Docket No. UM 1050
Exhibit PAC/100
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of R. Bryce Dalley

December 2015

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ATTACHED EXHIBITS

Q. Please state your name, business address and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is R. Bryce Dalley and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as Vice President, Regulation. I am testifying for PacifiCorp.

QUALIFICATIONS

Q. Please summarize your education and business experience.

A. I received a Bachelor of Science degree in Business Management with an emphasis in finance from Brigham Young University in 2003. I completed the Utility Management Certificate Program at Willamette University in 2009, and I also attended various educational, professional, and electric-industry-related seminars. I have been employed by PacifiCorp since 2002 in various positions within the regulation and finance organizations. I was appointed Manager of Revenue Requirement in 2008 and was promoted to Director, Regulatory Affairs and Revenue Requirement in 2012. I assumed my current position in January 2014. I am responsible for all regulatory activities in Oregon, California, and Washington.

PURPOSE AND OVERVIEW OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony describes the process and approaches leading up to this filing of the 2017 PacifiCorp Inter-Jurisdictional Allocation Protocol (2017 Protocol). Specifically, my testimony provides:

- a brief history of the Multi-State Process (MSP) leading to the 2017 Protocol;

- a summary of the work conducted by the Broad Review Work Group (BRWG) since November 2012 that has culminated in this filing;
- an overview of the 2017 Protocol;
- a discussion of the Company's view of the timing for commission proceedings necessary to process this Petition;
- a discussion of the annual commissioner's forum;
- an explanation of the purpose of the Equalization Adjustment;
- a discussion of the term of the 2017 Protocol; and
- a discussion of the Reservation of Rights.

Additionally, Mr. Steven R. McDougal addresses the calculation and implementation of the 2017 Protocol and discusses the revenue requirement analyses undertaken at the request of the BRWG.

Q. What is the purpose of your testimony in support of the 2017 Protocol?

A. My testimony describes and supports the 2017 Protocol agreed to among PacifiCorp and the signatories to the 2017 Protocol (referred to individually as a Party or collectively as the Parties). The 2017 Protocol describes the multi-jurisdictional allocation methodology that will be used by the Company in all rate proceedings beginning January 1, 2017.

Q. Are you also sponsoring an exhibit to your testimony?

A. Yes. Exhibit PAC/101 presents the 2017 Protocol with all of its appendices. Although I sponsor appendix A, Mr. McDougal sponsors the remaining appendices.

BRIEF HISTORY OF MSP AND THE DEVELOPMENT OF THE 2017 PROTOCOL

Q. Please provide a brief history of the events that gave rise to the 2017 Protocol.

A. MSP began in 2002, with PacifiCorp filing applications in each of its six jurisdictions to create a process to consider issues related to its status as a multi-jurisdictional utility. Following years of discussions and negotiations, the Revised Protocol was agreed to by the Parties and approved by the commissions in Idaho, Oregon, Utah, and Wyoming. The Revised Protocol allocated costs among PacifiCorp's jurisdictions and ensured that the Company operated its generation and transmission system on an integrated basis to achieve a least cost-least risk resource portfolio, while allowing each state to independently establish its ratemaking policies.

Thereafter, subsequent and substantial discussions occurred to address various concerns raised by stakeholders in different states that resulted in the development of the 2010 Protocol. The 2010 Protocol was agreed to by the parties on September 15, 2010, and was designed to allocate PacifiCorp's costs among its jurisdictions in an equitable manner, ensure PacifiCorp plans and operate its generation and transmission system on a six-state integrated basis that achieved a least cost-least risk resource portfolio for customers, allow each state to independently establish its ratemaking policies, and provide PacifiCorp with the opportunity to recover its prudently-incurred costs. The 2010 Protocol was approved by the commissions in Idaho, Oregon, Utah and Wyoming.

One of the terms of 2010 Protocol was a specified termination date. The Parties to the 2010 Protocol agreed that it would only be used for regulatory filings made before January 1, 2017. Knowing that it would take some time to develop a new allocation methodology, the MSP standing committee (a committee consisting of one member or delegate from each commission) and BRWG started collaborating in November 2012 to come up with potential solutions acceptable to all Parties in the context of an allocation methodology, including the performance of various studies by the Company at the request of the Standing Committee.

Q. Who participated in the MSP collaborative meetings?

A. The MSP meetings were typically attended by in excess of 50 individuals in person or by teleconference, representing 18 entities from the states of Idaho, Oregon, Utah, Washington, and Wyoming. These included representatives of state commission policy staffs, advocacy staffs, industrial customers and consumer groups.

Q. Did stakeholders from California and Washington participate in the MSP?

A. Not for the entire process. Representatives from the California Public Utilities Commission participated in the May 1, 2015 commissioner forum, but did not participate in the negotiations. PacifiCorp's inter-jurisdiction allocation methodologies are considered in the course of the Company's general rate case cycle in California, and prior approval is generally not required. Representatives from Washington participated in early discussions, but they are not signatories to the 2017 Protocol since the Washington Utilities and Transportation Commission has adopted a different allocation methodology for PacifiCorp's Washington rate proceedings.

Q. Who are the signatories to the 2017 Protocol?

A. The Parties signing the 2017 Protocol include: PacifiCorp, Public Utility Commission of Oregon Staff, the Citizens' Utility Board of Oregon, the Idaho Public Utilities Commission Staff, Utah Division of Public Utilities, Utah Office of Consumer Services, Wyoming Office of Consumer Advocate, Wyoming Industrial Energy Consumers, and the Wyoming Public Service Commission Staff. The Utah Association of Energy Users were a party to the negotiations and, although not available at the time of filing, the Company anticipates receiving a signature page and filing it with the Commission in the near future.

Q. Did the BRWG establish principles to guide their review of inter-jurisdictional cost allocation alternatives?

A. Yes, the BRWG developed principles and criteria to guide their review of allocation alternatives. The four key criteria that the allocation method should incorporate were to:

1. Maintain state sovereignty by not impeding states from pursuing policy directives or flexibility in establishing class allocation or rate design;
2. Provide an equitable solution for the Company and all states based on principles of cost causation;
3. Be sustainable by promoting rate stability and avoiding unreasonable or inappropriate cost shifts; and
4. Promote administrative ease.

Q. Do you believe the 2017 Protocol meets these requirements?

A. Yes. The 2017 Protocol generally accomplishes these requirements. During negotiations, however, some Parties requested that the 2017 Protocol be designed as a short-term methodology until impacts of the United States Environmental Protection Agency (EPA) rules governing carbon pollution from existing power plants under section 111(d) of the Clean Air Act (Rule 111(d)) and other issues could be better understood. Based on this feedback, the initial term of the 2017 Protocol is for two years with the option of a one year extension.

Q. How did the Parties address the equity issue with the 2017 Protocol?

A. Through extensive negotiations with the Parties, an Equalization Adjustment was added to the 2017 Protocol to account for inconsistent implementation of the 2010 Protocol, and to allow the Company a better opportunity to recover its costs.

Q. Does the 2017 Protocol allow the Company an opportunity to collect all of its prudently incurred costs?

A. Not entirely. The Equalization Adjustment mitigates the issues caused by inconsistent implementation of the 2010 Protocol but it does not fully provide the Company the ability to recover all its costs.

Q. Why was the Company willing to agree to a method that didn't allow it to recover all of its cost?

A. The Company agreed to the 2017 Protocol for two primary reasons: first because this was a short-term solution; and second, the Company appreciated the BRWG good faith approach to implement an Equalization Adjustment, which reduces the allocation shortfall the Company was experiencing with the 2010 Protocol.

Q. Does the 2017 Protocol contain provisions for continued dialogue among the states?

A. Yes. The Parties have committed to hold an annual public meeting to which all seated commissioners from each jurisdiction where the Company provides retail service will be invited to discuss the 2017 Protocol and other inter-jurisdictional allocation issues (Commissioner Forums), beginning in January 2017. All seated commissioners from each jurisdiction will be invited to participate in all Commissioner Forums. At the first Commissioner Forum, commissioners will be invited to discuss and make recommendations regarding extension of the 2017 Protocol and other inter-jurisdictional allocation issues that may arise.

In addition, before each annual Commissioner Forum, the Company will convene an MSP BRWG meeting for the purpose of discussing and monitoring emerging inter-jurisdictional allocation issues facing the Company and its customers, the status and implications of EPA's Rule 111(d), or the development of a regional independent system operator, in order to inform discussions at the Commissioner Forum.

OVERVIEW OF 2017 PROTOCOL

Q. Please provide an overview of the 2017 Protocol.

A. The 2017 Protocol was negotiated as an integrated, interdependent agreement. All sections were discussed, resulting in a negotiated agreement based on the entirety of the language. Any material alteration of any terms or conditions contained in the 2017 Protocol would require additional discussions and may affect any Party's continued support for the agreement.

Q. How was the 2017 Protocol developed?

A. The 2017 Protocol was largely developed using the 2010 Protocol as the starting point and further refining areas within that methodology to arrive at the new agreement and allocation methodology. A major focus was on arriving at a single allocation methodology that all of the Parties could support that made progress towards reducing the allocation shortfall resulting from differences in application of the 2010 Protocol. This resulted ultimately in the development of an Equalization Adjustment, that when combined with the Embedded Cost Differential (ECD), produces the 2017 Protocol Adjustment. The 2017 Protocol Adjustment is added to each state's annual revenue requirement. This modification to the 2010 Protocol is intended to reduce unintended ECD variations due to nonuniform implementation of the 2010 Protocol. Other changes were made to address direct access treatment, the duration of the 2017 Protocol, and process issues.

DETAILED DISCUSSIONS OF SECTIONS I TO XIV

Q. Please describe each section of the 2017 Protocol Agreement.

A. The 2017 Protocol has 14 sections that contain the terms and conditions agreed to by the Parties through the negotiations.

Section I provides an introduction to the 2017 Protocol. Section I makes it clear that the 2017 Protocol is not intended to prejudge the prudence of any costs or abrogate a State Commission's right and/or obligation to determine fair, just, and reasonable rates based upon the law of that State and the record established in rate proceedings conducted by that Commission. The Parties and State

Commissions are also not prohibited from considering any changes in laws, regulations or circumstances on inter-jurisdictional allocation policies and procedures when determining fair, just, and reasonable rates. The 2017 Protocol also does not prohibit the establishment of different allocation policies and procedures for purposes of allocation of costs and revenues within a State to different customers or customer classes.

Section II discusses the effective period and expiration of the 2017 Protocol.

Section III identifies the classification of resources between Demand-Related, meaning capital and fixed costs incurred or revenues received in order to be prepared to meet the maximum demand imposed upon the Company's system, or Energy-Related, costs and revenues that vary based on the amount of energy delivered to customers.

Section IV discusses the allocation of resource costs and wholesale revenues. Resources are assigned to one of two categories of inter-jurisdictional allocation: State Resources or System Resources. State Resources refer to those resources that accommodate jurisdiction-specific policy. Costs for these resources are assigned to a specific jurisdiction. There are four types of State Resources: demand-side management programs; portfolio standards; qualifying facility contracts; and jurisdiction-specific initiatives. System Resources are all other resources and are allocated across all jurisdictions.

Section V includes a commitment by the Company to submit filings seeking authorization from the State Commissions prior to filing for approval from the Federal Energy Regulatory Commission of the re-functionalization of facilities as transmission or distribution. This section also identifies the allocation for transmission costs and revenues as 75 percent Demand-Related and 25 percent Energy-Related.

Section VI states that distribution-related expenses and investments are directly assigned to the State in which the related facilities are located where possible. Costs that cannot be directly assigned are allocated based on the factors in Appendix B to the 2017 Protocol.

Section VII addresses the allocation of administrative and general costs. Such costs are allocated based on the factors in Appendix B to the 2017 Protocol.

Section VIII provides that any Special Contracts - contracts between the Company and one of its retail customers based on specific circumstances of the customer - will be included in load-based dynamic allocation factors identified in Appendix D to the 2017 Protocol.

Section IX states that any loss or gain from the sale of a Company-owned resource or transmission asset are allocated among the States based on the allocation factor used to allocate the fixed costs of the resource or asset at the time of the sale. The 2017 Protocol reserves to each State Commission the authority to determine the appropriate allocation between the Company’s customers and shareholders.

Section X addresses the treatment of loads lost to alternative energy suppliers through State direct access or other programs.

Section XI identifies the treatment of changes in retail load.

Section XII includes a commitment that the Company will plan and acquire resources on a system-wide least cost, least-risk basis, with prudently incurred investments reflected in rates consistent with the laws and regulations in each State.

Section XIII outlines the parameters for interpretation and governance. Section XIII also provides for a Commissioner Forum to be held annually and an MSP Workgroup, similar to the BRWG, open to any interested stakeholders. Proposals for new inter-jurisdictional allocation procedures, including any modifications proposed to the 2017 Protocol, can be submitted by any Party or Commission using the 2017 Protocol.

Section XIV contains additional, State-specific terms. These additional terms include the State-specific Equalization Adjustment negotiated by the Parties. This section also identifies specific commitments by the Company regarding general rate case timing during the effective period of the 2017 Protocol.

The 2017 Protocol also includes a set of appendices providing defined terms and specific details regarding allocation factors and their derivations. The appendices to the 2017 Protocol are more thoroughly discussed in the testimony of Mr. McDougal.

TERM OF 2017 PROTOCOL

Q. Did the Parties Agree to a specific effective period for the 2017 Protocol?

A. Yes. The Parties agreed to support Commission adoption or use of the 2017 Protocol in all PacifiCorp rate proceedings filed after December 31, 2016, through

December 31, 2018. The 2017 Protocol will expire December 31, 2018, unless all state Commissions that approved the 2017 Protocol determine, by no later than March 31, 2017, that the term of the 2017 Protocol will be extended by an optional one-year extension through December 31, 2019. In determining whether the 2017 Protocol should or should not be extended, each state Commission can take such steps or provide such processes for public input as that Commission determines to be necessary or appropriate under applicable state laws.

Q. Why did the Parties agree to a two-year inter-jurisdictional allocation methodology?

A. The 2017 Protocol is intended to be a transitional allocation mechanism while the impacts of EPA's Rule 111(d) and other multi-jurisdictional issues are better understood and analyzed. The 2017 Protocol also provides an opportunity for PacifiCorp to analyze, among other things, alternative allocation methods that may include the formation for a regional independent system operator, corporate structure alternatives, or divisional allocation methodologies, in light of the changing electric industry in the Western United States.

Q. Assuming that the four state Commissions acknowledge the 2017 Protocol, what ongoing processes does the Company envision related to the 2017 Protocol?

A. As reflected in the 2017 Protocol, the Company committed to perform studies and analysis and to continue to report the results of this ongoing work to the BRWG. Although the elements of the 2017 Protocol are designed to minimize controversy and provide predictability through calendar year 2018, and perhaps 2019, there are always emerging issues on which it is valuable for the BRWG to continue to engage in discussions.

RESOURCE CLASSIFICATION AND COST AND REVENUE ALLOCATION

Q. How does the 2017 Protocol allocate costs and revenues?

A. Resources fixed costs, wholesale contracts, and short-term firm purchases and sales are classified as 75 percent Demand-Related and 25 percent Energy-Related. Non-firm purchases and sales are classified as 100 percent Energy-Related. This allocation balances the impact of demand and load on system costs.

