing electric service in the State of Oregon within the meaning of ORS 757.005, and is subject to the Commission's jurisdiction with respect to the prices and terms of service for its Oregon retail customers. Pacific Power provides electric service to approximately 580,000 retail customers in Oregon.

On March 1, 2013, Pacific Power filed its request for a general rate revision under ORS 757.205 and ORS 757.220, seeking a revenue requirement increase to base rates of $56.0 million or 4.6 percent.[1] In its filing, Pacific Power used a historical base period of the 12 months ended June 2012, with normalizing and *pro forma* adjustments to calculate a 2014 calendar year future test period. We suspended the tariff sheets for investigation.[2]

During the course of the proceedings, the following were granted party status in this docket: the Industrial Customers of Northwest Utilities (ICNU); Fred Meyer Stores and Quality Food Centers, divisions of the Kroger Co. (Kroger); Noble Americas Energy Solutions (Noble); Portland General Electric Company (PGE); Wal-Mart Stores, Inc; and the League of Oregon Cities, Inc. The Citizens' Utility Board of Oregon (CUB) intervened as a matter of right under ORS 774.180.

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[1] The proposed increase to net rates was $56.2 million or 4.7 percent as a result of resetting the Rate Mitigation Adjustment to reflect forecast customer loads by rate schedule.
[2] Order No. 13-076 (Mar. 7, 2013) (suspended the filing for review for a period not to exceed nine months from March 31, 2013).

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OPUC Data Request 41

Please refer to PAC/100 Dalley/6 at line 9.

a. Please provide the 2014 and 2015 Allocation shortfall for PacifiCorp resulting from the "inconsistent implementation of the 2010 Protocol."
b. Please identify all inconsistencies in the implementation of the 2010 Protocol.
c. Please confirm the shortfall values developed in part (a) above assume Washington is on the 2010 Protocol proposed by PacifiCorp including the projected ECD values.
d. Please identify what the shortfall would have been if Washington, Oregon, California, Idaho, and Wyoming allocated according to the 2010 protocol using dynamic ECD and Utah allocated according to the method actually used in Utah.

Response to OPUC Data Request 41

a. When Mr. Dalley referred to "inconsistent implementation of the 2010 Protocol" this reference was primarily directed at each state's treatment of the ECD. The 2015 Results of Operation report is not yet available, for 2014 please refer to Attachment OPUC 41-1.

b. Please refer to Attachment OPUC 41-2. This is not an exhaustive list but a summary of items discussed by the Broad Review Work Group.

c. Confirmed.

d. Please refer to Attachment OPUC 41-3.

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OPUC 41

Attachment 41-1

December 2014	CA	OR	WA	WY	UT	ID	FERC	Shortfall[1]
ECD	(22,526)	(8,163,789)	(744,783)	(1,635,273)	-	835,542	59,506	(9,671,323)

(1) Assumes OR and WY use a dynamic ECD, Utah applies no ECD, and ID, CA, FERC and WA use the fixed ECD from the proposed 2010 Protocol.
(2) The Fixed ECD as calculated in the 2010 Protocol netted to zero.
(3) Data based on Oregon December 31, 2014 results of operations.

ECD Unintended Consequences

Past:

- 2010 Protocol Fixed vs. Dynamic ECD
- Purchased power expense included with no offset for sales for resale
- New renewable resources
- Normalized benefits with no true-up for Actual results

Present:

- Federal mandates impact on ECD for Pre-2005 resources
  - EPA Clean Air initiatives
    - Scrubbers increase cost and reduce plant generation - benefits West
    - Retirement of low cost coal plant - benefits West
    - Gas conversion - benefits West
- Post-2004 Resources may have an impact on Pre-2005 generation
  - Increases reserve requirement
  - Transmission constraints
- Replacement power from Owned Hydro and Mid-C Contracts?
  - Owned Hydro dropped from 4.4m MWh 1989 to 3.6m MWh today
  - Mid-Columbia Contracts dropped from 2m MWh in 2006 to 100k MWh by 2019
  - Grant Reasonable tied to market prices, allocation based on other Mid-C contracts
- Depreciation study – changing plant lives

Possible Future Impacts:

- 111(d) impacts
- Energy Imbalance Market Impacts

OR UM 1050
OPUC 41

Attachment 41-3

December 2014	CA	OR	WA	WY	UT	ID	FERC	Shortfall
Company Owned Hydro	(662,167)	(10,890,996)	(3,425,005)	(5,401,468)	-	-	-	(20,379,636)
Company Owned Hydro	316,132	5,199,591	1,635,169	3,136,736	-	1,159,559	77,917	11,525,105
Mid-C Contract	(173,737)	(6,373,346)	(1,472,485)	(1,723,859)	-	(637,260)	(42,821)	(10,423,508)
Mid-C Contract	237,176	3,900,962	1,226,776	2,353,318	-	869,953	58,457	8,646,642
Total ECD	(282,595)	(8,163,789)	(2,035,544)	(1,635,273)	-	1,392,252	93,553	(10,631,396)

