Application No. 18-04-___
Exhibit PAC/100
Witness: Scott D. Bolton

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP

Direct Testimony of Scott D. Bolton

Policy and Allocation Methodology

April 2018

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ATTACHED EXHIBITS

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

A. My name is Scott D. Bolton. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My current position is Senior Vice President, External Affairs & Customer Solutions.

I. QUALIFICATIONS

Q. Please describe your education and business experience.

A. I graduated from Portland State University with a bachelor's degree in political science. I received a Master of Business Administration from Marylhurst University. I also have a Utility Management Certificate from Willamette University. I joined PacifiCorp in 2004 as an analyst in the government affairs department. Since that time I have held various positions with increasing responsibility within the company. Before my current role, I was Vice President of External Affairs and Customer Solutions. I became Senior Vice President of External Affairs and Customer Solutions in May 2017.

II. PURPOSE OF TESTIMONY

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

A. My testimony provides an overview of PacifiCorp's general rate case filing proposing a modest $1.06 million increase to PacifiCorp's base electric rates. I also address the regulatory policy issues raised by this filing, including PacifiCorp's proposal to reinstitute shorter depreciation lives for the company's coal-fired resources and the company's proposed new allocation methodology for system costs, the 2017 Inter-jurisdictional Allocation Protocol (2017 Protocol). Finally, my testimony introduces other witnesses providing testimony on behalf of PacifiCorp.

III. OVERVIEW OF PACIFICORP'S FILING

Q. Please describe PacifiCorp's filing.

A. PacifiCorp is filing its first general rate case since 2011.[1] Since that time, the company, and indeed the electricity sector have undergone significant changes driven by public policy, emerging and maturing technologies, and new levels of customer engagement. PacifiCorp has managed this transition without losing focus on maintaining the affordability of essential electricity services for its approximately 45,000 customers in its heavily rural and economically challenged service territory. This filing updates costs to serve California customers by requesting a modest increase of approximately $1.06 million, or a 0.9 percent net increase, to its base electric rates in California.

This modest increase is evidence of the cost-conscious and prudent actions taken by PacifiCorp to control its costs and provide safe and reliable energy to its customers at a fair price. A significant driver of the increase requested in this case are the costs associated with regulations adopted in R.15-05-006 designed to mitigate the risk of catastrophic fires attributed to overhead utility equipment.[2] Despite that significant driver, PacifiCorp's diligence in managing its costs has allowed the company to propose to accelerate depreciation for its coal-fired generation resources

[1] *In the Matter of the Application of PACIFICORP (U901-E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2011*, Application (A.) 09-11-015 (filed November 20, 2009).
[2] *See Order Instituting Rulemaking to Develop and Adopt Fire Threat Maps and Fire Safety Regulations*, Decision (D.) 17-12-024 (December 21, 2017).

and invest in a clean energy future, while keeping rates relatively flat for its customers.

Q. Upon what test year is the rate increase request based?

A. As described in the testimony of Ms. Shelley E. McCoy, the rate increase is based on a forecast test period of the 12 months ending December 31, 2019, and certain specific adjustments based on known and measurable capital additions.

Q. What are the primary factors driving the overall rate increase?

A. As a regulated utility, PacifiCorp has a duty and an obligation to provide safe, adequate, and reliable service to customers in its California service territory while balancing cost, risk, and state energy policy objectives. PacifiCorp's proposed rate increase is due to a combination of factors, including increased operating expenses, company investments in generation, transmission, and distribution, the recent changes to the federal tax code, and the new fire safety regulations adopted in R.15-05-006, among other items.

PacifiCorp is in the process of transitioning to a clean energy future by investing in additional capacity from renewable resources. The test period in this case includes a portion of significant new renewable energy and infrastructure investments, known as Energy Vision 2020,[3] to serve customers from more clean energy resources, as part of PacifiCorp's long-term plan to build an energy future that is increasingly reliable, decreases greenhouse gas emissions, while maintaining affordability for its customers. One key component of Energy Vision 2020 is expanding the amount of wind power serving PacifiCorp customers with its

[3] *See* http://www.pacificorp.com/es/energy-vision-2020.html.

repowering project to increase the capacity of certain existing wind-generation facilities.

PacifiCorp also seeks to mitigate current risks by increasing flexibility to address changing carbon policy. Specifically, PacifiCorp is proposing to accelerate depreciation on coal-fired resources so that all coal facilities will be fully depreciated by 2029 or earlier. I discuss the basis for PacifiCorp's accelerated depreciation proposal for coal-fired resources later in my testimony.

PacifiCorp is also seeking recovery of its prior investments to reduce emissions in compliance with environmental requirements. Mr. Chad A. Teply discusses the company's 2012-2013 investment decisions on selective catalytic reduction (SCR) systems installed in accordance with state and federal environmental compliance requirements for Jim Bridger Units 3 and 4, Craig Unit 2, and Hayden Units 1 and 2. The SCR systems reduce oxides of nitrogen (NO_X) emissions.

While the proposed revenue requirement includes the company's generation, distribution, and transmission investments occurring for the benefits of the system, the proposed revenue requirement also includes two major investments in PacifiCorp's California service territory. Mr. Richard A. Vail discusses the construction of a new Lassen distribution substation to replace the aging Mt. Shasta substation and Mr. David M. Lucas presents PacifiCorp's deployment of advanced metering infrastructure in its California service territory.

Q. Is PacifiCorp seeking an increase to its currently authorized Return on Equity (ROE) in this proceeding?

A. No. PacifiCorp is not proposing any change to its currently authorized ROE. Based on recent changes to the federal tax code and the evidence provided in the testimony and exhibits of Ms. McCoy, PacifiCorp will earn a ROE in California of 10.08 percent for the test period. This return is less than the company's currently authorized 10.6 percent ROE, which is the ROE requested by the company and supported by the testimony of Mr. Kurt G. Strunk in this proceeding. An overall price increase of approximately $1.06 million or 0.9 percent is required to produce the 10.6 percent ROE necessary to maintain PacifiCorp's financial integrity while making the necessary capital investments to transition to a cleaner energy future.

