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July 15, 2019

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

Re: UE 356—PacifiCorp Reply Testimony and Exhibits

PacifiCorp d/b/a Pacific Power hereby submits for filing the Reply Testimony and Exhibits of Michael G. Wilding and Kelcey A. Brown.

Included with this filing is a CD containing the electronic workpapers. Confidential material in support of the filing has been provided to parties under Order No. 16-128.

Please direct any informal correspondence and questions regarding this filing to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosures

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **Reply Testimony and Exhibits** on the parties listed below via electronic mail and/or or overnight delivery in compliance with OAR 860-001-0180.

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UE 356

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Dated this 15th day of July, 2019.

Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

REDACTED
Docket No. UE 356
Exhibit PAC/400
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Michael G. Wilding

July 2019

REPLY TESTIMONY OF MICHAEL G. WILDING

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ATTACHED EXHIBITS

Exhibit PAC/401 – 2020 TAM Oregon-Allocated Net Power Costs Reply Filing

Exhibit PAC/402 – 2020 Results of Updated Net Power Cost Study Reply Filing

Exhibit PAC/403 – 2020 Corrections and Updates Summary Reply Filing

Exhibit PAC/404 – 2020 Other Revenue Reply Filing

Exhibit PAC/405 – 2020 Energy Imbalance Market Costs Reply Filing

Exhibit PAC/406 – Adopted Testimony Excerpts

Q. Are you the same Michael G. Wilding who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp)?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your reply testimony?

A. My testimony has two sections. First, I provide a Transition Adjustment Mechanism (TAM) update (reply update), as allowed under TAM Guidelines adopted by the Commission in Order No. 09-274 and revised in Order Nos. 09-432 and 10-363. In the reply update, I explain the reasonableness of the company's updated and reduced Oregon net power costs (NPC) of $379.2 million for the test period of the 12 months ending December 31, 2020.[1] This results in a rate decrease of $15.1 million or 1.2 percent on an overall basis. I provide corrections and contract, fuel, and forward prices curve updates to the company's April 1, 2019, filing (initial filing).

Second, my reply testimony responds to various issues and adjustments raised in the opening testimony of Public Utility Commission of Oregon Staff (Staff) witnesses Mr. Scott Gibbens, Ms. Sabrina Soldavini, Ms. Moya Enright, and Ms. Kathy Zarate, Alliance of Western Energy Consumers (AWEC) witness Mr. Bradley G. Mullins, and Oregon Citizens' Utility Board (CUB) witnesses Mr. Bob Jenks and Mr. William Gehrke.

Q. Please identify the other witnesses providing reply testimony supporting the 2020 TAM.

A. There is one other witness providing reply testimony in support of the company's

[1] Unless otherwise specified, references to NPC throughout my testimony are expressed on an Oregon-allocated basis.

2020 TAM filing: Ms. Kelcey Brown, who testifies in support of the company's updated calculation of total Energy Imbalance Market (EIM) benefits, and responds to adjustments proposed by Staff witness Moya Enright and CUB witness William Gehrke.

Q. Please summarize your reply testimony.

A. This TAM filing demonstrates how customers have benefited in a tangible and immediate way from PacifiCorp's innovative approach to providing electric service. The customer benefits PacifiCorp has achieved from pioneering and participating in the EIM and from repowering its wind fleet more than offset normal NPC increases, and produce a rate decrease in this TAM. In addition, PacifiCorp continues to refine and improve its NPC modeling to ensure the accuracy of its TAM forecasts in the face of rapidly changing power markets, and work on addressing parties' concerns through collaboration and compromise.

Despite PacifiCorp's effective and efficient operation of its system for the benefit of customers, PacifiCorp has chronically under-recovered its actual NPC in the TAM. In 2018, for example, PacifiCorp under-recovered its actual NPC by more than $20 million. The parties have proposed multiple adjustments that, collectively, would decrease NPC by approximately $44 million, likely resulting in yet another year of NPC under-recovery for the company. The largest adjustment relates to the calculation of EIM benefits and is addressed by company witness Ms. Kelcey Brown. Ms. Brown provides the reply update for EIM benefits, which represents a significant increase. Ms. Brown also explains how the company's new methodology for calculating EIM benefits improves the accuracy of the forecast.

In my testimony, I address Staff's and AWEC's proposal to reflect new resources which will not be in service until mid-to-late 2020 in this TAM. Because the fixed costs of these resources will not be reflected in base rates until January 1, 2021, inclusion of these resources in the 2020 TAM is contrary to the matching principle articulated in Commission precedent and the TAM Guidelines.

Staff and CUB have also proposed a production tax credit (PTC) floor for the company's Energy Vision 2020 (EV 2020) resources in this case. I explain that, by virtue of the company's adoption in this case of the capacity factors used in the company's underlying economic modeling, customers will be receiving the PTC benefits the company projected. For this reason and others, no PTC floor is warranted.

I respond to Staff's flawed adjustment to the company's QF modeling and explain that the Commission recently adopted a new approach to QF modeling, which the company applied in this case. The company's forecast is reasonable and Staff's adjustment to reduce it by amount of the over-forecast in previous years is unnecessary and problematic in its design and application.

Staff has also proposed to change the day-ahead/real-time (DA/RT) adjustment, which has been litigated and upheld by the Commission multiple times. The DA/RT adjustment has been critical in mitigating PacifiCorp's chronic NPC under-recovery; Staff's proposal is based on a misunderstanding of how the DA/RT operates and a miscalculation of the DA/RT price adder.

Staff proposes similar, unwarranted changes to the company's adjustment for economic cycling of its coal units. The company's current approach was developed in collaboration with other parties and reasonably models actual system operations. I demonstrate that Staff's modifications are contrary to the data demonstrating actual system operations and are therefore unreasonable.

I address and respond to Staff's and CUB's modeling concerns regarding the Official Forward Price Curve (OFPC) scalars. I also address Staff's concerns regarding the data underlying the solar hourly shape.

Staff's last adjustment is for wheeling expense. I show that the company's wheeling expense for this TAM is in line with the company's most recent wheeling expense history. Staff's adjustment is based on a selective use of historical data and would produce a less accurate forecast of this cost item.

I respond to AWEC's adjustments for natural gas optimization, a virtual transmission link, and the Gas Transmission Northwest (GTN) tax credit, and show that none of these adjustments is warranted. In each case, the adjustments artificially and unreasonably reduce NPC and decrease the accuracy of the forecast.

Lastly, I respond to CUB's proposal to limit modeling changes in the TAM, and require such changes to be made in a general rate case. CUB's proposal is directly contradicted by the TAM Guidelines. In addition, CUB's rationale for its proposal is flawed. Even though the backcasts performed by PacifiCorp show that Generation and Regulation Initiatives and Decision Tools (GRID) accurately models NPC, the backcasts do not support limiting modeling changes that will continue to ensure that GRID inputs remain accurate and to respond to changes in PacifiCorp's system operations and the markets.

REPLY UPDATE

Q. In the initial filing, the company requested NPC of $354.5 million for the test period ending December 31, 2020. How has your NPC recommendation changed?

A. Test period NPC decreased from $380.5 million to $379.2 million, a $1.3 million reduction from the initial filing. On a total company basis, NPC decreased by $3.5 million, from $1.480 billion to $1.477 billion.

Exhibit PAC/401 shows that PacifiCorp's reply update proposes a rate decrease of $15.1 million. The results of the company's updated NPC study are provided in Exhibit PAC/402. A list of all corrections and updates made, along with the approximate impact of each on NPC, is provided in Exhibit PAC/403. Exhibits PAC/404 and PAC/405 present updated information for Other Revenue and EIM costs, respectively, as contained in the company's reply update.

Q. Please explain the changes reflected in your revised NPC request.

A. First, consistent with the TAM Guidelines adopted in Order No. 09-274 and revised in Order Nos. 09-432 and 10-363,[2] the company made routine updates and corrections to the initial filing and updated the company's proposed NPC with (1) a correction to include Hunter 2 in the economic cycling of coal plants, (2) a correction to the wind plant generation to account for the portion of certain plants that will not be repowered, (3) the removal of Glenrock III repowering, (4) the most recent OFPC and short-term firm transactions, (5) new power, fuel, and transportation/transmission

[2] *In the Matter of PacifiCorp, dba Pacific Power 2009 Transition Adjustment Mechanism*, Docket No. UE 199, Order No. 09-274, Appendix A at 10 (July 16, 2009); *In the Matter of PacifiCorp's 2010 Transition Adjustment Mechanism*, Docket No. UE 207, Order No. 09-432 (Oct. 30, 2009); *In the Matter of PacifiCorp's 2011 Transition Adjustment Mechanism*, Docket No. UE 216, Order No. 10-363 (Sept. 16, 2010).

contracts and updates to existing contracts, and (6) EIM benefits based on most recent actual EIM benefit information as well as the updated OFPC.

Additionally, the company made two changes to the NPC in response to parties' testimony. First, the capacity factors for repowered wind included in the TAM have been updated to match the capacity factors from the company's February 2018 economic analysis for wind repowering (included in the 2017 Integrated Resource Plan (IRP) Update and in docket UE 352, the 2019 Renewable Adjustment Clause (RAC)).[3] Second, the pipeline expense was updated to reflect the current GTN tariff.

Q. Did PacifiCorp previously provide the parties a list of known corrections?

A. Yes. Under the TAM Guidelines, on May 28, 2019, the company provided a list of corrections known at the time. The current filing incorporates those corrections along with several updates identified since the initial filing. The individual corrections and updates and their impact on NPC are identified in Exhibit PAC/403.

Q. Please summarize the major changes in NPC resulting from the reply update.

A. Figure 1 illustrates the change in total-company NPC by category compared to the NPC originally filed in this case.

[3] *In the Matter of PacifiCorp d/b/a Pacific Power 2019 Renewable Adjustment Clause*, Docket No. UE 352, PAC/800, Link/4-5 (May 8, 2019).

FIGURE 1
Net Power Cost Reconciliation

	($ millions)	$/MWh
OR TAM 2020 Initial Filing	**$1,480**	**$24.77**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	($34)	
Purchased Power Expense	($0)	
Coal Fuel Expense	$16	
Natural Gas Fuel Expense	$14	
Wheeling and Other Expense	($0)	
Total Increase/(Decrease) to NPC	**($3)**	
OR TAM 2020 July Update	**$1,476**	**$24.71**

The changes in the components of total-company NPC from the initial filing are largely driven by an increase in the forward market prices for electricity and natural gas. While higher electricity prices increase wholesale sales revenue, this effect is offset by higher coal fuel expense and natural gas fuel expense. Finally, purchase power expense and wheeling expense are mostly flat from what was originally filed.

Q. Please explain the corrections included in the company's reply update.

A. The company included two corrections in its reply update (the NPC impacts are based on the initial filing).

- The Hunter 2 unit should have been included in the coal units allowed to cycle economically. This correction results in a decrease to Oregon-allocated net power cost of approximately $84,000.
- The partially repowered wind plant capacity factor was understated. Correcting this calculation decreased Oregon-allocated net power cost by

approximately $58,000.

Q. Please explain the updates included in the company's reply update.

A. The reply update includes the following updates (the NPC impacts are based on the initial filing):

- **Repowered Glenrock III Wind Facility—**Consistent with the treatment of repowering wind facilities coming online in 2020 and the new assets included in the company's EV 2020 project, the company excluded the impact of Glenrock III repowering in this update. This update increases NPC by approximately $44,000.
- **OFPC and Short-Term Firm Transactions—**The company updated the OFPC from December 31, 2018, to March 29, 2019. On average, market prices for electricity at the Mid-Columbia (Mid-C) and Palo Verde markets increased by approximately nine percent. Similarly, market prices for natural gas increased, on average, by approximately 14 percent. Short-term sales and purchase transactions for electricity and natural gas were also updated through June 1, 2019. These updates increase NPC by approximately $5.2 million.
- **Coal Costs—**The company updated coal costs to reflect changes in prices and volumes, as more fully described below. The update reduces NPC by approximately $1.5 million.
- **Qualifying Facilities (QF) Contract Status—**Two QF contracts have terminated: Mariah Wind and Orem Wind. Another QF contract, Douglas County Forest Product's, will not be renewed at the end of June, 2020. This update decreases NPC by approximately $327,000.

- **EIM Inter-Regional Transfer Benefit and Green House Gas (GHG) Benefits—** PacifiCorp's estimated EIM benefits for 2020 have been updated to include the most recent information through May 2019 and market policy changes at the California Independent System Operator (CAISO) associated with greenhouse gas (GHG) accounting changes. The total expected EIM benefits are [redacted] million, with an increase of [redacted] million, on total company basis. The company has refined its methodology to include GHG benefits, as explained by company witness Ms. Brown.
- **Long Term Contract Status Changes—**The company has terminated two long term contracts: Bonneville Power Administration (BPA) wind sales and Eugene Water & Electric Board (EWEB) exchange contracts. As an exchange, the company acquired the remaining portion of Foote Creek I wind plants owned by EWEB and the Foote Creek I nameplate capacity increased to 40.8 megawatts (MW). This change increases NPC by approximately $281,000.
- **Repowered Wind Facility Capacity Factor—**In response to parties' testimony, the company revised the capacity factors for the repowered wind facilities to align with the company's February 2018 economic analysis for wind repowering (included in the 2017 IRP Update and the 2019 RAC). Incorporating this adjustment in the company's initial filing decreases NPC by approximately $18,000.
- **GTN Pipeline Rates—**As proposed by AWEC, the company included the GTN pipeline rate reduction for 2020. This adjustment decreases NPC by approximately $50,000 on an Oregon allocated basis.

Q. Was there a change to other revenues?

A. Yes. Exhibit PAC/404 shows the update to "Other Revenues" compared to the level included in the initial filing and the 2019 TAM. Projected Other Revenues are approximately $100,000 lower than the 2019 TAM and approximately $32,000 lower than the initial filing. The change in other revenues from the initial filing is driven by the company's acquisition of EWEB's portion of Foot Creek I.

TAM REPLY UPDATE TO COAL COSTS

Q. Please describe the overall impact to PacifiCorp's coal fuel expense in the TAM reply update.

A. Under the TAM Guidelines, PacifiCorp updates coal costs in the reply update to reflect actual and projected changes in coal and transportation contracts that adjust costs. Coal fuel expense for the 2020 TAM has increased from $669.8 million in the initial filing to $685.8 million in the reply update, which reflects an increase of $16.0 million on a total company basis.[4] Higher coal consumed volume increased coal fuel expense by $23.2 million, while the updated prices reduced coal fuel expense by $7.2 million. The reply update increased coal volumes to 18.7 million tons compared to 18.5 million tons in the initial filing.

Q. Please identify the primary drivers of the $7.2 million fuel expense reduction due to lower coal prices in the reply update compared to the initial filing.

A. Affiliated captive mine unit cost reductions result in a [redacted] fuel expense decrease related to additional supplemental coal delivered by Bridger Coal Company (BCC) to Jim Bridger plant as shown in Confidential Figure 2 below. In the reply update, forecast generation at the Jim Bridger plant increased slightly resulting in more fuel required. This increase results in an additional [redacted] tons of

[4] All references to coal costs and revenues in this testimony are on a total company basis, unless noted otherwise.

supplemental coal deliveries from BCC above the base mine plan. Because the incremental BCC coal is produced at a lower unit cost than the base mine plan coal, the total weighted-average unit cost is reduced by delivering additional coal which results in a decrease to fuel expense.

Confidential Figure 2:
Coal and Transportation Contract Price Variance

Plant	Contract	Millions ($)
Naughton	Kemmerer Coal	[redacted]
Wyodak	Wyodak Coal	
Dave Johnston	Coal Creek and Caballo Coal	
Dave Johnston	Refined Coal	
Dave Johnston	BNSF Rail	
Jim Bridger	Bridger Coal	
Jim Bridger	Black Butte Coal	
Jim Bridger	UPRR Rail	
Hunter	Wolverine Coal	
Huntington	Wolverine and Castle Valley Coal	
Cholla	Lee Ranch Coal	
Cholla	BNSF Rail	
Colstrip	Rosebud Coal	
Craig	Trapper	
Hayden	Twentymile Coal and UPRR Rail	
Total Coal Price Increase/(Decrease)		

Third-party coal purchases and transportation unit costs decreases result in a [redacted] fuel expense reduction, primarily due to a [redacted] fuel cost benefit at the Dave Johnston plant related to the new refined coal facility which began operations in May 2019. The initial filing did not include the fuel cost benefit associated with the refined coal agreement because as of the April 1, 2019 filing date, the transaction had not been finalized or approved by the commission. The calculations of the forecast 2020 refined coal benefits at Dave Johnston and Hunter are contained in the coal cost workpapers accompanying the reply update.

An additional [redacted] decrease in fuel cost is due to the April 2019 Request for Proposals (RFP) solicitation for the Dave Johnston plant that is expected to result in the execution of two new coal supply agreements for 2020 that are lower priced than the Powder River Basin market price forecast in the initial filing. In the reply update, forecast generation at Hunter also increased resulting in more fuel required. The additional coal forecast to be procured under the coal supply agreement is at the lower-priced tier-2 pricing which results in a [redacted] reduction in fuel cost at the Hunter plant. [redacted]. These price estimates replace the costs in the 2019 Annual Operating Plan from Western Energy Company, the mine's previous owner, as the basis for the 2020 Colstrip costs in the reply update.

Q. Is PacifiCorp open to discussing the treatment of BCC depreciation costs in a future workshop?

A. Yes. PacifiCorp is amenable to further discussing BCC depreciation issues in a workshop by the end of 2019.

REPLY TESTIMONY

Treatment of New Resources

Q. PacifiCorp expects to bring a number of repowered and new wind facilities into service in mid-to-late 2020. How does PacifiCorp propose to reflect these resources in the 2020 TAM?

A. PacifiCorp plans to include its repowered and new wind facilities with 2020 in-service dates in the 2021 TAM, which PacifiCorp will file in conjunction with a general rate case for rates effective January 1, 2021. These wind resources, along with the Aeolus-to-Bridger/Anticline transmission line, are a key driver of the 2020 general rate case. PacifiCorp's proposal to include these resources in the 2021 TAM, with rates effective January 1, 2021, ensures that the costs and benefits are reflected concurrently in rates.

Q. Can you identify the specific resources that will be included in the 2021 TAM and the upcoming general rate case?

A. Yes. The resources consist of repowered and new wind facilities and a new transmission project. As more fully described in docket UE 352,[5] PacifiCorp's 2019 RAC, PacifiCorp will be repowering three wind resources located in Wyoming by the end of 2020: Glenrock III, a 39 MW facility, Dunlap I, a 111 MW facility, and Foote Creek I, a 41 MW facility. Glenrock III is expected to be in service in the summer of 2020; Dunlap I is expected to be in service in September of 2020 and Foote Creek I is expected to be in service in December 2020.

[5] *In the Matter of PacifiCorp d/b/a Pacific Power 2019 Renewable Adjustment Clause*, Docket No. UE 352, PAC/200, Hemstreet/4 (Dec. 28, 2019).

PacifiCorp also plans to have five new Wyoming wind resources in service by the end of 2020 as a part of its EV 2020 project. This includes TB Flats I, TB Flats II, Cedar Springs II, Ekola Flats and a power purchase agreement (PPA), Cedar Springs I, for a total of 1,150 MW. In addition, EV 2020 also includes a new 140 mile, 500 kilovolt transmission line between the Aeolus substation and the Jim Bridger plant (Aeolus-to-Bridger/Anticline line) to allow the interconnection of these facilities into PacifiCorp's transmission system. PacifiCorp also recently signed a PPA with NextEra for an additional 120 MW of wind at the Cedar Springs III Project. Since this project also depends on the Aeolus-to-Bridger/Anticline transmission to incorporate this resource into PacifiCorp's system, it will be included in the 2021 TAM.

Q. Do Staff and AWEC propose reflecting these new resources in this stand-alone TAM filing (the 2020 TAM), with rates effective January 1, 2020?

A. Yes. Staff recommends reflecting the variable costs and benefits of these new resources in the 2020 TAM, including PTC benefits, and proposes an adjustment of $12.2 million.[6] Notably, this amount does not reflect any offset for the matching fixed costs of the resources. AWEC proposes to include the incremental production of the wind facilities repowered in 2020 and the incremental production and transmission benefits of the EV 2020 project, but has not quantified its adjustment.[7]

PacifiCorp opposes these adjustments because inclusion of the benefits of the repowered and new resources in the 2020 TAM, with rates effective January 1, 2020, will result in variable resource benefits being reflected in rates in advance of the fixed

[6] Staff/100, Gibbens/12-13.
[7] AWEC/100, Mullins/12-13.

costs—and months in advance of the in-service date of the resources—contravening Oregon law and Commission precedent as described in my testimony below.

Q. Is PacifiCorp's reply position to include all 2020 repowered wind resources in the 2021 TAM a change from the initial filing?

A. Yes. In the initial filing, PacifiCorp proposed to include the repowered Glenrock III facility in the 2020 TAM, on the condition that the costs be matched in rates through a RAC filing in 2020. The company made this proposal in advance of the litigation of the 2019 RAC, however, which demonstrated the challenges of trying to match renewable resource costs and benefits in rates without deferred accounting for capital costs, and the incongruity of litigating the prudence of new resources after the benefits of these resources have already been reflected in rates. To minimize these challenges and to remain consistent with the important principle of matching costs and benefits in rates, the company is now proposing to treat Glenrock III in the same manner as all other repowered and new wind facilities, which means it will be included in the 2021 TAM, not the 2020 TAM. Removing Glenrock III increases the 2020 TAM by approximately $600,000, including both the NPC and PTC benefits.

Q. Is PacifiCorp's proposal to include the 2020 repowered and new wind facilities in the 2021 TAM instead of this case directly supported by Commission orders in dockets UM 1330 and UM 1662?

A. Yes. In Order No. 07-572 in docket UM 1330, the Commission adopted the principle that the costs and benefits of renewable resources must be matched in rates.[8] This was based on section 6(j) of a stipulation, signed by PacifiCorp, Staff, AWEC's predecessor Industrial Customers of Northwest Utilities (ICNU), and CUB,[9] which provides:

> **Matching of Costs and Benefits in RAC Schedules and Annual Power Cost Updates**: The Parties agree that if the fixed costs of an eligible resource are not included in RAC charges or otherwise included in rates, then the variable costs and cost offsets of the eligible resource should likewise not be included in the annual power cost update filings or power cost adjustment mechanisms.

In docket UM 1662, the Commission determined that ORS 469A.120(2), the broad cost recovery provision in Oregon's renewable portfolio standard (RPS), mandates dollar-for-dollar recovery of prudent, fixed costs in RPS-compliant resource investments.[10]

Including the repowered and new wind resources in the 2021 TAM results in an exact matching of the rate effective date for both the resources' costs and benefits. In contrast, including these resources in the 2020 TAM delivers benefits to customers effective January 1, 2020, while fixed cost recovery lags and remains uncertain for another year.

[8] *In the Matter of Public Utility Commission of Oregon, Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket No. UM 1330, Order No. 07-572, at 5 (Dec. 19, 2007) (explaining "the Joint Parties agree that, if the fixed costs of an eligible resource are not included in RAC charges, or otherwise included in rates, then the variable costs and cost offsets of the eligible resource likewise should not be included in the annual power cost update filings or power cost adjustment mechanisms."). *See also* PAC/600, Lockey/5, 7 & n.13.
[9] The stipulation in docket UM 1330 was also signed by Portland General Electric Company.
[10] *In the Matter of Portland General Electric Company and PacifiCorp, dba Pacific Power, Request for Generic Power Cost Adjustment Mechanism Investigation*, Docket No. UM 1662, Order No. 15-408, at 7 (Dec. 18, 2015) (analyzing ORS Section 469A.120(2)).

Q. Is PacifiCorp's proposal to include the 2020 repowered and new wind resources in the 2021 TAM supported by the provisions of the TAM Guidelines addressing the treatment of new resources?

A. Yes. In the 2010 TAM, the parties (PacifiCorp, Staff, AWEC's predecessor ICNU and CUB) stipulated that a new resource would be included in the TAM without fixed cost recovery only if (1) the resource is not eligible for recovery under the RAC (i.e., where unconditional matching of costs and benefits is required); and (2) it comes into service before April 1 in the year of the TAM filing.[11] The Commission adopted this guideline in Order No. 09-432.

Here neither condition is met because PacifiCorp's new resources are RAC eligible and will not come into service before April 1, 2019. Thus, the TAM Guidelines explicitly exclude their inclusion in the 2020 TAM.

Q. Is PacifiCorp's proposal to include the 2020 repowered and new wind resources in the 2021 TAM supported by the provisions of the TAM Guidelines addressing prudence determinations for new resources?

