ORDER NO. 19-351

ENTERED Oct 30 2019

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 356

In the Matter of PACIFICORP, dba PACIFIC POWER, 2020 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 2020 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, which provides that Oregon-allocated 2020 NPC will have a baseline of $349.1 million, with 2020 power costs of $24.40 MWh.[1] Compared to 2019 power costs, the 2020 power costs represent an overall rate decrease of $20.1 million or 1.6 percent.[2]

Next month, PacifiCorp will post indicative and final NPC updates in this docket showing the final rates in advance of the January 1, 2020 effective date. PacifiCorp will again update these rates in the summer and fall of 2020, to implement incremental NPC reductions as repowered and new wind projects come online and go into rates. The stipulation contains estimates of these future reductions, with power costs decreasing to $24.39 MWh with the three remaining repowering projects, and power costs decreasing to $24.13 with the new wind projects.

The stipulation reflects the agreement of all parties to resolve all issues in PacifiCorp's 2020 TAM. The parties to the stipulation are PacifiCorp; Staff of the Public Utility

[1] Stipulation at Exhibit 3.
[2] *Id.* at Exhibit 1, Exhibit 2.

Commission of Oregon; the Oregon Citizens' Utility Board (CUB); the Alliance of Western Energy Consumers (AWEC); and Calpine Energy Solutions, LLC (Calpine Solutions). The stipulation is attached to this order as Appendix A.

II. TAM FILING AND RESPONSIVE TESTIMONY

On April 1, 2019, PacifiCorp filed its 2020 TAM, with revised tariff sheets for Schedule 201 to be effective January 1, 2020. PacifiCorp's forecast NPC consists of wholesale sales, fuel expense, purchased power, 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 an increase in NPC of approximately $7.0 million more than the 2019 TAM in docket UE 339. The requested increase was due to lower volumes of wholesale sales (a credit to NPC), partially offset by cost savings from lower coal fuel expense and lower purchased power expense.

All parties conducted discovery on PacifiCorp's filing, participated in a technical workshop and filed opening testimony, which we briefly describe.

Staff filed testimony from four witnesses that addressed 19 different issues. Staff recommended adjustments to EIM benefits, wind capacity factors, Official Forward Price Curve (OFPC) scalars, solar hourly shape, wheeling costs, and qualifying facilities (QFs). Staff also recommended that the company include the variable costs and benefits of new wind projects and repowering certain wind projects in the 2020 TAM.

AWEC made four recommendations in its opening testimony, which relate to the Gas Transmission Northwest Pipeline expense, gas optimization revenues, a 300 MW transmission link between Jim Bridger and Walla Walla, and modeling the benefits of new and repowered wind facilities.

CUB filed testimony from two witnesses with four recommendations. CUB's recommendations related to overall modeling changes, hourly scalars in the OFPC, EIM benefits, wind capacity factors, and PTC benefits.

Calpine filed testimony supporting PacifiCorp's proposal for calculating the consumer opt-out charge for PacifiCorp's five year opt-out program.

Following the parties' opening testimony, PacifiCorp then filed reply testimony with a $1.3 million decrease in NPC (before PTCs were applied). Subsequently, the parties held four additional settlement conferences and reached an all-party stipulation that resolved all issues in the 2020 TAM.

III. STIPULATION AND SUPPORTING TESTIMONY

The stipulation decreases the NPC in PacifiCorp's reply testimony by $4.9 million. Once Oregon-allocated PTCs are applied, the stipulation results in a TAM baseline of $349.1 million, resulting in an overall 1.6 percent rate decrease for 2020. PacifiCorp's final update may slightly change the NPC baseline, the impact of the stipulated adjustments, and the overall rate change. The above amounts also do not include the NPC and PTC impacts from the 2020 repowering projects or new wind projects, which are estimated in the stipulation but will not flow into rates until later in 2020, as discussed below.

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 parties request that we adopt the stipulation as presented. Below we summarize the specific issues addressed in the stipulation.

A. 2020 Wind Repowering

The majority of PacifiCorp's wind facilities will be repowered in 2019. We approved PacifiCorp's cost recovery for 773.5 MW of repowered wind in docket UE 352.[3] These 2019 projects are not specifically discussed in the stipulation, because it is undisputed that the 2020 TAM reflects a full year of service for these projects, with $25 million in Oregon-allocated PTCs.[4]

There are three repowering projects remaining, and the stipulation addresses two of them as the "2020 repowering projects", Dunlap and Foote Creek I. PacifiCorp's reply testimony states these projects are expected to come online in September and December 2020. The stipulation contains a preliminary estimate of 2020 NPC and PTC benefits of $1.9 million based on projected online dates in late 2020.[5] The stipulation provides that PacifiCorp must have cost recovery for repowering Dunlap and Foote Creek I before the NPC and PTC benefits go into rates. PacifiCorp will make a repowering Renewable Adjustment Clause (RAC) filing by January 1, 2020.[6] The stipulating parties will support a RAC procedural schedule to allow the RAC Schedule 202 rates to be effective

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[3] *In the Matter of PacifiCorp, dba Pacific Power, 2019 Renewable Adjustment Clause,* Docket No. UE 352, Order No. 19-304 (Sep 16, 2019).
[4] PAC/400, Wilding/24.
[5] Stipulation at paragraph 15.
[6] The stipulating parties agree to a different timeline for the 2020 repowering RAC filing than the April 1 filing date in PacifiCorp's current Schedule 202.

contemporaneously with the 2020 repowering projects' online dates. Upon receipt of a Commission order approving cost recovery of the repowering projects, PacifiCorp will adjust the estimated PTC and NPC benefits to reflect the anticipated rate effective dates, and file a tariff change for Schedule 201 TAM rates to incorporate the repowering NPC and PTC benefits.

B. Glenrock III

Glenrock III repowering will come online earlier than Dunlap and Foote Creek I, expected by the end of 2019 or early 2020. Similar to Dunlap and Foote Creek, the stipulation estimates benefits with an Oregon-allocated TAM reduction of $1.08 million.[7] However, rather than re-calculating this amount later in 2020 when the RAC Schedule 202 rate effective date is known, the Glenrock III benefits will only be updated in the Final Update. Although the benefit value will be set in this proceeding, the benefits will flow into rates only once the new RAC Schedule 202 rates are approved, with the same Schedule 201 TAM update process as described for Dunlap and Foote Creek.

C. 2020 New Wind

There are four new, PacifiCorp-owned wind projects coming online towards the end of 2020. These projects are part of PacifiCorp's Energy Vision 2020: TB Flats I, TB Flats II, Cedar Springs II, and Ekola Flats. Similar to the repowering projects, the stipulation contains a preliminary estimate of 2020 NPC and PTC benefits of $10.7 million.[8] The stipulation states that PacifiCorp will seek cost recovery for these projects in a general rate case, seeking different rate effective dates to match the online dates of the new wind resources. Upon receipt of an order approving the cost recovery of the new wind resources, the company will adjust the estimated benefits to account for earlier or later than expected Schedule 200 general rate case rates, and then file a tariff change for Schedule 201 TAM rates to incorporate the new wind NPC and PTC benefits.

D. Direct Access

The stipulating parties agree that the consumer opt-out charge applicable to PacifiCorp's five-year direct access program will be calculated with no change to the fixed generation costs in years six through ten, without an inflation escalator. This is the calculation currently reflected in PacifiCorp's testimony in the 2020 TAM, and it matches the method used in the stipulation in the 2019 TAM.[9]

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[7] Stipulation at paragraph 16.
[8] *Id.* at 17.
[9] *Id.* at 23.