Q. Please provide an overview of PacifiCorp's repowering proposal for certain of its wind facilities.

A. PacifiCorp's wind repowering project is part of a plan to deliver more renewable generation along with long-term savings for customers. This is the type of investment required to transition a system the size of PacifiCorp's away from coal-fired generating plants and towards a clean-energy future. PacifiCorp's repowering effort was designed to lead this transition. The economic benefits of repowering—zero fuel-cost energy and Production Tax Credits (PTC)—will reduce the Energy Cost Adjustment Clause (ECAC) offset rate that will be effective January 1, 2019, which aligns with the rates effective in this proceeding. Over the first 10 years of the lives of the proposed project, federal PTC benefits drive net customer benefits across all nine price-policy scenarios presented in PacifiCorp's 2017 IRP.[4] PacifiCorp's repowering effort is discussed in the testimonies of Mr. Rick T. Link and Mr. Timothy J. Hemstreet.

[4] http://www.pacificorp.com/es/irp.html.

Q. Will the company incur other costs in 2019?

A. Yes. The repowering project included in the company's 2019 revenue requirement is part of PacifiCorp's Energy Vision 2020 effort. PacifiCorp will be making additional investments in 2019 related to new wind generation and transmission upgrades to deliver energy from new and repowered wind generation to customers. These additional investments will be financed, in part, during 2019, but will not go into service until after the test-year in this proceeding.

Q. Are the cost increases facing PacifiCorp unique in the industry?

A. No. There is a significant interest in finding cost effective ways to transition to cleaner energy resources and maintain compliance with federal and state environmental requirements. PacifiCorp's efforts to meet environmental requirements and develop cost effective opportunities to transition its system away from coal, with only a modest increase to rates, has allowed PacifiCorp to maintain competitive prices measured against other utilities in California. PacifiCorp's current and proposed rates are presented in the testimony of Ms. Judith M. Ridenour.

Q. What portion of the requested increase is related to net power costs?

A. The company is not requesting authorization to recover any revenue requirement related to net power costs in this filing. PacifiCorp collects net power costs through its ECAC, which is updated each August and collected through rate schedule ECAC-94. In compliance with the ECAC mechanism, PacifiCorp will file an application to set its 2019 ECAC rates by August 1, 2018.

Q. What has PacifiCorp done to mitigate the rate increase requested in this proceeding?

A. PacifiCorp has taken several steps to mitigate this rate increase request. First, PacifiCorp has proactively and aggressively controlled its costs. PacifiCorp's repowering project will qualify for an additional 10 years of federal PTCs, resulting in net benefits to customers. Additionally, repowering will reset the 30-year depreciable life of the assets and reduce run-rate operating costs, while increasing production capacity. PacifiCorp's SCR system projects were also implemented under budget and met all environmental compliance deadlines. Finally, as discussed in the direct testimony of Ms. Nikki L. Kobliha, PacifiCorp has been successful in securing favorable interest rates for recent bond issuances that directly benefit customers.

Q. Does PacifiCorp's rate increase include the impacts of the federal tax legislation, formally titled "To provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018", H.R. 1 (Tax Cuts and Jobs Act)?[5]

A. Yes. PacifiCorp's 2019 rate case revenue requirement includes the forecasted impact of the Tax Cuts and Jobs Act. The impacts of the Tax Cuts and Jobs Act is discussed in the direct testimony of Ms. McCoy.

Q. How is PacifiCorp addressing the 2018 impacts of the Tax Cuts and Jobs Act?

A. On December 28, 2017, PacifiCorp filed an application to establish a memorandum account to track the expected income tax impacts associated with the Tax Cuts and Jobs Act. PacifiCorp does not currently have a detailed estimate on the impacts of the

[5] Signed into law on December 22, 2017.

Tax Cuts and Jobs Act for 2018. PacifiCorp expects to know more once its 2017 results of operations are complete, and can be used as a proxy for 2018. PacifiCorp expects to complete this estimate mid-2018. Once PacifiCorp can estimate the 2018 impact of the Tax Cuts and Jobs Act, PacifiCorp will develop an amortization proposal.

Q. Does this filing address the California Public Utilities Commission's (Commission) direction to begin incorporating a risk-based decision-making process into PacifiCorp's general rate case?

A. Yes. In this filing PacifiCorp has taken steps to begin incorporating a risk-based decision making process as required by D.14-12-025.[6] The testimony of Mr. Brett S. Allsup addresses the safety risks that PacifiCorp faces in its system and operations, and explains how it plans to manage, mitigate, and minimize those risks.

IV. COST RECOVERY MECHANISMS

Q. Please describe the cost-recovery mechanisms currently authorized for PacifiCorp.

A. In PacifiCorp's 2005 General Rate Case, PacifiCorp was authorized to implement three cost-recovery mechanisms that operate outside the three-year cycle for general rate case proceedings.[7] The Commission authorized PacifiCorp to implement an ECAC to recover its volatile energy costs in a timely and efficient manner. In

[6] *Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the General Rate Case Plan for Energy Utilities*, D.14-12-025 (December 9, 2014).
[7] *In the Matter of the Application of PACIFICORP (U 901-E) for an Order Authorizing a General Rate Increase and Implementation of an Energy Cost Adjustment Clause and a Post Test-Year Adjustment Mechanism*, D.06-12-011 (December 18, 2018).

addition to the ECAC, the Commission authorized for PacifiCorp a Post Test Year Adjustment Mechanism (PTAM) for Major Capital Additions that allows the company to recover the California–allocated share of reasonable costs related to any plant additions greater than $50 million on a total-company basis, and an annual PTAM Attrition Factor adjustment that allows the company to adjust base rates for changes in inflation with an offsetting productivity factor of 0.5 percent. The PTAM Attrition Factor adjustment was effective on January 1 of the years when PacifiCorp did not file a general rate case.