A. Yes. Also in the 2010 TAM stipulation adopted in Order No. 09-342, the parties agreed that the Commission would determine the prudence of a new resource in the TAM before the variable costs and dispatch benefits would be reflected in rates. Thus, under the TAM Guidelines, before the Commission can reflect PacifiCorp's repowered and new resources in the 2020 TAM, it needs to determine that these resources are prudent. PacifiCorp intends to present evidence of prudence in its 2020 general rate case. It is inefficient and impractical to conduct an accelerated prudence

[11] *See In the Matter of PacifiCorp d/b/a Pacific Power, 2010 Transition Adjustment Mechanism*, Docket No. UE 207, Order No. 09-432 at 4 (Oct. 30, 2009).

review in this case, when the in-service dates of the resources are more than one year in the future.

Q. Have Staff and other parties previously relied on this guideline to exclude variable costs and benefits from the TAM in advance of a prudence determination?

A. Yes. In the 2018 TAM, Staff and CUB argued that the variable costs associated with the installation of selective catalytic reduction (SCR) equipment at the Jim Bridger plant should be excluded from the TAM because the Commission had not determined that the SCRs were prudent.[12] CUB made a similar argument in the company's 2017 TAM proceeding.[13] In both proceedings, the company agreed to remove the impact of the SCR equipment from the TAM.

In this case, Staff witness Ms. Kathy Zarate repeats this position in testifying that PacifiCorp properly excluded the impact of the Jim Bridger SCRs: "I note that given that the Commission has not determined the prudence of the upgrades, PacifiCorp's treatment is consistent with that lack of determination of prudence."[14] Staff has not explained why it invokes the TAM guideline on prudence determinations to support the exclusion of SCR-related impacts from this TAM, while ignoring this guideline to support the inclusion of new resources in this TAM.

Q. What is the basis for Staff's recommendation to include the repowered and new wind facilities in the 2020 TAM?

A. Staff relies on a limited view of existing Commission policy and precedent and

[12] *See* Docket UE 323, Staff/200, Kaufman/25; *see also* Docket UE 323, CUB/100, Jenks/2-3.
[13] *See* Docket UE 307, CUB/100, McGovern/7.
[14] Staff/400, Zarate/4.

claims that the Commission's 2017 IRP acknowledgment order requires Staff's preferred outcome. [15]

Q. Is PacifiCorp's proposal to include its new wind resources in the 2021 TAM consistent with Commission policy and precedent?

A. Yes. As outlined above, PacifiCorp's proposal is directly supported by all relevant precedent. Staff relies on Order No. 07-572 adopting the RAC stipulation, but it omits any mention of section 6(j) of the stipulation in which Staff expressly agreed that the variable benefits of a resource should not be included in the TAM if the fixed costs are not concurrently reflected in rates. Under section 9, Staff agreed to continue to support the stipulation in subsequent proceedings, and Staff remains bound by this position.

Staff points to the fact that the RAC was designed to cover costs not captured in the TAM.[16] While this is true, it does not support Staff's position that the benefits of PacifiCorp's new resources should be reflected in the TAM before the costs are reflected in rates.

Q. Does Staff mischaracterize any other Commission orders in support of its argument that the company's proposal is inconsistent with precedent?

A. Yes. Staff cites Order No. 15-408 from docket UM 1662, where the Commission rejected proposals to allow dollar-for-dollar recovery of variable RPS compliance costs.[17] Staff again fails to explain how this order supports its position that the variable benefits of PacifiCorp's new resources should be reflected in the TAM

[15] Staff/100, Gibbens/7-8.
[16] Staff/100, Gibbens/8-9.
[17] Staff/100, Gibbens/9.

before the fixed costs are reflected in rates. As noted above, the order affirms PacifiCorp's entitlement to dollar-for-dollar recovery of its prudent fixed costs for RPS eligible resources.

Staff also cites Order No. 16-482 from the 2017 TAM, allowing the company to provide an annual update of PTCs in the TAM. The order addresses how the company should make PTC updates for resources already in base rates; it did not address how PTCs for new resources, or repowered resources whose incremental fixed costs are not yet reflected in base rates are to be handled in the TAM.[18]

Q. Is Staff's position consistent with the TAM Guidelines on treatment of new resources?

A. No. Staff does not cite to the TAM Guidelines on the treatment of new resources. Staff also fails to reconcile its position here with its continuing obligation to support the underlying stipulation in docket UE 207, which proposed the TAM guideline on new resources.

Q. Does Staff rely on the Commission's acknowledgment order in the 2017 IRP docket to support its position?

A. Yes. Staff claims that PacifiCorp's decision to exclude repowered and new wind facilities from the 2020 TAM is inconsistent with the Commission's guidance in Order No. 18-138, which acknowledged the company's 2017 IRP and noted that cost recovery *may* be conditioned or limited to remain at least as favorable as IRP planning assumptions.[19] Without mentioning cost recovery, Staff claims that the company's proposal would allow PacifiCorp dollar-for-dollar recovery of the benefits

[18] Order No. 16-482 at 2, fn. 3.
[19] Staff/100, Gibbens/11-12, *citing* Commission Order No. 18-138 at 8.

of the EV 2020 resources that come online during 2020, despite the fact that PacifiCorp will not receive any fixed cost recovery until January 1, 2021, at the earliest.[20]

Q. Do you agree with Staff's position?

A. No. The Commission has not yet reviewed the prudence of the 2020 repowering projects or the new wind and transmission components of EV 2020, therefore it is premature for the Commission to determine whether conditions on cost recovery or reflection of benefits from these facilities is appropriate. In addition, the company's proposal does not, as Staff claims, allow dollar-for-dollar recovery of EV 2020 resource benefits. Under the company's proposal, the Commission will have the opportunity to holistically consider the costs and benefits of EV 2020 and can reflect both in rates—with or without conditions—concurrently and shortly after the in-service date of the new resources. During the period of regulatory lag in 2020, there will be no recovery of costs or reflection of benefits in rates.

Order No. 18-138 was specific to conditioning cost-recovery of the EV 2020 resources and did not modify the well-established matching principle adopted in Order No. 07-572 in docket UM 1330 or the treatment of new resources in the TAM adopted in Order No. 09-432 in docket UE 207.

Finally, the Commission specifically stated that the risks of proceeding with EV 2020 "remain with PacifiCorp unless and until the Commission completes a prudence review and approves cost recovery of these resources in rates."[21] The company's approach is consistent with that provision because, until the Commission

[20] Staff/100, Gibbens/12.
[21] Order No. 18-138 at 8.

determines that PacifiCorp's repowered and new wind facilities are prudent, neither the costs nor benefits are included in rates.

The company's proposal maintains the Commission's ability to consider whether and how to condition cost recovery of EV 2020 by ensuring holistic and concurrent review by the Commission of both the costs and benefits in a general rate case and concurrently filed TAM.

Q. What are AWEC's objections to PacifiCorp's proposal to include its repowered and new 2020 wind resources in the 2021 TAM?

A. AWEC claims that PacifiCorp's proposed approach is inconsistent for different resources. AWEC also claims that the Commission should not rely on PacifiCorp's clear and consistent representations that it will file a general rate case in 2020.[22]

Q. Has PacifiCorp taken a consistent position on treatment of new resources in the TAM?

A. Yes. PacifiCorp has consistently followed Commission precedent requiring the matching treatment of the costs and benefits of new resources. In the 2019 TAM, in light of ongoing uncertainty regarding the ability to use capital deferrals, PacifiCorp attempted to achieve this result through a stipulated, specially-designed RAC filing. In the 2021 TAM, PacifiCorp will achieve this result by filing a concurrent general rate case. To the extent that AWEC had concerns about PacifiCorp's initial proposal to treat Glenrock III differently than other resources repowered in 2020, PacifiCorp's reply testimony responds to this by treating Glenrock III the same as all other 2020 resources.

[22] AWEC/100, Mullins/11.

Q. AWEC argues that the Commission should not rely on PacifiCorp's plan to file a rate case, and assume the company will file a RAC to include new resources in rates.[23] Please respond.

A. PacifiCorp has consistently maintained its intent to file a general rate case in 2020. Indeed, PacifiCorp's pending depreciation study already reflects a requested rate effective date of January 1, 2021, which is intended to align with the rate effective date of PacifiCorp's 2020 general rate case filing. AWEC provides no evidence to support its position. In addition, even if AWEC's unfounded fear comes to fruition, a 2020 RAC filing would have the same rate effective date as a 2020 general rate case: January 1, 2021. Therefore, under either scenario, general rate case or RAC, it is premature to reflect the new resources in the 2020 TAM.

Q. AWEC specifically notes that its position on the treatment of new resources in the TAM does not indicate that it has concluded that these resources are prudent.[24] Is this position contrary to the TAM Guidelines?

A. Yes. As noted above, before a new resource may be reflected in the TAM, the Commission must make a prudence determination.

PTC Floor for Repowered Facilities and EV 2020 Resources

Q. Does the 2020 TAM reflect the wind facilities PacifiCorp expects to repower in 2019?

A. Yes. Under the stipulation adopted in the 2019 TAM, the 2020 TAM includes the benefits of the repowered wind facilities that will come online in 2019.[25] This

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[23] AWEC/100, Mullins/12.
[24] AWEC/100, Mullins/13.
[25] *See In the Matter of PacifiCorp, d/b/a Pacific Power, 2019 Transition Adjustment Mechanism*, Docket No. UE 339, Order No. 18-421 at 3-4 (Oct. 26, 2018).

includes the repowering of 773.5 MW at the Leaning Juniper, Seven Mile Hill I, Seven Mile Hill II, Glenrock I, Goodnoe Hills, High Plains, McFadden Ridge, Marengo I, and Marengo II wind facilities. The reflection of these benefits in the TAM was conditioned on the matching costs being included in rates concurrently through the 2019 RAC, a result that a pending, all-party stipulation in that case now seeks to effectuate. The benefits for these facilities in the reply update total $25.1 million.

Q. How are PTC benefits passed back to Oregon customers?

A. PTCs are passed back to customers in the TAM and are calculated based on the generation included in the NPC study. In its reply update, the company has adjusted the repowered wind capacity factors to match the February 2018 analysis so customers are now receiving the PTCs that were included in the February 2018 economic analysis.

Additionally, the PTCs are included in the company's power cost adjustment mechanism (PCAM) where the actual PTCs can be trued-up to what was included in the TAM, along with NPC. However, because of the deadbands and earnings test the PCAM has never triggered a rate change.

Q. Please describe the conditions Staff proposes with respect to PTC guarantees for repowered wind facilities and all EV 2020 resources.

A. Staff recommends the Commission "impute values of net PTC benefits that are no less than the [c]ompany included in its February 2018 analyses."[26] Staff further

[26] Staff/100, Gibbens/25.

recommends exempting benefits of wind repowering from the deadband, sharing, or earnings test provisions in PacifiCorp's annual PCAM.[27]

Q. What is CUB's position on a PTC floor?

A. CUB recommends the Commission impose a "[PTC] floor on the [c]ompany's repowered wind projects with a duration of ten years."[28] CUB further proposes that this "PTC floor" should be based on "the expected generation assumed by the [c]ompany in its February 2018 analysis."[29] Unlike Staff, however, CUB does not propose to impute PTC values in the TAM.[30]

Q. Did Staff and CUB initially make similar proposals for a PTC floor in the 2019 RAC, which they withdrew to pursue the issue in this case?

A. Yes. PacifiCorp filed extensive testimony in response, including the reply testimony of Ms. Etta Lockey,[31] Mr. Tim Hemstreet,[32] and Mr. Rick Link.[33] Rather than repeat all of that testimony, I am attaching the relevant excerpts of this testimony as Exhibit PAC/406 and adopting that testimony here.

Q. What risk related to wind production estimates are raised by the parties?

A. Staff states that customers face a risk that actual generation from the repowered facilities will be less than forecast resulting in lower PTCs than estimated.[34] CUB recommends that the Commission set a "PTC floor" that would guarantee that

[27] *See* Staff/100, Gibbens/25.
[28] CUB/200, Gehrke/8.
[29] OPUC/200, Gehrke 8.
[30] CUB/200, Gehrke/8.
[31] *In the Matter of PacifiCorp d/b/a Pacific Power 2019 Renewable Adjustment Clause*, Docket UE 352, PAC/600, Lockey/12-17. (May 8, 2019).
[32] *In the Matter of PacifiCorp d/b/a Pacific Power 2019 Renewable Adjustment Clause*, Docket UE 352, PAC/700, Hemstreet/3-7. (May 8, 2019).
[33] *In the Matter of PacifiCorp d/b/a Pacific Power 2019 Renewable Adjustment Clause*, Docket UE 352, PAC/800, Link/7-14. (May 8, 2019).
[34] Staff/100, Gibbens/24.

customers receive at least the projected value of the PTC benefit from the wind repowering project that was included in the company's economic analysis.[35]

Q. Does PacifiCorp agree with these recommendations?

A. No. A PTC floor shifts risk to PacifiCorp for situations beyond the company's control, such as extreme weather events, wind conditions that deviate from the prior operational history, or other unforeseen circumstances. This condition is unprecedented as the Commission has never adopted a mechanism that requires the company to guarantee the generation output from its wind facilities. It is also unwarranted because PacifiCorp's use of actual historical generation data, combined with the conservative use of this data to determine forecasted energy production for the repowered facilities, supports the accuracy of the company's forecast of customer benefits associated with PTCs.

Q. Please elaborate on your last point regarding how the company developed its PTC forecast.

A. As described in my opening testimony,[36] the company's estimate of the energy production (and thus capacity factors) for the repowered facilities is based on the extensive historical data of the currently-operating wind facilities.[37] This data includes actual curtailments, as well as planned and unplanned outages experienced at each of the facilities. Relying on the actual production history is more conservative and more accurate than relying upon estimates of how these impacts may affect energy production following repowering.

[35] CUB/100, Gehrke/8.
[36] PAC/100, Wilding/34-36.
[37] PAC/200, Wilding/34.

Q. Does the company's use of actual historical data to forecast energy production appropriately apportion risk between the company and customers?

A. Yes. As explained in Tim Hemstreet's direct testimony in the 2019 RAC, the energy estimates developed by the company are intentionally conservative to reduce risk to customers.[38] As further detailed in that testimony, technological advances that will be installed as part of the wind repowering project are likely to reduce turbine down-time, but these improvements to availability (compared to historical availability) were not included in the company's energy estimates.[39] As a result, energy production could be more than estimated and the risk alleged by Staff is unlikely. It is also important to note that availability guarantees further protect customers from the alleged risk that repowering will not increase generation as expected. The service and maintenance contracts that the company has entered into for the repowered facilities include availability guarantees that require the service providers to compensate the company for lost generation as a result of failing to meet guaranteed availability targets. Thus, customers are protected from risks that equipment down time will hamper production, and thus PTC benefits.

Q. Are there any other reasons that setting a PTC floor is inappropriate?

A. Yes. Setting a PTC floor requires the company to hold customers harmless and bear the associated risk from natural, variable wind conditions that are beyond its control. While there is no reason to expect long-term wind conditions to deviate substantially from past experience, differences in future frequency, duration, and intensity of wind

[38] *In the Matter of PacifiCorp d/b/a Pacific Power 2019 Renewable Adjustment Clause*, Docket No. UE 352, PAC/200, Hemstreet/13-14 (Dec. 28, 2019).
[39] *In the Matter of PacifiCorp d/b/a Pacific Power 2019 Renewable Adjustment Clause*, Docket No. UE 352, PAC/200, Hemstreet/14 (Dec. 28, 2019).

speed conditions will impact performance of the repowered turbines (and the resulting PTC Value). It is unfair for the company to unilaterally bear this risk.

If the Commission were to adopt a PTC floor, it would only be fair to also adopt the corollary, *i.e.*, that the company should solely benefit from any energy and PTC value produced from the repowered wind facilities that surpass the values included in the company's economic analysis.

Q. Do you have other concerns with a PTC floor condition?

A. Yes. Imposing a PTC floor could have unintended consequences because it is possible that the company could operate the wind facilities differently than it has historically and forecast in the company's economic analysis and create less PTC value, but still deliver equivalent or greater benefits to customers. This could occur if market conditions signal a dispatch of the facilities that is different than historical dispatch but that is more economic for customers. For instance, curtailment of the facilities during certain market and load/resource conditions could be more economic than running the facilities. Additionally, curtailment could be warranted under some conditions if it reduced equipment failure or maintenance requirements, thereby saving operational costs. A PTC floor would dictate the operational regime of the facilities to produce the highest PTC value, even if that regime doesn't provide the greatest benefit to customers.

Q. Could a PTC floor condition create other problems?

A. Yes. Parties have been unclear in articulating how the PTC value would be determined. Specifically, it is unclear if a PTC floor would require that a certain energy production floor be mandated, or simply that the PTC value in the company's economic analysis be guaranteed to customers. Because the value of the PTC for customers depends on the company's effective federal and state corporate tax rate, providing a PTC floor could require that the company hold customers harmless should these corporate tax rates be reduced. This would have the unreasonable effect of benefiting customers due to reduced income tax collected through rates, while also requiring the company to hold the PTC value constant for customers.

Q. Are economic backstops for the wind repowering project necessary?

A. No. No party has argued that the wind repowering project is imprudent, or that the wind repowering project presents risk factors different from normal resource acquisition that would warrant adoption by the Commission of extraordinary rate making conditions. Indeed, in the 2019 RAC, both Staff and CUB agreed that PacifiCorp decision to repower its wind facilities was prudent.[40]

Q. Contrary to Staff's position, is it premature for the Commission to determine PTC treatment for resources not included in this case, including the repowered and new wind facilities that will come on line in 2020?

A. Yes. The Commission should not consider the issue of a PTC floor for the new wind facilities that are part of the EV 2020 project before these facilities are subject to Commission review in PacifiCorp's 2020 general rate case.

Modeling QF contracts

Q. Please explain Staff's proposal to adjust PacifiCorp's QF contract costs.

A. Staff proposes to reduce QF contract costs in this case by approximately 5.5 percent to account for past over-forecasts of total QF costs. The adjustment reduces NPC by

[40] *In the Matter of PacifiCorp d/b/a Pacific Power 2019 Renewable Adjustment Clause*, Docket No. UE 352, Staff/100, Storm/56; CUB/200 Jenks-Gehrke/4.

approximately $5.3 million.

Q. Did the company model QF contracts using the contract delay rate (CDR) approved by the Commission in the 2018 TAM, docket UE 323?

A. Yes. As I noted in my direct testimony, PacifiCorp applied the CDR to all the new QFs coming online in the test period. The CDR is calculated based on the average days between the QF's expected Commercial Operation Date (COD) in the final TAM and its actual COD (or more recently estimated COD) from the last three TAM cases, weighted by the size of the delayed QF.[41]

Q. In this case, will the company continue to follow the attestation process for QF CODs, adopted in the 2015 TAM?[42]

A. Yes. Under this process, in the final update, the company attests to the projected QF CODs, stating that, based on the information known to it at the time of filing, it has a commercially reasonable good faith belief that these QFs will reach commercial operation before or during the forecast period.

Q. In adopting the CDR, did the Commission note that it would provide an incentive for the PacifiCorp to more conservatively estimate CODs beginning in the 2019 TAM?

A. Yes.

Q. Were the QF forecast costs in the 2018 TAM within two percent of the actual QF costs?

A. Yes. In the first year of the CDR's full application, the delta between forecast and

[41] PAC/100, Wilding/14.
[42] *In re PacifiCorp d/b/a Pacific Power's 2015 Transition Adjustment Mechanism*, Docket No. UE 287, Order No. 14-331 at 5 (Oct 1, 2014) (adopting stipulation that added the attestation process).

actual QF costs was less than one-half of the delta of any other year within the last four-year period. Based on this limited data the CDR appears to be working as designed, and in fact, the company's forecast of CODs for new QFs is improving as evidenced by the decreasing CDR in each TAM.

Q. Why does Staff propose a QF adjustment now, even though this is only the second year of the CDR's application?

A. Staff claims the CDR is inadequate, but bases this argument on the average over-forecast of QF costs for a four-year period that mostly precedes adoption of the CDR—2015-2018, where only one year, 2018, used the CDR.

Q. How does Staff calculate its adjustment?

A. Staff reviewed the difference in forecasted and actual QF costs between 2015 and 2018. Staff calculated an average over-forecast for this period of six percent. Staff subtracted a small amount to credit the CDR adjustment, leaving an average over-forecast rate of just over 5.5 percent. Staff applies that on top of the CDR-based QF forecast in this case to reduce QF costs by $5.2 million.

Q. Please explain your objections to this adjustment.

A. On its face, Staff's adjustment appears to violate the rule against retroactive ratemaking. Notwithstanding the fact that PacifiCorp under-recovered total NPC throughout 2015-2018, Staff isolates one cost item, calculates an average over-forecast of approximately 5.5 percent, and seeks to adjust forward-looking rates by that amount to true-up that over-forecast. Staff has not reviewed the new QF PPAs in this case to determine whether an across the board discount of 5.5 percent is reasonable or rational, nor has it considered the facts that its average is based mostly on pre-CDR years. Additionally, Staff's Confidential Table 4 portrays the differences between the forecasted QF costs and actual QF costs as being attributed to new QFs when in fact those cost numbers are the total cost numbers for all QFs.

Q. Are there other problems with Staff's QF adjustment?

A. Yes. Staff's proposal is one-sided by removing the cost of QF PPAs without removing the energy associated with these QF costs, essentially providing customers with free energy.

Coal Economic Cycling

Q. Please describe the issue related to modeling the economic cycling of coal plants.

A. In the 2018 TAM, Staff proposed an adjustment intended to model the economic cycling of coal plants, which had occurred in limited historical circumstances based on unusual market conditions in 2016 and 2017. The Commission rejected Staff's adjustment but expressed an interest in understanding how PacifiCorp's operations may be changing under evolving market conditions.[43]

Q. Did the company propose to model economic cycling of coal plants in the 2019 TAM and 2020 TAM?

A. Yes. In response to the Commission's interest and after workshops with Staff and other parties, PacifiCorp proposed modeling economic shutdowns for coal plants that are majority-owned by the company, not participating in the EIM, and not under operational constraints that would preclude an economic shutdown in the 2019. This modeling was agreed to by Staff in the 2019 TAM stipulation and the same modeling

[43] Order No. 17-444 at 11.

is used in the 2020 TAM. The economic cycling of coal plants reduced total company NPC by approximately $1.5 million in the initial filing.[44]

Q. How does the company model economic cycling?

A. The cycling period (*i.e.*, when a coal unit could be shut down for economic reasons) will run from February 1 to May 31, which corresponds to the spring hydro run-off period when loads are generally lower, weather is typically mild, market prices are lower, and solar imports from California are increasing.

Under the company's proposal, the "must run" setting in GRID for the eligible coal plants is removed and these plants are dispatched based on economics during the cycling period. The eligible coal plants incorporate the minimum up time, minimum downtime and startup costs as part of the economic dispatch parameters. The number of startups during the entire cycling period is limited to no more than four.

Q. What are the results of the company's economic cycling modeling and how do the results compare to actual coal operation experiences?

A. Confidential Figure 3 below compares the actual coal plant economic cycling in days from the year 2015, 2016, 2017, 2018, year to date 2019 and forecasted 2020. The table shows the 2020 forecast results in coal plants being offline for [redacted] hours or approximately [redacted] megawatt hours (MWh) which is higher than the total economic cycling hours in [redacted], the year with the highest number of economic cycling hours in the past five years. Based on the market price forecast and market condition forecast for 2020, PacifiCorp believes the coal economic cycling forecast for 2020 will reasonably capture possible economic cycling of coal units during 2020.

[44] PAC 100/Wilding Page 17

CONFIDENTIAL FIGURE 3

[redacted]

Q. Does Staff recognize that the company's method for modeling economic cycling produces more economic cycling hours than are realized in actual operation?

A. Yes. Staff points out that the GRID model cycled certain coal plants off for [redacted] hours compared to an average of [redacted] hours over the last two years.[45]

Q. If GRID is already producing more economic cycling than is achieved in actual operations why is Staff recommending changes to the modeling of coal plants?

A. Staff claims there are additional potential savings that can be realized by relaxing the parameters around which economic cycling is modeled.[46] Staff seems to imply that modeling more economic cycling in the TAM will lead to more economic cycling in actual operations, but this is a false premise. The TAM is a rate making mechanism to accurately forecast NPC costs; driving down NPC by cycling off more coal plants will only decrease the accuracy of the TAM by disconnecting it from the reality of actual system operation.

Q. Please summarize Staff's concerns with PacifiCorp's process of modeling economic cycling.

A. Staff seeks three changes in the company's process of modeling economic cycling. The first is to remove the four-month restriction and permit GRID to economically

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[45] Staff/300 Enright 17.
[46] Staff/300, Enright/18.

cycle a plant in any month. The second is to model economic cycling for non-majority owned units. The third is for PacifiCorp to conduct a cost benefit analysis of allowing EIM participating units to economically cycle in GRID.

Q. Please describe Staff's position on the four-month period of economic cycling in GRID.

A. Staff claims PacifiCorp can attain additional benefits by modeling economic cycling for the entire year, not just during the traditional period of February 1 to May 31.[47] Staff states actual economic cycling occurred 17 percent of the time outside the traditional economic cycling period for the years 2014 to 2018.[48]

Q. Does the company agree with Staff's analysis of economic cycling?

A. No. Staff analyzed the details of economic cycling carried out by any company plant for the period 2014 through 2018. Staff considered economic cycling as any unit whose event type is classified by North American Electric Reliability Corporation as a reserve shutdown. Of the reserve shutdowns analyzed by Staff, [redacted] followed or preceded a maintenance or a planned outage. These very short extensions of maintenance-related outages (a few hours or days) are not the same as a one-or-two month shutdown of a plant for economic reasons.

