ORDER NO. 20-392

ENTERED Oct 30, 2020

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 375

In the Matter of PACIFICORP, dba PACIFIC POWER, 2021 Transition Adjustment Mechanism.	ORDER

DISPOSITION: STIPULATION ADOPTED; DIRECTIVES FOR ADDITIONAL INFORMATION INCLUDED

I. INTRODUCTION

In this order, we adopt the parties' stipulated agreement on PacifiCorp, dba Pacific Power's 2021 Transition Adjustment Mechanism (TAM). The TAM is PacifiCorp's annual filing to update its net variable power costs (NPC) in rates and to set the transition adjustments for customers who choose direct access during the open enrollment window in November.

We adopt the stipulation, attached as Appendix A, which provides an Oregon-allocated TAM baseline (NPC and PTCs) of $291.4 million with 2021 power costs of $23.11 per MWh.[1] Compared to 2020, the 2021 power costs represent an overall rate decrease of $49.8 million or 3.8 percent.[2] PacifiCorp will post the final TAM rates next month just before the open enrollment window.

The stipulation reflects the agreement of all parties to resolve all issues in PacifiCorp's 2021 TAM. The parties to the stipulation are: PacifiCorp; Staff of the Public Utility Commission of Oregon; Alliance of Western Energy Consumers (AWEC); Oregon Citizens' Utility Board (CUB); Calpine Energy Solutions LLC; Klamath Water Users Association (KWUA); Sierra Club; and Vitesse, LLC (stipulating parties). The stipulation is attached to this order as Appendix A.

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[1] Stipulation at Exhibits 1 and 3 (Aug 18, 2020). The "TAM baseline" is comprised of $356 million in NPC, reduced by $64.6 million for Production Tax Credits (PTCs).
[2] Stipulation at Exhibits 1 and 2.

II. SUMMARY OF FILINGS

On February 14, 2020, PacifiCorp filed its 2021 TAM concurrently with its general rate case in docket UE 374, with proposed tariff sheets for Schedule 201 to be effective January 1, 2021. PacifiCorp's forecast NPC consists of fuel expense, purchased power, wholesale sales, and wheeling expense. The TAM also includes a forecast for other revenues related to NPC, Energy Imbalance Market (EIM) benefits and costs, and Production Tax Credits (PTCs).

Before PTCs are applied, PacifiCorp's initial filing reflected a decrease in Oregon-allocated NPC of approximately $13 million less than the 2020 TAM final update in docket UE 356.[3] The decrease was due to lower purchased power costs and lower overall coal costs.[4] PacifiCorp's reply update on June 9, 2020, revised this number upward by $2 million. The stipulation then reduced the NPC level by $2.4 million on an Oregon-allocated basis for the TAM baseline (including both NPC and PTCs) of $291.4 million.

Staff, AWEC, CUB, Sierra Club, and Calpine Solutions conducted discovery, participated in a Commission Workshop, and filed opening testimony. Many of the issues raised in parties' testimony are reflected in the stipulation and noted below. Parties submitted detailed argument and analysis on certain issues, and their testimony may be found in the docket.

After the parties' opening testimony, PacifiCorp filed reply testimony. PacifiCorp also responded to three bench requests during the proceeding. The parties held multiple settlement conferences and reached an all-party stipulation that resolved all issues in the 2021 TAM.

III. SUMMARY OF ISSUES RAISED AND STIPULATED OUTCOME

This section summarizes key issues raised in parties' testimony and notes how the topics are addressed in the stipulation and joint testimony.

A. Unspecified NPC Adjustment

In order to resolve the issues in this proceeding, the parties agreed to an unspecified reduction to Oregon-allocated NPC of $2.25 million.

[3] Subsequent to the final update in the 2020 TAM, PacifiCorp made two compliance filings to incorporate benefits of Glenrock III and Dunlap repowering coming online, and thus the effective TAM rates during much of 2020 are less than the final update from UE 356. *See In the Matter of PacifiCorp 2020 Transition Adjustment Mechanism,* Docket No. UE 356, Compliance Filings (Mar 17, 2020 and Sep 17, 2020).
[4] PAC/100, Webb/11, Figure 2.

B. Nodal Dispatch

PacifiCorp is transitioning away from the production cost model known as GRID[5] to the one known as AURORA. PacifiCorp is expecting to use AURORA for forecasting power costs in Oregon next year.[6]

Staff recommended adjustments to account for PacifiCorp's new nodal pricing model dispatch savings. Staff also recommended the company hold a workshop regarding the day ahead/real-time (DA/RT) mechanism and the transition to AURORA for NPC forecasts. AWEC recommended a downward adjustment to PacifiCorp's NPC due to over-estimation of the DA/RT market cost.

In the stipulation, PacifiCorp agrees to hold a workshop before filing next year's TAM.[7] The workshop will have information on the transition from GRID to AURORA, how AURORA will capture the benefits of nodal pricing, and information on the DA/RT adjustment. PacifiCorp will provide AURORA licenses to Commission Staff and intervenors for each future TAM. PacifiCorp will provide all inputs, data, model settings, constraints, and any other modeling changes. The costs of the licenses, training, and data sets will be included for cost recovery in any TAM until the next general rate case. PacifiCorp also agrees to conduct one reasonable AURORA model run per intervenor.

C. Coal Issues

Staff, Sierra Club, and CUB raised numerous issues about PacifiCorp's coal units. The stipulation addresses five of the main issues, summarized below.

1. Modeling of Coal Units

PacifiCorp includes a "must run" setting for coal units in GRID so that coal units are modeled as base load units, similar to actual operations.[8] Staff and Sierra Club recommended removal of the "must run" setting in GRID. In the stipulation, PacifiCorp agrees to remove the "must run" constraint as part of the transition to AURORA.

Two related modeling issues are the "minimum burn" constraint and PacifiCorp's use of incremental and supplemental coal costs, rather than actual costs, to increase coal unit dispatch. Sierra Club asserted that the "minimum burn" constraint causes an excessive amount of coal dispatch and ensures that the coal units operate a minimum number of hours, regardless of the availability of other resources. Sierra Club questioned whether

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[5] GRID stands for Generation and Regulation Initiative Decision Tool. GRID is PacifiCorp's hourly production cost model that the company has used in its Oregon rate filings since 2002.
[6] Stipulating Parties/100, Webb, Gibbens, Jenks, Higgins, Kaufman, Burgess, Reed, Dickman/11.
[7] References to the TAM are interchangeable with "NPC forecast mechanism" if the TAM is changed in docket UE 374.
[8] Stipulating Parties/100, Webb, Gibbens, Jenks, Higgins, Kaufman, Burgess, Reed, Dickman/13.

the coal contracts with minimum tonnage levels are in the best interests of PacifiCorp's customers. Sierra Club recommended removing all "minimum burn" constraints.