Q. Have these mechanisms been effective?

A. Yes. These mechanisms have allowed PacifiCorp to adjust its rates incrementally as the cost of serving customers changes, providing for recovery of prudently-incurred costs, and typically providing customers with small and gradual rate changes. The mechanisms also result in an efficient use of PacifiCorp and Commission resources to avoid the expense and effort of processing large litigated cases. PacifiCorp works closely with the Office of Ratepayer Advocates to communicate frequently and in advance of the PTAM filings. As a result, PacifiCorp's PTAM filings have been processed expeditiously and efficiently by the Commission.

These mechanisms also provide benefits to customers when PacifiCorp's costs decrease. PacifiCorp's 2016, 2017, and 2018 ECAC applications included a request for a rate decrease, reflecting lower loads across the company's system, and lower wholesale prices for electricity and natural gas. This illustrates that mechanisms like the ECAC and PTAM provide benefits to both PacifiCorp and its customers by providing accurate and timely recovery (or return) of costs prudently incurred by the company.

Q. Will PacifiCorp continue to use the mechanisms in 2019 and beyond?

A. Yes. The Commission's order in the 2011 Rate Case did not include any limitations on the continuation of the ECAC or the PTAM for Major Capital Additions. As such, PacifiCorp intends to continue to recover net power costs through the annual ECAC mechanism. The company will continue to make an annual filing on August 1 of each year for rate changes effective January 1 of the next calendar year.

PacifiCorp also intends to continue to utilize the PTAM for Major Capital Additions. The current filing includes forecast cost data and in-service dates for capital projects scheduled to be completed through calendar year 2019. As new, eligible plant additions are placed in service prior to the January 1, 2019 rate effective date of this proceeding, or after December 31, 2019, PacifiCorp plans to use the PTAM to add the California-allocated costs of these projects to rates based on actual cost data and in-service dates. Any material difference between the actual data and the forecast data included in the rate case will be adjusted following approval of the PTAM filings. Present revenues will also be updated to reflect the increase in rates, thereby reducing the revenue requirement increase requested in this proceeding.

The Commission authorized continuation of the PTAM Attrition Factor adjustment in PacifiCorp's 2011 Rate Case[8] and in the subsequent decisions modifying its decision in that case.[9] In PacifiCorp's 2011 Rate Case, the PTAM

[8] *In the Matter of the Application of PACIFICORP (U901-E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2011*, D.10-09-010 (September 3, 2010).
[9] *In the Matter of the Application of PACIFICORP (U901E), an Oregon Company, for an Order*

Attrition Factor adjustment was authorized for use in setting rates for 2012 and 2013,[10] and extended to years 2014 through 2017.[11] PacifiCorp respectfully requests that the PTAM Attrition Factor adjustment be authorized for setting rates in the calendar years between general rate cases on a going-forward basis, based on the same formula and applied to the same rate elements as was used for calculating the adjustment for calendar year 2011, and approved in D.10-09-010.

V. ACCELERATED DEPRECIATION OF COAL RESOURCES

Q. What is PacifiCorp's accelerated depreciation proposal?

A. To provide greater resource planning flexibility as California implements state and federal environmental policies, the company recommends that the Commission return PacifiCorp's coal-fired resources to their pre-2008 depreciable lives. This would accelerate the current depreciation schedules for coal-fired resources currently in California rates, and more closely aligns the depreciable lives for those resources in PacifiCorp's California, Oregon, and Washington service territories. The proposed depreciation schedules reflect the shorter depreciation lives California used before PacifiCorp's 2007 depreciation study. This change will provide greater resource planning flexibility for PacifiCorp and its customers as California implements state

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Authorizing a General Rate Increase Effective January 1, 2011, D.12-10-006 (October 17, 2012); *In the Matter of the Application of PACIFICORP (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2011*, D.13-07-026 (July 31, 2013); *In the Matter of the Application of PACIFICORP (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2011*, D.14-06-018 (June 13, 2014); *In the Matter of the Application of PACIFICORP (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2011*, D.15-12-018 (December 7, 2015); and *In the Matter of the Application of PACIFICORP (U901E), an Oregon Company, for an Order Authorizing a General Rate Increase Effective January 1, 2011*, D.16-09-046 (October 3, 2016).

[10] D.10-09-010.

[11] D.12-10-006; D.13-07-026; D.14-06-018; D.15-12-018; and D.16-09-046.

environmental policies described below. Exhibit PAC/101 includes a comparison of the current and proposed depreciable lives for PacifiCorp's coal-fired resources.

Q. Why does PacifiCorp propose to reinstate shorter depreciation schedules on its coal-fired resources?

A. The electric industry in undergoing a significant transformation, including the treatment of coal-based generation and greenhouse gas emissions. Currently in California, the depreciation schedules for PacifiCorp's coal-fired resources reflect depreciable lives ending between 2027 and 2046.[12]

It is reasonable to manage state climate policy risk by aligning depreciation schedules and returning to the shorter depreciable lives previously approved by the Commission. The shorter depreciable life for these resources provides the Commission, the company, and customers additional flexibility in resource planning to address state and federal environmental policies, mandates, and legislation.

This is also consistent with PacifiCorp's actions in its most recent depreciation study where it accelerated the retirement of the Carbon coal plant in Utah by five years to comply with United States Environmental Protection Agency (EPA) regulations. PacifiCorp concluded that retiring the Carbon plant in 2015 was the least-cost alternative while accounting for risk and uncertainty.

