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January 27, 2011

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OREGON PUBLIC UTILITY COMMISSION
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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.

Enclosed for electronic filing in the above-captioned docket is the Public Utility Commission Staff's Reply Testimony.

/s/ Kay Barnes
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PUBLIC UTILITY COMMISSION
OF OREGON

UM 1050

STAFF REPLY TESTIMONY OF

GEORGE R. COMPTON

In the Matter of
PACIFICORP
Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol.

January 27, 2011

CASE: UM 1050
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Reply Testimony

January 27, 2011

INTRODUCTION

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

A. My name is George R. Compton. I am a Senior Economist, employed by the Economic Research and Financial Analysis Division of the Public Utility Commission of Oregon (OPUC or Commission). My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551. I represent OPUC staff (Staff) in this docket.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/501.

Q. What is the purpose of your testimony?

A. My testimony describes the various elements of the inter-jurisdictional allocations protocols that are the subject of this docket and presents Staff's recommendations regarding Commission ratification of the proposed amendments to the Revised Protocol known collectively as the 2010 Protocol. For the past several years, the Revised Protocol has been the primary mechanism by which production and transmission costs are allocated among most of the six jurisdictions served by PacifiCorp (or Company).[1]

Q. What is Staff's recommendation to the Public Utility Commission of Oregon with regard to adopting the 2010 Protocol for ratemaking/interjurisdictional cost allocations purposes?

A. I recommend adopting the 2010 Protocol, subject to three conditions that I describe later in this testimony. Criticisms appearing later in this testimony notwithstanding, it is Staff's considered judgment that in view both of the benefits associated with approval and the risks associated with its rejection, approval of this new Protocol is warranted. Cost allocations to Oregon under the 2010 Protocol are projected to generally come quite close to what would have been the allocations under the Revised Protocol.[2] It is only in the last year of the formal effective period, 2016, that Oregon's revenue requirement under the

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[1] The six jurisdictions are Utah, Oregon, Wyoming, Idaho, Washington, and California. Washington does not recognize the Revised Protocol for allocations purposes. Oregon's ratification of the Revised Protocol occurred with OPUC Order No. 05-021, dated January 12, 2005.

[2] *See* Exhibit PPL/208 McDougal/1.

2010 Protocol would exceed the projected revenue requirement under the Revised Protocol by more than 0.25 percent. Even then the projected differential is only 0.5 percent. In two of the first three years under the 2010 Protocol the Oregon allocation would be less than what would have been the allocation under the Revised Protocol.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Topic 1 – A Brief History of PacifiCorp and the Multi-State-Process (MSP) Page 3
Topic 2 – Regulatory Objectives Pertaining to the Cost Allocations Process Page 5
Topic 3 – Key Elements of the Revised Protocol Page 8
Topic 4 – Critiquing the Revised Protocol Page 10
Topic 5 – Key Elements of the 2010 Protocol: A Critical Assessment Page 23
Topic 6 – Elements Under The 2010 Protocol For Protecting Oregon Rate-Payers Page 30
Addendum – A Critique of Rolled-In Page 34

Q. Did you prepare exhibits associated with your testimony?

A. Yes, they are listed as follows:

Staff/502 – An Algebraic Demonstration that the Embedded Cost Differential (ECD) for Hydro Power Can Produce Allocations Equivalent to its Direct Assignment

Staff/503 – Alternative Sum-of-the-Monthly-Coincident-Peak Allocators for Oregon

Staff/504 – The Recent Relationship Between Production Plant Additions and Transmission Plant Additions

Staff/505 – The Impact on Oregon of the 2010 Protocol's Proposed Levelizing

Staff/506 – An Illustrative Exercise Comparing Potential Outcomes of Alternative Inter-Jurisdictional Production Cost Allocation Approaches in the Presence of a Hydro Endowment

Q. Were formal Data Requests filed at your behest?

A. Yes. A total of 18 data requests were made of the Company regarding multiple facets of existing practices and results.

TOPIC 1 – A BRIEF HISTORY OF PACIFICORP AND THE MULTI-STATE-PROCESS (MSP)

Q. Would you please provide us with a very brief history of PacifiCorp and the multi-state process by which inter-jurisdictional allocations are addressed?

A. Yes. A little over twenty years ago, Portland-based Pacific Power and Light (PP&L) acquired[3] Salt Lake City-based Utah Power and Light (UP&L) and named the consolidated company PacifiCorp. For a few years thereafter the states having jurisdiction over PacifiCorp's retail electricity business were able to maintain a workable consensus regarding the methods used to allocate the generation/production and transmission resources which they used more or less in common.[4] Subsequently, faced with "the lack of agreement among regulatory jurisdictions regarding the Company's inter-jurisdictional cost allocation process" and other developments, PacifiCorp proposed as a remedy to reconfigure the utility into individual state distribution companies that would receive power from the erstwhile parent (or subsidiary/affiliate) on a wholesale basis.[5] In response to requests by some state regulators and others to pursue less radical means for resolving the concerns, PacifiCorp initiated discussions that led to the adoption of the Revised Protocol in 2005 by Utah, Oregon, Wyoming, and Idaho—with the adoption by Utah and Idaho being subject to a rate cap. Washington rejected the Revised Protocol and has continued since 2006 to allocate costs via a method of its own creation.[6] California bases its rates on the Revised Protocol without formally adopting it. The Revised Protocol

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3 Some would say "merged with," but PP&L was the moving party, and the new company's headquarters remained in Portland, as did most of the Company's officers and directors. Perceived benefits to Oregon, a state which appeared at the time to be growing faster than Utah, included an ability to utilize a major transmission corridor to the Southwest, plus enjoy access to UP&L's generous supply of coal-fired baseload capacity.

4 The Accord and Modified Accord were titles of the agreements.

5 *See* PPL/100 Kelly/2&3.

6 It is labeled the "Western Control Area Allocation Methodology."

has provided for ongoing discussions among the states through the Multi-State Process (MSP).[7]

A key element in persuading the states to endorse the Revised Protocol was a PacifiCorp study that compared revenue requirement projections under that allocations methodology with the methodologies that were favored or already in use in 2004 by the respective state regulatory agencies.[8] Utah in particular was persuaded by the prospects of the Revised Protocol producing—after a few years—smaller allocations for that state than would be produced by its favored approach, which was termed Rolled-In.[9] That expectation has not been fulfilled,[10] leading Utah (joined by Idaho) to petition the MSP to come up with an alternative allocations approach.

Q. From your Witness Qualification Statement I note that you were employed by the Utah Division of Public Utilities (the equivalent of a commission's permanent advocacy staff) for much, if not all, of the time when the history you just described was occurring. Were you a participant on behalf of Utah in the various protocol negotiations?

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[7] The MSP has entailed a Standing Committee (comprised of a commission staff person from each of the four states that adopted the Revised Protocol), an informal working group (accessible by any and all interested parties), a professional facilitator, and extensive technical and other support being provided by the Company.

[8] Oregon and Wyoming were using the Modified Accord and Utah had unilaterally shifted to Rolled-In. Under a fully rolled-in approach, all generation and transmission resource costs are averaged together—i.e., without regard to origin or location—to be "shared and shared alike." Most conspicuously, under Rolled-In the Northwest's (collectively the states of Oregon, Washington, and California) hydroelectric generation facility endowment (hydro endowment) would not be recognized as an asset primarily benefiting the Northwest.

[9] Lower-case "rolled-in" shall refer to the general approach of allocating costs that have been averaged across resources that serve a common function, e.g., generation/production. In the case of generation, transmission, and selected other non-production resources, their costs are allocated to the jurisdictions as a function of their relative shares of the system load(s). Capitalized "Rolled-In" shall refer to the entire package used or preferred by Utah in allocating system resources. Under Rolled-In, for example, production demand costs are allocated according to the jurisdictions' shares of the twelve monthly system coincident peak loads. Depending upon the circumstances, credible arguments can be made for allocating demand costs on the basis of as few as two, or even one, months' coincident peaks.

[10] Exhibit PPL/201 McDougal/1 compares the results of allocating costs according to the Revised Protocol, Modified Accord, and Rolled-In.

A. While not involved on an ongoing basis in the early negotiations, I was an active participant in the meetings that led up to the adoption of the Revised Protocol itself. I was not a part of the formal crafting of the Revised Protocol.

TOPIC 2 – REGULATORY OBJECTIVES PERTAINING TO THE COST ALLOCATIONS PROCESS

Q. What basic regulatory objectives did Staff apply when reviewing PacifiCorp's application to adopt the 2010 Protocol.

A. They are as follows…and I'll preface this list with the statement that I believe the Company shares these objectives:[11]

- The protocol should lead to allocations that are fair to PacifiCorp's Oregon ratepayers and to the Company's ratepayers in each of the other states served by PacifiCorp.
- The protocol, when followed, should provide PacifiCorp with the opportunity to recover all of its prudently incurred costs.
- Since investor confidence is fostered by explicit jurisdictional consensus, i.e., a uniformity of allocations methodology being endorsed by each state commission, regulatory consensus is preferable to some "promise/expectation" that different methodologies will produce very similar outcomes.
- Similarly, fostering protocol durability is preferable to having an agreement that by design incorporates the uncertainties associated with periodic or imminent renegotiations.
- Administration of the allocations protocol should be reasonably transparent, simple to understand, and not be overly burdensome to administer.
- The allocations should lead neither to undue revenue requirement volatility nor gross unpredictability.
- The method should allow for states to independently pursue their energy policies.

Q. The Company also lists the revised protocol objective of "ensuring [that] PacifiCorp plans and operates its generation and transmission [G & T] on a six-state integrated

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[11] S*ee PPL*/100 Kelly/4&5 for a PacifiCorp list.

basis in a manner that achieves a least cost-least risk resource portfolio for its customers." (S*ee PPL*/100 Kelly/5, lines 3-5.) Do you concur with that goal as well?

A. Not as it is stated. I would say that the allocations protocol should not *interfere* with efficient G & T planning and operations. Obviously desirable is achieving a least cost-least risk resource portfolio for serving PacifiCorp's customers. I do agree that an expectation of failing to recover all of its prudently incurred costs may very well compromise the Company's ability to assemble what is prospectively its least cost-least-risk portfolio. But during the period when Utah relied upon a different allocations approach, including the past several years when Washington also relied upon a different allocations approach, I didn't notice that PacifiCorp departed from planning and operating its system on a cost-efficient six-state integrated basis, nor should it have been expected to do so. What would more certainly harm efficient portfolio expansion would be one or more jurisdiction's disallowance of a particular resource, not the fact that different allocations approaches would lead to somewhat different outcomes among the states. And whatever the ultimate resource mix, it is difficult to see why the Company would not want to continue to operate on a six-state integrated basis in a fashion that minimizes costs and maximizes its operational efficiency.

Q. What you listed were generic regulatory objectives that, I expect, every commission in the nation would accept. Did Staff consider any regulatory objectives specific to the Northwest, e.g., that its hydro endowment[12] be preserved?

A. At least one party has stated that the non-rolled-in cost allocation treatment for hydro facilities should be inviolate.[13] In Staff's view, the fairness consideration—listed above and to be discussed in greater detail later in this testimony—should prevail, now and in the future, whether hydro resources are cheaper or more expensive than thermal resources. As

[12] By "hydro endowment" is meant the opportunity to benefit from the historically lower cost, as compared to the cost of electricity produced by thermal facilities (e.g., coal- or gas-fired power plants), of electricity produced by Company-owned hydro-electric facilities or from hydro-based purchase contracts.

[13] At the Portland Commissioners' Forum (April 6, 2010), the head of Oregon's Citizens' Utility Board (CUB), Bob Jenks, stated that, due to critical non-utility considerations regarding hydro (e.g., fisheries and flood control), Oregonians do not want hydro unit costs to be rolled-in with thermal resource unit costs even if the former came to exceed the latter.

was acknowledged by the Company, an "overarching concern expressed [by Staff and other Oregon parties] in the [MSP] meetings…[was to] retain the hydro endowment in some form." (*See* PPL/100 Kelly/11, lines 25-28.)

Q. Earlier you stated that the "protocol should lead to allocations that are fair to the ratepayers of Oregon and to the ratepayers of all the other states served by PacifiCorp." How do you define "fairness to Oregon ratepayers" in this context?

A. Without attempting an exhaustive definition of "fairness" in this instance, let me say that it should entail the following three elements at a minimum:

- Cost allocated to each state should reflect the relative cost burden upon the system imposed by each state.
- Costs allocated to Oregon should not exceed what the allocated costs would be if, hypothetically, the PacifiCorp's Pacific Division (or perhaps the original PP&L territory, which differs from the Northwest[14] by also including certain service areas in Wyoming) were separated from the rest of the Company for planning and operational purposes. Since it would be difficult to know with confidence what Oregon's revenue requirement would have been had there been no merger between PP&L and UP&L, I believe the fairness principle as here articulated is the best we can do with respect to the first condition of the OPUC's initial approval of the merger, i.e., that it should not harm Oregon ratepayers.
- Insofar as there are system cost savings resulting from the merger, Oregon ratepayers should receive some share of those savings.

