PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 31, 2017

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

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

Attn: Filing Center

Re: Advice No. 17-002/Docket UE 323—PacifiCorp's 2018 Transition Adjustment Mechanism

In compliance with ORS 757.205, OAR 860-022-0025, and OAR 860-022-0030, PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits for filing the following proposed tariff pages associated with Tariff P.U.C. OR No. 36, which sets forth all rates, tolls, charges, rules, and regulations applicable to electric service in Oregon. The Company requests an effective date of January 1, 2018.

A. Description of Filing

The purpose of the Transition Adjustment Mechanism (TAM) is to update net power costs for 2018 and to set transition credits for Oregon customers who choose direct access in the November open enrollment window. The following proposed tariff sheets are provided in Ms. Ridenour's Exhibit PAC/303. This tariff filing is supported by testimony and exhibits from the following witnesses:

- Michael G. Wilding, Manager, Net Power Costs
- Dana M. Ralston, Vice President, Coal Generation and Mining
- Judith M. Ridenour, Specialist, Cost of Service and Pricing

B. Tariff Sheets

Eighth Revision of Sheet No. 201-1	Schedule 201	Net Power Costs – Cost-Based Supply Service
Eighth Revision of Sheet No. 201-2	Schedule 201	Net Power Costs – Cost-Based Supply Service
Eighth Revision of Sheet No. 201-3	Schedule 201	Net Power Costs – Cost-Based Supply Service
Seventh Revision of Sheet No. 203	Schedule 203	Renewable Resource Deferral Supply Service Adjustment
Sixth Revision of Sheet No. 205-1	Schedule 205	TAM Adjustment for Other Revenues
Sixth Revision of Sheet No. 205-2	Schedule 205	TAM Adjustment for Other Revenues
Sixth Revision of Sheet No. 205-3	Schedule 205	TAM Adjustment for Other Revenues

The Company will file changes to the transition adjustment tariffs—Schedules 294, 295, and 296—once the final TAM rates have been posted and are known. The transition adjustment rates will be established in November, just before the open enrollment window.

C. Requirements of OAR 860-022-0025 and OAR 860-022-0030

To support the proposed rates and meet the requirements of OAR 860-022-0025 and OAR 860-022-0030, the Company provides the description and support indicated in Section A above. Please refer to the exhibits of Ms. Ridenour for the calculation of the proposed rate changes and impacts of proposed price changes by rate schedule.

This proposed change will affect approximately 606,000 customers, and would result in an overall annual rate increase of approximately $18.4 million or 1.5 percent. Residential customers using 900 kWh per month would see a monthly bill increase of $1.28 per month as a result of this change.

D. Correspondence

PacifiCorp respectfully requests that all communications related to this filing be addressed to:

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Portland, OR 97232
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419 SW 11th Ave, Suite 400
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Katherine@mcd-law.com

Additionally, PacifiCorp requests that all data requests regarding this matter be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232

Please direct informal correspondence and questions regarding this filing to Natasha Siores Manager, Regulatory Affairs, at (503) 813-6583.

A copy of this filing has been served on all parties to PacifiCorp's 2017 TAM proceeding, docket UE 307. Confidential material in support of the filing has been provided to parties under Order No. 16-128.

Sincerely,

R. Bryce Dalley
Vice President, Regulation

Enclosures

cc: UE 307 Service List

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of **PacifiCorp's 2018 Transition Adjustment Mechanism** on the parties listed below via electronic mail and/or overnight delivery in compliance with OAR 860-001-0180.

Service List
UE 307

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Dated this 31st day of March, 2017.

Jennifer Angell
Supervisor, Regulatory Operations

Docket No. UE 323
Exhibit PAC/100
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Michael G. Wilding

March 2017

DIRECT TESTIMONY OF MICHAEL G. WILDING

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ATTACHED EXHIBITS

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

A. My name is Michael G. Wilding. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Manager, Net Power Costs.

QUALIFICATIONS

Q. Briefly describe your education and business experience.

A. I received a Master of Accounting degree from Weber State University and a Bachelor of Science degree in accounting from Utah State University. I am a Certified Public Accountant licensed in the state of Utah. Before joining the company, I was employed as an internal auditor for Intermountain Healthcare and an auditor for the Utah State Tax Commission. I have been employed by the company since February 2014.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the Public Utility Commission of Oregon (Commission), and the public utility commissions in California, Idaho, Utah, and Wyoming.

PURPOSE OF TESTIMONY

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

A. I present the company's proposed 2018 Transition Adjustment Mechanism (TAM) net power costs (NPC). Specifically, my testimony:

- Summarizes the content of the filing;
- Defines NPC and describes the NPC increase in the 2018 TAM compared to the final NPC in the company's previous TAM, docket UE 307 (2017 TAM);
- Describes the major cost drivers in the 2018 TAM;

- Reports on the successful collaborative process required by the Commission's order in the 2017 TAM[1], and describes modeling changes the company is proposing as a result of the collaborative process; and
- Provides the historical analysis of fixed generation costs to verify the reasonableness of the forecasts used to determine the consumer opt-out charge.[2]

Q. Please identify the other PacifiCorp witnesses supporting the 2018 TAM.

A. Two additional company witnesses provide testimony supporting the company's filing. Mr. Dana M. Ralston, Vice President, Coal Generation and Mining, provides testimony supporting the coal costs included in the 2018 TAM. Ms. Judith M. Ridenour, Regulatory Specialist, Pricing & Cost of Service, presents the company's proposed prices and tariffs and provides a comparison of existing and estimated customer rates.

SUMMARY OF PACIFICORP'S 2018 TAM FILING

Q. Please provide background on PacifiCorp's 2018 TAM filing.

A. The TAM is PacifiCorp's annual filing to update its NPC in rates and to set the transition adjustments for direct access customers. Along with the forecast NPC, the 2018 TAM also includes test period forecasts for: (1) Other Revenues as stipulated in docket UE 216; (2) incremental benefits and costs related to the company's participation in the energy imbalance market (EIM) with the California Independent System Operator Corporation (CAISO); and (3) renewable energy production tax credits (PTCs). The company is filing the 2018 TAM on a stand-alone basis without a general rate case and proposes that new rates become effective on January 1, 2018.

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[1] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 (Dec. 20, 2016).
[2] *Id.* at 25.

As shown in Exhibit PAC/101, the 2018 TAM results in an increase to Oregon rates of approximately $18.4 million (unless otherwise specified, references to NPC throughout my testimony are expressed on an Oregon-allocated basis). As explained in Ms. Ridenour's testimony, the 2018 TAM results in an overall average rate increase of approximately 1.5 percent.

Q. What are the estimated NPC in the TAM for calendar year 2018?

A. The forecasted normalized NPC for calendar year 2018 are approximately $380.4 million.[3] This is approximately $9.6 million higher than the forecast NPC of approximately $370.7 million in the 2017 TAM. Details of total-company NPC for 2018 are provided in Exhibit PAC/102.

Q. Does the proposed rate increase for the 2018 TAM reflect changes in Oregon load since the 2017 TAM?

A. Yes. The 2018 load forecast used in the company's calculation of NPC reflects a decrease in Oregon load compared to the 2017 forecast loads in the 2017 TAM. Due to the decrease in Oregon load, the company anticipates it will collect $3.2 million less for NPC based on the rates approved in the 2017 TAM, increasing the overall rate change for the 2018 TAM.

Q. Have Oregon's allocation factors changed since the 2017 TAM?

A. Yes. The change in Oregon load relative to load in other states served by the company results in an increase in Oregon's allocation factors and the corresponding share of total-company NPC allocated to Oregon compared with the 2017 TAM. Of the $9.6 million increase in forecast NPC identified above, $7.0 million of the

[3] PAC/101, Wilding/1, line 33.

increase is driven by the change in allocation factors.

Q. How does the load forecast for the 2018 TAM compare to the load forecast used for the 2017 TAM?

A. The 2018 forecast loads, on a total-company basis, are 2.84 percent lower than the forecast loads used in the 2017 TAM. Oregon 2018 forecast loads are 160 GWh (1.11 percent) lower than the forecast loads used in the 2017 TAM. The forecast loads for Utah, Washington, and Wyoming also decrease, while the forecast loads for California and Idaho increase. Table 1 below shows the changes between the load forecasts for all states.

Table 1 Total Company Sales at System Input by Jurisdiction (GWh)

	2017 Previous TAM Forecast	2018 Current TAM Forecast	GWh Change	Percentage Change
Oregon	14,403	14,243	-160	-1.11%
Washington	4,538	4,359	-179	-3.94%
California	864	879	15	1.77%
Utah	26,561	25,420	-1,142	-4.30%
Idaho	3,738	3,793	54	1.45%
Wyoming	10,343	9,921	-422	-4.08%
FERC*	196	306	110	56.34%
Total	60,642	58,920	-1,722	-2.84%

*Includes sales for resale

Q. What are the major drivers for the changes between the load forecasts in the 2017 TAM and the 2018 TAM?

A. The changes to forecast load between the 2017 TAM and the 2018 TAM are attributable to a combination of factors. First, the 2018 TAM includes an additional year of historical data (March 2015 to February 2016) in the load forecasting model. This additional year of data updates the load forecasts for each state, but had a pronounced impact (reduction) to Utah, Wyoming, and Washington load forecasts. Second, the 2018 TAM includes updates to load forecasts based on economic, customer, and industry data. In Oregon, the significant drivers in the 2018 TAM load forecast include less optimistic economic forecasts, the loss of a large industrial customer, and poor market conditions in the timber industry. The lower forecast load in Utah is attributable to less optimistic economic forecasts, a decrease in large industrial customer load, increased private generation, and increased energy efficiency program adoption. Wyoming forecast load is lower primarily due to a decrease in large industrial customer load, less optimistic economic forecasts, and poor market conditions in the oil and gas industry. Lower Washington forecast load is attributable to poor market conditions in the fruit and vegetable processing industry.

Q. Because this is a stand-alone TAM filing, did the company include an update to Other Revenues for certain items related to NPC, as stipulated in docket UE 216?

A. Yes. Exhibit PAC/103 shows the update to "Other Revenues" compared to the level set in the 2017 TAM. Other Revenues reflect an increase in production and price, per the terms of the agreement, of the Seattle City Light State Line wind farm contract. Projected Other Revenues are approximately $0.3 million higher in 2018, causing a corresponding decrease in the TAM rate change.[4]

Q. Please explain how the benefits and costs associated with participation in the EIM are treated in the 2018 TAM.

A. PacifiCorp's initial filing includes both the benefits and costs associated with participation in the EIM. The expected incremental EIM benefits relative to the optimized NPC modeled by the Generation and Regulation Initiative Decision Tools

[4] Consistent with prior TAM filings, the variance in Other Revenues is adjusted for changes in load in the same manner as the adjustment to NPC-related components.

model (GRID) are reflected as a reduction to the NPC forecast. As discussed later in my testimony, the total-company EIM benefits included in the 2018 TAM are $27.5 million, an increase of $5.9 million in benefits over the 2017 TAM. EIM-related costs, including capital and operations and maintenance expense, are added to the TAM to match the benefits. The Commission approved this same treatment in the 2016 and 2017 TAMs, and it is consistent with the stipulation in docket UE 287 (2015 TAM), which first addressed EIM-related costs in the TAM. Details supporting EIM benefits and costs are included in Exhibit PAC/104 and Exhibit PAC/105.

Q. Has PacifiCorp's calculation of EIM benefits changed in this filing?

A. No, with one exception. After workshops with Staff and other parties to the 2017 TAM, the company agreed to change one aspect of its inter-regional EIM benefits calculation. I discuss that change and the process leading to it later in my testimony.

Q. Please describe the treatment of renewable energy PTCs in the 2018 TAM.

A. Consistent with Section 18(b) of SB 1547 and the Commission's order in the 2017 TAM,[5] the 2018 TAM includes changes in its projected PTCs in this filing. Exhibit PAC/106 shows the forecast level of PTCs for 2018 compared to the level of PTCs established in the 2017 TAM. Based on the expiration of PTCs at several company-owned facilities, the forecast of Oregon-allocated PTCs for the 2018 test period is approximately $10.2 million, which is down from the $13.8 million included in the 2017 TAM. After applying the tax gross-up factor, the reduction of PTCs results in an increase in the 2018 TAM of approximately $5.8 million.

[5] *See* Order No. 16-418. The Commission did not specifically discuss the modeling of PTCs, but PacifiCorp agreed to Staff's proposed methodology and the Commission accepted that approach.

DETERMINATION OF NPC

Q. Please explain NPC.

A. NPC are the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue.

Q. How does the TAM relate to NPC?

A. In the 2017 TAM Order, the Commission described the TAM and its purpose as follows:

> PacifiCorp's TAM is an annual filing in which PacifiCorp projects the amount of [NPC] to be reflected in customer rates for the following year, as well as to set transition charges for customers electing to move to direct access. The TAM effectively removes regulatory lag for the company because the forecasts are used to adjust rates. For that reason, the accuracy of the forecasts is of significant importance to setting fair, just and reasonable rates. Our goal, therefore, is to achieve an accurate forecast of PacifiCorp's [NPC] for the upcoming year.[6]

Q. Please explain how PacifiCorp calculates NPC.

A. PacifiCorp calculates NPC for a future test period based on projected data using GRID. GRID is a production cost model that simulates the operation of the company's power system on an hourly basis.

Q. Has the company improved the accuracy of the NPC forecasts in the TAM through recent modeling changes?

A. Yes. In previous TAM proceedings, PacifiCorp's NPC was systematically under-stated. In the 2016 TAM, the company proposed and the Commission adopted multiple modeling improvements designed to produce a more accurate NPC forecast.

[6] Order No. 16-482 at 2.

As a result, the 2016 TAM forecast was the most accurate of any of the previous TAMs as compared to actual NPC.

Q. Is the company's general approach to the calculation of NPC using the GRID model the same in this case as in previous cases?

A. Yes. PacifiCorp has used the GRID model to determine NPC in its Oregon filings since 2002. Over time, the company has implemented various improvements to the modeling of specific items in GRID to better reflect company operations and to achieve the most accurate NPC forecast for the test period.

Q. Has the company proposed any changes to the GRID model in the 2018 TAM?

A. No. PacifiCorp used the same version of the GRID model in the 2018 TAM that it used in the 2017 TAM.

Q. What inputs were updated for this filing?

A. The company updated all inputs to the 2018 TAM, including system load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, market prices for electricity and natural gas, fuel expenses, and the characteristics and availability of the company's generation facilities.

Q. What is the date of the Official Forward Price Curve the company used in this filing?

A. PacifiCorp's filing uses an Official Forward Price Curve (OFPC) dated December 30, 2016.

Q. Will the company continue to update the OFPC through the pendency of this proceeding?

A. Yes. In accordance with the TAM Guidelines, PacifiCorp's reply update will incorporate the most recent OFPC, the November indicative update will incorporate an OFPC from within nine days of the filing, and the November final update will incorporate an OFPC from within seven days of the filing.

Q. What reports does the GRID model produce?

A. The major output from the GRID model is the NPC report. This is the same information contained in Exhibit PAC/102, and an electronic version is included in the workpapers accompanying the company's filing. Additional data with more detailed analyses are also available in hourly, daily, monthly, and annual formats by heavy load hours (HLH) and light load hours (LLH).

DISCUSSION OF MAJOR COST DRIVERS IN NPC

Q. Please generally describe the changes in NPC compared to the 2018 TAM.

A. The increase in NPC is driven by a reduction in wholesale sales revenue and an increase in coal fuel expense, along with a small increase in wheeling expense. The increase is offset by reductions in purchased power and natural gas fuel expenses. Table 2 illustrates the change in total-company NPC by category from the NPC baseline in the 2017 TAM.

Table 2
Net Power Cost Reconciliation

	($ millions)	$/MWh
OR TAM 2017	**$1,536**	**$25.36**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	$83	
Purchased Power Expense	($69)	
Coal Fuel Expense	$18	
Natural Gas Fuel Expense	($25)	
Wheeling and Other Expense	$2	
Total Increase/(Decrease) to NPC	**$10**	
OR TAM 2018	**$1,546**	**$26.26**

Q. Please explain the reduction in wholesale sales revenue.

A. The reduction in wholesale sales revenue is driven by lower sales volumes. The reduction is partially offset by the higher average prices during 2018. Total wholesale sales revenue is $83.0 million lower than the 2017 TAM which includes a $79.2 million decrease in revenue from market sales (represented in GRID as short-term firm and system balancing sales) due to a reduction in volume of 3,209 GWh. The wholesale sales market prices in the 2018 TAM use an average price of $27.91/MWh, while the 2017 TAM used an average price of $27.17/MWh, a 3 percent increase.

Q. Why did purchased power expense decrease?

A. The decrease in purchased power expense is due to a forecast reduction in the volume of purchased power. The volume of purchased power from market purchases (represented in GRID as short-term firm and system balancing purchases) in the 2018 TAM is 2,850 GWh lower than the 2017 TAM, mainly due to the increase in market prices compared to the prior TAM and the lower volume of retail load. Market purchases (represented in GRID as short-term firm and system balancing purchases) in the current case are included at an average price of $27.29/MWh, while the 2017 TAM used an average price of $26.11/MWh, a 4 percent increase. Higher market purchase prices reduce the volume of the economic market transactions and shift the volume to the lower cost resources to meet the system balancing requirement. In addition, total company retail load in 2018 is 1,712 GWh[7] compared to the 2017 TAM load, a decrease of approximately 3 percent.

The reduction in purchased power expense is slightly offset by the increase in total expense for power purchased from Qualifying Facilities (QFs), which increased by approximately $5.6 million (total-company) compared to the 2017 TAM. The increase is attributed to several QFs that are expected to reach commercial operation in 2018.

Q. Does this case include new QF power purchase agreements (PPAs) that are not yet operational but that are expected to achieve commercial operation before the end of the forecast period?

A. Yes. The company includes four PPAs with QFs that are expected to reach commercial operation in 2018 and have not previously been included in rates. Based on the information known to the company at this time, the company has a commercially reasonable good faith belief that these QFs will reach commercial operation before or during the forecast period.

[7] This 1,712 GWh change reflects retail load net of the economic buy-through of certain industrial customers. The change of 1,722 GWh reflected in Table 1 is shown before the economic buy-through load is removed.

Q. Did PacifiCorp extend any PPAs in its NPC study that are scheduled to expire during the forecast period?

A. Yes. Several existing QF PPAs terminate before the end of the forecast period. PacifiCorp assumes these QFs will execute new PPAs to continue selling to the company at the most recent avoided cost rates. The company will update the status of these PPAs as new information becomes available per the TAM Guidelines.

Q. Please explain the increase in coal expense in the current proceeding.

A. The increase in coal fuel expense is driven by changes in third-party coal supply and rail contracts since last year's TAM. Mr. Ralston provides additional detail regarding the cost of coal during the test year in his direct testimony.

Q. Please discuss the change in natural gas fuel expense compared to the 2017 TAM.

A. Natural gas fuel expense in the 2018 TAM is $25.2 million lower than the natural gas fuel expense in the 2017 TAM, an 8 percent reduction. This reduction is due to the lower system load and lower natural gas generation volume and is partially offset by the higher average cost from natural gas-fueled resources. Generation from natural gas plants in the 2018 TAM is 1,141 GWh less compared to the 2017 TAM. The average cost of natural gas generation increases from $24.27/MWh in the 2017 TAM to $24.49/MWh in the current forecast.

Q. Please describe the increase in the wheeling and other expense category.

A. Expenses in this category are higher due to an increase in wheeling expense related to Idaho Power Company's firm point-to point rate change, which will be effective in October 2017. Additionally, the Bonneville Power Administration (BPA) Initial Rate

Proposal increases NPC by approximately $386,000. In November 2016, BPA issued an Initial Rates Proposal for the 24-month period beginning October 2017. BPA's draft Record of Decision (ROD) in its rate case will be released June 13, 2017, and its final ROD will be released July 26, 2017. Consistent with past TAMs, the company will update the BPA wheeling expense during the proceeding to reflect the final ROD.

Q. How are Jim Bridger Units 3 and 4 modeled in the 2018 TAM?

A. PacifiCorp's 2018 TAM incorporates environmental upgrades at Jim Bridger Units 3 and 4, which increases the minimum operating level of these units. The changes became effective November 2015 for Unit 3, and November 2016 for Unit 4. Reflecting current minimum operating levels at these units increases NPC by approximately $168,000.

Q. Why did the company include the impact of the upgrades at Jim Bridger Units 3 and 4 in the 2018 TAM?

A. PacifiCorp's update to its forecast of Jim Bridger Units 3 and 4 minimum plant capacity reflects the most accurate and up to date information. The update includes the indirect NPC impacts of the capital investment at the Jim Bridger plant in the 2018 TAM, but not the direct costs to recover the return of or return on this investment. The company's adjustment is consistent with its filing in the 2017 TAM, which was later withdrawn on a non-precedential basis in the reply update. Now that the upgrades at Jim Bridger Units 3 and 4 are fully in service, the company believes it is appropriate to model the actual costs at which these units are cost-effectively dispatching to serve customers.

Q. What updates are expected in the company's resource portfolio relative to the 2017 TAM?

A. Environmental upgrades will also have a minor change (a decrease of approximately one megawatt) to the nameplate capacity at Craig 2 in June 2017.

Q. How is Naughton Unit 3 treated in the 2018 TAM?

A. To match anticipated operations for Naughton Unit 3 during 2018, the unit is modeled in the 2018 TAM as a coal-fueled resource. The company recently received a permit to continue to operate Naughton Unit 3 as a coal-fueled resource through 2018. The company had previously anticipated converting Naughton Unit 3 to natural gas during 2018. The impact of reflecting Naughton 3 as a coal unit instead of a natural gas unit in the 2018 TAM is a decrease of approximately $1.1 million to NPC. The fueling of Naughton Unit 3 in 2018 is discussed further in the testimony of Mr. Ralston.

Q. Please explain the accounting change to the prepaid transmission expense at the Cholla coal plant.

A. The company prepaid for transmission (wheeling expense) from the Cholla plant and that expense is amortized over the same period as the depreciable life of the Cholla generation plant. The amortization period of the prepaid wheeling expense is updated in this year's TAM to correlate with the Oregon depreciable life of the Cholla generation plant. Previously, the amortization schedule erroneously correlated to the non-Oregon depreciable life of the plant. The impact of this correction is an increase of approximately $0.15 million.

COMPLIANCE WITH 2017 TAM ORDER

Q. What requirements did the Commission impose as part of its order in the 2017 TAM?

A. In Order No. 16-482, the Commission provided several directives to PacifiCorp, Staff, and the parties.

First, the Commission directed the parties to participate in workshops to examine certain contentious issues raised in both the 2016 and 2017 TAMs:

- The company's Day-Ahead/Real-Time Transaction (DA/RT) adjustment;
- The company's calculation of EIM benefits; and
- The valuation of Renewable Energy Certificates (REC) for purposes of calculating a potential credit for direct access customers.[8]

My testimony addresses these three directives, and the agenda and presentations from the workshops are included as Confidential Exhibit PAC/107.

Second, the Commission directed the parties to discuss future long-term fueling plans for the Jim Bridger coal plant and the company's other coal-fueled resources. Mr. Ralston's testimony addresses this directive.

Third, the Commission directed PacifiCorp to provide a historical time series of fixed generation costs broken down by its components (*e.g.*, capital, O&M) as a check on the reasonableness of the company's forecasts used for determining the consumer opt-out charge applicable to customers participating in the company's five-year/permanent direct access program (Schedule 296).[9] My testimony also responds to this directive.

[8] Order No. 16-482 at 24.
[9] *Id.* at 25.

Q. Did the company hold workshops addressing the DA/RT adjustment, EIM benefits, and REC valuation?

A. Yes. The parties first held a conference call on February 3, 2017, to discuss the scope of the workshops and to develop an agenda. PacifiCorp then held substantive workshops on February 9, 2017, February 23, 2017, and March 7, 2017. The company also responded to several informal data requests from parties during the discussions.

Q. Were the workshops useful in addressing issues raised in past TAMs?

A. Yes. All parties agreed that the workshops were useful. Staff presented a report on the workshops to the Commission at its March 21, 2017 Public Meeting. Staff reported that "[h]olding these workshops outside of a contested case environment served to foster collaborative communication regarding these issues," and the workshops were "helpful in clarifying the positions of all parties, and in developing additional information regarding the issues."[10] Staff noted that the parties "participated in good faith and made good progress towards understanding some of the issues."[11] Staff "found the workshops to be productive," and stated that participants "appeared to be satisfied with the progress made during the workshops."[12]

Staff also reported that the Industrial Customers of Northwest Utilities (ICNU) was "encouraged by some of the collaborative dialogue" and would "be supportive of further usage of that sort of process leading up to other

[10] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Staff Report at 2, 4 (Mar. 14, 2017).
[11] *Id.* at 4.
[12] *Id.*

proceedings[.]"[13]

Calpine Energy Solutions, LLC (Calpine) agreed with Staff's assessment, commenting that the "workshops were a valuable opportunity to find common ground toward an agreeable solution to the issues outside of the context of a contested case process."[14] Regarding the REC valuation issue, Calpine noted that the "parties made progress in discussing the issue and would support use of similar workshops in the future."[15]

The Citizens' Utility Board of Oregon (CUB) offered comments at the Commission Public Meeting that echoed the sentiments of the other parties.

Q. Did the collaborative process result in any changes to PacifiCorp's modeling of the DA/RT adjustment, EIM benefits, or REC valuation?

A. Yes. Although the parties did not reach consensus on all issues, the company has proposed three specific modeling changes (discussed below) responding to concerns raised in past TAMs and discussed at the workshops.

Q. Were there any other issues addressed at the workshops?

A. Yes. The workshops provided a meaningful opportunity for the company to address parties' concerns over the perceived lack of transparency in the company's TAM filings.

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[13] *Id.*
[14] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Calpine Energy Solutions, LLC's Comments on Transition Adjustment Mechanism Workshops at 1 (Mar. 17, 2017).
[15] *Id.* at 2.

Q. Please describe the changes the company is proposing to increase the transparency of TAM filings.

A. At the February 23, 2017 workshop, PacifiCorp agreed to maintain a step-log of model and input changes describing changes to the company's modeling or inputs that are not considered a standard annual update. PacifiCorp also agreed to provide a summary of any input and model changes in filed testimony. Staff described this agreement as "substantial progress."[16] The company has provided the step-log as Exhibit PAC/108.

Q. Did the company provide pre-filing notice to the parties of modeling and input changes in the 2018 TAM?

A. Yes. On March 1, 2017, PacifiCorp sent a letter to the 2017 TAM parties describing the three modeling changes agreed to at the workshops, and informing the parties of two additional changes to the 2018 TAM. The company's letter is attached as Exhibit PAC/109. The two additional changes identified in the pre-filing notice reflected updated depreciation expense at the Bridger Coal Company, as discussed in Mr. Ralston's testimony, and a change to the prepaid wheeling expense at the Cholla coal plant, discussed above.

Q. Other than the modeling changes mentioned above, has the company made any other modeling changes to the 2018 TAM?

A. No.

[16] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Staff Report at 4 (Mar. 14, 2017).