Q. Is PacifiCorp presenting a depreciation study in support of its recommendation in this case?

A. No. PacifiCorp's proposal is not based on a change in technical depreciation assumptions, methodologies, or calculations. Instead, PacifiCorp is seeking a policy-

[12] Exhibit PAC/101.

based change in the depreciable lives of one set of assets—coal-fired generation resources—based on new and proposed laws and regulations that may impact the useful lives of these assets. Reducing depreciable lives now mitigates future customer risk associated with coal-fired generation, and provides PacifiCorp additional flexibility to respond to existing and emerging environmental regulations.

Q. What value is provided by more closely aligning the depreciation rates in California, Oregon, and Washington?

A. Aligning coal plant depreciation rates in PacifiCorp's western service territories makes it easier for the company to implement environmental or regulatory policies adopted by California, Oregon, and Washington. California, Oregon, and Washington have a long history of collaboration to encourage the reduction of greenhouse gas emissions. In 2006, the Commission, Public Utility Commission of Oregon, and Washington Utilities and Transportation Commission executed the Western Public Utility Commissions' Joint Action Framework on Climate Change (Joint Action Framework). In the Joint Action Framework, the commissions agreed to a statement of shared principles on climate change and to work cooperatively to implement the shared principles.[13] More recently, in February 2016, the governors of California, Oregon, and Washington, along with governors from 14 other states signed the "Governors' Accord for a New Energy Future."[14] Through this accord, California, Oregon, and Washington have committed to diversify energy generation and expand clean energy sources by, among other commitments, working together to

[13] Exhibit PAC/102.
[14] Exhibit PAC/103, Bolton/1.

facilitate the transition away from coal and towards a cleaner resource mix. By shortening the depreciation schedules for the company's coal-fired resources now, the company can more effectively implement state policies common to all of PacifiCorp's western service territories.

VI. 2017 PROTOCOL

Q. Is PacifiCorp proposing a new inter-jurisdictional allocation methodology in this proceeding?

A. Yes. 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 filed in California until a new protocol is proposed.[15]

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

A. Yes. Exhibit PAC/104 presents the 2017 Protocol with all of its appendices.

<u>Brief History of PacifiCorp's Multi-State Process (MSP)</u>

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

A. In 2002 PacifiCorp filed 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 California, Idaho, Oregon, Utah, and Wyoming. The Revised Protocol allocated costs among PacifiCorp's jurisdictions and ensured that

[15] The 2017 Protocol was approved by the state commissions in Idaho, Oregon, Utah, and Wyoming for use starting January 1, 2017.

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. The Revised Protocol was approved by the Commission in PacifiCorp's 2011 Rate Case and is the allocation methodology that is currently in effect for California.

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 is a simplified version of the revised protocol intended to reduce unintended variations in the allocation of actual revenue requirement compared to the forecast used in the development of the revised protocol. The 2010 Protocol was approved by the commissions in Idaho, Oregon, Utah and Wyoming. Differing applications amongst states of both the Revised Protocol and 2010 Protocol resulted in PacifiCorp being unable to fully recover all of its prudently incurred costs.

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 MSP Broad Review Workgroup (BRWG)[16] started collaborating in November 2012 to come up with potential solutions acceptable to all Parties in the context of an allocation methodology,

[16] The BRWG is now referred to as the MSP Workgroup under the 2017 Protocol.

including the performance of various studies by PacifiCorp at the request of the Standing Committee.

Q. Who participated in the MSP 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 staff, advocacy staff, industrial customers, and consumer groups.

Q. Did stakeholders from California participate in the MSP?

A. Not for the entire process. Representatives from the Commission participated in the May 1, 2015 forum, but did not continue their participation through the negotiations. PacifiCorp's inter-jurisdictional allocation methodologies are considered in the course of the company's general rate case cycle in California, and prior approval is generally not required.

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.

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 PacifiCorp 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 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 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 PacifiCorp's allocation methodologies, and to allow the company a better opportunity to recover its costs.

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

A. Not entirely. The Equalization Adjustment mitigates the issues caused by inconsistent implementation of PacifiCorp's allocation methodologies, but it does not fully provide the company the ability to recover all its costs.

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

A. PacifiCorp agreed to the 2017 Protocol for two primary reasons. Most importantly, because this was an interim solution, it provided the company and its stakeholders time to explore more durable solutions to address state-specific energy and environmental policy impacts on allocations. Second, the company appreciated the BRWG good faith approach to implement an Equalization Adjustment which significantly reduced the short-fall the company was experiencing under both the Revised Protocol and 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 PacifiCorp provides retail service are invited to discuss the 2017 Protocol and other inter-jurisdictional allocation issues (Commissioner Forums), beginning in January 2017. At the first Commissioner Forum, commissioners were 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, PacifiCorp will convene an MSP Workgroup meeting for the purpose of discussing and monitoring emerging inter-jurisdictional allocation issues facing the company and its customers, state resource policies, or the development of a regional independent system operator, in order to inform discussions at the Commissioner Forum.

<u>Overview of 2017 Protocol</u>

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.

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 the 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 PacifiCorp's prior allocation methodologies is intended to reduce unintended ECD variations due to non-uniform implementation of those prior allocation methodologies. Other changes were made to address direct access treatment, the duration of the 2017 Protocol, and process issues.

<u>Detailed Discussions of Sections I to XIV of the 2017 Protocol</u>

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 or revenues incurred or received in order to be prepared to meet the maximum demand imposed upon PacifiCorp'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 (QF) Contracts; and Jurisdiction-Specific Initiatives. System Resources are all other resources and are allocated across all jurisdictions. This allocation methodology includes an Equalization Adjustment to be applied to each State's revenue requirement, as specifically identified in Section XIV of the 2017 Protocol.