The stipulating parties agree that the direct access transition adjustments will be calculated using the final update that includes the benefits from the 2020 repowering projects and the new wind resources.[10]

E. Miscellaneous Stipulated Issues

The parties agree to a confidential value for EIM benefits. PacifiCorp also agrees to decrease Oregon-allocated NPC by approximately $379,921 for the 300 MW transmission link between the Jim Bridger plant and the Walla Walla area described in AWEC's testimony.[11]

The stipulation describes workshops that PacifiCorp will hold with the stipulating parties. First, prior to January 1, 2020, PacifiCorp agrees to hold a workshop to discuss Bridger Coal Company (BCC) depreciation costs.[12] Second, prior to the 2021 TAM, PacifiCorp will hold a workshop to discuss modeling EIM benefits, and to provide more information on PacifiCorp's natural gas trading activities.[13]

IV. RESOLUTION

We will adopt the stipulation as filed. We find reasonable the parties' stipulated decrease to PacifiCorp's NPC for 2020. Below we discuss why we consider the terms of the stipulation reasonable on the timing and magnitude of PTCs. We also address the parties' request regarding matching costs and benefits in rates.

A. PTCs Calculated from Capacity Factors

Oregon law provides that each public utility that makes sales of electricity shall forecast on an annual basis the projected state and federal PTCs received by the public utility and that we shall allow those forecasts to be included in rates through any variable power cost forecasting process.[14] This is the fourth TAM forecast that includes PTCs, and the 2020 PTC forecast is the largest of any year. This stipulation focuses on how to allow the

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[10] *Id.* at 24.
[11] *Id.* at 20.
[12] *Id.* at 21.
[13] *Id.* at 19, 22.
[14] ORS 757.264 (2019).

PTCs in customer rates for projects coming online in 2020: with 191 MW of new repowered wind, and approximately 950 MW of new, PacifiCorp-owned, wind.[15]

The first aspect of the PTC forecast is the amount passed back to customers, which is calculated based on the generation included in the NPC study.[16] Last year, we cautioned PacifiCorp that, for new wind post-commercial operation date (COD) risks, "recovery may be structured to hold PacifiCorp to the cost and benefit projections in its analysis."[17] In this proceeding, the parties agreed to stipulated capacity factors for the 2020 TAM, and further agreed to carry these capacity factors forward until 2024 (the 2025 TAM).[18] The repowered projects' capacity factors are identical to the capacity factors presented in docket UE 352.[19]

PacifiCorp explains how the capacity factors for the four new PacifiCorp-owned wind projects relate to the publicly-available capacity factor estimate of 39.4 percent from the 2017 Integrated Resource Plan (IRP) Update.[20] PacifiCorp explains that removing the Cedar Springs power purchase agreement (PPA) and the Uinta project results in a capacity weighted average capacity factor of 39.2 percent.

We find the amount of PTCs to be calculated pursuant to the stipulation meets the standard we set in in the 2017 IRP order, with a level of benefits consistent with projections. We recognize the significant NPC savings from the repowered wind and anticipated new wind projects. In this proceeding we see a doubling of PTCs, which act as a credit to NPC and directly reduce customer rates. In addition, there is a gradual reduction to NPC as additional zero-fuel cost energy comes online.

B. Timing of PTCs and Matching Costs and Benefits

The timing of the PTC forecast involves uncertainty with projected online dates and anticipated rate proceedings that may shift in 2020. The parties evaluated a range of options for forecasting PTCs: a PTC floor,[21] a locked-in forecast of forward-looking

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[15] PAC/400, Wilding 13-14 (The remaining three repowering projects are Glenrock III at 39 MW, Dunlap I at 111 MW, and Foote Creek I at 41 MW. EV 2020 new wind 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).
[16] *Id.* at 24.
[17] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Integrated Resource Plan,* Docket No. LC 67, Order No. 18-138 (Apr 27, 2018).
[18] Stipulation at Exhibit 4.
[19] Official notice per OAR 860-001-0460 is taken of the same information shown in Docket No. UE 352, PacifiCorp Direct Testimony, PAC/204, Hemstreet/2 (Dec 28, 2018).
[20] Official notice per OAR 860-001-0460 of PacifiCorp's Response to Bench Request (Oct 18, 2019).
[21] CUB/200, Gehrke/8.

PTCs,[22] and PTCs delayed until actual amounts are known in the 2021 TAM.[23] The stipulation contains the parties' compromise on 2020 PTC timing. Upon receipt of orders approving the cost recovery of repowering and new wind projects, PacifiCorp will also file tariff changes for Schedule 201, with the same rate effective dates as Schedule 202 and Schedule 200, to incorporate the NPC and PTC benefits for the remainder of 2020.

We find this approach is reasonable as it will minimize lag and remove uncertainty with the partial year benefit forecast. There will be a relatively accurate flow through of benefits when PacifiCorp updates the benefit calculation with actual online and rate effective dates prior to the Schedule 201 TAM changes.

Stipulating parties explain that the 2007 RAC stipulation contains a statement to the effect that if fixed costs of an eligible resource are not included in RAC charges, then cost offsets should not be included in the annual power cost update filings.[24] The stipulating parties agree that we need not explicitly determine whether the ratemaking treatment proposed would require modification of the RAC.[25] Rather, the stipulating parties recommend we adopt language in this order that states the provisions of the RAC stipulation are amended to the extent necessary to achieve the 2020 TAM settlement.

We find it unnecessary to modify the RAC stipulation. We understand the stipulating parties' intent to match the costs of repowered and new wind plants with the benefits of PTCs in rates. We note, however, that we will be engaged in detailed and complex PacifiCorp regulatory proceedings in 2020, with a 2020 RAC filing, a likely general rate case that would be the first in seven years, a depreciation study, the annual TAM, and the 2019 Integrated Resource Plan (IRP) which may involve a subsequent request for proposals (RFP). We will strive to meet the parties' requested tariff effective dates, but this will be the first time that Schedule 201 rates will change multiple times mid-year, and we cannot guarantee precise adherence to the timelines in the parties' stipulation.

V. DIRECTIVES FOR ADDITIONAL INFORMATION

We include directives to PacifiCorp for additional information on three NPC categories where we see significant changes year to year: PTCs, wholesale sales, and Jim Bridger fueling. Below we describe the additional information that PacifiCorp shall include in upcoming filings.

[22] Staff/100, Gibbens/12-13; AWEC/100, Mullins/12-13.
[23] PAC/400, Wilding/14-15.
[24] *In the Matter of the Public Utility Commission of Oregon Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket No. UM 1330, Order No. 07-572 at 1 (Dec 19, 2007).
[25] Stipulating Parties/100, Wilding, Gibbens, Jenks, Mullins, Townsend/9.

First, in its indicative November update and in the 2021 TAM filing, we seek additional detail on PacifiCorp's PTC calculation. As we move from a partial forecast in 2020 toward a full-year forecast in 2021, additional information will help us track the PTC and NPC benefits. In its indicative November update, PacifiCorp has already agreed to update the expected in-service dates of the new wind projects, with corresponding updates to the stipulated benefits.[26] Along with these updates, we direct PacifiCorp to explain its calculations, and explain the relationship between the NPC cost savings shown in Exhibit 3 and the stipulated estimated TAM reduction of $1.91 million for Dunlap and Foote Creek, $1.08 million for Glenrock III, and $10.72 million for the new wind projects. Next, in the 2021 TAM filing, PacifiCorp is directed to update and expand its PTC calculation shown in this year's initial testimony.[27]

Second, wholesale sales also function as a large credit to customer rates, and we have seen significant variances in this benefit from year to year.[28] In the 2021 TAM filing, PacifiCorp is directed to include additional detail on its wholesale sales revenue, with explanations of the components of that category, and explanations of multi-year trends.

Lastly, we have closely tracked Jim Bridger plant fuel costs for several years, first due to concern over affiliate treatment,[29] and now due to early closures in the company's IRP preferred portfolio.[30] PacifiCorp is directed to update its Jim Bridger fuel plan in light of earlier end-of-life dates, with explanations of how PacifiCorp is planning ahead for flexible fueling arrangements to avoid minimum take penalties such as the penalties PacifiCorp incurred for lower volumes of coal deliveries at the Naughton plant in this TAM.[31]

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[26] Stipulation at paragraph 17.

