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Exh. MGW-1CT
Docket UE-19____
Witness: Michael G. Wilding

BEFORE THE WASHINGTON

UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP dba PACIFIC POWER & LIGHT COMPANY Respondent.	Docket UE-19____

PACIFICORP

REDACTED DIRECT TESTIMONY OF MICHAEL G. WILDING

December 2019

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ATTACHED EXHIBITS

Q. Please state your name, business address, and present position with PacifiCorp.

A. My name is Michael G. Wilding and my business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. I am currently employed as Director, Net Power Costs and Regulatory Policy. I am testifying for PacifiCorp dba Pacific Power & Light Company (PacifiCorp or the Company).

QUALIFICATIONS

Q. Please describe your education and professional experience.

A. I received a Master of Accounting from Weber State University and a Bachelor of Science degree in accounting from Utah State University. I am a Certified Public Accountant licensed in the state of Utah. During my tenure at the Company, I have worked on various regulatory projects including general rate cases, the multi-state process (MSP), and net power cost filings. I have been employed by PacifiCorp since 2014.

PURPOSE OF TESTIMONY

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

A. My testimony supports approval of the Washington Inter-Jurisdictional Allocation Methodology (WIJAM), by demonstrating the direct and quantifiable benefits that this new methodology provides to PacifiCorp's Washington customers. My testimony also explains the need to develop the Nodal Pricing Mechanism (NPM), and the memorandum of understanding (MOU) among the parties that supports the Company's investment in the development of the NPM. In the second section of my testimony, I present the forecast net power costs (NPC) for the test period, provide an overview of the modeling changes that have been implemented to provide more accurate forecast NPC, and describe PacifiCorp's suggested changes to the Power Cost Adjustment Mechanism (PCAM).

BACKGROUND ON THE WEST CONTROL AREA INTER-JURISDICTIONAL ALLOCATION METHODOLOGY

Q. What is the West Control Area Inter-Jurisdictional Allocation Methodology (WCA)?

A. The WCA is the inter-jurisdictional cost allocation methodology adopted by the Washington Utilities and Transportation Commission (Commission) in 2006 to allocate costs and benefits of PacifiCorp's system to Washington.

The WCA isolates the costs and revenues associated with assets electrically interconnected to PacifiCorp's West Balancing Authority Area (PACW), and allocates to Washington a proportionate share of the costs and benefits based primarily on Washington's relative contribution to demand and energy requirements within PACW. The WCA includes loads, generation and transmission assets, and wholesale contracts for facilities located in California, Oregon, and Washington. It also includes transmission and generation assets located outside of California, Oregon, and Washington that are electrically interconnected to PACW, such as the Jim Bridger coal plant, which is physically located in PacifiCorp's East Balance Authority Area (PACE). The WCA excludes all loads and assets located within PACE with the exception of the Jim Bridger Units 1-4 (Jim Bridger) and the associated transmission facilities.

Q. Is PacifiCorp proposing to replace the WCA?

A. Yes. PacifiCorp is proposing to replace the WCA with the WIJAM. Replacing the WCA with the WIJAM is necessary in response to changing energy policies across PacifiCorp's service territories, including the passage of the Clean Energy Transformation Act (CETA). Ms. Etta Lockey explains how the WIJAM interacts with the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol) and how the 2020 Protocol applies to Washington.

Q. Does the WIJAM reflect how PacifiCorp operates its system?

A. Yes, the WIJAM reflects PacifiCorp's single system operation while accounting for Washington's energy policy.

Q. Has the Commission ever determined that the assets not included in the WCA do not provide benefits to Washington customers?

A. No. From my understanding, in 2005, the Commission determined that the Company failed to meet its burden to show that the resources in the "Eastern service territories" provide tangible, quantifiable benefits to Washington customers.[1] Since the Company did not provide sufficient evidence to show that these assets were "used and useful" the Commission rejected the approach to allocating costs proposed by PacifiCorp in its 2005 general rate case.[2] However, in that same decision, the Commission determined that the Company does *not* need to "demonstrate each resource provides a direct benefit, *i.e.*, electron flow, to be considered used and useful for service in this state."[3] The appropriate test is whether the resource "provides quantifiable direct or

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[1] *WUTC v. Pac. Power & Light Co.*, Docket No. UE-050684, Order 04 at ¶62 (Apr. 17, 2006).
[2] *Id.* at ¶62
[3] *Id.* at ¶68.

indirect benefits to Washington commensurate with its cost."[4] In my testimony, I demonstrate that PacifiCorp's integrated system provides the requisite benefits commensurate with cost to Washington customers through the WIJAM to satisfy the Commission's standard, and recommend Commission approval of the WIJAM.

THE WASHINGTON INTER-JURISDICTIONAL ALLOCATION METHODOLOGY

Summary of the WIJAM

Q. Has PacifiCorp worked collaboratively with Washington stakeholders to develop the WIJAM?

A. Yes. Commission Staff have been engaged in the MSP, the stakeholder process for discussions related to PacifiCorp's inter-jurisdictional cost allocation methodology. As an outgrowth of the MSP discussions, in the spring of 2018, PacifiCorp and Staff began to specifically discuss a new cost allocation methodology. The Company worked collaboratively with Staff through various workshops, MSP meetings, and settlement negotiations to develop the WIJAM. Additionally, Staff spent considerable time reviewing data provided by PacifiCorp, visiting PacifiCorp's trading floor and transmission control center, and analyzing the operation of PacifiCorp's system. As the WIJAM took shape, the Public Counsel Unit of the Washington Attorney General's Office (Public Counsel) and Packaging Corporation of America (PCA) joined the discussions around the WIJAM. Additionally, PacifiCorp held a workshop with the parties on December 2, 2019, to discuss the quantification and analytical support behind the benefits of the WIJAM.

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[4] *Id.* at ¶68.

Q. Do Staff, Public Counsel, and PCA support the WIJAM?

A. Yes. PacifiCorp, Staff, Public Counsel, and PCA all signed the WIJAM MOU. PacifiCorp greatly appreciates the time and effort that parties have spent working to develop the WIJAM, and looks forward to continuing that collaboration to address allocation issues in the future.

Q. Please describe the WIJAM.

A. The WIJAM has four primary components:

- Costs and benefits associated with PacifiCorp's entire transmission system will use a system allocation.
- Costs and benefits associated with PacifiCorp's existing and new non-emitting, non-qualifying facility (QF) resources will use a system allocation. Non-emitting, non-QF resources include all wind, solar, hydro, and geothermal generating resources.
- NPC will be allocated using a spreadsheet method that reflects assets included in Washington rates, including the allocation of Energy Imbalance Market (EIM) benefits.
- Jim Bridger and Colstrip Unit 4 (Colstrip) will be depreciated by December 31, 2023, in Washington rates.

Q. What does "system allocation" mean in the context of the WIJAM?

A. In the context of the WIJAM, system allocation refers to a proportionate share of PacifiCorp's total system costs. Washington's proportionate share of allocation factors is based on Washington's share of the system monthly coincident peaks and system load. Under the WCA, the allocation factors are based on the monthly coincident peaks and loads of Washington, California, and Oregon. Attachment 1 to the WIJAM MOU (Attachment 1) includes the allocation factors used for each Federal Energy Regulatory Commission (FERC) account. For example, under the WCA, Washington is currently allocated 21.58 percent of the four owned-wind resources included in the WCA, while under the WIJAM, Washington will be allocated 7.8 percent of PacifiCorp's 18 owned-wind resources. As discussed later in my testimony, this nearly doubles the nameplate capacity of wind resources allocated to Washington.

Q. Is the cost allocation of all costs and benefits addressed in the WIJAM MOU?

A. Yes. Attachment 1 sets forth the allocation factors that will be used for all costs and benefits by FERC account, and identifies which allocation factors have changed between the WCA and the WIJAM.

Transition to System Transmission

Q. How are PacifiCorp's transmission costs and benefits allocated to Washington customers under the WIJAM?

A. Under the WIJAM, transmission costs and benefits are allocated on a system basis, regardless of physical location of the transmission assets.

Q. What are the transmission costs and benefits that are allocated to Washington?

A. The transmission costs of owned transmission include depreciation expense, operations and maintenance (O&M), and a return on the assets. PacifiCorp's transmission system provides many direct and indirect benefits as discussed in the testimony of Mr. Richard A. Vail, including the direct benefits of Open Access Transmission Tariff (OATT) revenues received by PacifiCorp from third-party transmission customers.

Q. Are there any transmission costs and benefits that are not allocated to Washington?

A. Yes. Under the WIJAM, Washington customers will not be allocated the costs and benefits of all transmission-voltage radial lines if the sole purpose is connecting resources not otherwise included in Washington rates to PacifiCorp's interconnected, network transmission system.

Q. How will the transition to a system allocation of the transmission costs and benefits occur?

A. The WIJAM MOU outlines a three-year phase-in approach to including these costs in Washington's rates through a combination of an update to the revenue requirement in this case and a separate tariff rider, the System Transmission Adjustment, discussed in the testimony of Ms. Shelley E. McCoy and Mr. Robert M. Meredith.

To quantify the impact from the transition, the costs and benefits that would have been allocated to Washington under the WCA are compared to the costs and benefits that are allocated to Washington under the WIJAM. An incremental allocation of one-third of the difference between the two allocation methods is included in the proposed revenue requirement of this case. An incremental allocation of an additional one-third of the difference of the two allocation methods will be included in the System Transmission Adjustment with a rate effective date on or before January 1, 2022. The final one-third will be included in Washington rates through a general rate case or through an amendment to the System Transmission Adjustment with a rate effective date on or before January 1, 2023. The System

Transmission Adjustment will end with the next general rate case once the entire allocation difference is in base rates.

Additionally, the final one-third of transmission costs and benefits, effective January 1, 2023, will be reduced for the costs and benefits of all transmission-voltage radial lines if the sole purpose is connecting resources not otherwise included in Washington rates to PacifiCorp's interconnected, network transmission system.

Q. What transmission assets are not included in the phase-in?

A. New transmission assets, defined as transmission that comes online after December 31, 2019, will be allocated on a system basis but are not included in the phase-in. As discussed in the testimony of Mr. Vail, new transmission assets are included in the revenue requirement in this case.

Q. Does this include PacifiCorp's costs for using third party transmission (*i.e.* wheeling costs)?

A. No. PacifiCorp's wheeling costs are included in NPC.

Non-Emitting, Non-QF Resources

Q. How will non-emitting, non-QF resources be allocated to Washington customers?

A. Non-emitting, non-QF resources are allocated on a system basis regardless of physical location.

Q. What are the costs and benefits associated with non-emitting, non-QF resources allocated to Washington?

A. The costs associated with non-emitting, non-QF resources can include depreciation expense, O&M and a return on the assets for owned resources or purchase power expense for power purchase agreements (PPAs). The benefits associated with non-emitting, non-QF resources include zero-fuel cost energy, production tax credits (PTCs), renewable energy credits (RECs), and associated environmental attributes.

Q. How are QFs allocated to Washington under the WIJAM?

A. QFs continue to be situs assigned meaning that Washington customer are assigned 100 percent of the costs and benefits of Washington QFs and are not allocated any of the costs and benefits of QFs in other states.

Net Power Costs

Q. Please describe the components of NPC.

A. NPC are the variable costs incurred by the Company to produce energy less the revenues from wholesale sales. Specifically, NPC includes the amounts booked to the following FERC accounts listed in Figure 1 below.