Section V includes a commitment by PacifiCorp to submit filings seeking authorization from the state commissions prior to filing for approval from the Federal Energy Regulatory Commission (FERC) of the re-functionalization of facilities as transmission or distribution. This section also identifies the cost 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 addressed 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 PacifiCorp 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 would be 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 PacifiCorp'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 PacifiCorp 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.

Term of 2017 Protocol

Q. What is the effective period in the 2017 Protocol?

A. The 2017 Protocol was intended to be used in all PacifiCorp rate proceedings filed after December 31, 2016, through December 31, 2018, in Idaho, Oregon, Utah, and Wyoming, with an optional one-year extension. The state commissions in Idaho, Oregon, Utah, and Wyoming subsequently approved the one-year extension, making the 2017 Protocol effective until December 31, 2019.

Q. Why was the 2017 Protocol intended to be a three-year inter-jurisdictional allocation methodology?

A. The 2017 Protocol was 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 term of 2017 Protocol also provided an opportunity for PacifiCorp to analyze alternative allocation methods in light of the changing electric industry in the Western United States.

Q. For what term is PacifiCorp requesting Commission approval to use the 2017 Protocol?

A. PacifiCorp requests that the Commission approve the use of the 2017 Protocol for all rate proceedings filed starting January 1, 2018, until a new allocation methodology is approved by the Commission. This would align allocation methodologies across five of PacifiCorp's six states while the company develops a more durable allocation solution that addresses diverging state resource policies.

Q. Will PacifiCorp be proposing revisions to the 2017 Protocol at the end of its term?

A. PacifiCorp is currently engaged in the development of a durable solution to its allocation issues that will address the interests of each state while continuing to provide the benefits of PacifiCorp's system to customers. PacifiCorp has presented a proposal to its stakeholders in the MSP workgroup that would assign fixed portions of generation resources to serve the company's retail load in each state. Participants from all states, including California, have been actively involved in this round of the MSP. PacifiCorp's proposal would allow PacifiCorp to accommodate each state's energy policies without adversely impacting customers in other states. This solution, however, is at least a couple of years away because of the significant changes being discussed in the MSP. Accordingly, PacifiCorp requests that the Commission approve the use of the 2017 Protocol until PacifiCorp proposes a new inter-jurisdictional allocation methodology.

Q. Will PacifiCorp be filing any other rate applications this year?

A. Yes. PacifiCorp expects to file its annual ECAC filing in August. Rates in both this proceeding and the ECAC will become effective January 1, 2019. PacifiCorp will use the 2017 Protocol for the ECAC offset rate so both rates are based on the same inter-jurisdictional allocation methodology.

<u>Resource Classification and Cost and Revenue Allocation</u>

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 and fuel expenses 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 PacifiCorp'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 associated with portfolio standards that exceed the costs PacifiCorp 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 QF contracts 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 QF 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 QF contracts on a system basis, unless a portion of the QF costs exceed what PacifiCorp 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 PacifiCorp's resource planning responsibility or a commission's authority?

A. No. Section XII provides that 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, and approved by that State's commission consistent with such laws and regulations.

Embedded Cost Differential

Q. Explain the use of the ECD 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.[17] The ECD is fixed for Wyoming, Idaho, and California; for Utah it is zero; and for Oregon, it is dynamic with a floor and a cap, 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 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.

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[17] In the Revised Protocol the ECD is referred to as the Hydro Endowment.

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 totaling $9.074 million that represents the sum of 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 PacifiCorp's allocation methodology 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 PacifiCorp's allocation methodology, 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 but capped between specified ranges its 2017 Protocol Adjustment will be between $5.6 million to $7.9 million credit.

<u>Cost Allocations</u>

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 FERC. 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 FERC.

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 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 defined in Appendix D.

Q. Will PacifiCorp 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.

<u>Changes to PacifiCorp Load</u>

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.

The 2017 Protocol also addresses Oregon's direct access program for large customers and the potential transfer of electricity service to an alternative electricity supplier in Utah under Utah Code Annotated Section 54-3-32. These programs affect a state's load relative to other states, and, thereby, have the potential to impact allocations. The company has committed to inform the State commission and MSP participants if any state adopts laws or regulations governing customer access to alternative electricity suppliers.

<u>Governance</u>

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. PacifiCorp conducted these analyses and presented them at the 2017 Commissioner Forum. As a result of that analysis, PacifiCorp began looking at an alternative proposal that would allow the company to meet the resource policy goals of each state, while maintaining the benefits of system dispatch.

PacifiCorp believes that annual Commissioner Forums are an appropriate way to keep commissioners and participants informed, and that they will be an opportunity for all Parties to discuss progress on a more durable allocation methodology. The company anticipates that all MSP participants will remain engaged in the process of analyzing the results of these studies, and that continuing to engage in this type of collaboration is in the best interests of the participants and PacifiCorp's customers. PacifiCorp is significantly encouraged by the participation of Commission representatives.

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

A. Yes. Any participant or state 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 PacifiCorp can distribute the proposal to the other Parties and State commissions and initiate discussions. The Party or State 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.

Commission Review of Approval of the 2017 Protocol

Q. Why should California approve the 2017 Protocol?

A. One of the primary objectives of PacifiCorp's 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 company more fully analyzed its multi-jurisdictional issues. 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. Are the terms of the 2017 Protocol for California reasonable compared to the terms for other states?

A. Yes. The 2017 Protocol represents a fair, just, and reasonable approach to PacifiCorp's inter-jurisdictional allocation issues while the company develops a more durable solution. The Equalization Adjustment is equivalent between states representing approximately two-tenths of one percent of each state's annual revenue requirement. While the Equalization Adjustment does not provide full recovery to the company, it is a reasonable approach considering the interim nature of the 2017 Protocol.