Day-Ahead and Real-Time System Balancing Transactions

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

A. PacifiCorp incurs system balancing costs that are not reflected in the company's forward price curve or modeled in GRID. To address this deficiency, in the 2016 TAM, the company proposed the DA/RT adjustment to more accurately model system balancing transaction prices and volumes. In the 2016 and 2017 TAMs, Staff, CUB, and ICNU objected to the DA/RT adjustment. The Commission rejected their arguments and approved the adjustment, concluding that it more accurately reflected the costs of system balancing transactions in the company's NPC forecast.[17]

Q. Based on the first full year of implementation, has the DA/RT adjustment increased the accuracy of the company's TAM forecast?

A. Yes. The company's 2016 TAM forecast was closer to the company's actual NPC than any previous TAM forecast.

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

A. System balancing transactions are required to balance the hourly load and resources in the GRID model for the TAM test period. The GRID model calculates the least-cost solution to balance the company's load and resources each hour. The model makes purchases in the wholesale market (labeled as "system balancing purchases" in the NPC report) in the hours for which the company does not have enough owned or contracted resources to meet its load. The model also makes wholesale market sales

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

(labeled as "system balancing sales" in the NPC report) when it has excess resources for a given hour.

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

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

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

A. Before the 2016 TAM, the GRID model used an hourly price curve developed from monthly HLH and LLH forward market prices. Hourly prices were simply the product of applying a scalar, or shape, to the monthly average prices. These scalars were identical within a given month for each weekday of that month. In addition, the prices were input into the model and did not change regardless of the volume of the system balancing transactions or other system conditions in the model. In reality, however, prices vary within each month and the company has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods. As a result, the average cost of the company's daily and hourly short-term firm purchases has been consistently higher than the average actual monthly market price, while the average revenues from its daily and hourly short-term firm sales has been consistently lower than the average actual monthly market price.

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

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

In contrast, GRID has perfect foresight and can model wholesale market transactions at whatever volume is necessary to balance the system. Because of GRID's perfect foresight, it can balance the system with far fewer transactions. The DA/RT adjustment adds additional volumes to NPC to more accurately model the transactions necessary to balance the company's system.

Q. Did PacifiCorp change its DA/RT adjustment in the 2017 TAM?

A. No, with one exception. In the 2017 TAM, PacifiCorp calculated the adjustment using 48 months of historical data, rather than the 36 months of historical data that was used in the 2016 TAM. Although parties objected generally to the DA/RT adjustment, no party objected to the use of additional historical data to normalize the adjustment. When approving the DA/RT adjustment in the 2017 TAM, the Commission found that "four years of data is sufficient to generate a normalized result[.]"[18]

[18] Order No. 16-482 at 13.

Q. What were the parties' objections to the DA/RT adjustment in the 2017 TAM?

A. Staff disputed the price component of the adjustment and argued that the adjustment is arbitrary for using monthly pricing, instead of a more granular time period, and that the adjustment unrealistically models two prices for every hour when the actual market has a single hourly price.[19] Staff, CUB, and ICNU also argued that a single hourly price that is properly correlated to demand would produce a better outcome than the DA/RT adjustment, although no party provided a proposal for determining a more accurate single price.[20]

The parties also disputed the volume component. Staff claimed that it was also arbitrary, that its reliance on historical data inequitably pushes historical costs into forecast NPC, and that the adjustment eliminates the value of arbitrage transactions.[21] CUB argued that the adjustment improperly relies on pre-EIM data.[22] ICNU further claimed that the adjustment double counts load integration costs that are already reflected in NPC.[23]

Q. How did the Commission address the parties' objections in the 2017 TAM?

A. As in the 2016 TAM, the Commission rejected the parties' arguments and affirmed the DA/RT adjustment:

> We reaffirm and uphold our decision in Order No. 15-394 approving PacifiCorp's system balancing adjustment. The DA/RT adjustment—while not perfect—reasonably addresses a deficiency of the GRID model and is likely to more fully capture PacifiCorp's net variable power costs.
>
> We decline to adopt Staff and CUB's recommendation that we eliminate the adjustment now and direct PacifiCorp and parties to

[19] *Id.* at 11-12.
[20] *Id.* at 12.
[21] *Id.*
[22] *Id.*
[23] *Id.* at 13.

> work on substitute modeling adjustments to better simulate, buy, and sell balancing transactions for future TAM proceedings. No persuasive evidence was offered to convince us that our decision last year was in error.[24]

Although the Commission affirmed the DA/RT adjustment, it also directed the parties to meet informally to examine the adjustment in detail to provide an opportunity to discuss potential alternative modeling approaches.[25]

Q. What occurred at the workshops addressing the DA/RT adjustment?

A. The parties discussed the mechanics of the DA/RT adjustment and the parties' specific concerns over how the adjustment is calculated and whether it is necessary. In response to parties' concerns, the company provided detailed analyses describing the sensitivity of the DA/RT adjustment to various scenarios suggested by the parties, including abnormal weather, thermal outages, and hydro conditions.

Q. What conclusions has the company drawn from these DA/RT sensitivity analyses?

A. There is no single driver of the DA/RT costs. DA/RT costs are the result of multiple variables across the company's complex system. PacifiCorp's analyses further support the Commission's decision that "four years of data is sufficient to generate a normalized result[.]"[26]

Q. Did the company agree to any modifications to the DA/RT adjustment as a result of the workshops?

A. Yes. To address concerns over the use of historical data to calculate the adjustment, PacifiCorp agreed to use 60 months of historical data to calculate the adjustment to

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[24] *Id.* at 13.
[25] *Id.* at 14.
[26] *Id.* at 13.

achieve better normalization. As discussed above, the 2016 TAM used 36 months of historical data, and the 2017 TAM used 48 months of historical data for the adjustment. For the 2018 TAM, using 60 months of historical data reduced the DA/RT adjustment by $1 million compared to using 48 months.

Q. What is the impact of the DA/RT adjustment to the 2018 TAM, as compared to the 2017 TAM?

A. The DA/RT adjustment in the 2018 TAM is approximately $0.7 million (total-company) lower than the DA/RT adjustment approved by the Commission in the 2017 TAM.

EIM Costs and Benefits

Q. Has the EIM continued to provide customer benefits?

A. Yes. The company has participated in the EIM since 2014, and has included EIM benefits in the 2015, 2016, and 2017 TAMs. As set forth in Table 3 below, each year, the benefits increased as regional participation in the market continued to grow. The 2018 TAM reflects increased utility participation in the EIM and still increasing benefits.

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

A. Consistent with its past modeling of EIM benefits, PacifiCorp's 2018 NPC forecast from GRID includes an adjustment to reflect incremental EIM benefits from inter-regional dispatch (i.e., exports and imports between EIM participants) and reduced flexibility reserves. The 2018 TAM includes approximately $27.5 million of EIM benefits on a total-company basis as a reduction to the NPC forecast.

Table 3
Total-Company EIM-Related Benefits

$ millions	**2015 TAM**	**2016 TAM**	**2017 TAM**	**2018 TAM**
Inter-regional dispatch		$8.4	$17.5	$24.4
Flexibility Reserves		$1.7	$4.1	$3.1
Test-period EIM benefits	**$6.7**	**$10.1**	**$21.6**	**$27.5**

Q. Please describe the EIM and the company's participation in the EIM.

A. The EIM is a real-time balancing market that optimizes generator dispatch every five and 15 minutes within and between the PacifiCorp and the CAISO balancing authority areas (BAAs). Through the EIM, the company's participating generation units are optimally dispatched using the CAISO's computerized security constrained economic dispatch model. The EIM's automated, expanded footprint, co-optimized dispatch replaces the company's largely isolated and manual dispatch within its two BAAs. Participation in the EIM benefits customers by reducing NPC, with relatively low initial start-up and ongoing operation costs.

Q. How does participation in the EIM reduce the company's actual NPC?

A. Participation in the EIM reduces the company's actual NPC in three ways. First, the EIM optimizes the automated dispatch of participating units in PacifiCorp's BAAs, subject to transmission constraints, using the CAISO's system model (i.e., intra-regional benefits). Second, the EIM facilitates transactions between CAISO, PacifiCorp, and other EIM participants on a five- and 15-minute basis (i.e., inter-regional transfer benefits). Third, the EIM reduces the amount of flexible generating capacity required to be held in reserve by PacifiCorp due to the collective reduction of reserves for the larger and more diversified EIM footprint (i.e., flexibility reserve savings). Benefits realized for the last two categories are highly dependent on the amount of transfer capacity between EIM participants that is made available for the EIM.

Q. Do the EIM benefits in the 2018 TAM account for the participation of an additional utility in the EIM in 2018?

A. Yes. The 2018 TAM includes an adjustment to estimate the impact of Idaho Power Company's (IPC) expected entry into the EIM in April 2018. The 2018 TAM will also include a full year of benefits due to the participation of NV Energy (NVE), Arizona Public Service (APS), Puget Sound Energy (PSE), and Portland General Electric (PGE), originally reflected in the 2017 TAM. This adjustment is calculated consistent with the methodology used for new participants in past TAMs, and increases the total company EIM benefits by $0.3 million.

Q. Do each of the three benefits identified above result in a reduction to the NPC forecast?

A. No. As the Commission found in the 2017 TAM, the GRID model NPC forecast already reflects the optimized (i.e., lowest cost) dispatch of PacifiCorp's generating resources within its two BAAs, so there are no additional benefits from EIM optimized dispatch (i.e., intra-regional and within-hour dispatch benefits).[27] The other two NPC benefits—inter-regional transactions and reduced flexibility reserves—do produce NPC savings relative to the optimized GRID NPC forecast.

Q. How did the company forecast the benefit associated with reduced flexibility reserves?

A. Using the same methodology as the 2016 and 2017 TAMs, PacifiCorp reduced the

[27] *Id.* at 16.

regulating reserve requirement modeled in GRID by roughly 89 MW to account for the company's share of the reserve benefit based on the diversified footprint of the EIM. The methodologies for determining the reduction in reserves associated with the participation of CAISO, NVE, APS, PSE, and PGE in the EIM are unchanged from the 2017 TAM. The company's 2018 TAM also includes the diversity benefit associated with IPC's participation in the EIM beginning in April 2018, using a comparable methodology to that used for PGE in the 2017 TAM. The overall reduction in the company's reserve requirement from its participation in EIM decreases NPC by approximately $3.1 million on a total-company basis.

Q. How did the company calculate the EIM benefits resulting from inter-regional transfers?

A. The inter-regional transfers benefit reflects the benefit received by PacifiCorp when it economically transfers energy to the EIM and when it imports energy from the EIM that allows it to displace a more expensive resource.

Generally, the benefit of EIM exports is equal to the revenue received less the production cost of generation assumed to supply the transfer. The production cost used in the company's calculation of EIM benefits is the marginal cost to produce an additional megawatt-hour at a given resource. The company's production costs used to calculate EIM benefits are equal to the resource bids submitted to the EIM.

The benefit of EIM imports is equal to the import expense less the avoided expense of the generation that would have otherwise been dispatched.

Q. In the 2017 TAM, did the parties dispute the methodology used to determine the inter-regional transfers benefit?

A. Yes. Staff and CUB both argued that the company's production costs used to determine the export benefits were excessive, which resulted in a lower benefit than the company was achieving in actual operations.[28] CUB also argued that the company unreasonably limited inter-regional benefits based on available transmission.

Q. How did the Commission resolve the company's modeling of EIM inter-regional transfer benefits?

A. The Commission rejected the parties' adjustments and found that PacifiCorp's calculation was reasonable and that the use of the bid price accurately reflected PacifiCorp's production cost.[29] The Commission also found that PacifiCorp appropriately accounted for transmission constraints in its modeling.[30]

Q. Has the company changed the methodology used to calculate the inter-regional EIM benefits from the methodology approved in the 2017 TAM?

A. Yes. As a result of the workshops, the company adopted CUB's proposal from the 2017 TAM. In both the 2016 and 2017 TAMs, the company modeled inter-regional transfers based on the available transmission between the PacifiCorp and CAISO systems expected during the test period. This calculation accounted for the fact that the same transmission path that is used for EIM transfers, the California-Oregon Intertie (COI), is also modeled in GRID to support market transactions at COB

[28] *Id.* at 14.
[29] *Id.* at 16.
[30] *Id.* at 17.

(California-Oregon Border). Because the same transmission path cannot be used for both COB transactions and EIM transactions, the company limited the EIM transfers based on the available transmission, taking into account the COB transactions that were already modeled as a reduction to NPC.

Q. Did CUB object to the company's modeling of inter-regional benefits?

A. Yes. CUB argued that there should be no limit based on forecasted transmission across the COI. Although the Commission rejected CUB's argument in Order No. 16-482, as a part of the collaborative workshop process, the company agreed to calculate inter-regional benefits using CUB's recommended approach.

Q. Are there any other changes in how the company calculated the 2018 EIM benefits?

A. No. Except for removing the transmission constraint discussed above, the company's EIM calculation is the same as what the Commission approved in the 2017 TAM.

Q. Did the company make an adjustment to the market caps as a part of its change in the calculation of EIM inter-regional benefits?

A. No. During the workshops, the company proposed to modify the COB market cap in GRID to be based on the historical time period in which the company has participated in EIM. This initial proposal was intended to address transmission constraints across the COI and limit the potential of using the COI beyond its capacity for both COB and EIM transactions. The company also included this proposed change in its March 1, 2017 notice letter. After discussing this with parties at the March 7, 2017 workshop, however, the company elected not to include the proposal in the 2018 TAM.

Q. Please describe the EIM-related costs included in the 2018 TAM.

A. Consistent with the 2015, 2016, and 2017 TAMs, the company includes EIM-related costs in the 2018 TAM. In the 2018 TAM, EIM-related costs are $6.0 million (total-company). These costs consist of the return on net rate base from the capital investment required to participate in the EIM, depreciation expense, and ongoing operations and maintenance (O&M) expenses and transaction fees. A summary of the various cost components is provided as Exhibit PAC/105.

REC Valuation

Q. Please describe the REC valuation issue.

A. In the 2017 TAM, Calpine argued that direct access customers should receive a credit in the transition adjustment to reflect the value of the RECs that are freed up because of a direct access customer's departure. The Commission previously rejected this same proposal in the 2016 TAM.

Q. How did the Commission resolve Calpine's recommended REC credit in the 2017 TAM?

A. The Commission rejected Calpine's proposal. The Commission concluded that in the near term, there was "little or no benefit from a reduction in [its Renewable Portfolio Standard (RPS)] obligation due to the loss of load from direct access" because "PacifiCorp has ample resources to comply with the RPS through the mid- to late-2020s."[31] Thus, according to the Commission, "a 'freed-up' REC today simply adds to the surplus of RECs that PacifiCorp already has or will have to comply with the RPS."[32]

[31] *Id.* at 22.
[32] *Id.*

The Commission observed that, over the long run, a freed-up REC may provide benefits to remaining customers "if there is a guaranteed loss of load due to direct access" that would allow PacifiCorp to delay taking "resource actions to comply with the RPS."[33] The Commission further noted that "[n]o party has offered a reliable way to estimate the value of loss of load in that time period and we note the complexities to derive such an estimate" and found that "any reasonable estimate of benefits from that time period would be *de minimis* when discounted to today's dollars."[34]

Q. Did the Commission direct the parties to further investigate this issue?

A. Yes. The Commission directed PacifiCorp, Staff, and other parties to discuss REC valuation at a workshop, with a focus on the potential benefits that may derive at the time PacifiCorp must take substantive action to comply with its RPS target.[35]

Q. Did the required workshops occur?

A. Yes. PacifiCorp presented materials on the REC valuation issue at both the February 23, 2017, and March 7, 2017, workshops.

Q. Were the parties able to agree on a reasonable valuation methodology?

A. No. While the parties did not agree on the methodology to calculate the value of freed-up RECs, there was general agreement that the transition adjustment should account for this value in some manner.

[33] *Id.*
[34] *Id.*
[35] *Id.*

Q. Please describe the company's proposed methodology for calculating the REC credit.

A. PacifiCorp proposes to include a credit for the value of these RECs in the transition adjustment for direct access consumers. PacifiCorp's RPS compliance requirements are calculated as a percentage of load and therefore a decrease in load results in a lower compliance requirement. Because PacifiCorp banks all Oregon-allocated RECs for RPS compliance, the impact of a lower compliance requirement in a particular year is to extend the point in time at which PacifiCorp will need to acquire new resources or RECs to meet its compliance requirements. Currently, PacifiCorp does not expect a compliance shortfall until the late 2020s. The proposed credit represents the future value associated with the delay in the timing of the company's RPS compliance shortfall. The credit will be applied to the transition adjustment and will remain fixed during the time period covered by the direct access program.

Q. Is this methodology consistent with the Commission's guidance in the 2017 TAM?

A. Yes. In Order No. 16-482, the Commission directed parties to "discuss whether there is a reasonable method to value RECs based on delaying the time when PacifiCorp is required to take any substantive action to ensure RPS compliance."[36] The company's proposal was based on this guidance.

Q. How does the company propose to calculate the value of the RECs for customers electing direct access?

A. The company proposes to value RECs based on the net present value of its future

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[36] *Id.* at 2.

compliance need by first calculating the delay in future RPS compliance resulting from lost load to direct access, and then discounting the future cost to today's dollars, on a dollar per MWh basis. Confidential Table 4 below details this calculation. RECs in the calculation are valued based on the execution of several recent long-term contracts for the purchase of RECs. The amount of assumed direct access load (25 aMW for the one and three year programs and 50 aMW for the five-year/permanent program) is multiplied by PacifiCorp's RPS percentage requirement in a particular year to determine the quantity of RECs freed up from reduced load. The weighted average cost of RECs in the year in which PacifiCorp's compliance shortfall is delayed is discounted to present value to calculate the credit on a dollar per MWh basis.

Confidential Table 4

[redacted]

PacifiCorp's first year in which it has a compliance shortfall is 2028 (i.e., the company will need to take some resource action before 2028 to meet its 2028 RPS obligation). To calculate the credit, the company applied the purchase price for RECs that are deliverable in 2028 to the amount of freed-up RECs. That savings is discounted back into 2018 dollars and applied to the volume of direct access load, which is then levelized over the period in which the customer elects direct access.[37]

Q. Why is it appropriate to use a discounted future value for the credit rather than the market value of the RECs at the time the customer elects direct access?

A. Because the company banks all Oregon-allocated RECs for future compliance, the RECs freed up by reduced loads do not have value to the company until those freed-up RECs result in an extension of PacifiCorp's RPS compliance shortfall. The company does not realize a benefit associated with these additional RECs until that time; it is therefore appropriate to discount their present value.

Q. Does this REC credit apply to the transition adjustments for all direct access consumers?

A. Yes. The company proposes this methodology will apply to the transition adjustments for the one-, three-, and five-year direct access programs.

Q. Was this proposal discussed with parties during the workshops held before this TAM filing?

A. Yes. The company discussed this proposal with the parties at the March 7, 2017 workshop. The company has since updated the proposal presented in that workshop to expand its applicability to five-year/permanent direct access customers.

Q. Does the company have any other proposed changes related to REC charges and credits for direct access customers?

A. Yes. In docket UE 313[38], the Commission recently found that one- and three-year

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[37] For the five-year/permanent program, the REC credit is calculated based on ten years of freed-up RECs but credited to the direct access customer over the five-year/permanent program period on a levelized basis consistent with the calculation of the consumer opt-out charge.

[38] *In the Matter of PacifiCorp, dba Pacific Power, Update to Schedule 203, Renewable Resource Deferral Supply Service Adjustment*, Docket No. UE 313, Order No. 17-019 (Jan. 24, 2017).

direct access customers are subject to Schedule 203, the Renewable Resource Deferral Supply Service Adjustment, which recovers the costs of RECs that were purchased following the company's 2016 RFP. Consistent treatment requires that customers who have not already elected the five-year/permanent program remain subject to current charges under Schedule 203, because the company included these loads in its RPS compliance planning at the time of the REC purchases.

Q. Please explain.

A. The load of customers that may elect five-year/permanent direct access in the 2018 election window or beyond was included in the company's most recent RPS compliance planning. The decision to purchase RECs as a result of the 2016 RFP was based on the company's expected future RPS compliance needs, which included those customers' loads. Therefore, customers who elect the five-year/permanent program in the future should continue to be subject to current charges under Schedule 203.

Q. Is the company proposing that current five-year/permanent direct access customers be subject to Schedule 203?

A. No. Only customers who elect five-year/permanent direct access in future election windows would be subject to the costs currently being recovered in Schedule 203. Furthermore, these customers would only be charged for Schedule 203 amounts at the time they elect direct access. In other words, a future five-year/permanent direct access customer will only be subject to charges included in Schedule 203 to the extent the load of those customers was reflected in the REC or resource acquisition decision.

Once the five-year/permanent direct access election is made, the company no longer includes that customer's load when planning for RPS compliance.

Historical Time Series of Fixed Generation Costs

Q. Please describe the requirements of Ordering Paragraph 5 in Order No. 16-482 in the 2017 TAM.

A. Ordering Paragraph 5 states:

> For the next TAM filing, we direct PacifiCorp, dba Pacific Power, to include a historical time series of fixed generation costs included in in its direct access opt-out charge, broken down by its components (e.g., capital, O&M) as a check on the reasonableness of its forecasts.[39]

Q. Have you prepared the requested historical time series of fixed generation costs?

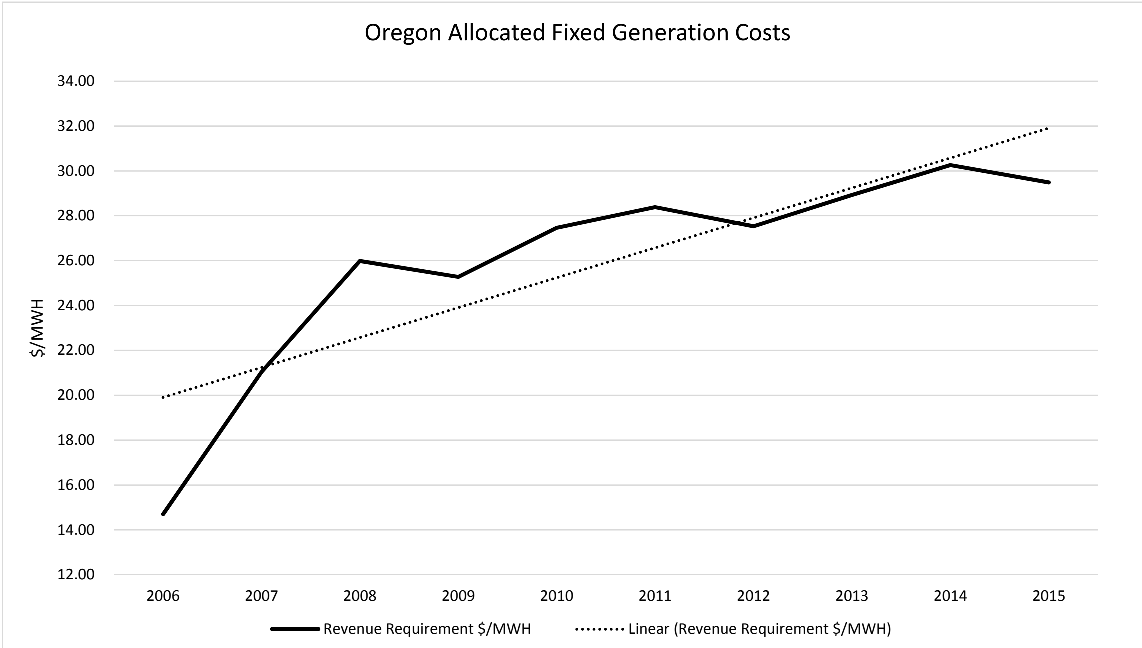
A. Yes. Exhibit PAC/110 presents a ten-year historical time series of fixed generation costs broken down by its components. This exhibit represents the functionalized fixed generation costs from the company's filed results of operations reports in Oregon from 2006 through 2015. The fixed generation components include return on rate base, operation and maintenance expenses, depreciation and amortization expenses, taxes other than income, federal and state income taxes, deferred income taxes, miscellaneous revenue and expenses, and revenue credits.

Q. What does the historical time series show about the trend in fixed generation costs?

A. As shown in the Chart 1 below, fixed generation costs have increased steadily over the past 10 years.

[39] Order No. 16-482 at 25.

CHART 1



Q. Does this information support the reasonableness of the calculation of the direct access consumer opt-out charge for the five-year direct access program?

A. Yes. The historical trend of increasing actual fixed generation costs demonstrates the reasonableness of the company's calculation of the consumer opt-out charge in the five-year direct access program. The Commission originally approved this calculation in docket UE 267[40] and affirmed it in the 2016 and 2017 TAMs. This calculation holds fixed generation costs flat in years six through ten on a real basis, adjusting them only for inflation. The historical data shows that in reality, fixed generation costs have increased at a significantly higher rate. In other words, the cost drivers that increase the company's fixed generation costs over time more than offset the accumulated depreciation that decreases fixed generation costs.

[40] *In the Matter of PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-060 (Feb. 24, 2015), order clarified, Order No. 15-067 (Mar. 10, 2015), *reconsid. den.*, Order No. 15-195 (June 16, 2015). *In the Matter of PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-Out*, Docket No. UE 267, Order No. 15-060 (Feb. 24, 2015), *order clarified*, Order No. 15-067 (Mar. 10, 2015), *reconsid. den.*, Order No. 15-195 (June 16, 2015).

Avian Curtailment Adjustment

Q. In the 2017 TAM, the Commission directed the company to remove the costs associated with avian curtailment obligations at two Wyoming wind sites.[41] Have these curtailment costs been removed from the 2018 TAM?

A. Yes.

COMPLIANCE WITH TAM GUIDELINES

Q. Did the company prepare this filing in accordance with the TAM Guidelines adopted by Order No. 09-274, as clarified and amended in later orders?

A. Yes. The company has complied with the TAM Guidelines applicable to the initial filing in a stand-alone TAM.

Q. Does this filing include updates to all NPC components identified in Attachment A to the TAM Guidelines?

A. Yes.

Q. Did the company provide information regarding its anticipated TAM updates?

A. Yes. Exhibit PAC/111 contains a list of known contracts and other items that could be included in the company's TAM updates in this case based on the best information available at the time the company prepared the NPC study.

Q. What workpapers did the company provide with this filing?

A. In compliance with Attachment B to the TAM Guidelines, the company provided access to the GRID model and workpapers concurrently with this initial filing. Specifically, the company provided the NPC report workbook and the GRID project report.