Q. Staff's endorsement of the 2010 Protocol at the beginning of your testimony seems to be contingent upon 2010 Protocol's yielding results that are comparable to those of

[14] "Northwest" or "Northwestern" in this testimony will refer to PacifiCorp's service territory within Oregon, Washington, and California, or, perhaps (depending on the context), those three states themselves. PacifiCorp's West/Western or Pacific Division is comprised of its Northwestern service territory and its production and transmission resources in that region plus major production resources in Wyoming and the transmission resources needed to bring that production output to the Northwest. PacifiCorp's East/Eastern or Rocky Mountain Division is comprised of its entire Utah, Idaho, and Wyoming service territories and its production and transmission resources contained therein that are not part of PacifiCorp's Pacific Division. *See* starting on line 24 on page 18 of this testimony for a slightly more detailed description of the makeup of the two divisions.

the Revised Protocol for the projected years—much as Utah's acceptance of the Revised Protocol was hinged on its mimicking Rolled-In. Have I characterized things accurately?

A. Not exactly. Staff's tying of our endorsement of the 2010 Protocol to its yielding results comparable to those of the Revised Protocol is based upon our general endorsement of the Revised Protocol insofar as it meets the regulatory objectives and fairness standards outlined above. If the Revised Protocol came to depart appreciably from those objectives and standards then it would become irrelevant as a 2010 Protocol comparator. Staff does not currently foresee that irrelevancy happening over the formal duration period for the 2010 Protocol.

In contrast with Oregon Staff's holding forth the Revised Protocol as a standard for comparison based upon its continued congruence with generally accepted regulatory objectives and fairness standards, some Utah parties have put forth their acceptance of Rolled-In as more or less axiomatic, i.e., as being so self-evidently just and true as to require no further empirical or conceptual substantiation. Staff does not believe this axiomatic acceptance of Rolled-In is warranted. Included with this testimony is an extensive criticism of Rolled-In as it has been advocated by various Utah parties.

TOPIC 3 – KEY ELEMENTS OF THE REVISED PROTOCOL

Q. Would you please describe the key elements of the Revised Protocol that pertain to this docket?

A. To begin with, it should be made clear that most provisions of the Revised Protocol have been replicated in the 2010 Protocol. Also, recall that the function of any allocations protocol is to allocate among jurisdictions the costs of all resources used in common, or somehow shared by, all the states served by PacifiCorp—namely the production/ generation and transmission resources. The key elements of the Revised Protocol pertinent to this proceeding are the allocation of all the production and transmission costs on a rolled-in basis and the allocation of the hydro endowment through the use of the Embedded Cost Differential (ECD) mechanism. The steps of the ECD are as follows:

1. Allocate all the hydro resource costs to *all* the jurisdictions in the same manner as *all the rest* of the production/generation resources are allocated, i.e., on a rolled-in basis.
2. Determine the amount by which the average unit cost of electricity produced by the hydro resources is exceeded by the average unit cost of all the other production—mostly thermal, but also inclusive of wind power and market purchases. This and the following two steps are performed separately for Company-owned hydro and the Mid-Columbia (Mid-C) hydro contracts.
3. Assign portions of the hydro output to the hydro-qualified jurisdictions in proportion to their relative annual energy loads.[15]
4. Multiply each jurisdiction's share of the hydro output by the hydro-versus-other-cost difference established in step two, and then subtract that amount from the jurisdiction's allocation established in step one.
5. Allocate the total step four dollars to all of the jurisdictions in the same manner as the production plant costs are allocated initially.

The ECD approach is also used to *add* quantities to the overall cost allocations of states, such as Oregon, which have permitted the unit-cost compensation to third-party power producers (typically co-generating Qualifying Facilities [QFs]) to exceed the system average cost for electricity production.[16]

Q. The ECD process that you just described seems quite complicated. I can visualize how a direct assignment of hydro benefits might work (i.e., by the hydro recipients' paying for all the hydro costs plus the direct costs of the non-hydro power that supplies the remainder of their loads), but the workings of the ECD evades me. Have

[15] For the purpose of allocating Company-owned hydro benefits, the Wyoming load is divided into the historic PP&L portion, which is hydro-qualifying, and the UP&L portion, which is not. All jurisdictions, not just the former PP&L ones, share in the benefits of the Rocky Reach and Wells Mid-C contracts. *See* Exhibit PPL/101 Kelly/1 for a presentation of how the Mid-C endowments are allocated.

[16] Both the Revised and 2010 Protocols provide for a direct assignment to states of costs they impose—e.g., due to the state's renewable portfolio standard—"which exceed the costs PacifiCorp would have otherwise incurred." *See* 2010 Protocol Section B. State Resource, Exhibit PPL/101 Kelly/6&7.

you prepared some simple algebra to show how the ECD might match hydro direct assignment in the cost allocations process?

A. I have. Exhibit Staff/502 consists of an algebraic demonstration of the proposition that the ECD can produce results comparable to what would be produced by the direct assignment approach you mentioned. Simplifying assumptions are described in the body of that exhibit as well as in the accompanying footnote.

TOPIC 4 – CRITIQUING THE REVISED PROTOCOL

Q. You previously listed a number of regulatory objectives that are pertinent to this docket. Since so much of the Revised Protocol is carried forward into the 2010 Protocol, I would be interested to hear how well that approach has met those objectives. Please comment first on the success in achieving the objective of allowing the utility to recover all of its prudently incurred costs.

A. Arguably, the Revised Protocol—as it was implemented (or not) among the states—accomplished that objective to as great a degree as could be hoped for. While the State of Washington did not participate, it has been represented to me[17] that PacifiCorp's Washington revenue requirement under that state's own customized approach has pretty well tracked what it would have been under the Revised Protocol. The clear disappointment with regard to this objective comes from the Rolled-In-plus-X Percent cap that Utah implemented. It consistently prevented the Company from obtaining revenues in that state as high as would have been generated by the Revised Protocol.[18] Admittedly, obtaining X percent above Rolled-In is better than only receiving the amount determined by Rolled-In *per se*, which would likely have been the case had Utah not accepted the Revised Protocol—with the cap.

Q. Based on that response, I would infer that the Revised Protocol delivered only partial success regarding the objective of explicit uniformity of the inter-jurisdictional allocations approach. Is this a reasonable assessment?

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[17] By the Company's Ms. Andrea Kelly, and some time ago.

[18] *See* Exhibit PPL/204 McDougal/1. Similar caps have been in effect for Idaho.

A. It is not a completely accurate assessment. Viewed on its own terms, the Revised Protocol would have delivered uniformity of the inter-jurisdictional allocations approach across jurisdictions. But one state (Washington) chose not to adopt the Revised Protocol at all, and two others (Utah and Idaho) insisted upon side conditions (i.e., the rate caps) which made it so that PacifiCorp was not able to recover its full costs. However, partial success should nowise be viewed as a failure insofar as the achievement of the Company's objectives generally was maximized. By this same token, future success may entail specific concessions that may entail the Company's not always collecting all the costs prescribed under the 2010 Protocol.

Q. And regarding the objectives of understandability, transparency, and administrative ease?

A. Unquestionably, full Rolled-In would have better served those objectives than has the Revised Protocol, which embodied the somewhat complicated ECD as the vehicle for preserving most[19] of the hydro endowment for the former PP&L jurisdictions. But given the necessary compromises to achieve a minimally satisfactory consensus among the states, it would have been difficult to derive an approach that was more understandable, more transparent, and easier to administer than the Revised Protocol.

Q. Among the fairness criteria you listed was that costs allocated among the states should reflect relative burdens imposed. How well has the Revised Protocol performed regarding that objective?

A. I believe it has performed reasonably well—again considering the compromises required to achieve the desired working consensus among the states. Having said that, I believe a number of elements of the Revised Protocol are biased against Oregon. By that I mean that the costs allocated to Oregon may exceed the costs imposed by Oregon's loads.

Q. What are those elements?

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[19] Actually, by restoring to the Northwest a large share of the Mid-Columbia portion of the hydro endowment, from Oregon's perspective the Revised Protocol was an improvement over the Modified Accord. The latter ceded all of the Mid-Columbia benefits to the system as a whole rather than retaining them for the former PP&L territories. An earlier justification for sharing the Northwest's hydro endowment with the former UP&L jurisdictions was that the latter shares its "transmission endowment" with the former PP&L jurisdictions. Transmission access to Arizona enables PacifiCorp to interconnect with the winter-season surpluses of that area.

A. They are listed below, in no particular order of importance or magnitude:

- The average-cost-based ECD does not credit the Northwest with the full, avoided-cost-based value of its hydro resource in the sense that hydro provides peaking power during the late summer period when the price of wholesale electricity in the western United States typically reaches its highest annual level. So, instead of calculating the ECD by comparing the average cost of hydro power with the average marginal cost of electricity at the time the hydro power is actually being delivered, the Revised Protocol comparison is made with the lower cost of non-hydro electricity resulting from averaging over the entire year.
- Production *plant* costs are for the most part allocated to Oregon on the basis of its share of the sum of the twelve monthly coincident load peaks (i.e., 12CP). This dilutes the cost advantage flowing from Oregon in the sense that its annual load peaks more in the winter than in the higher-cost late summer months. As Exhibit Staff/503 demonstrates, if either a 1CP, 2CP, 3CP, 5CP, 6CP, 7CP, or 8CP approach had been used, Oregon's allocation would have been smaller.[20]
- In allocating non-hydro *energy* costs to the jurisdictions, no recognition is given for the fact that energy costs vary over time and seasons, and that Oregon's larger loads come during the lower-cost periods. Instead, all energy costs are averaged together prior to their allocation.
- Relatively slow-growing states, such as Oregon, are burdened by revenue requirement increases caused by high-cost new plant additions required for accommodating the loads of relatively fast-growing states. This outcome is due to the allocations to the states being based on the average costs of all production resources, not on the costs of the resources installed earlier in time to serve the historic loads of the relatively slow-growing states.

[20] Prior to the merger, the three UP&L state jurisdictions (Utah, Wyoming, and Idaho) used the 8CP allocator. Parties in Oregon's recently completed PGE general rate case stipulated to using the 4CP (with two summer months and two winter months) to allocate production demand costs among the customer classes of that company.

- o Offsetting this argument to some degree is the fact that as the Mid-C contracts expire and are not renewed, and as the Company-owned dams are removed, PacifiCorp will be forced to add expensive new generation resources to replace them—causing a cost burden to the entire system.[21]
- The Secondary Hydro ECD adjustment is allocated on the basis of a combination of demand and energy (i.e., the SG factor) rather than energy by itself (i.e., the SE factor), even though conceptual consistency would argue for the latter. (*See* Exhibit Staff/502.) This increases the allocation to Oregon.[22]

Q. Your last point is directly contrary to PacifiCorp testimony that "because of the reallocation of fixed costs….[t]he load growth study showed that the dynamic allocation factors utilized under a Rolled-In allocation methodology protect individual states from bearing the cost of load growth in other [faster growing] states." (*See* lines 14-18 of PPL/200 McDougal/7.) How do you reconcile your last point with the conclusion in the Company's load growth studies, which was that costs borne by relatively slow-growing jurisdictions in a rolled-in cost allocations environment are not being inflated by the addition of the higher-cost generation facilities that are required to accommodate the loads of the relatively fast-growing jurisdictions?

A. I believe the Company's load growth studies are seriously flawed. First of all, one should view with skepticism studies whose results are not borne out by what seem to be obvious facts. Primarily driven by load growth in Utah and Wyoming, PacifiCorp has added several large generation plants to its portfolio in recent years.[23] These additions have been accompanied by large rate increases in Oregon, where load growth has been just a fraction of the growth in those other two states. PacifiCorp's load growth studies would have us believe that even though the average unit cost of production facilities has increased due to

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21 The Revised Protocol rolls-in the incremental costs of those replacement resources across all of its jurisdictions, not just to the former, originally served PP&L jurisdictions.

22 The four-year average SG value for Oregon for 2006-2009 was 27.93 percent versus a lower SE value of 26.56 percent. Data source: PacifiCorp response to OPUC Data Request 18.