In the stipulation, PacifiCorp agrees to perform an informational AURORA model run, based on the initial TAM filing, that removes any operational constraints related to the minimum take provisions in the coal supply agreements and uses an average coal price for purposes of dispatching coal plants. PacifiCorp will provide this informational AURORA model run in the initial TAM filing until all coal costs are removed from Oregon rates (through the 2029 forecast).

2. Review of New Coal Supply Agreements

Sierra Club made several arguments regarding coal contracts, such as recommending that PacifiCorp include for review in the Integrated Resource Plan process any new, modified, or updated coal supply agreements with minimum tonnage requirements. Sierra Club also proposed that PacifiCorp provide a report analyzing whether coal contracts with renegotiation provisions could be amended to reduce overall costs for Oregon ratepayers.

The stipulation requires PacifiCorp to provide additional information on coal supply agreements by providing testimony in the initial TAM filing regarding the prudence of any coal supply agreements that were entered into since the previous year's reply testimony. For contracts that are executed while a TAM filing is open, PacifiCorp will work with parties to identify the appropriate review timeline, regulatory process and rate review.[9]

3. Economic Cycling

Staff asserted that PacifiCorp unnecessarily restricts its modeling of economic cycling. Staff recommended removal of restrictions such as the limit on startups during the cycling period. Staff requested quarterly reports on coal plant operations. Staff also suggested that PacifiCorp engage with co-owners of coal plants regarding the potential for economic shutdowns, and to have the company conduct a study into non-fuel costs and savings of economic shutdowns.

The parties' agreement for economic cycling provides that PacifiCorp will hold quarterly calls in 2021 to provide information on the market conditions and actual dispatch of its coal plants. PacifiCorp will also provide a study on the costs and benefits of including the non-fuel cost impacts by March 1, 2021.

4. Jim Bridger Selective Catalytic Reduction

The costs of selective catalytic reduction (SCR) systems for Jim Bridger Units 3 and 4 are currently under review in docket UE 374. With the SCRs, Jim Bridger has an

[9] Stipulating Parties/100, Webb, Gibbens, Jenks, Higgins, Kaufman, Burgess, Reed, Dickman/14.

increased minimum operating level and altered performance that causes a small increase in power costs. In previous TAMs, PacifiCorp has agreed with parties to leave Jim Bridger at its pre-SCR operation levels. In this TAM, PacifiCorp proposed to model Jim Bridger operations with the SCRs, and CUB recommended removal of the SCRs' impact because they have not yet been found prudent.

The stipulation addresses the SCR issue by stating that, if the Commission disallows full capital cost recovery in docket UE 374, PacifiCorp will return its power cost models to an adjusted minimum operating level for Jim Bridger Unit 4. Currently, Jim Bridger Unit 3 has a lower minimum operating level than its pre-SCR level, therefore it will stay at this level.

5. *Wholesale Sales*

Sierra Club asserted that PacifiCorp's sales for resale are often made at prices lower than the production costs at its coal plants, resulting in TAM recovery "subsidizing" PacifiCorp's wholesale market transactions. Sierra Club recommended that the Commission direct PacifiCorp to report information for each hour of the sales period.

PacifiCorp has agreed to provide additional information on wholesale sales. In future proceedings, PacifiCorp will provide the Commission data including: the past year's bilateral trades for each hour ($/MWh), total wholesale sales revenue ($), total energy delivered through wholesale sales (MWh), hourly generation for PacifiCorp-owned generation, and monthly generation unit production costs ($/MWh). If PacifiCorp joins an expanded market in the future, it will work with intervenors to identify additional data.

D. New Wind and Transmission Projects

PacifiCorp has several new wind projects that are planned to be in service by the end of 2020—TB Flats I, TB Flats II, Cedar Springs II, Ekola Flats, Pryor Mountain and the repowering of Foote Creek. The Stipulation, at paragraph 18, contains three main points about these projects. First, if the projects are online before December 31, 2020, the full value of ratemaking benefits will be included in TAM rates beginning January 1, 2021. The stipulation continues that "[i]f the commercial in-service dates of one or more of the New Wind Projects are delayed beyond December 31, 2020, the Parties agree that customers will retain the full value of ratemaking benefits beginning with the commercial in-service date, but that Schedule 201 rates will be updated coincident with the timing of rate recovery of each New Wind project, which is anticipated to be determined in docket UE 374."[10] Lastly, paragraph 18 of the stipulation states that parties support aligning the timing of rate recovery from docket UE 374 to match the commercial in-service dates,

[10] *Id.*

and that benefits forecast in the 2021 TAM may be increased or reduced if cost recovery is approved earlier or later than the online date projected in the 2021 TAM.

E. EIM Benefits

Staff and CUB challenged PacifiCorp's methodology to calculate EIM benefits. Staff recommended that we reject PacifiCorp's calculations for past EIM and greenhouse gas (GHG) benefits. Staff suggested the GHG benefit be increased, that PacifiCorp update the flexible reserve benefit, and that PacifiCorp maintain copies of the California Independent System Operator (CAISO) benefit calculations on a quarterly basis.

PacifiCorp agreed to an unspecified increase of $213,429 to EIM benefits. The parties agree that PacifiCorp's EIM benefit calculation for 2021 is reasonable and may be updated consistent with other TAM updates, though this year's EIM benefit calculation does not set a precedent for the methodology to be used going forward. PacifiCorp has agreed to provide additional information on CAISO's calculation of EIM benefits and will make the additional supporting documentation available for review.

F. Transmission Line Losses

AWEC explained that when the Aeolus-to-Bridger/Anticline transmission project is added in parallel to the existing transmission lines, resistance is reduced, which lowers line losses. With reduced line losses, an incremental amount of energy will be able to flow out of eastern Wyoming each year.[11] AWEC proposed including transmission line loss savings of 11.6 average MW (aMW) in the GRID model and incorporating 36.5 aMW of transfer capability due to improved transmission reliability. In the stipulation, PacifiCorp agrees to include transmission line loss savings of 11.6 aMW in the Wyoming East load bubble for the 2021 TAM.

G. Issues that Overlap with docket UE 374

The stipulation addresses three issues that overlap with docket UE 374. The parties resolved two issues and agree to support changes in docket UE 374 for Deer Creek Mine pension costs and the long-term opt-out charge sample calculation. The third issue, whether wheeling revenues should be moved from base rates into the TAM, was not resolved and may be determined in docket UE 374. We briefly describe the stipulation provisions.