[41] *Id.* at 19.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 323
Exhibit PAC/101
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Oregon-Allocated Net Power Costs

March 2017

PacifiCorp
CY 2018 TAM
Initial Filing

			Total Company					Oregon Allocated	
Line no		ACCT.	UE-307 CY 2017 - Final Update	TAM CY 2018 - Initial Filing	Factor	Factors CY 2017	Factors CY 2018	UE-307 CY 2017 - Final Update	TAM CY 2018 - Initial Filing
1	**Sales for Resale**								
2	Existing Firm PPL	447	13,639,161	13,716,061	SG	25.230%	25.741%	3,441,206	3,530,588
3	Existing Firm UPL	447	-	-	SG	25.230%	25.741%	-	-
4	Post-Merger Firm	447	381,594,587	298,502,974	SG	25.230%	25.741%	96,277,598	76,836,267
5	Non-Firm	447	-	-	SE	23.757%	24.186%	-	-
6	**Total Sales for Resale**		395,233,748	312,219,035				99,718,804	80,366,854
7									
8	**Purchased Power**								
9	Existing Firm Demand PPL	555	5,136,503	4,615,778	SG	25.230%	25.741%	1,295,957	1,188,126
10	Existing Firm Demand UPL	555	23,760,262	23,985,699	SG	25.230%	25.741%	5,994,794	6,174,048
11	Existing Firm Energy	555	31,398,600	30,611,344	SE	23.757%	24.186%	7,459,433	7,403,812
12	Post-merger Firm	555	623,969,265	556,550,210	SG	25.230%	25.741%	157,429,544	143,259,010
13	Secondary Purchases	555	-	-	SE	23.757%	24.186%	-	-
14	Other Generation Expense	555	7,516,842	7,833,208	SG	25.230%	25.741%	1,896,524	2,016,310
15	**Total Purchased Power**		691,781,472	623,596,238				174,076,252	160,041,304
16									
17	**Wheeling Expense**								
18	Existing Firm PPL	565	20,923,037	21,399,139	SG	25.230%	25.741%	5,278,953	5,508,253
19	Existing Firm UPL	565	-	-	SG	25.230%	25.741%	-	-
20	Post-merger Firm	565	116,941,986	119,493,570	SG	25.230%	25.741%	29,504,856	30,758,286
21	Non-Firm	565	7,699,010	6,253,789	SE	23.757%	24.186%	1,829,070	1,512,572
22	**Total Wheeling Expense**		145,564,033	147,146,498				36,612,879	37,779,111
23									
24	**Fuel Expense**								
25	Fuel Consumed - Coal	501	735,897,583	755,958,645	SE	23.757%	24.186%	174,828,765	182,839,909
26	Fuel Consumed - Coal (Cholla)	501	53,338,302	51,489,296	SE	23.757%	24.186%	12,671,695	12,453,457
27	Fuel Consumed - Gas	501	3,089,382	3,609,585	SE	23.757%	24.186%	733,951	873,032
28	Natural Gas Consumed	547	294,175,127	268,576,421	SE	23.757%	24.186%	69,887,815	64,959,226
29	Simple Cycle Comb. Turbines	547	2,539,772	2,432,420	SE	23.757%	24.186%	603,379	588,317
30	Steam from Other Sources	503	4,416,891	5,002,321	SE	23.757%	24.186%	1,049,330	1,209,886
31	**Total Fuel Expense**		1,093,457,057	1,087,068,688				259,774,935	262,923,827
32									
33	**Net Power Cost (Per GRID)**		1,535,568,814	1,545,592,389				370,745,262	380,377,388
34									
35	Oregon Situs NPC Adustments		486,335	615,552	OR	100.000%	100.000%	486,335	615,552
36	**Total NPC Net of Adjustments**		1,536,055,148	1,546,207,942				371,231,597	380,992,941
37									
38	Non-NPC EIM Costs*		4,586,168	4,619,225	SG	25.230%	25.741%	1,157,106	1,189,013
39	Production Tax Credit (PTC)		(88,116,470)	(63,857,833)	SG	25.230%	25.741%	(22,232,082)	(16,437,349)
40	**Total TAM Net of Adjustments**		1,452,524,847	1,486,969,334				350,156,621	365,744,605
41									
42								Increase Absent Load Change	15,587,985
43									
44			Oregon-allocated NPC (incl. PTC) Baseline in Rates from UE-307					$350,156,621	
45			$ Change due to load variance from UE-307 forecast					(3,134,167)	
46			2018 Recovery of NPC (incl. PTC) in Rates					$347,022,454	
47	*EIM Benefits for the 2018 TAM are reflected in net power costs								
48								**Increase Including Load Change**	**18,722,152**
49									
50								Add Other Revenue Change	(360,057)
51									
52								**Total TAM Increase**	**18,362,095**

Docket No. UE 323
Exhibit PAC/102
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Net Power Costs Report

March 2017

PacifiCorp

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Net Power Cost Analysis

12 months ended December 2018	01/18-12/18	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
						$							
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	13,716,061	1,256,133	1,152,607	1,237,346	789,641	959,187	976,800	1,226,951	1,245,713	1,207,124	1,236,334	1,210,197	1,218,029
BPA Wind	2,593,849	288,856	283,292	261,564	192,047	181,765	176,794	109,030	115,486	160,963	172,214	318,702	333,137
Hurricane Sale	10,904	909	909	909	909	909	909	909	909	909	909	909	909
Leaning Juniper Revenue	86,497	5,954	5,967	8,983	4,914	5,779	6,347	10,568	10,658	8,535	6,987	5,762	6,043
UMPA II s45631	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Long Term Firm Sales	16,407,312	1,551,852	1,442,774	1,508,801	987,510	1,147,639	1,160,850	1,347,458	1,372,766	1,377,531	1,416,443	1,535,569	1,558,118
Short Term Firm Sales													
COB	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	1,315,160	444,080	409,920	461,160	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	12,461,380	4,284,190	3,877,560	4,299,630	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Electric Swaps Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Sales	13,776,540	4,728,270	4,287,480	4,760,790	-	-	-	-	-	-	-	-	-
System Balancing Sales													
COB	38,339,529	3,134,284	3,247,151	3,864,987	2,148,808	1,744,813	1,515,931	2,037,377	5,500,942	4,446,911	2,687,666	3,772,190	4,238,470
Four Corners	54,565,418	5,617,432	3,961,190	4,330,252	1,190,175	2,001,296	1,660,252	5,193,284	8,527,154	7,331,049	5,711,374	4,274,501	4,767,460
Mead	28,888,536	3,129,570	2,172,822	2,111,154	2,011,524	1,853,553	1,807,128	2,461,330	3,021,811	2,642,558	2,443,218	2,388,734	2,845,137
Mid Columbia	24,922,537	2,479,520	1,025,206	3,175,224	2,404,867	1,884,472	788,773	2,074,228	2,781,357	3,101,610	2,082,593	1,780,172	1,344,516
Mona	21,832,871	3,618,842	1,768,416	872,877	619,104	904,880	864,870	1,289,337	1,762,430	3,573,406	1,984,452	2,016,963	2,557,296
NOB	1,991,717	40,742	349,716	11,750	-	110,435	538,625	885,892	41,021	-	-	-	13,536
Palo Verde	92,032,091	7,083,572	6,146,199	6,506,970	5,957,485	5,412,857	7,736,294	10,846,669	8,763,617	7,870,741	8,336,172	8,982,729	8,388,788
EIM Exports	19,384,690	1,567,831	1,567,831	1,567,831	1,600,468	1,600,468	1,669,715	1,669,715	1,669,715	1,669,715	1,600,468	1,600,468	1,600,468
Trapped Energy	77,792	32,124	601	5,990	244	2,736	-	-	-	-	7,200	20,417	8,480
Total System Balancing Sales	282,035,183	26,703,915	20,239,131	22,447,035	15,932,674	15,515,508	16,581,586	26,457,832	32,068,047	30,635,988	24,853,142	24,836,174	25,764,150
Total Special Sales For Resale	312,219,035	32,984,037	25,969,385	28,716,626	16,920,184	16,663,148	17,742,436	27,805,289	33,440,813	32,013,520	26,269,585	26,371,743	27,322,268

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Net Power Cost Analysis

12 months ended December 2018	01/18-12/18	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Purchased Power & Net Interchange													
Long Term Firm Purchases													
APS Supplemental	716,659	71,553	104,226	256,575	-	-	-	211,458	21,523	51,324	-	-	-
Combine Hills Wind	4,963,441	308,137	435,589	504,456	513,807	448,450	358,694	417,067	352,633	331,757	344,645	422,697	525,509
Deseret Purchase	34,883,711	3,011,755	2,899,714	3,011,755	2,974,408	2,563,591	2,825,020	3,011,755	3,011,755	2,974,408	3,005,531	2,582,265	3,011,755
Douglas PUD Settlement	1,498,889	77,980	34,003	119,937	229,874	238,773	239,389	292,787	266,145	-	-	-	-
Eagle Mountain - UAMPS/UMPA	2,098,801	133,316	118,598	105,394	101,632	118,482	208,917	358,592	339,547	187,523	127,636	119,809	179,354
Gemstate	1,646,736	137,228	137,228	137,228	137,228	137,228	137,228	137,228	137,228	137,228	137,228	137,228	137,228
Hermiston Purchase	-	-	-	-	-	-	-	-	-	-	-	-	-
Hurricane Purchase	125,767	10,481	10,481	10,481	10,481	10,481	10,481	10,481	10,481	10,481	10,481	10,481	10,481
MagCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
MagCorp Reserves	7,422,510	613,530	665,660	569,420	633,580	601,500	625,560	601,500	601,500	625,560	613,530	649,620	621,550
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	-	-	-	-	-	-	-	-	-	-	-	-	-
P4 Production	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
Rock River Wind	4,936,059	614,972	552,287	529,921	446,629	270,353	232,773	176,342	187,950	254,197	476,265	586,082	608,288
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	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	20,567,750	2,680,986	2,018,601	2,046,635	1,574,711	1,395,062	1,118,614	812,910	955,925	1,191,051	1,745,262	2,362,356	2,665,636
Top of the World Wind	40,934,883	5,156,986	4,120,104	4,092,158	3,219,550	2,889,845	2,259,847	1,755,339	1,910,275	2,341,764	3,585,589	4,581,862	5,021,564
Tri-State Purchase	9,855,156	886,868	742,906	762,928	731,465	738,139	769,681	1,100,152	965,880	918,925	742,271	731,465	764,477
Wolverine Creek Wind	9,708,530	641,290	955,186	1,020,321	1,016,147	704,764	751,103	644,432	613,928	723,732	795,788	924,987	916,852
Long Term Firm Purchases Total	166,657,765	16,619,969	15,069,512	15,442,096	13,864,399	12,391,616	11,812,223	11,804,984	11,649,689	12,022,818	13,859,098	15,383,776	16,737,585
Seasonal Purchased Power													
Constellation 2013-2016	-	-	-	-	-	-	-	-	-	-	-	-	-
Seasonal Purchased Power Total	-	-	-	-	-	-	-	-	-	-	-	-	-

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Net Power Cost Analysis

12 months ended December 2018	01/18-12/18	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Qualifying Facilities													
QF California	6,204,166	677,731	757,642	850,562	1,075,314	1,091,539	842,612	210,042	110,456	95,115	90,698	127,544	274,912
QF Idaho	6,256,793	440,978	412,659	487,340	528,538	646,919	696,529	595,152	497,319	469,787	503,959	492,016	485,596
QF Oregon	56,540,623	3,646,081	3,675,911	4,586,131	5,572,340	6,079,554	6,117,628	5,678,141	5,582,238	4,884,636	4,108,071	3,188,146	3,421,746
QF Utah	9,521,859	669,391	694,538	807,828	837,825	911,557	928,458	864,720	859,375	814,786	783,440	703,677	646,264
QF Washington	303,094	-	-	-	11,725	27,496	48,710	65,017	69,530	56,851	23,763	-	-
QF Wyoming	213,813	22,907	20,234	23,521	17,712	15,902	12,454	14,997	14,437	13,402	14,963	21,356	21,929
Biomass One QF	14,559,531	1,424,065	1,380,530	1,345,317	1,413,434	917,951	895,332	909,656	1,211,439	1,294,241	1,268,029	1,220,309	1,279,230
DCFP QF	192,935	11,634	11,595	16,370	14,513	13,583	14,815	23,610	22,316	16,373	24,952	17,010	6,161
Enterprise Solar I QF	11,680,683	572,517	619,572	889,693	1,017,279	1,270,925	1,347,874	1,536,025	1,377,335	1,149,175	832,798	586,468	481,021
Escalante Solar I QF	11,041,077	523,548	578,192	845,292	978,524	1,174,518	1,263,433	1,437,145	1,327,993	1,080,740	812,187	556,862	462,643
Escalante Solar II QF	10,552,844	500,754	552,944	807,807	935,260	1,122,312	1,207,723	1,373,061	1,268,740	1,032,733	776,197	532,683	442,632
Escalante Solar III QF	10,114,950	486,387	538,722	781,907	906,966	1,088,810	1,169,181	1,323,235	1,225,478	997,432	704,597	487,070	405,165
Evergreen BioPower QF	-	-	-	-	-	-	-	-	-	-	-	-	-
Five Pine Wind QF	7,712,118	484,873	755,990	698,988	688,024	443,755	488,992	579,675	583,684	658,553	686,742	793,938	848,903
Foote Creek III Wind QF	1,719,778	178,153	205,651	224,931	156,368	82,669	72,556	85,717	95,619	100,185	166,322	174,784	176,824
Granite Mountain East Solar QF	11,253,754	564,501	631,754	920,461	1,017,045	1,199,904	1,308,040	1,385,653	1,315,669	1,003,185	834,775	594,913	477,856
Granite Mountain West Solar QF	7,453,410	373,799	418,300	610,696	674,907	795,138	865,935	918,896	870,413	663,543	552,433	393,447	315,905
Iron Springs Solar QF	11,559,221	652,373	680,328	922,344	1,045,869	1,172,694	1,335,765	1,397,031	1,376,056	1,032,744	841,820	591,742	510,455
Kennecott Refinery QF	183,564	-	-	14,072	14,795	22,068	19,129	29,387	30,221	15,074	7,577	15,005	16,236
Kennecott Smelter QF	879,946	-	36,989	45,624	34,289	72,438	78,524	149,190	145,988	62,277	46,918	89,768	117,942
Latigo Wind Park QF	9,674,638	1,011,726	917,570	1,126,955	893,263	860,620	745,979	668,253	572,323	612,790	802,754	709,690	752,715
Mountain Wind 1 QF	9,078,413	1,329,340	1,218,056	888,842	668,064	463,982	456,321	432,799	458,122	466,531	702,313	940,079	1,053,964
Mountain Wind 2 QF	13,927,597	1,910,255	1,769,428	1,368,928	1,020,578	708,474	813,837	797,113	752,079	768,486	1,040,163	1,441,482	1,536,775
North Point Wind QF	17,115,861	1,016,108	1,602,194	1,576,938	1,541,516	987,809	1,104,040	1,325,597	1,395,330	1,536,357	1,567,563	1,688,482	1,773,928
Oregon Wind Farm QF	12,272,883	640,653	923,186	1,075,651	1,283,745	1,269,470	1,160,964	1,267,142	1,131,359	924,107	751,860	801,179	1,043,567
Pavant II Solar QF	3,755,477	156,067	193,744	315,421	365,375	402,839	390,312	473,597	464,741	364,556	300,054	182,373	146,398
Pioneer Wind Park I QF	10,643,896	1,307,800	926,029	1,189,660	901,601	709,426	649,524	650,952	683,005	450,187	822,508	1,259,003	1,094,200
Power County North Wind QF	4,833,038	331,843	511,597	477,117	440,438	293,628	282,047	334,070	330,572	344,250	464,852	476,322	546,303
Power County South Wind QF	4,345,262	283,387	469,754	429,497	406,737	253,526	249,538	300,265	312,553	309,708	413,147	436,422	480,727
Spanish Fork Wind 2 QF	2,688,905	213,350	177,087	190,262	148,532	152,091	217,663	284,892	309,218	265,562	235,746	244,010	250,493
Sunnyside QF	29,503,387	2,606,893	2,424,404	2,578,820	1,677,912	2,547,644	2,542,126	2,616,990	2,545,583	2,586,479	2,187,107	2,545,143	2,644,285
Sweetwater Solar QF	513,761	-	-	-	-	-	-	-	-	-	-	307,413	206,348
Tesoro QF	616,621	22,305	62,342	99,930	67,297	79,833	35,192	33,792	35,870	37,681	32,963	47,611	61,806
Three Peaks Solar QF	8,675,658	422,110	483,455	639,551	852,767	888,395	939,458	1,075,211	1,043,941	811,841	691,202	451,445	376,282
Utah Pavant Solar QF	4,696,652	177,569	227,065	384,798	418,462	468,766	526,364	624,328	597,529	472,633	372,489	238,871	187,780
Utah Red Hills Solar QF	11,750,244	494,957	629,307	802,625	1,047,650	1,228,868	1,265,379	1,548,652	1,502,152	1,334,865	828,407	597,709	469,674
Qualifying Facilities Total	323,334,633	23,292,086	24,636,691	28,167,529	28,790,968	29,584,971	30,196,854	31,108,951	30,238,650	26,814,275	24,360,652	23,050,334	23,092,671
Mid-Columbia Contracts													
Douglas - Wells	2,481,751	310,219	310,219	310,219	310,219	310,219	310,219	310,219	310,219	-	-	-	-
Grant Reasonable	(1,052,321)	(87,693)	(87,693)	(87,693)	(87,693)	(87,693)	(87,693)	(87,693)	(87,693)	(87,693)	(87,693)	(87,693)	(87,693)
Grant Surplus	2,040,298	170,025	170,025	170,025	170,025	170,025	170,025	170,025	170,025	170,025	170,025	170,025	170,025
Mid-Columbia Contracts Total	3,469,728	392,550	392,550	392,550	392,550	392,550	392,550	392,550	392,550	82,331	82,331	82,331	82,331
Total Long Term Firm Purchases	493,462,126	40,304,606	40,098,753	44,002,175	43,047,918	42,369,138	42,401,628	43,306,485	42,280,889	38,919,424	38,302,081	38,516,441	39,912,587

PacifiCorp

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Net Power Cost Analysis

12 months ended December 2018	01/18-12/18	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Storage & Exchange													
APS Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
BPA FC IV Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
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
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
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	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	-	-	-	-	-	-	-	-	-	-	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
STF Electric Swaps	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
System Balancing Purchases													
COB	12,061,007	116,994	1,182,535	2,183,411	1,322,829	538,646	1,651,858	1,901,629	1,244,212	930,566	120,607	457,234	410,487
Four Corners	15,387,661	853,800	1,778,262	1,419,147	1,525,876	827,287	866,730	1,534,707	2,154,299	1,422,702	1,168,217	902,980	933,654
Mead	4,919,579	461,411	675,442	463,710	235,336	197,538	128,186	851,717	708,094	269,588	264,469	390,534	273,553
Mid Columbia	58,651,974	4,091,023	2,561,600	8,597,193	9,573,634	9,811,738	2,550,554	5,449,313	2,902,570	3,004,102	2,950,873	3,904,818	3,254,555
Mona	10,903,039	1,294,798	1,280,966	1,801,722	338,605	408,197	387,806	487,412	975,539	510,849	611,725	1,186,794	1,618,626
NOB	4,071,360	104,106	556,889	24,917	-	186,085	1,245,337	1,830,797	89,970	-	-	1,620	31,640
Palo Verde	15,068,331	878,670	612,801	992,405	813,127	931,950	1,494,299	2,170,051	1,925,863	1,270,560	1,266,604	979,552	1,732,451
EIM Imports	(4,972,631)	(513,399)	(513,399)	(513,399)	(513,399)	(513,399)	(216,359)	(216,359)	(216,359)	(216,359)	(513,399)	(513,399)	(513,399)
Emergency Purchases	810,586	-	-	-	3,358	31,814	655,845	-	56,652	-	56,590	5,363	963
Total System Balancing Purchases	116,900,905	7,287,402	8,135,096	14,969,106	13,299,367	12,419,855	8,764,255	14,009,267	9,840,839	7,192,007	5,925,687	7,315,495	7,742,529
Total Purchased Power & Net Inter	615,763,031	48,042,008	48,683,849	59,421,281	56,797,285	55,238,993	51,615,883	57,765,752	52,571,728	46,561,432	44,677,768	46,281,936	48,105,116

PacifiCorp

_ORTAM18 NPC Study_2017 03 21

Net Power Cost Analysis

12 months ended December 2018	01/18-12/18	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
Wheeling & U. of F. Expense													
Firm Wheeling	145,758,944	11,972,621	12,500,943	12,043,132	11,506,089	12,180,061	12,063,201	12,368,767	12,432,352	12,468,913	12,030,511	12,186,682	12,005,672
C&T EIM Admin fee	1,372,457	114,253	114,274	114,352	114,328	114,360	114,349	114,431	114,441	114,446	114,538	114,495	114,190
ST Firm & Non-Firm	15,096	7,692	1,690	-	408	-	389	-	-	-	-	-	4,917
Total Wheeling & U. of F. Expense	147,146,498	12,094,566	12,616,906	12,157,484	11,620,826	12,294,421	12,177,940	12,483,198	12,546,793	12,583,359	12,145,049	12,301,177	12,124,779
Coal Fuel Burn Expense													
Carbon	-	-	-	-	-	-	-	-	-	-	-	-	-
Cholla	51,489,296	5,646,078	5,126,095	5,667,956	2,414,073	2,786,295	3,526,946	5,180,502	6,236,381	3,559,775	3,929,991	3,656,116	3,759,088
Colstrip	16,147,848	1,509,055	1,368,072	1,482,090	1,278,519	1,486,934	1,372,955	1,445,076	1,424,792	1,380,294	1,149,530	805,648	1,444,884
Craig	24,973,169	2,411,565	2,141,262	2,380,430	1,533,054	1,431,660	1,893,927	2,313,167	2,143,320	2,202,689	2,225,335	2,069,189	2,227,572
Dave Johnston	62,203,920	4,742,886	4,641,130	4,887,890	5,096,561	5,595,887	5,640,062	5,735,463	5,660,413	5,387,497	5,161,483	4,968,040	4,686,609
Hayden	10,940,749	1,012,918	947,010	1,040,535	895,063	1,073,894	850,227	1,069,976	1,153,671	874,548	473,118	694,477	855,311
Hunter	150,211,510	14,108,953	11,381,562	10,886,407	10,358,446	11,561,690	11,104,616	13,087,211	13,516,051	13,170,510	13,032,606	13,857,172	14,146,288
Huntington	124,380,938	11,406,694	10,905,049	11,559,762	9,417,426	8,217,138	8,885,161	10,438,001	11,171,420	10,312,810	9,390,380	10,423,792	12,253,304
Jim Bridger	223,284,273	24,449,245	22,246,779	21,715,768	12,879,166	14,280,602	15,932,341	20,180,526	20,504,270	15,565,360	18,027,230	17,773,540	19,729,445
Naughton	114,667,841	9,788,507	9,153,372	9,700,568	8,730,224	7,354,715	9,352,348	9,619,138	10,438,371	9,687,950	10,241,972	10,330,658	10,270,018
Wyodak	29,148,398	2,458,265	2,481,884	2,000,244	1,671,008	2,386,829	2,605,752	2,670,953	2,468,334	2,684,650	2,469,004	2,574,973	2,676,503
Total Coal Fuel Burn Expense	807,447,942	77,534,166	70,392,214	71,321,651	54,273,539	56,175,643	61,164,335	71,740,014	74,717,022	64,826,081	66,100,649	67,153,605	72,049,022
Gas Fuel Burn Expense													
Chehalis	42,867,199	6,918,790	3,279,922	718,976	4,004,039	2,205,623	2,737,872	5,278,256	5,149,497	5,415,655	3,626,971	1,018,430	2,513,168
Currant Creek	30,712,892	1,325,291	947,850	178,191	-	1,158,408	3,460,724	6,133,954	5,840,931	4,222,340	2,073,097	2,720,722	2,651,385
Gadsby	2,861,523	-	-	-	-	-	-	1,251,757	1,287,924	321,842	-	-	-
Gadsby CT	1,328,423	8,431	-	-	-	-	92,088	406,430	438,194	192,081	114,898	35,239	41,062
Hermiston	29,689,109	3,361,857	3,016,959	1,735,184	925,221	406,646	2,339,160	2,833,088	2,821,222	2,998,497	2,996,549	2,883,426	3,371,299
Lake Side 1	55,744,013	5,784,409	2,699,481	711,656	897,289	5,414,534	5,769,975	7,132,558	7,210,751	6,208,062	3,558,018	4,400,054	5,957,227
Lake Side 2	64,451,985	6,843,284	4,349,898	3,728,172	2,946,349	4,213,861	5,041,949	6,748,623	6,906,944	6,138,091	6,236,710	5,289,097	6,009,009
Naughton - Gas	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Fuel Burn	227,655,145	24,242,062	14,294,110	7,072,178	8,772,898	13,399,071	19,441,768	29,784,667	29,655,463	25,496,567	18,606,243	16,346,967	20,543,150
Gas Physical	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Swaps	9,791,200	(814,448)	(504,910)	38,595	1,206,900	1,415,538	1,350,600	1,206,288	1,225,198	1,234,575	1,244,650	1,215,900	972,315
Clay Basin Gas Storage	(15,489)	(29,860)	(16,679)	31,050	-	-	-	-	-	-	-	-	-
Pipeline Reservation Fees	37,187,570	3,115,338	2,967,129	3,114,968	3,065,688	3,114,968	3,071,101	3,170,137	3,172,359	3,089,592	3,121,511	3,067,660	3,117,119
Total Gas Fuel Burn Expense	274,618,426	26,513,093	16,739,651	10,256,791	13,045,487	17,929,577	23,863,469	34,161,091	34,053,020	29,820,734	22,972,404	20,630,527	24,632,584
Other Generation													
Blundell	5,002,321	447,929	423,349	442,549	424,724	445,651	402,012	419,488	407,870	389,003	384,667	355,246	459,832
Blundell Bottoming Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-
Integration Charge	7,833,208	670,058	627,642	734,508	691,754	687,123	672,328	628,529	604,717	584,598	622,552	647,705	661,695
Total Other Generation	12,835,528	1,117,987	1,050,991	1,177,056	1,116,478	1,132,774	1,074,339	1,048,017	1,012,588	973,601	1,007,219	1,002,951	1,121,527
Net Power Cost	**1,545,592,389**	132,317,782	123,514,226	125,617,636	119,933,430	126,108,259	132,153,530	149,392,783	141,460,338	122,751,688	120,633,504	120,998,454	130,710,760
Net Power Cost/Net System Load	**26.26**	**25.20**	**26.43**	**26.41**	**26.83**	**27.02**	**27.11**	**26.84**	**26.45**	**26.04**	**26.15**	**25.73**	**25.09**

Docket No. UE 323
Exhibit PAC/103
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Update to Other Revenues

March 2017

PacifiCorp
CY 2018 TAM
Other Revenues - Stand Alone TAM Adjustment
Initial Filing

		Total Company					Oregon Allocated	
Line no		UE-307 Final	CY 2018 Initial	Factor	Factors CY 2017	Factors CY 2018	UE-307 Final	CY 2018 Initial
1	Seattle City Light - Stateline Wind Farm	(9,749,394)	(10,861,266)	SG	25.230%	25.741%	(2,459,805)	(2,795,748)
2	Non-company owned Foote Creek	(905,359)	(905,486)	SG	25.230%	25.741%	(233,044)	(233,077)
3	BPA South Idaho Exchange	-	-	SG	25.230%	25.741%	-	-
4	Little Mountain Steam Revenues	-	-	SG	25.230%	25.741%	-	-
5	James River Royalty Offset	-	-	SG	25.230%	25.741%	-	-
6							-	
7	Total Other Revenue	(10,654,753)	(11,766,752)				(2,692,849)	(3,028,825)
8								
9	Decrease (Increase) in Other Revenues Absent Load Change							(335,976)
10								
11	Baseline Other Revenues in Rates						(2,692,849)	
12	$ Change due to load variance from UE 307 CY 2017 forecast						24,081	
13	Other Revenues in Rates using 2018 load forecast						(2,668,768)	
14								
15	**Decrease (Increase) in Other Revenues Including Load Change**							**(360,057)**