Figure 1

FERC Account	Description
Account 447	Sales for resale
Account 501	Fuel, steam generation; excluding fuel handling, start-up fuel (gas and diesel fuel, residual disposal)
Account 503	Steam from other sources
Account 547	Fuel, other generation
Account 555	Purchased power, excluding the Bonneville Power Administration residential exchange credit pass-through if applicable
Account 565	Transmission of electricity by others

Q. How are NPC allocated under the WIJAM?

A. The NPC associated with resources that are included in Washington rates are allocated to Washington customers. For example, Washington customers are allocated a system share of PacifiCorp-owned wind generation, so they are allocated a system share of the zero-fuel cost energy from said resources. Additionally, Washington customers are allocated a WCA share of Jim Bridger, so they are allocated a WCA share of the coal fuel expense at Jim Bridger.

Q. Please explain the NPC allocation in further detail.

A. The starting point to allocate NPC to Washington customers is the total company NPC. On a monthly basis, the costs and benefits of each resource are allocated to Washington based on the allocation factors identified for the respective FERC Account in Attachment 1. Wholesale market sales and purchases are also allocated to Washington customers based on a system allocation. The energy from Washington's allocated share of resources and market transactions is then compared to the Washington's retail load, and to the extent a load and energy imbalance exists, the difference is accounted for by adjusting system balancing transactions volumes using the weighted average market price for the month. For example, when the energy from Washington-allocated resources and market transactions exceeds Washington retail load, the system balancing purchase volumes will be reduced using the weighted average market purchase price. Conversely, when the energy from Washington-allocated resources and market transactions is less than Washington retail load, the system balancing sales volumes will be reduced using the weighted average market purchase price.

Q. Is the NPC allocation method described above the same for both forecast NPC and actual NPC?

A. Yes. Both forecast NPC and actual NPC are allocated in the same manner and use total company NPC as a starting point. The difference is that actual total company NPC will be based on the Company's accounting records and forecast total company

NPC are modeled using the Company's Generation and Regulation Initiative Decision Tool (GRID) model, a production cost model that simulates the operation of the Company's power system on an hourly basis. By using the same allocation methodology and starting point, any inconsistency between the allocation of actual and forecast NPC is eliminated.

Jim Bridger and Colstrip Depreciation

Q. How will the Jim Bridger and Colstrip resources be allocated to Washington customers?

A. Washington customers will continue to be allocated the costs and benefits associated with Jim Bridger and Colstrip on a WCA basis.

Q. What are the costs and benefits associated with Jim Bridger and Colstrip that will be allocated to Washington?

A. The costs associated with Jim Bridger and Colstrip can include depreciation expense, O&M, coal-fuel expense, environmental regulation costs, and a return on the assets. The benefits associated with Jim Bridger and Colstrip include the energy generated from those units.

Q. What does PacifiCorp propose for depreciation of Jim Bridger and Colstrip in this case?

A. PacifiCorp is proposing to accelerate depreciation of Jim Bridger and Colstrip to December 31, 2023. PacifiCorp has a unique opportunity to accelerate depreciation of these facilities in advance of the CETA compliance date without a rate increase to customers in this case.

Q. Why is it appropriate to accelerate the depreciation on these plants to December 31, 2023?

A. The accelerated depreciation of these plants is a critical component of a possible "limited realignment" of the costs and benefits of existing coal-fired resources among PacifiCorp's six states. As discussed in the testimony of Ms. Lockey, the 2020 Protocol includes agreement among the parties to continue negotiations on a potential limited realignment that would, among other things, "realign" Washington's allocation of the costs and benefits of PacifiCorp's existing coal-fired resources to other states. As set forth in the 2020 Protocol, the limited realignment, if agreed to by all parties, would take effect no later than January 1, 2024. Accelerating depreciation of Jim Bridger and Colstrip in this case aligns with the 2019 Integrated Resource Plan (IRP) for Jim Bridger Unit 1 and maintains the ability of Washington to participate in a limited realignment proposal.

Q. Does this represent the estimated closure date for Jim Bridger and Colstrip?

A. In PacifiCorp's 2019 IRP, Jim Bridger Unit 1 is anticipated for retirement in 2023. However, for Jim Bridger Units 2-4 and Colstrip, this date does not necessarily represent the closure date, change in operations, or the end of the assignment to Washington of either benefits or costs associated with these plants.

Q. Will PacifiCorp remove Jim Bridger and Colstrip from Washington's rates as of December 31, 2023?

A. Not necessarily. CETA requires the costs of coal-fired resources to be fully depreciated and removed from Washington rates by December 31, 2025.[5]

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[5] *See* RCW 19.405.30.

Accelerating depreciation on Jim Bridger and Colstrip creates flexibility to remove these coal-fired resources from Washington rates as early as December 31, 2023, but neither the WIJAM nor the 2020 Protocol require early removal of Jim Bridger and Colstrip from Washington rates. Similarly, PacifiCorp does not take a position at this time as to whether removal of Jim Bridger and Colstrip from Washington rates as early as December 31, 2023, will qualify PacifiCorp for the early action credit contemplated in CETA.[6]

Q. How is depreciation for Jim Bridger and Colstrip addressed in the WIJAM MOU?

A. PacifiCorp and Staff agree to support a depreciable life of December 31, 2023, for Jim Bridger and Colstrip and any associated transmission assets solely dedicated to connecting these plants to the transmission network. Public Counsel and PCA reserve their right to make a recommendation on the depreciation of Jim Bridger and Colstrip that may differ from the WIJAM MOU.

Q. Has PacifiCorp quantified the rate impacts of this accelerated depreciation proposal?

A. Yes. Accelerating the depreciation of Jim Bridger and Colstrip from 2025 to 2023 increases revenue requirement by approximately $23.0 million, which is offset by the $17.4 million regulatory liability from the accelerated depreciation authorized in the 2015 Rate Case for a total increase of $5.6 million.

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[6] *See* RCW 19.405.40(11).

Q. How are capital investments at Jim Bridger and Colstrip treated under the WIJAM?

A. PacifiCorp will continue allocating a WCA share of ongoing capital investments and expenses for Jim Bridger and Colstrip to Washington customers, excluding incremental capital investments that are made primarily for the purpose of extending the life of these plants.

Q. What type of capital investments "are made primarily for the purpose of extending the life of these plants"?

A. Incremental capital investments that are made primarily for the purpose of extending the life of these plants include, but are not limited to, those associated with achieving compliance with environmental requirements or those necessitated by catastrophic failure.

Jim Bridger and Colstrip Decommissioning Costs

Q. What is your understanding of CETA's requirements for the decommissioning and remediation costs related to coal-fired resources?

A. It is my understanding that CETA requires that coal-fired resources costs be eliminated from rates by the end of 2025, but specifies that this "does not include the costs associated with the decommissioning and remediation."[7] Rather, CETA specifies that "the Commission shall allow in electric rates all decommissioning and remediation costs prudently incurred by an investor-owned utility for a coal-fired resource."[8] PacifiCorp proposes an approach to tracking and truing-up

[7] RCW 19.405.030(1)(a).
[8] RCW 19.405.030(1)(b).

decommissioning and remediation costs at Jim Bridger and Colstrip that is consistent with the Company's current understanding of the directives of CETA.[9]

Q. Has this issue been addressed by other parties in other proceedings?

A. Yes. The proposal described in my testimony is consistent with testimony that has been filed in Puget Sound Energy's (PSE) general rate case[10] and the settlement that has been filed in Avista's general rate case.[11]

Q. How does the WIJAM address decommissioning and remediation costs for Jim Bridger and Colstrip?

A. Washington customers will be allocated a WCA share of ongoing and expected decommissioning costs, including remediation costs. These costs will be estimated in independent engineering studies for decommissioning costs at Jim Bridger (to be completed by January 15, 2020), and Colstrip (to be completed by March 30, 2020). The results of the independent engineering studies for the decommissioning costs will be provided as an update to the 2018 Depreciation Study.

Q. Does the WIJAM MOU contemplate how decommissioning costs, including remediation costs, will be addressed for ratemaking?

A. No. The WIJAM MOU only addresses the inter-jurisdictional allocation of decommissioning costs and allows for flexibility as to the ratemaking treatment of these costs.

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[9] *Id.*
[10] *WUTC v. Puget Sound Energy*, Docket No. UE-190529, Testimony of Chris R. McGuire, Exhibit CMR-1T at 33 (Nov. 22, 2019) ("[A] more reasonable reading of the statute is that it requires that the amount recovered from ratepayers is ultimately no more or less than the actual, prudently incurred D&R costs.").
[11] *WUTC v. Avista Corporation d/b/a Avista Utilities*, Docket No. UE-190334, Partial Multiparty Settlement Stipulation (Nov. 19, 2019).

Q. What is PacifiCorp's proposal for the ratemaking treatment of decommissioning costs, including remediation costs?

A. PacifiCorp proposes the following ratemaking treatment for Jim Bridger and Colstrip decommissioning costs:[12]

- The decommissioning for Jim Bridger and Colstrip will be updated in the Company's depreciation study to reflect the decommissioning studies above.
- A balancing account will be created to track Jim Bridger and Colstrip decommissioning costs collected through rates and the actual decommissioning expenditures incurred through the end of decommissioning and remediation activities.
- Until the end of the remediation process, PacifiCorp will update decommissioning costs in every subsequent rate case.
- Decommissioning cost projections will be updated and trued-up in each rate case to actual expenditures net of any insurance proceeds so that the Company will recover only the actual, prudently incurred decommissioning costs.
- After all decommissioning costs have been incurred, the Company will come before the Commission and propose to either collect any under-collection or return any over-collection of these costs. This will ensure that customers will pay no more or no less than the actual prudently incurred decommissioning costs.

Other Components of the WIJAM

Q. How are the costs and benefits allocated for the thermal generation plants that are not mentioned in the WIJAM MOU?

A. Generally speaking, the thermal generation plants electrically located in PACW are allocated to Washington customers based on a WCA allocation, and thermal

[12] PacifiCorp consulted the settlement filed in Avista's general rate case when developing this proposal. *See WUTC v. Avista Corporation d/b/a Avista Utilities*, Docket No. UE-190334, Partial Multiparty Settlement Stipulation (Nov. 19, 2019).

generation plants electrically located in PACE are not allocated to Washington customers. Jim Bridger and Colstrip are addressed above. Additionally, the Chehalis and Hermiston natural gas plants are located in PACW and the associated costs and benefits are allocated to Washington customers based on a WCA share.

Q. Will the WIJAM continue if a new cost allocation methodology is not reached in MSP by the time the 2020 Protocol expires?

A. Yes. The WIJAM is a durable inter-jurisdictional cost allocation methodology that provides benefits to Washington customers independent of the 2020 Protocol. However, PacifiCorp continues to work collaboratively with parties to negotiate resolution of outstanding issues (referred to as "Framework Issues") identified in the 2020 Protocol.

Q. What happens if the 2020 Protocol expires and there is no agreement among the Washington stakeholders to a new cost allocation methodology for Washington in the MSP?

A. The WIJAM will continue until the Commission approves a new methodology. However, PacifiCorp has agreed to engage in collaborative discussions with the Washington stakeholders to explore a cost allocation methodology for Washington customers that will allow for an assignment method for new resources, and a methodology to allocate fixed shares of existing non-emitting resources.