23 Lakeside and Currant Creek are the names of those Utah-located plants.

the addition of new plants, the overall allocations (i.e., including all other costs) to the relatively slow-growing jurisdictions are no greater than would be the case if the relatively fast-growing states had grown at a pace no-faster than the rest of the system's, with the need to add new generation plants being reduced accordingly. In other words, the studies supposedly demonstrate that even though production costs are being increased by the disproportionate growth, total cost allocations to the relatively slow-growing states remain about the same. By implication, in order for total costs allocated to low-growth states to be unaffected by the growth of a major cost component, other costs—or at least their allocations to the low-growth states—must be reduced by a commensurate amount.

Q. I'm confused. How can an increase in a utility's generation costs cause the rest of the cost allocation to Oregon to decline?

A. As mentioned earlier, rolled-in methodologies have production, transmission, and selected other system-defined non-production costs being allocated to jurisdictions as a function of their shares of the system loads.[24] Accordingly, their expanded loads causes the high-growth states to pick up an expanded share of the transmission and other system-non-production costs, which are assumed to be fixed. This translates directly to a reduced percentage share of the fixed system-non-production costs borne by the slower-growth states. That reduction for the slower-growth states makes up for their increased dollar allocation of production costs that resulted from the addition of the high-cost new plants needed to accommodate the high-growth states' loads.

To further help your understanding, I will provide a more detailed description of the Company's referenced study itself. (*See* lines 1-15 of PPL/200 McDougal/7.) The mechanics of the study reduced the rate of load growth for Utah and Wyoming down to that of the rest of the system and adjusted downwards the electricity production capability and associated costs accordingly, *while holding all other costs and resources constant*. The costs of this smaller system were then allocated to the jurisdictions, and those allocations were compared to the allocations performed under the original growth levels of

[24] Non-system-defined costs, such as for distribution facilities, are allocated on a situs basis, i.e., directly to the jurisdictions where the costs are incurred. Load-based cost allocations only apply to facilities/ resources whose capabilities and uses are somehow shared across the entire system.

the high-growth states. What happened following the reduced growth to Utah and Wyoming was that, due to a now-smaller Utah and Wyoming load picking up a smaller share of the fixed transmission and other non-production costs, the *increased* amount of the allocation of those costs to the slower-growing states was about the same as the *decrease* in the amount of the slower-growing states' allocation of now-reduced production costs. So yes, the study concludes, while Oregon's costs will be expected to go up due to the load growth in Utah and Wyoming causing increased production costs, Oregon's costs would go up by just as much if Utah and Wyoming did <u>not</u> grow so fast and Oregon therefore had to pay a greater share of what all the rest of the costs would be whether or not a greater level of growth by Utah and Wyoming had in fact taken place.

Where I take exception to the Company's study is in its working assumption that transmission and other jointly allocated costs (i.e., for common overhead costs such as administration and general [A&G]) do not move in the same direction as generation costs—at least not in a significant way. In other words, I maintain that, as generation costs increased due to growth in Utah and Wyoming, so did transmission and A&G costs. Conversely, the growth study's assumption of fixed non-production costs in the presence of reduced production costs due to reduced growth should have been altered to reflect the reasonably expected reduction in transmission and other costs that would have followed the reduced growth. Instead of the hypothetical smaller growth on the part of the high-growth states' causing Oregon to pay more of non-production costs associated with higher production costs, the base against which Oregon's larger cost percentage share would have been determined should have been smaller than was reflected in the Company's study. The upshot is that the increased allocation of production costs to Oregon has not been and are not expected to be offset fully by a reduced allocation of "fixed" transmission and A&G costs because those costs have been growing as well. With rolled-in cost allocations, Oregon's allocation of higher unit production costs is also being accompanied by an allocation of an enlarged cost basis of all other costs. Even if the percentage share of non-production costs may be reduced by its lower growth, the fact that those costs are growing as well would prevent Oregon from benefiting by having a reduced non-production cost allocation that fully offsets the increased production cost allocation.

Q. What you have just said about transmission system growth tracking generation capability growth is intuitively obvious, but do you possess some numerical data in support of your analysis?

A. I do. I went to the FERC Forms No. 1 for PacifiCorp for the last half-dozen years and compared the growth in transmission plant with the growth in production plant. (*See* my Exhibit Staff/504.) My assumption was that the expansion of loads over time necessitates the addition of transmission facilities along with generation resources. Exhibit Staff/104 demonstrates that over the course of the six study years, the Company's production plant additions amounted to 79 percent of the study period's beginning balance while transmission plant additions amounted to 42 percent of its respective beginning balance. In total dollar terms, the transmission plant additions amounted to 25 percent of the production plant additions. So, while transmission costs may not grow at the same rate as generation costs, the former are far from the independence of changes in generation costs that the Company's load growth studies would have us believe.

Q. Your analysis seems to imply that generation growth is what is responsible for the growth in transmission costs. Is that categorically true?

A. No. While transmission capacity having to keep up with generation capacity is true as a general rule, other factors may be involved. Frankly, the requirements of Oregon's renewable portfolio standard (RPS) may drive costly future transmission plant expansion if much of those requirements are to be satisfied by power from wind farms in distant Wyoming. In that circumstance, the Eastern division states will be subsidizing Oregon unless a determination is made that the additional transmission costs are "[c]osts associated with Resources acquired pursuant to a State Portfolio Standard, which exceed the costs PacifiCorp would have otherwise incurred." In that event, the additional costs "will be assigned on a situs basis to the State [i.e., Oregon] adopting the standard."[25]

Q. While earlier you referred to A&G costs as also being elevated by system generation growth, you subsequently made no further mention of that dynamic. Why not?

[25] *See* Exhibit PPL/101 Kelly/7.

A. FERC Form 1 general plant accounting, including office furniture for example, does not distinguish between plant used for system purposes (e.g., for the corporate offices) and plant used for internal jurisdictional purposes. (Transmission is regarded as a system resource, and accordingly allocated to the jurisdictions as a function of their loads, and—unlike distribution plant—not on the basis of where the transmission lines happen to be located or the relative measures of directional electricity flow.[26]) But as a utility company adds customers and load to a substantial degree, there can be little doubt that common overheads will also be pushed upwards, and not remain fixed as assumed in the Company's growth studies.

Q. You have presented evidence confirming how rapid load growth in some states can cause rate increases in other states. While Northwestern load growth is much smaller than that of PacifiCorp's Rocky Mountain Division, a system cost burden is also being created over time by the Northwest due to the diminution of our area's hydro capabilities—i.e., from Mid-C contracts expiring and Company-owned dams being removed. Can't a case be made that the East's sharing of the cost burden of replacing the hydro capabilities might cancel the burden being placed on the Northwest from the East's more rapid growth?

A. There will indeed be some offsetting going on, but not enough to achieve your cancellation. I can point to two forms of evidence to support that assertion. First, PacifiCorp's recent IRP (Integrated Resource Plan) shows more than three times as much new production capacity being added in the East than in the West.[27] Second, the Company's structural separations studies (discussed immediately below) indicate that Oregon's revenue requirement would be reduced if the Pacific Division of the Company were separated from the Rocky Mountain Division. Implicit to that separation would be

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[26] Exhibit PPL/101 Kelly/29 shows the allocation factor SG (system generation) assigned to transmission plant, and the allocation factor S (situs by jurisdiction) assigned to distribution plant.

[27] Between 2012 and 2019, 1143 megawatts of CCCT capacity, 200 megawatts in a purchase power agreement, and an average of 338 megawatts of third-quarter, heavy-load-hour, front office transactions are being added in the East—in contrast with no CCCTs, no PPAs, and an average of 520 megawatts of third-quarter, heavy-load-hour, front office transactions being added in the West. *See* "208 IRP Update: Resource Portfolio," 2011 Integrated Resource Plan, First Public Input Meeting, April 28, 2010, page 21.

the requirement that the Pacific Division would bear the full burden of the production facilities brought on to replace the retiring hydro facilities.

Q. Included with your earlier Regulatory Objectives discussion were two other primary elements of fairness with respect to the treatment of Oregon ratepayers. They were that Oregon costs should not exceed what they would be if, hypothetically, the Northwest (or original PP&L territory) were separated from the rest of the Company for planning and operational purposes, and that insofar as there are merger benefits from the continued integration of the Eastern and Western divisions of the Company, Oregon should enjoy a share of those benefits. Have these two elements been satisfied under the Revised Protocol?

A. Evidence from the Company's structural separation studies suggests otherwise. In fact those studies indicate that Oregon's revenue requirement would actually be reduced if the Western division of the Company were separated from the Eastern division.[28] That having been said, let me enter two important caveats: 1. Many components of the studies are highly controversial, rendering the studies not, *per se*, dispositive. 2. Besides fairness to Oregon ratepayers, fairness to PacifiCorp's shareholders is also regarded as critical. Some compromise of positions with respect to elements of the Revised Protocol on Oregon's part back in the 2004 MSP era was essential if there was to be achieved any kind of workable consensus regarding how PacifiCorp's costs were to be allocated among its jurisdictions. That consensus was then and now regarded as more or less a necessary, if not sufficient, condition for the Company to recover all of its prudently incurred costs.

Q. What are the basic assumptions underlying the Company's structural separation studies?

A. PacifiCorp now operates with two interconnected divisions: 1) the Western, or Pacific Division, consisting of the loads and resources located in Oregon, Washington, and California, plus Montana's Colstrip and Wyoming's Jim Bridger generation plants along with the transmission system that connects these two plants with the Northwest; and 2) the

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[28] *Reference:* Control Area Structural Separation Study presented to MSP Work Group, February 18, 2010 and the response to OPUC Data Request No. 17.

Eastern, or Rocky Mountain Division, comprised of the remainder of the Company.[29] Under structural separation, the two divisions, and their corresponding balancing areas, are in most regards treated as two separate companies for planning and operational purposes. The assumed termination of existing cross-balancing area wholesale contracts and some dilution of efficiency from the loss of integrated balancing areas dispatch capability translates to the combined costs of the two separate entities exceeding the projected cost of the integrated whole.[30]

Q. Isn't it pointless to even raise the specter of structural separation if no one is contemplating such?

A. We can't really say that no one is contemplating structural separation. In its "Petition for Immediate Stay and for Reconsideration of MSP Order" (Utah Docket No. 09-035-23), PacifiCorp said, "the likely alternative to a consensus approach to allocation is some sort of division of the Company."[31] Since the Company currently operates in some regards on the basis of two divisions (Rocky Mountain Power and Pacific Power), the most likely "sort of division" in the absence of the noted consensus would be a more complete separation along the lines of the current actual *Divisions.*

Q. With the structural separation studies indicating that Oregon is being damaged by the Pacific Division's integration with the Rocky Mountain Division, what aspects of a hypothetical structural *separation* of those divisions do you see as benefiting Oregon ratepayers?

A. The following are listed as they came to my mind, and in no particular order of importance or magnitude:

- The benefits of two of the four Mid-Columbia hydro contracts, currently treated on a fully rolled-in basis (and therefore shared with the Eastern jurisdictions), would revert to the Pacific Division (i.e., to the Northwest jurisdictions).

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[29] *See* PPL/302 Duvall/1 for a pictorial representation of the two PacifiCorp balancing areas.

[30] *See* PPL/300 Duvall/5 for a description of the nature of the losses from PacifiCorp divisional structural separation.

[31] *See* page 7 of that Order.

- New high-cost existing and future thermal generation facilities located in Utah and driven by that state's and Wyoming's growth would not be part of the Pacific Division's rate base.
- It is my impression that the Pacific Division would be less dependent upon high-cost, natural gas-fueled combustion turbines for meeting the Division's peak and intermediate load requirements. The Pacific Division's resource mix is more of a combination of coal-fired base load and hydro-peaking versus the Rocky Mountain Division's mix, which employs natural gas-fired simple-cycle (SCCT) and combined-cycle (CCCT) generation plants to meet its peaking and intermediate-load needs. Furthermore, as a winter peaking region, the Pacific Division can make its peak-accommodating purchases during the winter, when western spot market costs are lower. This situation contrasts strongly with the circumstances in which the Rocky Mountain Division's loads force PacifiCorp to make its peak-accommodating purchases in the higher-cost summer. Analogously, the Pacific Division can sell out of its surpluses in the higher-priced summer period whereas the Rocky Mountain Division's surplus capacities are more likely to occur in the lower-priced winter period.
- Rather than sharing in the costs of *all* the PacifiCorp plants (with the allocation based upon the SG factor, which arguably allocates too much of the generation fixed costs on the basis of demand [75 percent] rather than energy [25 percent][32]), the generation plant cost burden to the Pacific Division would be based solely on the plants assigned to that division.

Q. You have been discussing the Company's structural separation studies. The Company also conducted what they labeled as "go-it-alone" studies. They show Oregon as losing the *most* if that kind of division of the Company were to occur[33]—which implies that Oregon is the jurisdiction that benefits the most from the Company's operation as an integrated system serving its six state jurisdictions.