1. Deer Creek Mine Legacy Pension Costs

CUB explained that the Commission previously approved PacifiCorp making an annual penalty payment to cover its withdrawal from a pension trust associated with the closed Deer Creek Mine.[12] This cost has been added into the TAM annually, but CUB explains

[11] AWEC/100, Mullins/6,
[12] CUB/100, Jenks 9-10.

that the cost is fixed, not variable, has no relationship to 2021 net power costs, and parallels the legacy pension costs associated with coal plant retirements. CUB proposed to remove legacy pension costs associated with the Deer Creek Mine from the TAM and move them into base rates, which will be determined in docket UE 374. PacifiCorp accepted this adjustment in reply testimony and removed the costs from the TAM. The stipulation states that it is appropriate to include these costs in base rates and "Parties agree to support this adjustment in PacifiCorp's current GRC, docket UE 374."[13]

2. Direct Access Long-Term Opt Out Charge Sample Calculation

AWEC proposed modifications to the Direct Access opt-out program and related transition charge. Calpine Solutions proposed that the TAM Guidelines be modified to include a sample calculation of Schedule 296.

For the long-term opt out charge under Schedule 296, the parties will support Calpine Solutions' proposal to amend the TAM Guidelines in docket UE 374 to provide a sample calculation of Schedule 296 as applicable to customers currently served under rate Schedules 30-Secondary and 48-Primary.

3. Wheeling Revenues

Wheeling revenues are currently forecast in the GRC and updated annually through a deferred accounting application. CUB proposed to change the TAM Guidelines to include wheeling revenues in the TAM. The stipulating parties agreed this issue should be considered in docket UE 374. PacifiCorp agrees to make any appropriate adjustments to the 2021 TAM for wheeling revenues based on a final order in docket UE 374.

IV. DISCUSSION AND ADDITIONAL INFORMATION REQUESTED

We adopt the stipulation as filed. We agree with the parties that the stipulation represents a reasonable compromise of numerous complex issues raised in this case. The record shows the parties' detailed review of the filing through their opening testimony and PacifiCorp's engagement with the parties' issues in its detailed reply testimony. The stipulation clearly sets out a path for PacifiCorp to provide new information next year on coal modeling, coal supply agreements, market conditions, and wholesale sales. We appreciate the provisions that allow for continued work into these issues. We add directives for PacifiCorp to provide additional information on two issues—PTC/NPC benefits and coal supply agreements.

[13] Stipulation at paragraph 22.

A. Rate Benefits from New Wind Projects

1. Clarification of the Terms of the Stipulation

We find the language in paragraph 18 of the stipulation is ambiguous as to whether Schedule 201 will contain a full year of PTC benefits for new wind projects, or whether the PTC benefits will be adjusted downward in the event of delays in the projects' online dates. We direct PacifiCorp to work with the stipulating parties to more clearly explain their agreement and to include an explanation in PacifiCorp's indicative update that is filed around November 8.

We briefly explain our uncertainty. The language in paragraph 18 states that, if the online dates are delayed beyond January 1, 2021, customers *will retain the full value* of ratemaking benefits beginning with the commercial in-service date, *but* that Schedule 201 rates *will be updated* coincident with the timing of rate recovery" (emphasis added). Because the 2021 TAM filing currently reflects a full year of PTCs for the new projects,[14] we are unsure whether the total PTC benefit of $64.6 million Oregon-allocated will carry over into January 1, 2021 rates, or whether a delay with the new wind projects would trigger a Schedule 201 update.

In the recent past, we have adopted two distinct (almost opposite) approaches to forecasting PTC and NPC benefits in the TAM for wind projects that are under construction. In the 2019 TAM, we adopted the parties' stipulation that used a set, expected in-service date to calculate benefits for each of the 2019 repowering projects.[15] When Schedule 201 was effective on January 1, the PTC benefits were already incorporated into the rates, and subsequent delays (i.e., Marengo I and II coming online in 2020)[16] did not reduce the benefits in 2019 rates. In contrast, in the 2020 TAM, we adopted the parties' stipulation where the benefits of the 2020 repowering projects were estimated in the stipulation, but did not flow into Schedule 201 rates unless and until the projects were online and cost recovery approved.[17] Either approach is a reasonable approach within a stipulation, but due to the significant rate impact from new wind (approx. $6 million, Oregon-allocated per month from PTC and NPC benefits),[18] it is

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[14] Stipulation at Exhibit 1.
[15] *In the Matter of PacifiCorp 2019 Transition Adjustment Mechanism,* Docket No. UE 339, Order No. 18-421, Partial Stipulation at 4 (Oct 26, 2018).
[16] *In the Matter of PacifiCorp 2019 Renewable Adjustment Clause,* Docket No. UE 352, PacifiCorp Compliance Filing (Mar 17, 2020).
[17] *See PacifiCorp,* Docket No. UE 356, Compliance Filings at Attachment 3, page 2 (showing that PTC benefits from Foote Creek and EV 2020 are estimated with an anticipated 12/1/2020 effective date, to be adjusted based on the pending online and rate recovery dates).
[18] *Id.* (shows the following Oregon-allocated benefits for one month of new EV 2020 wind: $3.64 million in PTCs and $2.34 million in NPC reduction).

important that the parties clearly explain their agreement. The additional explanation will also facilitate our processing of future compliance filings for this docket.

2. Ongoing Reporting Requirement for PTCs

The stipulation shows a notable $64.6 million credit for Oregon customers from PTCs, almost triple the amount seen from PacifiCorp's original 2008 wind fleet. In order to continue our oversight of costs and benefits of new projects, we extend PacifiCorp's reporting requirement from the 2020 TAM in Order 19-351 for initial TAM testimony to show the output (MWh) and PTC benefits ($) for the wind fleet. We request that PacifiCorp also explain its grossed-up PTC value used for the PTC benefits. We ask PacifiCorp to explain and quantify the other NPC benefits from the wind projects, whether the wind output displaces PacifiCorp's higher cost generation, or excess wind output is forecast to be sold to the market with revenues that benefit customers. We have recently asked Portland General Electric for similar information on its new wind project,[19] and the information request is similar to what PacifiCorp provided in the past for certain wind projects.[20]

B. Coal Supply Agreements

We appreciate the parties' agreement to specifically review new coal supply agreements. This record shows the new Hunter coal supply agreement will need a close review in the next power cost proceeding, and we intend to scrutinize the terms of that contract in our review.

Because the parties explained minimum delivery levels in testimony, we separately address this one specific aspect of coal supply agreements.[21] In this TAM, PacifiCorp was able to find new solutions to reduce the minimum take deliveries at Jim Bridger and Colstrip.[22] Reduced deliveries at these plants will allow PacifiCorp to better align the output of the plants with expected load and market conditions next year. However, we do not currently see the same flexibility for PacifiCorp to alter its Huntington coal delivery. We are concerned that, because of the minimum take level in the Huntington coal supply agreement, PacifiCorp may not be able to decrease output at Huntington in coming years when other lower-cost generation is available.