[27] PacifiCorp's expanded exhibit should include each wind project's Large Generator Interconnection Agreement (LGIA) limited capacity (MWs) and LGIA limited capacity factors agreed to in this stipulation as well as the forecasted energy production (MWh) and PTC value ($) shown in the current exhibit at PAC/106, Wilding/2.

[28] For example, 2016 NPC showed $82 million in Oregon-allocated wholesale sales, while 2019 NPC showed an increase to $130 million, with $100 million in this 2020 TAM. Stipulation at Ex. 1, line 6. Official Notice per OAR 860-001-0460 is taken of the final 2016 NPC shown in Docket No. UE 307, PacifiCorp's Compliance Tariff, Attachment 3, Final Update to NPC Allocation at 1 (Nov 15, 2016).

[29] *In the Matter of PacifiCorp, dba Pacific Power, 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 (Oct 28, 2013).

[30] *In the Matter of PacifiCorp, dba Pacific Power, 2019 Integrated Resource Plan*, Docket No. LC 70.

[31] PAC/200, Ralston/8.

VI. 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 (CUB); the Alliance of Western Energy Consumers (AWEC), and Calpine Energy Solutions, LLC (Calpine Solutions), attached as Appendix A, is adopted.

2. Advice No. 19-007 is permanently suspended.

3. 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 Net Power Costs for the calendar year 2020, filing tariffs to be effective January 1, 2020.

4. PacifiCorp, dba Pacific Power, shall include explanations in its final update of its repowering and new wind benefit calculations.

5. PacifiCorp, dba Pacific Power, shall include the following additional information in its 2021 Transition Adjustment Mechanism filing: expanded Production Tax Credit forecast and calculation; explanation of components in wholesale sales and multi-year trends; updated Jim Bridger plant fueling analysis and explanation of fuel plans in light of changing end-of-life dates.

Made, entered, and effective Oct 30 2019.

Megan W. Decker
Chair

Stephen M. Bloom
Commissioner

Letha Tawney
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 356

In the Matter of PACIFICORP, d/b/a PACIFIC POWER, 2020 Transition Adjustment Mechanism	**STIPULATION**

This Stipulation resolves all issues among all parties to the 2020 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), and Calpine Energy Solutions, LLC (Calpine Solutions) (collectively, the Stipulating Parties). No other party intervened in the 2020 TAM.

BACKGROUND

2. On April 1, 2019, PacifiCorp filed its 2020 TAM, with direct testimony and exhibits from Michael G. Wilding, Dana M. Ralston, and Judith M. Ridenour. PacifiCorp also filed revised tariff sheets for Schedule 201 and 205 to implement the 2020 TAM. The company filed the 2020 TAM on a stand-alone basis without a general rate case (GRC) and proposed that new rates become effective on January 1, 2020.

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 2020 TAM also includes test period forecasts for: (1) other revenues related to NPC; (2) incremental benefits and costs related to the company's participation in the energy imbalance market (EIM); and (3) renewable energy production tax credits (PTCs).

4. PacifiCorp's April 1, 2019 TAM filing (Initial Filing) reflected normalized, total-company NPC for the test period (the 12 months ending December 31, 2020) of approximately $1.480 billion. On an Oregon-allocated basis, NPC in the Initial Filing were approximately $380.5 million. This amount was approximately $7.0 million higher than the $373.5 million included in rates through the 2019 TAM (docket UE 339), and $14.7 million lower when adjusted for forecasted load changes, other revenues, and PTCs. The TAM Initial Filing reflected an overall average rate decrease of approximately 1.2 percent.

5. On April 2, 2019, CUB filed its notice of intervention. On April 8, 2019, AWEC filed a petition to intervene. On April 10, 2019, Calpine Solutions filed a petition to intervene. On April 30, 2019, Administrative Law Judge Sarah Rowe held a prehearing conference and subsequently issued a Prehearing Conference Memorandum granting the requested interventions and adopting a procedural schedule.

6. On May 28, 2019, PacifiCorp filed a list of corrections, as required by the TAM Guidelines adopted by the Commission in Order No. 09-274 and revised in Order Nos. 09-432 and 10-363.[1] The total impact of the identified corrections was a decrease of

[1] *In the Matter of PacifiCorp's 2009 Transition Adjustment Mechanism*, Docket No. UE 199, Order No. 09-274, App A at 10 (July 16, 2009); *In the Matter of PacifiCorp's 2010 Transition Adjustment Mechanism*, Docket No.

approximately $84,000 to the filed Oregon-allocated NPC. PacifiCorp indicated that the identified corrections would be included in the TAM Reply Update.

7. On May 29, 2019, the Stipulating Parties held a technical workshop.

8. On June 10, 2019, Staff, AWEC, CUB and Calpine Solutions filed opening testimony.

9. On June 25, 2019, the Stipulating Parties convened a settlement conference.

10. PacifiCorp filed Reply Testimony from Michael G. Wilding and Kelcey A. Brown along with updated NPC forecasts (July Update) on July 15, 2019. The July Update reflected normalized, total-company NPC for the test period (the 12 months ending December 31, 2020) of approximately $1.477 billion. On an Oregon-allocated basis, NPC in the July Update were approximately $379.2 million. This amount was approximately $5.7 million higher than the $373.5 million included in rates through the 2019 TAM (docket UE 339), and $15.2 million lower when adjusted for forecasted load changes, other revenues, and PTCs. The TAM July Update reflected an overall average rate decrease of approximately 1.2 percent.

11. The Stipulating Parties held an additional settlement conference on July 29, 2019, and two additional telephone settlement conferences on July 31, 2019. During that final conference, the Stipulating Parties reached an all-party stipulation that resolved all the issues in the 2020 TAM. The settlement establishes baseline 2020 NPC in rates, subject to the Final Update.

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).

12. On August 1, 2019, AWEC filed a Motion to Modify the Procedural Schedule based on the settlement agreement. The motion was granted on August 1, 2019.

AGREEMENT

13. Overall Agreement: The Stipulating Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented. The Stipulating 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 July Update of approximately $4.9 million on an Oregon-allocated basis, for an Oregon-allocated TAM baseline (both NPC and PTCs) of $349.1 million. This results in a rate decrease of $20.1 million from TAM 2019 (UE 339), or 1.6 percent on an overall basis, as shown in Exhibit 2. This does not include the NPC and PTC impacts from the 2020 wind repowering projects (2020 Repowering Projects) or new wind and transmission projects, which will be reflected through separate tariff filings as discussed in Paragraphs 15 and 16, below. A preliminary estimate of the impact of each adjustment is included as Exhibit 3. The impacts of the individual adjustments, described below and set forth in Exhibit 3, are based on one-off studies from the July Update.

14. TAM Adjustments and Updates: The Stipulating Parties agree that the NPC forecast reflected in the company's July Update, subject to the adjustments described in this Stipulation, is reasonable. The Stipulating Parties agree that PacifiCorp will file a Final Update to its 2020 TAM filing consistent with the TAM Guidelines, including the adjustments described in this Stipulation. The Stipulating Parties recognize that the

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

15. 2020 Repowering Projects: The 2020 Repowering Projects are Dunlap and Foote Creek I. The Stipulating Parties agree that PacifiCorp will forecast the NPC and PTC benefits of the 2020 wind Repowering Projects in the 2020 TAM, prorated to reflect their in-service dates in 2020, as described below. The Stipulating Parties agree to support timely filings that match the benefits of the repowered wind facilities, as reflected in Schedule 201, with costs, as will be reflected in Schedule 202 or Schedule 200. In the event that cost recovery is delayed beyond the online date projected in the 2020 TAM, the Stipulating Parties will support the proportionate reduction of benefits forecasted in the 2020 TAM to account for the delay. In the event that the cost recovery is approved earlier than the online date projected in the 2020 TAM, the benefits forecasted in the 2020 TAM will be proportionately increased to reflect an early online date.