PacifiCorp periodically extends outages for several hours or days for various operational reasons, including if there is no immediate need to bring the unit back online when the outage is over. Extending an outage for several additional hours should not be included in Staff's analysis of actual economic cycling.

[47] Staff/300, Enright/18.
[48] Staff/300, Enright/19.

After removing shutdowns that followed or preceded an existing outage, only six percent of reserve shutdowns occurred outside the traditional economic cycling period during 2014 through 2018. This is compared to the 17 percent computed by Staff.

In addition, in 2016, certain coal plants were displaced by historically low natural gas prices, which allowed greater dispatch of gas plants instead of coal plants. Calendar year 2016 was an anomaly that is not expected to recur in 2020. After removing 2016 economic cycling from the previously mentioned analysis, the percentage of economic cycling outside the traditional period goes from six percent to zero percent. This validates that economic cycling by the company only occurs during the traditional economic cycling period in the spring.

Q. Please respond to Staff's proposal that PacifiCorp model economic cycling for non-majority owned units.

A. Staff requests that PacifiCorp conduct a case study by running GRID without this restriction to determine which units can be economically cycled. Because the decision to economically shut down each unit is unique, however, it is not possible for PacifiCorp to adequately capture the unique and often times noneconomic variables that are considered when deciding whether to shut down a coal plant. Therefore, working with joint-owners to predict economic cycling would be complex, time-consuming, and non-conclusive. While it is possible to model in GRID economic cycling of non-majority owned units, syncing actual operations to such a forecast is not feasible.

Q. Staff proposes PacifiCorp conduct a cost benefit analysis of allowing EIM participating units to economically cycle in GRID.

A. Staff's proposal presumes that there are more benefits to economically cycling units instead of offering the units into the EIM.[49] But participating in the EIM automatically finds the lowest-cost energy to serve real-time customer demands. It does not make sense to economically cycle EIM participating units because the EIM is already producing the lowest cost energy for customers.

Additionally, of the three EIM participating units that were economically cycled units in 2018, the Jim Bridger 3 and Dave Johnston 4 shutdowns either preceded or followed a maintenance outage, which means these should not be considered actual economic shutdowns. The Hunter 3 shutdown was an isolated instance and that shutdown was only six days which is not comparable to a one-or-two month shutdown of a plant for economic reasons.

Day-Ahead and Real-Time System Balancing Transactions

Q. Please describe the DA/RT adjustment that the Commission approved in the 2016, 2017, 2018, and 2019 TAMs.

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, in the 2016 TAM, the company proposed the DA/RT adjustment to more accurately model system balancing transaction prices and volumes. In the 2016 and 2017 TAMs, Staff, CUB, and ICNU objected to the DA/RT adjustment. The Commission rejected their

[49] Staff/300, Enright/21.

arguments and approved the adjustment, concluding that it more accurately reflected the costs of system balancing transactions in the company's NPC forecast.[50]

In the 2018 TAM the Commission modified the DA/RT adjustment to use only post-EIM years as proposed by ICNU. Notably, in the 2019 TAM no party opposed the DA/RT adjustment.

Q. Please describe how system balancing transactions are included in GRID.

A. System balancing transactions are required to balance the hourly load and resources in the GRID model for the TAM test period. The GRID model calculates the least-cost solution to balance the company's load and resources 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.

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 forecasted 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.

[50] *In the Matter of PacifiCorp d/b/a Pacific Power's 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 4 (Dec. 11, 2015); Order No. 16-482 at 13.

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

A. Before the 2016 TAM, the GRID model used an hourly price curve developed from monthly Heavy Load Hour (HLH) and Light Load Hour (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. What is Staff's recommendation regarding the DA/RT adjustment?

A. Staff proposes that the DA/RT adjustment price component use the daily market price, rather than the monthly average market price to calculate the DA/RT price adders. Staff calculated the DA/RT price adjustment based on the proposed daily method and identified a significant difference in adjustment values, but Staff has not quantified the NPC impact of its proposal.

Q. Did Staff make any adjustment to the volume component of the DA/RT adjustment?

A. No.

Q. Does Staff's recommendation to the price component of the DA/RT adjustment have merit?

A. No. Staff's recommendation ignores the fundamental purpose of the price component of the DA/RT adjustment which is, as stated above, to better reflect in GRID the market prices available to the company when it transacts in the real-time market. These prices account for the historical price differences between the company's purchases and sales compared to the monthly average market prices. In other words, the price component of the DA/RT adjustment accounts for the system balancing costs which systemically exist in the company's actual operations but are not appropriately captured in the GRID model.

Q. Why does the price component of the DA/RT adjustment compare actual day-ahead and real-time transactions to the actual monthly average market price?

A. A monthly price is used because GRID transacts at a monthly average price with an hourly shape. The deficiency in the GRID model that is being corrected is that the company's prices associated with day-ahead and real-time transactions do not equal the average monthly price.

Q. Does Staff's recommendation miss the fundamental purpose of the DA/RT adjustment?

A. Yes. Staff compares the actual transacted price of the day-ahead and real-time transactions to the daily market prices. Staff states that this is appropriate because "[t]he trader cannot consistently transact at the monthly average market price because simply put, the price does not yet exist."[51] The company agrees with this statement. Where Staff misses the point of the DA/RT adjustment is that GRID is transacting at an average monthly price making the DA/RT adjustment necessary.

In actual operations, the average cost of the company's day-ahead and real-time market purchases have been consistently higher than the average actual monthly market price, while the average revenues from its day-ahead and real-time market sales have been consistently lower than the average actual monthly market price. These costs are not captured in GRID because, without the DA/RT adjustment, GRID

[51] UE 356 – Staff/300 Enright 27

will transact at an average monthly price. Comparing the actual transacted price to the average daily price is nonsensical because GRID does not transact at a daily price.

Q. Besides the fundamental flaw in Staff's proposal, does the company have concerns regarding how Staff's proposed price adder was constructed?

A. Yes. Staff calculated the average daily prices based on the actual day-ahead and real-time transactions on each day and compared it against the daily market price. For the days the company did not transact, Staff calculated the price difference between the average daily prices and the daily market prices as zero. Staff then took the average among the daily price differences by month by market and by HLH and LLH.

Q. Why is Staff's proposed price adder adjustment incorrect?

A. Calculating the price difference as zero for the days the company does not have any transactions is incorrect. This method implies that for the days the company does not have any transactions, the company faces a price that is equal to the average prices in a given period, not higher or lower. This is contrary to the fact that the company actually faces a price that is higher or lower than the average price on the non-transact days, as the example in Staff's testimony illustrates.[52]

In actual operations, the company must maintain a balanced system and when company did not have any day-ahead or real time transactions on a certain day, it does not imply that company is able to transact on the average prices. Using zero as the non-transact day price adder artificially reduces the price the company faces in the actual operations, and further reduces the price adders that the company uses in the

[52] Staff/300 – Enright/28-29 – Figure 7 and 8 both show no transactions on Tuesday and Wednesday but the daily market price on Tuesday is below the average market price and the daily price on Wednesday is above the daily market prices.

GRID model. Adopting Staff's DA/RT adjustment will create an incorrect price signal to the GRID model and decrease the accuracy of forecasted NPC.

Q. How does the company's price adder calculation handle non-transact days?

A. The company's calculation of the prices adder correctly considers the volume of each transaction. In other words, the company uses a weighted average when calculating the average price at which it has transacted. Staff uses a non-weighted or a simple average without considering volumes. This results in non-transact days showing a zero dollar difference which artificially lowers the price adder by supposing the company could have transacted at the average price on those non-transact day.

Q. How does Staff's proposed price adder compare to PacifiCorp's price adders?

A. If corrected to exclude the zero dollar price differences on the non-transact days, (*i.e.* correcting the false assumption that the company would have been able to transact at an average daily price on days it did not transact), Staff's corrected price adders are much closer to the DA/RT adjustment adders proposed by the company originally, as shown in Figure 4 below.

FIGURE 4

Buy Adder

Month	PAC	Staff Proposed w/o Zero Price Differences on Non-Transact Days	Difference $/Mwh	Staff Proposed	Difference $/Mwh
January	3.95	4.45	0.50	1.09	(2.86)
February	2.36	3.29	0.93	1.08	(1.28)
March	2.74	5.16	2.41	1.49	(1.25)
April	3.99	3.83	(0.15)	1.56	(2.42)
May	4.02	4.98	0.96	1.58	(2.45)
June	9.79	12.46	2.67	2.66	(7.13)
July	12.29	6.19	(6.10)	2.12	(10.17)
August	13.26	5.49	(7.77)	2.11	(11.16)
September	24.21	33.60	9.40	2.76	(21.45)
October	2.00	2.36	0.36	0.79	(1.21)
November	2.21	2.85	0.64	0.89	(1.32)
December	4.58	4.33	(0.25)	0.93	(3.66)
Average	7.12	7.42	0.30	1.59	(5.53)

Sell Adder

Month	PAC	Staff Proposed w/o Zero Price Differences on Non-Transact Days	Difference $/Mwh	Staff Proposed	Difference $/Mwh
January	(0.64)	(0.12)	0.53	0.14	0.78
February	(0.75)	0.20	0.95	0.24	0.99
March	(0.68)	(0.45)	0.24	0.03	0.71
April	(0.21)	0.56	0.78	0.47	0.69
May	0.31	0.93	0.62	0.65	0.34
June	(0.67)	(0.44)	0.22	(0.24)	0.42
July	(5.12)	(2.58)	2.54	(1.54)	3.58
August	(2.69)	(4.34)	(1.65)	(2.25)	0.44
September	(3.20)	(0.22)	2.98	(0.26)	2.94
October	0.02	(0.31)	(0.33)	(0.03)	(0.05)
November	(0.17)	0.52	0.69	0.48	0.65
December	(0.58)	0.27	0.85	0.27	0.85
Average	(1.20)	(0.50)	0.70	(0.17)	1.03

Q. Does PacifiCorp have other concerns about Staff's adjustment?

A. Yes. When there is missing data for historical daily market prices, Staff uses the prices from the next day or next available daily prices in the sequence of the date to substitute the missing prices. This substitution completely ignores the fact that a different day type will impact prices differently. If a Friday has a missing date for the historical daily market prices and there are prices for the next date (i.e., Saturday), based on Staff's method, Friday's prices will be substituted for the price from Saturday. However, the prices on weekdays can be very different from the prices on the weekends.

Q. Is the company accepting any changes to the DA/RT adjustment?

A. No. As evidenced in this TAM and in the 2016, 2017, and 2018 TAM the DA/RT adjustment is a reasonable approach to capture the costs not previously captured in GRID.

OFPC Price Scalars

Q. Please briefly describe the scalars that the company proposes to use to the Official Forward Price Curve (OFPC).

A. The company proposes using 12-month rolling CAISO day-ahead hourly market prices at California-Oregon Border (COB) and Palo Verde (PV) to scale the OFPC. The updated scalars produces a more reasonable hourly shape with a peak in the morning hours, valley shape during mid-day, and a larger peak in the evening hours. This change in data inputs to determine the hourly scalars does not alter the application of the scalars to the OFPC.

Q. What are the parties' concerns related to the scalar proposal?

A. Both Staff and CUB are concerned that the use of 12 months of data is insufficient to represent the normalized price shape for the OFPC. According to these parties, 12 months of data is more likely to be influenced by abnormal events than a longer period of data. Staff recommends using at least two years of CAISO data.

In addition, both Staff and CUB raise concerns about the use of COB prices to scale the market hubs in the PacifiCorp West balancing area authority (PACW), more specifically the Mid-Columbia (Mid-C) market. Staff recommends the company provide reasonable solution in its next round of testimony. CUB asks the Commission to reject PacifiCorp's scalar proposal.

Q. Does the company agree with parties' concerns related to the normalization issue?

A. No. However, the company is willing to move to a rolling two-year history of data to determine the normalized price shape for the OFPC. This will reduce the influence of abnormal events while ensuring that data is drawn from the historical periods that are most representative of conditions in the forecast period.

Q. What is the basis for the company's proposal?

A. Starting in 2017, both PacifiCorp and the western interconnect as a whole have experienced a significant increase in the number of solar resources, including additional solar resources in the last 12 months, and this trend is expected to continue over the next several years.[53] This trend has a meaningful impact to the market price shape the company has experienced in recent years.

The price scalar is constructed to provide a reasonable hourly shape to the monthly prices. When the prices used in the scalars are higher in some hours, there will be prices set to be lower in other hours within a month. As a result, the average of the scalars for a given month is always equal to one.

Because of the diurnal nature of solar, it impacts market prices very differently than how other variables impact market prices, such as load, hydro conditions, or natural gas prices. When solar generation output changes during a day, it changes very dramatically. The solar output can be either close to 100 percent of its total capacity or 0 percent. The lack of ramping from solar resources contributes to increased prices in the morning and evening hours, and decreased prices during the

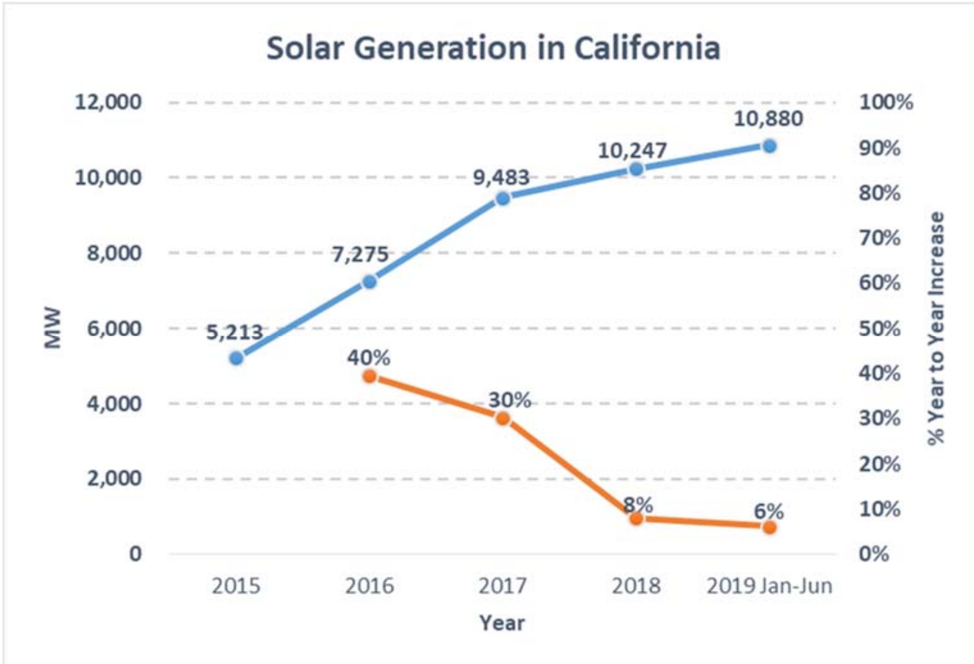
[53] U.S. ENERGY INFORMATION ADMINISTRATION. ANNUAL ENERGY OUTLOOK 2017, Tables 58.19-58.22, *available at* https://www.eia.gov/outlooks/aeo/tables_ref.php.

mid-day hours. This reflects the significant difference in system supply between periods when solar is available and periods when it is not. Other variables, such as load, hydro conditions and natural gas prices have impacts on prices, however, they are unlikely to impact the results of the proposed CAISO hourly prices shaping since they are more likely to impact all or most of the hours in a month. As a result, these variables are less likely to impact the hour-to-hour relationships embodied by the hourly scalars.

Q. Is there any evidence showing the increasing solar penetration in the region?

A. The following chart shows the annual maximum hourly solar generation forecasted in CAISO day-ahead market for California area from 2015 to 2019. From 2015 to 2019, the solar penetration forecast in California increased from 5,213 MW to 10,880 MW. The number of solar generation increased steadily in 2016 and 2017. From 2015 to 2016, the maximum hourly forecasted solar generation increase by 40 percent and 30 percent from 2016 to 2017. The increase trend starts to flatten starting 2018, and the year over year increase is about 8 percent from 2017 to 2018 and six percent from 2018 to the first half of 2019. If the trend since 2018 continues, solar generation will be 11,552 MW in 2020, which is 22 percent higher than the 2017 value.

FIGURE 5



Q. Has the company examined the scalar based on a two-year period?

A. Yes. The company applied its proposed approach to hourly shaping using actual data from 2017 and 2018. When two years of CAISO day ahead data are applied to the shape of the monthly prices used in GRID, the results show only a small change to NPC (an increase of approximately $552,000 total company, or just $143,000 on an Oregon-allocated basis). This demonstrates that the use of one year of data is reasonable and conservative.

Q. How does the company respond to concerns about using COB prices to represent the PACW hourly shape?

A. The Company uses scalars to efficiently optimize internal resources and least cost solution for net power costs. The scalars allows the company to optimally dispatch its resources based on the hourly value of energy to meet its energy obligations in PACW and PACE. Using COB prices to give an hourly shape to the energy value in

PACW is the best representation available for those hourly values. Additionally, the company transacts at COB to serve its obligations including its retail load located in Northern California and Southern Oregon.

Additionally, while there has historically been a spread between the prices at Mid-C and COB, there is significant transmission between these markets and several counterparties who can choose to transact in either, so Mid-C prices will be correlated with COB prices. Because the scalars reflect the relative differences from hour to hour the spread between the two markets is not an important distinguishing factor. The key reason for the use of COB data is its availability – comparable data is just not available for the Mid-C market.

Q. Are the same scalars used elsewhere in the company?

A. Yes. The same scalars are used in the integrated resource plan and in the company's trading activities.

Q. Why is CAISO day-ahead data the best available information the company has currently?

A. CAISO day-ahead data has deep market depth and it provides numerous amounts of actual trade data which provides a solid foundation to create the price shape. In contrast, Powerdex or other data resources, such as Platts from Standard & Poor's Global, only report voluntarily trade data by participant utilities. PacifiCorp itself does not report any prices to PowerDex or Platts. Numerous hours of the PowerDex index are derived without any actual market pricing inputs, but based on the extrapolation of the analyst's view of the market. For example, reported Mid-C prices by PowerDex only has a market depth of about 3.5 percent of CAISO's volumes.

Q. Will PacifiCorp use Mid-C prices in the future if Mid-C price data becomes available?

A. Possibly. The company continues explore acquiring Mid-C price shape data, but at this time the company is not aware of a viable source for this data. The company will continue examine the reasonableness of the data and its ability to accurately represent the hourly scalars for OPFC used in TAM for PACW.

Solar Hourly Shape

Q. Does Staff agree with the change the company proposes for the solar hourly shape?

A. Yes. Staff states it "agrees with the Company that incorporating hourly variations in solar generation is likely to improve forecast accuracy." Staff concurs that the P50 method does not reflect the intra-day variability that is inherent in solar generation and that some method of introducing this variability is reasonable.

Q. Does Staff propose an adjustment to solar generation shaping?

A. Yes. Staff objects to the use of a single year as the basis for shaping the P50 output and argues that a larger data set is required. Staff proposes that the company use the average of 2017 and 2018 data for solar hourly shaping in this TAM and, beginning with the 2021 TAM, use three years of historic generation data.

Q. Why did PacifiCorp use a single year, in this case 2017, to derive an hourly shape for solar energy?

A. PacifiCorp used 2017 data because: (1) 2017 was the first year that all of the company's solar resources were online for a full year; (2) 2017 represents the most recent data available at the time of the filing; and (3) the purpose of shape the solar generation is to present the intra-day relationship among the solar resources.

Q. Has the company performed any analysis of solar shaping using years other than 2017?

A. Yes. The company applied its new approach to solar shaping using actual data from 2018, which has become available since the time of the company's initial filing. When the solar shape based on 2018 is included in GRID, the results show an increase to NPC by $753,000 total company, or $195,000 on an Oregon-allocated basis.

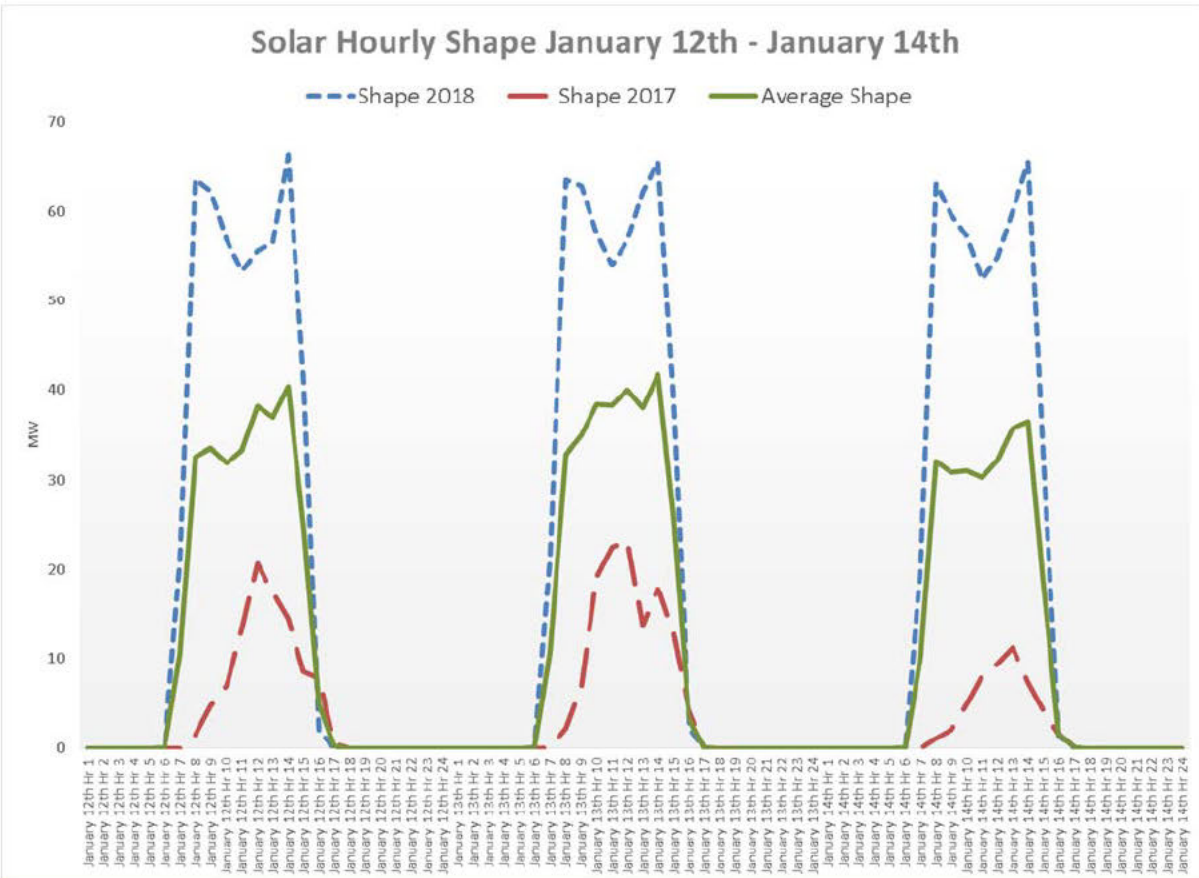
Q. Does PacifiCorp plan on using the most recent annual data available to determine the solar shape in future TAM filings?

A. Yes. The use of a single year solar shape is a way of creating a pattern of solar generation that reflects the actual operation of the company's solar resources while maintaining correlations between the various projects in the company's fleet.

Q. How should additional data be viewed?

A. Using data for different years for different plants would remove the correlations resulting from their geographic distribution. Averaging multiple years creates a "smoothing" effect which artificially reduces the volatility of hourly solar generation. Figure 6 shows how averaging between two years of actual generation will distort the solar shape that should be presented in the forecast. The two dotted lines are the historical hourly solar generation for one solar project on the company system from the period of January 12th to January 14th. The solid line is the averaged historical solar generation. This shows that the shape after averaging does not correctly represent the actual solar shape. By the nature of solar generation, solar energy output is either at the maximum or close to minimum of its capacity level, and rarely stays in the middle.

FIGURE 6



Q. What is your recommendation on the solar hourly shaping adjustment?

A. PacifiCorp's initial filing contains a reasonable hourly solar shape that conservatively forecasts NPC for the test period. Staff's proposal to use average historical solar generation to model solar shaping produces a less accurate representation of solar generation over the test period.

Wheeling Expense

Q. Does Staff propose an adjustment to PacifiCorp's wheeling expense?

A. Yes. Staff examined PacifiCorp's actual wheeling expense from 2015 to 2018 and concluded that the company over-forecast the wheeling expense in 2016, 2017 and 2018. Staff recommends setting the 2020 wheeling cost to the least actual annual values from 2016 to 2018. The adjustment reduces NPC by $530,000.