Docket No. UE 323
Exhibit PAC/104
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Energy Imbalance Market Import and Export Summary

March 2017

EIM Inter-regional Benefis for Existing Participants

	PACW Export MWh	PACE Export MWh	Export MWh	PACW Import MWh	PACE Import MWh	Import MWh	PACW Export Energy Margin $	PACE Export Energy Margin $	Export Margin $	PACW Import Margin $	PACE Import Margin $	Import Margin $	Mid C to COB Transmissio	Export GHG Margin $
1/1/2016	61,255	108,565	169,820	92,604	66,998	159,602	219,812	586,792	806,604	235,843	211,143	446,986	205,369	162,394
2/1/2016	84,342	92,616	176,958	61,650	67,133	128,783	347,195	462,465	809,660	238,119	230,511	468,630	190,363	274,155
3/1/2016	97,306	69,061	166,367	35,226	90,983	126,209	600,772	708,148	1,308,920	96,677	772,500	869,177	215,811	196,183
4/1/2016	82,337	62,143	144,480	33,144	126,718	159,862	384,556	756,878	1,141,434	144,150	810,506	954,656	230,237	246,220
5/1/2016	52,332	54,692	107,024	53,423	135,162	188,585	290,910	301,910	592,820	158,775	491,830	650,605	229,125	126,681
6/1/2016	70,107	135,440	205,546	44,124	28,203	72,326	501,404	899,877	1,401,281	61,715	77,177	138,893	236,547	118,228
7/1/2016	89,374	170,895	260,269	52,193	23,010	75,203	551,926	1,378,715	1,930,642	138,154	208,395	346,549	245,390	143,529
8/1/2016	85,321	161,104	246,424	51,201	18,947	70,148	410,952	829,620	1,240,572	196,686	44,416	241,103	243,816	110,045
9/1/2016	70,107	135,440	205,546	44,124	28,203	72,326	501,404	899,877	1,401,281	61,715	77,177	138,893	235,235	53,588
10/1/2016	68,708	204,766	273,475	72,991	61,663	134,654	287,444	1,420,334	1,707,778	76,463	93,859	170,323	181,263	387,785
11/1/2016	80,817	188,776	269,592	74,951	99,629	174,580	158,222	1,093,659	1,251,881	117,132	171,257	288,388	202,906	668,270
12/1/2016	137,766	222,972	360,739	57,102	87,170	144,271	544,522	1,309,719	1,854,241	173,952	84,477	258,429	203,498	709,326
Monthly EIM Benefit Through Dec. 2016														
Winter Month (Jan-May & Oct-Dec)									$ 1,184,167			$ 513,399		346,376
Summer Months (Jun-Sep)									1,493,444			216,359		106,347

Monthly EIM Inter-regional Benefis for New Participants

	Additional Inter-Regional Benefit per E3 Study **A**	PacifiCorp's Share of EIM Benefit **B**	Monthly EIM Benefit from New Participants **(A*B)/12**	New Participant Start Date
Portland General Electric	$ 2,700,000	17%	$ 37,287	Oct-17
Idaho Power Company	2,900,000	14%	32,636	Apr-18

Docket No. UE 323
Exhibit PAC/105
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Energy Imbalance Market Costs

March 2017

PacifiCorp
Oregon 2018 TAM
EIM Costs
Initial Filing - March 31, 2017

$ dollars

	CY 2018 EIM Costs 13 Month Average						
	Total Company		Factor	Factors	Factors	Oregon Allocated	
	2017 Final	Initial Filing		CY 2017	CY 2018	2017 Final	Initial Filing
Capital Investment	16,466,551	16,466,551	SG	25.230%	25.741%	4,154,566	4,238,579
ADIT	(3,447,093)	(2,892,489)	SG	25.230%	25.741%	(869,713)	(744,542)
Depreciation Reserve	(6,643,572)	(9,401,783)	SG	25.230%	25.741%	(1,676,196)	(2,420,069)
Net Rate Base	6,375,886	4,172,279				1,608,657	1,073,967
	10.75%	10.75%				10.75%	10.75%
Pre-Tax Return on Rate Base	$ 685,656	$ 448,683	SG	25.230%	25.741%	$ 172,993	$ 115,493
Operation & Maintenance (Ongoing)	1,532,526	1,554,589	SG	25.230%	25.741%	386,661	400,160
Depreciation	2,367,987	2,615,953	SG	25.230%	25.741%	597,451	673,360
Total Revenue Requirement	$ 4,586,168	$ 4,619,225				$ 1,157,106	$ 1,189,013
CAISO Fee in net power costs	$ 1,318,331	$ 1,372,457	SG	25.230%	25.741%	332,619	353,278
Total EIM Costs	$ 5,904,499	$ 5,991,683				$ 1,489,725	$ 1,542,291

Docket No. UE 323
Exhibit PAC/106
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Update to Renewable Energy Production Tax Credits

March 2017

PacifiCorp
CY 2018 TAM
Production Tax Credits

Line no	Plant Name	PTC Expiration Date	Total Company CY 2017 Final	Factor	Factors CY 2017	Oregon Allocated CY 2017 Final	Oregon Allocated Revenue Requirement
	PTC Revenue Requirement in UE-307						
1	JC Boyle	11/7/2015	$ -	SG	25.230%	$ -	$ -
2	Blundell Bottoming Cycle KWh	12/1/2017	(1,642,252)	SG	25.230%	(414,346)	(666,893)
3	Glenrock KWh	12/30/2018	(7,646,838)	SG	25.230%	(1,929,323)	(3,105,262)
4	Glenrock III KWh	1/16/2019	(2,861,406)	SG	25.230%	(721,942)	(1,161,972)
5	Goodnoe KWh	12/17/2017	(5,991,082)	SG	25.230%	(1,511,570)	(2,432,885)
6	High Plains Wind	10/14/2019	(7,115,510)	SG	25.230%	(1,795,267)	(2,889,498)
7	Leaning Juniper 1 KWh	9/13/2016	-	SG	25.230%	-	-
8	Marengo KWh	8/2/2017	(5,447,249)	SG	25.230%	(1,374,359)	(2,212,043)
9	Marengo II KWh	6/25/2018	(4,306,194)	SG	25.230%	(1,086,467)	(1,748,678)
10	McFadden Ridge	10/31/2019	(1,979,446)	SG	25.230%	(499,421)	(803,822)
11	Seven Mile KWh	12/30/2018	(8,040,700)	SG	25.230%	(2,028,696)	(3,265,203)
12	Seven Mile II KWh	12/30/2018	(1,583,828)	SG	25.230%	(399,605)	(643,168)
13	Dunlap I Wind KWh	9/29/2020	(8,132,932)	SG	25.230%	(2,051,966)	(3,302,657)
14							
15	Total Production Tax Credit		$ (54,747,437)			$ (13,812,962)	$ (22,232,082)
16							
17							
18							
19							

Line no	Plant Name	PTC Expiration Date	Total Company CY 2018 Initial	Factor	Factors CY 2018	Oregon Allocated CY 2018 Initial	Oregon Allocated Revenue Requirement
20	**PTC Revenue Requirement CY 2018**						
21							
22	Plant Name	PTC Expiration Date	CY 2018 Initial	Factor	Factors CY 2018	CY 2018 Initial	Revenue Requirement
23	JC Boyle	11/7/2015	-	SG	25.741%	-	-
24	Blundell Bottoming Cycle KWh	12/1/2017	-	SG	25.741%	-	-
25	Glenrock KWh	12/30/2018	(7,618,495)	SG	25.741%	(1,961,041)	(3,156,313)
26	Glenrock III KWh	1/16/2019	(2,861,406)	SG	25.741%	(736,541)	(1,185,470)
27	Goodnoe KWh	12/17/2017	-	SG	25.741%	-	-
28	High Plains Wind	10/14/2019	(7,115,510)	SG	25.741%	(1,831,570)	(2,947,928)
29	Leaning Juniper 1 KWh	9/13/2016	-	SG	25.741%	-	-
30	Leaning Juniper Indemnity	9/13/2016	-	SG	25.741%	-	-
31	Marengo KWh	8/2/2017	-	SG	25.741%	-	-
32	Marengo II KWh	6/25/2018	(2,378,851)	SG	25.741%	(612,329)	(985,549)
33	McFadden Ridge	10/31/2019	(1,979,446)	SG	25.741%	(509,520)	(820,077)
34	Rolling Hills KWh	1/16/2019	-	SG	25.741%	-	-
35	Seven Mile KWh	12/30/2018	(8,010,786)	SG	25.741%	(2,062,019)	(3,318,838)
36	Seven Mile II KWh	12/30/2018	(1,577,935)	SG	25.741%	(406,169)	(653,733)
37	Dunlap I Wind KWh	9/29/2020	(8,132,932)	SG	25.741%	(2,093,460)	(3,369,442)
38							
39	Total Production Tax Credit		(39,675,360)			(10,212,651)	(16,437,349)
40							
41					**Increase Absent Load Change**		**5,794,733**
42							
43							

Docket No. UE 323
Exhibit PAC/107
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Michael G. Wilding

Topics List and Presentations from TAM workshops

March 2017

PacifiCorp
Transmission Adjustment Mechanism
Order No. 16-482 Workshop Scoping Issues

WORKSHOP DATES: February 9 at PacifiCorp Learning Center 1:00pm – 5:00pm
February 23 at location OPUC - SALEM 1:00pm – 5:00pm
March 7 at OPUC – SALEM 9:30am – 11:30am

Topics 1 and 2 were discussed at the February 9, 2017 workshop. Carryover items from Topics 1 and 2 are listed in new Topic 4.

Topics 3, 4 and 5 were discussed at the February 23, 2017 workshop.

Topic 6 includes follow-up items from previous workshops and was discussed at the March 7, 2017 workshop.

1. Day-Ahead/Real-Time (DART) adjustments (discussed at February 9 workshop)
    a. PacifiCorp to describe modelling in detail.
    b. PacifiCorp to provide a complete list of all DART modeling changes it will implement in 2017, a complete list of all updates that will be added to the model, and a complete list of all inputs that will be added to the model.
    c. Explore the impact of non-normalized winter weather such as Oregon experienced this current winter on the DART, including its effect on system balancing transactions and unrecovered power costs.
    d. Explore the impact of non-normalized summer weather in PacifiCorp's Eastern Control Area on the DART, including its effect on system balancing transactions and unrecovered power costs.
    e. Description of the difference between the adjustment to reflect additional balancing volumes and the adjustment to prices input into the GRID model.
    f. PacifiCorp provide a back cast of the GRID model demonstrating that the DART adjustment increases the accuracy of NPC forecasts.
    g. Explore whether historic transactions are consistent with the system balancing process described in the TAM testimony.
    h. Explore whether the DART adjustment appropriately models the benefits of ongoing market arbitrage and economic sales and purchases.
    i. Discuss how DART type costs are modeled in IRP.
    j. Discuss PacifiCorp's ability to balance system without market transactions.

2. Energy Imbalance Market (EIM) benefit estimation (discussed at February 9 workshop)
    a. PacifiCorp to describe modelling in detail
    b. PacifiCorp to provide a complete list of all EIM modeling changes it will implement in 2017, a complete list of all updates that will be added to the model, and a complete list of all inputs that will be added to the model.
    c. PacifiCorp to detail the cost of EIM dispatch.
    d. PacifiCorp to categorize and calculate the gross benefit of EIM dispatch.

   e. Demonstrate scenarios such as: (a) intrahour changes resulting in a plant in PAC's own BA dispatching differently (say PAC east steps up to meet load in PAC west or vice versa), (b) intra hour changes resulting from PAC east selling to NVE and then PAC West buying from CAISO or PAC West selling to California and PAC East buying from NVE.
   f. Show what constraints in the model have been effective (i.e. transmission implications that are assumed to have an effect on eligible sales or benefits).
   g. Review of historical instructed imbalance payments (and other EIM related charges to and from the CAISO), relative to the amount of benefits forecast using the Company's proposed methodology.

3. REC valuation (discussed at February 23 workshop)
   a. PacifiCorp to provide a complete list of any REC modeling changes it will implement in 2017, a complete list of all updates that will be added to the model, and a complete list of all inputs that will be added to the model.
   b. Use of RFP Results for REC Valuation
   c. PacifiCorp's REC Valuation in Inter-regional Benefits Calculations: (See PAC/900, Brown/5-6; Tr. at 86-87); PAC/900, Brown/5-6 discusses how PacifiCorp values dispatch costs of wind facilities for EIM benefits purposes and states: "PacifiCorp's participating wind resources are bid in as a resource that would be paid to reduce production (negative price) with a price that is calculated based on the lost production tax credit plus the value of the renewable energy credit." See also Tr. at 86-87. Staff opposed this treatment, arguing that the marginal cost of wind units is viewed as zero, UE 307 Staff Response Br. at 44-45. The final order adopted PacifiCorp's valuation including a REC value. We'd like to know this REC valuation.
   d. PacifiCorp valuation of Company REC sales credited to non-RPS PacifiCorp jurisdictions.
   e. REC Values used in RPS Implementation Plan or IRP. What values does PacifiCorp use for planning purposes? Are there different values for bundled and unbundled RECs?

4. Follow-up items from February 9 workshop (discussed at February 23 workshop)
   a. Analysis of market arbitrage – comparison between GRID and actual
   b. Further analysis of the DART
      i. Remove extreme weather in place of using only extreme weather
      ii. Good hydro year vs. bad hydro year
      iii. Effects of plant outage
   c. Provide requested materials from DART and EIM presentations:
      i. Supporting workpapers for the weather analysis of DART
      ii. Supporting workpapers/example of how bids are calculated
      iii. Supporting workpapers for calculations used in the example EIM bids

5. Transparency (discussed at February 23 workshop)
   a. Step-log of changes
   b. TAM guidelines and how DART and EIM adjustments fit in

6. Follow-up items from previous workshops (discussed at March 7 workshop)
    a. Use of 5-year normalization for DART
    b. REC transfers – what are the difficulties, how can they be overcome
    c. $/MW EIM benefit calculation

Order No. 16-482 provides the following guidance on these workshops:

"We also direct PacifiCorp, Staff, and parties to participate in workshops to examine the following GRID issues: (1) Day-Ahead/Real-Time Transaction (DART) adjustments, (2) Energy Imbalance Market (EIM) benefit estimation, and (3) Renewable Energy Credit (REC) valuation.

With respect to the first two issues, our intent is for PacifiCorp to describe its modeling approach in detail during the workshops to facilitate the parties' deeper understanding of these issues. We expect parties challenging PacifiCorp's modeling choices to engage in these discussions in order to fully understand the rationale behind the adjustments. Our goal is to create an improved evidentiary record on these disputed issues going forward. While the workshops are intended to be informational in nature, parties may also use the workshops to discuss whether any adjustments to PacifiCorp's existing methodologies may be appropriate. With respect to the REC issue, the parties should discuss whether there is a reasonable method to value RECs based on delaying the time when PacifiCorp is required to take any substantive action to ensure RPS compliance, as discussed later in this order. Staff is to report back to us on the results of these workshops before PacifiCorp's 2018 TAM is filed.[2]"

[2] We do not seek recommendations from Staff based on tis set of informational workshops but simply a report on the parties' discussions.

Oregon 2017 TAM

DART and EIM Workshop

February 9, 2017

Redacted Version –
Subject to Protective Order No. 16-128

PACIFIC POWER

Let's turn the answers on.

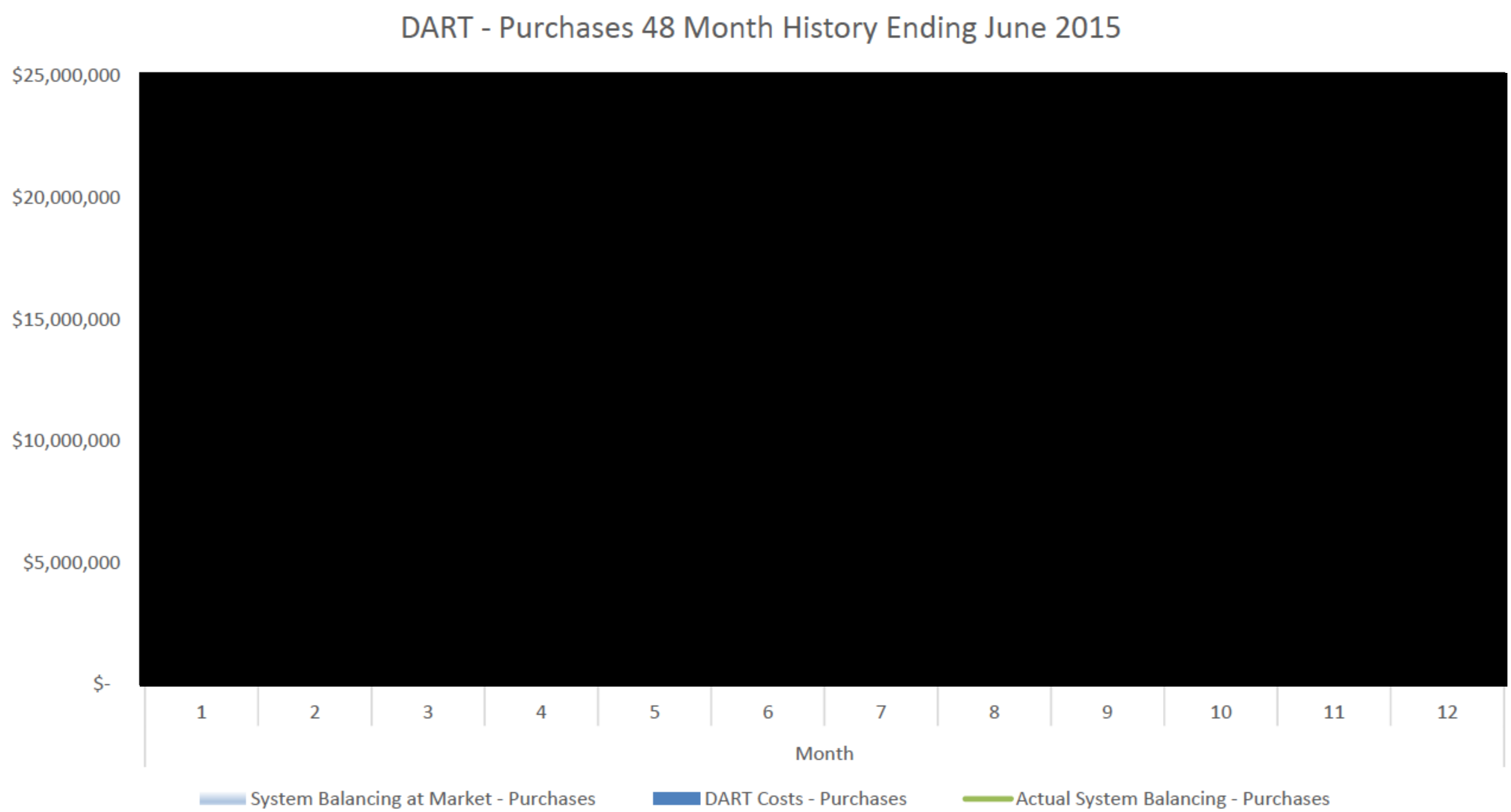
Agenda

- Overview of the DART Adjustment
- How the DART is calculated
  - Adjustment to prices in GRID
  - Volume adjustment outside of GRID
- Planned changes to the DART in the 2018 TAM
- Impact of extreme weather on the DART
- Impact of DART on prior TAMs
- DART in the IRP
- Other items

What is DART?

- DART (Day Ahead Real Time Adjustment) is an adjustment to more accurately capture the costs associated with balancing the system that historically were not captured in GRID.
- The historical average cost differential vs market for purchases and sales.

What is DART?



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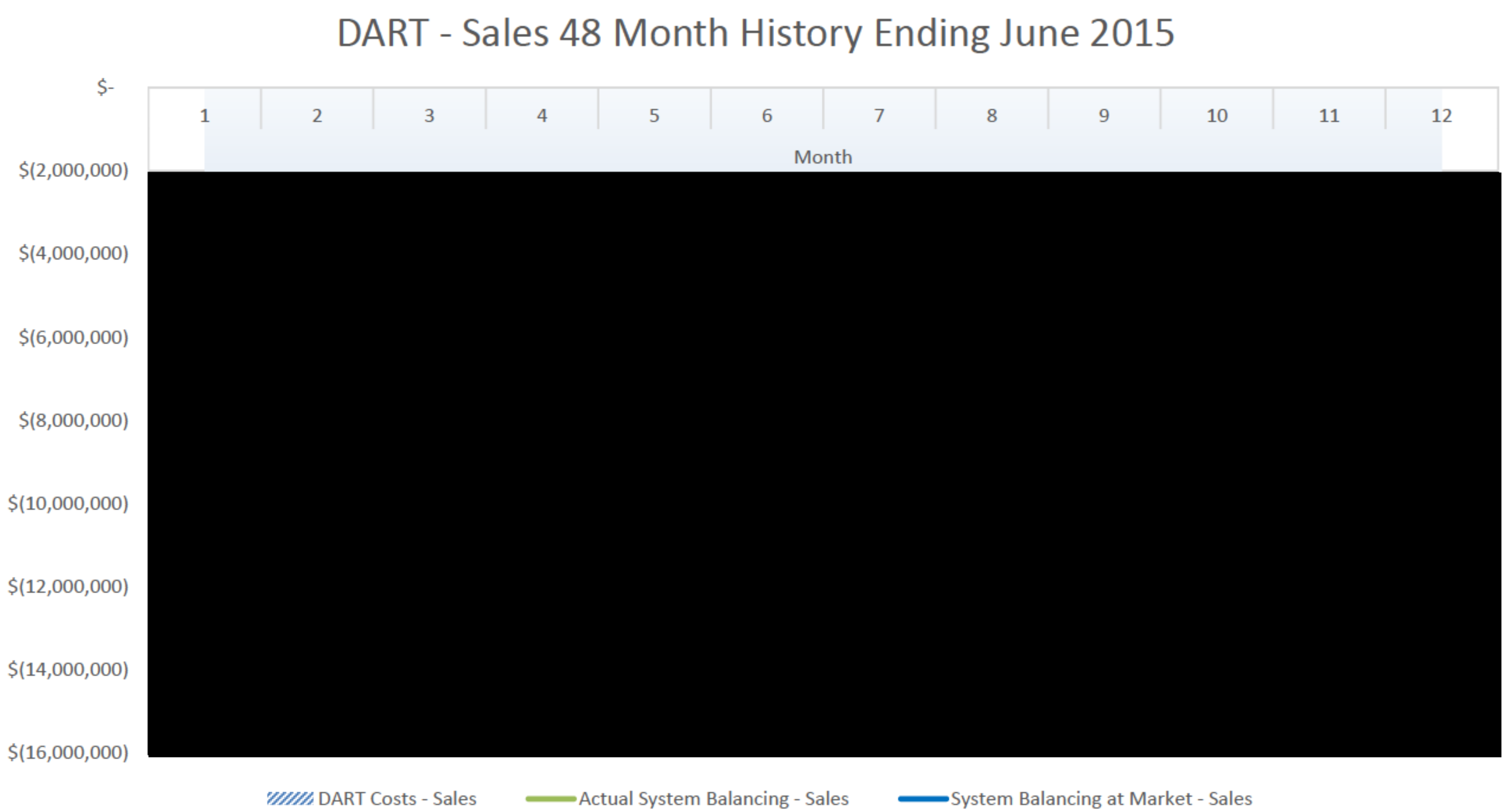
What is DART?



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What is DART?

DART Costs - 48 Months History Ending June 2015							
Month	System Balancing at Market -	Actual System Balancing - Purchases	DART Costs - Purchases	System Balancing at Market - Sales	Actual System Balancing - Sales	DART Costs - Sales	Total DART Costs
1	[redacted]						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
Total							

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Purposes of DART Adjustment

- Improve the accuracy of Net Power Cost forecast
- Better reflect the market prices available to the company when transacts in the markets
- Better reflect the combination of monthly, daily and hourly products that must be used to balance the system

Dual Purchase/Sale Markets

- Wholesale market hubs are divided into separate markets for purchases and sales
  - Historical results show that the Company is typically buying when prices are higher than the monthly average and selling when prices are lower than the monthly average
  - Forecasted prices for purchases and sales are adjusted from the OFPC based on four-year average of historical results
- Previously, the same price was used for purchases and sales
  - Monthly average price (now differentiated by purchases and sales)
  - No variation over the month – identical scalars for each weekday of the month (no change)
  - Hourly shape applied using a scalar (no change)

Dual Purchase/Sale Markets

- A separate purchase bubble was added to wholesale markets in the GRID model topology
  - Sales continue to be made in the original bubble
  - Transfers from purchase to sale bubble not limited

[redacted]

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Adjustments to Forward Price Curve

Step 1: Calculate the average price of actual day-ahead and real-time transactions from the 48 month historical period.

- **Done separately for each market, month, HLH/LLH, and Purchase/Sale**

Step 2: Compare the average price of actual real-time and day-ahead transactions to the average market price.

Step 3: Calculate the average cost differential between actual day-ahead and real-time transactions and the average market price. Calculate the average historical volume.

Step 4: Divide the average cost differential by the average historical volume to get the price adder. Adjust the forward price curve by the price adder and input to GRID to simulate system dispatch.

Example - Mid Columbia HLH

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Average Price ($/MWh)

	Period	Company Purchases	Market	Company Sales
Step 1	Sep-11		[redacted]	
	Sep-12			
	Sep-13			
	Sep-14			

Cost vs Market Average ($/MWh)

Step 2	Sep-11	[redacted]
	Sep-12	
	Sep-13	
	Sep-14	

Volume (MWh)

Sep-11	[redacted]
Sep-12	
Sep-13	
Sep-14	

Step 3

Volume Weighted Average Cost vs Market ($)

[redacted]

MWh - Monthly Average

[redacted]

Step 4

Actual vs Monthly Price - September Adder ($/MWh)

[redacted]

Additional Balancing Transactions

- **Volume:**
  - Identify monthly and daily 25MW standard HLH/LLH products that minimize the need for rebalancing with hourly products
  - Rebalancing results in additional offsetting purchase and sale volumes to achieve GRID's forecasted market position.
- **Cost:**
  - Offsetting monthly, daily, and hourly transactions are equal in volume but not equal in price. Incremental volumes are priced at monthly market index plus the difference between:
  - Historical average day-ahead and real-time cost vs. market (Slide 11, Step 3)
  - Day-ahead and real-time cost vs market in the GRID balancing result.

    GRID balancing cost vs market + Additional balancing cost vs market

    = Historical average cost vs market
- **Final Result:** NPC forecast matches the historical average cost differential vs market for purchases and sales.