Q. What process does PacifiCorp propose for the Commission review of this Application?

A. PacifiCorp proposes that the Commission will review and approve the 2017 Protocol in this proceeding. The Commission opened a separate investigation to explore PacifiCorp's system operations and planning, and current allocation methodology.[18] No parties to that proceeding have challenged PacifiCorp's current allocation methodology or proposed a different allocation methodology. Participants to

[18] *Order Instituting Investigation to determine whether PacifiCorp (U901-E) engages in least-cost planning on a control area basis and whether PacifiCorp's Inter-Jurisdictional Cost Allocation Protocol results in just and reasonable rates in California,* Investigation 17-04-019 (May 8, 2017).

PacifiCorp's MSP conducted significant analysis and review since November 2012 as the BRWG considered many options. This analysis enabled the MSP participants to confidently negotiate the 2017 Protocol. PacifiCorp believes that the result was a 2017 Protocol that is fair to all states.

Q. What action do you recommend the Commission take with respect to the 2017 Protocol?

A. I recommend that the Commission find that the 2017 Protocol is in the public interest and request that the Commission approve all the terms and conditions of the 2017 Protocol for determining rates in this and future proceedings in its order in this docket.

VII. INTRODUCTION OF WITNESSES

Q. Please list the PacifiCorp witnesses and provide a brief description of their testimony.

A. **Kurt G. Strunk**, Director, National Economic Research Associates, testifies concerning PacifiCorp's cost of equity. He presents support for the requested authorized ROE of 10.6 percent to account for the risks and operating challenges that PacifiCorp faces as a vertically integrated electric investor owned utility (Exhibit PAC/200).

Nikki L. Kobliha, Chief Financial Officer, describes the calculation of PacifiCorp's capital structure, costs of debt and preferred stock (Exhibit PAC/300).

Chad A. Teply, Senior Vice President, Strategy & Development, supports the prudence and necessity of certain major capital projects on coal-fired generation resources within the PacifiCorp generation portfolio, including the required installation of SCR systems on Jim Bridger Units 3 and 4, Craig Unit 2, and Hayden Units 1 and 2, in accordance with state and federal environmental compliance requirements for the individual units (Exhibit PAC/400).

Rick T. Link, Vice President, Resource & Commercial Strategy, describes the economic analysis performed in 2012 that supported the company's decisions to install SCR emission control systems on Units 3 and 4 of the Jim Bridger generating plant, the economic analysis that shows PacifiCorp's decision to upgrade, or "repower", certain wind resources, and summarizes PacifiCorp's assessment of the wind repowering project in its 2017 Integrated Resource Plan (Exhibit PAC/500).

Timothy J. Hemstreet, Director, Renewable Energy Development, provides the technical information supporting PacifiCorp's decision to repower certain wind facilities (Exhibit PAC/600).

Richard A. Vail, Vice President, Transmission, describes significant capital investment projects for new distribution and transmission systems (Exhibit PAC/700).

David M. Lucas, Vice President, Transmission & Distribution Operations, presents an overview of PacifiCorp's investment in advanced metering infrastructure in the state of California (Exhibit PAC/800).

Michael G. Wilding, Director, Net Power Costs & Regulatory Strategy, presents PacifiCorp's proposal to modify the ECAC to include updates to PTCs and start-up fuel costs (Exhibit PAC/900).

Brett S. Allsup, Director, Engineering Strategy & Cost Control, describes PacifiCorp's risk management process to implement a risk-based investment decision making framework (Exhibit PAC/1000).

Shelley E. McCoy, Manager, Revenue Requirement, addresses the calculation of the company's California-allocated revenue requirement based on the forecast test period of 12 months ending December 31, 2019, excluding net power costs (Exhibit PAC/1100).

Robert M. Meredith, Manager, Pricing & Cost of Service, describes PacifiCorp's functionalized class revenue requirement and supporting marginal cost-of-service study based on the forecast test period of 12 months ending December 31, 2019 (Exhibit PAC/1200).

Judith M. Ridenour, Pricing & Cost of Service Specialist, presents PacifiCorp's proposed rate spread, proposed rate design, and proposed revised tariffs (Exhibit PAC/1300).

Q. Does this conclude your direct testimony?

A. Yes.

Application No. 18-04-___
Exhibit PAC/101
Witness: Scott D. Bolton

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP

Exhibit Accompanying Direct Testimony of

Scott D. Bolton

Coal-Fired Resource Depreciation Comparison

April 2018

PACIFICORP
CALIFORNIA TEST YEAR 2019 GENERAL RATE CASE

Accelerated Depreciation of Coal-Fired Generation Resources
Summary of Change in Depreciable Life

	End of Depreciable Life		
	Current	**Accelerated**	**Change**
CHOLLA	2042	2025	17 years
COLSTRIP	2046	2029	17 years
CRAIG - UNIT 1	2034	2025	9 years
CRAIG - UNIT 2 & COMMON	2034	2026	8 years
DAVE JOHNSTON	2027	2023	4 years
HAYDEN	2030	2023	7 years
HUNTER	2042	2029	13 years
HUNTINGTON	2036	2029	7 years
JIM BRIDGER	2037	2025	12 years
NAUGHTON	2029	2028	1 years
WYODAK	2039	2026	13 years

See Exhibit PAC/1101, page 6.3.3.