[19] *In the Matter of Portland General Electric Co., 2021 Annual Power Cost Update Tariff*, Docket No. UE 377, Order No. 20-390 (Oct 28, 2020).
[20] *PacifiCorp,* Docket No. UE 356, Indicative Update, Exhibit F (Nov 8, 2019).
[21] Sierra Club/108, Burgess/1. PAC/700, Ralston/15, Confidential Table 2.
[22] PAC/700, Ralston/3 (deferral of a portion of Black Butte deliveries in 2021); PacifiCorp ALJ Bench Request Response 2.2 (June 29, 2020) (compares Colstrip's new delivery level to past consumption).

PacifiCorp explains that we approved the Huntington coal supply agreement in docket UM 1712 in 2015 when PacifiCorp closed the Deer Creek coal mine.[23] Nonetheless, since 2015, we have seen decreases in overall market and power supply costs, while we have seen increases in coal fueling costs, including at Huntington. This raises the question of how we should approach fuel costs if portions of the coal delivery required by Huntington's minimum take requirement are not economic on a $/MWh basis relative to the rest of PacifiCorp's generation fleet and PacifiCorp's market forecast. We ask parties to address whether it is reasonable for TAM rates to include coal costs required by minimum take delivery levels that may be uneconomic, or whether forecasts should be set based on the economic delivery level without reference to the minimum take.

V. ORDER

IT IS ORDERED that:

1. The stipulation between PacifiCorp, dba Pacific Power; Staff of the Public Utility Commission of Oregon; the Oregon Citizens' Utility Board; the Alliance of Western Energy Consumers; Calpine Energy Solutions LLC; Klamath Water Users Association; Sierra Club; and Vitesse, LLC, attached as Appendix A, is adopted.

2. Advice No. 20-002 is permanently suspended.

3. PacifiCorp, dba Pacific Power, shall explain in its Indicative Filing its Production Tax Credit (PTC) agreement in Paragraph 18 of the Stipulation.

4. PacifiCorp, dba Pacific Power, shall update its net power costs (NPC) to reflect the stipulation and its final update to establish its Transition Adjustment Mechanism NPC for the calendar year 2021, filing tariffs to be effective January 1, 2021.

[23] PAC/600, Schwartz/7-8, 26.

5. PacifiCorp, dba Pacific Power, shall include its grossed-up PTC value and explanation or calculation of the NPC benefits from repowered and new wind in its 2022 NPC filing.

Made, entered, and effective Oct 30 2020.

Megan W. Decker
Chair

Letha Tawney
Commissioner

Mark R. Thompson
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 375

In the Matter of PACIFICORP, d/b/a PACIFIC POWER, 2021 Transition Adjustment Mechanism	**STIPULATION**

This Stipulation resolves all issues among all parties to the 2021 Transition Adjustment Mechanism (TAM). The TAM is an annual filing by PacifiCorp, d/b/a Pacific Power, to update its net power costs (NPC) in rates and set the transition adjustments for direct access customers.

PARTIES

1. The parties to this Stipulation are PacifiCorp, Staff of the Public Utility Commission of Oregon (Staff), the Oregon Citizens' Utility Board (CUB), the Alliance of Western Energy Consumers (AWEC), Calpine Energy Solutions, LLC (Calpine Solutions), Sierra Club, Klamath Water Users Association (KWUA), and Vitesse, LLC (Vitesse) (collectively, the Parties).[1]

BACKGROUND

2. On February 14, 2020, PacifiCorp filed its 2021 TAM, with direct testimony and exhibits from David Webb, Ramon Mitchell, Dana Ralston, and Judith Ridenour. PacifiCorp also filed revised tariff sheets for Schedule 201 and 205 to implement the 2021 TAM. The company filed the 2021 TAM concurrently with its

[1] The Northwest and Intermountain Power Producers Coalition (NIPPC) has intervened in this docket as well, and they have indicated that they do not oppose the stipulation.

current general rate case (GRC)[2] and proposed that new rates become effective on January 1, 2021.

3. The TAM is PacifiCorp's annual filing to update its NPC in rates and to set the transition adjustments for customers who choose direct access during the open enrollment window in November. Along with the forecast NPC, the 2021 TAM also includes test period forecasts for: (1) other revenues related to NPC; (2) incremental benefits related to the company's participation in the energy imbalance market (EIM); and (3) renewable energy production tax credits (PTC).

4. PacifiCorp's February 14, 2020 TAM filing (Initial Filing) reflected normalized, total-company NPC for the test period (the 12 months ending December 31, 2021) of approximately $1.401 billion. On an Oregon-allocated basis, NPC in the Initial Filing were approximately $356.6 million. This amount was approximately $13.3 million lower than the $369.9 million included in rates through the 2020 TAM (docket UE 356), and $49.2 million lower when adjusted for forecasted load changes, other revenues, and PTCs. The TAM Initial Filing reflected an overall average rate decrease of approximately 3.7 percent.

5. On February 19, 2020, CUB and AWEC filed to intervene in this proceeding. On March 3, 2020, NIPPC filed a petition to intervene. On March 9, 2020, Calpine Solutions filed a petition to intervene. On March 25, 2020, Vitesse filed a petition to intervene. On April 6, 2020, Sierra Club filed a petition to intervene. On April 13, 2020 KWUA filed a petition to intervene. On February 27, 2020, Administrative Law Judge Sarah Rowe held a prehearing conference and subsequently issued a Prehearing

[2] *See* Docket No. UE 374.

Conference Memorandum granting certain requested interventions and adopting a procedural schedule.

6. On May 12, 2020, the Commission held a special public meeting discussing issues related to PacifiCorp's thermal generation units.

7. On May 15, 2020, Staff, AWEC, CUB, Sierra Club, and Calpine Solutions filed opening testimony.

8. On May 28, 2020, the Parties convened a settlement conference.

9. PacifiCorp filed Reply Testimony from David Webb, Seth Schwartz, Dana Ralston, Doug Young, and Ramon Mitchell, along with updated NPC forecasts (June Update) on June 9, 2020. The June Update reflected normalized, total-company NPC for the test period (the 12 months ending December 31, 2021) of approximately $1.406 billion. On an Oregon-allocated basis, NPC in the June Update were approximately $358.4 million. This amount was approximately $11.5 million lower than the $369.9 million included in rates through the 2020 TAM (docket UE 356), and $47.4 million lower when adjusted for forecasted load changes, other revenues, and PTCs. The TAM June Update reflected an overall average rate decrease of approximately 3.6 percent.

10. The Parties held additional settlement conferences on June 18, 2020, and July 2, 2020. During that final conference, the Parties reached an all-party settlement in principlethat resolved all the issues in the 2021 TAM. The settlement establishes baseline 2021 NPC in rates, subject to the Final Update. The terms of the settlement are captured in this stipulation.

11. On July 7, 2020, PacifiCorp filed a Motion to Modify the Procedural Schedule based on the settlement agreement. The motion was granted on July 8, 2020.