Q. What is the difference between State Resources and System Resources?

A. State Resources include four defined types of resources that are dependent on specific state policy. Accordingly, it is appropriate to allocate the benefits and costs associated with these resources to a particular jurisdiction on a situs basis. System Resources include the substantial majority of the Company's resources, and contribute to retail service across the Company's entire multi-jurisdictional service territory.

Q. What types of resources are included in State Resources?

A. There are four types of State Resources. The first type of State Resource is demand-side management programs. These programs may include incentives for energy efficiency and demand response to reduce load. Costs associated with these programs are assigned on a situs basis to the jurisdiction in which the investment is made. Benefits from demand-side management programs are reflected in the load-based dynamic allocation factors.

The second type of State Resource includes resources acquired to comply with a jurisdiction's mandated resource portfolio standard, adopted through legislative enactment or by a regulatory commission. The portion of costs associate with portfolio standards that exceed the costs the Company would have otherwise incurred acquiring comparable resources (resources with similar capacity factors, start-up costs, and other output and operating characteristics) are assigned on a situs basis to the jurisdiction adopting the portfolio standard.

The third type of State Resource includes qualifying facility contacts executed under the requirements of the Public Utility Regulatory Policies Act (PURPA). PURPA requires that a public utility agree to purchase energy from certain cogeneration and small renewable energy generating facilities that meet the definition of a qualifying facility under PURPA. State commissions set the prices for each public utility under its jurisdiction for power purchase agreements under PURPA. The 2017 Protocol assigns the costs associated with qualifying facility contracts on a system basis unless a portion of the cost exceeds the costs the Company would have otherwise incurred acquiring comparable resources (resources with similar capacity factors, start-up costs, and other output and operating characteristics), which would then be assigned on a situs basis to the jurisdiction that approved the contract.

The final type of State Resource includes any resources acquired in accordance with an initiative adopted by a specific jurisdiction. Any such resource is assigned on a situs basis to the jurisdiction adopting the initiative. Examples of these jurisdiction-specific initiatives include certain incentive programs, net-metering tariffs, capacity standard programs, solar subscription programs, electric vehicle programs, and the acquisition of renewable energy certificates.

Q. Does the 2017 Protocol alter the Company's resource planning responsibility or a Commission's authority?

A. No. Section XII provides that the Company will plan and acquire new resources on a system-wide least-cost least-risk basis. Prudently incurred investments in resources will be reflected in rates consistent with the laws and regulations in each State, and approved by that State's Commissions consistent with such laws and regulations.

EMBEDDED COST DIFFERENTIAL

Q. Explain the continued use of the Embedded Cost Differential in the 2017 Protocol?

A. As a result of negotiations, the Parties agreed that the ECD would continue as a component of the 2017 Protocol as modified and incorporated into an overall 2017 Protocol Adjustment that will be included in each State's revenue requirement. The ECD is fixed for Wyoming, Idaho and California; for Utah it is zero; and for Oregon, it is dynamic with upper and lower limits, for the duration of the 2017 Protocol. This treatment of the ECD during the term of the 2017 Protocol, eliminates or mitigates unintended allocation consequences that occurred under the 2010 Protocol.

The ECD in the 2017 Protocol is referred to as the Baseline ECD. For California and Wyoming, the Baseline ECD was established using the data, as filed by the Company on March 3, 2015, in the 2015 Wyoming general rate case (Docket No. 20000-469-ER-15). Oregon's 2017 Protocol Baseline ECD is dynamic and will change over time with the parameters described in the 2017 Protocol. Idaho's Baseline ECD is its 2010 Protocol Fixed ECD amount. Utah's Baseline ECD is zero consistent with its 2010 Protocol agreement.

Q. Please describe the 2017 Protocol Adjustment and how it is implemented.

A. For the period that the 2017 Protocol remains in effect, a 2017 Protocol Adjustment will be added to each state's annual revenue requirement. The 2017 Protocol Adjustment is the sum of the 2017 Protocol Baseline ECD and the 2017 Protocol Equalization Adjustment.

Q. Please explain the 2017 Protocol Equalization Adjustment.

A. The Equalization Adjustment is a fixed dollar adjustment to be applied to each state's revenue requirement as specified in Section XIV of the 2017 Protocol. Parties to the 2017 Protocol negotiated an annual Equalization Adjustment of $9.074 million representing approximately two-tenths of one percent of each state's annual revenue requirement. The Equalization Adjustment is intended to recognize differences among the states' implementation of the 2010 Protocol respective to the treatment of the ECD adjustment i.e.; fixed ECD, dynamic ECD, or no ECD. The result of the 2017 Protocol Equalization Adjustment is to equitably share the allocation shortfall resulting from differences in the implementation of the 2010 Protocol while analysis continues on the development of a more permanent allocation method.

Q. What is the amount of the 2017 Protocol Adjustment that will be added to each state's annual revenue requirement?

A. California's 2017 Protocol Adjustment is zero because its Equalization Adjustment exactly offsets its Baseline ECD, Idaho's is $0.986 million, Utah's is $4.4 million and Wyoming's is a credit of $0.251 million. Because Oregon's Baseline ECD is dynamic within specified ranges, its 2017 Protocol Adjustment will be between a $5.6 million and an $8.4 million credit.

Q. Describe the difference between the fixed Baseline ECD used by the other states versus Oregon's Baseline ECD.

A. As mentioned above, with the exception of Oregon, the Baseline ECD is fixed for the duration of the 2017 Protocol. Oregon will continue to use a dynamic ECD for its Baseline ECD but the value is subject to lower and upper limits based on the negotiations with Oregon Parties. Oregon's lower limit (or floor) of the Baseline ECD is $8.238 million and the upper limit (or cap) is $10.5 million for the first general rate case filed under 2017 Protocol. If the Company files a second general rate case using 2017 Protocol there's no change to the lower limit but the upper limit (or cap) is increased to $11.0 million.

Q. Why is Oregon's ECD dynamic?

A. The Company agreed to Oregon's continued use of a dynamic ECD calculation as part of the negotiations. A dynamic ECD for Oregon is consistent with the 2010 Protocol. However, establishing parameters around the dynamic ECD, as agreed to by Oregon Parties as part of a negotiated outcome, mitigates many of the issues faced by the Company under the 2010 Protocol.

COST ALLOCATIONS

Q. How are transmission costs and revenues allocated under the 2017 Protocol?

A. Costs associated with transmission assets and firm wheeling expenses are classified as 75 percent Demand-Related and 25 percent Energy-Related. These costs are allocated based on a system generation factor. Non-firm wheeling expenses and revenues are allocated on a system energy factor. The system generation factor and system energy factors are described in the appendices to the 2017 Protocol.

Q. How are distribution costs assigned under the 2017 Protocol?

A. Distribution-related expenses and investments are directly assigned to the state where they are located where possible. There are certain distribution expenses and investments that cannot be directly assigned. For the costs that cannot be directly assigned, they will be allocated consistent with the factors identified in Appendix B to the 2017 Protocol.

Q. Can the company reclassify its facilities between transmission and distribution?

A. Yes. The classification of facilities as transmission or distribution depends on how the facility is used, and may change over time. Any such reclassification is generally done following an analysis by the Company, using tests adopted by the Federal Energy Regulatory Commission. The Company has committed in the 2017 Protocol to seek review and authorization of any such reclassification with the State Commissions before filing any request to approve a reclassification of facilities with the Federal Energy Regulatory Commission.

Q. How does the 2017 Protocol allocate administrative and general costs?

A. Appendix B provides for the specific allocation of administrative and general costs, general plant costs and intangible plant costs are allocated consistent with the factors in Appendix B to the 2017 Protocol.

Q. How does the 2017 Protocol address special contracts?

A. The 2017 Protocol provides that revenues associated with special contracts - meaning contracts between the Company and a particular customer based on the specific circumstances of that customer and approved by the state commission - will be included in each State's revenues (situs assigned). Load under the special contract is included in the load-based dynamic allocation factors, for jurisdictional allocation purposes, as defined in Appendix D, as more thoroughly discussed in the direct testimony of Mr. McDougal.

Q. Will the Company allocate any gain or loss from a sale of a resource or transmission asset based on the factors used to allocate the cost associated with that resource or transmission asset for ratemaking purposes?

A. Yes. The allocation of any loss or gain from the sale of a Company-owned resource or transmission asset will be allocated based on the allocation factor used to allocate fixed costs at the time of its sale. Each state commission will determine the allocation of any loss or gain between the Company's customers and shareholders in accordance with its jurisdictional authority.

STATE PROGRAMS PROVIDING ACCESS TO ALTERNATIVE ELECTRICITY SUPPLIERS

Q. Does the 2017 Protocol Address the treatment of alternative Electricity Suppliers or State-specific Direct Access Programs?

A. Yes. The 2017 Protocol specifically addresses the Oregon direct access program. The 2017 Protocol also addresses the potential transfer of electricity service to an alternative electricity supplier in Utah under Utah Code annotated Section 54-3-32, along with a requirement that the Company inform the State commissions and Parties if any State adopts laws or regulations governing customer access to alternative electricity suppliers.

Q. How does the 2017 Protocol treat loads lost to the Oregon direct access programs during the term of the 2017 Protocol?

A. The 2017 Protocol provides that load associated with customers electing the one- or three-year Oregon direct access programs will be included in the load-based dynamic allocation factors for all resources. Transition adjustment payments from these customers will be situs assigned to Oregon.

The treatment of customers electing the five-year opt-out program under the Oregon direct access programs will be treated consistent with Public Utility Commission of Oregon Order No. 15-060, as clarified through Order No. 15-067, and Oregon Schedule 296, which allows customers to permanently opt-out of cost-of-service rates after payment of 10 years of transition costs in Oregon. During the 10-year period when Oregon direct access customers are paying transition costs, the Oregon direct access customers’ loads will be included in load-based dynamic allocation factors, and the transition cost payments from these customers will be situs-assigned to Oregon. At the end of the 10-year period covered by the transition cost payments, the loads of the Oregon direct access customers will be excluded from load-based dynamic allocation factors. Thereafter, if an Oregon direct access customer elects to return to Oregon cost-of-service rates by providing four-years notice under Schedule 296, its load will be included in load-based dynamic allocation factors at the time the customer returns to Oregon cost of service rates.

Q. Does the 2017 Protocol allow for potential modifications to the Oregon direct access program?

A. Yes. Section X of the 2017 Protocol includes a provision to clarify that if Oregon adopts new laws or regulations regarding direct access, the treatment of loads lost to those programs may be re-determined. The Company commits to inform all the State Commissions if this occurs. This is similar to the process that would apply if any State adopts laws or regulations governing customer access to alternative electricity suppliers.

Q. Does the Utah Public Service Commission have a direct access program?

A. No. However, Utah Code Annotated Section 54-3-32 allows certain eligible customers in Utah to transfer electricity service to a non-utility energy supplier. If an eligible customer elects to transfer electricity service to a non-utility energy supplier, the customer must provide its public utility 18 months' notice. Additionally, the Utah Division of Public Utilities must file a petition with the Utah Public Service Commission no later than eight months before the intended date of transfer seeking a determination by the commission regarding: (1) costs or credits allocated to Utah under any inter-jurisdictional cost allocation methodology the commission reasonably expects to be in effect; (2) costs of facilities used to serve the eligible that will not be used by other customers as a direct result of the eligible customer transferring service, and any credits offsetting the costs; and (3) any other costs to the public utility or to other customers of the public utility.

Q. Has the Company committed to notify the State commissions and Parties if the Utah Public Service Commission makes such a determination?

A. Yes.

CHANGES TO COMPANY LOAD

Q. Does the 2017 Protocol include a provision to address changes in load due to changes in the Company's retail service territory?

A. Yes. Section XI addresses the treatment of changes to load as a result of: condemnation or municipalization; the sale or acquisition of new service territory that involves less than five percent of system load; realignment of service territories; changes in economic conditions; or the gain or loss of large customers. These changes would be reflected in changes to the load-based dynamic allocation factors. The load-based dynamic allocation factors are calculated using the States' monthly energy usage and/or contribution to monthly system coincident peak. The allocation of costs and benefits arising from a merger, sale, or acquisition involving more than five percent of system load would be considered on a case-by-case basis in the course of any approval proceedings in each State.

GOVERNANCE

Q. What is the purpose of the annual Commissioner Forums?

A. During the term of the 2017 Protocol, PacifiCorp agreed to analyze alternative allocation methods including corporate structure alternatives, divisional allocation methodologies, alternative system allocation methodologies, potential implications of the EPA's Rule 111(d), and possible formation of a regional independent system operator. As part of the 2017 Protocol, the Company committed to present its analyses of these issues to the MSP BRWG and discuss them at Commissioner Forums.

The Company believes that annual Commissioner Forums are an appropriate way to keep the Commissioners and Parties informed, and that they will be an opportunity for all Parties to discuss whether to extend the 2017 Protocol for an additional year beyond the initial term. The Company anticipates that all Parties will remain engaged in the process of analyzing the results of these studies, and the Company believes that continuing to engage in this type of collaboration is in the best interests of the Parties and PacifiCorp's customers.

Q. Is there an opportunity for interested stakeholders to raise issues with the 2017 Protocol?

A. Yes. Any Party or Commission using the 2017 Protocol for inter-jurisdictional allocation purposes may submit proposals for a new inter-jurisdictional allocation procedure or change to the 2017 Protocol. Any such proposal must be provided to the Company so that Company can distribute the proposal to the other Parties and State Commissions and initiate discussions. The Party or Commission proposing the modification or new inter-jurisdictional allocation procedure must, consistent with its legal obligations, attempt to present the proposal to the Commissioner Forum or MSP Workgroup and negotiate a resolution in good faith.

RESERVATIONS OF RIGHTS

Q. What have the Parties agreed to with respect to reservations of rights?

A. Any Party may request that the Commission rescind, alter, or amend its order entered in connection with the 2017 Protocol if the Party concludes that the 2017 Protocol no longer produces results that are just, fair, reasonable, or in the public interest, due to unforeseen or changed circumstances. In addition, the 2017 Protocol will not bind or be used against any Party if unforeseen or changed circumstances, including new developments such as direct access programs implemented in a state, cause that Party to conclude that the 2017 Protocol no longer produces just and reasonable results, reasonable cost recovery for the Company, or is not in the public interest.

STATE-SPECIFIC TERMS

Q. What were the Oregon-specific terms?

A. In Oregon, the Company agreed that during the effective period of the 2017 Protocol, it will not have any pending general rate case that requests rates effective before January 1, 2018. The Oregon Parties agreed that Oregon's Equalization Adjustment of $2.6 million annually (or $216,667 monthly) would be deferred from January 1, 2017, until the 2017 Protocol Equalization

Adjustment is reflected in base rates through the Company's next general rate case. This deferral will be reflected as a debit or reduction to the existing credit balance to be returned to customers in the Open Access Transmission Tariff (OATT) revenue deferral account originally established through docket UE 246. The Oregon Parties agreed that during the general rate case stay-out period, Oregon Parties may file for deferrals, but such filings will be subject to the Commission's guidelines for deferrals established in docket UM 1147, unless otherwise authorized by the Commission. This provision of the agreement will not alter the operation or application of existing or new rate adjustment mechanisms authorized by the Commission, including, but not limited to, PacifiCorp's Transition Adjustment Mechanism, the Power Cost Adjustment Mechanism, and the Renewable Adjustment Clause.