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[32] Conversations with ICNU witness Donald Schoenbeck reinforced this notion.

[33] *See* PPL/303 Duvall/1.

Don't the results of the "go-it-alone" studies serve to discredit the structural separation studies?

A. Opposite conclusions are indeed drawn from the two studies with regard to Oregon. As a consequence, it is necessary to evaluate which studies employ the more credible assumptions. As described by the Company,[34] the "go-it-alone" studies are like the structural separation studies in being highly "assumption driven." The key assumption in the "go-it-alone" studies is that each jurisdiction would provide sufficient physical facilities to meet its own peak load needs—neither relying on outside purchases nor the portions of the system's generation capacity that becomes surplus when the other jurisdictions' loads are beneath their peaks. To estimate the added costs for a given jurisdiction from "going-it-alone," the Company employs new CCCTs to make up the difference between the generation capacity allocated to that jurisdiction from the diversity-advantaged system capacity and that jurisdiction's own annual peak. Since Oregon's peak is in the winter (enabling it to utilize then-spare capacity from resources that were sized to accommodate the Eastern jurisdictions' greater summer peaks), Oregon is assigned the most new capacity of any of the jurisdictions. No allowance is made for new off-system purchases and sales and, therefore, no consideration is given for the notions that: a) a winter-peaking jurisdiction *that resides in a summer-peaking region* might be able to obtain power from the open market much more cheaply than self-producing via its own CCCTs; and/or b) to the degree that that same winter-peaking jurisdiction did expand its capacity, it would have more power from which to make lucrative off-system sales in the summer months. A major advantage of the structural separation studies is that they don't require such far-reaching (and, in my mind, unrealistic) assumptions regarding major generation capacity additions and instead preserve most of the merits—albeit on a smaller, regional scale—of an integrated, Pacific Northwest system operating in the western United States.

[34] *See* PPL/300 Duvall/4 and /7-8.

Q. Given some evidence that Oregon would be better off if PacifiCorp were effectively split into two companies, why doesn't Staff recommend that Oregon's revenue requirement be set *as if* such were the case?

A. There are a number of reasons. First, there would be much debate regarding what would be the loads-and-resources composition of the hypothetical new northwestern company.[35] Second, additional costs would most likely be imputed under that hypothetical.[36] Third, PacifiCorp's capital costs would likely increase if its second-largest jurisdiction were to "go rogue" in its approach to inter-jurisdictional allocations—and in the process potentially leaving a substantial portion of the Company's costs unaccounted for. It is difficult to keep increased capital costs from translating to increased utility rates. Fourth, the preservation of system-embedded-cost-based transmission access by Oregon to the Wyoming wind resources, called for by Oregon's Renewable Portfolio Standard (RPS), would likely be compromised. The alternative may be a more expensive replication of those renewable resources here in Oregon. Fifth, faced with what would be viewed as a relatively untenable regulatory posture in Oregon, the Company may be tempted to actually spin-off this state—making the Oregon territory its own distribution utility with unknown generation capabilities and associated costs. In sum, while the Revised and the 2010 Protocols would undoubtedly have been different had they been authored by the Oregon Staff (just as they would have been different if they had been authored by Utah or Idaho regulatory staffs), we obviously did not have that prerogative. So, to reiterate: Staff is not arguing for Oregon to be regulated as if the merger had never taken place or as if the Company was structurally separated. Beyond that, Staff believes that the 2010 Protocol offers Oregon the best package feasible at this time given our commitment to labor in

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35 Example: As an employee of the Utah Division of Public Utilities, I argued that the Arizona Public Service exchange contract and associated Cholla resource belongs with the Pacific Division rather than the Rocky Mountain Division because the Arizona resources function more as winter resources which provide nothing in the summer, when the East is short. Also, I would expect Wyoming regulators would fight to include its former PP&L territory with the new Pacific Division so as to retain access to some of the hydro benefits.

36 As stated in PPL/300 Duvall/6, lines 5-8: "This [structural separations] study does not analyze the potential costs of refinancing, additional workforce and other costs associated with changing the operation of a single integrated system…to a control area structural[ly] separated system."

good faith within the multi-state process to achieve a working consensus among the jurisdictions, and in a manner to preserve something close to the status quo for Oregon.

TOPIC 5 – KEY ELEMENTS OF THE 2010 PROTOCOL: A CRITICAL ASSESSMENT

Q. WOULD YOU PLEASE DESCRIBE THE KEY ELEMENTS OF THE 2010 PROTOCOL THAT MOST PERTAIN TO THIS DOCKET?

A. The single most important element conceptually is limiting the application of the hydro ECD under the new protocol to a comparison with the costs connected to other production resources that were in place with the Company prior to the year 2005. (*See* Exhibit PPL/205 McDougal/1 for a list of those resources.) Excluding from the differential calculation the more costly and largely undepreciated production resources acquired in 2005 and thereafter, can potentially lead to an ever-diminishing value of the hydro endowment to Oregon and to the other former PP&L jurisdictions. Another key 2010 Protocol element—possessing at least some near-term substance—is the elimination of the ECD penalty for high-cost QF purchase contracts.[37] I say "near-term" because contract negotiations over time have been bringing QF costs more in line with system averages and the higher-cost QF contracts are being allowed to expire.

Q. What are some other noteworthy elements of the 2010 Protocol?

A. These elements include:

- To remove some of the instability in the allocations results the Company is proposing to project the hydro ECD adjustment over the entire six-year 2010 Protocol formal duration interval and then levelize that discounted series to produce the flat annual allocation inputs. (*See* McDougal/1 Exhibits PPL/206 and /207 for a comparison of levelized versus unlevelized results. Exhibit PPL/207 also shows the Klamath

[37] From PPL/200 McDougal/9, lines 4-10: "All QF contracts entered into prior to September 15, 2010, are considered system resources in the 2010 Protocol and will not be considered as part of the ECD calculation. New QF contracts will also be considered system resources unless deemed to be priced greater than comparable resources. The embedded cost of 'All Other' generation resources [i.e., used for calculating the hydro ECD] includes only resources that were part of the Company's integrated system prior to 2005."

Surcharge being levelized, but the effect of such is minimal because the original raw numbers of Exhibit PPL/206 were already essentially uniform over time.)

- "The 2010 Protocol will and [*sic*] apply to all [except for Washington's?] PacifiCorp rate proceedings filed prior to January 1, 2017." (*See* Exhibit PPL/101 Kelly/3, lines 4-5.)
- The Klamath dam removal surcharge will *not* be allocated on a rolled-in basis, but rather on a *situs* basis, with 92 percent of the surcharge burden going to Oregon and the remainder to California.[38]
- Consistent with a statement made by the MSP Standing Committee to the Commissioners' Forum conference call of July 26, 2010, there may be a Utah "carve-out" whereby that state is moved directly to Rolled-In.[39] That statement notwithstanding, I would expect the Company to strongly resist that outcome. With regard for the objective of having regulatory uniformity across all jurisdictions, it is one thing for one of the smaller jurisdictions (i.e., Washington) to go its own way and quite another for the largest jurisdiction to do so.

Q. The first item on the immediately preceding list was the advanced forecasting and subsequent levelizing of the hydro ECD. Referring back to Exhibit PPL/206 McDougal/1, I see that the projected Oregon value for the hydro ECD varies from about $1.6 million to about $12.5 million, depending upon the year. What are the mechanics behind the Company's proposed levelization, and what are its revenue requirement consequences?

A. PacifiCorp discounts the series using the familiar cost of capital approach (at 7.36 percent in this case). Exhibit Staff/505 shows the net present values for the six years of the 2010

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[38] Lines 5-17 of PPL/200 McDougal/10 comprise a general description of the treatment of the Klamath costs. Exhibit PPL/206 McDougal/1 shows the dollar magnitudes of the allocations in terms of what is required to remove the initial rolled-in allocations of the Klamath Surcharge to Washington, Utah, Idaho, Wyoming, and FERC so as to achieve the full *situs* allocation of those costs to Oregon and California.

[39] The statement: "In Utah this cost allocation methodology [i.e., essentially the 2010 Protocol, including the situs treatment of the Klamath Surcharge] 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." (*See* lines 4-11 of PPL/100 Kelly/11.)

Protocol, employing various discount rates to compare the raw hydro ECD series with the levelized series proposed by PacifiCorp. Also shown are comparisons of Klamath Surcharge figures on both raw and levelized bases. Comparing the Company's levelized values versus the raw values on either a simple-sum basis or based on a "standard" social discount rate equaling inflation[40] plus 3 percent shows that Oregon benefits slightly under PacifiCorp's levelization—*assuming the accuracy of the yearly ECD projections*.

Q. What would happen if the yearly ECD projections were inaccurate?

A. It would depend upon the direction(s) of the error(s). If, for example, the Company over-estimated hydro relicensing costs and/or under-estimated the cost of installing enhanced-capability anti-pollution scrubbers on older coal-burning plants, Oregon would suffer from a cost allocation based upon an under-valued hydro endowment.

Q. What are the pros and cons of levelizing a multi-year series of estimated revenue requirement cost inputs?

A. Preserving utility rates stability and avoiding costly rate cases where possible are recognized regulatory objectives. If hydro ECD variability were to be the only cause of PacifiCorp rates changes from year to year, and if somehow the utility would be damaged even though revenue shortfalls were balanced over time by revenue surpluses, then levelization would justifiably spare the Company and ratepayers the cost and rates disruption of annually filed rate cases that might be employed in an effort to equate each year's revenues with that year's costs. But even if the second premise is true (and I find it farfetched), the first is not—as long as PacifiCorp continues to grow and add to its rate base and average costs every year. This year (2011), PacifiCorp's rates in Oregon are going up by about 14 percent. It is expected that the Company will continue to file for rate increases because of continued upward pressure on costs. In the larger scheme of things, it will not make a substantial difference whether the amount sought includes an ECD adjustment of $1 million or $12 million (which is about 1.2 percent of PacifiCorp's Oregon revenue requirement). As long as there are going to be regular rate increases regardless of the level of the ECD figure, then the "bigger picture" isn't materially

[40] For the purpose of this study I use an inflation figure of 2 percent, the putative Federal Reserve target.

affected by an increase that is less than one percent greater or lesser than would otherwise be the case.

Also, by not employing several years' forecasted inputs, regulators need only evaluate a single-year test period, thereby avoiding the challenge of "auditing" a number of years of potentially highly speculative cost projections involving hydro re-licensing, pollution control capital investments, etc. Eliminating the less accurate, longer-term forecasting also minimizes the nuisance of revenue deferrals, balancing accounts, and rate true-ups that may occur in the presence of a strategy to levelize profits when, due to having levelized regulatory cost *inputs*, actual costs each year do not match revenues—thereby inducing rate-of-return *in*stability.

Q. In light of those pros and cons, does Staff have a recommendation on this subject?

A. Yes, it is to substitute year-by-year ECD and Klamath surcharge forecasts for the Company's five-year-forecasted, levelized approach.

Q. Would Oregon's decision not to adopt PacifiCorp's proposed multi-year cost forecasting and leveling method for the ECD seriously undermine PacifiCorp's efforts to achieve regulatory consensus around the 2010 Protocol?

A. I find it unfathomable that either the Company or the other states would turn away from the 2010 Protocol due to an insistence on the part of Oregon that the hydro ECD be estimated as accurately as possible. From the inclusion of Revised Protocol amendments providing for rate increase caps for Utah and Idaho we see precedence for tailoring the allocations protocol on a jurisdiction-by-jurisdiction basis to meet individual state requirements.

Q. Now let's turn to the Klamath Surcharge portion of the 2010 Protocol. I'm familiar with the settlement agreement (the Klamath Hydroelectric Settlement Agreement, or KHSA) that led to the 92 percent and 8 percent split between Oregon and California of ratepayer-provided funds for Klamath dam removal costs. Can't those figures be regarded as maximums, with the other states served by PacifiCorp also receiving some of the Klamath Surcharge burden? After all, Washington and a large portion of Wyoming have directly benefited from hydro resources that were part of the former PP&L. Even Utah and Idaho have benefitted from these hydro resources due

to their either basing their regulatory treatments of PacifiCorp directly upon Rolled-In (i.e., where the benefits of the hydro resources are shared across the system), or had their Revised Protocol allocations reduced according to ceilings reflecting cost increments above hydro-encompassing Rolled-In?

A. The PacifiCorp treatment of Klamath is directed by statute—requiring regulatory legerdemain for any departure therefrom. Obviously, a fully rolled-in treatment of the Klamath removal costs would relieve Oregon and California of a major expense. Notably, by allowing Utah and Idaho to *not* see rolled-in Klamath costs causes the 2010 Protocol to produce a lower revenue requirement for those states than what would be produced by a thoroughly consistent Rolled-In approach. The presence of a Rolled-In burden increases the likelihood of the adoption of the 2010 Protocol by those two states.[41] At the same time, by accepting "ownership" of the lion's share of the Klamath dam removal costs Oregon is able to keep most of its hydro endowment while enabling PacifiCorp to obtain a regulatory accord with Utah and Idaho that is "congenial" to Rolled-In.