Additional Balancing Transactions - Example

UE 307

PAC/100 Dickman/21, Figure 2

[redacted]

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Example - Mid Columbia HLH

	Period		Net Sales	GRID Sales	GRID Purchases
		MWh	[redacted]		
Step 1	Sep-17	aMW			
		25MW Blocks Net Sales			
		Volume (MWh)			
Step 2	Sep-17	Monthly 25MW blocks	[redacted]		
		Daily Blocks			
		Hourly			
		Incremental Volume = (Monthly + Daily + Hourly - GRID)			
Step 3	Sep-17	$			[redacted]
Step 4	Sep-17	$/MWh			

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48 Month History

- To normalize the DART it is based on the 48 month history
- Using a 48 month history is consistent with the following Net Power Costs items in the TAM
  - Market Capacity
  - Lost Hydro Capacity – planned and forced outages for storage hydro
  - Contract inputs
    - Large QF generation
    - Various other PPA and Sale take patterns
    - Non-owned generation – reserve requirements for OATT/Legacy generation in PAC BA
  - Short-term (Non-firm) Wheeling
  - Wind PPAs
  - Thermal Attributes
    - Equivalent Outage Rate
    - Ramp Losses
    - Station Service
    - Planned Outage Rate
    - Heat Rate Coefficients

Planned Changes to the DART

- Update 48 month history (will impact prices in GRID and volume adjustment)
  - July 2012 – June 2016
- No other changes

Extreme Weather

	Summer Months 2016			
Salt Lake City, UT	**June**	**July**	**August**	**September**
Actual Temperature	78.2	83.8	80.5	67.2
Normal Temperature	70.9	79.9	77.8	67.7
Delta	7.31	3.94	2.70	(0.57)

	Winter Months 2016			
Portland, OR	**January**	**February**	**November**	**December**
Actual Temperature	41.7	46.7	49.7	36.3
Normal Temperature	39.6	42.1	44.7	39.4
Delta	2.14	4.59	5.02	(3.13)

Extreme Weather

NPC	$	Delta
48month	[redacted]	
Extreme Weather (Jun 2016)		
Extreme Weather (Dec 2016)		

Total DA RT Amount	$	Delta
48month	[redacted]	
Extreme Weather (Jun 2016)		
Extreme Weather (Dec 2016)		

	Mid Columbia HLH Buy	Mid Columbia HLH Sell
48month Adders		
Jun-17	[redacted]	
Dec-17		
Extreme Weather Adders		
Jun-16		
Dec-16		

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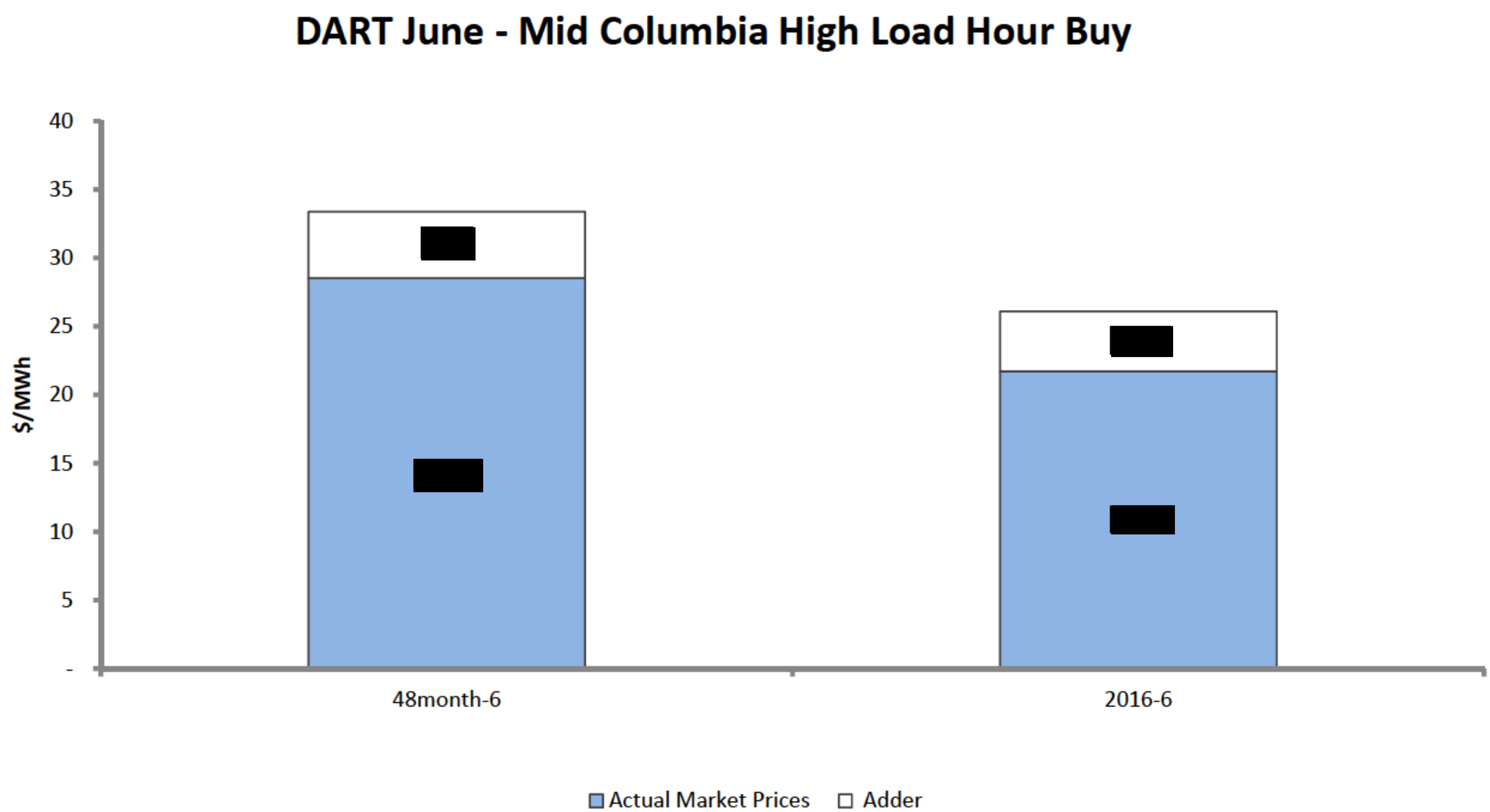
Extreme Weather



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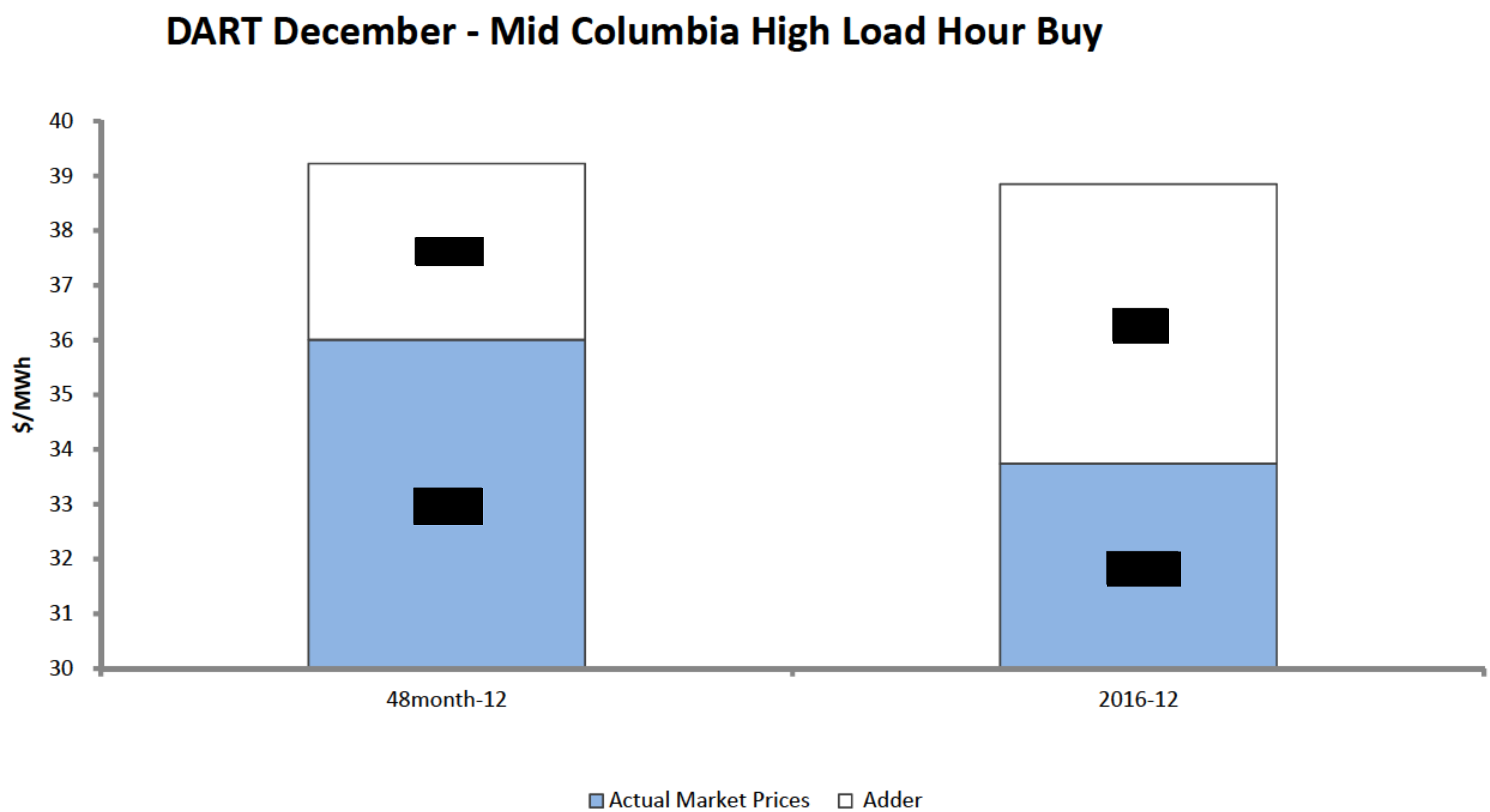
Extreme Weather



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Impact of DART on Prior TAMs

Total Company NPC Comparison ($/MWh)			
Year	Actual NPC	TAM	TAM + DART
2013	[redacted]		
2014			
2015			

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DART in the IRP

- The IRP identifies future resources needed to provide reliable, reasonable-cost service to customers with manageable risks.
- The IRP compares the relative differences between scenarios and the DART is not included as part of any scenario.
- Including DART in the IRP would result in zero impact.

Other Items

- Explore whether historical transactions are consistent with the system balancing process described in the TAM testimony.
- Explore whether the DART adjustment appropriately models the benefits of ongoing market arbitrage and economic sales and purchases.
- Discuss PacifiCorp's ability to balance system without market transactions.

Oregon 2017 TAM

Energy Imbalance Market

February 9, 2017




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Energy Imbalance Market Outline

- Daily operations and bid submission
- California Independent System Operator (ISO) EIM benefit explanation
- EIM revenue/cost calculation of the import/export
- EIM dispatch cost to facilitate the import/export
- Total EIM benefit calculation

EIM Day-Ahead Setup

- Variables considered in the day-ahead setup
  - Reserve requirement
  - Load
  - EIM flex requirements
  - Plant operating costs ($/MWh)
- The day-ahead schedule includes known updates for ramp capability, max and min capacity, outages and unit testing requirements
- Bids are submitted by end-of-day for all participating resources in EIM
  - Includes fuel price, unit heat rate, variable operation and maintenance and a ten percent adder

EIM Resources

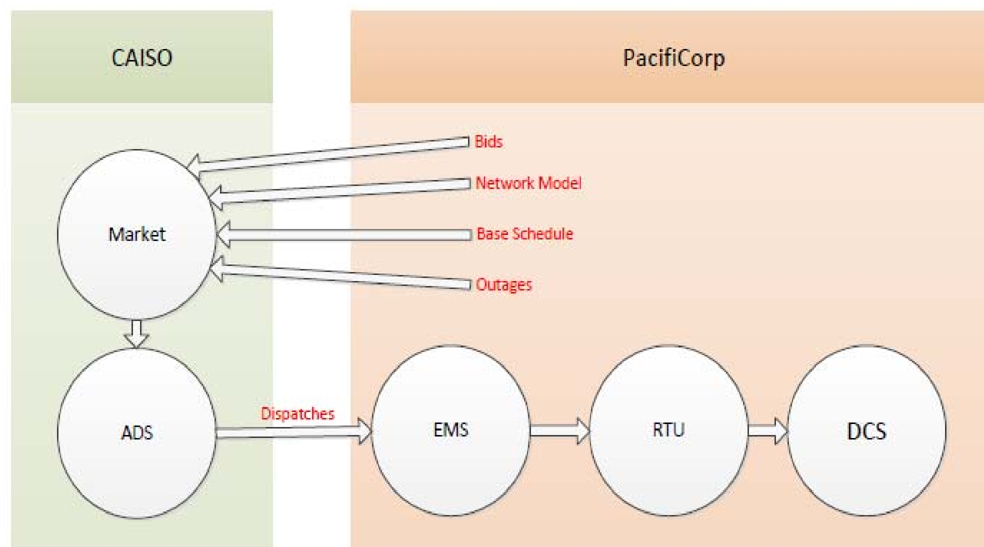
- Participating resources that are bid into the market are optimized by the ISO market model every fifteen minutes and again every five minutes to achieve the least-cost dispatch to serve load across the EIM footprint
  - PacifiCorp has chosen to maximize its participating resources to allow the most efficient optimization of the system within the hour
- Non-participating resources are not optimized by the ISO market model within the hour and maintain an hourly base schedule
  - Non-participating resources include resources that are shared units and not under PacifiCorp's operational control as well as run-of-river and constrained hydro resources
    - Hunter 1&2
    - Cholla
    - Craig
    - Hayden
    - Hydro resources other than Swift 1 and Yale

Market Timeline

- Base Schedule Balancing Test
- Bid Capacity Range Test
- Flex Ramp Required Sufficiency Test

EIM Plant Dispatch

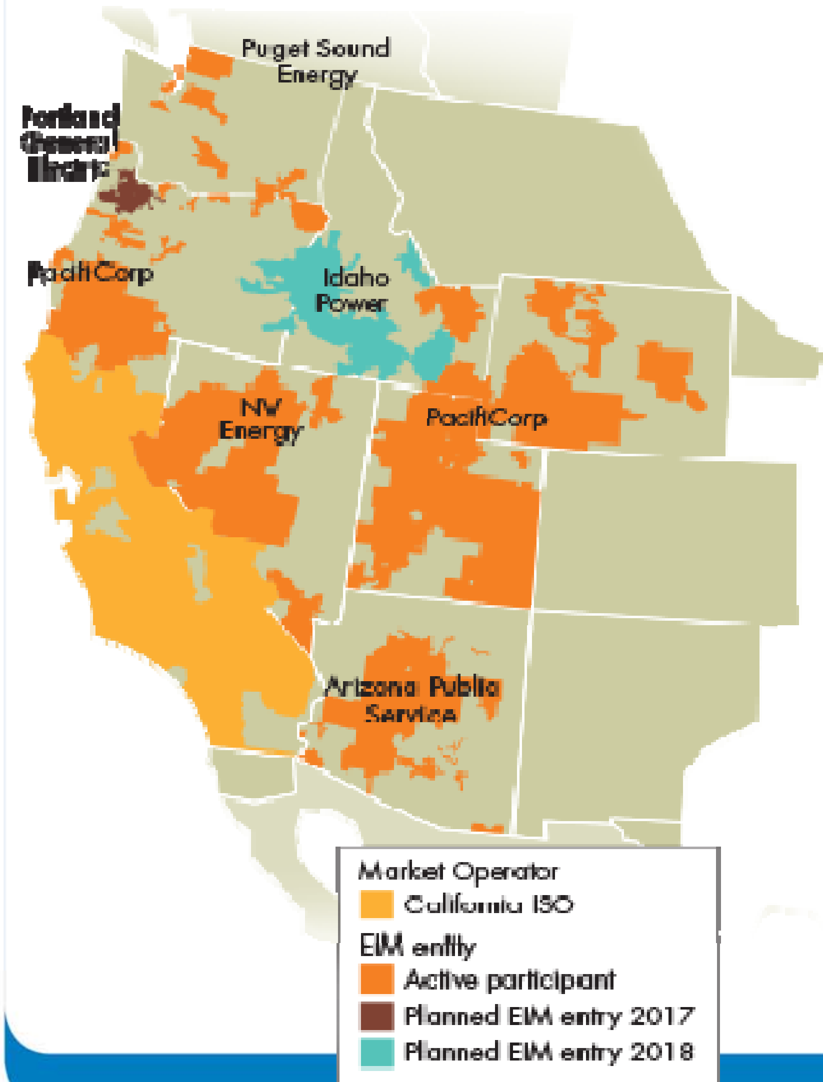
- Coordinating dispatches with plant operators
- Plant status feedback
- Data flow and generation control



Daily Bid Prices

- PacifiCorp is currently bidding in its thermal resources consistent with the DEB to accurately reflect the operating cost of its units
- Resource operating requirements for hydro facilities requires PacifiCorp to provide the market a correct price signal that can be at or below the DEB
  - During high run-off conditions PacifiCorp may submit a bid for the hydro resources that reflect a lower incremental cost and allow the resource to be dispatched first and decremented last in the PacifiCorp stack of resources
  - During periods of normal hydro operations PacifiCorp will maximize its hydro resource bid to the DEB price
- It is in the best interest of PacifiCorp to accurately reflect its cost of operations at each plant in order to achieve the most efficient market outcome in the reliable operation of the system.
- The ISO utilizes PacifiCorp's resource bids to create a "stack" of resources that is used by the market model to solve for a least-cost dispatch solution to meet demand

Energy Imbalance Market Expansion



- Arizona Public Service Company and Puget Sound Energy went live October 1, 2016
- Portland General Electric - Fall 2017
- Idaho Power - Spring 2018
- Entities exploring future entry
  - ➢ CENACE
  - ➢ Baja CA
  - ➢ Balancing Authority of Northern California (BANC)
  - ➢ Los Angeles Department of Water & Power (LADWP)
  - ➢ Seattle City Light (SCL)

EIM Benefits in the TAM

Total-Company EIM-Related Benefits and Costs

$ millions	**2016 TAM**	**2017 TAM (Nov Final)**
Inter-regional dispatch	$8.4	$17.5
Flexibility Reserves	$1.7	$4.1
Test-period EIM benefits	**$10.1**	**$21.6**
Test-period EIM costs	**$5.1**	**$6.2**

- EIM benefits reflected in the TAM continue to grow as the EIM expands with new entities

ISO EIM Benefit Calculation

- The California ISO utilizes a counter-factual analysis to calculate the EIM Benefits of each participant
  - The ISO estimates both intra and inter-regional EIM benefits in its analysis
- The intra-regional EIM benefit calculates what the costs would have been to serve load within each Balancing Area if the EIM did not exist
  - The ISO determines the load change within each area and utilizes the “stack” of resources within each area to determine what the dispatch would have been

EIM Benefits

- PacifiCorp calculates its EIM benefits based on the transfers that occur in the market and does not calculate the intra-regional benefits
  - All resources in the EIM footprint are put into a “stack” with highest cost resources at the top and lowest cost resources at the bottom. Dispatch of the stack of resources moves from bottom to top in order to serve demand at the lowest cost.
  - EIM Imports allow PacifiCorp to avoid dispatching more expensive resources
  - EIM Exports allow PacifiCorp to earn a margin on available capacity on its resources

EIM Stack and Dispatch Example

Day	hour	Interval	BAA	Price	Segment (MW)	Resource	Unit mimimum (MW)	Unit maximum (MW)	Base Schedule (MW)	EIM Dispatch (MW)	Difference (MW)
1-Jul-15	16	6	ISO	$80.0	200	California Resource	100	200	200	100	(100)
1-Jul-15	16	6	PACW	$45.0	150	Yale	80	150	99	80	(19)
1-Jul-15	16	6	PACE	$25.0	600	Lake Side 2	300	600	500	519	19
1-Jul-15	16	6	PACE	$24.0	500	Current Creek	250	500	400	500	100
								Total MW	1,199	1,199	-
								Total Cost	$3,546	$3,048	($498)

- Illustrative example of one five-minute interval in the EIM where the load did not change from the base schedule of 1,199 MW to the EIM dispatch of 1,199 MW
- All resources in the EIM Footprint are re-dispatched within their operating constraints to produce the least-cost dispatch solution, taking into consideration transmission constraints, resource ramping constraints and reserve requirements

EIM Transfers

Day	hour	Interval	BAA	Price	Segment (MW)	Resource	Unit mimimum (MW)	Unit maximum (MW)	Base Schedule (MW)	EIM Dispatch (MW)	Difference (MW)
1-Jul-15	16	6	ISO	$80.0	200	California Resource	100	200	200	100	(100)
1-Jul-15	16	6	PACW	$45.0	150	Yale	80	150	99	80	(19)
1-Jul-15	16	6	PACE	$25.0	600	Lake Side 2	300	600	500	519	19
1-Jul-15	16	6	PACE	$24.0	500	Current Creek	250	500	400	500	100

Total MW	1,199	1,199	-
Total Cost	$3,546	$3,048	($498)

- The above dispatch example shows that ISO resources decreased (net) in EIM 100 MW, PACW decreased 19 MW and PACE increased 119 MW
- Looking at resource dispatch that correspond with the changes in EIM, PACW transferred 100 MW to ISO and PACE transferred 119 MW to PACW so that all systems would have balanced

EIM Revenue Calculation of Transfer

- PacifiCorp uses the 15-minute (FMM) and 5-minute (rtd) prices and volumes to calculate the EIM Revenue of the transfer
- Using the previous slides EIM Dispatch example, the following table shows prices and transfers that correspond with the actual EIM dispatch

	PACE FMM	PACW FMM	CAISO FMM
Price	$25.00	$25.00	$80.00
Transfer Volume	50	50	-50
Revenue	$104.17	$218.75	-$218.75

	PACE rtd	PACW rtd	CAISO rtd
Price	$25.00	$25.00	$80.00
Transfer Volume	69	50	-50
Revenue	$143.75	$218.75	-$218.75

	PACE RTD	PACW RTD	CAISO RTD
Actual Transfer Volume	119	100	-100
Total Revenue	$247.92	$437.50	-$437.50

PACE FMM Revenue =(($25 + $25)/2) * 50/12 = $104.17
PACW FMM Revenue =(($25 + $80)/2) * 50/12 = $218.75
CAISO FMM Revenue =(($25 + $80)/2)*-50/12 = -$218.75

PACE FMM Revenue =(($25 + $25)/2) * 69/12 = $143.75
PACW FMM Revenue =(($25 + $80)/2) * 50/12 = $218.75
CAISO FMM Revenue =(($25 + $80)/2)*-50/12 = -$218.75

PACE RTD Revenue = $104.17 + $143.75 = $247.92
PACW RTD Revenue = $218.75 + $218.75 = $437.5
CAISO RTD Revenue = -$218.75 + -$218.75 = -$437.5

PacifiCorp EIM Dispatch Cost

- In the example provided PACW exported 100 MW to ISO and was paid $437.50
- The cost to serve that export was the cost it paid to PACE for the transfer of 119 MW or $247.92
- PACE costs to serve the 119 MW transfer was the 100 MW provided by Current Creek and 19 MW provided by Lake Side 2

Day	hour	Interval	BAA	Price	Segment (MW)	Resource	Unit mimimum (MW)	Unit maximum (MW)	Base Schedule (MW)	EIM Transfer Dispatch (MW)	Transfer (MW)
1-Jul-15	16	6	PACE	$25.0	600	Lake Side 2	300	600	500	519	19
1-Jul-15	16	6	PACE	$24.0	500	Current Creek	250	500	400	500	100

Transfer MW	119
Transfer Cost	$2,875.00
Five-Minute Total Cost	$239.58

PacifiCorp EIM Benefit Calculation

- The transfer revenue that was calculated for PACW and PACE is added together and the dispatch Cost to facilitate the transfer is subtracted to calculate the marginal revenue or EIM benefit for the five-minute interval
- The benefit for the ISO was its avoided cost of $80/MWh for 100 MW, or $666.67, at a cost of only $437.50
- The example also illustrated an intra-regional benefit of utilizing PACE resources to displace the Yale resource (19 MW)
  - The total EIM benefit (shown on slide 10) of $498.00 was $427.08 of inter-regional benefit and $71.25 of intra-regional benefit

	Revenue	Cost	EIM Benefit
PACW	$437.50	$247.92	$189.58
PACE	$247.92	$239.58	$8.33
ISO	-$437.50	$666.67	$229.17
Total	$685.42	$487.50	$427.08

Oregon 2017 TAM

DART and TAM Transparency

February 23, 2017

Redacted Version

PACIFIC POWER

Let's turn the answers on.

Agenda

- Follow-Up DART Analysis
  - Remove Extreme Weather
  - DART and Hydro Generation
  - DART and Thermal Outages
- TAM Transparency

DART - Extreme Weather

48month Winter Months Drybulb Temperature

	January	February	November	December
2011			43.68	35.74
2012	39.24	41.69	46.69	39.88
2013	35.39	41.38	43.81	33.41
2014	39.57	41.74	45.29	43.85
2015	41.85	47.23		

48month Summer Months Drybulb Temperature

	June	July	August	September
2011		78.29	78.95	68.85
2012	74.90	82.11	81.45	69.68
2013	76.89	83.88	82.15	69.54
2014	70.74	81.88	73.80	69.59
2015	78.14			

DART - Extreme Weather

[redacted]

Conclusion: Weather has a moderate affect on the DART adjustment.

DART – Hydro Generation

	DART Cost			Hydro Generation (MWh)
	Purchase	Sales	Total	
CY2012	[redacted]			
CY2016				
CY2014				
CY2013				
CY2015				
48month				

Conclusion: Hydro generation and DART costs are not strongly correlated.

DART – Thermal Outages

Forced Outage Events

[redacted]

Conclusion: Thermal outages alone are not a significant driver of DART costs.

DART Conclusions

- There is no single driver of DART costs.
- The DART costs are the result of multiple variables within a dynamic system in which the Company has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods.
- Four years of historic data is sufficient to normalize the DART adjustment in the TAM.

TAM Transparency

- As part of the current TAM Guidelines PacifiCorp provides all parties:
  - A pre-filing review of any proposed changes to the GRID model 30 days before the initial filing.
  - A one-off study showing the impact of the proposed changes to the GRID model as reported in the pre-filing review.
  - Corrections to the components in the initial filing per the TAM Guidelines.

TAM Transparency

- PacifiCorp proposes to provide an initial filing step log which will include:
  - The description and impact of any changes identified in the prefilling review.
  - The description and impact of non-routine updates to inputs.

Step Number	Description of Model Change/Input Update	Total NPC	NPC Delta	Cumulative Delta

TAM Transparency

- As per TAM Guidelines After the initial filing any changes to the TAM will continue to be captured in the step log.