For the Company's first Oregon general rate case filed under the 2017 Protocol (which will be effective no earlier than January 1, 2018), the dynamic ECD value for Oregon will be set at a level no less than $8.238million (the value of Oregon's ECD used to negotiate each State's contribution to the 2017 Protocol Equalization Adjustment), and will be capped at $10.5 million. If the Company files a second Oregon general rate case using the 2017 Protocol, the dynamic ECD in that general rate case filing will be set at a level no less than $8.238 million and will be capped at $11.0 million.

As part of the Oregon-specific agreement, Parties also agreed that the Company will file a new tariff to return to Oregon customers the balance of the OATT revenue deferral, net of the 2017 Protocol Equalization Adjustment deferral, within 60 days of an Oregon Commission order approving of the 2017 Protocol. The Company also committed to continued evaluation of the analysis I mentioned earlier and to distribute or present the results of its analysis to the BRWG, based on information available, no later than March 31, 2017.

Q. In addition to the Equalization Adjust discussed previously, were there state-specific implementation terms for states other than Oregon?

A. Yes. Idaho's $0.986 million annual 2017 Protocol Adjustment will be included in base rates through a general rate case beginning no earlier than January 1, 2018, or to the extent that a case is filed so the rate effective date is later than that date, its $0.150 million annual Equalization Adjustment will be deferred on a monthly basis ($12,500 per month) from January 1, 2018, forward as a regulatory asset until the rate effective date of the Company's next Idaho general rate case at which time (1) the deferred costs and (2) the ongoing impact of Idaho's 2017 Protocol Adjustment will be included in rates.

In Utah the Company agreed to an annual Utah Equalization Adjustment of $4.4 million and a 2017 Protocol Adjustment of the same amount. The Company also agreed that it will not file a Utah general rate case or major plant addition case prior to May 1, 2016, and new rates will not be effective prior to January 1, 2017. Utah's 2017 Protocol Adjustment shall be included in base rates through a general rate case with rates effective beginning on or after January 1, 2017. To the extent that a Utah general rate case or major plant addition case is filed with a rate effective date later than that date, Utah's Equalization Adjustment will be deferred on a monthly basis, ($366,667 per month), from January 1, 2017, forward as a regulatory asset until the rate effective date of PacifiCorp's next Utah general rate case at which time (1) the deferred costs and (2) the ongoing impact of Utah's 2017 Protocol Adjustment shall be included in rates. The deferred cost amortization period will be determined in the first case that the deferral of the Utah Equalization Adjustment is proposed for inclusion in rates.

Wyoming's 2017 Protocol Adjustment of a negative $0.251 million will be netted against Wyoming's 2017 Protocol revenue requirement. If the Company does not file a general rate case prior to January 1, 2017, Wyoming's Equalization Adjustment of $1.6 million annually will be deferred, as a regulatory asset, on a monthly basis, ($133,333 per month), beginning July 1, 2017, until the rate effective date of PacifiCorp's next Wyoming general rate case, at which time (1) the deferred costs and (2) Wyoming's ongoing impact of the 2017 Protocol Adjustment shall be included in rates.

Q. Has the Company agreed to stay-out provisions for other states?

A. Yes. In Idaho the Company agreed that it will not file a rate case with rates effective prior to January 1, 2018. In Utah the Company agreed that it will not file a general rate case or major plant addition case prior to May 1, 2016, and new rates will not be effective prior to January 1, 2017.

Q. Why should Oregon approve 2017 Protocol rather than reverting back to Revised Protocol, which is the default for Oregon if the 2010 Protocol expires without a new allocation methodology?

A. One of the primary objectives of the MSP was to develop a consistent allocation methodology to be used by all states. Through this process the Parties determined that it is in everyone's best interest, including PacifiCorp's customers, to support a new protocol governing inter-jurisdictional allocation procedures. The 2017 Protocol is designed to provide PacifiCorp, state Commissions, and other interested Parties a transitional allocation method while the impacts of the EPA's Rule 111(d) and other multi-jurisdictional issues are better understood and can be more fully analyzed for their allocation impacts on PacifiCorp and each State. Through the MSP, the Parties negotiated a balanced agreement with reasonable solutions to issues raised by the Company and stakeholders. The Parties agreed to support the 2017 Protocol with the intent to continue to achieve equitable resolutions to multi-jurisdictional allocation issues that are in the public interest.

Q. Please explain why the Company believes the treatment of the ECD for Oregon under the 2017 Protocol is reasonable.

A. The treatment of the ECD for Oregon is reasonable because it provides more rate certainty to both the Company and its customers during the term of the 2017 Protocol. Absent the parameters agreed to by Oregon Parties, the ECD could produce an allocation gap, which the 2017 Protocol is intended to mitigate. One of the primary objectives of the 2017 Protocol was to equitably address allocation differences created through inconsistent implementation of the 2010 Protocol. By allowing the Oregon ECD to be dynamic but subject to a floor and cap, and when considering the other elements of the agreement between Oregon Parties, such as the general rate case stay-out provision, the Company believes a reasonable balance has been achieved for the short-term nature of the 2017 Protocol. This agreement also provides increased predictability for all Parties. Additionally, the

2017 Protocol does not limit or compromise any Party's ability to argue for a different ECD or hydro endowment calculation in any future inter-jurisdictional allocation methodologies.

Q. What will happen if the 2017 Protocol expires before a new agreement is approved by the Commission?

A. The Oregon Parties agreed that absent formal action by the Commission to adopt an alternate allocation methodology by January 1, 2019, or unless the 2017 Protocol is extended through 2019 under the terms of the 2017 Protocol, PacifiCorp will use the Revised Protocol allocation method for general rate case filings in Oregon after January 1, 2019.

Q. Are the terms of the 2017 Protocol for Oregon reasonable compared to the terms for other states?

A. Yes. Oregon retains a dynamic ECD, within the range identified in 2017 Protocol. The Equalization Adjustment is equivalent between states representing approximately two-tenths of one percent of each state's annual revenue requirement. The Oregon Parties also negotiated significant state-specific terms to address issues important to the Oregon Parties, including a commitment by the Company to continue evaluation of alternative inter-jurisdictional allocation methods, including consideration of corporate structure alternatives, divisional allocation methodologies, and potential implications of EPA's Rule 111(d), and possible formation of a regional independent system operator.

PROCESS FOR COMMISSION REVIEW OF PETITION

Q. What process does the Company propose for the Commission's review of this Petition?

A. The Company is hopeful that the Commission will be able to complete its review of this Petition by July 1, 2016. Significant analysis has been undertaken and reviewed by many parties since November 2012 as the BRWG considered many options. This analysis enabled the Parties to confidently negotiate the 2017 Protocol. The Company anticipates that each of the Parties will file testimony in support of the 2017 Protocol, and the Company believes that the Commission review can be accomplished, with input from the Parties, in this time frame.

CONCLUSION

Q. What action do you recommend the Commission take with respect to the Agreement?

A. The Company recommends that the Commission find that the 2017 Protocol is in the public interest and requests that the Commission approve this Petition including all the terms and conditions of the 2017 Protocol in its order in this proceeding.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UM 1050
Exhibit PAC/101
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of R. Bryce Dalley

2017 Protocol

December 2015

2017 Protocol

2017 Protocol

I. Introduction:

This 2017 PacifiCorp Inter-Jurisdictional Allocation Protocol (the "2017 Protocol") is the result of general agreement that has been reached between representatives of PacifiCorp (or the "Company") and certain Commission staff members, consumer advocates and other interested parties from Idaho, Oregon, Utah, and Wyoming (collectively referred to as the "Parties" or individually as a "Party") regarding issues arising with regards to the 2010 Protocol, PacifiCorp's status as a multi-jurisdictional utility and future inter-jurisdictional allocation procedures.

The 2010 Protocol expires at midnight on December 31, 2016. The Parties have determined that it is in their best interest or the interest of PacifiCorp's customers to support a new protocol governing inter-jurisdictional allocation procedures. This 2017 Protocol is designed to provide PacifiCorp, State Commissions, and other interested Parties a transitional allocation method while the impacts of the United States Environmental Protection Agency (EPA) rules governing carbon pollution from existing power plants under section 111(d) of the Clean Air Act (111(d)) and other multi-jurisdictional issues are better understood and can be more fully analyzed for their allocation impacts on PacifiCorp and each State. During the term of the 2017 Protocol, PacifiCorp will analyze alternative allocation methods including but not limited to: corporate structure alternatives, divisional allocation methodologies, alternative system allocation methodologies, potential implications of the EPA's final Rule 111(d), and possible formation of a regional independent system operator. PacifiCorp will present its analyses of these issues to the Multi-State Protocol or MSP Workgroup and discuss them at Commissioner Forums.

During the term of the 2017 Protocol, PacifiCorp commits that its generation and transmission system will continue to be planned and operated prudently on an integrated basis designed to achieve a least cost/least risk resource portfolio for PacifiCorp's customers. This commitment will not prevent PacifiCorp from filing for and requesting State Commission approval to participate in a regional independent system operator organization.

The 2017 Protocol describes inter-jurisdictional allocation policies and procedures, which, if applied by each of the States for rate proceedings filed after December 31, 2016, or as otherwise agreed to in Section XIV, are intended to better afford, than would otherwise be the case, PacifiCorp a reasonable opportunity to meet the goal of recovering its prudently incurred cost of service.

The apportionment, assignment, or allocation of a particular expense or investment, or allocation of a share of an expense or investment, to a State under the 2017 Protocol is not intended to and will not prejudge the prudence of those costs. Nothing in the 2017 Protocol is intended to abrogate a State Commission's right and/or obligation to: (1) determine fair, just, and reasonable rates based upon the law of that State and the record established in rate proceedings conducted by that Commission; (2) consider the impact of changes in laws, regulations, or circumstances on inter-jurisdictional allocation policies and procedures when determining fair, just, and reasonable rates; or (3) establish different allocation policies and procedures for purposes of allocation of costs and revenues within that State to different customers or customer classes.

Parties who support the 2017 Protocol do so with the intent to continue to achieve equitable resolutions to multi-jurisdictional allocation issues that are in the public interest. A Party's support of the 2017 Protocol will not, however, in any manner negate the necessary flexibility of the regulatory process to address changed or unforeseen circumstances, including but not limited to changes in laws or regulations, and a Party's support of the 2017 Protocol will not bind or be used against that Party if a Party concludes that the 2017 Protocol no longer produces results that are just, reasonable, and in the public interest, or provides the Company with the opportunity to recover its prudently incurred cost of service. Support of the 2017 Protocol will not be deemed to constitute an acknowledgement by any Party of the validity or invalidity of any particular method, theory, or principle of regulation, cost recovery, cost of service, or rate design, and no Party will be deemed to have agreed that any particular method, theory, or principle of regulation, cost recovery, cost of service, or rate design employed or implied in the 2017 Protocol is appropriate for resolving any other issues.

The 2017 Protocol describes how the costs and revenues, including wholesale transactions, associated with PacifiCorp's generation, transmission, and distribution systems will be assigned or allocated among its six state jurisdictions.

Terms that are capitalized in the 2017 Protocol are either defined in the 2017 Protocol or set forth in Appendix A.

A table identifying the allocation factor to be applied to each component of PacifiCorp's revenue requirement calculation is included as Appendix B.

The algebraic derivation of each allocation factor is contained in Appendix C.

A description and numeric example of how Special Contracts and related discounts will be reflected in rates is set forth in Appendix D.

Additional terms specific to each State, including an Equalization Adjustment, are reflected in Section XIV.

II. Effective Period and Expiration:

The Parties agree to support Commission adoption or use of the 2017 Protocol in all PacifiCorp rate proceedings filed after December 31, 2016, or as otherwise agreed to by Parties in Section XIV, up to and including December 31, 2018.

The 2017 Protocol will expire December 31, 2018, unless all State Commissions that approved the 2017 Protocol determine, by no later than March 31, 2017, that the term of the 2017 Protocol will be extended by an optional one-year extension through December 31, 2019. In determining whether the 2017 Protocol should or should not be extended, each State Commission can take such steps or provide such processes for public input as that Commission determines to be necessary or appropriate under applicable State laws.

A Commissioner Forum will be held annually, beginning in January 2017, to discuss inter-jurisdictional allocation issues and whether the 2017 Protocol should be extended for an additional one-year term, as described above.

III. Classification of Resources:

All Resource Fixed Costs, Wholesale Contracts, and Short-term Firm Purchases and Firm Sales will be classified as 75 percent Demand-Related and 25 percent Energy-Related. All Non-Firm Purchases and Sales will be classified as 100 percent Energy-Related.

IV. Allocation of Resource Costs and Wholesale Revenues:

Resources will be assigned to one of two categories for inter-jurisdictional allocation purposes: State Resources or System Resources. A complete description of allocation factors to be used is set forth in Appendix B.

There are four types of State Resources. The remaining types of Resources are System Resources, which constitute the substantial majority of PacifiCorp's Resources. Benefits and costs associated with each category and type of Resource will be assigned or allocated to Jurisdictions on the following basis:

A. State Resources

Benefits and costs associated with the four types of State Resources will be assigned as follows:

1. Demand-Side Management ("DSM") Programs: Costs associated with DSM Programs, including Class 1 DSM Programs, will be assigned on a situs basis to the Jurisdiction in which the investment is made. Benefits from these programs, in the form of reduced consumption and contribution to Coincident Peak, will be reflected in the Load-Based Dynamic Allocation Factors.

2. Portfolio Standards: Costs associated with Resources acquired to comply with a Jurisdiction's Portfolio Standard adopted, either through legislative enactment or a State's Commission, the portion of which exceeds the costs PacifiCorp would have otherwise incurred, will be assigned on a situs basis to the Jurisdiction adopting the Portfolio Standard.

3. Qualifying Facility Contracts: Costs associated with Qualifying Facility Contracts, the portion of which exceeds the costs PacifiCorp would have otherwise incurred acquiring Comparable Resources will be assigned on a situs basis to the Jurisdiction that approved the contract.

4. Jurisdiction-Specific Initiatives: Costs and benefits associated with Resources acquired in accordance with a Jurisdiction-specific initiative will be assigned on a situs basis to the Jurisdiction adopting the initiative.

This includes, but is not limited to, the costs and benefits of incentive programs, net-metering tariffs, feed-in tariffs, capacity standard programs, solar subscription programs, electric vehicle programs, and the acquisition of renewable energy certificates.

B. System Resources

All Resources that are not State Resources are System Resources and will be allocated as follows:

1. Generally, all Fixed Costs associated with System Resources and all costs incurred under Wholesale Contracts will be allocated based upon the System Generation ("SG") Factor.
2. Generally, all Variable Costs associated with System Resources will be allocated based upon the System Energy ("SE") Factor.
3. Revenues received by PacifiCorp under Wholesale Contracts will be allocated based upon the SG Factor.