BENEFITS OF THE WIJAM

Summary of Total WIJAM Benefits

Q. Please provide a summary of the revenue requirement impacts of the WIJAM?

A. As described in more detail below, the WIJAM decreases revenue requirement by approximately $5.2 million, excluding the impacts of the second and third steps of the transmission phase-in.[13] The impact to revenue requirement includes customer benefits of approximately $13.5 million for NPC, $10.1 million for PTCs, and $1.2 million for wheeling revenues for a total of approximately $24.8 million. Additionally, the WIJAM provides benefits not included in the revenue requirement for renewable portfolio standard (RPS) compliance during the years of 2021 through 2023 of up to $1.6 million annually. Finally, in the first compliance period for CETA, the WIJAM is projected to provide an improvement to the Company's forecast compliance position in 2030 when it is required to be greenhouse gas (GHG) neutral.

Approval of the WIJAM

Q. What standard has been articulated by the Commission to approve changes to the WCA?

A. It is my understanding that any changes to the WCA will be "considered in the context of an overall review of that methodology"[14] and that any party advocating for these changes must demonstrate that "any changes proposed more closely aligns with the allocation of costs based on causation[.]"[15] Finally, "the party advocated for the

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[13] The impact of the second and third steps is a total of approximately $5.5 million.
[14] *WUTC v. Pac. Power & Light Co.*, Docket No. UE-130043, Order 05 ¶92-94 (Dec. 4, 2013).
[15] *Id.*

change must make a detailed and persuasive showing demonstrating that the proposed change is appropriate."[16]

Q. Did the Company undertake a comprehensive review of the WCA in developing the WIJAM?

A. Yes. As directed by the Commission, PacifiCorp has used the WCA since 2006. Since 2006, the energy landscape in the west has continued to evolve, with an increasing number of states adopting clean energy standards (including Washington), the development of the EIM and, more recently, region-wide discussions regarding regional resource adequacy and possible creation of a day-ahead energy market. In response to shifting energy policy in the west, along with changes in federal energy policy such as extension of federal PTCs, PacifiCorp is in the process of transitioning its existing generating and transmission fleet to accommodate additional renewable generation capacity, with approximately 1,500 MWs of new wind generation and transmission coming online by the end of 2020. PacifiCorp's system provides a unique opportunity for Washington to meet state policy objectives while also benefiting from PacifiCorp's geographically diverse footprint as conversations regarding regional resource adequacy and an energy day-ahead market develop. The WCA's limitation of PacifiCorp's system to PACW limited Washington's ability to take advantage of this unique opportunity. The WIJAM is more reflective of PacifiCorp's system operations and closely aligns with cost causation. Additionally, the WIJAM provides tangible and quantifiable direct and indirect benefits to

[16] *Id.*

Washington customers. Finally, the WIJAM provides a path to cost-effective RPS and CETA compliance.

Q. How does the WIJAM better align cost allocation with cost causation?

A. The WIJAM better aligns PacifiCorp's cost allocations in Washington with the manner in which PacifiCorp operates its system. Washington customers drive costs through their load, which is served through the operations of PacifiCorp's integrated system. The WIJAM, through a system reflection of some of these costs, provides a more accurate allocation of the costs caused by Washington customers.

Washington customers have always benefited from the entirety of PacifiCorp's system. As explained in the testimony of Mr. Vail, PacifiCorp's transmission system provides reliability for all customers. Additionally, Washington customers benefit from the load and geographic diversity of PacifiCorp's system. The WIJAM reflects PacifiCorp's integrated system and recognizes the value of the non-emitting, non-QF resources and transmission located in PACE while accounting for Washington's energy policy, including the need for increased access to renewable generation.

Q. Please describe PacifiCorp's system operations.

A. PacifiCorp operates its system on an integrated basis across its six-state territory. The Company's resource mix is very diverse with hydro, wind, solar, coal, natural gas, and geothermal generation used to meet its peak demand of over 12,500 megawatts (MW). In addition, PacifiCorp has over 170 interconnections with other balancing authority areas (BAAs) and transmission operators, including the California Independent System Operator (CAISO). For system balancing purposes, PacifiCorp relies on regional energy market hubs for wholesale energy transactions. The primary market hubs in PACW are Mid-Columbia (Mid-C) and California-Oregon Border (COB). In PACE, the primary market hubs are Mona, Four-Corners, and Palo Verde. PacifiCorp also joined the EIM in 2014, which, as of December 2019, is comprised of the CAISO, Arizona Public Service Company, Portland General Electric, Idaho Power Company, Powerex, PSE, and Nevada Energy. Many other utilities across the west are expected to join EIM over the next three years.

PacifiCorp currently has 1,600 MW of transmission rights, east to west, connecting its PACE and PACW BAAs. This includes 510 MW of Idaho Power Company transmission and 1,090 MW of PacifiCorp transmission. These transmission rights have allowed PacifiCorp to serve load in PACW without building additional resources in PACW. They also allow PacifiCorp to maintain reserves on its PACE generation resources, rather than duplicate reserve obligations in both BAAs, reducing total system operational costs. Further, PACE provides the blackstart capability required for both BAAs.

PacifiCorp's geographic footprint allows it to take advantage of efficiencies and economies from both a planning and operational perspective due to retail load characteristics, variable resource diversity, and wholesale power market opportunities. This diversity of load and variable resources is effectuated through the network of transmission capability and Jim Bridger's ability to export to PACE or deliver its energy into PACW. PacifiCorp has the flexibility to use Jim Bridger to serve load in PACW and PACE to avoid higher priced market purchases.

Additionally, PacifiCorp is able to deliver its PACE resources to PACW for both energy and ancillary services.

Due to the diversity of its dispatchable resource fuel mix across its BAAs, PacifiCorp is able to effectively manage price exposure to natural gas spikes, as well as market fluctuations that may be due to low hydro years or low periods of variable resource generation. This type of diversity benefit is only available through the management of both BAAs on an integrated basis. PacifiCorp has an extensive transmission capability throughout its service territory. Additionally, the introduction of the EIM and the capability to wheel power through the CAISO from PACE, as well as the spring 2018 entrance of Idaho Power Company into the EIM, provides PacifiCorp the ability to improve its intra-hour delivery of energy from the east to the west. As the EIM has grown and provided a significant benefit to customers, it has also provided PacifiCorp the ability to enhance the integration of its system across both BAAs due to the enhanced dispatch on a five-minute basis, and, more importantly, due to the availability of additional transmission capability. PACE has been an integral part of providing EIM benefits to Washington customers in its ability to decrement its coal fleet and receive imports from CAISO during times in the day when solar production is high in California. These imports from California carry the additional benefit of offsetting coal emissions and allow the Company to meets its load using low cost renewable generation. During the spring time, when California is more likely to be in over-supply conditions due to lower loads across the state, PacifiCorp's hydro facilities are less able to decrement to receive the low-priced imports due to stream flow management at the facilities. PACE, with its large operating range across the coal fleet, contains nimble resources that are able to decrement to very low operating levels to maximize the amount of renewable generation that can be allowed on the system, both internally and externally through the EIM. The benefit of importing low cost power through the EIM is a direct benefit to Washington customers through lower NPC, as well as the environmental benefit of displacing the thermal emissions.

Q. How did the Idaho Power Asset Exchange affect the transmission transfer capacity between PacifiCorp's BAAs?

A. As mentioned above, the Company has 1,600 megawatts (MW) of transfer capability, which includes 400 MW of dynamic transfer capacity from PACE to PACW. This transfer capability is partially enabled by the Idaho Power Asset Exchange transaction discussed in the testimony of Mr. Vail. This transaction provided PacifiCorp an owned-system path that connects existing, PacifiCorp-owned assets in the Jim Bridger substation area in Wyoming, the Goshen, Idaho area, and at the Midpoint substation near Shoshone, Idaho. Under this transaction PacifiCorp gained 200 MW of dynamic scheduling between Utah/Wyoming and Oregon/Washington as well as the ability to utilize PACE system resources to meet PACW load and reserve obligations. PacifiCorp's transfer capacity between its BAAs enables greater transparency, flexibility, and reliability with respect to system operations in regards to: (1) increasing flexibility in deciding which resources can be transferred from east to west; (2) additional PacifiCorp owned transmission assets to serve Goshen loads; and (3) increasing the ability to dynamically hold reserves on both BAAs to increase the system operational efficiency.

Q. Did this increase in transfer capacity occur after the WCA was approved by the Commission?

A. Yes. At the time the Commission approved the WCA, PacifiCorp did not have this owned system path, the additional 200 MW of dynamic scheduling or the ability to dynamically schedule generation from a resource other than Jim Bridger. Before the Idaho Power Asset Exchange, PacifiCorp could only dynamically transfer Jim Bridger generation from PACE to PACW. After the transaction, transfers were no longer restricted to Jim Bridger generation. This change in circumstances on PacifiCorp's system results in serving the customer load on both control areas with more flexibility and a resulting lower NPC across the BAAs.

Q. Has the Company previously proposed the inclusion of certain "Exchange and Reassignment Assets" in the WCA as a result of the Idaho Power Asset Exchange?

A. Yes. The Company previously proposed the inclusion of certain "Exchange and Reassignment Assets" in the 2015 rate case. However, the Commission denied PacifiCorp's proposal because "[t]he Company has not calculated the quantifiable benefits of the exchange or provided for their inclusion in the power cost baseline, nor is it proposing to reflect power costs savings resulting from the additional 200 MW of dynamic transfer capability."[17]

Q. Has the Company included these benefits in this case?

A. Yes. Consistent with the terms of the WIJAM MOU, PacifiCorp reflected these benefits in the NPC savings described later in my testimony.

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[17] *WUTC v. Pac. Power and Light Co.*, Docket No. UE-152253, Order 12 at ¶ 216 (Sept. 1, 2016).

Q. Can PacifiCorp hold reserves in PACE for PACW because of the available transfer capacity?

A. Yes. BAAs are required by the North American Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) to hold three percent of load and three percent of generation in contingency reserves that can be deployed within five minutes in instances of mechanical failure with measurable effects on power balance. PACW has relatively few dispatchable resources on which to hold reserves. Especially during times of hydro constraints, a feasible reserve plan may not be possible for PACW as a standalone system due to large volumes of water that must flow through the hydro system. Because PACW is connected with PACE it can rely on resources in PACE for reserves. As a result, PACW can consistently produce a feasible reserve plan without incurring additional cost, such as running a natural gas plant in PACW when the minimum load energy is not economic or when it is technically not possible due to high levels of reserves and system constraints.

Q. Can you provide an example when the ability to hold these reserves in PACE benefited Washington customers?

A. Yes. On December 12, 2017, the Lewis River hydro complex was forced to generate at its maximum load due to high stream flows, removing its ability to hold reserves. With peak load at 3300 MW, the reserve requirement for PACW was nearly 200 MW. The remaining available PACW units could only combine to hold 170 MW of reserves over the peak hours. PACE was able to hold reserves for PACW to compensate for this shortfall and avoid declaring an energy emergency in PACW.

Q. How does the connectivity of PACE and PACW provide system diversity benefits?

A. The PACW system is only connected to two liquid market hubs, Mid-C and COB. As a standalone system, PACW would be at the mercy of these two market points for serving PACW energy needs. Because of the geographic proximity, available transmission between these two market hubs, and the overlap of the participants at these hubs, trades at Mid-C and COB tend to be correlated. In instances of high prices at Mid-C, COB prices can be expected to be similarly elevated, providing no relief. However, combined with the PACE system, PACW has the ability to procure energy from alternative market points that trade on a less correlated basis to Mid-C, and will not be affected by a localized event, like a critical transmission outage, extreme weather in the northwest, or natural gas pipeline issues.