To allow implementation of this stipulation, the Stipulating Parties agree to a modification in 2020 of the Renewable Adjustment Clause (RAC), which was approved by the Commission in Order No. 07-572,[2] and is set forth in PacifiCorp's Schedule 202. Specifically, the RAC will be modified as follows: The Stipulating Parties agree that PacifiCorp will make a repowering RAC filing for one or more resources to be repowered in 2020 before January 1, 2020.[3] The Stipulating Parties agree to recommend and support implementation of an expedited procedural schedule for the repowering RAC docket to allow the Schedule 202 rates to be effective contemporaneously with the 2020

[2] *In the Matter of the Public Utility Commission of Oregon Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket No. UM 1330, Order No. 07-572 (Dec. 19, 2007).
[3] If a repowering project is not included in this filing, PacifiCorp will include the resource in a GRC or other filing to match the benefits with cost recovery.

Repowering Projects' online dates.[4] Upon receipt of an order approving the cost recovery of the 2020 Repowering Projects, the company will also file a tariff change for Schedule 201, with the same rate effective date(s) as Schedule 202, to incorporate the NPC and PTC benefits identified in this 2020 TAM. This term modifies the RAC schedule that calls for an April 1 filing with rates effective the following January.[5]

The Stipulating Parties further agree that if any repowering facility is fully disallowed in the RAC, then they will support that NPC and PTC benefits included in the 2020 TAM to be adjusted accordingly so that the costs and benefits remain matched. The preliminary, approximate estimate of this adjustment in the 2020 TAM to reflect the benefits of facilities repowered in 2020 is an Oregon-allocated TAM reduction of $1,913,315, which may be revised in the Final Update based on changes to the scope or expected in-service dates of the repowering projects.

16. Glenrock III Repowering: Glenrock III is projected to be online by the end of 2019 or early 2020. The Stipulating Parties agree that PacifiCorp will forecast the NPC and PTC benefits of the Glenrock III repowering in the 2020 TAM, to reflect the later of a January 1, 2020 or a projected online date at the time of the final TAM update. The rate change reflecting these NPC and PTC benefits will occur contemporaneous with the rate effective date for cost recovery of this project. The Stipulating Parties agree to support timely filings that will allow for expedited cost recovery in Schedule 202. PacifiCorp will include the Glenrock III repowering in the RAC filing described in Section 15. The

[4] Because individual repowering projects will be completed at different times in 2020, the Stipulating Parties agree that the RAC rates will not reflect any repowering project costs until the project is in service. The Stipulating Parties also agree that the inclusion of the NPC benefits of repowering in the 2020 TAM will occur simultaneously as the repowered facilities are incorporated into rates.
[5] Order No. 07-572 at 2.

preliminary, approximate estimate of this adjustment in the 2020 TAM to reflect the benefits of repowering Glenrock III is an Oregon-allocated TAM reduction of $1,081,787, which may be revised in the Final Update based on changes to the scope or expected in-service dates of the repowering projects.

17. New Wind Resources and Transmission: PacifiCorp's Energy Vision 2020 project (EV 2020) includes five new Wyoming wind resources that will be in service by the end of 2020: 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 megawatts (MWs). EV 2020 also includes a new 500 kilovolt transmission line between the Aeolus substation and the Jim Bridger plant (Aeolus-to-Bridger/Anticline line). In addition to EV 2020, Cedar Springs III, a PPA that depends on the Aeolus-to-Bridger/Anticline line to incorporate this resource into PacifiCorp's system, will be online in 2020. The Stipulating Parties agree that PacifiCorp will forecast the NPC and PTC benefits of these new resources in the 2020 TAM, prorated to reflect their in-service dates in 2020. These benefits will be matched to the cost recovery proceedings for the new wind resources such that the benefits will not be reflected in Schedule 201 until PacifiCorp begins recovering the costs of those resources. In the event that the cost recovery is delayed beyond the online date projected in the 2020 TAM, the benefits forecasted in the 2020 TAM will be proportionately reduced to account for the delay. In the event that the cost recovery is approved earlier than the online date projected in the 2020 TAM, the benefits forecasted in the 2020 TAM will be proportionately increased to reflect an early online date.

To implement this Stipulation, the Stipulating Parties agree to support a procedural schedule for PacifiCorp's upcoming GRC that includes multiple rate effective dates tied to the in-service dates of these new wind resources, requests an order for new wind resources and transmission prior to October 28, 2020, and allows these new wind resources to be reflected in rates before the end of the suspension period described in ORS 757.215. Upon receipt of an order approving the cost recovery of the 2020 new wind resources and transmission, the company will also file a tariff change for Schedule 201, with the same rate effective date(s) as Schedule 200, to incorporate the NPC and PTC benefits identified in this 2020 TAM.

The Stipulating Parties further agree that if any new wind resource is fully disallowed in the GRC, then they will support adjusting the NPC and PTC benefits included in the 2020 TAM accordingly so that the costs and benefits remain matched. The preliminary, approximate estimate of this adjustment is an Oregon-allocated TAM reduction of $10,716,054, which may be revised in the Final Update based on changes to the scope or expected in-service dates of the new wind resources.

18. PTC Floor and Wind Capacity Factors: The parties agree to drop their recommendation for a PTC floor. PacifiCorp agrees to use the following wind capacity factors for its owned wind facilities in its TAM forecasts: (a) non-repowered wind will use a 50/50 weighting of the actual historical capacity factor and P50 forecast, as proposed by PacifiCorp in its Initial Filing; (b) repowered wind facilities will be based on PacifiCorp's economic analysis from February 2018; (c) and new owned wind facilities will be based on the economic analysis used to justify the investment. Exhibit 4 lists each owned wind facility, the capacity factor and the source of the capacity factor. The Stipulating Parties expressly agree not to propose any changes to wind capacity factors until 2024, in the 2025 TAM or other annual NPC filing which uses a 2025 test year. In NPC filings in

2024 and thereafter, the Stipulating Parties may propose different wind capacity factors be used in PacifiCorp's power costs forecasts.

19. EIM Benefits: The Stipulating Parties agree that test-period benefits related to PacifiCorp's participation in the EIM should be forecast at $[redacted] consistent with the table shown below and that EIM benefits will not be updated.

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]

Based on the record developed in this case, the Stipulating Parties agree that this is a reasonable and appropriate level at which to set EIM benefits for 2020. PacifiCorp agrees to hold a workshop with the Stipulating Parties to discuss modeling EIM benefits prior to filing the 2021 TAM. The Stipulating Parties agree to work collaboratively through workshops next year on an EIM inter-regional benefits methodology for the 2021 TAM that is fair and reasonable.

20. Jim Bridger-to-Walla Walla Transmission Link: PacifiCorp agrees to an adjustment to decrease the Oregon-allocated NPC by approximately $379,921 for the 300 MW transmission link between the Jim Bridger plant and the Walla Walla area described in AWEC's testimony.[6] PacifiCorp does not agree to model this adjustment directly in the GRID model in this or future TAM filings and AWEC is not precluded from proposing a modeling change to account for the 300 MW transmission link in future TAM filings.

[6] AWEC/100, Mullins/21-22.

21. Bridger Coal Company (BCC) Depreciation: PacifiCorp agrees to hold a workshop with Stipulating Parties before January 1, 2020, to discuss PacifiCorp's BCC depreciation costs.

22. Gas Optimization Margins: PacifiCorp agrees to hold a workshop with Stipulating Parties before filing the 2021 TAM to provide more information on PacifiCorp's natural gas trading activities. Presentation materials, including any workpapers used in developing the presentation materials, will be provided to the parties no later than two weeks prior to the date of the workshop.