Q. Does the company agree the forecast wheeling expense should be changed in TAM?

A. No. The company uses the 12-month historical wheeling expense with known and measurable adjustments to forecast the wheeling expense in the test period. The wheeling expense in 2020 TAM is $132,801,884, which is well in line with the past three year average of $133,777,379.

Q. What is the company's response to Staff's adjustment?

A. Staff's adjustment is unfounded. While Staff claims the company overstated wheeling expense in the past three years, it ignores the fact that the company significantly under-forecasted wheeling expense in 2015. Staff removes 2015 as an outlier without providing any supporting evidence. Then Staff uses the least actual wheeling cost year (which is 2016) to replace the company's forecasted wheeling cost in 2020 TAM. There is no justification for this adjustment from a NPC modeling perspective, and it will likely decrease the accuracy of the NPC forecast in this case.

Gas Optimization Margins

Q. AWEC claims that PacifiCorp has many opportunities to purchase and sell natural gas transportation rights in order to optimize natural gas margins. Do you agree?

A. No. AWEC incorrectly assumes that the company buys and sells natural gas transportation rights for the purpose of optimizing margin in the natural gas market. In fact, the company procures natural gas supply to fuel its gas plants in order to serve the system load at the lowest possible cost. The company does not over procure the gas supply beyond that needed to serve system peak load. When the system peak load is met, the company may sell any excess gas supply into the market. However, the excess capacity is dependent on system conditions and this can change throughout the day and month. It is impossible to know when the excess gas supply may be available.

Q. Did AWEC properly study PacifiCorp's gas optimization revenues?

A. No. AWEC notes in testimony that it did not have the necessary "historical data for properly studying gas optimization revenues."[54] AWEC further states it "requested the actual accounting data PacifiCorp uses to calculate the cost of gas for each plant in AWEC DR 008".[55] However, AWEC DR 008 reads "Please provide an explanation of how PacifiCorp accounts for natural gas sales transactions when calculating and forecasting actual net power costs."[56] AWEC DR 008 clearly asks for an explanation as opposed to a data set. AWEC DR 009 clearly requested the data for each physical

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[54] AWEC/100/Mullin/7
[55] AWEC/100/Mullins/7
[56] PAC/Exhibit 406

natural gas sales transaction executed in 2018.

Q. Does AWEC's example have a merit?

A. No. AWEC picked two gas physical deals from the company's historical gas deals in November 2018 and claims these two gas physical deals represent gas optimization activities. The two deals AWEC used as an example were executed on November 7, 2018, and delivered on November 8, 2018.[57] AWEC's original example is included below as Confidential Figure 7.

Confidential Figure 7

[redacted]

The fatal flaw in this example is that PacifiCorp does not have natural gas transportation rights between Stanfield, where the natural gas was purchased, and Sumas, where the natural gas was sold. AWEC is inappropriately correlating two completely separate transactions.

Q. If the transactions in AWECs example were not to realize a margin between hubs, please explain the purpose of those transactions.

A. Both transactions occurred on November 7, 2018 for November 8, 2018. Natural gas for the company's Hermiston natural gas plant is supplied from either the Kingsgate or the Stanfield hub, and the natural gas supply for the company's Chehalis natural gas plant comes from the Sumas hub.

[57] AWEC/100/Mullins/7

On November 7, 2018, the company nominated [redacted] dekatherms (dth) for November 8, 2018 at its Hermiston plant. The company had an existing hedge for [redacted] dth and purchased an additional [redacted] dth in two separate deals. One of the deals is number [redacted] which AWEC identifies as being sold at Sumas when in reality it was burned at Hermiston for generation. On November 8, 2018 the Hermiston plant actually burned approximately [redacted] dth to generate [redacted] MWh.

The other deal AWEC uses in its example is deal number [redacted]. This deal was to unwind an existing natural gas hedge of [redacted] dth at the Chehalis plant. On October 9, 2018, the Enbridge natural gas pipeline that transports natural gas produced in the Western Canadian Sedimentary Basin to consumers in British Columbia and, through interconnecting pipelines, the Northwestern United States (U.S.), experienced a massive rupture. This caused prices to spike at the Sumas natural gas hub during the fourth quarter of 2018. On November 7, 2018 while trading for November 8, 2018, the Sumas natural gas price was approximately [redacted] per dth as AWEC shows in its example. This translates to a dispatch price of more than [redacted] per megawatt hour (MWh) at the Chehalis plant. On the same day Mid-C was trading at approximately [redacted] per MWh and therefore the natural gas hedge at Sumas was unwound as the Chehalis plant was not economic to dispatch and therefore did not generate on November 8, 2019.

300 MW Link Jim Bridger to Walla Walla

Q. Please describe AWEC's recommendation on this issue.

A. AWEC recommends including a virtual 300 MW transmission link between the Jim Bridger transmission area and Walla Walla transmission area in the GRID model to reflect the potential benefits resulting from increasing participation in the EIM. As part of the stipulation in docket UE 339, the 2019 TAM, the company included a monetary adjustment for this link.

Q. Did the company include this virtual link in this TAM?

A. No. The company did not include this link in the current TAM. The virtual 300 MW transmission link between the Jim Bridger to Walla Walls is not a “firm” transmission path available to the company after Idaho Power Company (IPC) joins the EIM. The transmission available for EIM use is limited by two factors. First, the transmission path is influenced by the status of large number of independent components in EIM market. Second, the availability of this transmission right is heavily depended on how IPC operates its system. If the company has scheduled forward transactions that use this path, IPC operates its system by using the path for its own delivery. There is less transfer capacity available for the company for EIM transactions.

The inter-regional EIM benefits includes benefits associated with inter-regional dispatch, which result from transactions between EIM participants. When the company enters the EIM market, as a requirement, the company submits its balanced base schedule 55 minutes prior to the hour. The company has no way to know that this 300 MW transmission link is available, and without this information, it is impossible for the company to schedule its transmission based on this 300 MW transmission link.

Even when the 300 MW transmission link becomes available to the company in sub-hourly EIM market, the realized benefits is already captured in the inter-regional EIM benefits in NPC. For example, when the transmission is available, the company is able to move zero cost wind energy from constrained areas of Wyoming to serve load of other EIM participants. This benefit is captured in an out-of-model adjustment as inter-regional EIM benefits.

Q. Why was this link assumed in the EV 2020 request for proposals (RFP) process?

A. This link was assumed in the RFP process related to new transmission and new wind in the transmission-constrained areas of Wyoming. Given that wind generation is at the bottom of the stack in any generation mix, it was reasonable to add the link to assess how the resources will move on the available path due to potential EIM transmission availability. In addition, in the RFP, there is no out-of-model adjustment to capture the EIM benefits related to the additional wind.

Including this virtual link directly in the GRID model will cause double counting on the EIM benefits. The GRID model is used to reflect the system optimization at hourly level. Inter-regional EIM benefits are added as an out-of-model adjustment to reflect EIM sub-hour market benefits. Furthermore, incremental transmission from increasing participant EIM entities will be available to the entire EIM footprint, not just PacifiCorp. To model this intra-hour transmission capacity using only PacifiCorp's resource is incorrect and overstates the benefit.

GTN Pipeline Rates

Q. What adjustments has PacifiCorp made to reflect the change in rates for the GTN Pipeline?

A. As described earlier in my testimony in the list of updates, the GTN pipeline rates have been changed to reflect the rate reduction for 2020 rates that was approved by FERC late last year.

Q. Is it appropriate to impute a rate reduction into the 2020 TAM for the revised 2019 rates?

A. No. The change in the 2019 rate for the GTN pipeline will be reflected in the 2019 PCAM. It is not appropriate to reflect the amount that was credited from a 2019 rate reduction in the 2020 TAM when it is outside the forecast period covered by this TAM. Making this change through the 2020 TAM could also violate the rule against retroactive ratemaking.

Q. Please describe the adjustment AWEC suggests regarding the Interim Period Tax Reform Credit.

A. The November 2018 invoice from GTN Pipeline to the company included a tax savings credit as a result of federal tax reform resulting from the Tax Cuts and Jobs Act. The current period charges, net of the tax savings credit, was booked as a natural gas expense in the period November 2018. AWEC asserts that the tax savings credit from GTN Pipeline should be passed back to customers through this docket or else the benefit will flow through the company's tax reform liability.[58]

Q. Does the company agree with this assertion?

A. No. The company netted the tax savings credit against the current period charges and booked the net amount to natural gas fuel expense in November 2018. The net expense was included in the computation of actual NPC and included in the company's PCAM in docket UE 361 for the period January 1, 2018 through December 31, 2018. The PCAM is the appropriate place to treat the tax savings credit because this is how all invoice adjustments and credits, including prior period

[58] AWEC/100, Mullins/5.

adjustments and accrual true-ups, are treated for wholesale sales, purchased power, coal fuel expense and natural gas fuel expense. To pass back the tax savings credit in this docket would be accounting for the same credit twice.

Q. Should the credit flow through the company's tax reform liability as suggested by AWEC?

A. No. As explained above the credit is captured in actual NPC and included in the PCAM.

Modeling Changes

Q. Has CUB made any general recommendations regarding the modeling changes proposed by PacifiCorp?

A. Yes. CUB has raised concerns that PacifiCorp's modeling changes are primarily one-sided changes to benefit shareholders. CUB claims that the GRID model is accurate based on company backcasts and PacifiCorp is no longer under-recovering its power costs.[59] As a result, CUB concludes that the company's NPC modeling is reasonably accurate, and modeling changes should be proposed only in a general rates case.[60]

Q. Do the TAM Guidelines specifically address when and how PacifiCorp can propose modeling changes in a stand-alone TAM?

A. Yes. In the 2010 TAM, the parties (PacifiCorp, Staff, AWEC's predecessor ICNU and CUB) stipulated that PacifiCorp could propose methodological changes in a

[59] CUB/100, Jenks/5-6.
[60] CUB/100, Jenks/6.

stand-alone TAM, and set forth certain procedural requirements.[61] The Commission adopted this guideline in Order No. 09-432.

Q. Did CUB attempt to reconcile its proposal to limit modeling changes with this TAM guideline?

A. No. CUB does not cite this guideline, even though it is directly on point.

Q. Do the TAM Guidelines address how a party can propose changes to the TAM Guidelines?

A. Yes. This is also covered in the stipulation supported by CUB and adopted in the 2010 TAM in Order No. 09-432. The TAM Guidelines require that all proposed modifications be presented in a general rate case, not in a stand-alone TAM.[62]

Q. Is CUB's proposal to limit modeling changes to a general rate case directly contrary to the TAM Guidelines?

A. Yes. Further, any proposal to change the TAM Guidelines is outside the scope of this stand-alone TAM.

Q. On the substance of CUB's proposal, are the model validation or "backcasts" conducted by PacifiCorp evidence that additional modeling changes are unnecessary?

A. No. The backcast results provide information on how the GRID model responds to the different data inputs. By replacing GRID inputs with actual data the model is producing a reasonable result when compared to actual NPC. The backcast does not provide evidence that all current inputs are the most accurate and will not need

[61] *See In the Matter of PacifiCorp d/b/a Pacific Power, 2010 Transition Adjustment Mechanism*, Docket No. UE 207, Order No. 09-432 at 4 (Oct. 30, 2009).
[62] Id. at 3.

adjustments from time to time. For example, in this case the price scalar adjustments proposed by the company was made to capture the changing shapes observed in the electric markets.

Q. Is it important to set the most accurate NPC forecast possible to meet the Commission's goals for the TAM and PacifiCorp's PCAM?

A. Yes. As noted in my direct testimony, in Order No. 16-482, issued in the 2017 TAM, the Commission reiterated the goal of accurate NPC modeling in the TAM:

> PacifiCorp's TAM is an annual filing in which PacifiCorp projects the amount of [NPC] to be reflected in customer rates for the following year, as well as to set transition charges for customers electing to move to direct access. The TAM effectively removes regulatory lag for the company because the forecasts are used to adjust rates. For that reason, the accuracy of the forecasts is of significant importance to setting fair just and reasonable rates. Our goal, therefore, is to achieve an accurate forecast of PacifiCorp's [NPC] for the upcoming year.[63]

In addition, the more accurate the NPC forecast is in the TAM, the less likely it is that PacifiCorp will need to adjust rates through a PCAM surcharge or surcredit in 2021.

Q. Are there any current mechanisms in place to check the accuracy of the TAM?

A. Yes. Each year the PCAM compares the NPC collected from Oregon customers in rates set in the TAM to the actual Oregon-allocated NPC. The PCAM variance, however, is subject to an asymmetrical deadband between a $30 million under-collection and a $15 million over-collection, a sharing band where the company absorbs 10 percent of the variance outside the deadband, and finally an earnings test where there is no pass through of the PCAM variance if the company is above or below its authorized return on equity by 100 basis points.

[63] Order No. 16-482 at 2-3.

Q. How have the actual NPC compared against the NPC collected through rates for Oregon customers?

A. PacifiCorp has proposed refinements to the modeling of NPC in the TAM to increase the accuracy of the TAM. However, as the table below shows, PacifiCorp still continues to systematically under-recover NPC in Oregon. Additionally, PacifiCorp's modeling refinements are intended to respond to a rapidly changing energy landscape. By preventing modeling changes, the Commission would effectively prevent the company and stakeholders from responding the major shifts in the energy sector for years.

Figure 8
Actual NPC vs. NPC Collected in Rates

Year	OR NPC Collected Through Rates	OR Actual NPC	Under/(Over) Recovery of OR NPC
2008	$ 252,556,048	$ 286,401,464	$ 33,845,416
2009	248,429,624	261,335,991	12,906,367
2010	241,238,092	276,837,681	35,599,589
2011	301,662,279	333,544,839	31,882,559
2012	336,201,734	351,814,385	15,612,651
2013	348,474,235	382,126,867	33,652,632
2014	341,351,338	377,421,181	36,069,843
2015	343,993,011	362,384,220	18,391,209
2016	347,055,570	342,591,463	(4,464,107)
2017	361,522,414	364,689,242	3,166,827
2018	350,555,442	370,884,594	20,329,152
Q1 2019	93,809,076	112,746,336	18,937,260

Q. Should the Commission reject CUB's proposal to limit NPC modeling changes to a general rate case?

A. Yes.

Direct Access Consumer Opt-Out Charge

Q. Did any party contest the company's calculation of the direct access consumer opt-out charge?

A. No. The company calculated the Consumer Opt-Out Charge consistent with the settlement in the 2019, meaning that Schedule 200 is held constant for years six through ten. Calpine supports the calculation of the consumer opt-out charge in the "spirit of compromise" and recommends this approach be approved by the commission.[64]

Q. Is there any evidence to support this calculation of the consumer-opt-out-charge?

A. Yes. Exhibit PAC/110 from the 2019 TAM provided an analysis of the historical fixed generation costs, before and after removing incremental generation and accounting for generation. This analysis shows that fixed generation costs have historically increased over time so holding Schedule 200 constant for years six through ten is a reasonable compromise. This analysis is attached as Exhibit PAC/408.

Q. Does this conclude your reply testimony?

A. Yes.

[64] Calpine Solution/100/Townsend/9.

Docket No. UE 356
Exhibit PAC/401
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Michael G. Wilding

2020 TAM Oregon-Allocated Net Power Costs Reply Filing

July 2019

PacifiCorp
CY 2020 TAM
Reply Update

Line no		ACCT.	Total Company UE-339 CY 2019 - Final Update	Total Company TAM CY 2020 - Initial Filing	Total Company TAM CY 2020 - Reply Update	Factor	Factors CY 2019	Factors CY 2020	Oregon Allocated UE-339 CY 2019 - Final Update	Oregon Allocated TAM CY 2020 - Initial Filing	Oregon Allocated TAM CY 2020 - Reply Update
1	**Sales for Resale**										
2	Existing Firm PPL	447	7,967,439	7,010,945	7,621,463	SG	26.725%	26.456%	2,129,283	1,854,805	2,016,322
3	Existing Firm UPL	447	-	-	-	SG	26.725%	26.456%	-	-	-
4	Post-Merger Firm	447	478,486,284	339,748,239	372,798,652	SG	26.725%	26.456%	127,874,540	89,883,268	98,627,034
5	Non-Firm	447	-	-	-	SE	25.322%	25.314%	-	-	-
6	**Total Sales for Resale**		486,453,723	346,759,184	380,420,115				130,003,823	91,738,073	100,643,356
7											
8	**Purchased Power**										
9	Existing Firm Demand PPL	555	3,133,795	4,795,373	3,261,949	SG	26.725%	26.456%	837,501	1,268,656	862,976
10	Existing Firm Demand UPL	555	3,332,695	3,793,638	3,793,638	SG	26.725%	26.456%	890,656	1,003,639	1,003,639
11	Existing Firm Energy	555	17,662,229	21,667,704	18,094,684	SE	25.322%	25.314%	4,472,499	5,485,049	4,580,560
12	Post-merger Firm	555	721,894,615	672,350,836	677,393,578	SG	26.725%	26.456%	192,924,948	177,876,096	179,210,196
13	Secondary Purchases	555	-	-	-	SE	25.322%	25.314%	-	-	-
14	Other Generation Expense	555	7,099,964	7,455,847	7,450,204	SG	26.725%	26.456%	1,897,452	1,972,507	1,971,015
15	**Total Purchased Power**		753,123,297	710,063,398	709,994,053				201,023,056	187,605,948	187,628,386
16											
17	**Wheeling Expense**										
18	Existing Firm PPL	565	22,380,362	22,079,714	22,079,714	SG	26.725%	26.456%	5,981,109	5,841,375	5,841,375
19	Existing Firm UPL	565	-	-	-	SG	26.725%	26.456%	-	-	-
20	Post-merger Firm	565	108,553,771	107,547,012	107,543,235	SG	26.725%	26.456%	29,010,787	28,452,471	28,451,472
21	Non-Firm	565	4,447,418	3,175,158	3,175,158	SE	25.322%	25.314%	1,126,193	803,772	803,772
22	**Total Wheeling Expense**		135,381,551	132,801,884	132,798,106				36,118,088	35,097,618	35,096,619
23											
24	**Fuel Expense**										
25	Fuel Consumed - Coal	501	702,622,248	642,746,510	649,756,250	SE	25.322%	25.314%	177,920,783	162,707,412	164,481,885
26	Fuel Consumed - Coal (Cholla)	501	40,481,392	27,072,484	36,084,281	SE	25.322%	25.314%	10,250,858	6,853,236	9,134,519
27	Fuel Consumed - Gas	501	5,440,263	5,823,881	7,515,588	SE	25.322%	25.314%	1,377,605	1,474,280	1,902,526
28	Natural Gas Consumed	547	293,704,139	299,969,224	312,083,535	SE	25.322%	25.314%	74,372,923	75,935,404	79,002,069
29	Simple Cycle Comb. Turbines	547	3,736,769	3,426,472	3,879,074	SE	25.322%	25.314%	946,239	867,391	981,964
30	Steam from Other Sources	503	4,597,639	4,676,489	4,676,489	SE	25.322%	25.314%	1,164,232	1,183,825	1,183,825
31	**Total Fuel Expense**		1,050,582,449	983,715,060	1,013,995,217				266,032,640	249,021,549	256,686,788
32											
33	TAM Settlement Adjustment**		(545,317)	-	-		As Settled		(141,911)	-	-
34											
35	**Net Power Cost (Per GRID)**		1,452,088,257	1,479,821,158	1,476,367,261				373,028,051	379,987,042	378,768,436
36											
37	Oregon Situs NPC Adustments		501,570	513,798	463,225	OR	100.000%	100.000%	501,570	513,798	463,225
38	**Total NPC Net of Adjustments**		1,452,589,826	1,480,334,955	1,476,830,487				373,529,620	380,500,839	379,231,662
39											
40	Non-NPC EIM Costs*		3,079,748	1,572,036	1,493,124	SG	26.725%	26.456%	823,057	415,895	395,019
41	Production Tax Credit (PTC)		(37,465,734)	(99,704,458)	(96,971,960)	SG	26.725%	26.456%	(10,012,645)	(26,377,657)	(25,654,751)
42	**Total TAM Net of Adjustments**		1,418,203,840	1,382,202,533	1,381,351,651				364,340,032	354,539,078	353,971,929
43											
44									Increase Absent Load Change	(9,800,954)	(10,368,103)
45											
46	Oregon-allocated NPC (incl. PTC) Baseline in Rates from UE-339								$364,340,032		
47	$ Change due to load variance from UE-339 forecast								4,921,525		
48	2020 Recovery of NPC (incl. PTC) in Rates								$369,261,556		
49	*EIM Benefits for the 2020 TAM are reflected in net power costs										
50	**TAM Settlement UE 339 - Partial Sipulation agreed to decrease Oregon-allocated NPC by $141,911								**Increase Including Load Change**	**(14,722,479)**	**(15,289,627)**
51											
52									Add Other Revenue Change	67,946	100,662
53											
54									**Total TAM Increase/(Decrease)**	**$ (14,654,533)**	**$ (15,188,966)**

Docket No. UE 356
Exhibit PAC/402
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Michael G. Wilding

2020 Results of Updated Net Power Cost Study Reply Filing

July 2019

PacifiCorp

JulyCum ORTAM20 NPC Study

Net Power Cost Analysis

12 months ended December 2020	01/20-12/20	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
						$							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	7,621,463	731,539	671,598	542,679	326,740	392,399	667,275	746,432	738,893	721,987	692,443	639,973	749,505
BPA Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
East Area Sales (WCA Sale)	-	-	-	-	-	-	-	-	-	-	-	-	-
Hurricane Sale	8,813	734	734	734	734	734	734	734	734	734	734	734	734
LADWP (IPP Layoff)	-	-	-	-	-	-	-	-	-	-	-	-	-
Leaning Juniper Revenue	88,241	5,662	5,479	7,528	4,498	5,656	5,807	13,819	13,156	9,806	5,980	4,954	5,895
SMUD	-	-	-	-	-	-	-	-	-	-	-	-	-
UMPA II s45631	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Long Term Firm Sales	7,718,517	737,936	677,812	550,941	331,973	398,790	673,816	760,985	752,784	732,528	699,157	645,661	756,134
Short Term Firm Sales													
COB	1,278,200	431,600	415,000	431,600	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	877,800	296,400	285,000	296,400	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	954,800	322,400	310,000	322,400	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	68,482,380	11,743,170	11,010,990	11,743,170	7,610,940	7,581,390	7,610,940	-	-	-	3,849,570	3,560,220	3,771,990
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Trading Margin	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	71,593,180	12,793,570	12,020,990	12,793,570	7,610,940	7,581,390	7,610,940	-	-	-	3,849,570	3,560,220	3,771,990
System Balancing Sales													
COB	56,864,780	4,796,103	5,409,850	4,993,337	4,459,485	4,493,550	2,932,101	3,309,680	5,344,807	5,810,415	4,336,995	4,996,607	5,981,851
Four Corners	56,436,303	5,408,892	4,252,298	2,570,121	1,934,549	2,604,678	2,953,991	8,355,664	8,637,084	6,237,855	4,785,084	4,108,846	4,587,240
Mead	39,926,804	4,348,421	3,791,335	1,757,807	1,593,966	1,268,607	2,179,288	2,124,308	5,600,938	3,839,675	4,694,101	4,128,454	4,599,903
Mid Columbia	58,339,199	5,831,952	5,345,964	6,105,087	2,157,005	3,483,899	2,274,695	7,852,132	8,616,125	4,223,426	4,569,655	3,953,184	3,926,074
Mona	24,051,287	2,314,312	1,208,129	1,748,980	997,917	694,349	2,451,022	2,055,664	3,150,207	3,667,507	1,648,149	2,001,037	2,114,014
NOB	7,787,271	720,548	769,665	651,909	727,568	512,790	35,672	1,487,404	1,457,020	106,698	107,236	336,560	874,201
Palo Verde	57,552,806	1,376,630	1,610,914	948,360	789,303	1,345,941	3,083,384	14,797,009	15,564,409	5,834,708	2,857,651	4,085,165	5,259,332
Trapped Energy	149,968	113,558	7,318	12,454	-	1,172	-	-	-	-	-	15,466	-
Total System Balancing Sales	301,108,418	24,910,417	22,395,473	18,788,054	12,659,794	14,404,985	15,910,152	39,981,861	48,370,591	29,720,285	22,998,870	23,625,319	27,342,616
Total Special Sales For Resale	380,420,115	38,441,923	35,094,275	32,132,565	20,602,707	22,385,165	24,194,908	40,742,846	49,123,375	30,452,813	27,547,597	27,831,201	31,870,740