Q. Can you provide an example of when this system diversity benefited Washington customers?

A. On October 9, 2018, a natural gas pipeline north of Prince George, British Columbia exploded creating a natural gas shortage in the northwest. Natural gas prices at the Sumas natural gas market hub increased substantially, and energy prices at Mid-C also increased. For months following the explosion, there was high price volatility for both natural gas and energy in the northwest. However, because natural gas plants in the southwest are on different pipelines, prices at the southwest market hubs did not experience the same volatility and did not rise to the levels seen in the northwest. Recognizing this, PacifiCorp procured transmission rights from PACE to PACW in excess of the transmission rights it already owns to mitigate the high prices and volatility through market purchases at market hubs in PACE, thus saving customers money through lower NPC. From November 2018 through March 2019, an average of 157 MWs were transferred from PACE to PACW each hour to take advantage of lower prices in the southwest markets, resulting in a benefit of approximately $15 million.

Q. Is it appropriate for the Commission to adopt the WIJAM at this time?

A. Yes. My testimony describes quantifiable direct or indirect benefits to Washington customers from the WIJAM, including NPC benefits, greater benefits for RPS compliance, greater flexibility for CETA compliance, increased PTCs, increased wheeling revenues, and increased system diversity. These benefits are commensurate with the costs resulting from the new allocation methodology.

Q. What are the impacts of the WIJAM on revenue requirement in this case?

A. As seen below in Figure 2, the system allocation of transmission and new, non-emitting, non-QF resources results in a year-one decrease to the revenue requirement in this case of $5.2 million. Included in this $5.2 million decrease in revenue requirement are the benefits of decreased NPC (approximately $13.5 million), increased PTCs (approximately $10.1 million), and increased OATT wheeling revenue (approximately $1.2 million), all of which are discussed in greater detail below. Because the full revenue requirement impact of the transition to system transmission is spread out over three years, there will be additional revenue requirement increases associated with the WIJAM in 2022 and 2023, reflecting the approximately $2.75 million step increases occurring through the System Transmission Adjustment tariff rider. Importantly, this does not reflect potential RPS compliance benefits or potential CETA compliance benefits, both of which will be discussed in greater detail below.

Figure 2

Estimated Washington Revenue Requirement Including Net Power Cost

		WCA		WIJAM		Variance
Other Operating Revenues	**$**	**25.7**	**$**	**14.7**	**$**	**(11.0)**
Operating Expenses:						
Operations and Maintenance		180.1		153.5		(26.6)
Customer Accounts/Service		8.2		8.2		(0.0)
Administrative & General		9.4		9.4		-
Depreciation Expense		110.6		117.4		6.8
Amortization Expense		3.8		3.4		(0.4)
Taxes Other		24.8		24.8		(0.0)
Income Taxes		(3.2)		(11.1)		(7.9)
Misc. Rev. and Exp.		0.1		0.1		-
Total Operating Expenses	**$**	**333.8**	**$**	**305.6**	**$**	**(28.1)**
Rate Base:						
Generation EPIS		*744.1*		*792.1*		*48.1*
Generation Accum. Depr.		*(261.4)*		*(240.5)*		*20.9*
Accumulated Amortization		(67.2)		(61.9)		5.4
ADIT		(215.3)		(222.7)		(7.4)
Other Rate Base		(30.0)		(30.0)		-
Total Rate Base	**$**	**868.6**	**$**	**1,023.8**	**$**	**155.2**
Pre-Tax ROR		7.69%		7.69%		7.69%
Estimated Revenue Requirement	**$**	**374.9**	**$**	**369.7**	**$**	**(5.2)**

Q. Are the impacts of accelerating Jim Bridger and Colstrip depreciation to December 31, 2023, included in the table above?

A. Yes. In the table above both the WCA scenario and the WIJAM scenario include the change to depreciation at Jim Bridger and Colstrip to provide an apples-to-apples comparison that isolates the impacts of the two allocation methodologies. As stated earlier in my testimony, accelerating the depreciation schedule at Jim Bridger and

Colstrip increases the revenue requirement by approximately $5.6 million in both scenarios.

Q. Does the WIJAM provide customers with increased PTC benefits when compared to the WCA?

A. Yes. The majority of PacifiCorp's wind fleet is located in PACE. By including a system share of non-emitting, non-QF resources, Washington customers are allocated approximately 176 MW of wind capacity compared to 92 MW of wind capacity under the WCA. This reflects an increase of approximately 325,000 MWh of wind generation during the test period. Additionally, PacifiCorp is in the process of repowering its wind fleet and is constructing new wind plants, which provides an additional 10 years of PTC benefits from PacifiCorp's existing wind fleet.

Q. Has PacifiCorp quantified the increased PTC benefit to Washington customers?

A. Yes. Figure 3 below shows the PTC benefits in the WIJAM compared to the WCA.

Figure 3

Production Tax Credits		WIJAM Total Generation (MWh)		WCA Total Generation (MWh)
Glenrock		340,529		
Glenrock III		113,994		
Goodnoe		284,290		284,290
High Plains Wind		381,845		
Leaning Juniper 1		299,842		299,842
Marengo		488,061		488,061
Marengo II		232,352		232,352
McFadden Ridge		116,455		
Rolling Hills		245,446		
Seven Mile		417,974		
Seven Mile II		87,580		
Dunlap I Wind		476,695		
Foote Creek I Wind		141,277		
Pryor Mountain Wind		811,936		
Cedar Springs Wind II		749,501		
Ekola Flats Wind		819,430		
TB Flats Wind		847,124		
TB Flats Wind II		819,430		
Total MWh Production		7,673,761		1,304,545
Tax Credit $/MWh (2021)	$	0.025	$	0.025
	$	191,844,032	$	32,613,634
Gross up for Taxes (1.266%)	$	242,874,545	$	41,288,860
WA Allocation Factor		7.81%		21.58%
Total PTC Benefits WA Allocated	$	18,971,174	$	8,908,980

Wheeling Revenues

Q. Is there an increased benefit to Washington customers for third-party wheeling revenues under the WIJAM?

A. Yes. Under the WIJAM Washington customers are allocated approximately $3.5 million more in third-party wheeling revenues as compared to the WCA. Wheeling revenues, as previously noted, are included in the System Transmission

Adjustment, and therefore approximately $1.2 million of the difference is included in this case and Figure 2. As discussed above, the System Transmission Adjustment will be approximately $2.75 million in both 2022 and 2023, which includes an additional $1.2 million in wheeling revenues in each step.

Net Power Cost Benefits

Q. Has PacifiCorp quantified the NPC benefits under the WIJAM?

A. Yes. Figure 4 shows the forecast NPC benefits associated with the WIJAM included in this case are $13.5 million.

Figure 4
Net Power Cost Reconciliation

	Washington Allocated ($ millions)
2021 GRC (WCA)	**$120.0**
Increase/(Decrease) to NPC:	
Wholesale Sales Revenue	$12.3
Purchased Power Expense	($5.3)
Coal Fuel Expense	($1.4)
Natural Gas Fuel Expense	($1.3)
Wheeling, Hydro and Other Expense	($17.8)
Total Increase/(Decrease) to NPC	**($13.5)**
2021 Rate Case (WA)	**$106.5**

Q. Please explain how PacifiCorp quantified these benefits.

A. PacifiCorp compared the Washington-allocated forecast NPC under the WCA to the Washington-allocated forecast NPC under the WIJAM.

Q. What are the drivers of the forecast NPC benefits?

A. The WIJAM allocates an increased amount, 11 percent, of renewable and non-emitting resources to Washington customers as compared the WCA. The increase of new renewable generation affects all components of forecast NPC including system balancing transactions and dispatch of thermal resources. Additionally, the WIJAM considers the entirety of PacifiCorp's system and allows the GRID model to optimize the system and dispatch the most favorable resources and transact in the most favorable markets. Finally, under the WIJAM the Washington-allocated wheeling costs are lower.

Q. Are all components of forecast NPC lower under the WIJAM?

A. No. Some components of forecast NPC may actually be higher under the WIJAM taking into account loads, market prices, and other model inputs. For example, Figure 4 above shows that off system sales under the WIJAM increase forecast NPC when compared to the WCA. This is explained in greater detail later in my testimony.

RPS Compliance

Q. Will the proposed allocation changes under the WIJAM MOU provide benefit to customers related to PacifiCorp's compliance with the Washington RPS?

A. Yes. Under the WCA, Washington customers are allocated renewable attributes equal to the Washington–allocation of RPS-eligible generation resources in the WCA. Under WCA PacifiCorp will not meet the Washington RPS without purchasing renewable energy certificates (RECs) for the years 2021 through 2023. PacifiCorp is repowering its existing wind fleet and building approximately 1,500 MW of new wind facilities. Under the WIJAM, the inclusion of these resources allow PacifiCorp to meet its RPS compliance targets during the 2021-2023 timeframe without the need to purchase additional RECs. As seen in Figure 5, PacifiCorp estimates the RPS compliance benefit under the WIJAM to be between $0.75 million and $1.6 million annually.

Figure 5

WIJAM REC Benefits		2021		2022		2023
RPS Target (MWh)		631,364		634,609		637,420
WCA Available Resources (MWh)		372,885		369,388		366,491
WIJAM Available Resources (MWh)		832,245		814,473		836,078
WCA RPS Position (MWh)		(258,479)		(265,222)		(270,929)
WIJAM RPS Position (MWh)		200,881		179,863		198,658
Avoided shortfall (MWh)		258,479		265,222		270,929
Potential WIJAM benefit (Low Case)	$	775,436	$	795,665	$	812,788
Potential WIJAM benefit (High Case)	$	1,550,873	$	1,591,329	$	1,625,577

CETA Compliance

Q. Does the WIJAM provide Washington customers with CETA compliance benefits?

A. With recognition that CETA regulatory implementation is still in its early stages, there are potential CETA compliance benefits to the additional resources that will be brought into Washington rates through the WIJAM. Under CETA all retail electric sales must be GHG neutral beginning January 1, 2030.[18] Of this requirement, at least 80 percent of GHG-neutral retail sales must be met with bundled resources, with the rest permitted to be met through the purchase of unbundled compliance instruments.[19]

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[18] *See* RCW 19.405.040.
[19] *See Id.*

Recognizing the Commission has not addressed interpretation of this section of CETA and that future compliance mechanisms are still unknown, the Company compared its forecast CETA position under the WCA and WIJAM, based on the 2019 IRP, for the first four-year compliance window from January 1, 2030, to December 31, 2033. This comparison shows that the potential CETA compliance benefit of the resources allocated to Washington under the WIJAM are considerable, approximately doubling the bundled resources available to meet Washington load, and avoiding close to seven million megawatt hours (MWh) of bundled procurement needed under the WCA to comply with CETA.

Q. Is the Company able to quantify the dollar amount of this CETA benefit?

A. Not precisely, as CETA implementation is still in its preliminary stages. However, the ability for non-emitting generation in PACE to be allocated to Washington customers is significant. The WIJAM allows Washington customers to benefit from the wind repowering and the new wind that was planned even before CETA. This is beneficial to Washington customers because the wind repowering and new wind plants increase Washington's renewable portfolio and qualify for full PTCs, and neither the PTCs nor wind resources in PACE would be available to Washington customers under the WCA. Additionally, Wyoming wind resources are the most cost-effective wind resources available to the Company. The 2019 IRP shows the total resource cost of Wyoming wind is approximately $15 per MWh less than both Oregon and Washington wind.[20] The second most cost effective is Idaho wind, which is

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[20] *Pacific Power & Light Company 2019 Integrated Resource Plan*, Docket No. UE-180259, Volume I at 141, Table 6.2 (Oct. 18, 2019) (These numbers are based on a total resource cost using a 40 percent PTC benefit).

approximately $9 per MWh less than both Oregon and Washington wind.[21] Even though CETA benefits cannot be precisely calculated, based on what is known today, the WIJAM puts PacifiCorp in a better CETA compliance position relative to the WCA and provides Washington customers with access to potentially more cost-effective non-emitting resources.