23. Consumer Opt-Out Charge: The Stipulating Parties agree that the consumer opt-out charge applicable to PacifiCorp's five-year direct access program will be calculated with no change to the fixed generation costs in years six through 10. Specifically, the charge will be calculated holding fixed generation costs flat in nominal terms in years six through 10, without an inflation escalator. This is the calculation currently reflected in PacifiCorp's testimony in the 2020 TAM, and it matches the method used in the Stipulation in the 2019 TAM. Unlike the 2019 TAM Stipulation and PacifiCorp's opening testimony in the 2020 TAM, the Stipulating Parties have agreed to remove the language that this method is "non-precedential."

24. Direct Access Transition Adjustments: The Stipulating Parties agree that the Direct Access Transition Adjustments will be calculated using the Final Update that includes the benefits from the 2020 Repowering Projects (described in section 15) and the new wind resources and transmission (described in section 16).

25. Gas Transmission Northwest (GTN) Adjustment: The Stipulating Parties agree that the inclusion of the GTN pipeline rate reduction for 2020 included in

PacifiCorp's reply testimony is appropriate. This adjustment decreases NPC by approximately $50,000 on an Oregon-allocated basis.

26. 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 356, to be effective January 1, 2020, 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 the repowered wind facilities and the new wind resources and transmission concurrently with cost recovery for those resources, as described in paragraphs 15 and 16 of this Stipulation.

27. Entire Agreement. The Stipulating 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.

28. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-001-0350(7). The Stipulating 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 Stipulating 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).

29. If this Stipulation is challenged, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation. The Stipulating 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.

30. The Stipulating 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 Stipulating 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. To withdraw from the Stipulation, a Stipulating Party must provide written notice to the Commission and other Stipulating Parties within five days of service of the final order rejecting, modifying, or conditioning this Stipulation. Stipulating 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.

31. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation, other than those specifically identified in the body of this Stipulation. No Stipulating 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.

32. This Stipulation is not enforceable by any Stipulating 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 Stipulating Parties agree that the Commission has exclusive jurisdiction to enforce or modify the Stipulation.

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

STAFF

By: ______________________

Date: 9/23/19

PACIFICORP

By: ______________________

Date: ______________________

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________

Date: ______________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________

Date: ______________________

CALPINE ENERGY SOLUTIONS LLC

By: ______________________

Date: ______________________

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STAFF

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Date: ______________________________

PACIFICORP

By: ______________________________

Date: 9/23/19

ALLIANCE OF WESTERN ENERGY CONSUMERS

By: ______________________________

Date: ______________________________

OREGON CITIZENS' UTILITY BOARD

By: ______________________________

Date: ______________________________

CALPINE ENERGY SOLUTIONS LLC

By: ______________________________

Date: ______________________________

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Date: ______________________

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By: ______________________

Date: 9/23/19

CALPINE ENERGY SOLUTIONS LLC

By: ______________________

Date: ______________________

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STAFF	**PACIFICORP**
By: ______________________	By: ______________________
Date: ______________________	Date: ______________________
ALLIANCE OF WESTERN ENERGY CONSUMERS	**OREGON CITIZENS' UTILITY BOARD**
By: ______________________	By: ______________________
Date: ______________________	Date: ______________________

CALPINE ENERGY SOLUTIONS LLC

By: ______________________

Date: 9/20/19

EXHIBIT 1

PacifiCorp
CY 2020 TAM
UE 356 Settlement

			Total Company							Oregon Allocated			
Line no		ACCT.	UE-339 CY 2019 - Final Update	TAM CY 2020 - Initial Filing	TAM CY 2020 - Reply Update	TAM CY 2020 - Settlement	Factor	Factors CY 2019	Factors CY 2020	UE-339 CY 2019 - Final Update	TAM CY 2020 - Initial Filing	TAM CY 2020 - Reply Update	TAM CY 2020 - Settlement
1	**Sales for Resale**												
2	Existing Firm PPL	447	7,967,439	7,010,945	7,621,463	7,621,463	SG	26.725%	26.456%	2,129,283	1,854,805	2,016,322	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	372,798,652	SG	26.725%	26.456%	127,874,540	89,883,268	98,627,034	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	380,420,115				130,003,823	91,738,073	100,643,356	100,643,356
7													
8	**Purchased Power**												
9	Existing Firm Demand PPL	555	3,133,795	4,795,373	3,261,949	3,261,949	SG	26.725%	26.456%	837,501	1,268,656	862,976	862,976
10	Existing Firm Demand UPL	555	3,332,695	3,793,638	3,793,638	3,793,638	SG	26.725%	26.456%	890,656	1,003,639	1,003,639	1,003,639
11	Existing Firm Energy	555	17,662,229	21,667,704	18,094,684	18,094,684	SE	25.322%	25.314%	4,472,499	5,485,049	4,580,560	4,580,560
12	Post-merger Firm	555	721,894,615	672,350,836	677,393,578	660,327,035	SG	26.725%	26.456%	192,924,948	177,876,096	179,210,196	174,695,098
13	Secondary Purchases	555	-	-	-	-	SE	25.322%	25.314%	-	-	-	-
14	Other Generation Expense	555	7,099,964	7,455,847	7,450,204	7,450,204	SG	26.725%	26.456%	1,897,452	1,972,507	1,971,015	1,971,015
15	**Total Purchased Power**		753,123,297	710,063,398	709,994,053	692,927,510				201,023,056	187,605,948	187,628,386	183,113,288
16													
17	**Wheeling Expense**												
18	Existing Firm PPL	565	22,380,362	22,079,714	22,079,714	22,079,714	SG	26.725%	26.456%	5,981,109	5,841,375	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	107,543,235	SG	26.725%	26.456%	29,010,787	28,452,471	28,451,472	28,451,472
21	Non-Firm	565	4,447,418	3,175,158	3,175,158	3,175,158	SE	25.322%	25.314%	1,126,193	803,772	803,772	803,772
22	**Total Wheeling Expense**		135,381,551	132,801,884	132,798,106	132,798,106				36,118,088	35,097,618	35,096,619	35,096,619
23													
24	**Fuel Expense**												
25	Fuel Consumed - Coal	501	702,622,248	642,746,510	649,756,250	649,756,250	SE	25.322%	25.314%	177,920,783	162,707,412	164,481,885	164,481,885
26	Fuel Consumed - Coal (Cholla)	501	40,481,392	27,072,484	36,084,281	36,084,281	SE	25.322%	25.314%	10,250,858	6,853,236	9,134,519	9,134,519
27	Fuel Consumed - Gas	501	5,440,263	5,823,881	7,515,588	7,515,588	SE	25.322%	25.314%	1,377,605	1,474,280	1,902,526	1,902,526
28	Natural Gas Consumed	547	293,704,139	299,969,224	312,083,535	312,083,535	SE	25.322%	25.314%	74,372,923	75,935,404	79,002,069	79,002,069
29	Simple Cycle Comb. Turbines	547	3,736,769	3,426,472	3,879,074	3,879,074	SE	25.322%	25.314%	946,239	867,391	981,964	981,964
30	Steam from Other Sources	503	4,597,639	4,676,489	4,676,489	4,676,489	SE	25.322%	25.314%	1,164,232	1,183,825	1,183,825	1,183,825
31	**Total Fuel Expense**		1,050,582,449	983,715,060	1,013,995,217	1,013,995,217				266,032,640	249,021,549	256,686,788	256,686,788
32													
33	TAM Settlement Adjustment**		(545,317)	-	-	(1,467,719)		As Settled		(141,911)	-	-	(388,297)
34													
35	**Net Power Cost (Per GRID)**		1,452,088,257	1,479,821,158	1,476,367,261	1,457,833,000				373,028,051	379,987,042	378,768,436	373,865,041
36													
37	Oregon Situs NPC Adustments		501,570	513,798	463,225	463,225	OR	100.000%	100.000%	501,570	513,798	463,225	463,225
38	**Total NPC Net of Adjustments**		1,452,589,826	1,480,334,955	1,476,830,487	1,458,296,225				373,529,620	380,500,839	379,231,662	374,328,266
39													
40	Non-NPC EIM Costs*		3,079,748	1,572,036	1,493,124	1,493,124	SG	26.725%	26.456%	823,057	415,895	395,019	395,019
41	Production Tax Credit (PTC)		(37,465,734)	(99,704,458)	(96,971,960)	(96,971,960)	SG	26.725%	26.456%	(10,012,645)	(26,377,657)	(25,654,751)	(25,654,751)
42	**Total TAM Net of Adjustments**		1,418,203,840	1,382,202,533	1,381,351,651	1,362,817,389				364,340,032	354,539,078	353,971,929	349,068,533
43													
44								Increase Absent Load Change			(9,800,954)	(10,368,103)	(15,271,498)
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 356 - Agreed to decrease Oregon-allocated NPC by $388,297.							**Increase Including Load Change**			**(14,722,479)**	**(15,289,627)**	**(20,193,023)**
51	**TAM Settlement UE 339 - Partial Stipulation agreed to decrease Oregon-allocated NPC by $141,911.												
52								Add Other Revenue Change			67,946	100,662	100,662
53													
54								**Total TAM Increase/(Decrease)**			**$ (14,654,533)**	**$ (15,188,966)**	**$ (20,092,361)**