Q. You just informed us that—to Utah's and Idaho's advantage—the 2010 Protocol would *not* allocate Klamath dam removal costs on a fully rolled-in basis across all jurisdictions. Instead, PacifiCorp's Oregon and California ratepayers cover those costs. Is that fair in your estimation?

A. Since Oregon has been the principal beneficiary of the Northwest's hydro endowment, it is fair that Oregon pay a large share of the costs, including those associated with removal of the Klamath dams. In a perfect world, all the other states would also bear a minor share, reflective of the benefits they have received. That share for the eastern states of Utah and Idaho would be well below a full rolled-in allocation.

Q. You have spoken of the various compromises being placed upon the Northwest's hydro endowment as it affects Oregon. Again, the most prominent feature along these lines contained in the 2010 Protocol is the clause limiting the hydro ECD to

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[41] Turn to Exhibit PPL/207 McDougal/1. Note that subtracting what would have been Utah and Idaho's share of the Klamath Surcharge under a rolled-in allocation is more than enough under the 2010 Protocol to offset what those states lose by foregoing of hydro benefits under the hydro ECD adjustment.

comparing hydro's average per kWh cost with that of all production resources that were in place with PacifiCorp prior to 2005. (The Revised Protocol placed no such limitation.) What is the conceptual basis of that limitation?

A. Utah representatives have observed that when parties first got together (*circa* 1989) to negotiate inter-jurisdictional allocations, the value of the hydro endowment *at the time* was basically the difference between hydro's average cost and the average cost of electricity from the other sources then in place. The idea, now expressed, was that the Northwest should share fully in the costs of whatever production resources were added to the system from that time, and that such sharing would be impossible without fixing the vintage of other resources to which the hydro ECD would be applied. The basis of the 2005 compromise year is the notion that if it had been adopted as part of the Revised Protocol, the cutover ECD vintage limitation might well have been when the Revised Protocol had been put into effect in most of the states; i.e., 2005.

Q. Have you any principled objection to the pre-2005 other-production-resource-limitation for the hydro ECD?

A. First let me say that the "impossible sharing of new production resources" argument is a red herring. A careful review of my Exhibits Staff/502 and /506 shows that—after setting aside the load served by the hydro resource—Oregon shares fully in the new plant costs under the Revised Protocol. To not give full consideration for the Northwest's hydro endowment could go against the basic principles of fairness enunciated earlier in this testimony. Had there never been a merger, the value of the hydro endowment would naturally be measured against the costs of *all* the resources in PP&L's portfolio, not just the resources that had been put in place prior to some arbitrary date. In that light, as long as hydro's costs are below the system average, and as long as the Northwest's growth burden does not exceed that of the East, then the Northwest should enjoy electricity production costs that are beneath the average for PacifiCorp.

Q. Might the way that the 2010 Protocol is constructed prevent that outcome?

A. It clearly might. To provide an indication of the potential perversity resulting from placing a vintaged other-production-resources limit on the ECD, consider the following hypothetical: Suppose that due to ongoing thermal plant depreciation, combined with rapidly escalating relicensing fees for hydro facilities, the average cost of hydro came to be contemporaneously *greater* than the average cost of electricity from the older, pre-2005-vintaged thermal plants but still cheaper than the overall average cost of thermal-produced electricity. The outcome would be for the hydro ECD adjustment under the 2010 Protocol to *add* to Oregon's revenue requirement rather than subtract from it. In this circumstance the ECD adjustment would make Oregon's cost allocation *exceed* what would have been the case under full Rolled-In even though hydro power would remain cheaper than thermal power. Needless to say, either a direct assignment of hydro power to the PP&L jurisdictions or an allocation reflecting what costs would have been absent the merger with UP&L would have preserved the proper value of hydro for the Northwest in its entirety.

Q. Have you prepared an exhibit with simple numerical examples illustrating how the 2010 Protocol can generate allocations to Oregon that are greater than what would come from Rolled-In even though hydro power continued to be cheaper than thermal-generated power?

A. I have. It is Exhibit Staff/506. The exhibit not only does what you just asked for, but it also shows the added allocation to Oregon that comes from not taking into consideration the fact that Oregon's load is growing more slowly than Utah's, and therefore is responsible for less of the new resource costs.[42]

Q. You have again referred to the potential costs of growth. Does the 2010 Protocol make explicit reference to such as a concern worth monitoring?

A. It does. Section IV. D. Load Growth states, "At the direction of the MSP Standing Committee, the Company and parties will continue to analyze and quantify potential cost shifts related to faster-growing states." *See* Exhibit PPL/101 Kelly/8.

Q. You have spent a lot of time discussing compromises that have been used to encourage Utah and Idaho to support a working inter-jurisdictional allocations consensus. Where do these compromises leave Oregon?

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[42] An IRP-related assumption behind the exhibit's results is that wind power is cost-effective at its planned-for level; i.e., that wind is no more costly than the conventional thermal alternatives.

A. Perhaps surprisingly, for the next several years Oregon is affected very little in going from the Revised Protocol to the 2010 Protocol. By referring to Exhibit PPL/208 McDougal/1 you'll see that in comparing the 2010 Protocol with the Revised Protocol for Oregon that it's pretty much a wash for the years 2011-2014, and that the projected increase is about 0.25 percent in 2015 and 0.50 percent in 2016, the last year of the formal effectiveness period of the 2010 Protocol.

Q. If Utah and Idaho benefit from substituting the 2010 Protocol for the Revised Protocol, and Oregon is held relatively harmless, which jurisdiction would be the loser from this change?

A. Reviewing that same PacifiCorp exhibit (PPL/208 McDougal/1), it is clear that most of the cost shift would be to Wyoming.[43] I would add that, as the fastest growing jurisdiction (in percentage terms), Wyoming probably gains the most from having new-plant costs rolled in with old-plant costs as part of a larger system in determining its revenue requirement.

TOPIC 6 – ELEMENTS UNDER THE 2010 PROTOCOL FOR PROTECTING OREGON RATE-PAYERS

Q. You are placing a lot of faith in PacifiCorp's modeling forecasts. What if the projections you just cited for Oregon do not pan out—i.e., what if the results depart substantially from what would have been produced by your relative standard of fairness, the Revised Protocol?

A. First a comment. Indeed we do place much faith in the integrity of the Company's modeling. One basis for that faith has been their forthrightness in conveying Utah's more recently projected outcomes as diverging from what the modeling had previously projected, and upon which Utah had originally based its support of the Revised Protocol.

But as your question implies, unmitigated reliance upon PacifiCorp's modeling forecasts would be imprudent. Staff's recommendation of support for the 2010 Protocol is based, in part, on the Commission adopting the specific protective mechanism regarding forecasts

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[43] Washington is also indifferent due to the expectation that it will remain with its own allocations scheme.

and leveling discussed above. We also find comfort in a general protection already included in the 2010 Protocol. Respectively, these two protections are revisited and elaborated upon as follows:

1. A specific protective mechanism: Expressed earlier was Staff's recommendation to substitute year-by-year ECD and Klamath surcharge forecasts for the five-year-forecasted, levelized approach. This approach protects ratepayers from having to rely upon the accuracy of more speculative, distant forecasts.[44]
2. A general protection: A key element of the 2010 Protocol Amendments is the following, "A party's initial support or acceptance of the 2010 Protocol will not bind or be used against that party in the event that unforeseen or changed circumstances cause that party to conclude that the 2010 Protocol no longer produces just and reasonable results." (*See* lines 25-27 of Kelly/13, and line 1 of Kelly/14 from Exhibit PPL/101.) That language acknowledges the right of any state to unilaterally alter its inter-jurisdictional allocations approach if it views the 2010 Protocol as no longer producing results that are deemed just and reasonable.

   Having said that, let me hasten to add that the "mere" fact of the projections regarding the future not "panning out" would not, by itself, warrant a finding that the 2010 Protocol no longer produced just and reasonable results. Just because someone or some jurisdiction is disappointed by an unexpected future does not signify that the person or jurisdiction has been served with an injustice. An unfortunate or unexpected outcome may still be just. Accordingly, to unilaterally depart from the 2010 Protocol outcome to achieve conformance with the earlier expectation may create its own injustice.

Q. Let's say, hypothetically, that Oregon regulators do conclude that the 2010 Protocol no longer produces just and reasonable results. What happens next?

A. 2010 Protocol Amendment language immediately following what was just cited reads as follows: "Prior to departing from the terms of the 2010 Protocol, consistent with their legal obligations, Commissions and parties will endeavor to cause their concerns to be

[44] Obviously the Company would also be protected against distant forecasting errors that worked to its detriment.

presented at meetings of the MSP Standing Committee and interested parties from all States in an attempt to achieve consensus on [a] proposed resolution of those concerns." (*See* lines 2-6 of Exhibit PPL/101 Kelly/14.)

Q. My last question pre-supposed Oregon regulators' initiating future investigations concerning the ongoing merits of the 2010 Protocol. Does that protocol contain an element designed to prompt such an investigation in the absence of regulator initiative?

A. It does. The 2010 Protocol contains the following language: "Proposed Effective Date The 2010 Protocol will and [*sic*] apply to all PacifiCorp rate proceedings filed prior to January 1, 2017."[45] Demonstrating unusual foresight, the 2010 Protocol embodies a formal recognition that a mechanism that produces just and reasonable results *now* may not do so in the future…and the more distant the future, the greater the likelihood of producing unreasonable results. An implication from this clause is that prior to such an undesirable outcome the Company and interested parties will be reviewing the 2010 Protocol to ascertain whether it will continue to produce just and reasonable outcomes…and if it will not, to have an alternative in place by 2017. Absent a consensus by that time, each state must weigh the pros and cons of staying with the 2010 Protocol for some indeterminate period until a new consensus is achieved, or unilaterally adopting some other mechanism that the state believes to be fair and then advocating it to the other jurisdictions in an attempt to achieve consensus.

Q. After Utah first raised concerns regarding what it viewed as unreasonable results based upon a departure of allocations outcomes from projections, it took about two years before the resolution embodied in the *proposed* 2010 Protocol was accomplished. And until the current application is ruled upon in all jurisdictions, we won't know that this cumbersome and time-consuming affair has indeed reached a satisfactory denouement.[46] Have protections been in place to benefit or protect Utah

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45 *See* lines 3-5 of Exhibit PPL/101 Kelly/3.

46 Note the State of Washington's never having joined the Revised Protocol and not even participating in the negotiations that led to the 2010 Protocol.

during the indefinite period when the revisions to the Revised Protocol are considered?

A. There were, and are. Currently, and without regard to how high the allocations under the Revised Protocol would have been, a side-agreement grants that Utah's revenue requirement is not to exceed what it would have been under full Rolled-In plus one percent.[47] Idaho has enjoyed a similar protective cap.

Q. As submitted, does the 2010 Protocol contain a similar protection for Oregon?

A. No, it does not. But I believe that it would be appropriate—and certainly consistent with historical precedent—for this Commission to include such as a condition of its approval of the 2010 Protocol. Language accommodating caps can readily be made supplemental to the 2010 Protocol without altering or further complicating what is already there. In Oregon's case, instead of some cap above Rolled-In, the constraint would be in the form of a cap above the approach which has previously been defended as just and reasonable for the state of Oregon—i.e., the Revised Protocol.

Q. What do you recommend as an appropriate level for such a cap?

A. I recommend a cap at 0.50 percent above the Revised Protocol outcome. That amount is equivalent to the greatest amount by which the Company projects the 2010 Protocol to produce outcomes for Oregon in excess of the Revised Protocol.[48] While the official effectiveness date for filings under the 2010 Protocol ends on January 1, 2017, I recommend that the proposed cap be in effect until some substitute for the 2010 Protocol is put into place—which may be years after the beginning of 2017.

Q. You have just suggested a cap in the form of an upper limit being placed upon Oregon's allocation under the 2010 Protocol. Has Staff considered installing a lower limit as well?

A. Yes. We are sympathetic to the notion of risk symmetry as seen by ratepayers and by shareholders. Accordingly, a lower limit of 0.50 percent beneath the Revised Protocol

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[47] Exhibit PPL/201 McDougal/1 shows the Utah one-percent--above Rolled-In cap to be in effect through 2014.