AGREEMENT

12. Overall Agreement: The Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented. The Parties agree that the rate change resulting from the Stipulation results in rates that are fair, just, and reasonable, as required by ORS 756.040. The Stipulation results in a decrease to the June Update filing of approximately $2.4 million on an Oregon-allocated basis, for an Oregon-allocated TAM baseline (including both NPC and PTCs) of $291.4 million. This includes a black box adjustment to NPC as described in Paragraph 14 below. This results in a rate decrease of $49.8 million from the 2020 TAM (UE 356), or 3.8 percent on an overall basis, as shown in Exhibit 2. This does include the NPC and PTC impacts from the new wind and transmission projects, which may be reflected through separate tariff filings as discussed in Paragraph 18, below. A preliminary estimate of the impact of adjustments is included as Exhibit 3.[3] The impacts of the individual adjustments, described below and set forth in Exhibit 3, are based on one-off studies from the June Update filing in the 2021 TAM.

13. TAM Adjustments and Updates: The Parties agree that the NPC forecast reflected in the company's June Update, subject to the adjustments described in this Stipulation, is reasonable. The Parties agree that PacifiCorp will file a Final Update to its 2021 TAM filing consistent with the TAM Guidelines, including the adjustments described in this Stipulation. The Parties recognize that the estimated impact of each of

[3] Adjustments in ¶22, ¶24 and a partial adjustment from ¶19 below have been included in the June Update listed as Item A01, Item U02 and Item U04 in Exhibit 503 from the June Update filing.

the agreed-upon adjustments may change in the TAM updates, along with the NPC baseline and overall rate change.

14. NPC Adjustment: The Parties agree to an Oregon-allocated unspecified reduction to NPC of $2.25 million.

15. Transition to AURORA for Modeling NPCs: As part of the transition from the Generation and Regulation Initiative Decision Tool (GRID) production cost model to the AURORA production cost model, PacifiCorp agrees to hold a workshop on this transition before filing next year's NPC forecast mechanism[4] and provide access to the AURORA production cost model.

a. AURORA Workshop: In addition to information on the transition from GRID to AURORA, the workshop will provide information on the Day-Ahead/Real-Time Adjustment and how the benefits of nodal pricing would be captured by AURORA prior to the filing of the power cost forecast mechanism. PacifiCorp will provide all inputs, data, model settings, additional constraints, and any other modeling changes that are identical to those included in the AURORA model runs to be used for the Company's power cost forecast mechanism's initial filing and workshop.

b. Access to AURORA: PacifiCorp agrees to providing an AURORA license to Commission Staff and intervenors for the TAM. PacifiCorp will provide all inputs, data, model settings, additional constraints, and any other modeling changes that are identical to those included in the AURORA model runs used for

[4] PacifiCorp has proposed a new power cost forecast mechanism in the current GRC, Docket No. UE 374. References to the NPC forecast mechanism in this Stipulation are inteneded to include any future TAM or other NPC forecast mecahanism adopted by the Commission.

the Company's TAM application and workshop. The Parties agree that the costs of this license, training, and data sets will be included for cost recovery in any NPC forecast mechanism until the Company's next GRC. PacifiCorp would additionally agree to conduct one AURORA model run per intervenor, so long as the request is reasonable and PacifiCorp has a reasonable time to complete the request during future NPC forecast mechanism proceedings.

16. Modeling of PacifiCorp's Coal Units: PacifiCorp agrees to remove the "must run" constraint on the modeling of the Company's coal units, as part of the transition to AURORA. PacifiCorp additionally agrees to perform a one-off informational AURORA model run, based on the initial TAM filing, that uses an average coal price for purposes of dispatching coal plants and removes any operational constraints related to the minimum take provisions in the coal supply agreements. This one-off study will be provided in the initial TAM filing as part of the 15-day workpapers until all coal costs are removed from Oregon rates.[5]

17. Coal Supply Agreement Review: PacifiCorp agrees to provide testimony in the initial TAM or other NPC forecast filing regarding the prudence of any Coal Supply Agreements (CSA) that were entered into after its reply testimony of the previous year's NPC forecast proceeding. PacifiCorp will notify Parties in the event of the execution of a CSA following the Company's initial testimony but prior to conclusion of the NPC forecast filing and work with Parties to identify the appropriate review timeline, regulatory process and rate implementation.

[5] PacifiCorp would not need to perform this model run after filing the NPC forecast for calendar year 2029.

18. New Wind Resources: The following PacifiCorp new wind resources (New Wind Projects) are planned to be in service by December 31, 2020: TB Flats I, TB Flats II, Cedar Springs II, Ekola Flats, Pryor Mountain and the repowering of Foote Creek. If these wind resources are online on or before December 31, 2020, the full value of ratemaking benefits will be included in TAM rates beginning January 1, 2021. If the commercial in-service dates of one or more of the New Wind Projects are delayed beyond December 31, 2020, the Parties agree that customers will retain the full value of ratemaking benefits beginning with the commercial in-service date, but that Schedule 201 rates will be updated coincident with the timing of rate recovery of each New Wind project, which is anticipated to be determined in docket UE 374. Parties agree to support aligning the timing of the rate effective dates in docket UE 374 to match the commercial in-service dates so long as the project comes online before July 1, 2021. In the event that the cost recovery is approved earlier than the online date projected in the 2021 TAM, the benefits forecasted in the 2021 TAM will be proportionately increased to reflect the early online date. In the event that the cost recovery is delayed beyond the online date projected in the 2021 TAM, but still comes online in 2021, the benefits forecasted from the 2021 TAM final update will be proportionately reduced to account for the delay.

In the event that the commercial in-service date for a project is delayed beyond July 1, 2021, PacifiCorp will notify the Parties, and Parties will meet to discuss what actions need to be taken.

19. EIM Benefits: The Parties agree that PacifiCorp's calculated EIM Inter-regional transfer benefits for 2021, included in the Company's initial filing, are reasonable and appropriate. PacifiCorp's forecast for EIM benefits will be updated consistent with

the other updates traditionally filed for the TAM. The Parties agree that the calculation of EIM benefits is limited to the 2021 TAM and does not set a precedent for the methodology to be used going forward. Additionally, PacifiCorp agrees to increase EIM benefits (as filed in the intial filing) by $214,555 on a Oregon-allocated basis as described below:

a. PacifiCorp agrees to an unspecified increase of $213,429 to EIM benefits. Part of this increase, $30,593, has been included in the June Update.

b. PacifiCorp agrees to include the flex transfer benefit of $1,126 in its calculation of EIM benefits, which was also included in the June Update.

c. PacifiCorp agrees to provide additional information on the California Independent System Operator's (CAISO) calculation of EIM benefits, including making the additional supporting documentation that is available to PacifiCorp available for review.