[redacted]

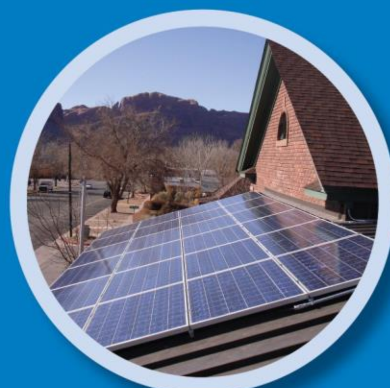
TAM Transparency

- All parties are given access to GRID.
- All GRID and forecast inputs provided to parties in electronic format as part three and five day workpapers.
  - Data provided for all filings; initial, rebuttal, indicative, and final.
- Any other relevant data will be provided upon request of parties.
- GRID training is available if needed.
  - Staff onsite visit and GRID training 2016
  - CUB onsite visit and GRID training February 2017

Oregon Transition Adjustment Mechanism Workshop

REC Valuation for Direct Access Customers

February 23, 2017

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Commission Conclusions in 2015 & 2016 TAM Orders

- In both the 2015 and 2016 TAM proceedings, the Commission stated that it saw little or no benefit to the company from a reduction in renewable portfolio standard (RPS) obligation due to loss of load from direct access.
  - December 2015, Docket No. UE-296 Order 15-394: "At best, the net present value of the value of any freed-up REC is *de minimis*"
  - Docket No. UE-307 Order 16-482 12/20/16: "PacifiCorp has stated that it will continue to bank RECs rather than sell them, so there is no benefit to other customers from a potential sale of RECs. Over the long run, if there is a guaranteed loss of load due to direct access, then there may be benefits to other customers by altering the point in time when PacifiCorp would need to take resource actions to comply with the RPS. However, based on the record, PacifiCorp would not need to take such action to ensure compliance with the RPS until the mid-2020s. No party has offered a reliable way to estimate the value of loss of load in that time period and we note the complexities to derive such an estimate. We also find that any reasonable estimate of benefits from that time period would be *de minimis* when discounted to today's dollars."

- Notwithstanding these findings, the Commission directed the company, staff, and parties to discuss REC valuation in workshops

Renewable Energy Credit Valuation for Direct Access Load

- Concept: decreased load can result in decreased RPS compliance requirements i.e., fewer renewable energy credits (RECs) may ultimately be required to be retired to demonstrate compliance

- If RPS compliance requirements are decreased in a particular year, the benefit of this decrease is not realized until the need to acquire additional RECs is deferred
  - PacifiCorp has a significant REC bank which currently extends an RPS compliance need to approximately 2028
  - A decrease in load may extend the compliance need for a certain period of time e.g., the RPS benefit of decreased load in 2018 may not be realized until the REC bank is exhausted in 2028

- A potential valuation methodology may look at future avoided compliance requirements

Potential REC Valuation Methodology

- The following example illustrates a potential methodology for valuing the future benefit of an avoided compliance requirement:
  - Estimate reduced load associated with Direct Access customer for the period of time the customer has chosen to opt-out and then estimate current benefit by calculating net present value of future benefit.
  - 50 aMW is subtracted from 2018 load resulting in reducing the 2028 RPS compliance requirement by 65,700 MWh
  - The cost of future need ($/REC) is discounted to present value to estimate incremental costs savings:

Cost of Future Need ($/REC)	Incremental Cost Savings ($/MWh of DA load)
$1	$0.08
$5	$0.40
$10	$0.79
$15	$1.19

- The challenge will be how to value cost of future need in terms of $/REC

Options for Estimating Future Value

- Future REC prices are very difficult to predict – no professional market forecasts exist and the market is volatile and illiquid

- RFP results from recent PacifiCorp REC RFP for long-term REC purchases
  - Issue if there is not a recent RFP for future vintage RECs

- Recent sales of PacifiCorp east-side allocated RECs
  - Generally short-term sales so do not reflect longer-term value
  - REC market is volatile and illiquid – prices vary based on compliance need and factors impacting production
  - Not all RECs are created equal (currently Pacific Northwest RECs have premium value over remainder of WECC)
  - Not all RECs are saleable

- EIM bid valuation
  - REC price in bid generally based on recent REC sales and observations regarding the current REC market

Oregon 2017 TAM

2018 Modeling Changes

March 7, 2017





Redacted Version –
Subject to Protective Order No. 16-128

PACIFIC POWER
Let's turn the answers on.

Agenda

- 2018 TAM Potential Modeling Changes (subject to discussion and agreement with parties)
  - EIM Benefit Calculation
  - DA/RT Normalization

Proposed EIM Benefit Calculation

- The EIM benefit realized from exporting energy to the CAISO will no longer be based on available transmission capacity in GRID. The EIM benefit from exports to CAISO will be based on a dollars per month approach, which is the same method used to estimate the benefit of exports to other EIM participants. To mitigate the potential of overstating the sales benefit at the COB market, the COB market cap in GRID will be based on a historic period that corresponds to EIM participation -November 2014 to June 2016 in place of a 48 month history.

EIM Interregional Benefits	CY2017 (in Millions)
ORTAM17	[redacted]
ORTAM17 (new format)	
Difference	

Confidential Version – Subject to Protective Order No. 16-128

Proposed EIM Benefit Calculation

2018 TAM COB Market Cap Comparison

	UExxx (48ME June16)				Only Uses Nov 14+			
2018	COB HLH	Cap Month	COB LLH	Cap Month	COB HLH	COB LLH	Delta HLH	Delta LLH
January	[redacted]							
February								
March								
April								
May								
June								
July								
August								
September								
October								
November								
December								

Confidential Version – Subject to Protective Order No. 16-128

Proposed DA/RT Adjustment

- To increase normalization, the DA/RT adjustment will be based on a 60 month history as opposed to a 48 month history as used in the 2017 TAM.

Historical Period	DART Cost (in Millions)
48month (Jul11-Jun15)	[redacted]
48month (Jul12-Jun16)	[redacted]
60month (Jul11-Jun16)	[redacted]

Confidential Version – Subject to Protective Order No. 16-128

Oregon Transition Adjustment Mechanism Workshop

REC Transfers for Direct Access Customers

March 7, 2017




PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

REC Transfer Alternatives

- Concept: when a Direct Access customer opts-out, the loss of load results in “freed-up” RECs that the company does not have to retire in that compliance year

- The company has identified two different options for determining which RECs can be transferred to an ESS
  - 1) Pro-rata share of RECs generated or acquired during the opt-out year(s)
  - 2) Pro-rata share of RECs used for compliance during the opt-out year(s)

- Both of these options are likely to be overly complex and administratively burdensome in light of the very small volume of RECs that are likely to be transferred
  - Not all RECs are created equal and with the passage of SB 1547 there are many different REC categories
    - Geographic and type variation of resources
    - Golden RECs v. 5-year RECs
    - Elimination of first-in first-out rule creates additional complexity in terms of which RECs are retired in a particular compliance year

Option 1: Share of RECs Generated

- Table below shows an example (amounts are all hypothetical) all of the categories of Oregon-allocated RPS RECs generated in 2018

2018 Vintage		5-year Life Bundled	Golden Bundled	5-year Life Unbundled	Golden Unbundled	2018 Vintage		5-year Life Bundled	Golden Bundled	5-year Life Unbundled	Golden Unbundled
Base Resources	Biogas	3,500	0	0	0	Oregon Situs (Including ETO)	Biogas	0	0	0	0
	Geothermal	18,000	0	0	0		Geothermal	0	0	0	0
	Wind	1,000,000	0	0	0		Wind	100,000	0	0	0
	Hydro - Low Impact	200,000	0	0	0		Hydro - Low Impact	0	0	0	0
	Hydro - Incremental	8,000	0	0	0		Hydro - Incremental	0	0	0	0
	Solar - OSIP	0	0	0	0		Solar - OSIP	14,500	0	0	0
	Solar - Utility	0	0	0	0		Solar - Utility	9,200	0	0	0
Resources with COD Between SB 1547 Passing and 12/31/22	Biogas	0	0	0	0	2016 REC RFP Purchase	Biogas	0	0	0	0
	Geothermal	0	0	0	0		Geothermal	0	0	0	0
	Wind	0	110,000	0	0		Wind	0	0	0	0
	Hydro - Low Impact	0	0	0	0		Hydro - Low Impact	0	0	0	0
	Hydro - Incremental	0	0	0	0		Hydro - Incremental	0	0	0	0
	Solar - OSIP	0	0	0	0		Solar - OSIP	0	0	0	0
	Solar - Utility	0	30,000	0	0		Solar - Utility	24,000	80,000	75,000	140,000
Total 2018 RECs		1,812,200									

- Given the various ‘buckets’ and sheer number of resources, transferring a pro-rata share of RECs generated in a given year creates a significant administrative burden
- RECs would need to be transferred from over 60 generating resources.

Option 2: Share of RECs Used for Compliance

- To demonstrate the impact of Direct Access on Pacific Power's RPS compliance, we use compliance year 2018 as an example, to illustrate the compliance position with and without an ESS's 2018 Direct Access load (load amounts are not actual forecasts):

	Without Direct Access	With Direct Access
2018 Oregon Retail Sales	13,000,000	13,200,000
2018 RPS Target Percentage	1,950,000	1,980,000
2018 RECs Retired	1,950,000	1,980,000
Delta	-30,000	
Delta (Percentage)	1.54%	
	(30,000 / 1,950,000)	

- Under this option, 1.54% of RECs retired from each RPS resource in 2018 would be transferred to the ESS
- Creates the same administrative challenges of Option 1 (too many REC buckets)
- Assumes there ARE adequate RECs from each resource in a compliance year to be transferred.
- Creates accounting issues with fractional/partial RECs

Company Proposal

- REC transfer options are administratively burdensome and overly complex given the very small quantity of RECs to be transferred
- PacifiCorp will not be able to transfer bundled RECs—when an ESS has bundled REC requirements, they may not be satisfied with the REC transfer option; therefore REC transfer option is only a short-term solution
- Company will propose to value RECs based on present value of future compliance need—the below table shows examples of how the incremental savings would be calculated based on a range of REC prices:

Cost of Future Need ($/REC)	Incremental Cost Savings ($/MWh of DA load)
$1	$0.08
$5	$0.40
$10	$0.79
$15	$1.19

- RECs will be valued based on recent REC RFP (weighted average $/REC in year of need)
- Applies to 1- and 3-year opt-out customers
- 5-year opt-out customers ineligible for this adjustment since these customers do not contribute to schedule 203
    - Subject to revision if the company acquires OR-situs renewable resource

Docket No. UE 323
Exhibit PAC/108
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Step Log Change

March 2017

	2018 TAM Step Log		
ORTAM17			$ 1,535,568,814
	Description	**Detail**	**Impact**
	Routine Updates		11,812,792.59
Step 1	Transmission link capacity updates	COB --> West Main (from 189 to 205 MW in average), West Main --> COB (from 294 to 324 MW in average), Colorado --> Mona (from 29 to 25 MW), Utah North --> Borah (from 400 to 475 MW from 11/2018 on), West Main --> MidC (from 151 to 123 MW)	26,589
Step 2	Thermal Attributes updates	Craig 2 nameplate capacity = 81.55 MW (was 82.04 MW), Jim Bridger 3 & 4 minimum operation level = 150 MW (was 80 MW).	692,391
Step 3	QF contract updates	New: Sweetwater solar QF COD=11/1/2018, Terminated: Rough and Ready Biomass QF (was 11/30/2018), COD change: OR Solar 8 - Dairy 7/31/2017 (was 12/31/2018), COD Change: Merrill Solar QF 7/31/2018 (was 7/1/2020) COD change: NW Energy 4 - Bonanza 7/31/2018 (was 11/30/2017), COD change: Bear Creek Solar 10/31/2017 (was 4/1/2018)	405,731
Step 4	BPA Rate Case	Proposed BPA-18 rates applied from 10/2017 onward	1,546,571
Step 5	Idaho Power joining EIM	Idaho Power joining EIM in 4/18	(410,270)
Step 6	DA/RT 60month	DART historicial period based on 60month (was 48month)	(4,050,228)
ORTAM18			$ 1,545,592,389

Docket No. UE 323
Exhibit PAC/109
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

March 1 Notice Letter

March 2017

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 1, 2017

VIA ELECTRONIC MAIL

Attn: Parties to Docket UE 307

**RE: 2018 Transition Adjustment Mechanism
Pacific Power's Notice of Methodology Changes**

Under the Transition Adjustment Mechanism (TAM) Guidelines, PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) provides this Notice of Methodology Changes for the 2018 TAM. This notice complies with an amendment to the TAM Guidelines adopted by the Public Utility Commission of Oregon (Commission) in Order No. 09-432. This amendment provides that "[t]he Company will provide notice of substantial changes to the methodologies used to calculate the cost elements and other inputs to the GRID[1] model or to the logic of the GRID model by March 1st of the year of a stand-alone TAM filing." Under another amendment to the TAM Guidelines adopted in Order No. 13-474 in Docket UE 263, the Commission removed the requirement for filing general rate cases concurrently with the TAM by March 1, allowing the Company to file a general rate case at any time during the year. Because the Company does not plan to file a general rate case by the April 1 filing date for the 2018 TAM, the Company is treating the 2018 TAM as a stand-alone filing for purposes of the methodology change notice requirement.

Per Order No. 16-482 (2017 TAM Order), the Company has held a series of collaborative workshops with parties[2] to examine the Day-Ahead/Real-Time Transaction (DA/RT) adjustment, the Energy Imbalance Market (EIM) benefit estimation, and the valuation of Renewable Energy Credits (REC) for direct access customers. The Company also convened separate workshops, as ordered by the Commission, to discuss the Company's approach to developing its long-term fuel strategy for the Jim Bridger plant. While discussions continue between the Company and parties regarding DA/RT and EIM, potential changes to these calculations are listed below. The final workshop is scheduled for March 7, 2017; if parties agree, the following changes will be made:

- <u>Day-Ahead and Real-Time Balancing Transactions</u> – To increase normalization, the DA/RT adjustment will be based on a 60 month history as opposed to a 48 month history as used in the 2017 TAM.
- <u>EIM Benefits</u> – The EIM benefit realized from exporting energy to the CAISO[3] will no longer be based on available transmission capacity in GRID. The EIM benefit from exports to CAISO will be based on a dollars per month approach, which is the same method used to estimate the benefit of exports to other EIM participants. To mitigate the potential of overstating the sales benefit at the COB[4] market, the COB market cap in

[1] Generation and Regulation Initiative Decision tools model.
[2] Parties participating in the workshops include Commission Staff, Citizens' Utility Board of Oregon, Industrial Customers of Northwest Utilities and Calpine Energy Solutions LLC.
[3] California Independent System Operator.
[4] California-Oregon Border.

GRID will be based on a historic period that corresponds to EIM participation - November 2014 to June 2016 in place of a 48 month history.

In addition, the Company plans to continue discussions with parties concerning the valuation of RECs for direct access customers. To comply with Order No. 16-482 that the REC valuation "focus on the potential benefits that it may derive at the time PacifiCorp must take substantive action to comply with its RPS targets", the Company may propose a REC value for direct access customers equal to net present value of the future benefit. The Company may also propose a different methodology for REC valuation based on continued discussion with the parties.

The Company will include an exhibit to testimony in the direct filing identifying all changes based on discussions with parties as outlined above.

The Company also provides notice of the following planned changes to the 2018 TAM:

- Coal fuel costs at the Jim Bridger plant will reflect updated depreciation expense that corresponds to the operations of the underground mine; and
- Amortization of prepaid wheeling expenses associated with the Cholla coal plant will reflect an amortization period that correlates with the Oregon depreciable life of the plant. Previously, the amortization schedule erroneously correlated to the non-Oregon depreciable life of the plant.

Please direct informal correspondence and questions regarding this notice to Natasha Siores at 503-813-6583.

Sincerely,

R. Bryce Dalley
Vice President, Regulation

cc: UE 307 Service List

Docket No. UE 323
Exhibit PAC/110
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

Time Series of Fixed Generation Costs

March 2017

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

	2006 Fixed Generation Costs ($)	2007 Fixed Generation Costs ($)	2008 Fixed Generation Costs ($)	2009 Fixed Generation Costs ($)	2010 Fixed Generation Costs ($)	2011 Fixed Generation Costs ($)	2012 Fixed Generation Costs ($)	2013 Fixed Generation Costs ($)	2014 Fixed Generation Costs ($)	2015 Fixed Generation Costs ($)
Total Rate Base	719,894,639	1,336,508,766	1,648,371,025	1,713,216,752	1,736,954,242	1,815,681,297	1,794,346,075	1,741,041,460	1,826,116,636	1,739,528,889
Return On Rate Base	64,124,515	109,072,480	133,092,971	140,980,607	144,705,658	145,853,679	138,451,743	133,485,908	138,457,223	130,996,877
Operating & Maintenance Expense	92,140,549	112,008,196	125,482,619	121,104,940	152,130,476	150,819,888	138,323,152	141,947,327	135,214,927	131,405,825
Depreciation Expense	38,586,197	63,647,725	73,558,287	78,272,259	82,673,386	87,223,385	97,979,807	117,977,610	124,957,867	126,319,661
Amortization Expense	5,662,778	9,141,066	9,063,926	8,407,431	9,090,180	8,660,604	7,679,640	8,268,200	8,969,338	8,521,880
Taxes Other Than Income	9,609,011	11,989,900	14,060,167	15,439,056	17,203,839	19,052,597	19,151,857	19,728,897	20,128,593	20,996,832
Federal Income Taxes	10,360,962	22,917,351	(8,228,622)	(47,947,716)	(101,224,567)	(80,071,075)	(52,659,018)	(22,320,370)	(34,470,831)	(13,355,054)
State Income Taxes	1,354,613	4,376,898	429,505	(4,447,668)	(11,062,618)	(8,721,273)	(4,834,371)	(770,019)	(647,970)	412,968
Deferred Income Taxes	(764,258)	10,795,533	68,400,565	87,034,858	125,582,322	104,256,684	72,928,113	37,266,342	65,285,463	37,775,968
Misc Revenue & Expenses	(394,395)	(2,708,250)	(3,682,256)	(2,066,374)	(1,323,121)	(705,446)	(370,209)	(125,422)	(80,155)	(233,471)
Revenue Credits	(3,487,558)	(14,358,942)	(13,512,764)	(24,765,022)	(17,404,366)	(17,533,328)	(16,390,747)	(14,380,891)	(11,649,449)	(9,314,713)
Revenue Requirement	217,192,412	326,881,959	398,664,399	372,012,372	400,371,190	408,835,716	400,259,968	421,077,583	446,165,007	433,526,775
MWH @ Input	14,779,272	15,543,706	15,342,576	14,715,193	14,576,188	14,403,902	14,537,470	14,555,494	14,744,774	14,702,656
Revenue Requirement $/MWH	14.70	21.03	25.98	25.28	27.47	28.38	27.53	28.93	30.26	29.49

Note: 2006 data based on March 2006 Results of Operations; All other years based on December Results of Operations.

Docket No. UE 323
Exhibit PAC/111
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Michael G. Wilding

List of Expected or Known Contract Updates

March 2017

List of Known Items Expected to be Updated During the 2018 Oregon TAM

Sales and Purchases of Electricity and Natural Gas

1. New electricity sales and purchase contracts, physical and financial, including contracts with qualifying facilities.
2. Changes in contract terms of existing electricity sales and purchase and exchange contracts.
3. New natural gas sales and purchase contracts, physical and financial.
4. Changes in contract terms of existing natural gas sales and purchase contracts.
5. Contracts whose prices are linked to market indexes and inflation rates.
6. Sales contract with Black Hills Company for energy price and fixed payments.
7. Purchase contracts for generation and fixed costs from the Mid Columbia projects.
8. Purchase contract with Tri-State Generation and Transmission Association Inc. for energy price.
9. Purchase expenses of PGE Cove based on PGE projection.
10. Election decision for Grant Meaningful Priority.

Transportation and Storage of Natural Gas

11. New pipeline and storage contracts for transporting natural gas from market to Company's generating facilities.
12. Changes in contract terms of existing pipeline and storage contracts.
13. Contracts whose prices are linked to market indexes and inflation rates.

Wheeling Expenses and Transmission

14. New transmission contracts to wheel power to serve the Company's load obligations.
15. Changes in contract terms of existing transmission contracts.
16. Wheeling expenses that are impacted by changes in third-parties' transmission tariff rates.
17. Contracts whose prices are linked to market indexes and inflation rates.
18. The Company plans to update the Bonneville Power Administration (BPA) wheeling expenses to reflect BPA's final Record of Decision in its rate case, which is expected to be released July 26, 2017.

<u>Other</u>

19. Energy Imbalance Market benefit estimates, including import and export margins and volumes, as well as flexibility reserve diversity credits.

<u>Coal Expense Update Items</u>

The table below lists the coal and transportation contracts that may be affected by changes in volumes as well as changes to market indexes and inflation rates.

		Captive		Fixed Price Coal Contracts		Variable Price Coal Contracts		Transportation Contracts	
Plant	Supplier/Mine	Volume	Price	Volume	Price	Volume	Price	Volume	Price
Bridger	Bridger Coal Company/Bridger	√							
	Lighthouse Resources/Black Butte					√	√		
	Union Pacific Railroad							√	√
Cholla	Peabody/Lee Ranch					√	√		
	BNSF Railway							√	√
Colstrip	Westmoreland/Rosebud					√	√	√	√
Craig	Trapper Mining Inc/Trapper	√							
Hayden	Peabody/Twentymile					√	√		
	Union Pacific Railroad							√	√
Hunter	Bowie/Sufco, Dugout, Skyline			√	√				
Huntington	Bowie/Sufco, Dugout, Skyline			√	√				
	Rhino Energy/Castle Valley			√	√				
	Utah Trucking							√	√
D Johnston	Unidentified PRB					√	√		
	Cloud Peak/Cordero								
	Western Fuels/Dry Fork						√		
	BNSF Railway							√	√
Naughton	Westmoreland/Kemmerer					√	√		
Wyodak	Black Hills/Wyodak					√	√		

Docket No. UE 323
Exhibit PAC/200
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Dana M. Ralston

March 2017

DIRECT TESTIMONY OF DANA M. RALSTON

TABLE OF CONTENTS

ATTACHED EXHIBIT

Confidential Exhibit PAC/201—Presentations Provided at Fuel Planning Workshops

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

A. My name is Dana M. Ralston. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah 84116. My title is Vice President of Coal Generation and Mining.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Science Degree in Electrical Engineering from South Dakota State University. I have been PacifiCorp's Vice President of Coal Generation and Mining since March 2015, and I was the Vice President of Generation from January 2010 to March 2015. For 34 years before that, I held a number of positions of increasing responsibility within Berkshire Hathaway Energy's generation organization, including the plant manager position at the Neal Energy Center, a 1,600 megawatt generating complex. In my current role, I am responsible for operating and maintaining PacifiCorp's coal-fueled generation fleet, coal fuel supply, and mining.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified in proceedings before the public utility commissions in Utah, Oregon, Washington, and Wyoming.

PURPOSE AND SUMMARY

Q. What is the purpose of your testimony?

A. I explain PacifiCorp's overall approach to providing the coal supply for its coal-fueled generating plants, and I support the level of coal costs included in fuel expense in this docket, PacifiCorp's 2018 Transition Adjustment Mechanism (TAM). To demonstrate the reasonableness of these costs, my testimony will:

- Explain the primary causes behind the changes to the total-company coal-fuel expense reflected in the 2018 TAM;
- Review the status of the Jim Bridger Long-Term Fuel Plan, explain the company's near-term plan for fuel supply to the Jim Bridger plant, and discuss the 2018 fuel supply costs for the Jim Bridger plant; and
- Provide background on third-party coal contracts, current contract price re-openers, and coal prices at the Trapper mine.

OVERVIEW OF PACIFICORP'S COAL SUPPLIES

Q. How does PacifiCorp plan to meet fuel supplies for its coal plants in 2018?

A. PacifiCorp employs a diversified coal supply strategy, as reflected below in Confidential Table 1. PacifiCorp will supply 84.5 percent of its 2018 coal requirements with third-party coal supplies and 15.5 percent with coal from its affiliate mines. More specifically: (1) 43.4 percent of the total coal requirement will be supplied under fixed-price contracts; (2) 32.2 percent will be supplied under contracts that escalate or de-escalate based on changes to producer and consumer price indices; and (3) 8.9 percent of the total coal requirement will be supplied from new contracts for the Dave Johnston and Jim Bridger plants to be negotiated during 2017.

Confidential Table 1: Coal Source Deliveries

	Plant	Price Reopener	New Contract	MMBtus (000's)	(000's)	Percent
Affiliate Mines						
Bridger Coal/Bridger	Jim Bridger			[redacted]		
Trapper Mining Inc/Trapper	Craig					
Subtotal Affiliate Mines					[redacted]	15.5%
Fixed Price Contracts						
Lighthouse Resources/Black Butte	Jim Bridger			[redacted]		
Rhino Energy/Castle Valley	Huntington	√				
Bowie/Sufco, Dugout, Skyline	Huntington					
Bowie/Sufco, Dugout, Skyline	Hunter					
Cloud Peak/Cordero Rojo	Dave Johnston					
Subtotal Fixed Price Contracts					[redacted]	43.4%
Variable Price Contracts						
Peabody/Lee Ranch	Cholla	√		[redacted]		
Westmoreland/Rosebud	Colstrip					
Peabody/Twentymile	Hayden	√				
Western Fuels/Dry Fork	Dave Johnston					
Westmoreland/Kemmerer	Naughton					
Black Hills/Wyodak	Wyodak					
Subtotal Variable Price Contracts					[redacted]	32.2%
Other						
Unidentified PRB Mines	Dave Johnston		√	[redacted]		
Black Butte	Jim Bridger		√			
Total Other					[redacted]	8.9%
Total Coal Supplies					[redacted]	100%

Note: Delivered MMBtus are calculated from consumption estimates provided by the generation requirements in GRID to accommodate targeted inventory stockpiles

Q. Has total coal-fuel expense in the 2018 TAM increased from the level reflected in PacifiCorp's 2017 TAM?

A. Yes. As stated in the testimony of Mr. Michael G. Wilding, coal-fuel expense has increased by $18.2 million—from $789.2 million in the 2017 TAM final update to $807.4 million in this initial filing in the 2018 TAM. This increase is a result of approximately $28.5 million in higher coal prices that are partially offset by a reduction of $10.3 million due to lower coal-fueled generation volumes. All dollar and volume amounts in my testimony are on a total-company basis.

JIM BRIDGER FUEL SUPPLY

Long-Term Fuel Plan

Q. Is PacifiCorp currently developing a new long-term fuel plan for the Jim Bridger plant?

A. Yes. PacifiCorp is developing a new long-term fuel plan to determine the least-cost, least-risk strategy for fueling the Jim Bridger plant. In the plan, the company will address how to best meet the plant's lower fuel requirements, which result from reduced dispatch and the shorter operating lives for Jim Bridger Units 1 and 2 reflected in the preferred portfolio in PacifiCorp's 2017 Integrated Resource Plan (IRP), which will be filed April 4, 2017.

Q. Does PacifiCorp's development of a new long-term fuel plan for the Jim Bridger plant comply with Order No. 16-482 in the 2017 TAM?