EXHIBIT 2

TAM

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 ENDING DECEMBER 31, 2020

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
											Base Rates		Net Rates		
Line No.	Description	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)	
							(5) + (6)			(8) + (9)	(8) - (5)	(11)/(5)	(10) - (7)	(13)/(7)	
	Residential														
1	Residential	4	517,792	5,416,910	$625,841	($20,908)	$604,933	$617,374	($20,908)	$596,466	($8,467)	-1.4%	($8,467)	-1.4%	1
2	**Total Residential**		517,792	5,416,910	$625,841	($20,908)	$604,933	$617,374	($20,908)	$596,466	($8,467)	-1.4%	($8,467)	-1.4%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	82,002	1,137,606	$126,606	($149)	$126,457	$124,909	($149)	$124,760	($1,697)	-1.3%	($1,697)	-1.3%	3
4	Gen. Svc. 31 - 200 kW	28	10,697	2,024,568	$186,146	($4,212)	$181,934	$183,053	($4,212)	$178,841	($3,093)	-1.7%	($3,093)	-1.7%	4
5	Gen. Svc. 201 - 999 kW	30	860	1,320,150	$107,693	($3,075)	$104,618	$105,754	($3,075)	$102,679	($1,939)	-1.8%	($1,939)	-1.9%	5
6	Large General Service >= 1,000 kW	48	196	3,358,471	$236,075	($19,427)	$216,648	$231,620	($19,427)	$212,193	($4,455)	-1.9%	($4,455)	-2.0%	6
7	Partial Req. Svc. >= 1,000 kW	47	6	50,503	$5,702	($295)	$5,407	$5,639	($295)	$5,344	($63)	-1.9%	($63)	-2.0%	7
8	Agricultural Pumping Service	41	7,931	220,786	$25,751	($2,321)	$23,430	$25,417	($2,321)	$23,096	($334)	-1.3%	($334)	-1.4%	8
9	**Total Commercial & Industrial**		101,692	8,112,084	$687,973	($29,479)	$658,494	$676,392	($29,479)	$646,913	($11,581)	-1.7%	($11,581)	-1.8%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,215	8,880	$1,145	$161	$1,306	$1,134	$161	$1,295	($11)	-1.0%	($11)	-0.8%	10
11	Street Lighting Service	50	223	7,833	$875	$132	$1,007	$867	$132	$999	($8)	-0.9%	($8)	-0.8%	11
12	Street Lighting Service HPS	51	834	19,135	$3,372	$542	$3,914	$3,342	$542	$3,884	($30)	-0.9%	($30)	-0.8%	12
13	Street Lighting Service	52	35	990	$130	$16	$146	$129	$16	$145	($1)	-0.8%	($1)	-0.7%	13
14	Street Lighting Service	53	342	11,894	$751	$112	$863	$744	$112	$856	($7)	-0.9%	($7)	-0.8%	14
15	Recreational Field Lighting	54	104	1,383	$115	$17	$132	$114	$17	$131	($1)	-0.9%	($1)	-0.8%	15
16	**Total Public Street Lighting**		7,753	50,115	$6,388	$980	$7,368	$6,330	$980	$7,310	($58)	-0.9%	($58)	-0.8%	16
17	**Total Sales before Emp. Disc. & AGA**		627,237	13,579,109	$1,320,202	($49,407)	$1,270,795	$1,300,096	($49,407)	$1,250,689	($20,106)	-1.5%	($20,106)	-1.6%	17
18	Employee Discount				($486)	$18	($468)	($479)	$18	($461)	$7		$7		18
19	**Total Sales with Emp. Disc**		627,237	13,579,109	$1,319,716	($49,389)	$1,270,327	$1,299,617	($49,389)	$1,250,228	($20,099)	-1.5%	($20,099)	-1.6%	19
20	AGA Revenue				$2,439		$2,439	$2,439		$2,439	$0		$0		20
21	**Total Sales**		627,237	13,579,109	$1,322,155	($49,389)	$1,272,766	$1,302,056	($49,389)	$1,252,667	($20,099)	-1.5%	($20,099)	-1.6%	21

[1] Excludes effects of the Low Income Bill Payment Assistance Charge (Sch. 91), BPA Credit (Sch. 98), Klamath Dam Removal Surcharges (Sch. 199), 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 2020 (April 2019 Initial Filing)	**NPC ($) =**	**1,479,821,158**
	$/MWh =	**24.77**

Oregon TAM 2020 (July 2019 Update Filing)	**NPC ($) =**	**1,476,367,261**
	$/MWh =	**24.71**

	Impact ($) Oregon Allocated Basis	NPC ($) Total Company
Settlement Adjustment		
S01 - 300 MW Link Jim Bridger -to-Walla Walla	(379,921)	
S02 - EIM Inter-regional benefits	(4,417,695)	
Total Changes =	(4,797,616)	
Oregon TAM 2020 (July 2019 Filing with Settlement)	**NPC ($) =**	**1,457,833,000**
	$/MWh =	**24.40**

Oregon TAM 2020 (Settlement with Repower Benefits)	**NPC ($) =**	**1,456,979,108**
	$/MWh =	**24.39**
Glenrock III Repower	(92,244)	
Foote Creek I and Dunlap Repower	(177,403)	
Oregon TAM 2020 (Settlement with EV2020 Benefits)	**NPC ($) =**	**1,441,577,003**
	$/MWh =	**24.13**

REDACTED

EXHIBIT 4

	Repowered Wind Capacity Factor in February 2018 Analysis
Glenrock Wind	[redacted]
Glenrock III Wind	
Seven Mile Wind	
Seven Mile II Wind	
High Plains Wind	
McFadden Ridge Wind	
Dunlap I Wind	
Rolling Hills Wind	
Leaning Juniper 1	
Marengo I	
Marengo II	
Goodnoe Wind	
Foote Creek I*	

	New Wind Capacity Factor in February 2018 Analysis
TB Flats I	[redacted]
TB Flats II	
Cedar Springs II	
Ekola Flats	

*Note: * resources capacity factors are based on studies developed later than the referred studies*

EXHIBIT 5

PacifiCorp

JulyCum ORTAM20 NPC Study_2019 06 30 (settlement)

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	(70,268,849)	(4,818,314)	(4,362,557)	(8,008,335)	(7,761,163)	(8,068,510)	(4,124,783)	(7,675,278)	(7,493,573)	(5,001,983)	(4,112,051)	(4,085,682)	(4,756,619)
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	140,045,442	9,445,816	12,437,762	9,103,502	8,988,118	15,089,100	9,740,492	33,437,717	25,705,225	9,192,259	2,460,618	2,082,787	2,362,045
Total Purchased Power & Net Inter	685,477,306	55,896,435	57,732,022	60,740,875	57,551,362	61,694,667	56,684,340	79,939,552	70,779,032	50,934,832	44,455,512	43,899,731	45,168,946