20. Economic Cycling: PacifiCorp agrees to hold a quarterly call in 2021 with Parties to provide information on the actual operations of Energy Supply Management including the dispatch of its coal facilities and market conditions. PacifiCorp additionally agrees to provide a study on the costs and benefits of economic cycling including the non-fuel cost impacts by March 1, 2021.

21. Jim Bridger Selective Catalytic Reduction: PacifiCorp agrees to return its power cost models to an adjusted minimum operating condition for Jim Bridger Unit 4 if the Commission disallows full cost recovery for these capital additions.

22. Legacy Pension Costs at the Deer Creek Mine: Parties agree that an adjustment to move legacy United Mine Workers of American pension costs associated

with the Deer Creek Mine from the TAM into base rates is appropriate. Parties agree to support this adjustment in PacifiCorp's current GRC, docket UE 374.

23. Wheeling Revenues: The Parties agree that the inclusion of wheeling revenues in the TAM and a subsequent change to TAM Guidelines (or APCA guidelines) should be considered in the GRC, and PacifiCorp agrees to make any appropriate adjustments to the 2021 TAM for wheeling revenues based on the Commission's final order in the current GRC.[6]

24. Transmission Line Losses: PacifiCorp agrees to include transmission line loss savings of 11.6 average megawatts in Wyoming East load bubble for the GRID model in the 2021 TAM.

25. Wholesale Sales: In future power cost forecast proceedings, PacifiCorp agrees to provide the Commission for the most recent past actual calendar year: for each hour of the sales period: the $/megawatt-hour (MWh) of bilateral trades total wholesale sales revenue ($); total energy delivered (MWh) through wholesales sales; hourly generation logs for PacifiCorp owned generation; and monthly generation unit production costs ($/MWh). If the Company joins expanded markets in the future such as the proposed CAISO Extended Day-Ahead Market, the Company agrees to work with intervenors to identify additional wholesale sales data to be provided in future forecast NPC filings.

26. Inclusion of long-term opt out charge under Schedule 296: Parties agree that in in PacifiCorp's current GRC,[7] they will support Calpine Solutions' proposal that the TAM guidelines (or APCA guidelines, as applicable) be amended to provide a sample

[6] *Id.*
[7] Id.

calculation of Schedule 296 as applicable to customers currently served under rate Schedules 30-Secondary and 48-Primary.[8]

27. Tariff Revisions: Upon approval of this Stipulation, concurrent with the filing of the Final Update, PacifiCorp will file revised Schedules 201 and 205, Schedules 293 and 220 (if necessary), and revised transition adjustment Schedules 294, 295, and 296 as a compliance filing in docket UE 375, to be effective January 1, 2021, reflecting the agreements in this Stipulation and the results of the Final Update. PacifiCorp will then file additional tariff revisions to incorporate the benefits, including NPC and PTC benefits, for any delayed New Wind Resources as described in Paragraph 18 of this Stipulation.

28. Entire Agreement: The Parties agree that this agreement represents a compromise among competing interests and a resolution of all contested issues in this docket. Any adjustment to PacifiCorp's Initial Filing or Reply Update not incorporated into this stipulation directly or by reference is resolved without an adjustment for the purposes of this proceeding.

29. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-001-0350(7). The Parties agree to support this Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein. The Parties also agree to cooperate in drafting and submitting joint testimony or a brief in support of the Stipulation in accordance with OAR 860-001-0350(7).

[8] Calpine Solutions/100, Higgins/7-8.

30. If this Stipulation is challenged, the Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation. The Parties agree to cooperate in any hearing and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Stipulation.

31. The Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material part of this Stipulation or adds any material condition to any final order that is not consistent with this Stipulation, each Party reserves its right, pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation or to withdraw from the Stipulation. The Parties agree that in the event the Commission rejects all or any material part of this Stipulation or adds any material condition to any final order that is not consistent with this Stipulation, the Parties will meet in good faith within fifteen days and discuss next steps. A Party may withdraw from the Stipulation after this meeting by providing written notice to the Commission and other Parties. Parties shall be entitled to seek rehearing or reconsideration pursuant to OAR 860-001-0720 in any manner that is consistent with the agreement embodied in this Stipulation.

32. By entering into this Stipulation, no Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Party in arriving at the terms of this Stipulation, other than those specifically identified in the body of this Stipulation. No Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in this Stipulation.

33. This Stipulation is not enforceable by any Party unless and until adopted by the Commission in a final order. Each signatory to this Stipulation acknowledges that they are signing this Stipulation in good faith and that they intend to abide by the terms of this Stipulation unless and until the Stipulation is rejected or adopted only in part by the Commission. The Parties agree that the Commission has exclusive jurisdiction to enforce or modify the Stipulation.

34. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

STAFF

By: ______________________________

Date:______________________________

PACIFICORP

By: ______________________________

Date: August 18, 2020

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________________

Date:______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date:______________________________

CALPINE ENERGY SOLUTIONS LLC

By: ______________________________

Date:______________________________

KLAMATH WATER USERS ASSOCIAITION

By: ______________________________

Date:______________________________

SIERRA CLUB

By: ______________________________

Date:______________________________

VITESSE, LLC

By: ______________________________

Date:______________________________

STAFF

By: /s/ Sommer Moser

Date: August 17, 2020

PACIFICORP

By: ______________________________

Date: ______________________________

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________________

Date: ______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date: ______________________________

CALPINE ENERGY SOLUTIONS LLC

By: ______________________________

Date: ______________________________

KLAMATH WATER USERS ASSOCIAITION

By: ______________________________

Date: ______________________________

SIERRA CLUB

By: ______________________________

Date: ______________________________

VITESSE, LLC

By: ______________________________

Date: ______________________________

STAFF	**PACIFICORP**
By: ____________________	By: ____________________
Date:____________________	Date:____________________
ALLIANCE OF WESTERN ENERGY CONSUMERS	**OREGON CITIZENS' UTILITY BOARD**
By: ____________________	By: ____________________
Date:____________________	Date:______8/17/2020______________
CALPINE ENERGY SOLUTIONS LLC	**KLAMATH WATER USERS ASSOCIAITION**
By: ____________________	By: ____________________
Date:____________________	Date:____________________
SIERRA CLUB	**VITESSE, LLC**
By: ____________________	By: ____________________
Date:____________________	Date:____________________

STAFF

By: ______________________________

Date:______________________________

PACIFICORP

By: ______________________________

Date:______________________________

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: Brent Coleman

Date: August 17, 2020

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date:______________________________

CALPINE ENERGY SOLUTIONS LLC

By: ______________________________

Date:______________________________

KLAMATH WATER USERS ASSOCIAITION

By: ______________________________

Date:______________________________

SIERRA CLUB

By: ______________________________

Date:______________________________

VITESSE, LLC

By: ______________________________

Date:______________________________

STAFF

By: ______________________________

Date:______________________________

PACIFICORP

By: ______________________________

Date:______________________________

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________________

Date:______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date:______________________________