A. Yes. In Order No. 16-482, the Public Utility Commission of Oregon (Commission) directed PacifiCorp to delay filing a new long-term fuel plan to allow the company to informally meet with Commission Staff (Staff) and other parties. The Commission ordered the parties to discuss information and analyses required to meaningfully evaluate the long-term fuel plan.

Q. Did PacifiCorp informally meet with Staff and other parties regarding the new long-term plan as directed by the Commission?

A. Yes. The company met with parties for workshops on January 20, 2017, and March 1, 2017. PacifiCorp's confidential presentations from these workshops are attached as Confidential Exhibit PAC/201. During the Commission's January 24, 2017 public meeting, Staff reported on the first workshop.

Q. When does PacifiCorp expect to complete its new long-term fuel plan?

A. The company expects to complete the long-term fuel plan by the end of 2017. This timing will better align the long-term fuel plan with the 2017 IRP, allow updated detailed studies and analyses as plan inputs, and permit additional meetings with parties as the plan evolves.

Q. What was the first step PacifiCorp took in preparing its new long-term fuel plan?

A. PacifiCorp first identified a set of options to determine the least-cost, least-risk fuel plan assuming some level of coal supply from Bridger Coal Company. This analysis led to four scenarios, each with a different mine plan and a different closure date for the Bridger Coal Company underground mine. The company then selected the least-cost, least-risk scenario. This scenario, referred to as "Option D," contemplates a continuation of the company's current approach to supplying the Jim Bridger plant, which relies on a combination of supplies from Bridger Coal Company and the Black Butte mine, with supplemental coal from the Southern Powder River Basin (SPRB) as necessary and feasible. Under Option D, the underground mine [redacted], and PacifiCorp contracts for an average of [redacted] tons annually from the [redacted]. The company reviewed the comparative analysis of the four options with the parties at the March 1, 2017 workshop. Option D is now the current fuel plan for the Jim Bridger plant, pending conclusion of the long-term fuel plan.

Q. What is the next step in developing the long-term fuel plan?

A. PacifiCorp plans to compare the optimum scenario for continued reliance on Bridger Coal Company, Option D, with [redacted]

[redacted]. To conduct this comparative analysis, PacifiCorp is now developing updated studies and information [redacted]. The company expects to have this information gathered by August 2017.

Q. How will PacifiCorp complete the long-term fuel plan?

A. Once the company has the information it needs for [redacted], it will prepare the comparative analysis between [redacted] and Option D. PacifiCorp plans to meet again with parties as the long-term fuel plan moves into this final stage.

Q. What is the company's near-term fuel strategy for the Jim Bridger plant?

A. PacifiCorp's goal is to provide the least-cost, least-risk fuel supply to the Jim Bridger plant for the next [redacted], which will allow time for the company to assess and implement any changes in the long-term fuel strategy. Because of the capital improvements required, a market option is estimated to take at least four years to implement on an expedited basis. Option D contemplates [redacted].

Q. Are third-party supply options for the Jim Bridger plant limited?

A. Yes. There are only three potential third-party coal suppliers that can feasibly serve the Jim Bridger plant: the Black Butte mine; the Kemmerer mine; and SPRB mines. Each of these suppliers has unique constraints that limit their availability:

- Because the Jim Bridger plant is [redacted] at less than approximately [redacted] tons per year (PacifiCorp's two-thirds share).
- Coal from the Kemmerer mine [redacted].
- Without coal-handling upgrades, the Jim Bridger plant cannot safely accept more than approximately [redacted] of SPRB coal per year (PacifiCorp's share). Aside from the coal-handling issue, the current rail infrastructure limits deliveries to [redacted] tons annually (PacifiCorp's share) due to the [redacted].

Q. **Given these limitations, what is the least-cost, least-risk near-term supply option for the Jim Bridger plant?**

A. The optimum near-term strategy is a continuation of PacifiCorp's current fueling strategy, with approximately two-thirds of the fuel supply sourced from Bridger Coal Company and one-third from the Black Butte mine. While the company considered [redacted]. Therefore, the [redacted] if required and if determined to be economically feasible.

Jim Bridger Third-Party Coal Supply in 2018

Q. Do the Black Butte coal supply and rail agreements expire this year?

A. Yes. The current Black Butte coal supply agreement expires at the end of 2017. It contains a fixed price for the three-year contract term. Under the contract, approximately [redacted] tons (PacifiCorp's share) from the 2015-2017 contract years will be deferred to 2018. The fixed contract price will remain in effect for those deferred tons delivered in 2018, mitigating the price increase associated with a new contract. The Union Pacific Railroad (UPRR) transportation agreement expires concurrently with the Black Butte coal supply agreement.

Q. How does PacifiCorp propose to respond to the expiration of this contract?

A. Consistent with PacifiCorp's near-term fuel strategy outlined above, the company is currently negotiating a new contract with the Black Butte mine [redacted].

Q. What is the expected increase in third-party coal prices for the Jim Bridger plant?

A. For this initial filing, the company forecasts an [redacted] in the Black Butte coal supply contract, with no incremental SPRB coal supply. The company also projects a [redacted] in the UPRR rail agreement, which aligns with PacifiCorp's recent experience negotiating rail contracts with UPRR plus additional escalations in diesel fuel and rail index inflation. Based on these forecasts, Jim Bridger plant third-party coal prices increase [redacted], or [redacted], compared to the 2017 TAM. The price of Black Butte coal delivered to the Jim Bridger plant increases [redacted] per ton, from [redacted] per ton in the 2017 TAM to [redacted] per ton in the 2018 TAM. The overall price increase in third-party coal is approximately [redacted]. Additionally, the new rail agreement is forecast to result in a [redacted] increase in delivered costs.

Bridger Coal Company

Q. Please describe the change in Bridger Coal Company costs in the 2018 TAM.

A. Bridger Coal Company costs show a slight increase of [redacted] per ton, from [redacted] per ton in the 2017 TAM to [redacted] per ton in the 2018 TAM ([redacted] overall). Bridger Coal Company's heat content is [redacted] British Thermal Units (Btu) per pound in the 2017 TAM and [redacted] Btu per pound in the 2018 TAM.

Q. Please explain how Bridger Coal Company's production levels have changed in the 2018 TAM.

A. Bridger Coal Company's mine production has decreased from [redacted] tons in the 2017 TAM to [redacted] tons in the 2018 TAM, a reduction of [redacted]. Additionally, Bridger Coal Company deliveries have decreased from [redacted] tons in the 2017 TAM to [redacted] tons in the 2018 TAM, a reduction of [redacted]. These changes are shown in Confidential Table 2 below.

Confidential Table 2: Bridger Coal Production

	Deliveries to Bridger Plant			Mine Production		
	2018 TAM	2017 TAM	Variance	2018 TAM	2017 TAM	Variance
Bridger Coal	[redacted]					
Surface Mine						
Underground Mine						

Q. Please summarize the operational changes at the surface mine between the 2018 and 2017 TAM filings.

A. As noted in Confidential Table 2, surface mine coal deliveries [redacted] by [redacted]. In the 2018 TAM, the company assumes the draglines operate three 12-hour shifts per day, seven days per week. In the 2017 TAM, the company assumed the draglines operated on two 12-hour shifts per day, seven days per week. The truck/loader and scraper fleets operate on the same shift schedules in both the 2018 and 2017 TAM filings.

Q. Please summarize the operational changes at the underground mine between the 2018 and 2017 TAM filings.

A. As noted in Confidential Table 2, underground mine coal deliveries [redacted] by [redacted]. In the 2018 TAM, the company assumes longwall coal production is transitioned to the eastern district after the [redacted] Right longwall panel is mined. In the 2017 TAM, the company assumed longwall coal production transitioned to the eastern district after the [redacted] Right panel was mined. The change to fewer projected longwall and continuous miner shifts in the 2018 TAM reflect PacifiCorp's efforts to reduce operational risk.

Q. Why does the transition from the western to the eastern district accelerate in the 2018 TAM?

A. As discussed above, in the first phase of its long-term fuel planning process, PacifiCorp evaluated several fueling options assuming various production levels between surface and underground mining operations at Bridger Coal Company. The company selected Option D as the least-cost, least-risk option, which includes the accelerated transition.

Q. Please explain the reasons for the minimal cost increase at Bridger Coal Company.

A. The minimal cost increase is primarily driven by operational changes between the 2018 and 2017 TAM filings. In the 2018 TAM, surface mine coal deliveries increase by [redacted] tons or [redacted], and the underground mine deliveries decrease by [redacted] tons or [redacted]. The change in mix between the surface and underground mines results in slightly higher costs but significantly reduced operational risk. Cost increases are primarily due to changes in coal inventory, royalty, severance tax and extraction taxes that are partially offset by reductions for labor, depreciation and other miscellaneous items.

Q. Please explain the cost increase associated with changes in coal inventory between the 2018 TAM and the 2017 TAM.

A. Approximately [redacted], or [redacted] per ton, can be attributed to changes in Bridger Coal Company's coal inventory. The 2017 TAM reflected a decrease in underground inventory levels of 70,222 tons and a projected decrease in surface inventory levels of 26,800 tons. The decrease in inventory levels in the 2017 TAM resulted in approximately [redacted] being credited to coal inventory and debited to coal expense. The 2018 TAM reflects a decrease in underground inventory levels of 135,527 tons and a decrease in surface inventory levels of 26,799 tons. The decrease in inventory levels in the 2018 TAM results in a credit of [redacted] to coal inventory and a debit to coal expense.

Q. Why have royalty costs increased in the 2018 TAM?

A. Royalty costs increased from [redacted] in the 2017 TAM to [redacted] per ton in the 2018 TAM, or [redacted] per ton. The increase is due to producing [redacted] more coal from the surface mine, which is charged a higher royalty rate than coal from the underground mine, and more coal from federal and state leases compared to the 2017 TAM. Coal extracted from federal and state leases is assessed a royalty rate of 12.5 percent from surface mines and 8.0 percent from underground mines. Federal and state royalties are based on a cost-plus-return valuation methodology. Private royalties are based on a contract price adjusted for changes in specified indices.

Q. Did severance and extraction tax costs increase in the 2018 TAM?

A. Yes. Severance and extraction costs increased [redacted] per ton, from [redacted] per ton in the 2017 TAM to [redacted] per ton in the 2018 TAM. The increase is due to a change in the market-based imputed sales price and producing [redacted] more tons from the surface mine in the 2018 TAM relative to the 2017 TAM. Coal extracted from surface operations is subject to a 7.00 percent severance tax rate, and coal extracted from underground operations is subject to a 3.75 percent severance tax rate.

Q. Do labor and benefit costs increase in the 2018 TAM?

A. No. Projected expenditures are [redacted] lower in the 2018 TAM compared to the 2017 TAM. Costs expressed on a per-ton basis are projected to decrease by [redacted] per ton. The cost-per-ton decrease is primarily driven by changes in the underground mine plan. As the underground mine transitions to the eastern district in 2018 and underground coal production decreases by [redacted] tons, the staffing level at the mine is reduced by [redacted] positions relative to the 2017 TAM. This decrease is possible because the active mining area in the underground mine is significantly reduced once production is terminated in the western district. Staffing levels have also been adjusted to reflect decreased underground mine production and reduced continuous miner development requirements. However, the surface mine is projected to produce [redacted] and deliver [redacted] more tons in the 2018 TAM than in the 2017 TAM. To accomplish this, the surface mine will operate a dragline one more 12-hour shift per day, seven days per week in the 2018 TAM. The workforce level at the surface mine is projected to increase by [redacted] positions. The net staffing reduction at Bridger Coal Company between the 2018 TAM and the 2017 TAM is [redacted] positions.

Q. Do depreciation and depletion costs expressed on a cost-per-ton basis decrease in the 2018 TAM?

A. Yes. Depreciation and depletion costs decrease [redacted] per ton, from [redacted] per ton in the 2017 TAM to [redacted] per ton in the 2018 TAM. The decrease is primarily due to reduced capital spending in the 2018 TAM partially offset by a slight increase associated with terminating the underground mine's life in [redacted] in the 2018 TAM versus [redacted] in the 2017 TAM, and accelerating the transition from the western district. Additionally, the decrease is partially offset by an approximate [redacted]-per-ton increase for assets placed in-service in 2018 in the current TAM filing.

Q. Please summarize changes in other cost components in the 2018 TAM versus the 2017 TAM.

A. The net change in other cost components represents an increase of [redacted]. A slight increase for final reclamation is partially offset by reductions for materials and supplies, outside services, and other miscellaneous items.

Q. In Order No. 13-387, the Commission ordered the company to remove certain operations and maintenance costs embedded in the costs of coal from its affiliate mines.[1] In this filing, does the company adjust the price of coal from Bridger Coal Company consistent with Order No. 13-387?

A. Yes. In the 2018 TAM, the company reduces Bridger Coal Company costs by approximately [redacted] to reflect removal of management overtime and 50 percent of annual incentive plan awards.

TRAPPER MINE

Q. Have Trapper mine costs changed from the 2017 TAM?

A. Yes. Trapper mine costs have decreased [redacted] per ton, from [redacted] per ton in the 2017 TAM to [redacted] per ton in the 2018 TAM ([redacted] overall). This decrease is primarily attributable to increased production at Trapper mine as a result of the expiration of the third-party coal supply agreement with the Colowyo mine. Deliveries from Trapper mine have increased [redacted] from [redacted] tons in the 2017 TAM to [redacted] tons in the 2018 TAM. Increased coal production has a significant impact on delivered costs in the 2018 TAM. Due to the increase in volume, costs expressed on a per-ton basis will decrease.

THIRD-PARTY COAL CONTRACTS

Q. Please discuss the change in third-party coal-supply costs.

A. PacifiCorp expects a net increase in third-party coal-supply costs, as shown in Confidential Table 3 below:

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

Confidential Table 3: Third-Party Coal and Transportation Contract Price

Plant	Contract	Millions ($)
Naughton	Kemmerer Coal	[redacted]
Wyodak	Wyodak Coal	
Dave Johnston	Powder River Basin Coal	
Dave Johnston	BNSF Rail	
Jim Bridger	Black Butte Coal	
Jim Bridger	UPRR Rail	
Hunter	Bowie Coal	
Huntington	Bowie and Castle Valley Coal	
Cholla	Lee Ranch Coal	
Cholla	BNSF Rail	
Colstrip	Rosebud Coal	
Hayden	Twentymile Coal and UPRR Rail	
Craig	Colowyo Coal and UPRR Rail	
Total Third-Party Contract Price Increase/(Decrease)		

Q. Do some third-party coal contracts include minimum-take requirements?

A. Yes. [redacted] are fueled either partially or entirely with coal supply agreements or transportation agreements (or both) that contain minimum take-or-pay provisions based on certain annual tonnage volumes of coal delivered. In addition, the [redacted] plant's coal supply agreement and the transportation agreements for the [redacted] plants currently provide or will provide for payment of liquidated damages below certain minimum volumes.

Q. Do these minimum-take requirements affect coal costs in the 2018 TAM initial filing?

A. No. Based on current market-price and coal-dispatch projections, there are no adjustments in the company's 2018 TAM initial filing reflecting minimum-take requirements.

Coal Supply Agreements for the Wyoming Plants

Naughton

Q. Please describe the coal supply arrangement for the Naughton plant.

A. The Naughton plant is supplied by an overland conveyor by Westmoreland's adjacent Kemmerer mine under a long-term coal supply agreement through 2021. The current coal supply agreement includes a contract minimum of [redacted] tons and a maximum of [redacted] tons. The first [redacted] tons are priced at a tier-1 price, and tons above that level are delivered at a tier-2 price.

Naughton Unit 3 was initially slated to end coal-fueled generating activities December 31, 2017. In March 2017, the Wyoming Department of Environmental Quality revised the Naughton Unit 3 coal-burning deadline to January 2019 to align with the requirements of the Wyoming Regional Haze State Implementation Plan. Therefore, the 2018 TAM continues to reflect Naughton as a coal-fueled unit.

Q. Please describe the Naughton plant's coal cost change from the 2017 TAM.

A. Delivered coal cost at the Naughton plant increased [redacted] per ton, from [redacted] per ton in the 2017 TAM to [redacted] per ton in the 2018 TAM ([redacted] overall), as shown in Confidential Table 4. Automatic adjustments based on changes in contract-specific producer and consumer price indices, as well as production taxes and royalties, result in [redacted] of this increase. Higher diesel fuel, labor and medical index escalation is the primary driver of the increase. A change in the amount of coal purchased under each price tier—namely less tier-2 coal, which is lower priced than tier-1 coal—is the driver of [redacted] of the increase. The Kemmerer coal supply agreement calculates tier-1 and tier-2 volumes based on a July through June contract year. The forecast of tier-2 coal delivered in calendar year 2018 is lower than 2017 due to [redacted] under the contract because of Naughton Unit 3's anticipated cessation as a coal-fueled generation resource on December 31, 2017.

Confidential Table 4: Naughton Contract Tonnage

	2018 TAM			2017 TAM		
Contract Tiers	Tons	Dollars	Price	Tons	Dollars	Price
Naughton Plant	[redacted]			[redacted]		
Tier 1						
Tier 2						
Subtotal						
Other Coal Costs						
Kemmerer Btu Adjustment		[redacted]			[redacted]	
Iron & Calcium Premiums						
Subtotal						
Naughton Plant Cost	[redacted]					
Btu/lb						
$/MMBtu						

Wyodak

Q. Please describe the price increase related to the Wyodak plant contract.

A. Delivered coal cost has increased from [redacted] per ton in the 2017 TAM to [redacted] per ton in the 2018 TAM, or [redacted] overall. The cost increase is primarily the result of escalation in diesel fuel and labor contract indices.

Dave Johnston

Q. Please describe the Dave Johnston plant coal supply cost increases.

A. Dave Johnston plant delivered coal cost has increased by [redacted] compared to the 2017 TAM, or [redacted]. The increase is due to a coal cost increase of approximately [redacted] and an increase in rail costs of [redacted], as described in further detail below.

Q. Please explain the unidentified coal for the Dave Johnston plant included in Confidential Table 1.

A. The Dave Johnston plant is projected to consume approximately [redacted] tons in 2018. The company currently has [redacted] tons of coal for the plant under contract. The company intends to solicit multi-year coal supplies from various Powder River Basin (PRB) mines through a request for proposals (RFP) during the second quarter of 2017.

Q. What are the coal supply arrangements for the Dave Johnston plant in the 2018 TAM?

A. After the April 2015 RFP for PRB coal supplies, the company executed a coal supply agreement to purchase coal from Cloud Peak Energy's Cordero Rojo mine through 2018. The Cordero Rojo mine will supply [redacted] tons in 2018 ([redacted] of the plant's requirements). Following the April 2016 RFP, the company executed a coal supply agreement with Western Fuel's Dry Fork mine through 2019. The Dry Fork mine will supply [redacted] tons in 2018 ([redacted] of the plant's requirements). The coal price for the Dave Johnston plant's open position of approximately [redacted] tons in the 2018 TAM reflects the average 2018 forward price for PRB 8400 Btu coal of [redacted] per ton, as published in Coal Daily in February 2017. This 2018 price is [redacted] higher than the 2017 PRB 8400 Btu adjusted price quote received in the April 2016 RFP of [redacted] per ton that was used for the open position in the 2017 TAM.

The rail cost increase of [redacted] is primarily a result of a new BNSF Railway agreement to replace the existing contract that expires in 2017. The new rail price assumption includes an expected [redacted] increase due to the company's experience negotiating with BNSF plus escalations in diesel fuel and rail-index inflation.

Coal Supply Agreements for the Utah Plants

Q. Please explain how the company's Utah plants are supplied with coal.

A. The Utah plants are sourced collectively through a portfolio of coal sources under three different multi-year coal supply agreements. The primary coal supply for the Hunter plant is provided through a coal supply agreement with Bowie Coal Sales, LLC (Bowie). The agreement is a "delivered to plant" agreement, and Bowie is responsible for the transportation of the coal from the mine to the plant.

The primary coal supply to the Huntington plant is also provided under a contract with Bowie through 2029. Coal received under this agreement is designated for the Huntington plant. This is also a "delivered to the plant" agreement that requires Bowie to pay the transportation cost. The Huntington plant also receives coal under a coal supply agreement with Rhino Energy, LLC's Castle Valley mine.

Q. Please discuss the coal supply arrangement with Castle Valley.

A. The Castle Valley mine supplies [redacted] tons of coal annually through 2017 for PacifiCorp's Huntington plant. The contract terms contain a mutual right to extend the agreement during an "Option Term" from January 1, 2018, through December 31, 2020, to deliver [redacted] tons per year. The agreement prescribes a calculation for the new 2018 coal price. Based upon the forecast calculation of the 2018 coal price, PacifiCorp anticipates exercising its right to extend the agreement under the Option Term. The estimated 2018 Castle Valley coal price results in a cheaper delivered fuel price when compared to additional coal available under the current long-term coal supply agreements with Bowie.

Q. Does the 2018 TAM reflect Energy West pension costs?

A. Yes. As authorized by Order No. 15-161 in docket UM 1712, the 2018 TAM includes [redacted] for contributions to the 1974 United Mine Workers Association pension plan.[2] Approximately [redacted] is included in Huntington plant costs in the 2018 TAM, consistent with the 2017 TAM. Approximately [redacted] of the [redacted] in pension costs is included in Hunter plant costs in the 2018 TAM, consistent with the 2017 TAM.

Hunter

Q. Have prices for coal supply to the Hunter plant changed from levels reflected in the 2017 TAM?

A. Yes. Coal prices have slightly increased [redacted] per ton, from [redacted] per ton in the 2017 TAM to [redacted] per ton in the 2018 TAM ([redacted] overall). The increase at the Hunter plant is primarily due to the inflation-index escalation under the Bowie agreement. The Bowie coal price escalates from [redacted] per ton in the 2017 TAM to [redacted] per ton for the 2018 TAM. This results in an increase of [redacted] or approximately [redacted].

[2] *In the Matter of PacifiCorp d/b/a Pacific Power Application for Approval of Deer Creek Mine Transaction*, Order No. 15-161 at 1 (May 27, 2015), *clarified and amended*, Order No. 15-166 (June 1, 2015).

Q. Please describe how the expiration of the West Ridge contract at the end of 2016 affects coal deliveries at the Hunter plant.

A. The company's agreement with the West Ridge mine expired at the end of 2016; however, [redacted] tons of carryover coal will be delivered in 2017 with no coal delivered in 2018. This reduction in West Ridge coal in 2018 results in a cost increase of approximately [redacted] in the 2018 TAM.

Huntington

Q. What coal supply costs for the Huntington plant are included in the 2018 TAM?

A. For the Huntington plant, delivered coal prices increased from [redacted] per ton in the 2017 TAM to [redacted] per ton in the 2018 TAM, a slight increase of [redacted] per ton or [redacted]. The overall price per ton for the Bowie contract increased [redacted] per ton, from [redacted] per ton in the 2017 TAM to [redacted] per ton in the 2018 TAM ([redacted] overall). The Bowie price is higher primarily because of reduced tier-2 coal delivered due to approximately [redacted] lower generation volume at the Huntington plant. A cost savings of [redacted] is also achieved by delivering coal from the Rock Garden stockpile adjacent to the Huntington plant in place of the additional volume of Castle Valley coal in the 2017 TAM.

Coal Supply Agreements for the Jointly Owned Plants

Cholla

Q. Please describe the coal supply arrangement for the Cholla plant.

A. The Cholla plant is supplied under a coal supply agreement with Peabody's Lee Ranch and El Segundo mine complex through 2024, which includes two price re-openers: the first price re-opener was January 1, 2013; the second price re-opener is

January 1, 2018. PacifiCorp owns Unit 4, and Arizona Public Service (APS) owns Units 1, 2, and 3. PacifiCorp and APS are joint parties to the coal supply agreement with Peabody.

Q. Please explain the amendment to the Cholla coal supply agreement signed in 2017.

A. An amendment to the coal supply agreement was signed in February 2017, which became effective for the period January 1, 2017, to December 31, 2024. The amendment settled all prior claims between Peabody, PacifiCorp and APS related to Peabody's 2016 bankruptcy filing. The amendment [redacted] from the original agreement, established fixed amounts related to unrecovered captive mine investment, and capped the 2018 price re-opener at a [redacted] maximum increase.

Q. What price does the company assume for the Cholla coal supply in the 2018 TAM?

A. The company forecasts that delivered coal prices at the Cholla plant will increase [redacted] per ton, from [redacted] per ton in the 2017 TAM to [redacted] per ton in the current 2018 TAM ([redacted] overall). The coal supply agreement accounts for [redacted] of the increase, and [redacted] is a result of the new rail agreement. Of the [redacted], [redacted] is triggered by liquidated-damage payments for coal not purchased under the contract due to a [redacted] generation volume reduction at the Cholla plant compared to the 2017 TAM. Additionally, the company assumes that the January 1, 2018 price re-opener will contain the maximum step increase of [redacted] due to the generation volume reductions. As a reference, the January 1, 2013 price re-opener resulted in an increase of approximately [redacted]. The balance of the [redacted] is mainly attributable to escalation in diesel fuel, natural gas and other producer and consumer price indices under the agreement.

The [redacted] rail cost increase is primarily a result of a new BNSF Railway agreement to replace the existing contract that expires in 2017. The new rail price assumes an expected [redacted] increase due to the company's previous experience negotiating with BNSF at Cholla plus escalations in diesel fuel and rail-index inflation.

Hayden

Q. Please describe the change in Hayden plant's coal cost in the 2018 TAM.

A. Delivered coal prices decreased [redacted] per ton, from [redacted] per ton in the 2017 TAM to [redacted] per ton in the 2018 TAM, a reduction of [redacted]. The contract includes a price re-opener on January 1, 2018, which results in a decrease in costs of [redacted] or [redacted], primarily due to reductions in market-price projections. The price re-opener decrease is partially offset by price adjustments with changes in producer and consumer price indices of [redacted].

Colstrip

Q. Please describe the change in coal cost at the Colstrip plant in the 2018 TAM.

A. Coal prices for the Colstrip plant have increased slightly by [redacted] per ton, from [redacted] per ton in the 2017 TAM to [redacted] per ton in the 2018 TAM ([redacted] overall). Costs for the Colstrip plant are developed based on Western Energy's Annual Operating Plan (AOP) for the Rosebud mine. The AOP is reviewed and approved annually by the owners of Colstrip Units 3 and 4. The increase in 2018 is primarily attributable to an increase in the Rosebud mine's production cost.

Craig

Q. Please describe the coal supply arrangements for the Craig plant.

A. In 2018, the Craig plant will be supplied exclusively by the Trapper mine, which is an affiliate captive mine owned by the owners of the Craig plant. The pricing under the coal supply agreement is based upon the annual mine cost associated with the Trapper mine. The Colowyo mine coal supply agreement expires in 2017, which results in a decrease of [redacted] in the 2018 TAM.

SUMMARY

Q. Please summarize the benefits of PacifiCorp's coal fuel strategy.

A. Customers have significantly benefited from PacifiCorp's diversified fueling strategy, which relies upon fixed-price contracts, index-priced contracts, and affiliate-owned mines to meet the fuel needs of its coal-fueled generating plants. While various factors have contributed to an increase in coal costs in this filing, PacifiCorp's strategy has resulted in long-term, stable, low-cost coal supplies for its customers, as demonstrated in Confidential Table 5.