Application No. 18-04-___
Exhibit PAC/102
Witness: Scott D. Bolton

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP

Exhibit Accompanying Direct Testimony of

Scott D. Bolton

Joint Action Framework on Climate Change

April 2018

WESTERN PUBLIC UTILITY COMMISSIONS'

JOINT ACTION FRAMEWORK ON CLIMATE CHANGE

California Public Utilities Commission
Washington Utility and Transportation Commission
Oregon Public Utility Commission
New Mexico Public Regulation Commission

WESTERN PUBLIC UTILITY COMMISSIONS' JOINT ACTION FRAMEWORK ON CLIMATE CHANGE

Global warming is a serious and growing threat to the health, safety and welfare of all peoples. Fossil fuel-based electricity generation is a major contributor of greenhouse gas emissions that cause climate change, and policy makers at all levels are recognizing the need to mitigate the adverse impacts of climate change resulting from continued reliance on fossil fuels. Moreover, climate change itself may lead to a significant increase in demand for energy as well as significant decreases in hydropower resources on which all three states depend.

The Washington, Oregon, New Mexico and California Public Utilities/Transportation Commissions ("Commissions") provide regulatory oversight of energy utilities, the policies and practices of which determine the extent to which utilities contribute to the emission of greenhouse gases. Vigilant regulatory oversight ensures that the utilities operate in a manner that protects the environment and human health and safety, and protects ratepayers from economic risks of failure to plan for future regulation of emissions that cause climate change.

While the Commissions operate under distinct state laws and jurisdictional constraints, they are committed to regional cooperation where appropriate to address climate change and to implement the principles set forth in the September 2003, West Coast Governors' Global Warming Initiative. The Governors of Washington, Oregon and California launched the Initiative to develop regional policies to reduce greenhouse gas emissions, including greater reliance on energy efficiency and renewable energy resources.

STATEMENT OF SHARED PRINCIPLES

These Shared Principles serve as a general guide for energy resource oversight by the Commissions as well as planning by the regulated utilities and the investment communities.

- Regional cooperation to address climate change.
- Development and use of low carbon technologies in the energy sector.
- Promotion of conservation and demand response programs.
- A strong, continued commitment to renewable energy resources.
- Reliance upon Integrated Resource Plans to inform utility and Commission decisions.

ACTION ITEMS

The Commissions will work cooperatively on the following actions to implement the Shared Principles:

- Review best practices for energy efficiency and pursue joint opportunities to identify and secure cost-effective conservation. Develop policies to recognize energy efficiency as an energy resource, including strong evaluation, measurement and verification standards and protocols, and integration of energy efficiency into utility resource portfolios.

- Review best practices for demand response and develop joint activities to increase beneficial demand response capability.

- Explore ways to remove barriers to the development of advanced, low-carbon technologies for fossil fuel-powered generation capable of capturing and sequestering carbon dioxide emissions.

- Explore the development and implementation of greenhouse gas emissions standards for new long-term power supplies.

- Examine opportunities to further support and implement renewable energy development to serve the West Coast states, including policies to encourage the development of transmission that provides access to prime resource sites.

- Commit to outreach with neighboring states.

IMPLEMENTATION ACTIONS

The Commissions direct their respective staffs to implement this Statement and provide an annual workplan and summary of progress for their consideration commencing in 2007. The Commissions also commit to schedule joint workshops to address the action items set forth in this document. For cost-efficiency and convenience such workshops will be coordinated when practical with the schedule of other meetings regularly attended by the states.

Signed this 1st day of December 2006 in San Francisco, California.

California Public Utilities Commission

By

Michael Peevey, President

John Bohn
Geoffrey Brown
Rochelle Chong
Dian Grueneich
Commissioners

Washington Utilities and Transportation Commission

By

Mark Sidran, Chair

Philip Jones
Patrick Oshie
Commissioners

Oregon Public Utility Commission

By

Lee Beyer, Chair

Ray Baum
John Savage
Commissioners

New Mexico Public Regulation Commission

By

Ben Lujan, Chairman

Jason Marks
Vice Chairman

David W. King
Lynda Lovejoy
E. Shirley Baca
Commissioners

Application No. 18-04-___
Exhibit PAC/103
Witness: Scott D. Bolton

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP

Exhibit Accompanying Direct Testimony of

Scott D. Bolton

Governors' Accord for a New Energy Future

April 2018

GOVERNORS' ACCORD FOR A NEW ENERGY FUTURE

American prosperity has always depended on embracing new ideas and technologies. By deploying renewable, cleaner and more efficient energy solutions, we can make our national economy more productive and resilient. These technologies help to diversify energy sources that power our economy and reduce dependence on foreign energy sources while securing abundant, domestically produced electricity. Embracing these new energy solutions also modernizes our infrastructure and transportation systems, decreases air pollution, and supports the growth of innovative American companies.

Current challenges also demand these new energy solutions. Extreme weather events, such as floods, droughts, wildfires and sea-level rise, can negatively impact electric reliability and the economy. Embracing new energy solutions can provide more durable and resilient infrastructure, and enable economic growth, while protecting the health of our communities and natural resources. These improvements will help secure a safe and prosperous future for our country.

We recognize that now is the time to embrace a bold vision of the nation's energy future. And to do so, states are once again poised to lead. We join together, despite unique opportunities and challenges in each state, to embrace a shared vision of this future:

Our states will diversify energy generation and expand clean energy sources.

Expanding energy efficiency and renewable energy in a cost-effective way strengthens our states' economic productivity, reduces air pollution and avoids energy waste. Integrating more of these clean energy sources into our electricity grids can also improve the flexibility and stability of these grids. Promoting energy savings through efficiency and conservation programs is the fastest, most reliable and often cheapest way to meet our energy needs. Technologies that capture solar, wind, hydroelectric and geothermal power have become viable and cost-effective to integrate into our states' energy portfolios. These technologies are already providing energy to millions of Americans while reducing energy waste and air pollution. Amidst decreasing costs of renewable energy, and rapid advances in efficiency throughout entire energy systems, our states will diversify our energy portfolios for economic, health and environmental benefits.

Our states will modernize energy infrastructure.