C. Equalization Adjustment

The 2017 Protocol includes an Equalization Adjustment to be applied to each State's revenue requirement, as summarized in Section XIV, for purposes of ratemaking proceedings filed prior to the expiration of the 2017 Protocol. The Equalization Adjustment recognizes differences among the States in the 2010 Protocol Agreement implemented in each State and the respective treatment of the embedded cost differential ("ECD") adjustment – i.e. Baseline ECD, Dynamic ECD, or no ECD. The 2017 Protocol with the Equalization Adjustment is designed to allow PacifiCorp the opportunity to equitably allocate revenue requirement components in rate recovery proceedings in the States.

V. <u>Re-functionalization and Allocation of Transmission Costs and Revenues</u>

Before filing any request to approve a reclassification of facilities as transmission or distribution with FERC, PacifiCorp will submit filings seeking review and authorization of any such reclassification with the State Commissions. The cost responsibility for any assets reclassified under FERC policy will be assigned or allocated consistent with other assets in the relevant function.

Costs associated with transmission assets, and firm wheeling expenses and revenues, will be classified as 75 percent Demand-Related, 25 percent Energy-Related and allocated based upon the SG Factor. Non-firm wheeling expenses and revenues will be allocated based upon the SE Factor. In the event that PacifiCorp joins a regional independent system operator, the allocation of transmission costs and revenues may be reevaluated and revised as provided for in Section XIII.

VI. <u>Assignment of Distribution Costs:</u>

All distribution-related expenses and investment that can be directly assigned will be directly assigned to the State where they are located. Those costs that cannot be directly assigned will be allocated consistent with the factors set forth in Appendix B.

VII. <u>Allocation of Administrative and General Costs:</u>

Administrative and General Costs, General Plant costs, and Intangible Plant costs will be allocated consistent with the factors set forth in Appendix B.

VIII. <u>Allocation of Special Contracts:</u>

Revenues associated with Special Contracts will be included in State revenues, and loads of Special Contract customers will be included in Load-Based Dynamic Allocation Factors as appropriate (see Appendix D). Special Contracts may or may not include Customer Ancillary Service Contract attributes. Load curtailments and buy-through arrangements will be handled as appropriate (see Appendix D).

IX. <u>Allocation of Gain or Loss from Sale of Resources or Transmission Assets:</u>

Any loss or gain from the sale of a Company-owned Resource or transmission asset will be allocated based upon the allocation factor used to allocate the Fixed Costs of the Resource or the transmission asset at the time of its sale. Each Commission will determine the appropriate allocation of loss or gain allocated to that Jurisdiction as between customers and PacifiCorp shareholders.

X. <u>State Programs Regarding Access to Alternative Electricity Suppliers:</u>

A. Treatment of Oregon Direct Access Programs:

This Section describes treatment of loads lost to Oregon Direct Access Programs during the term of the 2017 Protocol.

1. Customers electing PacifiCorp's one- and three-year Oregon Direct Access Programs – The load of customers electing to be served on PacifiCorp's one- and three-year Oregon Direct Access Programs will be included in the Load-Based Dynamic Allocation Factors for all Resources, and the transition cost payments from these customers will be situs assigned to Oregon.

2. Customers electing PacifiCorp's five year opt-out program under the Oregon Direct Access Program – The treatment will be consistent with Order No. 15-060, as clarified through Order No. 15-067, of the Oregon Public Utility Commission in Docket UE 267, and Oregon Schedule 296, which allow Oregon Direct Access Program

Customers to permanently opt-out of cost-of-service rates after payment of ten years of transition costs in Oregon. During the ten-year period for which Oregon Direct Access Customers are paying transition costs, the Oregon Direct Access Customers' loads will be included in Load-Based Dynamic Allocation Factors, and the transition cost payments from these customers will be situs-assigned to Oregon. At the end of the 10-year period covered by the transition cost payments, the loads of the Oregon Direct Access Customers will be excluded from Load-Based Dynamic Allocation Factors. Thereafter, if an Oregon Direct Access Customer elects to return to Oregon cost-of-service rates by providing four-years notice under Schedule 267, its load will be included in Load-Based Dynamic Allocation Factors at the time the customer returns to Oregon cost of service rates.

3. To the extent Oregon adopts new laws or regulations regarding Oregon Direct Access Programs, Oregon's treatment of loads lost to Oregon Direct Access Programs may be re-determined in a manner consistent with the new laws and regulations. In the event Oregon adopts such new laws or regulations, the Company will inform the State Commissions and the Parties of the same.

B. Utah Eligible Customer Program:

If, pursuant to Utah Code Annotated Section 54-3-32, an eligible customer in Utah transfers service to a non-utility energy supplier, the Public Service Commission of Utah will make determinations under Utah law as contemplated therein. The Company will inform the State Commissions and the Parties of the Public Service Commission of Utah's determinations.

C. Other State Actions:

In the event any State adopts laws or regulations governing customer access to alternative electricity suppliers, the Company will inform the State Commissions and the Parties of the same.

XI. <u>Loss or Increase in Load:</u>

Any loss or increase in retail load occurring as a result of condemnation or municipalization, sale, or acquisition of new service territory that involves less than five percent of system load, realignment of service territories, changes in economic conditions, or gain or loss of large customers will be reflected in changes in the Load-Based Dynamic Allocation Factors. The allocation of costs and benefits arising from merger, sale, or acquisition transactions proposed by the Company involving more than five percent of system load will be considered on a case-by-case basis in the course of Commission approval proceedings.

XII. <u>Commission Regulation of Resources:</u>

PacifiCorp will plan and acquire new Resources on a system-wide least-cost, least-risk basis. Prudently incurred investments in Resources will be reflected in rates consistent with the laws and regulations in each State, as approved by individual State Commissions.

XIII. <u>Interpretation and Governance:</u>

A. Issues of Interpretation

If questions of interpretation of the 2017 Protocol arise during rate proceedings, audits of results of PacifiCorp's operations, or both, Parties will attempt, consistent with their legal obligations, to resolve them in good faith in light of the language of the 2017 Protocol and the intent of the Parties.

B. Commissioner Forum

A Commissioner Forum will be held annually beginning January 2017 to discuss the 2017 Protocol and other inter-jurisdictional allocation issues that may arise. All seated commissioners from each Jurisdiction will be invited to participate in all Commissioner Forums.

Each Commissioner Forum will be a public meeting and all interested parties will be allowed to attend. Prior to attending a Commissioner Forum, each Commission can take such steps and provide such process for public input as the Commission determines to be necessary or appropriate under applicable State laws.

At the Commissioner Forum, commissioners will be invited to discuss and may make recommendations regarding extension of the 2017 Protocol and other inter-jurisdictional allocation issues that may arise.

C. MSP Workgroup

The MSP Workgroup will be open to any utility regulatory agency, customer, and other person or entity potentially affected by inter-jurisdictional allocation procedures that expresses an interest in participating. The MSP Workgroup may create sub-committees to investigate, evaluate, or make recommendations as to specified issues. MSP Workgroup meetings may be held in person or by telephone.

The Company will promptly convene one or more MSP Workgroup meetings: (i) to discuss the possibility of a new inter-jurisdictional allocation agreement if any Commission indicates that the 2017 Protocol should not be extended pursuant to Section II or as a result of new developments pursuant to Section X, (ii) to discuss an inter-jurisdictional allocation issue identified by any Commission, or (iii) to discuss any other inter-jurisdictional allocation issue raised by any interested stakeholders. MSP Parties will work in good faith to achieve resolution of any issues brought before the MSP Workgroup.

Before each annual Commissioner Forum, PacifiCorp will convene an MSP Workgroup meeting for the purpose of discussing and monitoring emerging inter-jurisdictional allocation issues facing PacifiCorp and its customers, the status and implications of Rule 111(d), or the development of a regional independent system operator, in order to inform discussions at the Commissioner Forum. PacifiCorp will provide reasonable staffing and resources to provide minutes of any MSP Workgroup meeting, coordinate MSP Workgroup activities and conduct studies and analysis as agreed to by the MSP Workgroup, and as suggested by the Commissioner Forum.

D. Proposals for New Inter-Jurisdictional Allocation Procedures

Proposals for new inter-jurisdictional allocation procedures, including any changes to the 2017 Protocol, ranging from minor modifications to major modifications, may be submitted by any Party or any Commission utilizing the 2017 Protocol. Proposals shall be provided to the Company for the purpose of circulating the proposals to the other Parties and State Commissions and initiating discussions to attempt to address and resolve specific concerns.

If any Party intends to propose a new inter-jurisdictional allocation procedure, the Party will attempt, consistent with their legal obligations, to: (1) bring that proposal to the Commissioner Forum or the MSP Workgroup and (2) resolve the proposal in good faith.

A Party's initial support or acceptance of the 2017 Protocol will not bind or be used against that Party if unforeseen or changed circumstances, including new developments pursuant to Section X, cause that Party to conclude that the 2017 Protocol no longer produces just and reasonable results, reasonable cost recovery for the Company, or is not in the public interest. Before a Party asks a Commission to deviate from the terms of the 2017 Protocol, the Parties, will be invited by the Company to enter into a discussion, or series of discussions, to attempt to address and resolve their concerns at MSP Workgroup meetings and/or a Commissioner Forum, consistent with any applicable legal obligations.

E. Interdependency among Commission Approvals

The 2017 Protocol has been developed by the Parties as an integrated, interdependent, organic whole. Support by any Party or Commission of the 2017 Protocol is expressly conditioned upon similar support of the 2017 Protocol by the Commissions of at least the States of Idaho, Oregon, Utah, and Wyoming, without material alteration. If a Commission materially deletes, alters, or conditions approval of the 2017 Protocol, Parties shall promptly meet and discuss the implications of the material alteration, and will have the opportunity to accept or reject continued support of the 2017 Protocol in light of such action.

XIV. <u>Additional State-Specific Terms:</u>

For the period that the 2017 Protocol remains in effect, a 2017 Protocol Adjustment will be added to each State's annual revenue requirement. For California, Idaho, Utah, and Wyoming, the 2017 Protocol Adjustment is the sum of the Baseline ECD and the Equalization Adjustment. For Oregon, the 2017 Protocol Adjustment is the sum of the Baseline ECD, which is dynamic with the parameters described in paragraph three below, and the Equalization Adjustment. The Parties agree to an annual Equalization Adjustment of $9.074 million, with specific State-by-State 2017 Protocol Adjustment impacts as summarized in this table:

Revenue Requirement ($000)	Total Company	California	Oregon	Utah	Idaho	Wyoming
2017 Protocol Baseline ECD **	(9,578)	(324)	(8,238) *	0	836	(1,851)
2017 Protocol Equalization Adjustment	9,074	324	2,600	4,400	150	1,600
2017 Protocol Adjustment		(0)	(5,638)	4,400	986	(251)

* Oregon's 2017 Protocol Baseline ECD is dynamic and will change over time with the parameters described in paragraph 3 below. For the other states, the 2017 Protocol Baseline ECD is fixed and does not change over time.
** 2017 Protocol Baseline ECD amounts shown in the table for California, Oregon, and Wyoming are based on the test year data as filed by the Company in the 2015 Wyoming general rate case (Docket 20000-469-ER-15) on March 3, 2015. The amount for Idaho's 2017 Protocol Baseline ECD is its 2010 Protocol Fixed ECD amount. Utah's 2017 Protocol Baseline ECD is zero based on its 2010 Protocol agreement.

State specific implementation is summarized below:

1. California's 2017 Protocol Adjustment is zero.
2. The Idaho Parties and PacifiCorp agree to an annual Idaho 2017 Protocol Adjustment of $0.986 million to be added to Idaho's 2017 Protocol revenue requirement. Idaho's Equalization Adjustment is $0.150 million. The Idaho 2017 Protocol Adjustment shall be included in base rates through a general rate case beginning January 1, 2018, or to the extent that a case is filed so the rate effective date is later than that date, the Equalization Adjustment shall be deferred on a monthly basis ($12,500 per month) from January 1, 2018, forward as a regulatory asset until the rate effective date of PacifiCorp's next Idaho general rate case at which time (1) the deferred costs and (2) the ongoing impact of Idaho's 2017 Protocol Adjustment shall be included in rates.
3. The Public Utility Commission of Oregon Staff ("Commission Staff"), the Citizens' Utility Board of Oregon ("CUB"), and PacifiCorp ("Oregon Parties"), agree to an Oregon Equalization Adjustment of $2.6 million. The Oregon Parties agree that Oregon's Equalization Adjustment of $2.6 million annually (or $216,667 monthly) be deferred from January 1, 2017, until the 2017 Protocol Equalization Adjustment is reflected in base rates through the Company's next general rate case. The Oregon Parties agree that the 2017 Protocol Equalization Adjustment deferral will be reflected as a debit (reduction to the existing credit balance to be returned to customers) in the Open Access Transmission Tariff ("OATT") revenue deferral account originally established through docket UE 246.[1] The Parties agree that the Company will file a new tariff to return to

[1] As a result of the stipulation and Commission Order No. 12-493 in docket UE-246, the Company filed for, and the Commission approved the Company's application to defer incremental OATT revenues from January 1, 2013, until

(Continued…)

Oregon customers the balance of the OATT revenue deferral, net of the 2017 Protocol Equalization Adjustment deferral, within 60 days of an Oregon Commission order approving of the 2017 Protocol. The Company commits to continued evaluation of alternative inter-jurisdictional allocation methods, including consideration of corporate structure alternatives, divisional allocation methodologies, and potential implications of the Environmental Protection Agency's final Rule 111(d), and possible formation of a regional independent system operator. The Company will distribute or present the results of its analysis, based on information available, no later than March 31, 2017. If PacifiCorp does not distribute or present the results of its analysis on or before March 31, 2017, for each month the analysis is not provided after that date $216,667 will be credited to the OATT revenue deferral balance unless otherwise waived by the Commission for good cause. The Company agrees that during the effective period of this agreement regarding the 2017 Protocol, the Company will not have any pending general rate case that requests rates effective before January 1, 2018. Oregon Parties may file for deferrals during the general rate case stay-out period, but such filings will be subject to the Commission's guidelines for deferrals established in docket UM 1147, unless otherwise authorized by the Commission. This provision will not alter the operation or application of existing or new rate adjustment mechanisms authorized by the Commission, including but not limited to PacifiCorp's Transition Adjustment Mechanism, the Power Cost Adjustment Mechanism, and the Renewable Adjustment Clause. The Oregon Parties agree that for the duration of the 2017 Protocol, Oregon's results of operations reports

(…continued)
these revenues are reflected in base rates. Commission Order Nos. 13-045, 14-023, and 15-020 approved the Company's applications to defer these incremental revenues for 2013, 2014, and 2015, respectively.

and general rate case filings will reflect a Dynamic ECD calculated consistent with the 2010 Protocol inter-jurisdictional allocation methodology with the parameters as described below:

- For the Company's first Oregon general rate case filing under the 2017 Protocol (which will be effective no earlier than January 1, 2018), the Dynamic ECD value for Oregon will be set at a level no less than $8.238m (the baseline value of Oregon's ECD used to negotiate each State's contribution to the 2017 Protocol Equalization Adjustment), and will be capped at $10.5 million; and
- If the 2017 Protocol is extended to 2019, and the Company files a second Oregon general rate case using the 2017 Protocol, the Dynamic ECD in that general rate case filing will be set at a level no less than $8.238m and will be capped at $11.0 million. The Dynamic ECD provisions apply only to the 2017 Protocol as an integrated agreement and do not in any way limit or compromise any party's ability to argue for a different ECD or hydro endowment calculation in any future inter-jurisdictional allocation methodologies.