CALPINE ENERGY SOLUTIONS LLC

By: ______________________________

Date: August 17, 2020

KLAMATH WATER USERS ASSOCIAITION

By: ______________________________

Date:______________________________

SIERRA CLUB

By: ______________________________

Date:______________________________

VITESSE, LLC

By: ______________________________

Date:______________________________

STAFF

By: ______________________________

Date: ______________________________

PACIFICORP

By: ______________________________

Date: ______________________________

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________________

Date: ______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date: ______________________________

CALPINE ENERGY SOLUTIONS LLC

By: ______________________________

Date: ______________________________

KLAMATH WATER USERS ASSOCIAITION

By: Paul S. Simmons

Date: 8-17-20

SIERRA CLUB

By: R Monahan

Date: August 17, 2020

VITESSE, LLC

By: ______________________________

Date: ______________________________

STAFF	**PACIFICORP**
By: ____________________	By: ____________________
Date:____________________	Date:____________________
ALLIANCE OF WESTERN ENERGY CONSUMERS	**OREGON CITIZENS' UTILITY BOARD**
By: ____________________	By: ____________________
Date:____________________	Date:____________________
CALPINE ENERGY SOLUTIONS LLC	**KLAMATH WATER USERS ASSOCIAITION**
By: ____________________	By: ____________________
Date:____________________	Date:____________________
SIERRA CLUB	**VITESSE, LLC**
By: ____________________	By: ____________________
Date:____________________	Date: 08/18/2020

EXHIBIT 1

PacifiCorp
CY 2021 TAM
Settlement Filing

Line no		ACCT.	Total Company: UE-356 CY 2020 - Final Update	Total Company: TAM CY 2021 - Initial Filing	Total Company: TAM CY 2021 - Reply Filing	Total Company: TAM CY 2021 - Settlement Filing	Factor	Factors CY 2020	Factors CY 2021	Oregon Allocated: UE-356 CY 2020 - Final Update	Oregon Allocated: TAM CY 2021 - Initial Filing	Oregon Allocated: TAM CY 2021 - Reply Filing	Oregon Allocated: TAM CY 2021 - Settlement Filing
1	**Sales for Resale**												
2	Existing Firm PPL	447	7,454,128	7,542,788	7,364,161	7,364,161	SG	26.456%	26.023%	1,972,052	1,962,832	1,916,348	1,916,348
3	Existing Firm UPL	447	-	-	-	-	SG	26.456%	26.023%	-	-	-	-
4	Post-Merger Firm	447	422,493,915	274,078,000	246,508,905	246,508,905	SG	26.456%	26.023%	111,774,336	71,322,311	64,148,107	64,148,107
5	Non-Firm	447	-	-	-	-	SE	25.314%	25.101%	-	-	-	-
6	**Total Sales for Resale**		429,948,043	281,620,789	253,873,066	253,873,066				113,746,388	73,285,143	66,064,455	66,064,455
7													
8	**Purchased Power**												
9	Existing Firm Demand PPL	555	11,573,498	2,848,086	2,847,480	2,847,480	SG	26.456%	26.023%	3,061,867	741,147	740,989	740,989
10	Existing Firm Demand UPL	555	3,793,812	2,484,823	2,484,823	2,484,823	SG	26.456%	26.023%	1,003,685	646,616	646,616	646,616
11	Existing Firm Energy	555	37,613,980	15,046,383	15,044,970	15,044,970	SE	25.314%	25.101%	9,521,753	3,776,866	3,776,511	3,776,511
12	Post-merger Firm	555	674,728,706	592,134,446	608,735,645	608,015,977	SG	26.456%	26.023%	178,505,181	154,088,971	158,409,040	158,221,764
13	Secondary Purchases	555	-	-	-	-	SE	25.314%	25.101%	-	-	-	-
14	Other Generation Expense	555	7,454,837	-	-	-	SG	26.456%	26.023%	1,972,240	-	-	-
15	**Total Purchased Power**		735,164,833	612,513,738	629,112,919	628,393,250				194,064,726	159,253,600	163,573,157	163,385,881
16													
17	**Wheeling Expense**												
18	Existing Firm PPL	565	22,079,714	21,615,814	21,615,814	21,615,814	SG	26.456%	26.023%	5,841,375	5,625,004	5,625,004	5,625,004
19	Existing Firm UPL	565	-	-	-	-	SG	26.456%	26.023%	-	-	-	-
20	Post-merger Firm	565	106,215,175	114,763,115	114,742,965	114,742,965	SG	26.456%	26.023%	28,100,122	29,864,384	29,859,140	29,859,140
21	Non-Firm	565	3,175,158	2,694,259	2,694,259	2,694,259	SE	25.314%	25.101%	803,772	676,299	676,299	676,299
22	**Total Wheeling Expense**		131,470,047	139,073,187	139,053,037	139,053,037				34,745,269	36,165,687	36,160,443	36,160,443
23													
24	**Fuel Expense**												
25	Fuel Consumed - Coal	501	655,082,891	612,737,366	576,061,622	576,061,622	SE	25.314%	25.101%	165,830,293	153,806,196	144,600,039	144,600,039
26	Fuel Consumed - Coal (Cholla)	501	36,986,850	-	-	-	SE	25.314%	25.101%	9,362,999	-	-	-
27	Fuel Consumed - Gas	501	7,690,635	6,894,972	6,196,453	6,196,453	SE	25.314%	25.101%	1,946,838	1,730,741	1,555,402	1,555,402
28	Natural Gas Consumed	547	297,308,679	303,050,501	301,951,689	301,951,689	SE	25.314%	25.101%	75,261,903	76,070,185	75,794,367	75,794,367
29	Simple Cycle Comb. Turbines	547	4,355,357	3,721,741	3,344,450	3,344,450	SE	25.314%	25.101%	1,102,532	934,212	839,507	839,507
30	Steam from Other Sources	503	4,676,489	4,519,705	4,508,022	4,508,022	SE	25.314%	25.101%	1,183,825	1,134,513	1,131,580	1,131,580
31	**Total Fuel Expense**		1,006,100,902	930,924,285	892,062,236	892,062,236				254,688,390	233,675,847	223,920,895	223,920,895
32													
33	TAM Settlement Adjustment**		(1,467,719)	-	-	(8,802,107)		As Settled		(388,297)	-	-	(2,250,000)
34													
35	**Net Power Cost (Per GRID)**		1,441,320,020	1,400,890,421	1,406,355,126	1,396,833,350				369,363,700	355,809,991	357,590,040	355,152,763
36													
37	Oregon Situs NPC Adustments		522,082	786,770	846,893	846,893	OR	100.000%	100.000%	522,082	786,770	846,893	846,893
38	**Total NPC Net of Adjustments**		1,441,842,102	1,401,677,191	1,407,202,019	1,397,680,244				369,885,782	356,596,762	358,436,933	355,999,656
39													
40	Non-NPC EIM Costs*		1,456,461	-	-	-	SG	26.456%	26.023%	385,319	-	-	-
41	Production Tax Credit (PTC)		(96,935,002)	(248,328,203)	(248,328,203)	(248,328,203)	SG	26.456%	26.023%	(25,644,974)	(64,621,536)	(64,621,536)	(64,621,536)
42	**Total TAM Net of Adjustments**		1,346,363,561	1,153,348,988	1,158,873,816	1,149,352,041				344,626,127	291,975,226	293,815,397	291,378,121
43													
44										Increase Absent Load Change	(52,650,901)	(50,810,730)	(53,248,006)
45													
46								Oregon-allocated NPC (incl. PTC) Baseline in Rates from UE-356		$344,626,127			
47								$ Change due to load variance from UE-356 forecast		(3,440,369)			
48								2021 Recovery of NPC (incl. PTC) in Rates		$341,185,758			
49	*EIM Benefits for the 2020 TAM are reflected in net power costs												
50	**TAM Settlement UE 356 - Agreed to decrease Oregon-allocated NPC by $388,297. TAM Settlement UE 375 - Agreed to decrease Oregon-allocated NPC by $2,250,000.									**Increase Including Load Change**	**$ (49,210,532)**	**$ (47,370,361)**	**$ (49,807,637)**