Purchased Power & Net Interchange

Long Term Firm Purchases													
APS Supplemental	972,021	38,703	49,462	154,361	106,103	116,649	107,716	123,618	131,266	61,488	82,656	-	-
Avoided Cost Resource	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Combine Hills Wind	5,392,106	373,200	468,350	548,798	548,105	467,372	399,201	450,693	380,844	359,837	371,319	456,705	567,682
Cove Mountain Solar	5,522	-	-	-	-	-	-	-	-	-	-	-	5,522
Cove Mountain Solar II	17,478	-	-	-	-	-	-	-	-	-	4,173	13,304	-
Deseret Purchase	31,983,377	2,873,619	2,448,105	2,374,104	2,474,005	2,404,938	2,844,018	2,873,619	2,873,619	2,844,018	2,499,906	2,599,809	2,873,619
Douglas PUD Settlement	-	-	-	-	-	-	-	-	-	-	-	-	-
Eagle Mountain - UAMPS/UMPA	2,363,115	150,613	139,233	118,590	116,670	134,398	240,245	402,632	367,412	213,183	143,145	133,684	203,311
Gemstate	1,591,536	132,628	132,628	132,628	132,628	132,628	132,628	132,628	132,628	132,628	132,628	132,628	132,628
Georgia-Pacific Camas	-	-	-	-	-	-	-	-	-	-	-	-	-
Hermiston Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Hunter Solar	10,537	-	-	-	-	-	-	-	-	-	-	-	10,537
Hurricane Purchase	148,941	12,412	12,412	12,412	12,412	12,412	12,412	12,412	12,412	12,412	12,412	12,412	12,412
IPP Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	6,247,580	517,290	505,260	517,290	521,300	517,290	521,300	501,250	529,320	529,320	529,320	529,320	529,320
Milican Solar	1,858	-	-	-	-	-	-	-	-	-	-	-	1,858
Milford Solar	326,041	-	-	-	-	-	-	-	-	-	-	13,137	312,904
Nucor	7,129,800	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150	594,150
Old Mill Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
Monsanto Reserves	19,999,999	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667	1,666,667
Pavant III Solar	-	-	-	-	-	-	-	-	-	-	-	-	-
PGE Cove	154,785	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899	12,899
Prineville Solar	2,264	-	-	-	-	-	-	-	-	-	-	-	2,264
Rock River Wind	5,095,508	655,201	527,014	534,974	441,661	287,465	265,265	183,629	196,416	264,393	495,489	611,007	632,994
Sigurd Solar	8,732	-	-	-	-	-	-	-	-	-	-	-	8,732
Small Purchases east	14,288	1,173	1,213	1,172	1,172	1,233	1,203	1,226	1,202	1,153	1,157	1,209	1,176
Small Purchases west	-	-	-	-	-	-	-	-	-	-	-	-	-
Soda Lake Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	20,822,069	2,803,421	1,880,006	2,145,315	1,623,997	1,433,919	1,207,512	812,094	955,458	1,191,673	1,747,775	2,357,430	2,663,470
Top of the World Wind	41,669,886	5,550,388	3,820,130	4,333,284	3,336,656	2,969,901	2,451,079	1,756,423	1,911,182	2,345,982	3,590,503	4,580,644	5,023,717
Tri-State Purchase	4,066,491	840,294	834,593	819,792	780,932	790,880	-	-	-	-	-	-	-
West Valley Toll													
Wolverine Creek Wind	10,316,938	762,470	922,708	1,133,737	1,045,118	791,605	843,689	671,821	642,114	753,711	831,267	962,703	955,995
Long Term Firm Purchases Total	158,340,870	16,985,126	14,014,830	15,100,171	13,414,474	12,334,405	11,299,980	10,195,759	10,407,588	10,983,511	12,715,466	14,677,707	16,211,854
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

Qualifying Facilities													
QF California	4,819,520	440,899	514,012	517,210	745,353	786,126	619,761	285,229	166,427	146,016	143,607	176,905	277,976
QF Idaho	9,039,785	732,020	718,003	739,350	755,012	801,825	843,737	794,903	694,326	670,317	702,318	736,268	851,708
QF Oregon	52,742,411	3,133,716	3,389,597	4,099,608	5,063,607	5,564,532	5,676,010	5,687,071	5,354,718	4,770,184	3,876,278	2,944,145	3,182,946
QF Utah	10,960,570	749,850	794,917	929,868	970,006	1,066,659	1,083,414	1,010,521	1,002,172	942,756	897,995	790,653	721,760
QF Washington	292,617	-	-	-	9,513	44,679	58,343	71,859	64,590	30,886	12,746	-	-
QF Wyoming	249,822	23,214	24,006	27,089	19,682	17,700	11,318	17,118	17,717	16,317	20,199	25,302	30,160
Biomass One QF	14,977,024	1,210,032	1,427,397	1,270,508	1,559,816	969,411	954,363	1,431,306	1,191,857	1,263,564	1,249,911	1,398,039	1,050,822
Boswell Wind I QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind II QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind III QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Boswell Wind IV QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Chevron Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
DCFP QF	66,115	2,987	6,842	8,355	7,170	8,222	11,671	20,868	-	-	-	-	-
Enterprise Solar I QF	12,790,172	629,205	788,456	988,106	1,135,259	1,278,347	1,404,078	1,597,159	1,536,597	1,200,408	972,610	710,022	549,925
Escalante Solar I QF	11,800,647	575,962	713,369	889,952	1,030,798	1,213,056	1,330,364	1,471,738	1,417,639	1,110,348	887,207	646,625	513,591
Escalante Solar II QF	11,104,089	541,414	669,019	838,337	968,014	1,147,052	1,258,546	1,388,843	1,330,382	1,047,309	831,993	604,996	478,184
Escalante Solar III QF	10,694,485	526,327	653,951	813,067	942,929	1,117,277	1,227,758	1,350,547	1,290,901	1,017,498	761,428	554,461	438,340
Evergreen BioPower QF	-	-	-	-	-	-	-	-	-	-	-	-	-
ExxonMobil QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	8,361,116	515,285	866,754	745,168	788,454	483,154	522,325	625,934	591,857	743,010	732,178	871,508	875,489
Foote Creek III Wind QF	1,742,230	216,919	174,011	218,302	143,046	89,735	83,416	88,507	98,280	101,095	169,997	177,284	181,638
Glen Canyon A Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Glen Canyon B Solar QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Granite Mountain East Solar QF	11,084,598	558,297	643,875	901,031	1,003,509	1,176,290	1,281,912	1,364,359	1,283,850	992,426	822,717	585,218	471,114
Granite Mountain West Solar QF	7,344,916	369,404	426,514	599,000	665,754	778,994	849,690	904,914	851,560	656,067	544,532	386,998	311,488
Iron Springs Solar QF	11,381,994	644,229	694,013	903,013	1,031,635	1,148,681	1,306,627	1,374,749	1,343,796	1,020,316	829,581	582,212	503,143
Kennecott Refinery QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Kennecott Smelter QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Latigo Wind Park QF	9,708,539	1,011,726	950,837	1,122,669	897,120	856,897	745,979	673,722	567,152	616,686	802,754	706,758	756,240
Monticello Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Mountain Wind 1 QF	9,102,733	1,446,879	1,096,826	876,503	703,941	484,210	512,295	418,955	448,834	461,812	689,229	921,902	1,041,346
Mountain Wind 2 QF	14,207,209	2,113,279	1,644,653	1,371,849	1,095,940	758,021	923,407	777,214	747,136	769,890	1,033,054	1,430,289	1,542,480
North Point Wind QF	18,588,632	1,075,669	1,857,161	1,651,305	1,760,917	1,071,380	1,179,515	1,445,356	1,457,525	1,756,754	1,691,899	1,840,557	1,800,596
Oregon Wind Farm QF	12,943,996	752,656	1,039,810	1,148,985	1,363,047	1,295,867	1,261,905	1,312,194	1,151,716	954,443	765,973	811,538	1,085,862
Pavant II Solar QF	3,773,198	157,116	200,910	311,238	368,118	403,364	392,847	480,400	460,039	367,175	300,011	183,743	148,236
Pioneer Wind Park I QF	10,692,333	1,307,644	990,925	1,209,776	887,852	716,990	653,221	637,737	687,071	449,915	796,183	1,251,720	1,103,300
Power County North Wind QF	5,449,253	415,337	564,183	523,161	516,308	350,113	345,127	369,513	365,191	376,825	506,390	521,472	595,635
Power County South Wind QF	4,862,397	367,416	497,306	473,011	480,284	302,355	307,607	327,628	340,903	334,044	443,727	471,423	516,693
Roseburg Dillard QF	637,982	38,507	27,483	36,455	63,230	70,324	67,356	69,584	68,224	48,210	60,471	51,725	36,412
Sage I Solar QF	2,287,218	81,380	83,272	191,063	207,247	236,416	264,294	339,923	335,626	209,804	157,123	105,215	75,856
Sage II Solar QF	2,289,663	81,465	83,371	191,264	207,469	236,630	264,592	340,285	335,994	210,042	157,280	105,343	75,927
Sage III Solar QF	1,884,319	68,601	69,376	157,807	168,916	193,787	216,172	277,394	273,689	173,157	131,807	89,173	64,441
Spanish Fork Wind 2 QF	2,686,723	215,401	177,052	198,291	156,304	148,847	207,936	281,840	306,755	262,818	236,090	242,231	253,157
Sunnyside QF	30,667,985	2,699,367	2,572,985	2,629,201	1,695,831	2,662,041	2,695,401	2,707,160	2,722,633	2,597,876	2,321,412	2,682,607	2,681,471
Sweetwater Solar QF	7,873,760	262,286	391,420	569,656	695,008	820,880	993,452	1,130,956	1,047,054	822,457	635,392	301,437	203,764
Tesoro QF	494,677	39,103	37,731	59,051	35,490	70,662	21,040	29,680	28,545	38,546	36,494	37,119	61,215
Threemile Canyon Wind QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Peaks Solar QF	8,592,999	420,587	495,052	626,242	846,984	874,824	926,714	1,066,749	1,022,891	809,146	685,359	445,103	373,347
Utah Pavant Solar QF	5,366,654	197,452	245,263	397,940	451,614	521,878	600,035	704,825	705,129	601,317	441,354	270,363	229,484
Utah Red Hills Solar QF	11,634,586	492,902	645,138	789,814	1,037,436	1,213,566	1,249,482	1,538,818	1,466,926	1,325,368	820,489	589,303	465,343
Qualifying Facilities Total	343,196,967	24,114,533	26,175,490	29,023,242	30,478,611	30,980,792	32,351,708	34,415,556	32,775,700	28,914,802	26,167,789	24,249,657	23,549,088
Mid-Columbia Contracts													
Douglas - Wells	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Reasonable	(910,306)	(75,859)	(75,859)	(75,859)	(75,859)	(75,859)	(75,859)	(75,859)	(75,859)	(75,859)	(75,859)	(75,859)	(75,859)
Grant Meaningful Priority	-	-	-	-	-	-	-	-	-	-	-	-	-
Grant Surplus	2,262,222	188,519	188,519	188,519	188,519	188,519	188,519	188,519	188,519	188,519	188,519	188,519	188,519
Grant - Priest Rapids	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid-Columbia Contracts Total	1,351,916	112,660	112,660	112,660	112,660	112,660	112,660	112,660	112,660	112,660	112,660	112,660	112,660
Total Long Term Firm Purchases	502,889,753	41,212,318	40,302,979	44,236,073	44,005,744	43,427,857	43,764,347	44,723,975	43,295,947	40,010,973	38,995,914	39,040,024	39,873,601

Storage & Exchange													
APS Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Black Hills CTs	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC II Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA So. Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
PSCO FC III	-	-	-	-	-	-	-	-	-	-	-	-	-
Redding Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
Tri-State Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	5,400,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
Short Term Firm Purchases													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	32,723,310	4,491,900	4,256,280	4,491,900	2,729,500	2,727,710	2,729,500	1,327,860	1,327,860	1,281,600	2,548,980	2,326,920	2,483,300
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	4,418,800	296,400	285,000	2,459,400	1,378,000	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Index Trades	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	37,142,110	4,788,300	4,541,280	6,951,300	4,107,500	2,727,710	2,729,500	1,327,860	1,327,860	1,281,600	2,548,980	2,326,920	2,483,300
System Balancing Purchases													
COB	10,619,542	307,660	954,727	326,258	1,171,512	747,613	1,981,047	1,703,094	1,901,089	1,110,504	84,723	331,313	-
Four Corners	39,713,473	1,974,870	4,634,622	7,516,367	7,733,315	4,227,184	1,124,020	3,207,388	1,855,291	2,715,529	1,998,437	1,809,759	916,692
Mead	4,888,348	57,552	203,538	150,486	477,811	349,284	544,390	907,306	598,579	1,015,044	188,065	243,123	153,172
Mid Columbia	86,544,320	2,278,084	1,984,252	2,086,202	3,708,883	12,728,764	6,251,811	25,398,051	21,698,636	6,173,724	1,214,580	1,226,801	1,794,534
Mona	11,586,180	1,406,343	938,757	1,177,179	390,907	375,301	475,764	1,364,636	1,163,405	1,127,198	1,073,575	1,045,879	1,047,236
NOB	19,102,345	1,872,130	977,725	911,160	1,323,909	820,156	119,476	5,163,717	4,633,315	306,138	253,250	621,121	2,100,248
Palo Verde	36,781,289	6,366,280	7,027,027	4,559,890	1,635,388	3,909,308	3,361,302	3,359,384	1,345,839	1,460,185	1,760,038	890,150	1,106,498
EIM Imports/Exports	(53,202,306)	(3,719,929)	(3,383,837)	(5,982,596)	(5,800,322)	(6,026,971)	(3,148,205)	(5,766,474)	(5,632,478)	(3,799,682)	(3,143,412)	(3,123,967)	(3,674,433)
Emergency Purchases	1,078,795	1,212	79,673	384,297	307,556	-	7,466	9,419	2,645	285,919	-	324	285
Total System Balancing Purchases	157,111,985	10,544,201	13,416,483	11,129,242	10,948,959	17,130,640	10,717,070	35,346,520	27,566,320	10,394,560	3,429,256	3,044,502	3,444,231
Total Purchased Power & Net Interc	702,543,849	56,994,820	58,710,742	62,766,615	59,512,204	63,736,207	57,660,917	81,848,355	72,640,127	52,137,133	45,424,151	44,861,446	46,251,132

Wheeling & U. of F. Expense													
Firm Wheeling	130,829,566	11,311,836	11,248,707	11,034,734	11,075,440	10,156,885	11,021,387	10,793,423	10,561,834	10,625,959	10,750,813	10,945,089	11,303,456
C&T EIM Admin fee	1,857,444	143,950	147,442	179,201	193,210	220,555	188,965	118,803	123,981	132,890	139,034	135,191	134,221
ST Firm & Non-Firm	111,096	14,815	4,842	1,956	2,394	3,643	6,050	15,961	18,039	13,859	8,138	10,080	11,318
Total Wheeling & U. of F. Expense	132,798,106	11,470,601	11,400,991	11,215,892	11,271,044	10,381,084	11,216,401	10,928,188	10,703,855	10,772,709	10,897,985	11,090,360	11,448,996
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	36,084,281	4,268,236	2,501,182	-	-	2,070,864	3,750,574	4,679,149	5,032,739	3,036,148	2,694,721	3,665,640	4,385,028
Colstrip	14,243,510	1,538,436	1,309,515	1,247,588	991,149	642,603	1,089,632	1,529,840	1,319,172	1,205,240	1,034,986	1,011,098	1,324,251
Craig	21,938,953	1,988,597	1,489,822	1,690,549	1,566,424	1,781,438	1,952,520	2,201,815	2,276,414	1,575,396	1,820,907	1,775,045	1,820,028
Dave Johnston	55,753,798	4,496,208	4,285,199	4,285,398	4,077,692	4,685,766	4,692,535	4,831,904	5,343,513	4,889,186	4,807,120	4,768,066	4,591,212
Hayden	12,517,489	1,118,799	1,164,524	552,806	694,877	1,054,850	1,020,468	1,276,027	1,233,485	1,234,788	1,102,316	935,608	1,128,940
Hunter	124,511,816	14,778,697	9,571,184	4,972,995	2,493,863	4,087,312	10,075,646	14,165,169	14,493,313	13,537,008	10,537,791	11,219,650	14,579,190
Huntington	93,998,065	11,292,148	9,575,569	8,170,739	6,290,963	5,816,070	6,807,853	10,733,420	9,227,433	6,267,679	4,596,734	5,495,872	9,723,585
Jim Bridger	218,687,356	21,611,048	21,401,126	18,838,571	13,950,183	13,400,136	14,914,777	21,336,920	19,782,227	15,095,493	15,592,889	21,257,718	21,506,267
Naughton	81,797,345	7,092,226	6,981,601	6,883,810	6,633,295	5,142,411	6,444,133	7,214,005	7,412,172	6,645,670	7,018,093	6,932,208	7,397,722
Wyodak	26,307,919	1,992,526	1,920,729	1,596,502	1,513,098	2,447,409	2,391,336	2,687,078	2,793,261	2,213,087	2,610,185	2,039,382	2,103,326
Total Coal Fuel Burn Expense	685,840,531	70,176,920	60,200,451	48,238,959	38,211,543	41,128,859	53,139,473	70,655,326	68,913,729	55,699,693	51,815,742	59,100,287	68,559,549
Gas Fuel Burn Expense													
Chehalis	52,139,910	5,337,153	5,467,854	4,386,189	3,259,216	1,634,411	2,810,478	4,304,862	5,625,487	5,511,833	5,104,155	3,212,605	5,485,667
Currant Creek	59,258,487	5,557,333	3,975,843	5,065,974	3,350,974	4,634,454	4,769,894	5,406,111	5,201,352	5,227,711	5,160,522	4,571,407	6,336,911
Gadsby	6,094,654	293,549	431,011	445,827	358,760	397,714	472,548	1,041,048	1,017,373	770,733	399,074	90,632	376,385
Gadsby CT	3,044,973	123,097	202,935	261,217	241,199	220,669	202,257	526,554	478,371	381,708	161,962	54,477	190,527
Hermiston	24,726,021	2,710,680	2,303,182	2,583,557	1,544,959	371,201	1,786,030	1,679,989	2,099,658	2,207,437	2,205,462	2,469,015	2,764,851
Lake Side 1	66,843,652	6,210,347	5,311,039	5,712,109	4,141,859	3,997,709	5,538,791	6,162,997	6,267,950	5,920,188	5,731,877	5,901,609	5,947,179
Lake Side 2	67,009,792	5,424,869	5,476,681	5,378,232	5,048,782	5,220,807	5,717,363	6,653,619	6,359,180	6,067,158	5,805,046	5,156,573	4,70 ,481
Little Mountain	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton - Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
Not Used	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	279,117,489	25,657,029	23,168,544	23,833,106	17,945,748	16,476,965	21,297,361	25,775,180	27,049,371	26,086,768	24,568,097	21,456,318	25,802,999
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	10,530,268	(527,620)	32,335	1,481,025	812,550	994,248	879,525	846,145	801,970	892,350	1,913,785	1,569,900	834,055
Clay Basin Gas Storage	-	-	-	-	-	-	-	-	-	-	-	-	-
Pipeline Reservation Fees	33,830,440	2,837,324	2,763,955	2,847,356	2,792,233	2,832,894	2,795,689	2,861,646	2,859,216	2,808,861	2,830,393	2,772,441	2,828,432
Total Gas Fuel Burn Expense	323,478,197	27,966,733	25,964,834	28,161,487	21,550,532	20,304,107	24,972,576	29,482,971	30,710,557	29,787,979	29,312,275	25,798,659	29,465,486
Other Generation													
Blundell	4,676,489	420,164	379,337	390,099	334,480	382,059	368,962	393,286	395,628	376,077	396,646	412,279	427,471
Blundell Bottoming Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-
Cedar Springs Wind II	-												
Dunlap I Wind	-												
Ekola Flats Wind	-												
Foote Creek I Wind	-												
Glenrock Wind	-												
Glenrock III Wind	-												
Goodnoe Wind	-												
High Plains Wind	-												
Leaning Juniper 1	-												
Marengo I Wind	-												
Marengo II Wind	-												
McFadden Ridge Wind	-												
Rolling Hills Wind	-												

Seven Mile Wind	-												
Seven Mile II Wind	-												
Black Cap Solar													
TB Flats Wind													
TB Flats Wind II													
Integration Charge	7,450,204	655,485	596,496	619,963	586,682	602,965	623,486	682,947	653,558	581,779	583,138	604,372	659,335
Total Other Generation	12,126,693	1,075,649	975,832	1,010,062	921,162	985,024	992,447	1,076,233	1,049,186	957,856	979,784	1,016,651	1,086,806
Net Power Cost	**1,476,367,261**	129,242,799	122,158,576	119,260,449	110,863,778	114,150,116	123,786,907	153,248,227	134,894,079	118,902,557	110,882,340	114,036,203	124,941,230
Net Power Cost/Net System Load	**24.71**	**24.42**	**25.60**	**24.94**	**24.46**	**24.22**	**24.99**	**26.91**	**24.81**	**25.09**	**23.78**	**23.66**	**23.37**

Docket No. UE 356
Exhibit PAC/403
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Michael G. Wilding

2020 Corrections and Updates Summary Reply Filing

July 2019

Oregon TAM 2020 (April 2019 Initial Filing)			
		NPC ($) =	1,479,821,158
		$/MWh =	24.77

	Impact ($) Oregon Allocated Basis	NPC ($) Total Company
Corrections		
C01 - Hunter 2 Cycling	(83,715)	
C02 - Partial Repower Wind Plant	(58,303)	
Accepted Adjustments		
A01 - Repower Capacity Factor (February 2018 Analysis)	(18,295)	
A02 - Gas Transmission Northwest Tariff Rate	(50,494)	
Updates		
U01 - Glenrock III Repower	44,114	
U02 - Official Forward Price Curve and Short Term Firm Transactions	5,206,639	
U03 - Coal Costs	(1,503,176)	
U04 - QF Contract Status	(326,194)	
U05 - EIM Benefits	(4,208,326)	
U06 - Long Term Contracts	281,401	
Total Changes =	(716,349)	
Total Change from April 2019 Initial Filing		(3,453,897)
Oregon TAM 2020 (July 2019 Filing)	**NPC ($) =**	**1,476,367,261**
	$/MWh =	**24.71**

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Exhibit Accompanying Reply Testimony of Michael G. Wilding

2020 Other Revenue Reply Filing

July 2019

PacifiCorp
CY 2020 TAM
Other Revenues - Stand Alone TAM Adjustment
Reply Update

Line no		Total Company UE-339 Final	Total Company CY 2020 Initial	Total Company CY 2020 Reply	Factor	Factors CY 2019	Factors CY 2020	Oregon Allocated UE-339 Final	Oregon Allocated CY 2020 Initial	Oregon Allocated CY 2020 Reply
1	Seattle City Light - Stateline Wind Farm	(11,086,374)	(11,302,961)	(11,302,961)	SG	26.725%	26.456%	(2,962,812)	(2,990,294)	(2,990,294)
2	Non-company owned Foote Creek	(884,834)	(691,961)	(568,297)	SG	26.725%	26.456%	(236,470)	(183,064)	(150,348)
3	BPA South Idaho Exchange	-	-	-	SG	26.725%	26.456%	-	-	-
4	Little Mountain Steam Revenues	-	-	-	SG	26.725%	26.456%	-	-	-
5	James River Royalty Offset	-	-	-	SG	26.725%	26.456%	-	-	-
6										
7	Total Other Revenue	(11,971,208)	(11,994,922)	(11,871,258)				(3,199,282)	(3,173,358)	(3,140,642)
8										
9	Decrease (Increase) in Other Revenues Absent Load Change								25,924	58,641
10										
11	Baseline Other Revenues in Rates							(3,199,282)		
12	$ Change due to load variance from UE 339 CY 2019 forecast							(42,021)		
13	Other Revenues in Rates using 2020 load forecast							(3,241,304)		
14										
15	**Decrease (Increase) in Other Revenues Including Load Change**								**67,946**	**100,662**

Docket No. UE 356
Exhibit PAC/405
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Michael G. Wilding

2020 Energy Imbalance Market Costs Reply Filing

July 2019

PacifiCorp
Oregon 2020 TAM
EIM Costs
Reply Update - July 15, 2019

$ dollars

	CY 2020 EIM Costs 13 Month Average							
	Total Company			Factor	Factors	Oregon Allocated		
	2019 Final	Initial Filing	Reply Update		CY 2020	2019 Final	Initial Filing	Reply Update
Capital Investment	16,437,307	16,437,307	16,437,307	SG	26.456%	4,392,839	4,348,628	4,348,628
ADIT	(1,853,075)	(1,225,243)	(1,149,299)	SG	26.456%	(495,231)	(324,148)	(304,057)
Depreciation Reserve	(11,426,214)	(12,019,754)	(12,085,344)	SG	26.456%	(3,053,634)	(3,179,927)	(3,197,280)
Net Rate Base	3,158,017	3,192,309	3,202,664			843,974	844,552	847,292
	9.30%	9.30%	9.30%			9.30%	9.30%	9.30%
Pre-Tax Return on Rate Base	$ 293,558	$ 296,746	$ 297,709	SG	26.456%	$ 78,453	$ 78,507	$ 78,761
Operation & Maintenance (Ongoing)	1,300,577	997,976	918,102	SG	26.456%	347,577	264,023	242,892
Depreciation	1,485,613	277,314	277,314	SG	26.456%	397,027	73,366	73,366
Total Revenue Requirement	$ 3,079,748	$ 1,572,036	$ 1,493,124			$ 823,057	$ 415,895	$ 395,019
CAISO Fee in net power costs	$ 1,429,782	$ 1,857,444	$ 1,857,444	SG	26.456%	382,107	491,403	491,403
Total EIM Costs	$ 4,509,530	$ 3,429,480	$ 3,350,568			$ 1,205,163	$ 907,298	$ 886,421

Docket No. UE 356
Exhibit PAC/406
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Michael G. Wilding

Adopted Testimony Excerpts

July 2019

WIND PRODUCTION ESTIMATES AND PRODUCTION TAX CREDIT (PTC) IMPUTATION

Q. What risk related to wind production estimates are raised by the parties?

A. Staff states that customers face "quantity risk" which he defines as the risk that actual generation from the repowered facilities will be less than forecast resulting in lower PTCs than estimated.[2] CUB recommends that the Commission set a "PTC floor" that would guarantee that customers receive at least the projected value of the PTC benefit from the wind repowering project that was included in the company's economic analysis.[3]

Q. Does the company agree with these recommendations?

A. No, these extraordinary conditions unreasonably penalize the company for prudently operating its existing generation facilities. PacifiCorp's use of actual historical generation data, combined with the conservative use of this data to determine forecasted energy production for the repowered facilities should give the Commission confidence that the company's forecast of customer benefits associated with PTCs is accurate. A PTC floor, which is effectively an imputation of a set capacity factor, inappropriately shifts risk to PacifiCorp for situations beyond the company's control, such as extreme weather events, wind conditions that deviate from the prior operational history, or other unforeseen circumstances.