[48] *See* Exhibit PPL/208 McDougal/1.

outcome is also proposed. The Company now projects that the greatest amount by which the 2010 Protocol's outcome for Oregon will be beneath the outcome of the Revised Protocol is about 0.2 percent.[49]

Q. The "Future Reporting" section of PPL/200 McDougal/12 (*see* lines 9-18) contains the sentence, "The Company proposes to no longer provide reports or comparisons using any other allocation methodologies [i.e., other than the 2010 Protocol]." Comment?

A. Clearly if there is to be a Revised Protocol-based cap, the Company will have to continue to provide reports using that allocation methodology. There is no question but that Utah and Idaho will also insist that reports continue to be provided based upon the Rolled-In methodology.

Q. Would you please review Staff's recommendations with regard to the 2010 Protocol?

A. I recommend approval of the 2010 Protocol with the following exceptions or provisions:

1. In developing the overall cost allocation to Oregon, year-by-year ECD and Klamath surcharge forecasts are to be substituted for the five-year-forecasted, levelized approach that is contained in the Draft 2010 Protocol.
2. As long as the 2010 Protocol is in effect, the overall cost allocation to Oregon in any year should not depart, positively or negatively, by more than 0.50 percent from what would have been allocated under the Revised Protocol.
3. In adopting the 2010 Protocol, the Commission's Order should make clear that Oregon will be revisiting this subject (under MSP auspices) should it be apparent that the 2010 Protocol unacceptably compromises the integrity of the Northwest's hydro endowment or places an undue cost burden upon Oregon from other states' growth.

ADDENDUM – A CRITIQUE OF ROLLED-IN

Q. As you suggested earlier, Utah appears to countenance no alternative to full Rolled-In insofar as it constitutes *the* just and reasonable approach to inter-jurisdictional allocations. Is there a commonly accepted theory of justice that would justify Rolled-

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[49] *Ibid.*

In as preeminent among all allocations approaches?

A. I'm unaware of a theory of justice *per se* that would warrant Rolled-In's legitimacy, much less preeminence. In fact, the only theoretical/conceptual justification for Rolled-In that I know of is *simplicity*, or administrative ease. Regulatory accounting and inter-jurisdictional allocations processes in particular are greatly simplified if resources don't have to be identified by location, age, etc. But if simplicity can lower administrative costs, it may also come at a price—in terms of unfairness—that is regarded as unacceptable.

Q. I would think that "unfairness" and "fairness" would be regarded as quite subjective in their own right. Obviously "justice" and "fairness" can be used somewhat interchangeably, but is there some generally accepted *theory* or principle that would support what Staff would hold out as fair in the inter-jurisdictional allocations context?

A. There is such a theory. It relates to a *first principle* of exchange with regard to human behavior and economic efficiency. Behaviorally it holds that no party will voluntarily enter into an exchange that he expects will leave him worse off than if he'd never undertaken that exchange. Economic inefficiency occurs when an exchange is not consummated even though it is capable of leaving all parties to the exchange better off than if they hadn't entered into the exchange. It can easily be shown that a slavish allegiance to Rolled-In can lead to economic inefficiency of that nature. I can illustrate this contention with a simple thought experiment.

Q. Please proceed.

A. Consider two utilities of equal size that are contemplating a merger. Assume that the average cost of power for utility A is 40 mills and the average for B is 50 mills, for a combined average cost of 45 mills. Now assume that diversity benefits from consummating the merger would reduce the combined average to 43 mills. Obviously if utility B held out for rolled-in treatment of costs—with both utilities experiencing costs of 43 mills—it would kill the merger, thereby denying both parties an opportunity to reap some benefit. Insisting upon rolled-in cost averaging would violate that first principle of exchange and lead to economic inefficiency. Utility A simply will not accept paying costs of 43 mills when foregoing the merger leaves its costs at 40 mills. Utility A would be made worse off by the merger under rolled-in terms because Utility B would not only reap all of the system benefits from the merger but would also extract an economic penalty from Utility A.

Q. I understand that the achievement of economic efficiency in your example would require the abandonment of rolled-in as the cost and benefit allocator. What happens next in your thought experiment?

A. Given that utility B is rational and does not want to kill a merger from which it would reap benefits, the next step is to determine what the post-merger cost assignment would be. Here the discipline of economics (to my knowledge) provides no definitive insight. However, adopting a commonsensical equal sharing of benefits rule would yield a cost to A of 38 mills and a cost to B of 48 mills:[50] thereby each utility would see its average cost go down by two mills. Depending upon the relative strengths of their negotiating positions, departures from equal benefit sharing will occur, but in nowise would a voluntary outcome correspond with rolled-in. In fact, most objective observers would agree that to impose rolled-in in conjunction with dictating that the merger take place (or to not be allowed to dissolve if it had already taken place) would constitute a gross social inequity.

Q. Would you now apply the efficiency principle which you have just developed to this docket and Oregon.

A. Possessing a valuable hydro-power endowment, the Northwest has long enjoyed lower cost electricity than, on average, has the rest of the western United States. Since the merger, Oregon and Washington have unwaveringly insisted that PacifiCorp's hydro benefits be preserved for the Northwest lest the advantage of lower cost power be lost.[51]

Needless to say, the resource that Utah and Idaho have always wanted rolled-in is the Northwest's hydro. The justification for preserving the benefits of that resource for the

[50] Note that the average of those two figures remains at 43 mills.

[51] While Oregon has been willing to compromise those benefits somewhat, there has never been any question that as long as hydro remains attractive cost-wise, then those benefits should not be lost via a fully rolled-in inter-jurisdictional cost allocations methodology.

Northwest is that absent a merger with Utah Power & Light (or with any other utility outside our region), there would be no question regarding hydro benefits remaining entirely with the prior PP&L jurisdictions. Given such a merger, sharing of the hydro benefits would only be countenanced if there were compensating benefits contributed by the other party to the merger.[52]

Q. Are there circumstances that would suggest the suitability of rolled-in treatment of the Northwest's hydro endowment?

A. If the cost of hydropower came to be anticipated as roughly equaling in the long run the average cost of electricity from other sources, that would be grounds for treating hydro as a rolled-in system resource rather than a regional resource with benefits reserved for our region.[53] But if hydro was projected to be *more* expensive than the average for other production resources, then I would expect that to the degree they have not benefited from hydro in the past, some jurisdictions would insist upon not being burdened by the extra hydro-related costs in the future.

Q. Representatives from Utah and Idaho have argued that because PacifiCorp is planned and operated as an integrated system, the only way that inter-jurisdictional allocations makes sense is on a fully rolled-in basis. Comment?

A. That connection is spurious as it applies to the hydro endowment. PacifiCorp, through its integrated resource planning (IRP) process, is charged with operating and planning its system so as to minimize total system costs (in an optimizing cost-risk framework). No one questions that. I have yet to see a case made for how or why preserving a hydro endowment for the Northwest would cause the Company to not achieve that goal. The hydro endowment has been in place since the very beginning of the merger and, to my knowledge, no one has argued that this has interfered with PacifiCorp's operating and planning its system as efficiently as it knows how.

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[52] Mentioned earlier in this testimony were load diversity benefits received by the Northwest from the merger as well as the benefit of transmission access to production resources in Arizona.

[53] As stated earlier, CUB, as represented by Mr. Bob Jenks, has stated that due to fishing, flood control and other considerations ancillary to hydroelectric production, hydro should always be carved-out as a regional resource for cost allocations purposes.

Q. At least one Utah party has argued that PacifiCorp's costs should be allocated purely on the basis of cost-causation…which is to say, on the basis of jurisdictional loads throughout the course of the year. Since no recognition is given to resources' origins, isn't this position equivalent to full Rolled-In?

A. Yes. Frankly, the cost-causation argument is even less credible than is the integrated system argument—with which I suppose it is related. Let me first say that you should have placed "cost-causation" in quotation marks because contemporary (e.g., 2011) loads—particularly loads in Utah and eastern Idaho—are not what actually *caused* the dams in Oregon and Washington to be built fifty or so years ago. But yes, economics-oriented regulators almost inevitably endorse the idea of cost-based ratemaking. And in typical (i.e., rolled-in) circumstances, loads are what causes costs to be incurred—*at least in the near term*. But we shouldn't be swayed by some notion of "cost-causation" that *only* considers the short term. Vertically integrated utilities such as PacifiCorp have huge investments in plants that were acquired long ago. Those acquisitions were based upon *true* cost-causation—i.e., not upon contemporaneous loads but rather future loads forecasted for what were then their service territories. Particularly in view of the very long lives of most utility facilities, it is unimaginable how anyone would not recognize the role played by resources introduced into a system well in the past, and what the implications of that role might be for cost allocations purposes.

Q. Earlier you mentioned having the hydro benefits remain *entirely* with the prior PP&L jurisdictions in the event that the merger with UP&L had never occurred. Under Rolled-In those benefits would not be entirely lost to the Northwest, but "merely" shared. What would be wrong with that?

A. As I indicated earlier, nothing would be wrong with the Northwest's sharing the hydro benefits as long as the merger benefits accruing to the Northwestern jurisdictions from other sources were sufficient to compensate for the dilution of the hydro advantages; i.e., so that Oregon and the other Northwestern jurisdictions would remain net beneficiaries from the merger.[54] But I would remind you that by definition, full Rolled-In would entail

[54] As has been noted earlier, the Revised Protocol already contains some sharing of the hydro benefits with Utah and Idaho (i.e., via some of the Mid-C contracts).

full sharing, and sharing on a loads basis. That means that with Utah comprising the largest share of the system load, that state would get the largest share of the hydro benefits.

Q. So tell me, and this is key…would Rolled-In cause Oregon to be in a position of not gaining any of the merger benefits, and in fact potentially being made worse off than had the merger never taken place?

A. I won't speculate about what might have been had the merger never taken place. But evidence from the structural separation studies[55] have shown that—under either the Revised Protocol or the 2010 Protocol—Utah's and Idaho's combined benefits from integration of the two divisions of the Company far exceed the total benefits of integration. That excess implies, mathematically, that other states, including Oregon, suffer relative to what their conditions would be if the two divisions were operated separately.[56] Full Rolled-In would make matters even worse for Oregon.[57] Even if it could be proven that Oregon is a net beneficiary from the integration of the Eastern and Western divisions of PacifiCorp, the evidence depicts a grossly uneven sharing of benefits.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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[55] *See* PPL/300 Duvall/4-6 for the Company's discussion of its structural separations studies—including a number of study caveats. The conclusions contained in this sentence derive from the structural separations study dated February 18, 2010 that was presented to the MSP Standing Committee Work Group and from PacifiCorp's response to OPUC Data Request 17.

[56] The impact on Wyoming is more complicated insofar as much of its loss under the defined structural separations is attributable to Wyoming's no longer receiving the hydro benefits to which the portion of the state within the former Pacific Power & Light has been entitled. Accordingly, some of the benefits to the Northwestern states under structural separations can be attributed to the loss to Wyoming constituting a benefit transfer to the Northwest. Washington has preserved the benefits of hydro that were established in the Modified Accord allocations protocol by unilaterally retaining that approach in regulating PacifiCorp.

[57] This is subject to the qualification that if Utah and other states would accept a full rolled-in treatment of the Klamath surcharge, thereby largely reducing Oregon's obligation, such would mitigate the burden to Oregon of adopting Rolled-In as a substitute for the Revised Protocol.

CASE: UM 1050
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualification Statement

January 27, 2011

WITNESS QUALIFICATION STATEMENT

NAME: George R. Compton

EMPLOYER: Oregon Public Utility Commission

TITLE: Senior Economist (3/4), Economic Research & Financial Analysis Division (ERFA)

ADDRESS: 550 Capital Street NE, Suite 215
Salem, OR 97301-2551

EDUCATION: Doctor of Philosophy, Economics (1976)
University of California, Los Angeles (UCLA) – Westwood, CA

Master of Science, Statistics (1968)
Brigham Young University (BYU) – Provo, UT

Bachelor of Science, Mathematics and Psychology (1963)
Brigham Young University – Provo, UT

EXPERIENCE: I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah's Department of Commerce (formerly Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah I also taught economics part-time for about ten years at BYU. Prior to my utility regulatory career I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California. I joined the OPUC staff soon after "retiring" to Oregon at the end of 2006. Principal cases of my involvement here have included the IRP/CO_2 Risk Guideline (UM 1302), the 2007 AVISTA General Rate Case (UG 181), the 2008 and 2010 PGE General Rate Cases (UE 197 & 215), the 2009 and 2010 PacifiCorp General Rate Cases (UE 210 & 217), and the Idaho Power General Rate Case (UE 213).