Using Oregon December 31, 2014 ECD included in the Results of Operations

Does not differentiate by state based on differences in authorized ROE, capital structure or normalizing adjustments

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April 1, 2016

Oregon

Kate Brown, Governor

Public Utility Commission
201 High Street Suite 100
Salem, OR 97301
Mailing Address: PO Box 1088
Salem, OR 97308-1088
Consumer Services
1-800-522-2404
Local: (503) 378-6600
Administrative Services
(503) 373-7394

March 28, 2016

Data Request Response Center
PacifiCorp
825 NE Multnomah St. Suite 2000
Portland, OR 97232
datarequest@pacificorp.com

RE:	Docket No.	Staff Request No.	Response Due By
	UM 1050	DR 44-46	April 11, 2016

Please provide responses to the following request for information. Contact the undersigned before the response due date noted above, if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with cell formulae intact.

44. Please refer to Article X of the 2017 Protocol. Please provide an illustrative table of the cost impact (net of both offsets from off-system sales and SE and SG allocations) to Oregon Cost of Service customers as a result of Direct Access loads under the following scenarios:
    a. Market variable costs are less then PacifiCorp variable costs;
    b. Market variable costs equal PacifiCorp variable costs; and
    c. Market variable costs are greater than PacifiCorp variable costs.
45. Please explain how the 2017 Protocol allows Oregon customers to receive the benefit of freed up generation resulting from Direct Access, given that Direct Access loads will continue to be assigned as PacifiCorp system-Oregon loads.
46. Please refer to Article X of the 2017 Protocol. Please confirm that Oregon Direct Access loads are excluded from all energy based load allocation calculations. If confirmed please identify the language in the 2017 Protocol supporting this confirmation.

Non-confidential responses should be sent via electronic mail to puc.datarequests@state.or.us.

Confidential information should not be sent via electronic mail. Instead, please file an original and one copy, or a CD containing the confidential response if it is voluminous. Paper copies of confidential responses must be on Yellow Paper and clearly marked "Confidential." CDs must be clearly marked "Confidential."

Please send your confidential responses to the attention of Kay Barnes, PO Box 1088, Salem, OR 97308-1088 and send a redacted version via electronic mail to (puc.datarequests@state.or.us).

One complete copy of the confidential response needs to be filed to the attention of counsel for PUC Staff, Jason Jones, Department of Justice, 1162 Court St NE, Salem, OR 97301-4096; **and** electronically at (jason.w.jones@state.or.us).

/s/ Marc Hellman
Administrator
Rates, Finance & Audit
(503) 378-6355
Marc.hellman@state.or.us

Staff Initiator: Lance Kaufman

cc: Service List: UM 1050 (electronic only)

CASE: UM 1050
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 109

Exhibits in Support
Of Direct Testimony

April 1, 2016

OPUC Data Request 31

For the years 2017, 2018 and 2019, provide the projected values of the Oregon dynamic ECD under Revised Protocol. Please explain the reasons for any significant differences between the annual values of the ECD under Revised Protocol and the projected values under the 2017 Protocol.

Response to OPUC Data Request 31

Please see the direct testimony of Mr. Steven R. McDougal PAC/200, Page 7, lines 17-18, for the Company's projected values of the Oregon dynamic embedded cost differential (ECD) for the years 2017 and 2018. The projected value of the Oregon dynamic ECD under Revised Protocol for the year 2019 is $5.9 million.

There are many factors that cause differences between a Revised Protocol and 2010 Protocol dynamic ECD. Some of the most significant factors are:

- The QF differential component of the Revised Protocol ECD, which does not exist under the 2010 Protocol. During the 2016 through 2019 time period, inclusion of the QF differential component reduces Oregon's benefit under the Revised Protocol ECD by approximately $1.4 million to $3 million, depending on the year.

- The west hydro differential component in the 2010 Protocol is calculated as the differential between the west hydro embedded costs and the pre-2005 all other generation resources. Under Revised Protocol, the west hydro differential component compares west hydro embedded costs to all other generation resources. During the 2017 through 2019 time period, the pre-2005 all other generation resources embedded costs are higher on a $/MWh basis than all other generation resources used in the Revised Protocol. Accordingly, using pre-2005 resources provides approximately $1 million of additional value to Oregon's 2010 Protocol dynamic ECD.

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STAFF EXHIBIT 110

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April 1, 2016

OPUC Data Request 34

Provide PacifiCorp's latest forecast of Oregon dynamic ECD values from 2016 through 2019, inclusive.

Response to OPUC Data Request 34

As reflected in Steve McDougal's direct testimony, the Company's projections for the Oregon ECD credit are $8.2 million for 2016, $8.7 million for 2017, and $10.0 million for 2018 (PAC/200, p. 7). The projection for 2019 is $9.2 million.