Q. Has PacifiCorp quantified its CETA compliance position under the WIJAM?

A. Yes. Using the 2019 IRP data, as shown in Figure 6, starting in 2030, PacifiCorp's compliance position improves by an average of 1.73 million MWh annually during the first compliance period, ending in 2033.

Figure 6

WIJAM Potential CETA Benefit (MWh)	2030	2031	2032	2033
GHG-neutral target	4,566,757	4,566,757	4,566,757	4,566,757
WCA Available Resources	1,166,992	1,182,585	1,186,990	1,450,291
WIJAM Available Resources	2,012,273	2,043,402	2,062,081	2,119,114
CETA 20% Unbundled REC cap	913,351	913,351	913,351	913,351
WCA CETA Position	(3,399,765)	(3,384,172)	(3,379,767)	(3,116,466)
WIJAM CETA Position	(1,641,133)	(1,610,004)	(1,591,325)	(1,534,292)
WIJAM CETA Position Benefit	1,758,632	1,774,169	1,788,442	1,582,174

Q. Are there other possible benefits to the WIJAM for CETA compliance that cannot be quantified at this time?

A. Yes. The Company's identification of potential CETA compliance benefits is limited and conservative to account for the preliminary nature of CETA implementation. In addition, the potential CETA compliance benefits presented in my testimony do not address potential benefits of the WIJAM relative to CETA's requirement that

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[21] *Id.*

100 percent of retail sales be from non-emitting resources by 2045.[22] As discussed in the testimony of Ms. Lockey, the WIJAM and the 2020 Protocol provide a potential pathway for a limited realignment of coal and natural gas resources that could further improve PacifiCorp's path to CETA compliance. As implementation of CETA progresses, the Company expects that the CETA compliance benefits of the WIJAM will increase. For example, the Company's current analysis does not attempt to quantify a compliance cost value of the WIJAM, or address any future policy changes that could occur, such as changes in REC banking requirements, that could produce additional value associated with Washington's transition to the WIJAM.

Q. What is the recommendation to the Commission regarding the WIJAM?

A. Based on the immediate direct and quantifiable benefits and the potential future benefits, I recommend the Commission approve the WIJAM.

NODAL PRICING MODEL

Q. Are there other inter-jurisdictional cost allocations that affect Washington customers?

A. Yes. As explained by Ms. Lockey the Company recently entered into an agreement with stakeholders in the MSP for an inter-jurisdictional cost allocation methodology referred to as the 2020 Protocol. As part of the 2020 Protocol, future allocation factors for generation will potentially be fixed and each state will potentially have a different generation portfolio. This change may impact how NPC are allocated to each jurisdiction in the future.

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[22] *See* RCW 90.405.050(1).

Q. If states have differing generation portfolios in the future, can the Company continue to rely on its past practice of allocating NPC on a system basis?

A. No. The ability to dynamically allocate NPC in a reasonable manner hinges on a common resource portfolio in which all states share proportionately in the resources. It is likely that after the Interim Period,[23] states will no longer participate in a common resource portfolio. Washington already participates in a unique resource portfolio when compared to PacifiCorp's other states. In addition to providing a path for states to have unique resource portfolios, it is important to maintain the benefits of system dispatch and optimization as much as practicable. To fairly and reasonably allocate NPC with unique state resource portfolios while maintaining the benefits of system dispatch and optimization, the allocation methodology for NPC must be changed.

Q. Will a new approach to allocating NPC be developed during the Interim Period?

A. Yes. This is a complex issue, requiring additional time for the Company to develop a new system to track the real-time costs of generation based on each state's allocated share of each resource. The additional time during the Interim Period will also allow for further discussions with parties relative to the usage and implementation of a new system for ratemaking purposes in the Post-Interim Period Method.[24] The new system is referred to as the Nodal Pricing Model, or NPM.

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[23] The 2020 Protocol describes certain cost-allocation issues that will be implemented during an "interim period," from January 1, 2020, until the earlier of resolution of all remaining cost-allocation issues or December 31, 2023 (the Interim Period).

[24] The Post-Interim Period Method is the term used in the 2020 Protocol to refer to the potential allocation method that will be used beginning January 1, 2024.

Q. Will the NPM be used for cost allocations during the Interim Period?

A. No. Under the 2020 Protocol in all states but Washington, NPC will continue to be dynamically allocated as they were under the 2017 Protocol, with the exception of the changes related to QF PPAs. The NPM is a Framework Issue and will be subject to further development and refinement during the Interim Period.[25] If the Framework Issues are resolved, the NPM will be part of the Post-Interim Period Method to be filed for consideration and approval by the states. For Washington, NPC will be allocated as described above under the WIJAM until another method is approved by the Commission.

Q. Even though the NPM will not be used for cost allocation purposes during the Interim Period, can it be used for day-ahead scheduling during that timeframe?

A. Yes. When the NPM is developed and fully operational, the Company anticipates that it will be used at a total company level for day-ahead schedules and commitment decisions, also referred to as day-ahead setup, and capture any co-optimized system efficiencies that the NPM creates.

Q. How does the Company intend to use the NPM?

A. The use of the NPM to allocate NPC is a Framework Issue in the 2020 Protocol, meaning there are still items to be resolved before the NPM is used to determine NPC by state. Once the Framework Issues are resolved, the NPM may be used for NPC allocations in the Post-Interim Period Method. However, during the Interim Period the Company will make best efforts to implement the NPM by January 2021.

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[25] Framework Issues is the term used in the 2020 Protocol to refer to outstanding issues that stakeholders intend to resolve during the Interim Period.

Therefore, while the 2020 Protocol is in effect, the Company's day-ahead schedule may be based on the NPM, but NPC, for ratemaking purposes, will be allocated per the WIJAM in Washington and dynamically allocated in all other states. Parties intend for this period to provide an opportunity for experience with the NPM before it is used for ratemaking as part of the Post-Interim Period Method.

Q. What principles did the Company establish to evaluate a method for allocating NPC when the states do not share a common resource portfolio?

A. The Company established five guiding principles for evaluating a NPC allocation method, namely that it should:

- Support individual states' abilities to have a unique resource portfolio mix that does not adversely impact other states;
- Assign costs to the state(s) that benefit from and/or drive those costs;
- Provide appropriate incentives and transparency of cost drivers to better inform resource decision making;
- Maximize the transparency of cost allocation and dispatch decisions; and
- Reduce reliance on subjective assumptions.

Q. Please describe the NPM.

A. The NPM is a tool designed to track NPC by generation resources and by state. The Post-Interim Period Method will no longer dynamically allocate costs among states based on their respective loads. Instead, generation-related costs will follow the assignment of those resources. To develop such a method, PacifiCorp is working with CAISO who, acting as a third-party vendor, will produce optimal unit commitment and hourly energy schedules for supply resources in the PacifiCorp balancing authority areas using its day-ahead market model. PacifiCorp will use the

NPM to track costs and benefits associated with the different resource portfolios used to serve PacifiCorp's load in each state for ratemaking purposes.

Q. Did the Company research alternatives to the NPM?

A. Yes. The Company evaluated alternative methodologies that attempted to fairly allocate NPC among states with unique resource portfolios. However, none of these methods were consistent with the guiding principles outlined above.

Q. Why did the Company decide to pursue the NPM as opposed to the other options?

A. The NPM was the only identified method consistent with the guiding principles. Additionally, the NPM builds on the Company's experience gained through its participation in the EIM. The EIM dispatches the Company's system on an intra-hour basis using locational marginal prices (LMP), and the NPM will extend a similar concept to the day-ahead setup of the system. PacifiCorp will settle the NPM at the state level compared to the balancing area authority in the EIM.

Q. Please describe conceptually how the NPM will work.

A. The NPC associated with each generating resource will be assigned to the states based on each generating resource's assignment. For example, if a state is assigned 25 percent of a natural gas plant, then it is also assigned 25 percent of the fuel costs associated with that resource, regardless of load. Each resource also receives a credit based on the LMP for its generation, which is also assigned to each state per its assignment of each generating resource. The assigned NPC, less the credit received, will be the state's total NPC.

Q. Please explain the credit received by each generating resource in more detail.

A. Each generating resource will receive a credit for the energy it generates or the reserves it provides, and each state's load will be charged a load aggregated point price. The total credits the generating resources receive will equal the dollar amount that each state's load is charged. This facilitates a transfer of energy between states at a fair price based on the LMP and preserves the benefits of a system dispatch and optimization.

Q. What is the primary benefit associated with the NPM?

A. NPM provides a method to allocate and track actual NPC even as states move to unique generation portfolios. The NPM is intended to and is being developed to help preserve the benefit of operating as a single system while providing states the flexibility to have unique resource portfolios that align with a state's energy policy and interests.

Q. Are there any secondary benefits associated with the NPM?

A. Yes. In addition to providing a method to allocate NPC among unique resource portfolios, the NPM potentially provides more granular day-ahead setup information resulting in potential operational cost savings. The potential operational cost savings will be the result of a more efficient day-ahead setup and the cost savings will be embedded in the actual NPC. These potential cost saving will be impossible to accurately and precisely track as the calculation of such savings would rely on a counterfactual setup of the system without the NPM.

Q. What are the benefits of partnering with CAISO for the development of the NPM?

A. As the Company implements a NPC allocation methodology based on the NPM solution, partnering with CAISO's existing technology platform reduces both schedule and budget risk. Since the day-ahead market in the CAISO is based on the day-ahead LMPs at the nodal level, the Company will be able to leverage CAISO's existing day-ahead market model and experience in developing and implementing the NPM. Additionally, partnering with CAISO ensures consistency between the NPM and the EIM dispatch since both will be based on the same underlying full-network model. Even though transfers will not be allowed between CAISO and PacifiCorp in the NPM, the day-ahead dispatch for both systems will be based on the same model run and could potentially result in a more efficient day-ahead setup that takes into consideration a more accurate power flow solution.

Lastly, if CAISO offers a day-ahead market to external entities for optional participation, the NPM solution development would allow PacifiCorp to seamlessly participate in the CAISO day-ahead market, if and when PacifiCorp decides to participate in that market.

Q. Is development of the NPM with CAISO as the third-party vendor equivalent to PacifiCorp joining CAISO in any way?

A. No. As the third-party vendor, CAISO will provide optimized advisory day-ahead schedules and commitment information only. PacifiCorp will not relinquish control of its transmission assets to CAISO or otherwise be considered as having joined

CAISO as the result of engaging CAISO as the third-party vendor for NPM development.

Q. What are the costs associated with the NPM?

A. CAISO will charge PacifiCorp a grid management charge or service fee that is estimated to be between $8 million and $10 million annually once the NPM is operational beginning in January 2021. Additionally, there will be some initial capital cost and ongoing O&M expense, such as upgrades for PacifiCorp's information technology hardware and software for both regulatory and accounting purposes.

Q. Will the NPM provide both actual and forecast NPC results?

A. No. The NPM will provide a way to assign costs by state on an actual basis. For forecast NPC used in various ratemaking processes, the Company will use best efforts to implement a model that can forecast NPC based on the NPM concept, and is currently working with Energy Exemplar to develop the modeling setups and test run a model known as the Aurora Model. During the Interim Period the Aurora Model may be used by the Company for forecast analysis of NPC. After the Interim Period, the Company intends to propose the use of the Aurora Model for NPC forecasts in applicable ratemaking proceedings.