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	4,701,481
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
Settlement Adjustment	(1,467,719)	(474,731)	(96,008)	(112,651)	(66,177)	(48,067)	2,586	(33,306)	(86,203)	(71,871)	(46,609)	(87,816)	(346,865)
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	**1,457,833,000**	127,669,683	121,083,847	117,122,059	108,836,760	112,060,510	122,812,915	151,306,118	132,946,781	117,628,385	109,867,092	112,986,671	123,512,179
Net Power Cost/Net System Load	**24.40**	**24.12**	**25.38**	**24.49**	**24.01**	**23.77**	**24.79**	**26.57**	**24.45**	**24.82**	**23.56**	**23.44**	**23.11**

EXHIBIT 6

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 4 + Cost-Based Supply Service
Residential Service

	Monthly Billing*			Percent
kWh	Present Price	Proposed Price	Difference	Difference
100	$19.75	$19.60	($0.15)	-0.76%
200	$29.01	$28.72	($0.29)	-1.00%
300	$38.27	$37.83	($0.44)	-1.15%
400	$47.53	$46.94	($0.59)	-1.24%
500	$56.81	$56.08	($0.73)	-1.28%
600	$66.08	$65.20	($0.88)	-1.33%
700	$75.34	$74.31	($1.03)	-1.37%
800	$84.61	$83.42	($1.19)	-1.41%
850	**$89.24**	**$87.99**	**($1.25)**	**-1.40%**
900	$93.86	$92.54	($1.32)	-1.41%
1,000	$103.14	$101.67	($1.47)	-1.43%
1,100	$115.57	$113.90	($1.67)	-1.45%
1,200	$127.98	$126.12	($1.86)	-1.45%
1,300	$140.42	$138.34	($2.08)	-1.48%
1,400	$152.84	$150.56	($2.28)	-1.49%
1,500	$165.27	$162.79	($2.48)	-1.50%
1,600	$177.69	$175.03	($2.66)	-1.50%
2,000	$227.39	$223.92	($3.47)	-1.53%
3,000	$351.65	$346.18	($5.47)	-1.56%
4,000	$475.90	$468.44	($7.46)	-1.57%
5,000	$600.16	$590.69	($9.47)	-1.58%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Note: Assumed average billing cycle length of 30.42 days.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Secondary Delivery Voltage

		Monthly Billing*				Percent Difference	
		Present Price		Proposed Price			
kW Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$70	$79	$69	$78	-1.16%	-1.03%
	750	$96	$105	$95	$103	-1.27%	-1.17%
	1,000	$122	$131	$120	$129	-1.34%	-1.24%
	1,500	$174	$183	$172	$180	-1.40%	-1.34%
10	1,000	$122	$131	$120	$129	-1.34%	-1.24%
	2,000	$226	$235	$223	$232	-1.44%	-1.39%
	3,000	$330	$339	$325	$334	-1.48%	-1.44%
	4,000	$417	$426	$411	$420	-1.46%	-1.42%
20	4,000	$444	$453	$438	$447	-1.37%	-1.34%
	6,000	$619	$628	$610	$619	-1.37%	-1.35%
	8,000	$794	$802	$783	$791	-1.37%	-1.35%
	10,000	$968	$977	$955	$964	-1.37%	-1.36%
30	9,000	$935	$944	$923	$931	-1.29%	-1.28%
	12,000	$1,197	$1,205	$1,181	$1,190	-1.31%	-1.30%
	15,000	$1,459	$1,467	$1,439	$1,448	-1.32%	-1.31%
	18,000	$1,721	$1,729	$1,698	$1,707	-1.33%	-1.32%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 23 + Cost-Based Supply Service
General Service - Primary Delivery Voltage

		Monthly Billing*				Percent	
kW		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$68	$77	$68	$76	-1.15%	-1.02%
	750	$94	$103	$93	$101	-1.26%	-1.15%
	1,000	$119	$128	$117	$126	-1.32%	-1.24%
	1,500	$170	$178	$167	$176	-1.39%	-1.32%
10	1,000	$119	$128	$117	$126	-1.32%	-1.24%
	2,000	$220	$229	$217	$226	-1.43%	-1.38%
	3,000	$321	$330	$317	$325	-1.47%	-1.43%
	4,000	$406	$415	$400	$409	-1.45%	-1.42%
20	4,000	$433	$441	$427	$436	-1.36%	-1.33%
	6,000	$603	$611	$594	$603	-1.36%	-1.34%
	8,000	$772	$781	$762	$771	-1.37%	-1.35%
	10,000	$942	$951	$929	$938	-1.37%	-1.35%
30	9,000	$910	$919	$898	$907	-1.29%	-1.27%
	12,000	$1,165	$1,174	$1,150	$1,159	-1.30%	-1.30%
	15,000	$1,420	$1,429	$1,401	$1,410	-1.32%	-1.31%
	18,000	$1,675	$1,683	$1,652	$1,661	-1.32%	-1.32%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	3,000	$341	$337	-1.39%
	4,500	$450	$443	-1.59%
	7,500	$666	$655	-1.79%
31	6,200	$686	$676	-1.43%
	9,300	$910	$895	-1.62%
	15,500	$1,357	$1,333	-1.81%
40	8,000	$879	$866	-1.44%
	12,000	$1,168	$1,149	-1.63%
	20,000	$1,746	$1,714	-1.82%
60	12,000	$1,311	$1,291	-1.45%
	18,000	$1,744	$1,715	-1.64%
	30,000	$2,594	$2,546	-1.82%
80	16,000	$1,736	$1,710	-1.46%
	24,000	$2,307	$2,269	-1.64%
	40,000	$3,435	$3,372	-1.82%
100	20,000	$2,161	$2,129	-1.47%
	30,000	$2,866	$2,819	-1.65%
	50,000	$4,276	$4,198	-1.83%
200	40,000	$4,228	$4,166	-1.48%
	60,000	$5,638	$5,545	-1.66%
	100,000	$8,459	$8,303	-1.84%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 28 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
15	4,500	$437	$430	-1.57%
	6,000	$535	$526	-1.71%
	7,500	$634	$622	-1.81%
31	9,300	$876	$862	-1.62%
	12,400	$1,080	$1,061	-1.75%
	15,500	$1,283	$1,259	-1.84%
40	12,000	$1,123	$1,105	-1.63%
	16,000	$1,386	$1,361	-1.76%
	20,000	$1,648	$1,618	-1.85%
60	18,000	$1,675	$1,647	-1.64%
	24,000	$2,062	$2,026	-1.77%
	30,000	$2,446	$2,401	-1.85%
80	24,000	$2,212	$2,176	-1.65%
	32,000	$2,724	$2,676	-1.77%
	40,000	$3,236	$3,176	-1.86%
100	30,000	$2,747	$2,701	-1.65%
	40,000	$3,387	$3,327	-1.78%
	50,000	$4,027	$3,952	-1.86%
200	60,000	$5,383	$5,293	-1.67%
	80,000	$6,663	$6,543	-1.79%
	100,000	$7,943	$7,793	-1.88%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
100	20,000	$2,600	$2,566	-1.31%
	30,000	$3,167	$3,118	-1.54%
	50,000	$4,302	$4,224	-1.82%
200	40,000	$4,555	$4,492	-1.40%
	60,000	$5,690	$5,597	-1.64%
	100,000	$7,960	$7,808	-1.92%
300	60,000	$6,681	$6,588	-1.40%
	90,000	$8,383	$8,246	-1.64%
	150,000	$11,788	$11,562	-1.92%
400	80,000	$8,688	$8,565	-1.42%
	120,000	$10,958	$10,776	-1.66%
	200,000	$15,498	$15,197	-1.94%
500	100,000	$10,726	$10,573	-1.42%
	150,000	$13,563	$13,337	-1.67%
	250,000	$19,238	$18,863	-1.95%
600	120,000	$12,764	$12,582	-1.43%
	180,000	$16,169	$15,898	-1.68%
	300,000	$22,979	$22,530	-1.96%
800	160,000	$16,840	$16,598	-1.43%
	240,000	$21,380	$21,020	-1.69%
	400,000	$30,460	$29,862	-1.96%
1000	200,000	$20,916	$20,615	-1.44%
	300,000	$26,591	$26,142	-1.69%
	500,000	$37,941	$37,195	-1.97%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 30 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage

kW Load Size	kWh	Monthly Billing* Present Price	Proposed Price	Percent Difference
100	30,000	$3,104	$3,056	-1.55%
	40,000	$3,661	$3,598	-1.71%
	50,000	$4,217	$4,140	-1.83%
200	60,000	$5,580	$5,488	-1.64%
	80,000	$6,692	$6,572	-1.80%
	100,000	$7,805	$7,655	-1.92%
300	90,000	$8,216	$8,080	-1.65%
	120,000	$9,884	$9,705	-1.81%
	150,000	$11,553	$11,330	-1.92%
400	120,000	$10,756	$10,577	-1.66%
	160,000	$12,981	$12,744	-1.83%
	200,000	$15,205	$14,910	-1.94%
500	150,000	$13,309	$13,087	-1.67%
	200,000	$16,090	$15,795	-1.83%
	250,000	$18,871	$18,503	-1.95%
600	180,000	$15,862	$15,596	-1.68%
	240,000	$19,199	$18,846	-1.84%
	300,000	$22,536	$22,096	-1.95%
800	240,000	$20,968	$20,615	-1.68%
	320,000	$25,417	$24,948	-1.85%
	400,000	$29,867	$29,281	-1.96%
1000	300,000	$26,074	$25,634	-1.69%
	400,000	$31,636	$31,050	-1.85%
	500,000	$37,197	$36,467	-1.96%

* Net rate including Schedules 91, 199, 290 and 297.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Secondary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	2,000	$183	$212	$155	$180	$208	$155	-1.69%	-1.81%	0.00%
	3,000	$275	$303	$155	$270	$298	$155	-1.69%	-1.77%	0.00%
	5,000	$458	$486	$155	$450	$478	$155	-1.69%	-1.74%	0.00%
Three Phase										
20	4,000	$366	$423	$309	$360	$416	$309	-1.69%	-1.81%	0.00%
	6,000	$549	$606	$309	$540	$596	$309	-1.69%	-1.77%	0.00%
	10,000	$915	$972	$309	$900	$955	$309	-1.69%	-1.74%	0.00%
100	20,000	$1,830	$2,116	$1,349	$1,800	$2,078	$1,349	-1.69%	-1.81%	0.00%
	30,000	$2,746	$3,031	$1,349	$2,699	$2,978	$1,349	-1.69%	-1.77%	0.00%
	50,000	$4,576	$4,862	$1,349	$4,499	$4,777	$1,349	-1.69%	-1.74%	0.00%
300	60,000	$5,491	$6,349	$3,409	$5,399	$6,234	$3,409	-1.69%	-1.81%	0.00%
	90,000	$8,237	$9,094	$3,409	$8,098	$8,933	$3,409	-1.69%	-1.77%	0.00%
	150,000	$13,729	$14,586	$3,409	$13,497	$14,332	$3,409	-1.69%	-1.74%	0.00%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Pacific Power
Billing Comparison
Delivery Service Schedule 41 + Cost-Based Supply Service
Agricultural Pumping - Primary Delivery Voltage

		Present Price*			Proposed Price*			Percent Difference		
kW Load Size	kWh	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge	April - November Monthly Bill	December-March Monthly Bill	Annual Load Size Charge
Single Phase										
10	3,000	$265	$293	$155	$261	$288	$155	-1.69%	-1.78%	0.00%
	4,000	$354	$382	$155	$348	$375	$155	-1.69%	-1.76%	0.00%
	5,000	$442	$470	$155	$435	$462	$155	-1.69%	-1.75%	0.00%
Three Phase										
20	6,000	$531	$586	$309	$522	$576	$309	-1.69%	-1.78%	0.00%
	8,000	$708	$763	$309	$696	$750	$309	-1.69%	-1.76%	0.00%
	10,000	$885	$940	$309	$870	$924	$309	-1.69%	-1.75%	0.00%
100	30,000	$2,654	$2,931	$1,339	$2,609	$2,878	$1,339	-1.69%	-1.79%	0.00%
	40,000	$3,539	$3,815	$1,339	$3,479	$3,748	$1,339	-1.69%	-1.76%	0.00%
	50,000	$4,423	$4,700	$1,339	$4,349	$4,618	$1,339	-1.69%	-1.75%	0.00%
300	90,000	$7,962	$8,792	$3,399	$7,827	$8,635	$3,399	-1.69%	-1.79%	0.00%
	120,000	$10,616	$11,446	$3,399	$10,437	$11,244	$3,399	-1.69%	-1.76%	0.00%
	150,000	$13,270	$14,100	$3,399	$13,046	$13,853	$3,399	-1.69%	-1.75%	0.00%

* Net rate including Schedules 91, 98, 199, 290 and 297.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Secondary Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$26,005	$25,560	-1.71%
	500,000	$36,919	$36,177	-2.01%
	650,000	$45,104	$44,140	-2.14%
2,000	600,000	$51,578	$50,688	-1.73%
	1,000,000	$71,155	$69,672	-2.08%
	1,300,000	$86,701	$84,773	-2.22%
6,000	1,800,000	$149,501	$146,831	-1.79%
	3,000,000	$211,683	$207,233	-2.10%
	3,900,000	$258,320	$252,535	-2.24%
12,000	3,600,000	$297,677	$292,338	-1.79%
	6,000,000	$422,042	$413,143	-2.11%
	7,800,000	$515,315	$503,746	-2.25%

Notes:

On-Peak kWh	64.46%
Off-Peak kWh	35.54%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Primary Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	300,000	$24,554	$24,140	-1.69%
	500,000	$34,649	$33,959	-1.99%
	650,000	$42,221	$41,324	-2.12%
2,000	600,000	$48,634	$47,805	-1.70%
	1,000,000	$66,575	$65,195	-2.07%
	1,300,000	$80,894	$79,099	-2.22%
6,000	1,800,000	$140,266	$137,782	-1.77%
	3,000,000	$197,540	$193,400	-2.10%
	3,900,000	$240,496	$235,113	-2.24%
12,000	3,600,000	$279,177	$274,209	-1.78%
	6,000,000	$393,726	$385,445	-2.10%
	7,800,000	$479,637	$468,872	-2.24%

Notes:

On-Peak kWh	61.37%
Off-Peak kWh	38.63%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.

Pacific Power
Monthly Billing Comparison
Delivery Service Schedule 48 + Cost-Based Supply Service
Large General Service - Transmission Delivery Voltage
1,000 kW and Over

kW Load Size	kWh	Monthly Billing Present Price	Monthly Billing Proposed Price	Percent Difference
1,000	500,000	$34,344	$33,700	-1.87%
	650,000	$41,366	$40,529	-2.02%
2,000	1,000,000	$65,552	$64,264	-1.96%
	1,300,000	$78,772	$77,098	-2.12%
6,000	3,000,000	$194,645	$190,783	-1.98%
	3,900,000	$234,305	$229,284	-2.14%
12,000	6,000,000	$387,143	$379,418	-2.00%
	7,800,000	$466,462	$456,420	-2.15%
50,000	25,000,000	$1,606,294	$1,574,106	-2.00%
	32,500,000	$1,936,791	$1,894,948	-2.16%

Notes:

On-Peak kWh	56.82%
Off-Peak kWh	43.18%

* Net rate including Schedules 91, 199 and 290. Schedule 297 included for kWh levels under 730,000.