The Oregon Parties agree that unless there is formal action by the Public Utility Commission of Oregon to adopt an alternate allocation methodology by January 1, 2019, or unless the 2017 Protocol is extended through 2019 under the terms of the 2017 Protocol, PacifiCorp will use the Revised Protocol allocation method for general rate case filings in Oregon after January 1, 2019. The Oregon Parties have negotiated this settlement as an integrated agreement. If the Public Utility Commission of Oregon rejects all or any material portion of this agreement or imposes additional material conditions in approving this agreement, any of the Oregon Parties are entitled to withdraw from the settlement. If the Public Utility Commission of Oregon rejects the 2017 Protocol, this agreement terminates upon the date of the order rejecting the 2017 Protocol.

4. The Utah Parties and PacifiCorp agree to an annual Utah Equalization Adjustment of $4.4 million and a 2017 Protocol Adjustment of the same amount. The Company agrees that it will not file a Utah general rate case or major plant addition case prior to May 1, 2016, and new rates will not be effective prior to January 1, 2017. Utah's 2017 Protocol Adjustment shall be included in base rates through a general rate case with rates effective beginning on or after January 1, 2017. To the extent that a Utah general rate case or major plant addition case is filed with a rate effective date later than that date, Utah's Equalization Adjustment shall be deferred on a monthly basis, ($366,667 per month), from January 1, 2017, forward as a regulatory asset until the rate effective date of PacifiCorp's next Utah general rate case at which time (1) the deferred costs and (2) the ongoing impact of Utah's 2017 Protocol Adjustment shall be included in rates. The deferred cost amortization period will be determined in the first case that the deferral of the Utah Equalization Adjustment is proposed for inclusion in rates.

5. The Wyoming Parties and PacifiCorp agree to an annual credit for Wyoming's 2017 Protocol Adjustment of $0.251 million to be netted against Wyoming's 2017 Protocol revenue requirement. If the Company does not file a general rate case prior to January 1, 2017, Wyoming's Equalization Adjustment of $1.6 million annually shall be deferred, as a regulatory asset, on a monthly basis, ($133,333 per month), beginning July 1, 2017, until the rate effective date of PacifiCorp's next Wyoming general rate case, at which time (1) the deferred costs and (2) Wyoming's ongoing impact of the 2017 Protocol

Adjustment shall be included in rates. The deferred cost amortization period will be determined in the first case that the deferral of the Wyoming Equalization Adjustment is proposed for inclusion in rates. If a Wyoming general rate case is filed prior to January 1, 2017, then the Wyoming Equalization Adjustment shall not be deferred and will only be included in base rates from the rate effective date of a general rate case filing occurring on or after January 1, 2017. The Wyoming Parties also agree that the Company no longer is required to file Revised Protocol results (Tab 9) as part of its results of operations reports effective January 1, 2017.

ROCKY MOUNTAIN POWER A DIVISION OF PACIFICORP Jeffrey K. Larsen *Vice President, Regulation*	PACIFIC POWER A DIVISION OF PACIFICORP Bryce Dalley *Vice President, Regulation*
IDAHO PUBLIC UTILITIES COMMISSION STAFF Terri Carlock *Deputy Administrator of Idaho Public Utilities Commission Staff*	OREGON PUBLIC UTILITY COMMISSION Jason W. Jones *Counsel for Oregon Public Utility Commission Staff*
CITIZENS UTILITY BOARD OF OREGON Bob Jenks *Executive Director of Citizens Utility Board of Oregon*	UTAH DIVISION OF PUBLIC UTILITIES Chris Parker *Director of Utah Division of Public Utilities*
UTAH OFFICE OF CONSUMER SERVICES Michelle Beck *Director of Utah Office of Consumer Services*	UTAH ASSOCIATION OF ENERGY USERS Gary Dodge *Attorney for Utah Association of Energy Users*

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IDAHO PUBLIC UTILITIES COMMISSION STAFF ____________________ Terri Carlock *Deputy Administrator of Idaho Public Utilities Commission Staff*	OREGON PUBLIC UTILITY COMMISSION ____________________ Jason W. Jones *Counsel for Oregon Public Utility Commission Staff*
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*This signature does not represent the position of any Wyoming Public Service Commission Commissioner or any Commission staff not directly involved with the negotiations leading to this Settlement Agreement (the "2017 Protocol").

2017 Protocol – Appendix A
Defined Terms

2017 Protocol - Appendix A

Defined Terms

For purposes of this 2017 Protocol, these terms will have the following meanings:

"2010 Protocol" means the PacifiCorp inter-jurisdictional allocation method that was approved by the Idaho, Oregon, Utah, and Wyoming Commissions in 2012 to apply to all PacifiCorp rate proceedings filed after each commission's approval and before December 31, 2016.

"2017 Protocol Adjustment" means the result of netting the 2016 Baseline ECD against the $9.074 million Equalization Adjustment for each State's revenue requirement as specified in Section XIV of the 2017 Protocol. The 2017 Protocol Adjustment is intended to cause PacifiCorp and each of the States participating in the 2017 Protocol to bear a reasonable proportion of the allocation shortfall resulting from differences in the 2010 Protocol inter-jurisdictional allocation procedures utilized by such States.

"Administrative and General Costs" means costs included in FERC accounts 920 through 935.

"Class 1 DSM Programs" means DSM Programs designed to reduce peak loads.

"Coincident Peak" means the hour each month that the combined demand of all PacifiCorp retail customers is greatest. In States using a historic test period Coincident Peak is based upon actual, metered load data adjusted for normalized weather conditions and in States using future test periods Coincident Peak is based upon forecasted normalized loads, in both cases adjusted as appropriate for interruptibility of Special Contracts.

"Commission" means a utility regulatory commission in a Jurisdiction.

"Commissioner Forum" means an annual public meeting held in January of each year beginning in 2017 to which all seated commissioners from each Jurisdiction will be invited to discuss the 2017 Protocol and other inter-jurisdictional allocation issues.

"Company" means PacifiCorp.

"Comparable Resource" means Resources with similar capacity factors, start-up costs, and other output and operating characteristics.

"Customer Ancillary Service Contracts" means contracts between the Company and a retail customer pursuant to which the Company pays the customer for the right to curtail service so as to lower the costs of operating the Company's system.

"Demand-Related" means capital and other Fixed Costs or revenues incurred or received by the Company in order to be prepared to meet the maximum demand imposed upon its system.

"Demand-Side Management Programs" or "DSM Programs" means programs intended to reduce electricity use through activities or programs that promote electric energy efficiency or conservation, more efficient management of electric energy loads, or reductions in peak demand.

"Embedded Cost Differential" or "ECD" means the sum of (1) PacifiCorp's total production costs of Pre-2005 Resources expressed in dollars per megawatt-hour compared to the Hydro-Electric Resources forecasted production costs expressed in dollars per megawatt-hour multiplied by the Hydro-Electric Resources megawatt-hours of production, and (2) the differential between the Pre-2005 Resources dollars per megawatt-hour compared to Mid-Columbia Contracts forecasted costs in dollars per megawatt-hour multiplied by the Mid-Columbia Contracts megawatt-hours.

- "Baseline ECD" means the amount of the ECD for each State to be used in the determination of the 2017 Protocol Adjustment. For the states of California, and Wyoming, their Baseline ECD amounts are based on the test year data, as filed by the Company in the 2015 Wyoming General Rate Case (Docket 20000-469-ER-15, Exhibit SRM-2), on March 3, 2015. Idaho's Baseline ECD is its 2010 Protocol Fixed ECD amount. Utah's 2017 Protocol Baseline ECD is zero based on its 2010 Protocol agreement. For Oregon, the Baseline ECD is dynamic with the parameters described in paragraph three of Section XIV.

- "Dynamic ECD" means the ECD components are updated to the test period utilized in the filing.

"Energy-Related" means costs and revenues, such as fuel costs and transmission costs, or sales revenues that vary with the amount of energy delivered by the Company to its customers during any hour plus any portion of Fixed Costs that have been deemed to have been incurred or received by the Company in order to meet its energy requirements.

"Equalization Adjustment" means a fixed dollar adjustment to be applied to each State's revenue requirement as reflected in Section XIV of the 2017 Protocol intended to cause PacifiCorp and each of the States participating in the 2017 Protocol to bear a reasonable proportion of the allocation shortfall resulting from differences in current inter-jurisdictional allocation procedures utilized by such states.

"FERC" means the Federal Energy Regulatory Commission.

"Fixed Costs" means costs incurred by the Company that do not vary with the amount of energy delivered by the Company to its customers during any hour.

"General Plant" means capital investment included in FERC accounts 389 through 399.

"Hydro-Electric Resources" means Company-owned hydro-electric plants located in Oregon, Washington or California.

"Intangible Plant" means capital investment included in FERC accounts 301 through 303.

"Jurisdiction" means any one of the six states where the Company provides retail service.

"Load-Based Dynamic Allocation Factor" means an allocation factor that is calculated using States' monthly energy usage and/or States' contribution to monthly system Coincident Peak.

"Mid-Columbia Contracts" means the various power sales agreements between PacifiCorp and Public Utility District No. 2 of Grant County, PacifiCorp and Douglas County Public Utility District, and PacifiCorp and Chelan County Public Utility District, specifically: the

Power Sales Contract with Public Utility District No. 2 of Grant County dated May 22, 1956; the Power Sales Contract with Public Utility District No. 2 of Grant County dated June 22, 1959; the Priest Rapids Project Product Sales Contract with Public Utility District No. 2 of Grant County dated December 31, 2001; the Additional Products Sales Agreement with Public Utility District No. 2 of Grant County dated December 31, 2001; the Priest Rapids Project Reasonable Portion Power Sales Contract with Public Utility District No. 2 of Grant County dated December 31, 2001; the Power Sales Contract with Douglas County Public Utility District dated September 18, 1963; the Power Sales Contract with Chelan County Public Utility District dated November 14, 1957 and all successor contracts thereto.

"Multi-State Protocol Workgroup" or "MSP Workgroup" means a group consisting of utility regulatory agencies, customers and others potentially affected by inter-jurisdictional allocation procedures who desire to participate in a cooperative workgroup context and who agree to comply with reasonable confidentiality and other procedures adopted by the MSP Workgroup.

"Non-Firm Purchases and Sales" means transactions at wholesale that are not Wholesale Contracts or Short-Term Purchases and Sales.

"Oregon Direct Access Customers" means Oregon retail electricity consumers that procure electricity from a supplier other than PacifiCorp under an Oregon Direct Access Program.

"Oregon Direct Access Program" means Oregon laws, regulations and orders that permit PacifiCorp's Oregon retail consumers to purchase electricity directly from a supplier other than PacifiCorp.

"Portfolio Standard" means a law or regulation that requires PacifiCorp to acquire: (a) a particular type of Resource, (b) a particular quantity of Resources, (c) Resources in a prescribed manner or (d) Resources located in a particular geographic area.

"Pre-2005 Resources" means Resources (other than Mid-Columbia Contracts and Hydro-Electric Resources) that were part of the Company's integrated system prior to January 1, 2005.

"Qualifying Facility Contracts" means contracts to purchase the output of small power production or cogeneration facilities developed under the Public Utility Regulatory Policies Act of 1978 (PURPA) and related State laws and regulations.

"Resources" means Company-owned and leased generating plants and mines, Wholesale Contracts, Short-Term Firm Purchases and Firm Sales and Non-firm Purchases and Sales.

"System Energy Factor" or "SE Factor" - refer to Appendix B.

"System Generation Factor" or "SG Factor" - refer to Appendix B.

"Short-Term Firm Purchases and Firm Sales" means physical or financial contracts pursuant to which PacifiCorp purchases, sells or exchanges firm power at wholesale and Customer Ancillary Service Contracts that are less than one year in duration.

"Special Contract" means a contract entered between PacifiCorp and one of its retail customers with prices, terms, and conditions based on the specific circumstances of that customer. Special Contracts may account for Customer Ancillary Services Contract attributes.

"State" means any state that is utilizing the 2017 Protocol for inter-jurisdictional allocation purposes, and is intended to include the states of California, Idaho, Oregon, Utah, or Wyoming.

"State Resources" means Resources whose costs are assigned to a single jurisdiction to accommodate jurisdiction-specific policy preferences.

"System Resources" means Resources that are not State Resources and whose associated costs and revenues are allocated among all States on a dynamic basis.

"Variable Costs" means costs incurred by the Company that vary with the amount of energy delivered by the Company to its customers during any hour.

"Wholesale Contracts" means physical or financial contracts pursuant to which PacifiCorp purchases, sells or exchanges firm long-term power and/or energy at wholesale or Customer Ancillary Service Contracts as discussed in Appendix D.