CASE: UM 1050
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Exhibits in Support
Of Reply Testimony

January 27, 2011

An Algebraic Demonstration that the Embedded Cost Differential (ECD) For Hydro Power Can Produce Allocations Equivalent to Its Direct Assignment

Defining terms:

c_h = Average cost of power produced by hydro facilities

c_o = Average cost of power produced by all other facilities, which are equally shared by all jurisdictions

k_h = MWhs of power produced by hydro facilities

k_o = MWhs of power produced by all other facilities in support of jurisdictional loads

k_1 = MWhs of power consumed by hydro-possessing Jurisdiction 1

k_2 = MWhs of power consumed by non-hydro-possessing Jurisdiction 2

k_T = Total MWhs = $k_h + k_o = k_1 + k_2$

C_T = Total system costs = $c_h \times k_h + c_o \times k_o$

C_{1D} = Total cost to the hydro-possessing Jurisdiction 1 given direct assignment of hydro power to that jurisdiction on an average-cost basis plus the assignment of the average cost (on a non-time-differentiated basis) of non-hydro power to the balance of that jurisdiction's load.

C_{1E} = Total non-time-differentiated cost to the hydro-possessing Jurisdiction 1 given rolled-in plus the ECD adjustments.

Hypothesis (given the assumptions): $C_{1E} = C_{1D}$

Where, by definition or Revised Protocol formulation…

C_{1D} = Total cost of direct-assigned hydro power to jurisdiction 1

+ Total cost of non-hydro power to jurisdiction 1

$= \{c_h \times k_h\} + \{c_o \times (k_1 - k_h)\}$ [the basic formulation]

and

C_{1E} = Jurisdiction 1's share of Rolled-In total costs

- Primary ECD adjustment for Jurisdiction 1 [this is Jurisdiction 1's explicit hydro benefit]

+ Secondary ECD adjustment for Jurisdiction 1 [i.e.., spreading back the above hydro benefit to *all* the jurisdictions in proportion to their shares of the total load]

$$C_{1E} = \{k_1/(k_1 + k_2)\} \times C_T$$
$$- \{k_h \times (c_o - c_h)\}$$
$$+ \{k_1/(k_1 + k_2)\} \times \{k_h \times (c_o - c_h)\}$$
[the basic formulation[1]]

$$C_{1E} = \{k_1/(k_1 + k_2)\} \times \{(c_h \times k_h) + (c_o \times k_o)\}$$
$$- \{k_h \times (c_o - c_h)\}$$
$$+ \{k_1/(k_1 + k_2)\} \times \{k_h \times (c_o - c_h)\}$$
[expanding C_T]

$$C_{1E} = \{k_1/(k_1 + k_2)\} \times \{(\cancel{c_h \times k_h}) + (c_o \times k_o)\}$$
$$- \{k_h \times (c_o - c_h)\}$$
$$+ \{k_1/(k_1 + k_2)\} \times \{k_h \times (c_o - \cancel{c_h})\}$$
[cancelling terms]

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[1] The truthfulness of the Hypothesis depends on the Secondary ECD adjustment being allocated on the basis of relative energy consumption, i.e., the SE factor, rather than, as per the Revised Protocol, the SG factor, which is a combination of energy (25%) and demand (75%). Generally speaking, the SE and SG factors are quite similar for the PacifiCorp jurisdictions. Exhibit PPL/101 Kelly/51 displays this same simplicity expedient.

Testing the hypothesis…

$C_{1E} = C_{1D}$ [i.e., posing the hypothesis]

$\{k_1/(k_1 + k_2)\} x \{c_o x k_o\} - \{k_h x (c_o - c_h)\} + \{k_1/(k_1 + k_2)\} x \{k_h x c_o\}$
$= c_h x k_h + c_o x (k_1 - k_h)$ [de-composing the C's]

$\{k_1/(k_1 + k_2)\} x \{c_o x k_o\} - \{k_h x (\cancel{c_o} - c_h)\} + \{k_1/(k_1 + k_2)\} x \{k_h x c_o\}$
$= c_h x k_h + c_o x (k_1 - \cancel{k_h})$ [cancelling terms]

$k_1 x \{c_o x k_o\} + (k_1 + k_2)\{k_h x c_h\} + \{k_1\} x \{k_h x c_o\}$
$= \{(k_1 + k_2) x (c_h x k_h)\} + \{(k_1 + k_2) x (c_o x k_1)\}$ [multiplying both sides of equality by $(k_1 + k_2)$]

$k_1 x \{c_o x k_o\} + (\cancel{k_1} + \cancel{k_2})\{k_h x c_h\} + \{k_1\} x \{k_h x c_o\}$
$= \{(\cancel{k_1} + \cancel{k_2}) x (c_h x k_h)\} + \{(k_1 + k_2) x (c_o x k_1)\}$ [cancelling terms]

$k_1 x c_o x (k_o + k_h) = k_1 x c_o x (k_1 + k_2)$ [collecting and rearranging terms]

$(k_o + k_h) = (k_1 + k_2)$ [dividing both sides by $k_1 x c_o$]

$k_T = k_T$

QED Since the sum of the amounts assigned to the jurisdictions will equal the sum of the amounts produced by the various sources in support of jurisdictional loads.

NOTE: For additional clarity regarding the operation of the ECD, refer to Exhibit Staff/506.

CASE: UM 1050
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 503

Exhibits in Support
Of Reply Testimony

January 27, 2011

ALTERNATIVE SUM-OF-THE-MONTHLY-COINCIDENT-PEAKS ALLOCATORS FOR OREGON

Jurisdictional Contribution to Firm System Retail Coincidental Peaks.

Sum of the Indicated Number of Largest Monthly Peaks

2004

DIVISION:	Pac. Power	Pac. Power	Pac. Power	Pac. Power	Pac. Power	R.M.P.	R.M.P.	R.M.P.	R.M.P.	*Sum*	*Sum*	*Sum*	*Sum*	*Sum*	*Sum*	*Sum*	*Sum*
MONTH:	CALIFORNIA	OREGON	WASHINGTON	MONTANA	WYOMING	UTAH	IDAHO	WYOMING	FERC	*Twelve*	*Eight*	*Six*	*Five*	*Four*	*Three*	*Two*	*One*
Apr-04	136.9	2,015.4	525.1	0.0	844.8	2,463.8	397.1	136.5	24.3	*6,544.1*							
May-04	156.6	1,665.6	504.7	0.0	882.5	2,596.7	476.0	122.7	29.1	*6,433.9*							
Jun-04	129.3	1,928.3	598.4	0.0	926.0	3,256.4	600.2	133.8	33.3	*7,605.7*	*7,605.7*	*7,605.7*					
Jul-04	112.2	2,055.0	620.4	0.0	1,018.4	3,480.2	657.7	135.0	38.2	*8,117.0*	*8,117.0*	*8,117.0*	*8,117.0*	*8,117.0*	*8,117.0*	*8,117.0*	*8,117.0*
Aug-04	144.9	1,949.3	624.6	0.0	910.6	3,387.2	478.3	136.6	36.8	*7,668.3*	*7,668.3*	*7,668.3*	*7,668.3*				
Sep-04	138.1	1,970.4	646.1	0.0	910.9	3,028.4	435.6	122.5	36.0	*7,287.9*	*7,287.9*						
Oct-04	149.4	2,073.6	645.1	0.0	883.8	2,524.3	471.9	140.2	21.8	*6,910.1*							
Nov-04	152.0	2,235.0	691.4	0.0	967.3	3,133.8	351.2	142.9	29.2	*7,702.8*	*7,702.8*	*7,702.8*	*7,702.8*	*7,702.8*	*7,702.8*		
Dec-04	167.6	2,349.3	702.0	0.0	933.6	3,097.7	510.1	143.5	28.1	*7,932.0*	*7,932.0*	*7,932.0*	*7,932.0*	*7,932.0*	*7,932.0*	*7,932.0*	
Jan-05	151.7	2,332.6	660.1	0.0	967.1	2,976.4	429.8	145.3	25.5	*7,688.4*	*7,688.4*	*7,688.4*	*7,688.4*	*7,688.4*			
Feb-05	137.7	2,324.7	698.9	0.0	897.6	2,724.3	396.7	138.1	21.9	*7,339.9*	*7,339.9*						
Mar-05	161.8	2,023.9	628.1	0.0	887.0	2,637.3	396.1	138.6	21.6	*6,894.3*							
Load Curtailment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*							
Total	1,738.2	24,923.2	7,544.8	0.0	11,029.8	35,306.5	5,600.8	1,635.4	345.8								
System Sum of the Monthly Peaks:										***88,124.5***	***61,342.0***	***46,714.2***	***39,108.5***	***31,440.2***	***23,751.8***	***16,048.9***	***8,117.0***
Oregon's Sum:										***24,923.2***	***17,144.7***	***12,849.7***	***10,921.3***	***8,972.0***	***6,639.4***	***4,404.3***	***2,055.0***
Oregon's Allocation:										***28.3%***	***27.9%***	***27.5%***	***27.9%***	***28.5%***	***28.0%***	***27.4%***	***25.3%***

2009

DIVISION:	Pac. Power	Pac. Power	Pac. Power	Pac. Power	Pac. Power	R.M.P.	R.M.P.	R.M.P.	R.M.P.	*SUM*	*SUM*	*SUM*	*SUM*	*SUM*	*SUM*	*SUM*	*SUM*
MONTH:	CALIFORNIA	OREGON	WASHINGTON	MONTANA	WYOMING	UTAH	IDAHO	WYOMING	FERC	*Twelve*	*Eight*	*Six*	*Five*	*Four*	*Three*	*Two*	*One*
Jan-09	164.1	2,671.0	841.6	0.0	1,077.1	3,077.1	457.9	239.0	25.4	*8,553.2*	*8,553.2*	*8,553.2*	*8,553.2*	*8,553.2*			
Feb-09	156.9	2,415.2	652.2	0.0	1,012.6	3,205.2	423.8	220.6	25.3	*8,111.8*	*8,111.8*						
Mar-09	153.1	2,409.1	663.7	0.0	1,007.0	2,763.6	359.0	228.1	24.6	*7,608.2*							
Apr-09	131.5	2,084.2	581.1	0.0	959.4	2,714.1	326.6	242.6	26.0	*7,065.4*							
May-09	125.6	2,019.6	639.7	0.0	931.1	3,391.7	502.1	211.9	29.3	*7,851.1*							
Jun-09	144.6	1,982.5	597.8	0.0	955.3	4,170.1	338.4	204.2	27.6	*8,420.5*	*8,420.5*	*8,420.5*	*8,420.5*				
Jul-09	148.8	2,404.0	773.8	0.0	861.3	4,374.1	311.6	149.4	43.1	*9,066.1*	*9,066.1*	*9,066.1*	*9,066.1*	*9,066.1*	*9,066.1*	*9,066.1*	*9,066.1*
Aug-09	133.3	2,296.0	769.8	0.0	944.3	4,225.4	373.7	158.4	42.2	*8,943.1*	*8,943.1*	*8,943.1*	*8,943.1*	*8,943.1*	*8,943.1*	*8,943.1*	
Sep-09	131.9	2,079.6	683.0	0.0	967.8	3,769.3	392.8	157.4	41.1	*8,223.0*	*8,223.0*	*8,223.0*					
Oct-09	128.6	2,106.6	593.5	0.0	999.7	2,816.7	391.3	237.0	27.2	*7,300.6*							
Nov-09	129.3	2,200.6	674.6	0.0	1,018.1	3,287.0	438.8	259.8	29.1	*8,037.4*	*8,037.4*						
Dec-09	183.1	2,782.6	804.6	0.0	1,074.4	3,188.6	461.9	262.1	27.8	*8,785.1*	*8,785.1*	*8,785.1*	*8,785.1*	*8,785.1*	*8,785.1*		
Load Curtailment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	*0.0*							
Total	1,730.8	27,450.9	8,275.5	0.0	11,808.3	40,982.9	4,777.6	2,570.5	368.8								
System Sum of the Monthly Peaks:										***97,965.4***	***68,140.1***	***51,990.9***	***43,767.9***	***35,347.4***	***26,794.2***	***18,009.2***	***9,066.1***
Oregon's Sum:										***27,450.9***	***18,831.5***	***14,215.6***	***12,136.0***	***10,153.5***	***7,482.5***	***4,700.0***	***2,404.0***
Oregon's Allocation:										***28.0%***	***27.6%***	***27.3%***	***27.7%***	***28.7%***	***27.9%***	***26.1%***	***26.5%***

Observation: Only the 4 CP method allocates more costs to Oregon than does the 12 CP.

Data Source: PacifiCorp response to Staff Data Request No. 4.