Q. Is Staff's fear of "quantity risk" valid?

A. No. As described in my opening testimony,[4] the company's estimate of the energy

[2] OPUC/100, Storm/54.
[3] CUB/100, Gehrke/3.
[4] PAC/200, Hemstreet/12-13.

production (and thus capacity factors) for the repowered facilities is based on the extensive historical data of the currently-operating wind facilities.[5] This data includes actual curtailments, as well as planned and unplanned outages experienced at each of the facilities. Relying on the actual production history is more conservative and likely more accurate than relying upon estimates of how these impacts may affect energy production following repowering.

Q. Does the company's use of actual historical data to forecast energy production appropriately apportion risk between the company and customers?

A. Yes. As explained in my opening testimony, the energy estimates developed by the company are intentionally conservative to reduce risk to customers.[6] As further detailed in my opening testimony, technological advances that will be installed as part of the wind repowering project are likely to reduce turbine down-time, but these improvements to availability (compared to historical availability) were not included in the company's energy estimates.[7] As a result, energy production could be more than estimated and the "quantity risk" alleged by Staff is unlikely. It is also important to note that availability guarantees further protect customers from the alleged risk that repowering will not increase generation as expected. The service and maintenance contracts that the company has entered into for the repowered facilities include availability guarantees that require the service providers to compensate the company for lost generation as a result of failing to meet guaranteed availability targets. Thus,

[5] PAC/200, Hemstreet/13-14.
[6] PAC/200, Hemstreet/13-14.
[7] PAC/200, Hemstreet/14.

customers are protected from risks that equipment down time will hamper production, and thus PTC benefits.

Q. Have any of the parties raised issues with the manner in which the company estimated the expected energy production that would result from the wind repowering project?

A. No.

Q. What is the impact to customers if energy production, and thus PTC value, is less than the company's estimates?

A. As discussed in Mr. Rick T. Link's opening testimony, the wind repowering project is forecast to provide present-value revenue requirement differential (PVRR(d)) benefits under all evaluated price-policy scenarios, with project-wide benefits evaluated in February 2018 ranging between $121 million to $466 million.[8] Given this range of substantial benefits, I believe customers will still benefit even if energy production, and thus PTC value, is less than the company's estimates. Setting a PTC floor will not result in increased forecast accuracy and would penalize the company for deviations, however reasonable and normal, from the estimated customer benefit.

Q. Are there any other reasons that setting a PTC floor is inappropriate?

A. Yes. Setting a PTC floor requires the company to hold customers harmless and bear the associated risk from natural, variable wind conditions that are beyond its control. While there is no reason to expect long-term wind conditions to deviate substantially from past experience, differences in future frequency, duration, and intensity of wind

[8] PAC/300, Link/3.

speed conditions will impact performance of the repowered turbines (and the resulting PTC Value). It is unfair for the company to unilaterally bear this risk.

If the Commission were to adopt a PTC floor, it would only be fair to also adopt the corollary, *i.e.*, that the company should solely benefit from any energy and PTC value produced from the repowered wind facilities that surpass the values included in the company's economic analysis.

Q. Has the Commission ever mandated that the company guarantee production and PTC values for the company's wind facilities?

A. To my knowledge, the Commission has never adopted a mechanism that requires the company to guarantee the generation output from its wind facilities. In fact, and as discussed in greater detail in the reply testimony of Ms. Etta P. Lockey, the Commission has consistently rejected this approach.[9]

Q. Do you have other concerns with a PTC floor condition?

A. Yes. Imposing a PTC floor could have unintended consequences because it is possible that the company could operate the wind facilities differently than it has historically and forecast in the company's economic analysis and create less PTC value, but still deliver equivalent or greater benefits to customers. This could occur if market conditions signal a dispatch of the facilities that is different than historic but that is more economic for customers. For instance, curtailment of the facilities during certain market and load/resource conditions could be more economic than running the facilities. Additionally, curtailment could be warranted under some conditions if it reduced equipment failure or maintenance requirements, thereby saving operational

[9] PAC/600, Lockey/16-17.

costs. A PTC floor would dictate the operational regime of the facilities to produce the highest PTC value, even if that regime doesn't provide the greatest benefit to customers.

Q. Could a PTC floor condition create other problems?

A. Yes. Parties have been unclear in articulating how the PTC value would be determined. Specifically, it is unclear if a PTC floor would require that a certain energy production floor be mandated, or simply that the PTC value in the company's economic analysis be guaranteed to customers. Because the value of the PTC for customers depends on the company's effective federal and state corporate tax rate, providing a PTC floor could require that the company hold customers harmless should these corporate tax rates be reduced. This would have the unreasonable effect of benefiting customers due to reduced income tax collected through rates, while also requiring the company to hold the PTC value constant for customers.

Q. Are economic backstops for the wind repowering project necessary?

A. No. No party has argued that the wind repowering project is imprudent, or that the wind repowering project presents risk factors different from normal resource acquisition that would warrant adoption by the Commission of extraordinary rate making conditions.

PROJECT COSTS

Q. What does CUB recommend with regard to project costs?

A. CUB recommends that cost recovery be subject to a construction cost cap to protect customers from the risk of construction cost overruns.[10]

[10] CUB/100, Gehrke/7.

III. IRP ACKNOWLEDGMENT

Q. Did the Commission acknowledge repowering in the 2017 IRP?

A. Yes, at the Special Public Meeting on December 11, 2017, the Commission acknowledged the 2017 IRP, including the action items related to PacifiCorp's Energy Vision 2020 projects (which includes repowering along with new wind and transmission), with conditions.[6] In particular, the Commission directed PacifiCorp to update its analysis supporting wind repowering as part of the 2017 IRP Update.[7] The Commission also clarified that risk of proceeding with these Energy Vision 2020 projects remains with PacifiCorp unless and until the Commission completes a prudence review and authorizes recovery. In so doing, the Commission noted that it could "hold PacifiCorp to the cost and benefit projections in its analysis[]" as a potential means of mitigating customer risk exposure.[8]

Q. Please provide some context for the Commission's order.

A. Because of the critical timelines associated with qualification for PTCs, the company pursued IRP acknowledgment and pre-approvals of the Energy Vision 2020 projects concurrently with the development of these projects. The uncertainty around some key project inputs led to concerns about potential project risk. While most of these concerns focused on the new wind and transmission projects, with respect to wind repowering, the federal income tax law changes passed in December 2017 raised questions about the economics of the project.

[6] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Integrated Resource Plan*, Docket No. LC 67, Order No. 18-138, at 1, 12 (Apr. 27, 2018) ("Order No. 18-138").
[7] *Id.* at 8.
[8] *Id*.

Q. Did PacifiCorp update its economic analysis of wind repowering to take into account federal income tax changes, consistent with the Commission's direction in the 2017 IRP acknowledgment order?

A. Yes. As noted above, PacifiCorp developed its February 2018 analysis and included it in the 2017 IRP Update. This analysis confirmed that wind repowering continues to provide significant net benefits to customers after accounting for changes in the federal income tax law.

Q. In the 16 months that have passed since IRP acknowledgement, has the company managed and mitigated other project risks raised in the IRP process, such as the risk of construction cost overruns or delays?

A. Yes. PacifiCorp witness Mr. Timothy J. Hemstreet testifies that repowering of the wind facilities in this case is on schedule and on budget.[9]

Q. Does PacifiCorp's robust economic analysis also address concerns about project risk?

A. Yes. As described in my opening testimony, PacifiCorp's analysis accounts for a significant range of risks by reviewing nine different price and policy scenarios, measured over a 20-year and 30-year time frame. PacifiCorp reviewed the economics of repowering on a total-project and facility-by-facility basis and tested the results with several different sensitivities. In virtually every case, wind repowering shows substantial net benefits to customers, demonstrating the risk-resilient nature of the wind repowering project.

[9] PAC/700, Hemstreet/1.

Q. In its testimony, Staff focuses on the results of the July 2017 analysis and a PacifiCorp presentation to the Commission in September 2017, not the February 2018 analysis. Why does Staff take this approach?

A. While it is not entirely clear, it appears that Staff views the 2017 IRP order as setting a floor on repowering benefits based on the then most current analysis—which it claims is the July 2017 analysis and the September 2017 presentation.

Q. Is this approach correct?

A. No. Prudence reviews are based on the most recent information the company has at the time it makes a decision to move forward with a project, not on historical, outdated analysis. In this case, the February 2018 analysis, as validated by the August 2018 analysis, was the analysis that the company relied upon for its decision to repower its wind facilities.

Q. Does the IRP order create a floor on repowering benefits for ratemaking purposes as both Staff and CUB[10] allege?

A. No. In the acknowledgment order, the Commission simply noted that it retains the right to impose conditions on recovery if appropriate.[11] As the Commission explained elsewhere in the Order:

> Our decision to acknowledge or not acknowledge an action item does not constitute ratemaking. The question of whether a specific investment made by a utility in its planning process *was prudent* will be fairly examined in the subsequent rate proceeding. Acknowledgment, or non-acknowledgment, of an IRP is a relevant but not exclusive consideration in our subsequent examination of whether the utility's resource investment *is prudent* and should be recovered from customers.[12]

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[10] CUB/100, Gehrke/5.
[11] Order No. 18-138 at 8.
[12] *Id.* at 3 (emphasis added).

In other words, when the prudence of a utility action is challenged, the Commission's acknowledgement decision and any conditions imposed during the resource planning process is one factor used to inform the prudence review. Here, however, no party even challenges the prudence of wind repowering, given the substantial value proposition for customers. Therefore, the Commission's conditions on acknowledgement in docket LC 67 do not dictate ratemaking treatment, and Staff's and CUB's efforts to convert the acknowledgement order into a ratemaking order are improper.

Q. In its testimony, Staff includes two slides from the September 14, 2017 presentation.[13] Were these slides based on the first update to the IRP analysis filed in July 2017?

A. Yes.

Q. Staff describes the content of these slides in its testimony. Do you agree with Staff's summary?

A. Not entirely. Staff claims that Figure 3 on slide four shows that, on an annual revenue requirement basis, repowering does not show a net cost for any year prior to 2029.[14] The updated analysis in July 2017 includes a more granular depiction of annual revenue requirement impacts in Figure 3.2.[15] This shows small increases in revenue requirement in certain years until 2021 when repowering is fully implemented.

[13] Staff/100, Storm/30-36.
[14] Staff/100, Storm/32.
[15] PacifiCorp's 2017 Integrated Resource Plan, Energy Vision 2020 Update at 19 (July 28, 2017).

Q. Why is this distinction important?

A. Staff appears to be relying on Figure 3 on slide four to support the argument that PacifiCorp's economic analysis in July and September of 2017 showed no net revenue requirement costs from repowering before 2029, so PacifiCorp must now demonstrate that the benefits in the TAM are greater than the costs in the RAC.[16] This argument is incorrect for a number of reasons. First, as explained above, the 2017 IRP acknowledgment order did not impose a floor on wind repowering benefits. Second, it is inappropriate to look to the July 2017 analysis in determining the prudence of wind repowering, because it was superseded by the company's February 2018 economic analysis. Third, as just noted, the July 2017 analysis does not show that there are no net costs in post-wind repowering revenue requirement until 2029. Fourth, PacifiCorp's revenue requirement economic analysis does not forecast the rate impacts of wind repowering because it does not consider base rates. Instead, the analysis simply reviews the revenue requirement differential with and without wind repowering. While the revenue requirement analysis provides an indication of how wind repowering will impact rates all else equal, it does not forecast specific rate changes relative to current base rates.

[16] Staff/100, Storm/62-63 (noting that the company's proposed RAC revenue requirement produces a rate increase of approximately $5 million in 2019, which when compared with the $7.7 million in benefits in the TAM "adequately validates the general result depicted in Figure 3 for calendar 2019; i.e. that wind repowering benefits exceed costs.") As explained in Ms. Lockey's reply testimony, in the final TAM update, the repowering benefits are approximately $4.5 million PAC/600, Lockey/5.

IV. REPOWERING AND SYSTEM NEED

Q. Staff asserts "that PacifiCorp is making these wind repowering investments at this time due to the [net customer] benefits . . . , including the availability of the PTC[.]"[17] What point is Staff making in this statement?

A. It is my understanding that Staff is reiterating a position it took on the issue of system need during the 2017 IRP proceeding, a position that was fully litigated without resolution. Specifically, Staff appears to be asserting that PacifiCorp does not have a "near-term and clearly identified capacity or RPS compliance need" for repowering and therefore that the Commission should take extraordinary steps in this proceeding to mitigate customer risk.[18] CUB takes a similar position in its testimony to justify imposition of a floor on PTC benefits.[19]

Q. Is Staff's and CUB's focus on system need appropriate in the context of reviewing the prudence of the wind repowering project?

A. No. Repowering involves upgrading and optimizing an existing resource to reduce customer costs, so system resource need is not a requisite finding to approve cost recovery of the wind repowering project. Staff's and CUB's argument that PacifiCorp should not repower its existing wind facilities in the absence of a system resource need is effectively an argument that the company should not optimize its system resources in real time to minimize costs simply because the activity is not required to serve customers.

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[17] Staff/100, Storm/19.
[18] *Id.* at 19-20, 56-59.
[19] CUB/100, Gehrke/5.

Q. Did CUB file comments in the 2017 IRP contesting the applicability of the "need" standard to wind repowering for the reasons just stated?

A. Yes. In its comments on Staff's Public Meeting Memorandum in docket LC 67, CUB observed that "repowering of existing wind facilities" is more properly evaluated as a form of utility asset management:

> Utilities are generally expected to manage their rate[]-based assets in the best interest of customers. This means utilities take opportunities for off-system sales when the revenue can be used to offset rates. The Energy Imbalance Market is a form of asset management, where the utility adds remote dispatch functionality to a plant. This added functionality allows the plant to participate in the EIM and therefore generate revenue to offset costs. Repowering plants is not new. Utilities have repowered hydro plants to increase production. PGE upgraded two low pressure turbines at Boardman in 2000 by installing new rotors to increase efficiency. *In such a case, the question of need rests with the original investment in the plant. Once that investment is made and is found to be prudent, repowering can be viewed through the lens of whether it is an economically beneficial use of the underlying plant.*[20]

Q. Do you agree with Staff's and CUB's implication that there is no near-term system resource need for wind repowering?

A. No. In developing the load-and-resource-balance for the 2017 IRP, PacifiCorp incorporated a 13 percent target planning reserve margin to calculate its total projected resource obligations over the planning period. PacifiCorp's existing, committed resources were insufficient to meet these obligations, even in the near term.[21] By definition, therefore, the company faced a near-term resource need.

The IRP evaluated a wide range of resources that could help meet this need, such as gas-fired resources, uncommitted front office transactions, and renewable

[20] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Integrated Resource Plan*, Docket No. LC 67, Oregon Citizens' Utility Board's Comments on Staff's Recommendations, at 9-10 (Oct. 30, 2017) (emphasis added; paragraph structure altered).

[21] *See* 2017 IRP p.17 (even with both repowering and front office transactions incorporated into the preferred portfolio, projecting an energy shortfall during on-peak hours in the summer of 2022).

resources, including the wind repowering project. All of these resources competed on an equal basis, and none of the model runs that include repowering achieved a planning reserve margin above 13 percent. The preferred portfolio resulting from this analysis included the wind repowering project. This means that repowering is part of the optimal (least-cost, least-risk) mix of resources for fulfilling a resource need in the IRP.

Q. Staff implies that in docket LC 67, the Commission found there was no system need for the wind repowering project.[22] Do you agree with this characterization of the Commission's 2017 IRP order?

A. No. In docket LC 67, the issue presented to the Commission was whether there was a system need for the collective set of Energy Vision 2020 projects, which includes new wind and transmission projects in addition to the wind repowering project. In that proceeding, the need discussion was primarily focused on new wind projects, not repowering. In any event, in Order No. 18-138, the Commission did not find there was no need for the Energy Vision 2020 projects, let alone no need for the wind repowering project specifically. In fact, the Commission left the issue of need explicitly unresolved.[23]

[22] Staff/100, Storm/19 ("As the wind repowering projects are motivated by potential economic benefits to customers and not by meeting some near-term and clearly identified capacity or RPS compliance need, the Commission included language that makes clear that it will appropriately mitigate risks to customers regarding a number of uncertainties associated with the wind repowering projects.").
[23] Order No. 18-138 at 9 ("[W]e do not definitively resolve questions surrounding need[.]"); *id.* at 11 (adding conditions to PacifiCorp's 2017 IRP Action Plan to help address various questions in future IRPs regarding front office transactions, including "whether displacing FOTs could constitute a resource need").

the wind repowering project for PTCs, and Staff's recommendation would severely penalize the Company for taking an action that delivers substantial PTC benefits to customers.

Q. AWEC takes issue with PacifiCorp's proposal to leave base rates unchanged and include only incremental costs of repowering in the RAC.[28] How do you respond?

A. As Mr. McDougal explains, PacifiCorp's proposal to leave base rates unchanged is a fair and reasonable way to address cost recovery of the replaced equipment on an interim basis.[29] While AWEC claims this proposal is too complex, AWEC proposes an even more complex solution: AWEC attempts to retroactively account for past accumulated depreciation, creates a regulatory asset under ORS Section 757.140(2), uses a sinking fund method for amortizing the regulatory asset balance over a period of seven or nine years, and applies a pre-tax or post-tax carrying charge depending on the amortization period.[30]

IV. PROPOSED CONDITIONS ARE UNWARRANTED

Q. Please describe the conditions Staff and CUB propose with respect to PTC guarantees.

A. Staff recommends the Commission "impute values of net PTC benefits" in each annual TAM filing to be "no less than the net PTC benefits included in the company's economic analyses supporting these wind repowering projects."[31] For purposes of

[28] *See* AWEC/100, Mullins/14-17.
[29] PAC/900, McDougal/1-2.
[30] *See* AWEC/100, Mullins/17-20.
[31] Staff/100, Storm/58-59.

establishing this PTC floor, it is not clear whether Staff seeks to rely on the economic analysis from the 2017 IRP or on a more recent vintage.[32] Staff further recommends exempting benefits of wind repowering from the deadband, sharing, or earnings test provisions in PacifiCorp's annual PCAM.[33]

CUB similarly recommends the Commission set the PTC benefits projected in this proceeding as "a floor on PTCs included in rates."[34]

Q. On what basis do Staff and CUB seek to impose conditions on cost recovery for wind repowering?

A. Notably, Staff and CUB do not seek cost recovery conditions on the basis that wind repowering is imprudent. Instead, they claim that conditions are justified because repowering is driven purely by economic opportunity rather than need.[35] They also rely on the Commission's order acknowledging PacifiCorp's 2017 IRP, because the Commission observed that recovery could be structured to hold PacifiCorp to the economic projections in its original IRP analysis.[36]

Q. Do these arguments support imposition of a PTC floor or other cost recovery conditions?

A. No. As explained by Mr. Link in his reply testimony, (1) wind repowering should be evaluated through the lens of utility asset management, not resource need;[37] (2) wind repowering does help fill an established need for uncommitted resources, as identified

[32] *See* Staff/100, Storm/59, 75.
[33] *See* Staff/100, Storm/2, 58, 75-76.
[34] CUB/100, Gehrke/5.
[35] Staff/100, Storm/56, 58; CUB/100, Gehrke/5.
[36] Staff/100, Storm/56 (quoting Order No. 18-138 at 8); CUB/100, Gehrke/4 (quoting Order No. 18-138 at 8).
[37] PAC/800, Link/13.

in the 2017 IRP;[38] and (3) the Commission itself caveated that its conditions on acknowledgment do not dictate ratemaking treatment.[39]

Q. Is there an Oregon statute that governs how PTCs are to be included in rates?

A. Yes. ORS 757.264 requires that utilities forecast PTC benefits on an annual basis. The statute provides that "the Public Utility Commission shall allow those forecasts to be included in rates through any variable cost forecasting process established by the Commission."

Q. As a result of ORS 757.264, does PacifiCorp include annual PTC forecasts in the TAM?

A. Yes. PacifiCorp includes annual PTC benefit forecasts in the TAM; issues relating to PTC benefits are therefore addressed in the TAM, not the RAC.

Q. Is the PTC floor proposed by Staff and CUB contrary to ORS 757.264?

A. Yes. The statute requires the Commission to set rates based on PacifiCorp's annual PTC forecast in the TAM, not impute PTC benefits in the RAC based on a ten-year forecast.

Q. On the whole, are the PTC benefits for repowering in the 2019 and 2020 TAM higher than the PTC benefits in the company's economic analysis for wind repowering?

A. Yes. PTC benefits are primarily a function of a wind facility's capacity factor. As noted in Mr. Hemstreet's opening testimony, the capacity factors used in PacifiCorp's economic analysis for wind repowering are based on cumulative historical averages.[40]

[38] PAC/800, Link/13-14.
[39] PAC/800, Link/3.
[40] *See* PAC/200, Hemstreet/13-14.

In the 2019 TAM, the company proposed to use the same historical averages to forecast wind plant performance and PTCs.[41] Staff and AWEC objected, however, and the parties stipulated on an approach that uses a 50/50 blend of (1) the P50 production estimates when each wind facility was initially developed; and (2) cumulative historical averages. To avoid controversy, the company continued this approach in the 2020 TAM on a non-precedential basis.[42] For all but two of the wind facilities (McFadden Ridge and Seven Mile Hill II), the 50/50 blend produces higher capacity factors—and therefore higher PTCs—than the cumulative historical average. Thus, to the extent there is any difference between the PTC forecasts in the 2019 and 2020 TAM and the company's repowering economic analysis, it is because Staff and AWEC proposed these changes and they are beneficial to customers on an overall basis.

Q. Staff and CUB claim that there is a need for a PTC benefit floor because of the risk of wind underperformance. Do you agree that this risk warrants the proposed condition?

A. No. As described by Mr. Hemstreet in his opening testimony, PacifiCorp worked with an expert consultant, relying on extensive data history from these facilities, including millions of data points from the operational record, to generate the capacity factors.[43] In other words, unlike the construction of a new wind facility, capacity factors for the repowering project incorporate actual production history. In addition, PacifiCorp negotiated mechanical availability guarantees with the manufacturers of

[41] Docket No. UE 339, PAC/100, Wilding/39.
[42] Docket No. UE 356, PAC/100, Wilding/32.
[43] PAC/200, Hemstreet/13.

the new wind equipment, GE and Vestas, including liquidated damage provisions if the turbines fail to meet guaranteed availability.[44]

Q. Does Staff acknowledge that PacifiCorp has managed the capacity factor risk associated with its wind repowering economic forecasts?

A. Yes.[45]

Q. In the 2019 TAM, did AWEC agree that the PTC forecasts used in PacifiCorp's repowering analysis were reasonable and accurate?

A. Yes. AWEC noted that "the capacity factors assumed in the repowering proposal were the result of engineering studies that were based on the most recent data available to PacifiCorp."[46] Therefore, AWEC opined that "there is no reason to doubt the accuracy of those assessments in the long term."[47] This supports the company's position that the risk of wind underperformance is insufficient to justify Staff's and CUB's proposed PTC floor.

Q. Is there any Commission precedent for imputing capacity factors as Staff and CUB effectively propose?

A. No, the Commission has consistently rejected such an approach. In PacifiCorp's 2009 RAC proceeding, the Commission denied a proposal by Staff to impute a higher capacity factor to the Glenrock facility in determining net variable power costs, based on an outdated CH2M Hill study that had since been superseded.[48] The Commission stated:

[44] PAC/200, Hemstreet/18.
[45] *See* Staff/100, Storm/55-56.
[46] Docket No. UE 339, AWEC/100, Mullins/7.
[47] *Id.*
[48] Order No. 08-548, at 4-5, 21.