2017 Protocol – Appendix B

Allocation Factor Applied to each Component of Revenue Requirement

2017 Protocol - Appendix B
Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
Sales to Ultimate Customers			
440	Residential Sales		
		Direct assigned - Jurisdiction	S
442	Commercial & Industrial Sales		
		Direct assigned - Jurisdiction	S
444	Public Street & Highway Lighting		
		Direct assigned - Jurisdiction	S
445	Other Sales to Public Authority		
		Direct assigned - Jurisdiction	S
448	Interdepartmental		
		Direct assigned - Jurisdiction	S
447	Sales for Resale		
		Direct assigned - Jurisdiction	S
		Non-Firm	SE
		Firm	SG
449	Provision for Rate Refund		
		Direct assigned - Jurisdiction	S
			SG
Other Electric Operating Revenues			
450	Forfeited Discounts & Interest		
		Direct assigned - Jurisdiction	S
451	Misc Electric Revenue		
		Direct assigned - Jurisdiction	S
		Other - Common	SO
453	Water Sales		
		Common	SG
454	Rent of Electric Property		
		Direct assigned - Jurisdiction	S
		Common	SG
		Other - Common	SO
456	Other Electric Revenue		
		Direct assigned - Jurisdiction	S
		Wheeling Non-firm, Other	SE
		Common	SO
		Wheeling - Firm, Other	SG
		Customer Related	CN
Miscellaneous Revenues			
41160	Gain on Sale of Utility Plant - CR		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
41170	Loss on Sale of Utility Plant		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO
4118	Gain from Emission Allowances		
		SO2 Emission Allowance sales	SE
41181	Gain from Disposition of NOX Credits		
		NOX Emission Allowance sales	SE
421	(Gain) / Loss on Sale of Utility Plant		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General Office	SO
		Customer Related	CN
Miscellaneous Expenses			
4311	Interest on Customer Deposits		
		Customer Service Deposits	CN
		Direct assigned - Jurisdiction	S
Steam Power Generation			
500, 502, 504-514	Operation Supervision & Engineering		
		Remaining Steam Plants	SG
501	Fuel Related		
		Remaining steam plants	SE
503	Steam From Other Sources		
		Steam Royalties	SE
Nuclear Power Generation			
517 - 532	Nuclear Power O&M		
		Nuclear Plants	SG
Hydraulic Power Generation			
535 - 545	Hydro O&M		
		Pacific Hydro	SG
		East Hydro	SG
Other Power Generation			
546, 548-554	Operation Super & Engineering		
		Other Production Plant	SG
547	Fuel		
		Other Fuel Expense	SE
Other Power Supply			
555	Purchased Power		
		Direct assigned - Jurisdiction	S
		Firm	SG
		Non-firm	SE

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
556	System Control & Load Dispatch		
		Other Expenses	SG
557	Other Expenses		
		Direct assigned - Jurisdiction	S
		Other Expenses	SG
		Cholla Transaction	SGCT
TRANSMISSION EXPENSE			
560-564, 566-573	Transmission O&M		
		Transmission Plant	SG
565	Transmission of Electricity by Others		
		Firm Wheeling	SG
		Non-Firm Wheeling	SE
DISTRIBUTION EXPENSE			
580 - 598	Distribution O&M		
		Direct assigned - Jurisdiction	S
		Other Distribution	SNPD
CUSTOMER ACCOUNTS EXPENSE			
901 - 905	Customer Accounts O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
CUSTOMER SERVICE EXPENSE			
907 - 910	Customer Service O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
SALES EXPENSE			
911 - 916	Sales Expense O&M		
		Direct assigned - Jurisdiction	S
		Total System Customer Related	CN
ADMINISTRATIVE & GEN EXPENSE			
920-935	Administrative & General Expense		
		Direct assigned - Jurisdiction	S
		Customer Related	CN
		General	SO
		FERC Regulatory Expense	SG
DEPRECIATION EXPENSE			
403SP	Steam Depreciation		
		Steam Plants	SG
403NP	Nuclear Depreciation		
		Nuclear Plant	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
403HP	Hydro Depreciation		
		Pacific Hydro	SG
		East Hydro	SG
403OP	Other Production Depreciation		
		Other Production Plant	SG
403TP	Transmission Depreciation		
		Transmission Plant	SG
403	Distribution Depreciation Direct assigned - Jurisdiction		
		Land & Land Rights	S
		Structures	S
		Station Equipment	S
		Storage Battery Equipment	S
		Poles & Towers	S
		OH Conductors	S
		UG Conduit	S
		UG Conductor	S
		Line Trans	S
		Services	S
		Meters	S
		Inst Cust Prem	S
		Leased Property	S
		Street Lighting	S
403GP	General Depreciation		
		Distribution	S
		Remaining Steam Plants	SG
		Mining	SE
		Pacific Hydro	SG
		East Hydro	SG
		Transmission	SG
		Customer Related	CN
		General SO	SO
403MP	Mining Depreciation		
		Remaining Mining Plant	SE
AMORTIZATION EXPENSE			
404GP	Amort of LT Plant - Capital Lease Gen		
		Direct assigned - Jurisdiction	S
		General	SO
		Customer Related	CN
404SP	Amort of LT Plant - Cap Lease Steam		
		Steam Production Plant	SG
404IP	Amort of LT Plant - Intangible Plant		
		Distribution	S
		Production, Transmission	SG
		General	SO
		Mining Plant	SE
		Customer Related	CN

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
404MP	Amort of LT Plant - Mining Plant		
		Mining Plant	SE
404HP	Amortization of Other Electric Plant		
		Pacific Hydro	SG
		East Hydro	SG
405	Amortization of Other Electric Plant		
		Direct assigned - Jurisdiction	S
406	Amortization of Plant Acquisition Adj		
		Direct assigned - Jurisdiction	S
		Production Plant	SG
407	Amort of Prop Losses, Unrec Plant, etc		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Trojan	TROJP
Taxes Other Than Income			
408	Taxes Other Than Income		
		Direct assigned - Jurisdiction	S
		Property	GPS
		System Taxes	SO
		Misc Energy	SE
		Misc Production	SG
DEFERRED ITC			
41140	Deferred Investment Tax Credit - Fed		
		ITC	DGU
41141	Deferred Investment Tax Credit - Idaho		
		ITC	DGU
Interest Expense			
427	Interest on Long-Term Debt		
		Direct assigned - Jurisdiction	S
		Interest Expense	SNP
428	Amortization of Debt Disc & Exp		
		Interest Expense	SNP
429	Amortization of Premium on Debt		
		Interest Expense	SNP
431	Other Interest Expense		
		Interest Expense	SNP
432	AFUDC - Borrowed		
		AFUDC	SNP

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
Interest & Dividends			
419	Interest & Dividends		
		Interest & Dividends	SNP
DEFERRED INCOME TAXES			
41010	Deferred Income Tax - Federal-DR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Bad Debt	BADDEBT
		Tax Depreciation	TAXDEPR
41011	Deferred Income Tax - State-DR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Bad Debt	BADDEBT
		Tax Depreciation	TAXDEPR
41110	Deferred Income Tax - Federal-CR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Contributions in aid of construction	CIAC
		Production, Other	SGCT
		Book Depreciation	SCHMDEXP

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
41111	Deferred Income Tax - State-CR		
		Direct assigned - Jurisdiction	S
		Electric Plant in Service	DITEXP
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Property Tax related	GPS
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
		Contributions in aid of construction	CIAC
		Production, Other	SGCT
		Book Depreciation	SCHMDEXP
SCHEDULE - M ADDITIONS			
SCHMAF	Additions - Flow Through		
		Direct assigned - Jurisdiction	S
SCHMAP	Additions - Permanent		
		Direct assigned - Jurisdiction	S
		Mining related	SE
		General	SO
		Production / Transmission	SG
		Depreciation	SCHMDEXP
SCHMAT	Additions - Temporary		
		Direct assigned - Jurisdiction	S
		Contributions in aid of construction	CIAC
		Miscellaneous	SNP
		Trojan	TROJD
		Pacific Hydro	SG
		Mining Plant	SE
		Production, Transmission	SG
		Property Tax	GPS
		General	SO
		Depreciation	SCHMDEXP
		Distribution	SNPD
		Production, Other	SGCT
SCHEDULE - M DEDUCTIONS			
SCHMDF	Deductions - Flow Through		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Pacific Hydro	SG
SCHMDP	Deductions - Permanent		
		Direct assigned - Jurisdiction	S
		Mining Related	SE
		Miscellaneous	SNP
		General	SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
SCHMDT	Deductions - Temporary		
		Direct assigned - Jurisdiction	S
		Bad Debt	BADDEBT
		Miscellaneous	SNP
		Pacific Hydro	SG
		Mining related	SE
		Production, Transmission	SG
		Property Tax	GPS
		General	SO
		Depreciation	TAXDEPR
		Distribution	SNPD
		Customer Related	CN
State Income Taxes			
40911	State Income Taxes		
		Income Before Taxes	CALCULATED
40911		Renewable Energy Tax Credit	SG
40910		FIT True-up	S
40910		Renewable Energy Tax Credit	SG
		PMI	SE
		Foreign Tax Credit	SO
Steam Production Plant			
310 - 316			
		Steam Plants	SG
Nuclear Production Plant			
320-325			
		Nuclear Plant	SG
Hydraulic Plant			
330-336			
		Pacific Hydro	SG
		East Hydro	SG
Other Production Plant			
340-346			
		Other Production Plant	S
		Other Production Plant	SG
TRANSMISSION PLANT			
350-359			
		Transmission Plant	SG
DISTRIBUTION PLANT			
360-373			
		Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT		DESCRIPTION	ALLOCATION FACTOR
GENERAL PLANT			
389 - 398			
		Distribution	S
		Pacific Hydro	SG
		East Hydro	SG
		Production / Transmission	SG
		Customer Related	CN
		General	SO
		Mining	SE
399	Coal Mine		
		Remaining Mining Plant	SE
399L	WIDCO Capital Lease		
		WIDCO Capital Lease	SE
1011390	General Capital Leases		
		Direct assigned - Jurisdiction	S
		General	SO
		Generation / Transmission	SG
INTANGIBLE PLANT			
301	Organization		
		Direct assigned - Jurisdiction	S
302	Franchise & Consent		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
303	Miscellaneous Intangible Plant		
		Distribution	S
		Pacific Hydro	SG
		East Hydro	SG
		Production / Transmission	SG
		Customer Related	CN
		General	SO
		Mining	SE
303	Less Non-Utility Plant		
		Direct assigned - Jurisdiction	S
Rate Base Additions			
105	Plant Held For Future Use		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining Plant	SE
114	Electric Plant Acquisition Adjustments		
		Direct assigned - Jurisdiction	S
		Production Plant	SG
115	Accum Provision for Asset Acquisition Adjustments		
		Direct assigned - Jurisdiction	S
		Production Plant	SG

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
120	Nuclear Fuel		
		Nuclear Fuel	SE
124	Weatherization		
		Direct assigned - Jurisdiction	S
		General	SO
128	Pensions		
		General	SO
182W	Weatherization		
		Direct assigned - Jurisdiction	S
186W	Weatherization		
		Direct assigned - Jurisdiction	S
151	Fuel Stock		
		Steam Production Plant	SE
152	Fuel Stock - Undistributed		
		Steam Production Plant	SE
25316	DG&T Working Capital Deposit		
		Mining Plant	SE
25317	DG&T Working Capital Deposit		
		Mining Plant	SE
25319	Provo Working Capital Deposit		
		Mining Plant	SE
154	Materials and Supplies		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining	SE
		Production - Common	SG
		General	SO
		Distribution	SNPD
		Production, Other	SG
163	Stores Expense Undistributed		
		General	SO
25318	Provo Working Capital Deposit		
		Provo Working Capital Deposit	SG
165	Prepayments		
		Direct assigned - Jurisdiction	S
		Property Tax	GPS
		Production, Transmission	SG
		Mining	SE
		General	SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
182M	Misc Regulatory Assets		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Mining	SE
		General	SO
		Production, Other	SGCT
186M	Misc Deferred Debits		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General	SO
		Mining	SE
		Production - Common	SG
Working Capital			
CWC	Cash Working Capital		
		Direct assigned - Jurisdiction	S
OWC		Other Working Capital	
131		Cash	SNP
135		Working Funds	SG
141		Notes Receivable	SO
143		Other Accounts Receivable	SO
232		Accounts Payable	SO
		Accounts Payable	SE
		Accounts Payable	SG
253		Deferred Hedge	SE
25330		Other Deferred Credits - Misc	SE
230		Other Deferred Credits - Misc	SE
254105		ARO Reg Liability	SE
Miscellaneous Rate Base			
18221	Unrec Plant & Reg Study Costs		
		Direct assigned - Jurisdiction	S
18222	Nuclear Plant - Trojan		
		Trojan Plant	TROJP
		Trojan Plant	TROJD
141	Notes Receivable		
		Employee Loans - Hunter Plant	SG
Rate Base Deductions			
235	Customer Service Deposits		
		Direct assigned - Jurisdiction	S
2281	Prov for Property Insurance		SO
2282	Prov for Injuries & Damages		SO

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
2283	Prov for Pensions and Benefits		SO
22841	Accum Misc Oper Prov-Black Lung		
		Mining	SE
		Other Production	SG
22842	Accum Misc Oper Prov-Trojan		
		Trojan Plant	TROJD
254105	FAS 143 ARO Regulatory Liability		
		Trojan Plant	TROJP
		Trojan Plant	TROJD
230	Asset Retirement Obligation		
		Trojan Plant	TROJP
		Trojan Plant	TROJD
252	Customer Advances for Construction		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		Customer Related	CN
25398	S02 Emissions		SE
25399	Other Deferred Credits		
		Direct assigned - Jurisdiction	S
		Production, Transmission	SG
		General	SO
		Mining	SE
254	Regulatory Liabilities		
		Regulatory Liabilities	S
		Regulatory Liabilities	SE
		Insurance Provision	SO
190	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Bad Debt	BADDEBT
		Pacific Hydro	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJD
		Distribution	SNPD
		Mining Plant	SE
281	Accumulated Deferred Income Taxes		
		Production, Transmission	SG
282	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Depreciation	DITBAL
		Hydro Pacific	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJP
		Depreciation	TAXDEPR
		Depreciation	SCHMDEXP
		System Gross Plant	GPS
		Contribution in Aid of Construction	CIAC
		Mining	SE

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
283	Accumulated Deferred Income Taxes		
		Direct assigned - Jurisdiction	S
		Depreciation	DITBAL
		Hydro Pacific	SG
		Production, Transmission	SG
		Customer Related	CN
		General	SO
		Miscellaneous	SNP
		Trojan	TROJD
		Production, Other	SGCT
		Property Tax	GPS
		Mining Plant	SE
255	Accumulated Investment Tax Credit		
		Direct assigned - Jurisdiction	S
		Investment Tax Credits	ITC84
		Investment Tax Credits	ITC85
		Investment Tax Credits	ITC86
		Investment Tax Credits	ITC88
		Investment Tax Credits	ITC89
		Investment Tax Credits	ITC90
		Investment Tax Credits	SG
PRODUCTION PLANT ACCUM DEPRECIATION			
108SP	Steam Prod Plant Accumulated Depr		
		Steam Plants	SG
108NP	Nuclear Prod Plant Accumulated Depr		
		Nuclear Plant	SG
108HP	Hydraulic Prod Plant Accum Depr		
		Pacific Hydro	SG
		East Hydro	SG
108OP	Other Production Plant - Accum Depr		
		Other Production Plant	SG
TRANS PLANT ACCUM DEPR			
108TP	Transmission Plant Accumulated Depr		
		Transmission Plant	SG
DISTRIBUTION PLANT ACCUM DEPR			
108360 - 108373	Distribution Plant Accumulated Depr		
		Direct assigned - Jurisdiction	S
108D00	Unclassified Dist Plant - Acct 300		
		Direct assigned - Jurisdiction	S
108DS	Unclassified Dist Sub Plant - Acct 300		
		Direct assigned - Jurisdiction	S
108DP	Unclassified Dist Sub Plant - Acct 300		
		Direct assigned - Jurisdiction	S

Allocation Factor Applied to each Component of Revenue Requirement

FERC ACCT	DESCRIPTION		ALLOCATION FACTOR
GENERAL PLANT ACCUM DEPR			
108GP	General Plant Accumulated Depr		
		Distribution	S
		Pacific Hydro	SG
		East Hydro	SG
		Production / Transmission	SG
		Customer Related	CN
		General SO	SO
		Mining Plant	SE
108MP	Mining Plant Accumulated Depr.		
		Mining Plant	SE
108MP	Less Centralia Situs Depreciation		
		Direct assigned - Jurisdiction	S
1081390	Accum Depr - Capital Lease		
		General	SO
1081399	Accum Depr - Capital Lease		
		Direct assigned - Jurisdiction	S
ACCUM PROVISION FOR AMORTIZATION			
111SP	Accum Prov for Amort-Steam		
		Steam Plants	SG
111GP	Accum Prov for Amort-General		
		Distribution	S
		Pacific Hydro	SG
		East Hydro	SG
		Production / Transmission	SG
		Customer Related	CN
		General SO	SO
111HP	Accum Prov for Amort-Hydro		
		Pacific Hydro	SG
		East Hydro	SG
111IP	Accum Prov for Amort-Intangible Plant		
		Distribution	S
		Pacific Hydro	SG
		Production, Transmission	SG
		General	SO
		Mining	SE
		Customer Related	CN
111IP	Less Non-Utility Plant		
		Direct assigned - Jurisdiction	S
111399	Accum Prov for Amort-Mining		
		Mining Plant	SE

2017 Protocol - Appendix C
Allocation Factors
Algebraic Derivations

Allocation Factors

PacifiCorp serves eight jurisdictions. Jurisdictions are represented by the index i = California, Idaho, Oregon, Utah, Washington, Eastern Wyoming, Western Wyoming, & FERC.