EXHIBIT 2

TAM Price Change

PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2021

						Present Revenues ($000)			Proposed Revenues ($000)			Change				
												Base Rates		Net Rates		
Line No.	Description	Sch No.	Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1]	Net Rates	($000)	%[2]	($000)	%[2]	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	
								(6) + (7)			(9) + (10)	(9) - (6)	(12)/(6)	(11) - (8)	(14)/(8)	
	Residential															
1	Residential	4	4	517,740	5,521,127	$628,518	$8,453	$636,972	$607,421	$8,453	$615,874	($21,097)	-3.4%	($21,097)	-3.3%	1
2	**Total Residential**			517,740	5,521,127	$628,518	$8,453	$636,972	$607,421	$8,453	$615,874	($21,097)	-3.4%	($21,097)	-3.3%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23	23	82,822	1,130,147	$126,081	$5,748	$131,829	$121,685	$5,748	$127,433	($4,396)	-3.5%	($4,396)	-3.3%	3
4	Gen. Svc. 31 - 200 kW	28	28	10,562	2,038,726	$186,682	$4,020	$190,703	$177,566	$4,020	$181,586	($9,116)	-4.9%	($9,116)	-4.8%	4
5	Gen. Svc. 201 - 999 kW	30	30	880	1,361,426	$110,812	$1,603	$112,415	$105,660	$1,603	$107,263	($5,152)	-4.7%	($5,152)	-4.6%	5
6	Large General Service >= 1,000 kW	48	48	195	3,079,837	$213,804	($8,589)	$205,215	$205,413	($8,589)	$196,824	($8,391)	-3.9%	($8,391)	-4.0%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	6	41,898	$5,249	($114)	$5,135	$5,148	($114)	$5,034	($101)	-3.9%	($101)	-4.0%	7
8	Dist. Only Lg Gen Svc >= 1,000 kW	848	848	1	0	$2,222	$12	$2,234	$2,222	$12	$2,234	$0	0.0%	$0	0.0%	8
9	Agricultural Pumping Service	41	41	7,894	221,554	$25,947	($1,115)	$24,832	$24,780	($1,115)	$23,665	($1,167)	-4.5%	($1,167)	-4.7%	9
10	**Total Commercial & Industrial**			102,360	7,873,589	$670,797	$1,565	$672,362	$642,474	$1,565	$644,039	($28,323)	-4.2%	($28,323)	-4.2%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	6,045	8,693	$1,146	$214	$1,361	$1,044	$214	$1,258	($102)	-8.9%	($102)	-7.5%	11
12	Street Lighting Service Comp. Owned	50,51,52	51	1,097	20,238	$3,220	$664	$3,884	$2,919	$664	$3,583	($301)	-9.4%	($301)	-7.8%	12
13	Street Lighting Service Cust. Owned	53	53	302	12,046	$754	$154	$908	$755	$154	$908	$0	0.0%	$0	0.0%	13
14	Recreational Field Lighting	54	54	105	1,457	$121	$24	$145	$112	$24	$136	($9)	-7.6%	($9)	-6.3%	14
15	**Total Public Street Lighting**			7,549	42,434	$5,242	$1,056	$6,298	$4,829	$1,056	$5,885	($412)	-7.9%	($412)	-6.6%	15
16	**Total Sales to Ultimate Consumers**			627,649	13,437,150	$1,304,557	$11,074	$1,315,631	$1,254,724	$11,074	$1,265,799	($49,832)	-3.8%	($49,832)	-3.8%	16
17	Employee Discount			*1,036*	*13,933*	($392)	($5)	($397)	($379)	($5)	($384)	$14		$14		17
18	AGA Revenue					$2,993		$2,993	$2,993		$2,993	$0		$0		18
19	COOC Amortization					$1,727		$1,727	$1,727		$1,727	$0		$0		19
20	**Total Sales with AGA**			627,649	13,437,150	$1,308,885	$11,069	$1,319,954	$1,259,066	$11,069	$1,270,135	($49,819)	-3.8%	($49,819)	-3.8%	20

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Public Purpose Charge (Sch. 290) and Energy Conservation Charge (Sch. 297).

[2] Percentages shown for Schedules 48 and 47 reflect the combined rate change for both schedules

EXHIBIT 3

Oregon TAM 2021 (February 2020 Initial Filing)		
	NPC ($) =	1,400,890,421
	$/MWh =	23.14

Oregon TAM 2021 (June 2020 Update Filing)		
	NPC ($) =	1,406,355,126
	$/MWh =	23.27

	Impact ($) Oregon Allocated Basis	NPC ($) Total Company
Settlement Adjustment*		
S01 - Blackbox Settlement Adjustment	(2,250,000)	
S02 - EIM Benefits (part of this adjustment--Paragraph 19 in the Stipulation--has been included in the June Update)	(183,962)	
Total Changes =	(2,433,962)	(9,521,776)
Oregon TAM 2021 (June 2020 Filing with Settlement)	**NPC ($) =**	**1,396,833,350**
	$/MWh =	**23.11**

** The adjustments from Paragraph 22, Paragraph 24 and partial adjustment from Paragraph 19 in the Stipulation have been included in the June Update listed as Item A01, Item U02 and Item U04 in Exhibit 503 from the Update filing.*