> Although the estimated capacity factor at the time of project approval is dispositive for purposes of prudency review, it is not dispositive for purposes of forecasting resource availability for ratemaking purposes. The most recent reliable data should be used to set rates for the test period[.] . . .[49]

Similarly, in PacifiCorp's 2016 TAM proceeding, docket UE 296, the Commission approved the company's proposal to use actual production data to develop capacity factors for wind purchase power agreements, over the objection of ICNU.[50] ICNU had recommended using the original capacity factor forecasts, because actual generation had been lower than expected when the wind resources were acquired.[51] In rejecting ICNU's recommendation, the Commission found that "[f]orty-eight months of actual operation is sufficient for deriving a reasonable forecast of expected wind generation at a site that is superior to the long-range forecasts provided by the project owners."[52]

Q. As part of the PTC floor described above, Staff proposes tracking 100 percent of the wind repowering benefits in the PCAM.[53] Is this approach reasonable?

A. No. PacifiCorp does not support the PCAM's deadbands, sharing bands, and earnings test, in part because PacifiCorp wants to provide customers 100 percent of all variable cost offsets, such as the wind repowering benefits in this case. However, Staff proposes the removal of the deadbands and sharing bands as part of the PTC floor. There is no justification to modify the PCAM in this proceeding.

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[49] *Id.* at 21.
[50] *In the Matter of PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Order No. 15-394 at 6-7 (Dec. 11, 2015).
[51] *Id.* at 6-7.
[52] *Id.* at 7.
[53] Staff/100, Storm/2, 58, 75-76.

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Exhibit PAC/407
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Michael G. Wilding

AWEC Data Request 008 and 009

July 2019

UE 356 / PacifiCorp
May 28, 2019
AWEC 1st Set Data Request 008

AWEC Data Request 008

Please provide an explanation of how PacifiCorp accounts for natural gas sales transactions when calculating and forecasting actual net power costs.

Response to AWEC Data Request 008

The company assumes that this request intended to ask about transactions when calculating and forecasting "net power costs" as opposed to forecasting "actual net power costs" on the basis that net power costs (NPC) are either forecasted or actuals. Based on the foregoing assumption, the company responds as follows:

The natural gas sales transactions forecast are based on the natural gas transactions the company executes on a forward basis. The dollar amount of each natural gas sales transaction is the multiplication of the transacted volume and the prices. The prices can be fixed prices or floating prices, depending on how each natural gas transaction is constructed. For the detailed calculation of the natural gas sales transactions, please refer to the confidential 5-day transition adjustment mechanism (TAM) work papers supporting the direct testimony of company witness, Michael G. Wilding, specifically file "ORTAM20w_Gas Swaps (1812) FEB19 CONF.xlsx," tab "Gas Swap Source," columns AD to AJ.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

UE 356 / PacifiCorp
May 28, 2019
AWEC 1st Set Data Request 008

AWEC Data Request 009

Please provide detail of each physical natural gas sales transaction executed over the period January 1, 2018 through December 31, 2018 in a format substantially similar to the work paper "ORTAM20w_Gas Swaps (1812) FEB19 CONF."

Response to AWEC Data Request 009

Please refer to the Confidential Attachment AWEC 009.

Confidential Attachment AWEC 009 is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

Docket No. UE 356
Exhibit PAC/408
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Michael G. Wilding

Exhibit PAC 110 from UE 339

July 2019

PacifiCorp Fixed Generation Revenue Requirement (Oregon Allocated)

PacifiCorp
State of Oregon
Historical Time Series of Fixed Generation Costs by Component

PacifiCorp Calculation:	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2006-2015 CAGR	2007-2016 CAGR
Total Rate Base	719,894,639	1,336,508,766	1,648,371,025	1,713,216,752	1,736,954,242	1,815,681,297	1,794,346,075	1,741,041,460	1,826,116,636	1,739,528,889	1,805,483,948		
Return On Rate Base	64,124,515	109,072,480	133,092,971	140,980,607	144,705,658	145,853,679	138,451,743	133,485,908	138,457,223	130,996,877	136,582,739		
Operating & Maintenance Expense	92,140,549	112,008,196	125,482,619	121,104,940	152,130,476	150,819,888	138,323,152	141,947,327	135,214,927	131,405,825	130,145,756		
Depreciation Expense	38,586,197	63,647,725	73,558,287	78,272,259	82,673,386	87,223,385	97,979,807	117,977,610	124,957,867	126,319,661	134,023,569		
Amortization Expense	5,662,778	9,141,066	9,063,926	8,407,431	9,090,180	8,660,604	7,679,640	8,268,200	8,969,338	8,521,880	8,692,851		
Taxes Other Than Income	9,609,011	11,989,900	14,060,167	15,439,056	17,203,839	19,052,597	19,151,857	19,728,897	20,128,593	20,996,832	21,800,785		
Federal Income Taxes	10,360,962	22,917,351	(8,228,622)	(47,947,716)	(101,224,567)	(80,071,075)	(52,659,018)	(22,320,370)	(34,470,831)	(13,355,054)	6,315,414		
State Income Taxes	1,354,613	4,376,898	429,505	(4,447,668)	(11,062,618)	(8,721,273)	(4,834,371)	(770,019)	(647,970)	412,968	2,924,138		
Deferred Income Taxes	(764,258)	10,795,533	68,400,565	87,034,858	125,582,322	104,256,684	72,928,113	37,266,342	65,285,463	37,775,968	25,003,898		
Misc Revenue & Expenses	(394,395)	(2,708,250)	(3,682,256)	(2,066,374)	(1,323,121)	(705,446)	(370,209)	(125,422)	(80,155)	(233,471)	(87,310)		
Revenue Credits	(3,487,558)	(14,358,942)	(13,512,764)	(24,765,022)	(17,404,366)	(17,533,328)	(16,390,747)	(14,380,891)	(11,649,449)	(9,314,713)	(7,448,743)		
Revenue Requirement ($)	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	433,526,775	457,953,097	**7.98%**	**3.82%**
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821	**-0.06%**	**-0.62%**
Revenue Requirement ($/MWh)	**14.70**	**21.03**	**25.98**	**25.28**	**27.47**	**28.38**	**27.53**	**28.93**	**30.26**	**29.49**	**31.15**	**8.04%**	**4.46%**
Removal of New Generation Resources													
Gross Plant in Service	(49,761,699)	(176,569,028)	(369,536,740)	(559,776,877)	(655,685,369)	(691,632,310)	(679,220,340)	(660,057,047)	(749,958,320)	(839,283,616)	(867,921,408)		
Accumulated Depreciation	1,705,852	7,651,256	20,686,507	40,038,375	61,385,629	86,513,258	109,156,546	129,609,237	155,074,563	183,020,814	216,695,793		
Accumulated Deferred Income Taxes	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA		
Total Rate Base Reduction	(48,055,847)	(168,917,772)	(348,850,233)	(519,738,503)	(594,299,740)	(605,119,052)	(570,063,794)	(530,447,810)	(594,883,757)	(656,262,802)	(651,225,615)		
Return On Rate Base	(4,280,568)	(13,785,379)	(28,166,907)	(42,769,281)	(49,511,111)	(48,609,213)	(43,986,122)	(40,669,513)	(45,104,432)	(49,420,494)	(49,264,453)		
Operating & Maintenance Expense													
Depreciation Expense	(1,705,852)	(5,995,311)	(12,827,327)	(19,865,909)	(23,216,345)	(24,649,243)	(24,207,334)	(23,524,131)	(23,850,855)	(26,559,231)	(27,465,244)		
Amortization Expense													
Taxes Other Than Income													
Federal Income Taxes	(1,152,461)	(3,711,448)	(7,583,398)	(11,514,807)	(13,329,915)	(13,087,096)	(11,842,418)	(10,949,484)	(12,143,501)	(13,305,518)	(13,263,506)		
State Income Taxes	(156,600)	(504,324)	(1,030,458)	(1,564,671)	(1,811,314)	(1,778,319)	(1,609,188)	(1,487,853)	(1,650,100)	(1,807,999)	(1,802,290)		
Deferred Income Taxes													
Misc Revenue & Expenses													
Revenue Credits													
Revenue Requirement ($)	(7,295,480)	(23,996,463)	(49,608,090)	(75,714,668)	(87,868,684)	(88,123,871)	(81,645,062)	(76,630,981)	(82,748,888)	(91,093,242)	(91,795,493)		
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821		
Revenue Requirement ($/MWh)	(0.49)	(1.54)	(3.23)	(5.15)	(6.03)	(6.12)	(5.62)	(5.26)	(5.61)	(6.20)	(6.24)	2006-2015	2007-2016
Revenue Requirement excl. New Generation Resources ($)	209,896,932	302,885,496	349,056,308	296,297,704	312,502,506	320,711,844	318,614,906	344,446,602	363,416,119	342,433,533	366,157,604	**5.59%**	**2.13%**
MWh @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656	14,703,821	**-0.06%**	**-0.62%**
Revenue Requirement excl. New Generation Resources ($/MWh)	**14.20**	**19.49**	**22.75**	**20.14**	**21.44**	**22.27**	**21.92**	**23.66**	**24.65**	**23.29**	**24.90**	**5.65%**	**2.76%**

Net to Gross Factor 1.611629519

REDACTED
Docket No. UE 356
Exhibit PAC/500
Witness: Kelcey A. Brown

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Kelcey A. Brown

July 2019

DIRECT TESTIMONY OF KELCEY A. BROWN

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

A. My name is Kelcey A. Brown. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My present title is Director, Market Policy and Analytics.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have been employed by PacifiCorp since May 2011. I have been the Director of Market Policy and Analytics since July 2015. My responsibilities at PacifiCorp are primarily related to the Energy Imbalance Market (EIM). My group is responsible for submitting bids and resource schedules to the California Independent System Operator (CAISO) on a daily basis, scheduling resource outages, reviewing actual EIM operations on a daily basis, and the calculation of EIM benefits. As stated by several parties in this proceeding, the EIM is a complex operation that produces large amounts of data that PacifiCorp must monitor and utilize to ensure that its resource schedules are correct, bid prices accurately reflect the cost of operation, and resources are dispatched accordingly.

Before that time, I worked as the Manager of Load Forecast and in the Regulatory Net Power Costs Department. Before joining PacifiCorp, I worked at the Public Utility Commission of Oregon (Commission) as a Senior Economist from November 2007 through May 2011. During my time at the Commission, I sponsored testimony in several dockets involving net power costs (NPC), integrated resource planning, and various revenue and policy issues. From

2003 through 2007, I was the Economic Analyst with Blackfoot Telecommunications Group, where I was responsible for revenue forecasts, resource acquisition analysis, pricing, and regulatory support. I have a Bachelor of Science degree in Business Economics from the University of Wyoming, and I have completed all course work towards a Master's degree in Economics from the University of Wyoming.

PURPOSE AND SUMMARY OF TESTIMONY

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

A. My testimony sponsors PacifiCorp's forecast of EIM benefits for calendar year 2020, which has been updated using the most recent EIM benefit information through May 2019. I also support the forecast of Green House Gas marginal (GHG) revenues included in this update. In addition, I respond to EIM-related adjustments in the testimony of the Public Utility Commission of Oregon Staff witness Ms. Moya Enright (Staff) and Oregon Citizens' Utility Board (CUB) witness Mr. William Gehrke.

Q. Please summarize your testimony.

A. In the reply update, PacifiCorp's EIM benefit forecast is [redacted], an increase of [redacted] from the initial filing.[1] The company's forecast of inter-regional EIM benefits is reasonable and the update is based on the most recent actual EIM benefit information as well as the updated Official Forward Price Curve (OFPC). The update uses the new methodology PacifiCorp introduced in this year's Transition Adjustment Mechanism (TAM), which replaces a linear regression model, dependent only on time as the forecast variable, and instead uses commodity prices, spring-time over-

[1] Unless otherwise stated all numbers in this testimony are total company.

supply conditions, and transfer capability between balancing authority areas (BAA). Lastly, the company has updated the GHG marginal revenues that have been realized since a policy change in the CAISO in November 2018. The historical period used in the company's forecast reflects the latest participants in the EIM and operational changes made at the company's plants to better achieve EIM benefits.

Staff and CUB, through their testimony, have recommended two different forecast methodologies, both of which are dependent on only time as a variable impacting EIM benefits. My reply testimony explains how these methodologies fail to account for the key variables that drive the company's EIM benefits, such as market prices.

PACIFICORP'S CALCULATION OF EIM BENEFITS

Q. What are inter-regional dispatch EIM benefits and how does the company forecast them?

A. Inter-regional EIM benefits result from economic transactions between PacifiCorp and other EIM participants. In the 2020 TAM, the company forecasted inter-regional EIM benefits by developing a linear regression model using the following four independent variables: electric market prices, natural gas market prices, EIM transfer capability, and spring oversupply conditions. The regression modeling for the 2020 TAM is more comprehensive than the methodology used in the 2019 TAM, which used a regression model that had only one independent variable—time—and therefore did not capture all the variables that actually impact inter-regional EIM benefits. The more simplistic modeling used in the 2019 TAM was appropriate considering the continued growth of the EIM through new participants, but as that growth stabilizes, the use of more independent variables provides a more robust and accurate view of the future.

Based on the more comprehensive modeling used in this case, the company forecasted benefits for 2020 based on its actual calendar year 2015 to 2019 benefits and forecast an EIM inter-regional benefit of [redacted], total-company in the initial filing.

Q. Can you please summarize the change in EIM benefits from the initial filing?

A. Yes. PacifiCorp's estimated EIM benefits for 2020 have been updated to include the most recent information through May 2019 and market policy changes at the CAISO associated with GHG accounting changes. The total expected EIM benefits are shown in the confidential table below:

[redacted]

Q. The company's expected EIM benefits for 2020 increased by [redacted]; please explain the increase in the benefits relative to the initial filing.

A. The company's forecast of EIM benefits increased by [redacted] for expected inter-regional dispatch and [redacted] for expected GHG marginal benefits. The increase in EIM benefits is driven by changes in the OFPC as well as an increase in actual first quarter EIM benefits in 2019 and inclusion of expected GHG margins for 2020. The updated 2020 TAM EIM total EIM benefits are now higher than the 2019 TAM EIM forecast of [redacted].

Q. Can you explain why EIM benefits were higher in the first quarter of 2019?

A. Yes. EIM benefits were higher in the first quarter of 2019 due to a price spike that occurred in the bilateral gas and electricity markets across the west due to lower than average temperatures, lower than average hydro conditions, and a gas pipeline constraint that decreased the supply of natural gas into the Northwest.

Q. How do increased market prices affect the EIM margins realized by PacifiCorp?

A. PacifiCorp's bidding of its hydro resources into the EIM provides a simple demonstration of the cause and effect of bilateral electric market prices in the EIM. For example, if market prices are $150/megawatt-hour (MWh) in the bilateral market and there is limited flexibility due to low stream flows and required outflows for compliance obligations, PacifiCorp will reflect in its hydro EIM bid price the opportunity cost of its hydro resources consistent with the bilateral market. In this example, PacifiCorp would place a bid price of $150/MWh on its hydro resource, meaning that PacifiCorp is willing to pay up to $150/MWh to have the EIM serve its load rather than using the hydro resource. If the EIM clears at $60/MWh (*i.e.*, the EIM serves PacifiCorp's load at $60/MWh), then the benefit that PacifiCorp realized from the transaction was $90/MWh ($150/MWh less $60/MWh). If bilateral market prices are only $30/MWh (and therefore PacifiCorp's hydro resource bid price is only $30/MWh) and the EIM clears at $25/MWh, then the margin realized by PacifiCorp is only $5/MWh ($30/MWh less $25/MWh). As this example shows, PacifiCorp has higher benefits when there are higher margins.

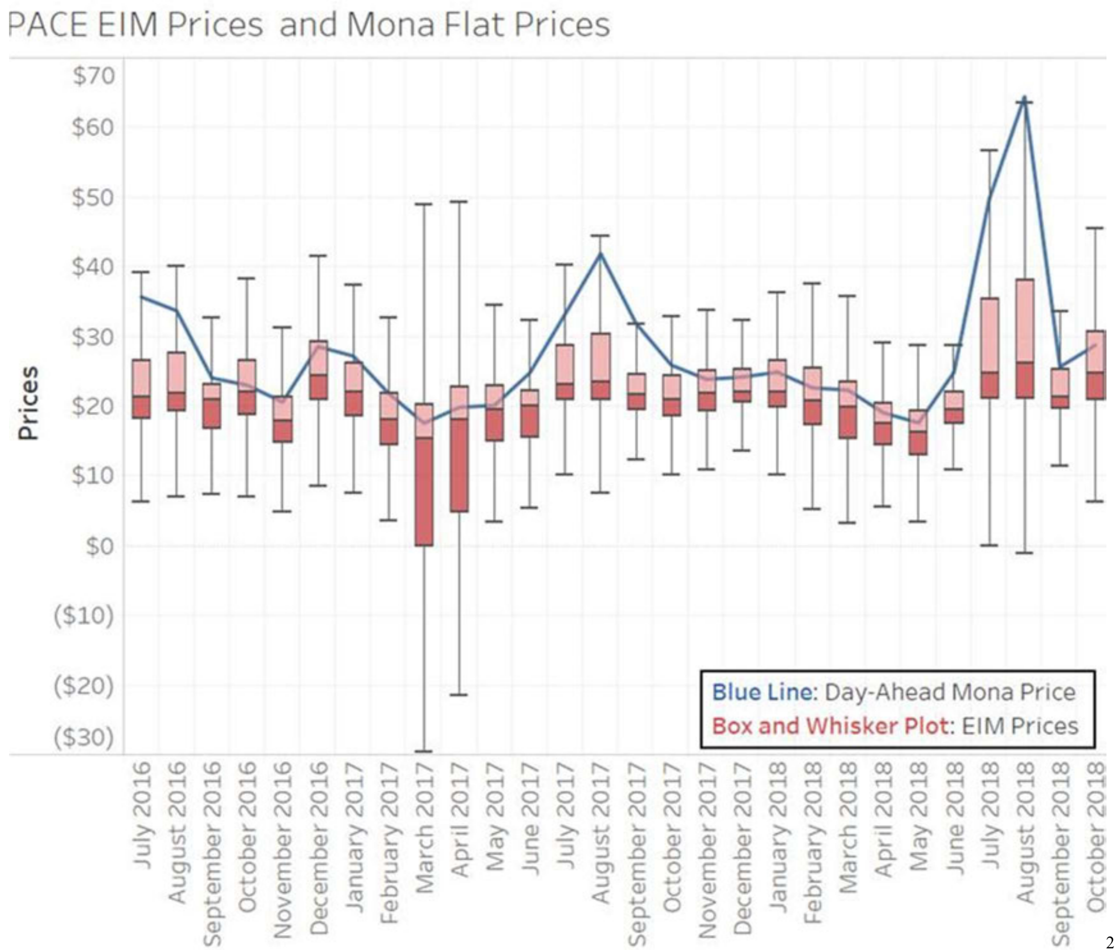
Q. Is it likely that prices in the EIM will be higher if prices in the bilateral market are higher?

A. Yes. The EIM is an intra-hour market that uses the resources and energy that were contracted for and committed on a day-ahead basis. The prices that were contracted for reflect the costs of the underlying electric generation that is scheduled to serve load the next day. So, the EIM bid price is correlated to the bilateral market price because both prices correspond to the generation cost of the underlying resource. EIM bid prices drive the cleared prices in the EIM through the dynamics of supply and demand. For these reasons the prices in the EIM will be higher if prices in the bilateral market are higher.

These cleared prices would likely be stable and consistent to the bilateral market were it not for changes in load, variable energy resources and unit outages that occur within the real-time market. If loads are higher or wind and solar resources underperform, then we are likely to see slightly higher prices in the EIM, but similarly, if loads are lower or variable resources over-perform then prices are likely to be lower.

Q. Is the direct relationship between day-ahead market prices and EIM prices the basis for using market prices in the EIM benefit forecast?

A. Yes. The figure below shows the historical average EIM prices in PacifiCorp East (PACE) and the historical average day-ahead prices at Mona. This figure shows there is a strong relationship between day-ahead and EIM prices—*i.e.*, when the bilateral prices are higher or lower, EIM prices are higher or lower, which is reflected in the EIM benefits.



[2]

It is precisely because of the strong relationship between day-ahead market prices and EIM benefits that the company has proposed to use its OFPC as a variable to determine the expected EIM benefits for 2020.

Q. Is the level of EIM benefits also driven by EIM transfer capability?

A. Yes. The figure below shows the monthly EIM inter-regional benefits for imports into PacifiCorp's BAAs with total transfer capability (TTC) illustrated over a continuous color scale. The darker the color the greater the TTC. This figure shows

[2] The above graph shows PacifiCorp East EIM Load Aggregated Price in a Box and Whisker Plot (five minute-granularity) and monthly average ICE Day-ahead Mona Flat electricity prices.

a strong relationship between the EIM inter-regional import benefits and the TTC—*i.e.*, as TTC increases over time the EIM inter-regional import benefits increase.

EIM Inter-Regional Benefits for <u>**Imports**</u> into PacifiCorp's BAAs

[redacted]

PACIFICORP'S RESPONSE TO STAFF

Q. Staff proposes to increase the inter-regional EIM benefits in the TAM to [redacted].[3] How does that compare to the company's forecast?

A. As noted above, the initial filing included forecasted inter-regional benefits of [redacted] and the 2020 TAM Update includes forecasted benefits of [redacted]. Staff's recommendation is therefore 125 percent higher than the company's forecast.

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[3] Staff/300, Enright/ 2.

Q. How does Staff's estimate compare to the 2018 actual inter-regional EIM benefits?

A. Staff's recommendation is 49 percent higher than the 2018 actual EIM benefits.

Q. Were EIM benefits under forecast for the period from 2016 to 2018?

A. Yes. The 2016, 2017 and 2018 forecasts were largely qualitative forecasts in which estimations were based on best judgement utilizing historical results. During those years the EIM was a new, dynamic and constantly evolving market in which PacifiCorp made continuous improvements to its operations as the company gathered experience and operational knowledge.

Q. Has the EIM benefit forecast methodology changed since the 2018 forecast?

A. Yes. As of the 2019 forecast, PacifiCorp has utilized quantitative forecasts in which estimations are based on statistical modeling and trend analyses. The 2019 forecast included the introduction of quantitative forecasts for EIM inter-regional benefits, while the 2020 forecast includes the introduction of quantitative forecasts for EIM GHG benefits. Support for the use of quantitative forecasts, is justified by the now over four years of monthly EIM data as of the 2020 forecast as well as the maturity and stabilization of operational expertise, brought about through years of experience in operating within the EIM. This wealth of historical data combined with the maturity of the EIM justified the fundamental change in forecast methodology from qualitative to quantitative.

Q. Will the switch to quantitative forecasts improve the estimation of the EIM inter-regional benefits for calendar year 2020?

A. Yes. With the introduction of quantitative forecasts the estimation of benefits are grounded in historical data and numerical based analytics which are driven by statistical modeling techniques. When it comes to developing a quantitative forecast for the estimation of EIM inter-regional benefits, a key consideration is consistency with the rest of the net power cost forecast. EIM benefits are embedded in the underlying NPC that they impact, *e.g.*, when PacifiCorp exports power in the EIM it uses a fuel cost that is a reflection of current natural gas prices or electricity prices; similarly, if PacifiCorp imports in the EIM it avoids current fuel costs or market purchases when hydro resources are displaced and there is additional available water behind the reservoir. Net power cost forecasts are driven by the OFPC, which informs expected electric market prices and natural gas market prices. The 2020 TAM EIM inter-regional benefits forecast, by using the OFPC to inform the expected market prices within the forecast models, is now consistent and aligned with the underlying NPC. This consistency is the foundation of the assertion that the 2020 EIM inter-regional benefits forecast is an improved and more accurate forecast.

Q. What methodology does Staff use to calculate its estimated inter-regional EIM benefits?

A. Staff uses a simple linear regression model to forecast the 2020 TAM benefits based on only one independent variable—time. In other words, Staff's model assumes that EIM benefits increase with time, without considering any of the underlying reasons that inter-regional benefits have historically increased. Staff recommends using a simpler linear regression model because it was used in the 2019 TAM settlement and it is simpler, more transparent, and maintains the trend of increasing benefits over time.[4]

Q. Do you believe that PacifiCorp's model is not transparent or is overly complex?

A. No. PacifiCorp has shared its work papers and data with all stakeholders and has explained its use of modeling techniques through discussions with stakeholders and in workshops since the 2019 TAM. With regard to simplicity, while it is true that the use of additional independent variables does increase the complexity of a model, the benefits of a forecast that reflect the underlying fundamentals of the electric power system outweigh the additional complexity.