Modern distribution and transmission grids are required to give consumers more control over their own energy use, increase electricity reliability, and integrate more renewable energy and energy efficiency technologies into our energy systems. Electrical grid improvements, advanced in a cost-effective way, can empower utilities and consumers to manage electricity flexibly and efficiently.

Our states will encourage clean transportation options.

Hundreds of thousands of electric vehicles, and tens of millions of vehicles using alternative fuels, are driving on American roads, and fuels such as natural gas, biofuels and hydrogen are increasingly available to power vehicles. Supporting automakers' and fueling companies' market expansion for these new vehicles and fuels expands consumer choice, lessens dependence on petroleum and reduces pollution. By supporting needed infrastructure development, incentives and policies when appropriate, our states will encourage expanded use of these new technologies.

Our states will plan for this energy transition.

Given the complexity of state-wide energy systems and the scale of modernizing these systems, many states have developed energy plans and strategies to implement energy improvements. These approaches have incorporated best practices and lessons-learned from new technologies, other states' energy policies, consumer programs, and workforce training efforts. These state-by-state approaches enable each state to meet benchmarks it sets for itself in areas such as energy diversification, reduced energy waste, improved air and water, and economic performance. Our states will support each other in developing, refining and implementing these plans through sharing expertise among our policy experts.

Our states will work together to make these transformational policy changes.

Our states are already transforming energy and transportation to be cleaner, more efficient, and more resilient. Many actions taking place in one state can be adapted to meet the needs of other states and scaled across regions. Examples include streamlining siting of environmentally-desirable infrastructure, setting renewable and energy efficiency standards, adopting incentives for clean vehicles and fuels, and diversifying energy portfolios to integrate peak shaving, efficiency and renewable energy into a state's energy mix. Building on current efforts, our states will help each other reach shared energy and transportation objectives. This collaboration will be advanced through periodic meetings and technical convenings of our states.

Our states will help secure a stronger national energy future.

Given the unique energy portfolio and regulatory framework of each state, Governors are uniquely positioned to drive lasting improvements to our country's energy system. Federal agencies lend technical expertise, provide funding, and enable research and development that can help our states make energy improvements. In order to provide effective support, federal agencies must work closely with states to tailor technical support, funding and research to the needs of each state and avoid presupposing the best types of assistance. Strong partnerships among our states and between our states and the federal government will improve our country in the decades to come.

Signed, on the 16th day of February, 2016,

Governor Edmund G. Brown, Jr.
State of California

Governor Dannel P. Malloy
State of Connecticut

Governor Jack Markell
State of Delaware

Governor David Y. Ige
State of Hawaii

Governor Terry E. Branstad
State of Iowa

Governor Charlie Baker
Commonwealth of Massachusetts

Governor Rick Snyder
State of Michigan

Governor Mark Dayton
State of Minnesota

Governor Brian Sandoval
State of Nevada

Governor Maggie Hassan
State of New Hampshire

Governor Andrew M. Cuomo
State of New York

Governor Kate Brown
State of Oregon

Governor Tom Wolf
Commonwealth of Pennsylvania

Governor Gina M. Raimondo
State of Rhode Island

Governor Peter Shumlin
State of Vermont

Governor Terence R. McAuliffe
Commonwealth of Virginia

Governor Jay Inslee
State of Washington

Application No. 18-04-___
Exhibit PAC/104
Witness: Scott D. Bolton

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP

Exhibit Accompanying Direct Testimony of

Scott D. Bolton

PacifiCorp 2017 Inter-jurisdictional Allocation Methodology Protocol

April 2018

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. Allocation of Gain or Loss from Sale of Resources or Transmission Assets:

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. State Programs Regarding Access to Alternative Electricity Suppliers:

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. Additional State-Specific Terms:

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.

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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*

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.

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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.

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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.

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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.

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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.

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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.

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UTAH OFFICE OF CONSUMER SERVICES Michele Beck ____________________ ~~Michelle Beck~~ Michele Beck *Director of Utah Office of Consumer Services*	UTAH ASSOCIATION OF ENERGY USERS ____________________ Gary Dodge *Attorney for Utah Association of Energy Users*

WYOMING OFFICE OF CONSUMER ADVOCATE Ivan Williams Ivan Williams *Senior Counsel of Wyoming Office of Consumer Advocate*	WYOMING INDUSTRIAL ENERGY CONSUMERS Robert M. Pomeroy, Esq. Thorvald A. Nelson, Esq. *Attorneys for Wyoming Industrial Energy Consumers*
WYOMING PUBLIC SERVICE COMMISSION STAFF Darrell Zlomke *Commission Administrator for Wyoming Public Service Commission*	

WYOMING OFFICE OF CONSUMER ADVOCATE ______________________________ Ivan Williams *Senior Counsel of Wyoming Office of Consumer Advocate*	WYOMING INDUSTRIAL ENERGY CONSUMERS ______________________________ Robert M. Pomeroy, Esq. Thorvald A. Nelson, Esq. *Attorneys for Wyoming Industrial Energy Consumers*
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WYOMING PUBLIC SERVICE COMMISSION STAFF ____________________ * Darrell Zlomke *Commission Administrator for Wyoming Public Service Commission*	

*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.

System Overhead - Gross Factor ("SO")

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

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

Income Before Taxes Factor ("IBT")

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

$IBTi$ = **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.

<u>Schedule M - Deductions (“SCHMD”)</u>

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

where:

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

<u>Trojan Plant (“TROJP”)</u>

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

where:

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

<u>Trojan Decommissioning (“TROJD”)</u>

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

where:

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

Tax Depreciation ("TAXDEPR")

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

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.)

Deferred Tax Expense ("DITEXP")

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

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.)

Deferred Tax Balance ("DITBAL")

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

where:

$DITBAL_i$	=	**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**