The following assumptions are made in the factor derivations:

It is assumed that the 12CP (j=1 to 12) method is used in defining the System Capacity ("SC")

It is assumed that twelve months (j=1 to 12) method is used in defining the System Energy ("SE").

In defining the System Generation ("SG") factor, the weighting of 75 percent System Capacity, 25 percent System Energy is assumed to continue.

While it is agreed that the peak loads & input energy should be temperature adjusted, no decision has been made upon the methodology to do these adjustments.

System Capacity Factor ("SC")

$$SCi = \frac{\sum_{j=1}^{12} TAP_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} TAP_{ij}}$$

where:

SC_i	=	**System Capacity Factor** for jurisdiction i.
TAP_{ij}	=	Temperature Adjusted Peak Load of jurisdiction i in month j at the time of the System Peak.

System Energy Factor (“SE”)

$$SEi = \frac{\sum_{j=1}^{12} TAE_{ij}}{\sum_{i=1}^{8}\sum_{j=1}^{12} TAE_{ij}}$$

where:

SE_i = **System Energy Factor** for jurisdiction i.
$TAEi_j$ = Temperature Adjusted Input Energy of jurisdiction i in month j.

System Generation Factor (“SG”)

$$SG_i = .75 * SC_i + .25 * SE_i$$

where:

SG_i = **System Generation Factor** for jurisdiction i.
SC_i = System Capacity for jurisdiction i.
SE_i = System Energy for jurisdiction i.

Division Generation - Pacific Factor (“DGP”)

$$DGP_i = \frac{SG_i^*}{\sum_{i=1}^{i=8} SG_i^*}$$

where:

DGP_i = **Division Generation - Pacific Factor** for jurisdiction i.
$SG_i^* = SG_i$ if i is a Pacific jurisdiction, otherwise
$SG_i^* = 0.$
SG_i = System Generation for jurisdiction i.

<u>Division Generation - Utah Factor ("DGU")</u>

$$DGU_i = \frac{SG_i^*}{\sum_{i=1}^{i=8} SG_i^*}$$

where:

DGU_i = **Division Generation - Utah Factor** for jurisdiction i.
$SG_i^* = SG_i$ if i is a Utah jurisdiction, otherwise
$SG_i^* = 0.$
SG_i = System Generation for jurisdiction i.

<u>System Net Plant - Distribution Factor ("SNPD")</u>

$$SNPD_i = \frac{PD_i - ADPD_i}{(PD - ADPD)}$$

where:

$SNPD_i$	=	**System Net Plant - Distribution Factor** for jurisdiction i.
PD_i	=	Distribution Plant - for jurisdiction i.
$ADPD_i$	=	Accumulated Depreciation Distribution Plant - for jurisdiction i.
PD	=	Distribution Plant.
$ADPD$	=	Accumulated Depreciation Distribution Plant.

System Gross Plant - System Factor ("GPS")

$$GPS_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i}{\sum_{i=1}^{i=8}(PP_i + PT_i + PD_i + PG_i + PI_i)}$$

$GP\text{-}S_i$ = **Gross Plant - System Factor** for jurisdiction i.
PP_i = Production Plant for jurisdiction i.
PT_i = Transmission Plant for jurisdiction i.
PD_i = Distribution Plant for jurisdiction i.
PG_i = General Plant for jurisdiction i.
PI_i = Intangible Plant for jurisdiction i.

System Net Plant Factor ("SNP")

$$SNP_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i - ADPP_i - ADPT_i - ADPD_i - ADPG_i - ADPI_i}{\sum_{i=1}^{i=8}(PP_i + PT_i + PD_i + PG_i + PI_i - ADPPi - ADPT_i - ADPD_i - ADPG_i - ADPI_i)}$$

SNP_i = **System Net Plant Factor** for jurisdiction i.
PP_i = Production Plant for jurisdiction i.
PT_i = Transmission Plant for jurisdiction i.
PD_i = Distribution Plant for jurisdiction i.
PG_i = General Plant for jurisdiction i.
PI_i = Intangible Plant for jurisdiction i.
$ADPP_i$ = Accumulated Depreciation Production Plant for jurisdiction i.
$ADPT_i$ = Accumulated Depreciation Transmission Plant for jurisdiction i.
$ADPD_i$ = Accumulated Depreciation Distribution Plant for jurisdiction i.
$ADPG_i$ = Accumulated Depreciation General Plant for jurisdiction i.
$ADPI_i$ = Accumulated Depreciation Intangible Plant for jurisdiction i.

<u>System Overhead - Gross Factor ("SO")</u>

$$SOG_i = \frac{PP_i + PT_i + PD_i + PG_i + PI_i - PP_{oi} - PT_{oi} - PD_{oi} - PG_{oi} - PI_{oi}}{\sum_{i=1}^{i=8}(PP_i + PT_i + PD_i + PG_i + PP_i - PP_oi - PI_{oi} - PD_{oi} - PG_{oi} - PI_{oi})}$$

SOG_i = **System Overhead - Gross Factor** for jurisdiction i.
PP_i = Gross Production Plant for jurisdiction i.
PT_i = Gross Transmission Plant for jurisdiction i.
PD_i = Gross Distribution Plant for jurisdiction i.
PG_i = Gross General Plant for jurisdiction i.
PI_i = Gross Intangible Plant for jurisdiction i.
PP_{oi} = Gross Production Plant for jurisdiction i allocated on a SO factor.
PT_{oi} = Gross Transmission Plant for jurisdiction i allocated on a SO factor
PD_{oi} = Gross Distribution Plant for jurisdiction i allocated on a SO factor
PG_{oi} = Gross General Plant for jurisdiction i allocated on a SO factor
PI_{oi} = Gross Intangible Plant for jurisdiction i allocated on a SO factor

<u>Income Before Taxes Factor ("IBT")</u>

$$IBT_i = \frac{TIBT_i}{\sum_{i=1}^{i=8} TIBT_i}$$

IBTi = **Income before Taxes Factor** for jurisdiction i.
TIBTi = Total Income before Taxes for jurisdiction i.

Bad Debt Expense Factor ("BADDEBT")

$$BADDEBT_i = \frac{ACCT904_i}{\sum_{i=1}^{i=8} ACCT904_i}$$

$BADDEBT_i$ = **Bad Debt Expense Factor** for jurisdiction i.
$ACCT904i$ = Balance in Account 904 for jurisdiction i.

Customer Number Factor ("CN")

$$CN_i = \frac{CUST_i}{\sum_{i=1}^{i=8} CUST_i}$$

where:
CN_i = **Customer Number Factor** for jurisdiction i.
$CUST_i$ = Total Electric Customers for jurisdiction i.

Contributions in Aid of Construction ("CIAC")

$$CIAC_i = \frac{CIACNA_i}{\sum_{i=1}^{i=8} CIACNA_i}$$

where:
$CIAC_i$ = **Contributions in Aid of Construction Factor** for jurisdiction i.
$CIACNA_i$ = Contributions in Aid of Construction – Net additions for jurisdiction i.

Schedule M - Deductions ("SCHMD")

$$SCHMD_i = \frac{DEPRC_i}{\sum_{i=1}^{i=8} DEPRC_i}$$

where:

$SCHMD_i$	=	**Schedule M - Deductions (SCHMD) Factor** for jurisdiction i.
$DEPRC_i$	=	Depreciation in Accounts 403.1 - 403.9 for jurisdiction i.

Trojan Plant ("TROJP")

$$TROJP_i = \frac{ACCT18222_i}{\sum_{i=1}^{i=8} ACCT18222_i}$$

where:

$TROJP_i$	=	**Trojan Plant (TROJP) Factor** for jurisdiction i.
$ACCT18222_i$	=	Allocated Adjusted Balance in Account 182.22 for jurisdiction i.

Trojan Decommissioning ("TROJD")

$$TROJD_i = \frac{ACCT22842_i}{\sum_{i=1}^{i=8} ACCT22842_i}$$

where:

$TROJD_i$	=	**Trojan Decommissioning (TROJD) Factor** for jurisdiction i.
$ACCT22842_i$	=	Allocated Adjusted Balance in Account 228.42 for jurisdiction i.

<u>Tax Depreciation (“TAXDEPR”)</u>

$$TAXDEPR_i = \frac{TAXDEPRA_i}{\sum_{i=1}^{i=8} TAXDEPRA_i}$$

where:

$TAXDEPR_i$	=	**Tax Depreciation (TAXDEPR) Factor** for jurisdiction i.
$TAXDEPRA_i$	=	Tax Depreciation allocated to jurisdiction i.

(Tax Depreciation is allocated based on functional pre merger and post merger splits of plant using Divisional and System allocations from above. Each jurisdiction’s total allocated portion of Tax depreciation is determined by its total allocated ratio of these functional pre and post merger splits to the total Company Tax Depreciation.)

<u>Deferred Tax Expense (“DITEXP”)</u>

$$DITEXP_i = \frac{DITEXPA_i}{\sum_{i=1}^{i=8} DITEXPA_i}$$

where:

$DITEXP_i$	=	**Deferred Tax Expense (DITEXP) Factor** for jurisdiction i.
$DITEXPA_i$	=	Deferred Tax Expense allocated to jurisdiction i.

(Deferred Tax Expense is allocated by a run of PowerTax based upon the above factors. PowerTax is a computer software package used to track Deferred Tax Expense & Deferred Tax Balances. PowerTax allocates Deferred Tax Expense and Deferred Tax Balances to the states based upon a computer run which uses as inputs the preceding factors. If the preceding factors change, the factors generated by PowerTax change.)

<u>Deferred Tax Balance ("DITBAL")</u>

$$DITBAL_i = \frac{DITBALA_i}{\sum_{i=1}^{i=8} DITBALA_i}$$

where:

$DITBAL_{\boldsymbol{i}}$	=	**Deferred Tax Balance (DITBAL) Factor** for jurisdiction i.
$DITBALA_i$	=	Deferred Tax Balance allocated to jurisdiction i.

(Deferred Tax Balance is allocated by a run of PowerTax based upon the above factors. PowerTax is a computer software package used to track Deferred Tax Expense & Deferred Tax Balances. PowerTax allocates Deferred Tax Expense and Deferred Tax Balances to the states based upon a computer run which uses as inputs the preceding factors. If the preceding factors change, the factors generated by PowerTax change.)

2017 Protocol – Appendix D
Special Contracts

2017 Protocol - Appendix D
Special Contracts

Special Contracts without Ancillary Service Contract Attributes

For allocation purposes Special Contracts without identifiable Ancillary Service Contract attributes are viewed as one transaction.

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors.

When interruptions of a Special Contract customer's service occur, the reduction in load will be reflected in the host jurisdiction's Load-Based Dynamic Allocation Factors.

Actual revenues received from Special Contract customer will be assigned to the State where the Special Contract customer is located.

See example in Table 1

Special Contracts with Ancillary Service Contract Attributes

For allocation purposes Special Contracts with Ancillary Service Contract attributes are viewed as two transactions. PacifiCorp sells the customer electricity at the retail service rate and then buys the electricity back during the interruption period at the Ancillary Service Contract rate.

Loads of Special Contract customers will be included in all Load-Based Dynamic Allocation Factors.

When interruptions of a Special Contract customer's service occur, the host jurisdiction's Load-Based Dynamic Allocation Factors and the retail service revenue are calculated as though the interruption did not occur.

Revenues received from Special Contract customer, before any discounts for Customer Ancillary Service attributes of the Special Contract, will be assigned to the State where the Special Contract customer is located.

Discounts from tariff prices provided for in Special Contracts that recognize the Customer Ancillary Service Contract attributes of the Contract, and payments to retail customers for Customer Ancillary Services will be allocated among States on the same basis as System Resources.

See example in Table 2

Buy-through of Economic Curtailment

When a buy-through option is provided with economic curtailment, the load, costs and revenue associated with a customer buying through economic curtailment will be excluded from the calculation of State revenue requirements. The cost associated with the buy-through will be removed from the calculation of net power costs, the Special Contract customer load associated with the buy-through will be not be included in the calculation of Load-Based Dynamic Allocation Factors, and the revenue associated with the buy-through will not be included in State revenues.

2017 Protocol - Appendix D - Table 1
Interruptible Contract Without Ancillary Service Contract Attributes
Effect on Revenue Requirement

		Factor	Total system	Jurisdiction 1	Jurisdiction 2	Jurisdiction 3
1	**Loads**					
2	Jurisdictional Loads - No Interruptible Service					
3	Jurisdictional Sum of 12 monthly CP demand (MW)		72,000	24,000	36,000	12,000
4	Jurisdictional Annual Energy (MWh)		42,000,000	14,000,000	21,000,000	7,000,000
5						
6	Jurisdictional Loads - With Interruptible Service - Reflecting Actual Interruptions					
7	Jurisdictional Sum of 12 monthly CP demand (MW)		71,700	24,000	35,700	12,000
8	Jurisdictional Annual Energy (MWh)		41,962,500	14,000,000	20,962,500	7,000,000
9						
10	Special Contract Customer Revenue and Load - Non Interruptible Service					
11	Special Contract Customer Revenue		$ 20,000,000		$ 20,000,000	
12	Special Contract Customer Sum of 12 CPs (MW) (Included in line 2)		900	-	900	-
13	Special Contract Annual Energy (MWh) (Included in line 3)		500,000	-	500,000	-
14						
15	Special Contract Customer Revenue and Load - With Interruptible Service (75 MW X 500 Hours of Interruption)					
16	Special Contract Customer Revenue		$ 16,000,000		$ 16,000,000	
17	Discount for Ancillary Services				-	
18	Net Cost to Special Contract Customer		$ 16,000,000		$ 16,000,000	
19	Special Contract Sum of 12 CP- Reflecting Actual Interruptions (MW) (Included in line 7)		600	-	600	-
20	Special Contract Annual Energy- Reflecting Actual Interruptions (MWh) (Included in line 8)		462,500	-	462,500	-
21						
22	System Cost Savings from Interruption		$4,000,000			
23						
24	**Allocation Factors**					
25	No Interruptible Service					
26	SE factor (Calculated from line 4)	SE1	100.00%	33.33%	50.00%	16.67%
27	SC factor (Calculated from line 3)	SC1	100.00%	33.33%	50.00%	16.67%
28	SG factor (line 27*75% + line 26*25%)	SG1	100.00%	33.33%	50.00%	16.67%
29						
30	With Interruptible Service (Reflecting Actual Physical Interruptions)					
31	SE factor (Calculated from line 8)	SE2	100.00%	33.36%	49.96%	16.68%
32	SC factor (Calculated from line 7)	SC2	100.00%	33.47%	49.79%	16.74%
33	SG factor (line 32*75% + line 31*25%)	SG2	100.00%	33.45%	49.83%	16.72%
34						
35						
36	**No Interruptible Service**					
37						
38	**Cost of Service**					
39	Energy Cost	SE1	$ 500,000,000	$ 166,666,667	$ 250,000,000	$ 83,333,333
40	Demand Related Costs	SG1	$ 1,000,000,000	$ 333,333,333	$ 500,000,000	$ 166,666,667
41	Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
42						
43	**Revenues**					
44	Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
45	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**
46						
47						
48	**With Interruptible Service**					
49						
50	**Cost of Service**					
51	Energy Cost	SE2	$ 498,000,000	$ 166,148,347	$ 248,777,480	$ 83,074,173
52	Demand Related Costs	SG2	$ 998,000,000	$ 334,058,577	$ 496,912,134	$ 167,029,289
53	Sum of Cost		$ 1,496,000,000	$ 500,206,924	$ 745,689,614	$ 250,103,462
54						
55	**Revenues**					
56	Special Contract Revenue	Situs	$ 16,000,000		$ 16,000,000	
57	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,206,924**	**$ 729,689,614**	**$ 250,103,462**