NODAL PRICING MODEL MEMORANDUM OF UNDERSTANDING

Q. Please describe the NPM MOU executed by the Parties and provided as Appendix D to the 2020 Protocol.[26]

A. The NPM MOU sets out the Company's proposal for a third-party day-ahead dispatch model to determine the schedules for each of its generation resources to serve state

[26] The 2020 Protocol is provided as Exhibit No. EL-3.

loads on a least-cost basis, while tracking costs and benefits associated with the different resource portfolios used to serve PacifiCorp's load in each state. The MOU lists the CAISO as the third party that will develop the tool, the scope of work, and costs of the work identified by the CAISO, as well as CAISO's estimated costs and benefits of the work. The MOU also provided an explanation of the anticipated benefits, including cost-savings and compliance with state policy directives impacting resource portfolio decisions. Based on the information provided by the Company, parties to the NPM MOU agree that the Company's decision to invest capital funds and pay ongoing grid management charges to develop and implement an NPM is reasonable and prudent. The MOU was signed by 17 parties, including the Company, regulatory agencies, consumer advocates, and other interested parties from Idaho, Oregon, Utah, Washington, and Wyoming. No party to date has indicated their objection to the Company's investment to develop the NPM.

Q. Does the NPM MOU address the training for parties?

A. Yes. The Company will use its best efforts to provide adequate training and documentation regarding the NPM such that Parties may understand, review, and audit NPM-derived NPC. The Company will also provide training and facilitate access to the Company's forecasting model for any appropriate party for regulatory purposes.

Q. Are the parties to the 2020 Protocol asking the Commission to approve the use of the NPM at this time?

A. No. As indicated previously, the NPM is a Framework Issue as defined in the 2020 Protocol, and the process and timeframe for developing NPM is what is before the

Commission for consideration, not the method itself. Once the NPM is fully developed and agreed to by Parties, a subsequent filing will be made for approval of the end result of the Framework Issue process and the implementation of a Post-Interim Period Method.

Q. What action do you recommend the Commission take with respect to the 2020 Protocol, including the Company's pursuit of the NPM?

A. The Company recommends that the Commission find that the 2020 Protocol, including the development of the NPM, is in the public interest and requests that the Commission approve the 2020 Protocol in this proceeding.

FORECAST NPC

Q. Please provide an overview of NPC in the Company's filing.

A. The Washington NPC are approximately $106.5 million before applying the production factor. NPC are determined using forecast expenses and revenues for the calendar year 2021. A report detailing the Washington-allocated NPC forecast is attached to my testimony as Exhibit No. MGW-3.

Q. How do the forecast NPC in this proceeding compare to the NPC authorized in the Company's 2014 general rate case, docket UE-140762 (2014 Rate Case)?

A. The forecast Washington NPC in the current proceeding are approximately $19.9 million lower than the level authorized by the Commission in the 2014 Rate Case.

Q. Is the Company's general approach to forecast NPC using the GRID model the same in this case as in the 2014 Rate Case?

A. Yes. To forecast NPC, the Company used the GRID model in both this case and in the 2014 Rate Case. As discussed below, the Company has updated the inputs to the GRID model.

Q. What GRID inputs were updated for this filing?

A. The Company updated inputs to the GRID model to reflect the information available at the time the Company prepared the forecast NPC for the current filing. The updated GRID inputs include:

- Total company load;
- Contracts for wholesale sales and purchases of electricity, natural gas and wheeling;
- Market prices for electricity and natural gas or the official forward price curve (OFPC);
- Coal fuel expenses;
- Transmission capability including the impacts of the Idaho Power Asset Exchange;
- Characteristics of the Company's generation facilities; and
- Planned outages and forced outages of the Company's generation resources.

Q. What is the date of the OFPC the Company used for its forecast NPC?

A. The forecast NPC use the OFPC dated September 30, 2019.

Q. What reports does the GRID model produce?

A. The major output from the GRID model is the NPC report. An electronic version is included in the workpapers accompanying the Company's filing. Additional data with more detailed analyses are also available in hourly, daily, monthly, and annual formats by heavy load hours (HLH) and light load hours (LLH).

IMPACTS OF THE WIJAM ON THE NPC FORECAST

Q. How does the WIJAM impact the modeling of forecast NPC?

A. The WIJAM changes the following items in the NPC forecast model:

- Inclusion of all power generation resources on the Company's system, except emitting resources that are not electrically located in PACW and non-Washington QFs;
- Inclusion of system transmission on both a firm and non-firm basis;
- Inclusion of the new transmission incremental to the existing transmission system;
- Inclusion of EIM benefits on a system basis; and
- Modification to certain Commission-ordered adjustments in NPC modeling as described below.

Q. What are the Company adjustments in the 2014 Rate Case that are removed due to the WIJAM?

A. These following items only apply when PACW is treated as one stand-alone entity. They are not applicable under the WIJAM and therefore they were removed from the NPC study:

- An imputed sale from PACW to PACE, referred to as the Control Area Generation East Sale (CAGE Sale);
- Prorated wheeling expenses for Colstrip based on the transmission capacity from Colstrip to PACW;
- Margin on arbitrage transactions based on the four-year historical average; and
- Excluded non-firm transmission capability and expenses.

Q. Why did the Company remove the CAGE sale?

A. The WCA is based on the assumption that PACE does not serve Washington customers. Since the WCA does not recognize any transmission rights or costs outside of the WCA, GRID assumes the Company buys and sells power at markets in the WCA only—Mid-C, COB, and Nevada-Oregon Border (NOB). The WIJAM assumes the Company operates on the total system basis and has access to market hubs in both PACW and PACE (*e.g.*, Mid-C, COB, NOB, Mona, Four-Corners, Mead and Palo Verde). The market transactions benefits have already been reflected in the total company NPC and further allocated to Washington. As a result, there is no foundation for imputing a sale from PACW to PACE.

Q. Aside from the CAGE Sale, why did the Company remove the prorated wheeling expenses for Colstrip, the margin on arbitrage transactions, and the exclusion of non-firm transmission capability and expenses?

A. These adjustments are no longer necessary make sense in a total company NPC run, which is the starting point for Washington allocated NPC under the WIJAM.

Q. What are the Company adjustments in the 2014 Rate Case that are unchanged?

A. The Company's current filing is consistent with Order 05 in the 2014 Rate Case, as follows:

- Jim Bridger Coal Costs—Coal supplied by Bridger Coal Company to fuel Jim Bridger is included based on the cost of production during the test period.
- DC Intertie—The cost of transmission rights on the Bonneville Power Administration (BPA) Direct Current (DC) Intertie transmission line is included in NPC, and the related transmission capacity and access to the NOB market hub are included in the GRID topology.

- Hedging Costs—Hedging costs are included in NPC, valued using the Company's OFPC.

- Market Caps—Market caps are modeled in GRID based on the 48-month historical average of short-term firm sales transactions at wholesale market hubs.

- Wheeling Cost—The Idaho Power Company 200 MW point-to-point wheeling contract costs and benefits are all reflected in the NPC study.

Q. Are any Washington QF contracts currently included in rates?

A. Yes. Two Washington QF contracts are currently included in this study at an average price of $31.1/MWh. The Company proposes to update NPC for additional signed QF contracts in its rebuttal filing.

DISCUSSION OF COST DRIVERS IN NPC

Q. Please generally describe the changes in NPC compared to the 2014 Rate Case.

A. Figure 7 illustrates the change in Washington-allocated NPC under the WIJAM from the NPC included in the 2014 Rate Case. The NPC in the test period under the WIJAM is $19.9 million lower than the NPC in the 2014 Rate Case. The decrease in NPC is driven by reductions in purchased power expenses, coal fuel expenses, natural gas fuel expenses, and wheeling and other expenses, partially offset by a decrease in wholesale sales revenue.

Figure7
Net Power Cost Reconciliation

	Washington Allocated ($ millions)
2014 Rate Case (WCA)	**$126.4**
Increase/(Decrease) to NPC:	
Wholesale Sales Revenue	$18.8
Purchased Power Expense	($15.4)
Coal Fuel Expense	($5.4)
Natural Gas Fuel Expense	($4.0)
Wheeling, Hydro and Other Expense	($13.9)
Total Increase/(Decrease) to NPC	**($19.9)**
2021 Rate Case (WA)	**$106.5**

Q. Please explain the $18.8 million reduction in wholesale sales revenue.

A. The decrease in wholesale sales revenue is driven by lower sales volumes. The CAGE sales revenue in the 2014 Rate Case was $48.4 million on a total company basis, at an average price of $30.41/MWh. As discussed above in my testimony, these imputed CAGE sales are not applicable under the WIJAM, therefore, they are not included in wholesale sales revenue in this test period. Market sales (represented in GRID as short-term firm and system balancing sales) in the 2014 Rate Case had an average price of $33.44 per megawatt-hour (MWh), while market sales in the current case are included at an average price of $29.99/MWh, a 10 percent decrease.

Q. Why did purchased power expense decrease by $15.4 million?

A. The total purchased power expense is lower than the 2014 Rate Case because several long-term PPAs have expired since the 2014 Rate Case. The following long-term PPAs that expired are:

- One-half of the output of the Hermiston power plant;

- The output from a turbine located at the Georgia Pacific paper mill in Camas, Washington; and
- The output from hydro plants with Douglas County Public Utility District.

These contracts previously produced approximately 1,339 GWh in the 2014 Rate Case at an average price of $65.71/MWh. The decrease in purchase power expense is also due to lower market purchase prices (represented in GRID as short-term firm and system balancing purchases). Market purchases in the current case are at an average price of $28.47/MWh, while the 2014 Rate Case used an average price of $30.53/MWh, a seven percent decrease.

Q. Please explain the $5.4 million decrease in coal expense in the current proceeding.

A. Total coal fuel expense is $5.4 million lower than the 2014 Rate Case primarily due to lower coal generation volume at the Company's coal generation facilities. Average coal prices are $3.52/MWh higher than the prices in the 2014 Rate Case. Please refer to the detailed discussion of forecast coal costs further below.

Q. Please discuss the $4.0 million change in natural gas fuel expense compared to the 2014 Rate Case.

A. Natural gas fuel expense in the test period is $4.0 million lower than the natural gas fuel expense in the 2014 Rate Case. The decrease in natural gas fuel expense is attributed to lower gas plant generation volume and lower gas generation prices. The average cost of natural gas generation decreased from $39.03/MWh in the 2014 Rate Case to $18.54/MWh, a decrease of 52 percent.

Q. Please describe the $13.9 million decrease in the wheeling and other expense category.

A. Expenses in this category are lower due to using the WIJAM. In the 2014 Rate Case, which used the WCA, approximately 75 percent of the total company wheeling expense was from PACW.

MODELING CHANGES TO IMPROVE NPC FORECAST ACCURACY

EIM Benefits

Q. Please summarize the EIM benefits included in this case.

A. Since the EIM was launched in late 2014, EIM benefits were not included in the 2014 Rate Case, but have been reflected in subsequent PCAM filings. In the current test period, the Company proposes to include EIM benefits in the base NPC. PacifiCorp's 2021 NPC forecast from GRID includes an adjustment to reflect incremental EIM inter-regional benefits and GHG marginal revenues in this case. The test period includes approximately $45.6 million of inter-regional benefits and $5.0 million of GHG benefits on a total company basis as a reduction to the NPC forecast.