CASE: UM 1050
WITNESS: George R. Compton

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STAFF EXHIBIT 504

Exhibits in Support
Of Reply Testimony

January 27, 2011

The Recent Relationship Between Production Plant Additions and Transmission Plant Additions

Year	Form No.1 Page No.	Plant Type	Balance at First of Year or Study	Plant Additions	Percent Added	Trans. Added $ as % of Prod. Added $
2009	206	Transmission	$ 3,054,528,950	$ 290,605,412	9.5%	32%
2009	204	Production	$ 7,843,110,481	$ 918,175,807	11.7%	
2008	206	Transmission	$ 2,874,659,491	$ 216,509,847	7.5%	19%
2008	204	Production	$ 6,804,803,585	$ 1,153,927,387	17.0%	
2007	206	Transmission	$ 2,688,838,612	$ 183,569,758	6.8%	23%
2007	204	Production	$ 6,133,570,884	$ 790,017,926	12.9%	
2006	206	Transmission	$ 2,578,317,498	$ 121,301,060	4.7%	17%
2006	204	Production	$ 5,486,817,905	$ 697,503,624	12.7%	
2005	206	Transmission	$ 2,487,677,072	$ 92,287,163	3.7%	27%
2005	206	Production	$ 5,197,612,430	$ 343,537,891	6.6%	
2004	206	Transmission	$ 2,396,664,935	$ 101,775,919	4.2%	70%
2004	206	Production	$ 5,129,606,624	$ 144,929,531	2.8%	
2004 -	Cumulative	Transmission	$ 2,396,664,935	$ 1,006,049,159	42%	25%
2009	Cumulative	Production	$ 5,129,606,624	$ 4,048,092,166	79%	

Observation: **As generation/production resources are increased, the other common system-based facility, transmission, is not static but grows as well.**

Data Source: FERC Form No. 1 (Q4)

CASE: UM 1050
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 505

Exhibits in Support
Of Reply Testimony

January 27, 2011

The Impact on Oregon of 2010 Protocol's Proposed Levelizing

Oregon's **Hydo ECD Benefit** Under 2010 Protocol by Year @ Different Discount Rates ($000)

Year		Original Raw Values				
2011		12469		12469		12469
2012		5876		5876		5876
2013		1635		1635		1635
2014		6019		6019		6019
2015		5895		5895		5895
2016		8577		8577		8577
NPV Sum If Discounted @	0%	40,471	7.36%	32,298	5%	34,588
Year		**Levelized Values**				
2011		6745		6851		6814
2012		6745		6851		6814
2013		6745		6851		6814
2014		6745		6851		6814
2015		6745		6851		6814
2016		6745		6851		6814
NPV Sum If Discounted @	0%	40,470	7.36%	32,296	5%	34,586

Observation: Receiving 6851 per year is better on a NPV basis than receiving each year's raw values themselves or the levelized values obtained from discounting at the lower indicated rates.

Oregon's **Klamath Surcharge Burden** by Year @ Different Discount Rates ($000)

Year		Original Raw Values				
2011		11308		11308		11308
2012		11396		11396		11396
2013		11466		11466		11466
2014		11573		11573		11573
2015		11640		11640		11640
2016		11694		11694		11694
NPV Sum If Discounted @	0%	69,077	7.36%	54,195	5%	58,378
Year		**Levelized Values**				
2011		11513		11496		11501
2012		11513		11496		11501
2013		11513		11496		11501
2014		11513		11496		11501
2015		11513		11496		11501
2016		11513		11496		11501
NPV Sum If Discounted @	0%	69,078	7.36%	54,192	5%	58,376

Observation: Giving up 11496 per year is better on a NPV basis than giving each year's raw values themselves or the levelized values obtained from discounting at the lower indicated rates.

Data Source: Exhibits PPL/206 and PPL/207.

CASE: UM 1050
WITNESS: George R. Compton

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 506

Exhibits in Support
Of Reply Testimony

January 27, 2011

An Illustrative Exercise Comparing Potential Outcomes of Alternative Interjurisdictional Production Cost Allocation Approaches in the Presence of a Hydro Endowment

				Hydro		Pre-05 Thermal		Post-05 Thermal		Combined Thermal		Cost Allocations, etc. for Indicated Years (i.e., 2005, V<2016, X>2016, Y>>X): Hydro is Direct Assigned		Rolled-In		Revised Protocol					2010 Protocol				
Study Year	State	MWh x 1000	% of MWh	Cost $/MWh	MWh x 1000	Cost $/MWh	MWh x 1000	Cost $/MWh	MWh x 1000	Cost $/MWh	MWh x 1000	Cost $/MWh	Allocation $ x 1000	Cost $/MWh	Allocation $ x 1000	ECD ($/MWh)	ECD Debit ($)	ECD Credit ($)	Cost $/MWh	Allocation $ x 1000	ECD ($/MWh)	ECD Debit ($)	ECD Credit ($)	Cost $/MWh	Allocation $ x 1000
Initial Period (2005) Loads												Direct Assigned; No Thermal Vintaging		Rolled-In		Revised Protocol (No Thermal Vintaging)					2010 Protocol (No Thermal Vintaging)				
'05	OR	450,000	45%		150,000		300,000			-	300,000	43.3	19,500,000	47.0	21,150,000	20.0	3,000,000	1,350,000	43.3	19,500,000	20.0	3,000,000	1,350,000	43.3	19,500,000
'05	UT	550,000	55%	N.A.	-		550,000			-	550,000	50.0	27,500,000	47.0	25,850,000			1,650,000	50.0	27,500,000			1,650,000	50.0	27,500,000
'05	Total	1,000,000	100%	30	150,000	50	850,000		-	50.0	850,000	47.0	47,000,000	47.0	47,000,000				47.0	47,000,000				47.0	47,000,000
Year V Loads												Dir. Assigned; No Post-05 Thermal Vintaging		Rolled-In		Revised Protocol (No Thermal Vintaging)					2010 Protocol (No Thermal Vintaging)				
V<'16	OR	480,000	40%		125,000					-	355,000	51.5	24,731,395	54.0	25,900,000	15.6	1,947,674	779,070	51.5	24,731,395	5.0	625,000	250,000	53.2	25,525,000
V<'16	UT	720,000	60%	N.A.	-					-	720,000	55.6	40,018,605	54.0	38,850,000			1,168,605	55.6	40,018,605			375,000	54.5	39,225,000
V<'16	Total	1,200,000	100%	40	125,000	45	750,000	80	325,000	55.6	1,075,000	54.0	64,750,000	54.0	64,750,000				54.0	64,750,000				54.0	64,750,000
Year X Loads												Dir. Assigned; No Post-05 Thermal Vintaging		Rolled-In		Revised Protocol (No Thermal Vintaging)					2010 Protocol (No Thermal Vintaging)				
X>'16	OR	500,000	38%		110,000					-	390,000	59.5	29,752,101	61.2	30,576,923	12.2	1,340,336	515,514	59.5	29,752,101	(10.0)	(1,100,000)	(423,077)	62.5	31,253,846
X>'16	UT	800,000	62%	N.A.	-					-	800,000	62.2	49,747,899	61.2	48,923,077			824,822	62.2	49,747,899			(676,923)	60.3	48,246,154
X>'16	Total	1,300,000	100%	50	110,000	40	750,000	100	440,000	62.2	1,190,000	61.2	79,500,000	61.2	79,500,000				61.2	79,500,000				61.2	79,500,000
Year X Loads												Dir. Assigned; With Post-05 Thermal Vintaging		Rolled-In		Revised Protocol (No Thermal Vintaging)					2010 Protocol (No Thermal Vintaging)				
X>'16	OR	500,000	38%		110,000		337,500		52,500	-	390,000	48.5	24,250,000	61.2	30,576,923	12.2	1,340,336	515,514	59.5	29,752,101	(10.0)	(1,100,000)	(423,077)	62.5	31,253,846
X>'16	UT	800,000	62%	N.A.	-		412,500		387,500	-	800,000	69.1	55,250,000	61.2	48,923,077			824,822	62.2	49,747,899			(676,923)	60.3	48,246,154
X>'16	Total	1,300,000	100%	50	110,000	40	750,000	100	440,000	62.2	1,190,000	61.2	79,500,000	61.2	79,500,000				61.2	79,500,000				61.2	79,500,000
Year Y Loads												Dir. Assigned; With Post-05 Thermal Vintaging		Rolled-In		Revised Protocol (No Thermal Vintaging)					2010 Protocol (No Thermal Vintaging)				
Y>>X	OR	520,000	37%		100,000		135,000		285,000	-	420,000	90.6	47,100,000	103.6	53,857,143	46.9	4,692,308	1,742,857	97.9	50,907,692	(30.0)	(3,000,000)	(1,114,286)	107.2	55,742,857
Y>>X	UT	880,000	63%	N.A.	-		165,000		715,000	-	880,000	111.3	97,900,000	103.6	91,142,857			2,949,451	106.9	94,092,308		-	(1,885,714)	101.4	89,257,143
Y>>X	Total	1,400,000	100%	60	100,000	30	300,000	130	1,000,000	106.9	1,300,000	103.6	145,000,000	103.6	145,000,000				103.6	145,000,000				103.6	145,000,000

NOTES: OR denotes a jurisdiction with a substantial hydro endowment; UT denotes a jurisdiction that lacks hydro. The indicated Loads and Costs capture conceptual relationships rather than denoting actual projections for Oregon or Utah.
For purposes of this exercise, the only difference between the Revised Protocol and the 2010 Protocol is in how the Embedded Cost Differential (ECD) is defined.

ECD definition for the Revised Protocol: The difference (in $/MWh) between the average cost of themal production and the average cost of hydro production.

ECD definition for the 2010 Protocol: The difference (in $/MWh) between the average cost of production from pre-2005 thermal resources and the average cost of hydro production.

ECD simplifying assumption: The SG factors (used to allocate the ECD Credit) are identical to the MWh percentage shares, i.e., the SE factors.

ECD Debit: The amount **subtracted from** the original (i.e., rolled-in) production cost allocation to the hydro-possessing state (i.e., OR). It is calculated as the product of the ECD, per se, and the number of MWhs assigned to the recipient state (OR).

ECD Credits: The amounts **added to**, respectively, the original (i.e., rolled-in) production cost allocations to both states (i.e., OR and UT) so as to appropriately offset the ECD debit. It is calculated as the product of the ECD Debit and the state's SG factor (or here the SE factor).

Rolled-In production cost allocation: The product of the system-average production costs and the state's total load. System-average costs are total costs divided by total loads.

Direct Assigned operating assumption: No production cost efficiencies are lost because the utility continues to be operated as an overall cost-minimizing entity.

Diect Assigned cost allocation with no vintaging: Allocation to OR is the average cost of hydro times the total volume of hydro plus the average cost of combined thermal times the OR volume not served by hydro.
Allocation to UT is the average cost of combined thermal times the entire UT load.

Rule for post-2005 thermal resource vintage assignments: Output is assigned to the jurisdictions in proportion to their shares of the 2005 loads.

Direct Assigned cost allocation with vintaging: Allocation to OR is the average cost of hydro times the total volume of hydro plus the average cost of the pre-2005 thermal production times the volume of pre-2005 thermal output assigned to OR plus the average cost of the post-2005 thermal times the volume of post-2005 thermal output assigned to OR.
Allocation to UT is the average cost of the pre-2005 thermal production times the volume of pre-2005 thermal output assigned to UT plus the average cost of the post-2005 thermal production times the volume of post-2005 thermal output assigned to UT.

CONCLUSIONS:

from the '05 study year: The Revised Protocol is not fundamentally inconsistent with a Direct Assigned cost allocator in terms of preserving the benefits of the hydro endowment.

from the V<2016 study year: Some of the benefits of the hydro endowment would be lost in achieving the 2010 Protocol's compromise between Rolled-In and the Revised Protocol.

from the first X>2016 study; no thermal vintaging: The 2010 Protocol would, perniciously, cause what should be a valuable hydro endowment to become a burden -- yielding an allocation to OR that would exceed the Rolled-In allocation.

m the second X>2016 study; with thermal vintaging: Compared with a "vintaged" Direct Assigned allocation, the Revised Protocol does not protect OR from UT's greater growth rate.

from the Y>>X study: This shows the possibility of having circumstances where over time hydro comes to be substantually more expensive than pre-05 thermal (due to expensive hydro relicensing expenses coupled with largely depreciated pre-05 thermal plants), thereby causing the ECD under the 2010 Protocol to become strongly negative, and resulting in the OR cost allocation under the 2010 Protocol exceeding Rolled-In's by a substantial amount -- even though, on average, hydro remains significantly cheaper than thermal. The Revised Protocol does keep OR's cost allocation below Rolled-In's allocation for OR.

Note: For additional/algebraic clarity regarding the ECD, refer to Exhibit Staff/502.

CERTIFICATE OF SERVICE

UM 1050

I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated at Salem, Oregon, this 27th day of January, 2011.

Kay Barnes

Kay Barnes
Public Utility Commission
Regulatory Operations
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UM 1050
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