2017 Protocol - Appendix D - Table 2
Interruptible Contract With Ancillary Service Contract Attributes
Effect on Revenue Requirement

		Factor	Total system	Jurisdiction 1	Jurisdiction 2	Jurisdiction 3
1	**Loads**					
2	Jurisdictional Loads - No Interruptible Service					
3	Jurisdictional Sum of 12 monthly CP demand (MW)		72,000	24,000	36,000	12,000
4	Jurisdictional Annual Energy (MWh)		42,000,000	14,000,000	21,000,000	7,000,000
5						
6	Jurisdictional Loads - With Interruptible Service - Reflecting Actual Interruptions					
7	Jurisdictional Sum of 12 monthly CP demand (MW)		71,700	24,000	35,700	12,000
8	Jurisdictional Annual Energy (MWh)		41,962,500	14,000,000	20,962,500	7,000,000
9						
10	Special Contract Customer Revenue and Load - Non Interruptible Service					
11	Special Contract Customer Revenue		$ 20,000,000		$ 20,000,000	
12	Special Contract Customer Sum of 12 CPs (MW) (Included in line 2)		900	-	900	-
13	Special Contract Annual Energy (MWh) (Included in line 3)		500,000	-	500,000	-
14						
15	Special Contract Customer Revenue and Load - With Interruptible Service (75 MW X 500 Hours of Interruption)					
16	Tariff Equivalent Revenue		$ 20,000,000		$ 20,000,000	
17	Ancillary Service Discount for 75 MW X 500 Hours of Economic Curtailment				$ (4,000,000)	
18	Net Cost to Special Contract Customer		$ 16,000,000		$ 16,000,000	
19	Special Contract Sum of 12 CP- Reflecting Actual Interruptions (MW) (Included in line 7)		600	-	600	-
20	Special Contract Annual Energy- Reflecting Actual Interruptions (MWh) (Included in line 8)		462,500	-	462,500	-
21						
22	System Cost Savings from Interruption		$4,000,000			
23						
24	**Allocation Factors**					
25	No Interruptible Service					
26	SE factor (Calculated from line 4)	SE1	100.00%	33.33%	50.00%	16.67%
27	SC factor (Calculated from line 3)	SC1	100.00%	33.33%	50.00%	16.67%
28	SG factor (line 27*75% + line 26*25%)	SG1	100.00%	33.33%	50.00%	16.67%
29						
30	With Interruptible Service (Reflecting Actual Physical Interruptions)					
31	SE factor (Calculated from line 8)	SE2	100.00%	33.36%	49.96%	16.68%
32	SC factor (Calculated from line 7)	SC2	100.00%	33.47%	49.79%	16.74%
33	SG factor (line 32*75% + line 31*25%)	SG2	100.00%	33.45%	49.83%	16.72%
34						
35						
36	**No Interruptible Service**					
37						
38	**Cost of Service**					
39	Energy Cost	SE1	$ 500,000,000	$ 166,666,667	$ 250,000,000	$ 83,333,333
40	Demand Related Costs	SG1	$ 1,000,000,000	$ 333,333,333	$ 500,000,000	$ 166,666,667
41	Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
42						
43	**Revenues**					
44	Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
45	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**
46						
47						
48	**With Interruptible Service & Ancillary Service Contract**					
49						
50	**Cost of Service**					
51	Energy Cost	SE1	$ 498,000,000	$ 166,000,000	$ 249,000,000	$ 83,000,000
52	Demand Related Costs	SG1	$ 998,000,000	$ 332,666,667	$ 499,000,000	$ 166,333,333
53	Ancillary Service Contract - Economic Curtailment (Demand)	SG1	$ 2,000,000	$ 666,667	$ 1,000,000	$ 333,333
54	Ancillary Service Contract - Economic Curtailment (Energy)	SE1	$ 2,000,000	$ 666,667	$ 1,000,000	$ 333,333
55	Sum of Cost		$ 1,500,000,000	$ 500,000,000	$ 750,000,000	$ 250,000,000
56						
57	**Revenues**					
58	Special Contract Revenue	Situs	$ 20,000,000		$ 20,000,000	
59	**Revenues from all other customers**	Situs	**$ 1,480,000,000**	**$ 500,000,000**	**$ 730,000,000**	**$ 250,000,000**

Docket No. UM 1050
Exhibit PAC/200
Witness: Steven R. McDougal

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Steven R. McDougal

December 2015

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Q. Please state your name, business address and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Steven R. McDougal, and my business address is 1407 West North Temple, Suite 330, Salt Lake City, Utah 84116. I am currently employed as the Director of Revenue Requirement.

QUALIFICATIONS

Q. Briefly describe your educational and professional background.

A. I received a Master of Accountancy degree from Brigham Young University with an emphasis in Management Advisory Services in 1983, and a Bachelor of Science degree in Accounting from Brigham Young University in 1982. In addition to my formal education, I have also attended various educational, professional, and electric industry-related seminars. I have been employed by PacifiCorp or its predecessor companies since 1983. My experience at PacifiCorp includes various positions within regulation, finance, resource planning, and internal audit.

Q. What are your responsibilities as director of revenue requirement?

A. My primary responsibilities include overseeing the calculation and reporting of the Company's regulated earnings or revenue requirement, assuring that the inter-jurisdictional cost allocation methodology is correctly applied, and explaining those calculations to regulators in the jurisdictions in which the Company operates.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have provided testimony before the Public Service Commission of Utah, the Washington Utilities and Transportation Commission, the California Public Utilities Commission, the Idaho Public Utilities Commission, the Public Service Commission of Wyoming, and the Public Utility Commission of Oregon.

PURPOSE AND OVERVIEW OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony summarizes the analysis performed by the Company to evaluate allocation alternatives, explains how the 2017 Protocol is calculated and reflected in results of operations, and provides a summary of the Appendixes included with the testimony of Mr. R. Bryce Dalley.

MULTI-STATE PROCESS (MSP) ANALYSIS

Q. Please describe some of the analysis the Company performed and provided to the Broad Review Work Group (BRWG) to help develop the 2017 Protocol.

A. In preparation for the transition from the 2010 Protocol to a new allocation method for filings made after December 31, 2016, the BRWG began meeting in November 2012, to support the development of a new allocation methodology by evaluating alternative allocation methods. The BRWG met regularly over a three-year period to analyze and discuss various alternatives. The Company prepared foundational studies in 2013 and then updated the base data in the foundational study in 2014 to reflect more current data and to incorporate changes such as new depreciation rates. At the request of the BRWG, various scenarios and sensitivity studies were identified to study the impact of: 1) high load growth; 2) low load growth; 3) varying gas and electric purchase prices; and 4) adding new resources versus front office transactions. Structural separation scenarios were also analyzed by comparing a slice-of-the-system approach versus a control area assignment of resources by the area in which they are physically located. The BRWG also explored the impact of allocating generation resources on separate factors using differing demand and energy weightings and numbers of coincident peaks and peak weightings rather than the System Generation factor, as currently defined.

The Company also provided experts to explain the transmission system and transfer capabilities between the East and West balancing authority areas. Analyses were also performed regarding the variability of the Embedded Cost Differential (ECD) and the demand-side management (DSM) activities in each state along with the possibility of system versus situs treatment of those costs.

2017 PROTOCOL

Q. How will the 2017 Protocol Adjustment be included in the Company's Results of Operation reports?

A. The 2017 Protocol Adjustment is a single line item added to each state's annual revenue requirement. The impact relative to current revenue requirements in each state is an incremental increase by the amount of the 2017 Protocol Equalization Adjustment. California's annual 2017 Protocol Adjustment is zero, because the Baseline ECD is exactly offset by the Equalization Adjustment ($0.324 million incremental increase); Idaho's 2017 Protocol Adjustment increases its revenue requirement by $0.986 million ($0.150 million incremental increase); Utah's 2017 Protocol Adjustment increases its annual revenue requirement by $4.4 million ($4.4 million incremental increase); and Wyoming's 2017 Protocol Adjustment reduces its annual revenue requirement by $0.251 million ($1.6 million incremental increase). Oregon's 2017 Protocol Adjustment will depend on the amount of the dynamic ECD calculation but it is banded within the ranges discussed in the 2017 Protocol. Table 1 below summarizes the Baseline ECD, Equalization Adjustment and 2017 Protocol Adjustment for each state:

Table 1
Revenue Requirement ($000)

Revenue Requirement ($000)	**Total Company**	**California**	**Oregon**		**Utah**	**Idaho**	**Wyoming**
2017 Protocol Baseline ECD **	(9,578)	(324)	(8,238)	*	0	836	(1,851)
2017 Protocol Equalization Adjustment	9,074	324	2,600		4,400	150	1,600
2017 Protocol Adjustment		(0)	(5,638)		4,400	986	(251)

*Oregon's 2017 Protocol Baseline ECD is dynamic and will change over time with the parameters described in the 2017 Protocol. For the other states, the 2017 Protocol Baseline ECD is fixed and does not change over time.

**2017 Protocol Baseline ECD amounts shown in the table for California, Oregon, and Wyoming are based on the test year data as filed by the Company in the 2015 Wyoming general rate case (Docket No. 20000-469-ER-15) on March 3, 2015. The amount for Idaho's 2017 Protocol Baseline ECD is its 2010 Protocol Fixed ECD amount. Utah's 2017 Protocol Baseline ECD is zero based on its 2010 Protocol agreement.

MSP 2017 PROTOCOL APPENDICES

Q. Please summarize the 2017 Protocol Appendices.

A. The 2017 Protocol has four appendices: Appendix A contains the defined terms used in the protocol; Appendix B summarizes the allocation factors utilized by each Federal Energy Regulatory Commission (FERC) account; Appendix C summarizes the algebraic derivations of the allocation factors; and Appendix D explains two alternative allocation treatments for special contracts.

Q. Please describe Appendix A.

A. Appendix A of the 2017 Protocol is a summary of frequently used terms. Rather than defining each term in the Protocol itself Appendix A is provided as a quick reference resource for defined terms. During the development of the 2017 Protocol, Appendix A was reviewed to identify defined terms no longer used or new terms added to the 2017 Protocol. Terms no longer used were deleted and new terms were added to the 2017 Protocol.

Q. Please describe Appendix B - Allocation Factors Applied to each Component for Revenue Requirement.

A. Appendix B is a summary by FERC account of the appropriate allocation factors used to allocate either the costs or revenues recorded to that account. Only minor changes were made to the 2017 Protocol Appendix B from the 2010 Protocol. These changes included removing any account/factor combinations no longer used or adding new account/factor combinations that have been added since 2010 Protocol was approved. For example, FERC accounts 230 and 254105 are new accounts added to Appendix B that prior to 2013 the costs were booked to FERC Account 22842.

Q. Please describe Appendix C - Allocation factor - Algebraic Derivations.

A. Appendix C is a summary of the algebraic derivations of the factors used in the 2017 Protocol. The derivations of the factors is the same as the derivations used in the 2010 Protocol and no new factors were added to the 2017 Protocol Appendix C.

Q. Please describe Appendix D - Special Contracts.

A. Appendix D is consistent with the 2010 Protocol, with no differences between this Appendix in the 2010 Protocol and 2017 Protocol. The appendix has two options for special contracts designed to provide consistency between the allocation of revenues, costs and benefits derived from adjusting allocation factors. Under option 1, the costs of the contract are embedded in the tariff price, resulting in the jurisdiction approving the contract absorbing the full cost of the program, similar to DSM costs. Since the costs are absorbed by the jurisdiction approving the contract, it also receives the benefits associated with the program through reduced allocation factors. Under option 2, the contract costs are separately identified and allocated to all states. Since the costs are allocated to all states and not to a specific jurisdiction, the monthly load used to calculate allocation factors is calculated assuming no curtailment occurs.

Q. When was the Company's last Oregon general rate case filed and what ECD level is currently included in Oregon rates?

A. The Company's last general rate case in Oregon was docket UE 263, filed March 1, 2013, using a 2014 forecast test year. The Oregon ECD value included in customers' rates from that case, under the 2010 Protocol, was a credit of $8.8 million.

Q. How does the ECD value from the Company's last general rate case compare to the Oregon ECD range agreed to by Oregon parties for the 2017 Protocol?

A. As discussed in Mr. Dalley's testimony, for the duration of the 2017 Protocol, Oregon parties agreed that Oregon's ECD would remain dynamic with lower and upper limits (i.e. a floor and caps). For the first general rate case filed by the Company, the lower limit or floor for the Oregon ECD is a credit of $8.238 million and the upper limit or cap is a credit of $10.5 million. If there is a second general rate case filed in Oregon using the 2017 Protocol, there is no change to the ECD lower limit, but the upper limit increases to a credit of $11.0 million. The $8.238 million lower limit agreed to by Oregon parties was established using calendar year 2016 data from the Company's 2015 Wyoming general rate case.

Q. Do the Company's projections for the Oregon ECD fall within the lower and upper ECD limits agreed to by Oregon parties for the 2017 Protocol?

A. Yes. The Company's projections for the Oregon ECD credit are $8.2 million for 2016, $8.7 million for 2017, and $10.0 million for 2018. These values fall within the ECD range (floor and caps) agreed to by Oregon parties for the 2017 Protocol. Accordingly, continued use of a dynamic ECD for Oregon, with the parameters described in Mr. Dalley's testimony is reasonable.

Q. How does Oregon's ECD under Revised Protocol compare to the lower and upper ECD limits agreed to by Oregon Parties in the 2017 Protocol?

A. Oregon's projected ECD credit under Revised Protocol is $7.1 million for 2016, $6.3 million for 2017, and $7.1 million for 2018. The lower limit for the ECD for general rate cases under the 2017 Protocol is expected to provide more benefit to Oregon customers than the Revised Protocol.

Q. Does this conclude your direct testimony?

A. Yes.