Q. How did the Company calculate the EIM inter-regional benefits?

A. The inter-regional benefits reflect the value PacifiCorp receives when it economically exports energy to the EIM and when it imports energy from the EIM that allows it to displace a more expensive resource.

Generally, the benefit of EIM exports is equal to the revenue received less the production cost of generation assumed to supply the transfer. The production cost used in the Company's calculation of EIM benefits is the marginal cost to produce an additional megawatt-hour at a given resource. The Company's production costs used to calculate EIM benefits are equal to the resource bids submitted to the EIM. The benefit of EIM imports is equal to the import expense less the avoided expense of the generation that would have otherwise been dispatched.

Q. How did the Company forecast the inter-regional EIM benefits in the test period?

A. Using EIM benefits by month, a linear regression model was developed using the following four independent variables: electric market prices, natural gas market prices, EIM transfer capability, and spring oversupply conditions. The linear regression model with multiple independent variables will reflect market conditions which drive EIM benefits resulting in a reasonable forecast.

Q. Why is it appropriate to use market prices in the forecast of EIM benefits?

A. If market prices are high, due to high loads, low water conditions, or transmission constraints, among other things, EIM export benefits will be higher. Similarly, if market prices are low, due to lower loads, no transmission constraints or normal water conditions, then EIM export benefits will be lower. In addition, using the market prices as a predictor of EIM benefits more closely aligns the expected benefits with the rest of the NPC forecast in GRID. In other words, by expressing EIM benefits as a function of market prices, the costs incurred to serve system load and the EIM benefits are better matched. For example, the Company is required in EIM to show it has sufficient resources on its own to serve its load every hour, and in a period of high market prices the Company may need to purchase energy at those higher prices to balance the system. However, within the hour when the EIM is optimized, the

Company can realize greater benefits from exporting energy in the EIM than it would during lower priced periods.

Q. How does the Company calculate the GHG benefits?

A. GHG benefits are realized when the GHG revenue is higher than the Company's resulting compliance obligation. The total company GHG benefits for the forecast year 2021 is about $5 million.

Day-Ahead and Real-Time System Balancing Transactions

Q. Please describe the Day-Ahead and Real-Time (DA/RT) adjustment.

A. PacifiCorp incurs system balancing costs that are not reflected in the Company's forward price curve or modeled in GRID. To address this deficiency, the Company proposes the DA/RT adjustment to more accurately model system balancing transaction prices and volumes.

Q. Please explain how the GRID model currently balances load and resources on an hourly basis.

A. The GRID model calculates the least-cost solution to balance the Company's load and resources to fractions of a megawatt for each hour. The model makes purchases in the wholesale market (labeled as "system balancing purchases" in the NPC report) in the hours for which the Company does not have enough owned or contracted resources to meet its load. The model also makes wholesale market sales (labeled as "system balancing sales" in the NPC report) when it has excess resources for a given hour. These system balancing transactions are calculated for each hour independently and are for the precise volume required by the model. Wholesale market prices for the system balancing sales are based on an hourly forward price curve that is developed from monthly HLH and LLH prices with hourly scalars applied. These scalars are identical within a given month for each weekday of that month. The prices are input into the model and do not change based on the volume of the system balancing transactions.

Q. How do actual operations differ from the GRID model logic?

A. In actual operations, the Company continually balances its market position—first with monthly products, then with daily products, and finally with hourly products. The monthly and daily position is calculated as the average for the respective time horizon during HLH and LLH periods; for example, the average HLH position during the month of January or the average LLH position on a given day in February. The monthly and daily products used to balance the Company's position in the wholesale market are available in flat 25 MW blocks. The Company's load and resource balance, however, varies continuously each hour in quantities that may vary widely from a flat 25 MW block. In real-time operations, the Company balances its hourly position in the hourly real-time market. At that point, the Company must transact to maintain a balanced system and, as a result, becomes a price-taker subject to whatever price is available at the time.

Q. How do the system balancing volumes in GRID compare to the Company's actual volumes?

A. The volume of system balancing transactions generated by GRID is smaller than the volume of similar transactions in actual results. Because GRID balances the Company's load and resources to fractions of a MW for each hour in a single step, it avoids the additional purchase and sale transactions that occur in actual operations as the Company progresses through balancing its system on a monthly, daily, and real-time system basis.

For instance, when the Company buys a monthly product that aligns with the Company's average open position for the month, one can expect that roughly half of the days will still have a remaining position to be covered by additional daily purchases. On the other days, the Company will have to make daily sales to unwind the excess volume. The same is true for daily transactions—in some hours the volume acquired will be too low, while in others it will be too high, and additional purchases and sales will be required to cover the Company's actual position.

In addition, buying or selling standard block products for monthly and daily average requirements will not result in a perfect balance of load and resources. This difference then must be closed out in the real-time market where the Company is a price-taker.

Q. Please describe the price component of the DA/RT adjustment.

A. To better reflect the market prices available to the Company when it transacts in the real-time market, PacifiCorp includes in GRID separate prices for forecast system balancing sales and purchases. These prices account for the historical price differences between the Company's purchases and sales compared to the monthly average market prices.

Q. Why is the DA/RT adjustment needed to differentiate the market prices for purchases and sales?

A. The GRID model used an hourly price curve developed from monthly HLH and LLH forward market prices. Hourly prices were simply the product of applying a scalar, or shape, to the monthly average prices. These scalars were identical within a given month for each weekday of that month. In addition, the prices were input into the model and did not change regardless of the volume of the system balancing transactions or other system conditions in the model. In reality, however, prices vary within each month and the Company has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods. As a result, the average cost of the Company's daily and hourly short-term firm purchases has been consistently higher than the average actual monthly market price, while the average revenues from its daily and hourly short-term firm sales has been consistently lower than the average actual monthly market price.

Q. Please describe the volume component of the DA/RT adjustment.

A. The Company reflects additional volumes to account for the use of monthly, daily, and hourly products. In actual operations, the Company continually balances its market position—first with monthly products, then with daily products, and finally with hourly products. The products used to balance the Company's forward position in the wholesale market are available in flat 25 MW blocks. The Company's load and resource balance, however, varies continuously each hour in quantities that may vary widely from a flat 25 MW block. Thus, in real world operations, the Company must continuously purchase or sell additional volumes to keep the system in balance.

In contrast, GRID has perfect foresight and can model wholesale market transactions at whatever volume is necessary to balance the system. Because of GRID's perfect foresight, it can balance the system with far fewer transactions. The

DA/RT adjustment adds additional volumes to NPC to more accurately model the transactions necessary to balance the Company's system.

Q. Where else does PacifiCorp use the DA/RT adjustment in forecast NPC?

A. Since 2015, PacifiCorp has used the DA/RT adjustment in all filings for all jurisdictions that have included forecast NPC.

Thermal Plant Forced Outages

Q. Please summarize the Company's proposal to more accurately model thermal plant forced outages.

A. The Company previously modeled forced outages at thermal units using a percentage de-rate or "haircut" to nameplate capacity in all hours. In this case, the Company modeled forced outages and unit de-rates as discrete events, rather than applying a uniform de-rate to the plant operating characteristics across all hours. In addition, because outages are no longer modeled as de-rates, the Company removed the corresponding adjustments to heat rates and minimum operating levels.

Q. Please explain the basis for the Company's previous modeling of forced outages on thermal units in GRID.

A. Under the Company's previous methodology, forced outages and unit de-rates were modeled in GRID as a percentage reduction to the maximum capacity of each unit. The percentage reduction was calculated using a four-year average of actual outage events. In GRID, this approach constrained unit output between minimum operating level and a de-rated maximum, with a slice of each unit being unavailable for dispatch in every hour. Because thermal units typically operate most efficiently near full capacity, a low cost operating segment was thus unavailable to GRID.

Q. How are thermal plant outages modeled in the Company's current filing?

A. With the new method, the percentage reduction for forced outage on thermal units in GRID remains unchanged, and the forced outage events are discrete in the forecast period, which more realistically reflects the impact of outages on the Company's operations in the forecast period. The uniform deration has been removed and replaced with an hourly schedule of outages. The revised modeling better reflects the range of system operating conditions faced by the Company in actual operations. During intervals without outage events, units are 100 percent available, and can be used over their full operating range. Because outages are no longer modeled as de-rates, adjustments to heat rates and minimum operating levels are no longer necessary. Because the timing and duration of forced outages are not predictable, the 48-month history of actual events was used to develop a schedule during the forecast test year. Forecast outage and de-rate events were created by compressing the 48-month history of outage events for each unit into an annual period (*i.e.*, the relative timing and duration of each event in the four-year history was divided by four and placed in the forecast test year in the same sequence the events occurred).

Regulating Reserve Requirement

Q. How did PacifiCorp update its regulating reserve requirement modeling?

A. The Company's regulating reserve requirements are now based on the 2019 Flexible Reserve Study that was included in the 2019 IRP.[27]

[27] *Pacific Power & Light Company 2019 Integrated Resource Plan*, Docket No. UE-180259, Volume II at Appendix F.

Actual Capacity Factor for Owned Wind Generation and Purchased Wind Generation

Q. Please describe the adjustment made to the forecast capacity factor for owned wind generation and purchased wind generation.

A. Previously, the generation from PacifiCorp's owned wind generation and purchased wind generation was based on long-range forecasts from the time the project was developed. PacifiCorp proposes to calculate the annual capacity factor using a cumulative average methodology for any wind generation with a history of generation longer than four years. For those wind generation facilities with less than four years of history, the project owner's forecast is used for the period until the actual results become available.

Actual wind generation at these facilities has varied somewhat from those forecasts, causing PacifiCorp to incur higher or lower power expenses. To better align forecast NPC with actual results, the Company modeled the forecast wind generation for each of wind generation facility to match the levels in the cumulative historical period. This change brings the modeling of wind generation facility in line with the historical actuals, which will better reflect reasonable level of generation for the future period.

Q. Which capacity factors will the repowered wind plants use?

A. The capacity factor for all the repowered wind plants will be based on the Company's February 2018 economic analysis for wind repowering (included in the 2017 IRP Update). This economic analysis is presented in the testimony of Mr. Rick T. Link.

FORECAST COAL COSTS

Q. Has forecast coal expense in the test period decreased from the amount in the 2014 Rate Case?

A. Yes. As shown in Figure 7 above, forecast coal fuel expense decreased by $5.4 million on a Washington-allocated basis, from $57.2 million in the 2014 Rate Case to $51.8 million in the test period. Reduced volumes account for an $11.1 million decrease and are partially offset by a $5.7 million coal price increase.

Q. Please explain why coal consumption decreased in the test period?

A. Increased generation from non-emitting resources and natural gas resources has significantly reduced coal generation in the test period compared to the 2014 Rate Case.

Q. Please quantify the reduced coal consumption amount in the test period?

A. On a Washington-allocated basis, the test period forecast [redacted] million million British Thermal Units (MMBtus) of coal will be consumed, which is [redacted] million less MMBtus than the 2014 Rate Case. This is a [redacted] percent decrease.

Q. Is the impact of the reduced coal consumption similar at Jim Bridger and Colstrip?

A. Yes. On a Washington-allocated basis, Jim Bridger is projected to consume [redacted] million MMBtus in the test period, which is [redacted] million MMBtus or [redacted] percent less than in the 2014 Rate Case. On a Washington-allocated basis, Colstrip is projected to consume [redacted] million MMBtus in the test period, which is [redacted] million MMBtus or [redacted] percent less than forecast in the 2014 Rate Case.