Q. Has Staff presented any evidence that the level of EIM benefits is not driven by electricity and gas market prices?

A. No. Staff has not disputed the fact that EIM benefits are driven by market prices, as discussed in detail above. If the OFPC is higher, then PacifiCorp's NPC are higher—but so are EIM benefits. EIM benefits are embedded in the underlying NPC that they impact.

Q. Has Staff presented any evidence that the level of EIM benefits is not driven by spring oversupply conditions?

A. No. Although this is the only variable Staff's testimony addresses, Staff simply claims that the company has not demonstrated how oversupply conditions drive EIM benefits.[5]

[4] Staff/300, Enright/9.
[5] Staff/300, Enright/7.

Q. Is there evidence that the level of EIM benefits is driven by spring oversupply conditions?

A. Yes. The figure below shows the monthly EIM inter-regional benefits for imports into PacifiCorp's BAAs with the spring months highlighted. This figure shows there is a strong relationship between the spring months and EIM inter-regional import benefits—*i.e.*, as time progresses, each spring exhibits an increase in EIM inter-regional import benefits. This increase is driven in large part by the changes PacifiCorp has made in its operation of its thermal plants since participation in EIM. PacifiCorp is able to provide much more operating flexibility, e.g., lower operating minimum levels and higher ramp rates, from many of its thermal facilities to import lower cost or negatively priced energy in the EIM.

EIM Inter-Regional Benefits for **Imports** into PacifiCorp's BAAs

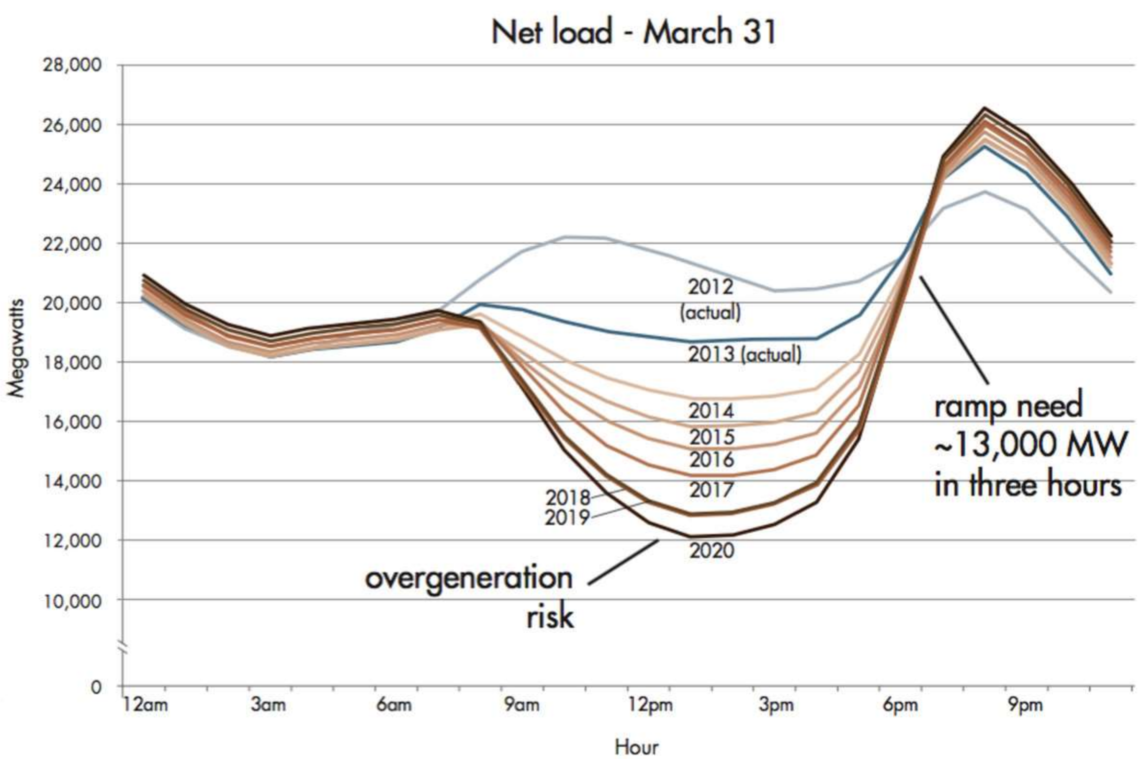
[redacted]

It is precisely because of this relationship between spring oversupply conditions and EIM benefits that the company has proposed to use spring oversupply conditions as a variable to determine the expected EIM benefits for 2020.

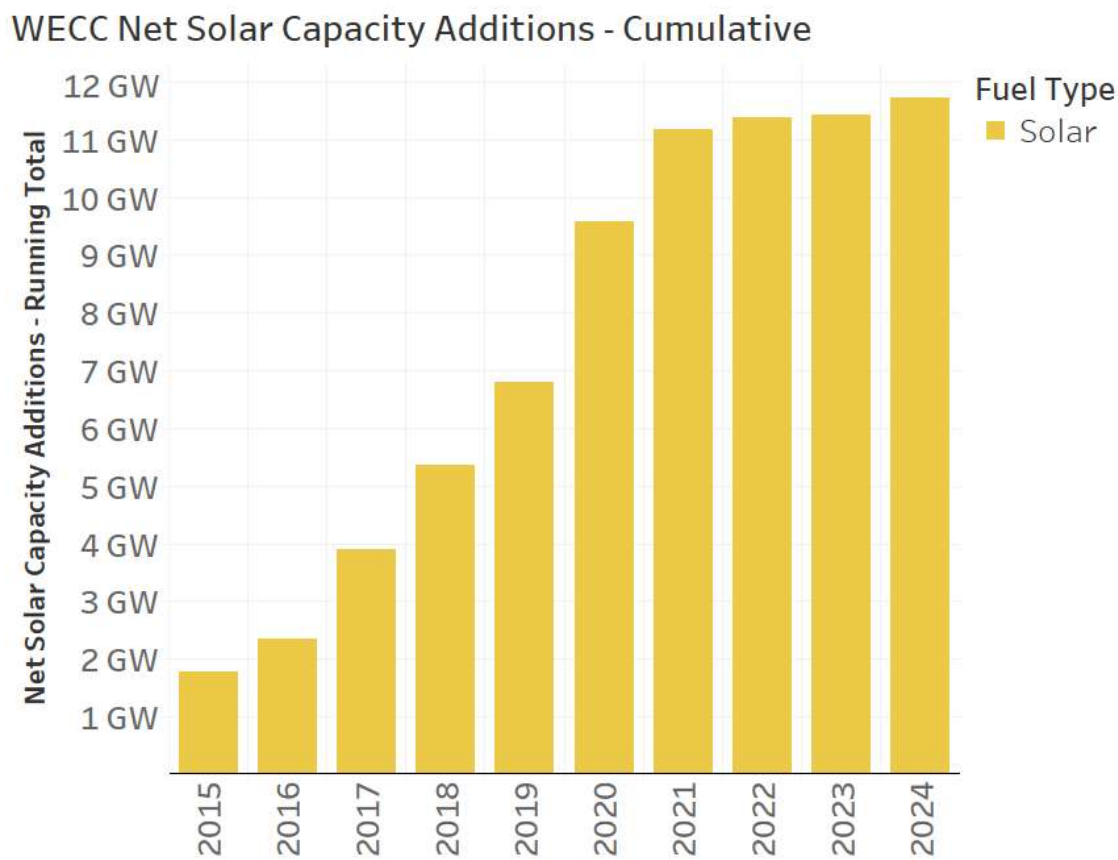
Q. Is there evidence that supports the continuation of spring oversupply conditions into the 2020 period and beyond?

A. Yes. Multiple agencies have published data which informs the expectations of continued spring oversupply conditions. The CAISO published the 'duck curve'—referenced in the figure below—which is an illustration of the challenges the CAISO faces during the spring time due to lower Spring-time loads and high levels of output from solar resources. The over-generation risk—referenced in the below figure—is excess energy which is imported out of the CAISO into neighboring BAAs during the spring time and plays a large role in the spring oversupply conditions that are referenced throughout this testimony. As the years progress the ‘belly of the duck’—the trough in the middle of the graph—gets lower and lower. This illustrates the expectation of year-over-year increases in the amount of excess energy within the CAISO and, correspondingly, the expectation of year-over-year increases in spring oversupply conditions.

Figure 2: The duck curve shows steep ramping needs and overgeneration risk



The Energy Information Administration publishes data on planned generation additions and retirements. The figure below shows the expected growth of solar resources within the Western Electricity Coordinating Council (WECC) as reported by utilities and developers. The majority of this solar growth occurs within the CAISO.



Source: Energy Information Administration Form 860

From this data we can confirm that spring oversupply conditions will persist well beyond the 2020 forecast period.

Q. Staff supports its use of a simple linear regression model by observing that EIM benefits have increased every year and therefore it is reasonable to assume they will do so again in 2020.[6] Why did PacifiCorp's EIM benefits increase from 2017 to 2018?

A. The primary driver of EIM benefits in 2018 was due to high market prices in the summer and fall of that year, as well as PacifiCorp's continued ability to import large amounts of low-price power in the spring of 2018. In other words, the 2018 benefits

[6] Staff/300, Enright/6.

were driven by market prices and transfer capability—two of the key factors Staff recommends the company ignore when forecasting 2020 benefits. The following excerpt was from the CAISO EIM Benefit Report Third Quarter 2018:[7]

EIM BENEFITS IN Q3 2018

Table 1 shows the estimated EIM gross benefits by each region per month[2]. The monthly savings presented in the table show $39.66 million for July, $45.09 million for August, and $15.83 million for September with a total estimated benefit of $100.58 million. The benefits in Quarter 3 of this year were higher than usual due to more economical transfers in periods of high loads and higher electric prices following higher fuel prices. This was mainly observed in July and August; the estimated benefits dropped in September to typical ranges tracking lower load levels and fuel prices.

Region	July	August	September	Total
APS	$9.48	$9.34	$1.96	$20.78
ISO	$9.93	$7.85	$3.24	$21.02
IPCO	$4.55	$6.36	$2.40	$13.31
NVE	$4.07	$4.96	$2.06	$11.09
PAC	$5.80	$9.46	$2.56	$17.82
PGE	$3.29	$3.90	$2.28	$9.47
PWRX	$0.93	$1.20	$0.52	$2.65
PSE	$1.61	$2.02	$0.81	$4.44
Total	$39.66	$45.09	$15.83	$100.58

TABLE 1: Third quarter 2018 benefits in millions USD by month

Q. The CAISO references higher fuel prices and higher loads as a driver of EIM benefits in the third quarter of 2018. Did PacifiCorp incur higher power costs in 2018 due to higher fuel costs and higher loads?

A. Yes. The table below shows the higher NPC PacifiCorp incurred in 2018 due to high natural gas and electricity prices and higher than expected loads. This same outcome can also be seen in the first quarter of 2019.

[7] *Western EIM Benefits Report Third Quarter 2018* at 4, CALIFORNIA ISO (Oct. 29, 2018), *available at* https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ3-2018.pdf.

Year	Total Company Base NPC	Total Company Actual NPC	Under/(Over) Recovery of NPC
2018	1,473,532,539	1,594,973,694	121,441,155
Q1 2019	359,903,034	438,789,406	78,886,371
2020	1,476,367,261	N/A	N/A

This data demonstrates the counter-intuitive nature of Staff's recommendation.

Q. Staff recommends forecasting [redacted] in inter-regional transfer benefits in 2020.[8] Is this a reasonable amount in light of PacifiCorp's forecast for 2020 NPC?

A. No, as seen in the above table, forecast 2020 NPC are significantly below actual 2018 NPC, yet Staff recommends a nearly 50 percent increase in EIM benefits.

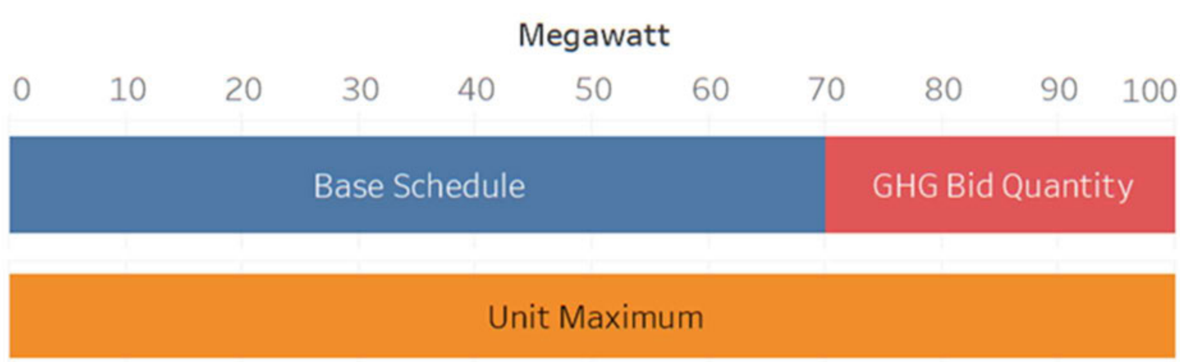
Q. Staff contends that PacifiCorp customers did not realize the full EIM benefits in 2018, due to the fact that actual EIM benefits were higher than forecast.[9] Do you agree?

A. While it is true that EIM benefits were under-forecast in 2018 by [redacted], the company also under-forecast total NPC by approximately $121.4 million. Thus, the under-forecast of EIM benefits in 2018 did not result in customers being overcharged for NPC in 2018. EIM benefits are embedded in NPC, so it is inappropriate to view EIM benefits in isolation.

[8] Staff/300, Enright/9.
[9] Staff/300, Enright/8.

Q. Staff has also proposed an adjustment to the GHG marginal revenues forecasted for 2020 based on the fact that the company's initial filing did not include a forecast of GHG margin revenues.[10] Has the company now included GHG marginal revenues in the 2020 TAM?

A. Yes. PacifiCorp has included a GHG marginal benefit forecast in the 2020 TAM reply update of [redacted]. These benefits are realized when the GHG revenue is higher than the company's resulting compliance obligation. In November 2018, the CAISO implemented a GHG policy change that limited the GHG bid quantity of a resource for purposes of determining the quantity of a resource that is imported into California. Using the illustration below, if a resource has a 70 Megawatt (MW) base schedule and an upper economic limit of 100 MW, the GHG bid quantity that is available for imports to California is only 30 MW.



In the past, if the resource was dispatched to 100 MW, then California could have deemed the entire unit maximum of 100 MW as being delivered to the state for purposes of determining GHG compliance. This approach, however, would have resulted in a "backfill" of the resource that was scheduled to serve load with the

[10] Staff/300, Enright/11-13.

initial 70 MW. The November 2018 policy change limits the amount that a resource can be "deemed" delivered—meaning that under the current policy, only the 30 MW of generation that was not included in PacifiCorp's base schedule would be deemed to be delivered to California. This policy change particularly impacts hydro resources because they are typically scheduled close to their maximum output in the company's base schedules intended to serve native load.

Q. How did the November 2018 policy change affect PacifiCorp's expectation of GHG margins?

A. Prior to this policy change, PacifiCorp earned GHG margins only on its hydro resources, which are zero-emitting resources and do not incur a compliance obligation. If a gas resource was deemed delivered to California, then the GHG revenues were typically equal to the compliance obligation and PacifiCorp earned no margin. Since the policy change, there has been a significant increase in the average GHG marginal price because zero-emitting resources, like hydro, have been limited in their ability to provide power to California. Now gas and, in a small number of intervals, coal resources have been deemed delivered to California, increasing the marginal GHG price. This has resulted in a smaller volume of deemed imports on PacifiCorp's resources, but margins have been positive relative to the cost of the compliance allowances—meaning the company has earned GHG marginal revenues above its compliance obligations. Based on these changes, the company has now included GHG marginal revenue as a component of its overall EIM benefits calculations.

Q. Staff has proposed to include a GHG revenue forecast in the TAM, but not the compliance costs.[11] Is that reasonable?

A. No. Staff claims that PacifiCorp provided discovery responses indicating that its compliance costs are not separately tracked for EIM resources. Based on those responses, Staff claims that the company "has not been forthcoming with the details of its EIM-related GHG expenses," and therefore the Commission should ignore the expenses and include the gross GHG revenues as an offset to NPC.[12] But, as explained in the company's discovery response,[13] the compliance mechanism used by California does not provide the granularity Staff requested in its data request. PacifiCorp can identify which resource was deemed delivered to California and its estimate of its compliance cost based on the then-cleared allowance market price—an example of this is represented in the table below which shows the EIM GHG marginal revenue calculated for a single resource over a period. However, PacifiCorp purchases its compliance cost allowances for its retail load, bilateral transactions and EIM transactions in batches based on market dynamics and the requirements of the California Air Resources Board, not on a resource or market specific basis.

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[11] Staff/300, Enright/11-12.
[12] Staff/300, Enright/11-12.
[13] For ease of reference, the full text of the discovery response cited by Staff and included as Staff/302, Enright/3 is: "PacifiCorp does not calculate a net proceeds on greenhouse gas (GHG) related to wholesale activities and the energy imbalance market (EIM). PacifiCorp's goal is to procure a sufficient quantity of allowances to cover the GHG obligation incurred by making bilateral wholesale sales into California and the EIM. PacifiCorp can identify the revenues received from the EIM to cover the obligation incurred in the EIM - please refer to the Company's response to OPUC Data Request 36. PacifiCorp records expense related to the bilateral and EIM activity by accruing expense at the average cost of inventory of GHG allowances purchased - please refer to the company's response to OPUC Data Request 37. PacifiCorp, however, does not know the proceeds received to cover the GHG obligation incurred by non-EIM bilateral sales into California. There is no GHG cleared price in the California Independent System Operator (CAISO) day-ahead market. Thus, when PacifiCorp sells into the CAISO day-ahead market and receives a day-ahead locational marginal price (LMP) proceeds, it is not possible to know how much of those proceeds relate specifically to GHG and not energy."

Given the apparent misunderstanding of how the company complies with its GHG obligations in California, PacifiCorp welcomes the opportunity to hold a workshop with stakeholders on this issue to aid in the understanding of the CAISO GHG policy, as well as PacifiCorp's ongoing compliance obligation to the California Air Resources Board.

PACIFICORP'S RESPONSE TO CUB

Q. Has CUB accurately and fairly characterized PacifiCorp's modeling techniques and the estimation of 2020 EIM inter-regional benefits?

A. No. CUB incorrectly claims that PacifiCorp's model closely fits the historical data because of the use of weights in the regression. The first figure below shows how closely PacifiCorp's model fits the historical data with weights and the second figure below shows how closely PacifiCorp's model fits the historical data without weights. There is little difference between the historical fit of the model with weights and the model without weights.

EIM Inter-Regional Benefits <u>**with**</u> Weights

[redacted]

EIM Inter-Regional Benefits <u>**without**</u> Weights

[redacted]

Q. If there is no substantial difference in the model with weights and the model without weights, why did PacifiCorp elect to use weights?

A. PacifiCorp elected to use weights in its model to further emphasize more recent EIM benefits results, which resulted in an increase of the EIM benefits forecast of [redacted] relative to a model without weights.

Q. CUB recommends an EIM benefit of [redacted] in 2020 based on an exponential smoothing model, which uses the exponential moving average of actual EIM benefits.[14] What is CUB's support for their model and the increase in EIM benefits relative to PacifiCorp's forecast?

A. CUB's proposed exponential smoothing model uses EIM actuals and moves them forward in time by exponentially weighting past observations. It is effectively a naïve forecast[15] that uses a weighting scheme to favor more recent actual data and time as the independent variable. CUB supports this approach by claiming there is insufficient historical data to support using a regression model and the market is not mature enough to have developed a relationship with market prices.

Q. Is it more accurate to use only actuals in a forecast and not use any type of independent forecast variable, such as market prices?

A. Not usually. Using only actuals to forecast load provides an example of the challenge of this approach: the short-term load forecast is primarily driven by weather variables such as temperature with higher temperatures yielding higher loads. A naïve forecast would suggest that if loads increased over the last four days, they will be higher on the fifth day, but this is an unreasonable assumption without consideration of the

[14] CUB/200, Gehrke/6-7.
[15] A naïve forecast uses the last period actual results as the forecast for the future period.

expected temperature. Thus, when PacifiCorp forecasts load, it uses regression models comparable to those used to forecast inter-regional EIM benefits. It would be similarly unreasonable to forecast EIM benefits based exclusively on recent actual data without consideration of expected market conditions during 2020. As described above, there is a strong relationship between market prices and inter-regional EIM benefits and to ignore that relationship, as CUB recommends, is unlikely to produce an accurate forecast.

Q. CUB suggests that it is premature to use monthly price data to estimate EIM benefits because three years of historical data is insufficient.[16] Do you agree with that statement?

A. No. As shown above, EIM benefits are related to market prices, and market prices reflect the resource costs that are available in the EIM. CUB's concern over the use of three years of historical data is unfounded. First, CUB presented no analysis showing that three years of historical data is insufficient. Ignoring this historical data, as CUB effectively recommends, would be akin to ignoring temperature when doing a load forecast because you only had four years of load data.

Second, it is my understanding that the Commission has previously approved the use of comparable historical data to forecast other elements of NPC, including aspects of market prices. For example, in the 2008 TAM, the Commission adopted Staff's proposed adjustment to reflect the margin earned by the company from its arbitrage and trading activity and calculated the adjustment using three years of

[16] CUB/200, Gehrke/6.

historical data.[17] In the 2012 TAM, the Commission approved a proposal for more realistic pricing of purchase and sales transactions with hourly scalars derived from historical data.[18] And in several recent TAMs, the Commission approved the use of historical data when approving the day-ahead and real-time balancing transactions adjustment.[19]

Q. Did CUB present any evidence that market prices are not a driver of EIM benefits?

A. No. CUB questioned the use of historical data to forecast EIM benefits but did not directly dispute the fact that electricity and natural gas prices are a function of EIM benefits in the same manner that electricity and natural gas prices are a function of NPC.

Q. CUB also claims that the EIM continues to grow with new entrants and it is not yet a mature market.[20] Do you agree with CUB that the market is immature?

A. No. The EIM market currently encompasses 57 percent of the generation and loads in the WECC and while there are one or two entities being added each year, they are a small percentage of the current EIM market.[21] The planned entrants in 2020 are Seattle City Light and Salt River Project which together encompass only 5 percent of WECC load.[22] The driving force behind increased EIM benefits with new entrants is

[17] In the Matter of PacifiCorp d/b/a/ Pacific Power 2008 Transition Adjustment Mechanism, Docket No. Docket No. UE 191, Order No. 07-446 at 11 (Oct. 17, 2007).
[18] In the Matter of PacifiCorp d/b/a/ Pacific Power 2012 Transition Adjustment Mechanism, Docket No. UE 227, Order No. 11-435 (Nov. 4, 2011).
[19] See, e.g., In the Matter of PacifiCorp d/b/a/ Pacific Power 2016 Transition Adjustment Mechanism, Docket No. UE 296, Order No. 15-394 (Dec. 11, 2015).
[20] CUB/200, Gehrke/3-4.
[21] Initial Analysis Finds $42.7 Million Annual Benefit from BPA Joining EIM, CLEARING UP, May 24, 2019, Issue No. 1903 at 8.
[22] *See* Anchor Data Set, Western Energy Coordinating Council, *available at* https://www.wecc.org/SystemStabilityPlanning/Pages/AnchorDataSet.aspx.

the transmission connectivity they bring to PacifiCorp. None of the 2020 entrants have transmission connectivity to PacifiCorp.

Q. How does PacifiCorp's estimation of EIM inter-regional benefits compare to the estimation proposed by Staff and the estimation proposed by CUB?

A. The figure below compares and contrasts the estimation of EIM inter-regional benefits proposed by PacifiCorp, Staff and CUB with historical EIM inter-regional benefits. Staff's estimation is a simple linear trend which grows indefinitely and shows no response to the month by month changes observed in the historical data. CUB's estimation, although developed with an 'Exponential Smoothing State Space model', produces what is effectively a naïve forecast with no regard for trend, seasonality or any potential for change whatsoever. PacifiCorp's estimation is driven by market fundamentals and demonstrates the best fit to the historical data while being consistent with NPC through the OFPC which informs the entirety of the net power cost forecast.

Comparison of Forecasts - PacifiCorp, Staff, CUB - with Actuals

[redacted]

Q. Why is PacifiCorp's 2020 estimation of EIM inter-regional benefits lower than recent historical data and the estimation proposed by Staff and CUB?

A. For the 2020 period, the electric market prices and natural gas market prices which drive PacifiCorp's forecast are tied to the company's OFPC upon which the entirety of PacifiCorp's NPC are based. The market prices forecast for 2020 in the OFPC are lower than market prices observed in 2018 and the first quarter of 2019. As discussed in detail above, market prices in 2018 and the first quarter of 2019 were higher than normal which drove higher than normal EIM inter-regional benefits as well as higher than expected NPC. The OFPC is a representation of expected market prices and is the company's best forecast of conditions in 2020. This expectation of lower market prices in 2020—relative to 2018 and the first quarter of 2019—drives the relatively lower EIM inter-regional benefits.

Q. Does this conclude your reply testimony?

A. Yes.