Jim Bridger Coal Costs

Q. Please explain the coal supply arrangements for Jim Bridger.

A. Similar to the 2014 Rate Case, Jim Bridger is expected to be supplied by a combination of coal supplies from Bridger Coal Company (BCC) and the Black Butte mine in the test period.

Q. Can you please quantify the cost increase at Jim Bridger?

A. Yes. As shown in Confidential Figure 8, Jim Bridger costs increased [redacted] million on a Washington-allocated basis.

Confidential Figure 8

Jim Bridger Plant Coal Deliveries - PacifiCorp Portion

	2021 Test Period			2014 Rate Case			Variance			WA Allocated Price
Supplier	Tons	Dollars	$ / Ton	Tons	Dollars	$ / Ton	Tons	Dollars	$ / Ton	Variance
Bridger Coal Deliveries	[redacted]			[redacted]			[redacted]			[redacted]
Black Butte Deliveries	[redacted]			[redacted]			[redacted]			[redacted]
Total Jim Bridger Plant	[redacted]			[redacted]			[redacted]			[redacted]

Q. Of the $[redacted] million coal cost increase at Jim Bridger, how much is attributable to BCC?

A. BCC coal costs increased from [redacted] per ton to [redacted] per ton, or by [redacted] per ton, which resulted in a Washington-allocated price variance of [redacted] million.

Q. Please identify the primary drivers impacting test period costs at BCC.

A. Test period cost increases are primarily due to: (1) decreased coal deliveries; (2) escalation; and (3) the ending of coal production earlier than assumed in the 2014 Rate Case. Off-setting test period cost decreases are primarily due to: (1) an increase in the coal's heat content; (2) an increase in final reclamation activities (reduces operating costs charged to coal); and (3) other miscellaneous items.

Q. Please identify reduced coal deliveries by source and discuss the impact on delivered coal costs from BCC.

A. As noted in Confidential Figure 9 below, BCC is projected to deliver on a total PacifiCorp basis [redacted] million or [redacted] percent fewer tons in the test period.

Confidential Figure 9

Jim Bridger Plant Coal Deliveries - PacifiCorp Portion

[redacted]

Reduced coal deliveries increase costs expressed on a per ton basis because fixed costs are recovered over smaller volumes. On a Washington-allocated basis, BCC delivered coal costs increased by [redacted] million due to delivering fewer tons in the test period.

Q. Can you provide a directional estimate of the inflationary impact on BCC coal costs in the test period relative to the 2014 Rate Case?

A. Yes. The 2014 Rate Case test period was April 2015 through March 2016 and the current test period is calendar year 2021. The mid-point between the two periods is 5.75 years (October 1, 2015, and July 1, 2021). The compound annual growth rate for the Gross Domestic Product-Implicit Price Deflator (GDP-IPD) for October 1, 2015, through the mid-point in the test period (July 1, 2021) is 2.00 percent. The calculated inflation rate of 12.04 percent is determined by multiplying the annualized growth rate in the GDP-IPD by the appropriate escalation period (5.75 years). On a

Washington-allocated basis, cost increases driven by inflation are estimated at [redacted] million in the test period.

Q. Can you briefly describe the impact of shuttering coal production activities in the test period earlier than was assumed in the 2014 Rate Case?

A. Yes. The 2014 Rate Case assumed the BCC surface mine would continue to produce coal through 2037 and the underground mine would produce coal through 2023. The test period projects surface coal deliveries cease in 2028 and underground mine production terminates in 2021. Early closure of mining operations increased final reclamation contribution amounts and increased depreciation expense expressed on a cost per ton basis. On a Washington-allocated basis, BCC final reclamation contributions increased $[redacted] million and depreciation expense increased $[redacted] million.

Q. BCC cost increases totaling $[redacted] million dollars have been identified above. Please identify cost reductions that result in a total BCC coal cost increase of $[redacted] million.

A. The heat content of BCC coal delivered in the test period is [redacted] Btus per pound which is [redacted] Btus per pound higher than the [redacted] Btus per pound amount assumed in the 2014 Rate Case. This increase in heat content results in a BCC coal cost reduction of $[redacted] million. A BCC coal cost decrease of $[redacted] million is associated with increased final reclamation activities. Final reclamation expenditures are removed from costs charged to coal production. The remaining net cost decrease of $[redacted] million is driven by reductions for materials and supplies and coal inventory.

Q. Did the Black Butte coal price increase in the test period compared to the 2014 Rate Case?

A. Yes. The Black Butte coal price in the test period is based on the existing contract amount of $[redacted] per ton for 2021 which is $[redacted] per ton higher than the $[redacted] per ton, free on board (FOB) mine price assumed in the 2014 Rate Case. Including Union Pacific rail transportation costs from the Black Butte mine to Jim Bridger and application of anti-freeze agent applied to railcars during winter months, the delivered cost of Black Butte coal increased from $[redacted] per ton in the 2014 Rate Case to $[redacted] per ton in the test period, or by $[redacted] per ton. The increased price is primarily due to inflation over the 5.75 year difference. The annualized escalation rate of the Black Butte coal price between the test period and the 2014 Rate Case is slightly lower than the calculated GDP-IPD inflation for the same period.

Colstrip Coal Costs

Q. Did coal prices increase at Colstrip in the test period compared to the 2014 Rate Case?

A. Yes. Coal costs on a Washington-allocated basis increased by $[redacted] million in the test period compared to the 2014 Rate Case.

Q. Please explain the coal supply arrangements for Colstrip.

A. Colstrip is supplied by coal delivered from the Rosebud Mine owned by Westmoreland Rosebud Mining, LLC.

Q. Please describe the price increase associated with the Colstrip coal supply.

A. Coal costs increased from [redacted] per ton in the 2014 Rate Case to [redacted] per ton in the test period, or by [redacted] per ton. The current coal supply agreement expires

December 31, 2019. The new coal supply agreement was fully executed in the first week of December, and will go into effect January 1, 2020. Pricing used in the test period is based on the new coal supply agreement between Westmoreland Rosebud Mining, LLC and the Colstrip owners. The coal price increase on an annualized basis is [redacted] percent. The coal price increase is impacted not only by inflation, but also by a volume decrease of [redacted] percent.

CHANGES TO THE POWER COST ADJUSTMENT MECHANISM

Changes to include PTCs in the PCAM

Q. What changes are the Company proposing to the PCAM?

A. The Company proposes to include PTCs in the PCAM. Under the Company's proposal, PTCs will be trued-up annually in the PCAM outside of the deadband and sharing bands ensuring customers receive actual PTC benefits.

Q. Why is PacifiCorp proposing that PTCs not be subject to the deadbands and sharing bands in the PCAM?

A. As PacifiCorp completes the Energy Vision 2020 projects, leading to new renewable and repowered renewable resources on the system, the PTCs associated with these projects represent a significant source of additional value for customers. The amount of PTCs received is dependent on the amount of generation at eligible facilities. Currently, PTCs are forecast and included in general rates, remaining unchanged until the Company's next general rate case. PacifiCorp's proposal to track and true-up PTCs through the PCAM mechanism—outside of the deadbands and sharing bands—is designed to pass back to customers the full and actual value of PTCs.

Q. Is the Company's proposed treatment of PTCs in the public interest?

A. Yes. The customer will be able to receive the actual benefits from PTCs. Additionally, as PacifiCorp continues to invest in renewable energy resources, including the PTCs in the PCAM without a forecast will allow the Company to pass these benefits to customers in a timely manner.

Q. Has the Commission approved a similar mechanism in the past?

A. Yes. In PSE's 2005 Power Cost Only Rate Case, the Commission approved a stipulation that included a PTC Tracker in PSE's Power Cost Adjustment Mechanism.[28] Similar to what PacifiCorp is proposing, this mechanism was not subject to PSE's Power Cost Adjustment sharing bands.[29]

Q. What is the current level of PTCs included in rates?

A. This case includes approximately $19 million of PTCs.

Q. Will the annual PTC variance be added to the PCAM balancing account?

A. Yes. The annual PTC variance be added to the PCAM balancing account and will be included any PCAM rate change that is triggered.

Other Changes to the PCAM

Q. Is the Company proposing any other changes to the PCAM?

A. Yes. The Company is proposing to change the annual PCAM filing date to June 15 to alleviate a particularly deadline-heavy filing time every year. June 1 is a particularly difficult day because numerous filings are due to state commissions and other regulatory agencies across the Company's six states. In Washington, there are seven

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[28] *WUTC v. Puget Sound Energy, Inc*, Docket No. UE-050870, Order No. 04 at ¶13-14(Oct. 20, 2005).
[16] Docket No. UE-050870, Order 06 at ¶3 (Dec. 21, 2010).

or eight reports, depending on the year, due to the Commission on or around June 1. This is in addition to the reports due to the Department of Commerce and other state agencies. Many of these reports' deadlines are inflexible. PacifiCorp respectfully requests that the Commission adjust the annual due date for PCAM filings to two weeks later to ease the administrative burden.

Additionally, as required by the Commission in the 2015 rate case, EIM benefits have been included in base NPC through this filing.[30] As a result, the non-NPC EIM costs will be removed from the PCAM beginning with the deferral period starting January 1, 2021.

CONCLUSION

Q. Please summarize your testimony.

A. After a lengthy collaborative process, the Company is pleased to present the WIJAM and the 2020 Protocol for Commission review and approval in this case. The WIJAM and the 2020 Protocol meet the needs of PacifiCorp and its customers for a new inter-jurisdictional cost allocation methodology that responds to changes in Washington's state energy policy. The WIJAM provides numerous direct or indirect benefits to Washington customers, including NPC savings, facilitating RPS and CETA compliance, increased PTCs, wheeling revenues, and system diversity. For these reasons, the Company requests that the Commission approve the WIJAM and the 2020 Protocol, including the development of the NPM.

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[30] *WUTC v. Pac. Power and Light Co.*, Docket No. UE-152253, Order 12 at ¶224.

The NPC forecast for the test period reflects a reduction of almost $20 million from NPC now in rates. The Commission should approve this forecast as a fair and reasonable estimation of NPC for the rate effective period.

The Company's proposal to include PTCs in its PCAM, without deadbands or sharing, reflects the importance of delivering 100 percent of this benefit to customers as a component of the Company's NPC. The Company respectfully requests approval of this modification to its PCAM.

Q. What actions are you recommending the Commission take?

A. I recommend that the Commission approve the WIJAM MOU, and adopt the WIJAM as the cost allocation protocol for PacifiCorp which includes:

- All existing system transmission costs and benefits will be allocated using the SG as specified in Attachment 1 to the WIJAM MOU.
- A System Transmission Adjustment Tariff Rider to implement the second and third step of the phase-in of system transmission costs.
- All new transmission will be system allocated using the SG factor specified in Attachment 1.
- All existing and new non-emitting, non-QF resources will be dynamically allocated using the SG factor as specified in Attachment 1 to the WIJAM MOU.
- Approve the acceleration of Jim Bridger and Colstrip to support a final depreciation date of December 31, 2023.

In addition, I also recommend the approval of the proposal outlined in my testimony for the handling of Decommissioning costs. Further, I recommend that the Commission approve the NPM MOU and the associated costs included in revenue requirement.

With regards to NPC, I recommend the approval of a forecast level of NPC outlined in my testimony including the associated modeling changes. Finally, I recommend the following modifications to the PCAM:

- The inclusion of PTCs in the PCAM as described in my testimony
- Adjusting the filing of the annual PCAM from June 1 to June 15.

Q. Does this conclude your direct testimony?

A. Yes.