Confidential Table 5: Total Coal Fuel Variance Increase/(Decrease)

Plant	Contract	Millions ($)
Price Variance		
Affiliate Mines		
Jim Bridger	Bridger Coal Company	[redacted]
Craig	Trapper Coal	
Subtotal Affiliate Mines		
Third-Party Contracts		
Naughton	Kemmerer Coal	
Wyodak	Wyodak Coal	
Dave Johnston	Powder River Basin Coal	
Dave Johnston	BNSF Rail	
Jim Bridger	Black Butte Coal	
Jim Bridger	UPRR Rail	
Hunter	Bowie Coal	
Huntington	Bowie and Castle Valley Coal	
Cholla	Lee Ranch Coal	
Cholla	BNSF Rail	
Colstrip	Rosebud Coal	
Hayden	Twentymile Coal and UPRR Rail	
Craig	Colowyo Coal and UPRR Rail	
Subtotal Third-party Contracts		
Total Price Variance		
Volume Variance		
Jim Bridger		
Cholla		
Craig		
Hunter		
Huntington		
Naughton		
Other Plants		
Total Volume Variance		
Total Coal Fuel Variance		

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 323
Exhibit PAC/201
Witness: Dana M. Ralston

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Exhibit Accompanying Direct Testimony of Dana M. Ralston

Presentations Provided at Fuel Planning Workshops

March 2017

Oregon Transition Adjustment Mechanism
UE 307
Order No. 16-432

Jim Bridger Plant
Long-term Fueling Discussion

January 12, 2017

REDACTED

Background

- In Docket UE 287, PacifiCorp agreed to prepare periodic fuel supply plans for its affiliate mines as follows:
    - Use best available data to determine the least-cost, least-risk coal supplies for the plant
    - Prepare least-cost mine plans
    - Review market cost alternatives for coal, transportation and plant modifications
    - Review and compare fuel supply options with sensitivities
    - Prepare updates every 5 years or more often as necessary to address fuel plan changes
  - PacifiCorp filed a long-term fuel supply plan for the Jim Bridger plant in Oregon (Dec. 2015).
    - Base versus market alternative plan comparison; Base Plan was the preferred option
      - Base Plan – BCC S - [redacted], UG - [redacted], Black Butte - [redacted], PRB [redacted]
      - Market Plan – BCC S/UG - [redacted], Black Butte - [redacted], PRB [redacted]
      - Incremental plant capital
- In UE 307, Order No. 16-432 required the parties to:
    - Discuss information and analyses required to "meaningfully" evaluate Jim Bridger and other plant long-term fueling plans
    - Report back to the Commission on January 24, 2017

Proposed Jim Bridger Plant Fueling Options

- All Options
  - Same annual plant generation requirements

- Option A
  - Bridger Coal Company
    - Surface Mine
      - [redacted] draglines in full production
      - Deadman Wash coal production in [redacted], mine shuttered in [redacted]
    - Underground Mine
      - Depletes the majority of coal reserves in the western and eastern districts – shuttered in [redacted]
      - [redacted]
  - External Coal Supplies
    - Black Butte Coal Company
    - PRB Coal
  - Plant
    - Operating expenditures (incremental)
    - Capital expenditures (incremental)

Proposed Jim Bridger Plant Fueling Options

– Option B

- Bridger Coal Company
  - Surface Mine
    - » [redacted] draglines in full production
    - » Deadman Wash coal production in [redacted], mine shuttered in [redacted]
  - Underground Mine
    - » Operation shuttered in [redacted] after the [redacted] is mined in the western district
    - » [redacted]
- External Coal Supplies
  - Black Butte Coal Company
  - PRB Coal
- Plant
  - Operating expenditures (incremental)
  - Capital expenditures (incremental)

Proposed Jim Bridger Plant Fueling Options

– Option C

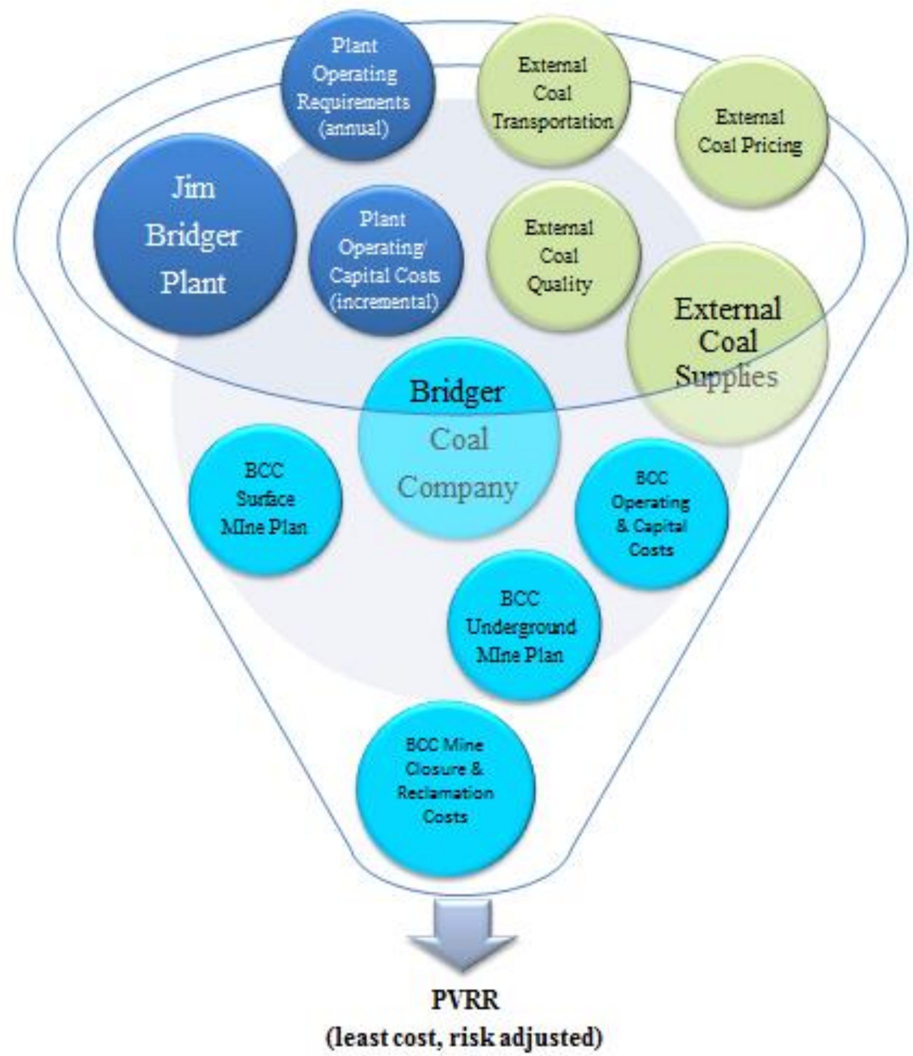
- Bridger Coal Company
  - Surface Mine
    - » [redacted] draglines in full production
    - » Deadman Wash coal production in [redacted], mine shuttered in [redacted]
  - Underground Mine
    - » [redacted] mined, [redacted] mined
    - » Operation shuttered in [redacted]
    - » [redacted]
- External Coal Supplies
  - Black Butte Coal Company
  - PRB Coal
- Plant
  - Operating expenditures (incremental)
  - Capital expenditures (incremental)

Proposed Jim Bridger Plant Fueling Options

– Option D

- **Bridger Coal Company**
  - Surface Mine
    - » [redacted] production thru [redacted], [redacted] draglines in full production thereafter
    - » Deadman Wash coal production in [redacted], mine shuttered in [redacted]
  - Underground Mine
    - » [redacted] [redacted] mined, [redacted] [redacted] mined
    - » Operation shuttered in [redacted]
    - » [redacted]
- **External Coal Supplies**
  - Black Butte Coal Company
  - PRB Coal
- **Plant**
  - Operating expenditures (incremental)
  - Capital expenditures (incremental)

PVRR Evaluation Inputs



Fueling Plan Workshop #2

March 1, 2017

REDACTED VERSION

PACIFICORP

Discussion Topics

- IRP Assumptions For Long-term Fueling Plan
  - Unit #1 closure [redacted]; Unit #2 closure [redacted]; Unit #3 & Unit #4 closure [redacted]
- Long-term Fueling Plan Assumptions for Bridger Coal Company (BCC)
  - Developed four different options for BCC
  - Identification of least cost/least risk BCC option and planned comparison to market option.
- Near-term Fueling Strategy For The Jim Bridger Plant
- Status of “Other” Significant Expiring Coal & Transportation Contracts

Timeline

Jim Bridger LT Fueling Plan Filed	Jim Bridger Fueling Plan for 2017 IRP	Current Jim Bridger Fueling Plan	Jim Bridger LT Fueling Plan
Dec 2015	To be filed March 2017 (Prepared using fuel data from Aug. 2016)	•Dec 2016	(To be filed Dec. 2017)

→ → →

Bridger Coal
Surface-[redacted]
Underground-[redacted]
External
[redacted]

Est. Annual
Consumed Tons*
[redacted]

Bridger Coal
Surface-[redacted]
Underground-[redacted]
External
[redacted]

Est. Annual
Consumed Tons*
[redacted]

Bridger Coal
Surface-[redacted]
Underground-[redacted]
External
[redacted]

Est. Annual
Consumed Tons*
[redacted]

Bridger Coal
Option D
Surface-[redacted]
Underground-[redacted]
Option E
Market Analysis
[redacted]

* Consumed tonnage based upon 4 units operating

Bridger Coal Company Option Assumptions

- Bridger Coal Company Annual Coal Production Based on [redacted] tons
  - Option A
    - Surface – [redacted]   Underground – [redacted]
  - Option B
    - Surface – [redacted]   Underground – [redacted]
  - Option C
    - Surface – [redacted]   Underground – [redacted]
  - Option D
    - Surface – [redacted]   Underground – [redacted]

Bridger Coal Company Option Overview

Assumptions	Option A (S - [redacted] U - [redacted])	Option B (S - [redacted] U - [redacted])	Option C (S - [redacted] U - [redacted])	Option D (S - [redacted] U - [redacted])
Bridger Coal Company - [redacted]				
Mine Plan Map	[redacted]	[redacted]	[redacted]	[redacted]
Surface Mine Schedule	DL's Half 4x4 - [redacted] DL's Full 4x4 - [redacted] DL's Final Reclam - [redacted]	DL's Full 4x4 - [redacted] DL's Final Reclam - [redacted]	DL's Full 4x4 - [redacted] DL's Final Reclam - [redacted]	One DL Half 4x4 - [redacted] One DL Full 4x4 - [redacted] DL's Full 4x4 - [redacted] DL's Final Reclam - [redacted]
Deadman Wash Production	[redacted]	[redacted]	[redacted]	[redacted]
Surface Tons (dlvd)	Total - [redacted] Existing reserves - [redacted] Deadman Wash - [redacted]	Total - [redacted] Existing reserves - [redacted] Deadman Wash - [redacted]	Total - [redacted] Existing reserves - [redacted] Deadman Wash - [redacted]	Total - [redacted] Existing reserves - [redacted] Deadman Wash - [redacted]
Highwall Mining	[redacted]	[redacted]	[redacted]	[redacted]
Draglines Transition to Reclamation	[redacted]	[redacted]	[redacted]	[redacted]
Underground Mine Schedule	LW - [redacted] 8 hrs/shift CM - [redacted] 8 hrs/shift	LW - [redacted] 8 hrs/shift CM - [redacted] 8 hrs/shift	LW - [redacted] 8 hrs/shift CM - [redacted] 8 hrs/shift	LW - [redacted] 8 hrs/shift CM - [redacted] 8 hrs/shift
DBT Longwall Coal Extraction	West - [redacted] East - [redacted]	West - [redacted] East - [redacted]	West - [redacted] East - [redacted]	West - [redacted] East - [redacted]
Underground Tons (dlvd)	[redacted]	[redacted]	[redacted]	[redacted]
Longwall Production Terminates	[redacted]	[redacted]	[redacted]	[redacted]
Continuous Miners Idled	[redacted]	[redacted]	[redacted]	[redacted]
Third Party Coal - [redacted]				
Black Butte Coal Deliveries	[redacted]	[redacted]	[redacted]	[redacted]
PRB Coal Deliveries	[redacted]	[redacted]	[redacted]	[redacted]
Third party coal conversion capital cost estimate - [redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Bridger Coal Company Options
PVRR Summary Based on IRP Unit Closure Dates

(PacifiCorp Share) PVRR Summary	PVRR 000's	Differential (from lowest $)
Option A (S - [redacted], U - [redacted])	2,548,604	14,927
Option B (S - [redacted], U - [redacted])	2,563,580	29,902
Option C (S - [redacted], U - [redacted])	2,568,556	34,878
Option D (S - [redacted], U - [redacted])	2,533,678	0

Bridger Coal Company Options

(PacifiCorp Share) PVRR Summary	Financial Ranking (low to high)	Operational Risk Ranking (low to high)
Option A (S - [redacted], U - [redacted])	2	4
Option B (S - [redacted], U - [redacted])	3	2
Option C (S - [redacted], U - [redacted])	4	3
Option D (S - [redacted], U - [redacted])	1	1

Key Goals of Updated Long-term Jim Bridger Plant Fueling Strategy

- Evaluate BCC Option "D" Against Option "E" (Market Option)
  - Option "E" Assumptions:
    [redacted]
- Develop and Provide PVRR Financial Analysis For These Two Options
- Provide Recommendation And Steps Moving Forward

Status of Long-Term Fuel Plan Action Items

- In discussions with [redacted]
- Updating the study on capital improvements needed [redacted]
- Updating the [redacted]
  - Estimated completion of "action items" (mid-late summer)
  - Future workshop status update meeting (late summer)

2018 v. 2017 TAM Changes

- Under Option D, [redacted]
  - Option E assumes similar timeframe [redacted]
- Slight adjustment to depreciation schedules under either scenario
  - Western District ([redacted])
  - Life-of-mine assets ([redacted])

Near-Term Fuel Supply Strategy

- Provide least cost, least risk fuel supply to Jim Bridger for next [redacted] years ([redacted])
  - Required capital projects needed to accommodate increased third party coal requires at least 4 years on an expedited basis
- Preserve flexibility to assess and implement long-term fuel options and capital investments
- Evaluate existing fuel plan (two-thirds BCC, one-third Black Butte) under current conditions

[redacted]

Black Butte Coal Supply Contract

- Current agreement expires 12/31/2017; but does allow for [redacted] deliveries
- Mine source location – 17 miles from plant
- Method of coal delivery – rail delivery via Union Pacific Railroad (UPRR)
- Capable of receiving [redacted] per day (up to [redacted] tons per year assuming no other rail deliveries)
- Mine provides for coal delivery flexibility

  [redacted]

Limited Third-Party Fuel Suppliers

- Southwest Wyoming
  - Black Butte mine – Lighthouse Resources
  - Kemmerer mine – Westmoreland
    - Kemmerer acquiring Haystack reserve
- Southern Powder River Basin (SPRB)
  - 8800 Btu/lb mines
    - Antelope mine – Cloud Peak
    - Black Thunder mine – Arch Coal
    - North Antelope Rochelle – Peabody Energy

Notable Supply Constraints/Issues

- Black Butte mine – Lighthouse Resources
  [redacted]
- Kemmerer mine – Westmoreland
  [redacted]

Supplier Constraints/Issues

- SPRB coal
  - [redacted]
  - [redacted]

Near-Term Third-Party Supply Options

- Option 1 - Black Butte mine
  [redacted]
- Option 2 – SPRB and Black Butte mine
  [redacted]
- Prior analysis supports Option [redacted] because [redacted]

Near-Term Fuel Strategy Goals

- Optimize Bridger Plant fueling
  - Establish optimal production/delivery volume for all sources
  - Provide least cost, least risk mine/fueling plan
  - Provide the most cost effective coal quality available
- Determine proper coal supply volume [redacted]

[redacted]

Near-Term Fuel Strategy Goals

- Additional fuel requirements could be comprised of three sources (as necessary)

  [redacted]

  – Least cost, least risk fuel option will be evaluated and selected.

Additional Questions?

Expiring Contracts

- CY 2017
  - Coal
    - [redacted]
    - [redacted]
    - [redacted]
  - Transportation
    - [redacted]
    - [redacted]
    - [redacted]
    - [redacted]
    - [redacted]
    - [redacted]

CY 2018

- Coal
  [redacted]

Docket No. UE 323
Exhibit PAC/300
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Judith M. Ridenour

March 2017

DIRECT TESTIMONY OF JUDITH M. RIDENOUR

TABLE OF CONTENTS

ATTACHED EXHIBITS

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

A. My name is Judith M. Ridenour. My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232. My current position is Specialist, Pricing and Cost of Service, in the regulation department.

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I have a Bachelor of Arts degree in Mathematics from Reed College. I joined the company in the regulation department in October 2000. I assumed my present responsibilities in May 2001. In my current position, I am responsible for the preparation of rate design used in retail price filings and related analyses. Since 2001, with levels of increasing responsibility, I have analyzed and implemented rate design proposals throughout the company's six-state service territory.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present PacifiCorp's proposed rate spread, rates, and revised tariff pages for the 2018 Transition Adjustment Mechanism (TAM) to recover the Oregon-allocated forecast net power costs (NPC) and the TAM adjustments for other revenues identified by Mr. Michael G. Wilding. I also provide a summary of the impact of the proposed rate change on customers' bills.

PROPOSED RATE SPREAD AND RATE DESIGN

Q. Please describe the company's tariff rate schedule that collects NPC.

A. PacifiCorp collects NPC through Schedule 201, Net Power Costs, Cost-Based Supply

Service. Collecting NPC through a separate rate schedule allows NPC to be more easily and accurately updated through TAM filings.

Q. What is the test period for this TAM?

A. In accordance with the TAM Guidelines adopted in Order No. 09-274,[1] the test period for the TAM is the year during which the Schedule 201 rates will be effective, which is the 12 months ending December 31, 2018.

Q. How did the company allocate NPC to the rate schedule classes?

A. PacifiCorp allocated forecast NPC to the customer classes based on the present spread of NPC revenue. This is consistent with the TAM Guidelines and the stipulated generation allocation factors in the company's last general rate case, approved by the Public Utility Commission of Oregon in Order No. 13-474,[2] updated for the change in load.

Q. Did you prepare an exhibit showing the rate spread and present and proposed Schedule 201 rates and revenues?

A. Yes. Exhibit PAC/301 shows present Schedule 201 rates and revenues, and the associated rate spread and revenue targets for each rate schedule based on the Oregon-allocated forecast NPC, including the adjustment for non-NPC Energy Imbalance Market costs and the updated amount for Production Tax Credits, identified by Mr. Wilding. The final columns in the exhibit show the proposed Schedule 201 rates and revenues. As explained by Mr. Wilding, forecast NPC is subject to updates throughout this proceeding.

[1] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2009 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service*, Docket No. UE 199, Order No. 09-274 (July 16, 2009).
[2] *In the Matter of PacifiCorp, d/b/a Pacific Power, Request for a General Rate Revision,* Docket No. UE 263, Order No. 13-474 (December 18, 2013).

Q. Is the proposed Schedule 201 rate design consistent with the TAM Guidelines?

A. Yes. The proposed Schedule 201 rates are designed to collect revenues from rate schedules based on the proposed rate spread described above. Additionally, the rates in PacifiCorp's proposed Schedule 201 use the same rate blocks and relationships between rate blocks as the existing Schedule 201 rates.

Q. How does the company propose to reflect in rates the amounts related to other revenues associated with this TAM filing?

A. PacifiCorp's Schedule 205, TAM Adjustment for Other Revenues, is used to collect or distribute the adjustment related to other revenues in a stand-alone TAM filing. Present rates for Schedule 205 were established in the company's 2017 TAM, docket UE 307.[3] PacifiCorp proposes adders to the present Schedule 205 rates reflecting the adjustment related to other revenues described in Mr. Wilding's testimony. The proposed rate spread and rate design for the Schedule 205 adders parallels the generation-based rate spread and rate design of Schedule 201 for NPC as described above, consistent with past treatment of this adjustment.

Q. Did you prepare an exhibit showing proposed Schedule 205 rates and revenues?

A. Yes. Exhibit PAC/302 shows the proposed adjustments to Schedule 205 rates and revenues based on the amounts in the 2018 TAM for other revenues along with the total combined Schedule 205 rates for the tariff, which reflect the present Schedule 205 rates plus the additional adjustment for the 2018 TAM.

Q. Does the company propose any other tariff changes in this TAM?

A. Yes. As described in Mr. Wilding's testimony, PacifiCorp proposes changes to the

[3] *In the Matter of PacifiCorp, d/b/a Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, preliminary Order No. 16-418 (October 27, 2016), final Order No. 16-482 (December 20, 2016).

applicability section of Schedule 203, Renewable Resource Deferral Supply Service Adjustment. The proposed tariff is included in my Exhibit PAC/303.

Q. Please describe Exhibit PAC/303.

A. Exhibit PAC/303 contains the proposed revised Schedules 201, 203 and 205.

Q. Is the company proposing changes to its transition adjustment tariff schedules at this time?

A. No. The company will file changes to the transition adjustment tariffs—Schedules 294, 295, and 296—once the final TAM rates have been posted and are known. The Transition Adjustment rates will be established in November, just before the open enrollment window.

COMPARISON OF PRESENT AND PROPOSED CUSTOMER RATES

Q. What are the overall rate effects of the changes proposed in this filing?

A. The overall proposed effect is a rate increase of 1.5 percent, on a net basis. The rate change varies by customer type. Page one of Exhibit PAC/304 shows the estimated effect of PacifiCorp's proposed prices by delivery service schedule both excluding (base) and including (net) applicable adjustment schedules. The net rates in Columns 7 and 10 exclude effects of the Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Klamath Dam Removal Surcharges (Schedule 199), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

Q. Did you prepare an exhibit that shows the impact on customer bills as a result of the proposed changes to Schedule 201 and Schedule 205?

A. Yes. Exhibit PAC/304, beginning on page 2, contains monthly billing comparisons for customers at different usage levels served on each of the major delivery service schedules. Each bill impact is shown in both dollars and percentages. These bill comparisons include the effects of all adjustment schedules including the Low Income Bill Payment Assistance Charge (Schedule 91), the Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (Schedule 98), the Klamath Dam Removal Surcharges (Schedule 199), the Public Purpose Charge (Schedule 290), and the Energy Conservation Charge (Schedule 297).

Q. What is the estimated monthly impact to an average residential customer?

A. The estimated monthly impact to the average residential customer using 900 kilowatt-hours per month is a bill increase of $1.28.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 323
Exhibit PAC/301
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed TAM Rate Spread and Rates

March 2017

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Net Power Costs
Present and Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2018

		Present Schedule 201		Present Rate	Target	Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Revenues	Spread	Revenues	Rates	Revenues
Schedule 4, Residential							
First Block kWh (0-1,000)	3,882,367,724	2.606 ¢	$101,174,503	29.2611%	$106,633,044	2.747 ¢	$106,648,641
Second Block kWh (> 1,000)	1,369,562,218	3.560 ¢	$48,756,415	14.1011%	$51,386,909	3.752 ¢	$51,385,974
	5,251,929,942		$149,930,918		$158,019,953		$158,034,615
						Change	$8,103,697
Employee Discount							
First Block kWh (0-1,000)	11,221,813	2.606 ¢	$292,440			2.747 ¢	$308,263
Second Block kWh (> 1,000)	5,282,861	3.560 ¢	$188,070			3.752 ¢	$198,213
	16,504,674		$480,510				$506,476
Discount			-$120,128				-$126,619
						Change	-$6,492
Schedule 23, Small General Service							
Secondary Voltage							
1st 3,000 kWh, per kWh	886,189,510	2.886 ¢	$25,575,429	7.3968%	$26,955,268	3.042 ¢	$26,957,885
All additional kWh, per kWh	237,590,159	2.141 ¢	$5,086,805	1.4712%	$5,361,247	2.257 ¢	$5,362,410
	1,123,779,669		$30,662,234		$32,316,515		$32,320,295
						Change	$1,658,061
Primary Voltage							
1st 3,000 kWh, per kWh	742,993	2.796 ¢	$20,774	0.0060%	$21,895	2.947 ¢	$21,896
All additional kWh, per kWh	324,975	2.074 ¢	$6,740	0.0019%	$7,104	2.186 ¢	$7,104
	1,067,968		$27,514		$28,998		$29,000
						Change	$1,486
Schedule 28, General Service 31-200kW							
Secondary Voltage							
1st 20,000 kWh, per kWh	1,417,425,049	2.822 ¢	$39,999,735	11.5685%	$42,157,791	2.974 ¢	$42,154,221
All additional kWh, per kWh	578,602,933	2.745 ¢	$15,882,651	4.5935%	$16,739,548	2.893 ¢	$16,738,983
	1,996,027,982		$55,882,386		$58,897,338		$58,893,204
						Change	$3,010,818
Primary Voltage							
1st 20,000 kWh, per kWh	9,427,769	2.717 ¢	$256,152	0.0741%	$269,972	2.864 ¢	$270,011
All additional kWh, per kWh	8,625,555	2.645 ¢	$228,146	0.0660%	$240,455	2.788 ¢	$240,480
	18,053,324		$484,298		$510,427		$510,491
						Change	$26,193
Schedule 30, General Service 201-999kW							
Secondary Voltage							
1st 20,000 kWh, per kWh	180,571,770	3.017 ¢	$5,447,850	1.5756%	$5,741,771	3.180 ¢	$5,742,182
All additional kWh, per kWh	1,067,873,816	2.616 ¢	$27,935,579	8.0794%	$29,442,752	2.757 ¢	$29,441,281
	1,248,445,586		$33,383,429		$35,184,523		$35,183,463
						Change	$1,800,034
Primary Voltage							
1st 20,000 kWh, per kWh	12,283,897	2.984 ¢	$366,551	0.1060%	$386,327	3.145 ¢	$386,329
All additional kWh, per kWh	79,465,238	2.579 ¢	$2,049,408	0.5927%	$2,159,977	2.718 ¢	$2,159,865
	91,749,135		$2,415,959		$2,546,304		$2,546,194
						Change	$130,235
Schedule 41, Agricultural Pumping Service							
Secondary Voltage							
Winter, 1st 100 kWh/kW, per kWh	2,906,663	4.030 ¢	$117,139	0.0339%	$123,459	4.247 ¢	$123,446
Winter, All additional kWh, per kWh	2,406,724	2.746 ¢	$66,089	0.0191%	$69,655	2.894 ¢	$69,651
Summer, All kWh, per kWh	214,281,260	2.746 ¢	$5,884,163	1.7018%	$6,201,624	2.894 ¢	$6,201,300
	219,594,647		$6,067,391		$6,394,737		$6,394,397
						Change	$327,006
Primary Voltage							
Winter, 1st 100 kWh/kW, per kWh	11,013	3.899 ¢	$429	0.0001%	$452	4.106 ¢	$452
Winter, All additional kWh, per kWh	62,989	2.660 ¢	$1,676	0.0005%	$1,766	2.803 ¢	$1,766
Summer, All kWh, per kWh	391,509	2.660 ¢	$10,414	0.0030%	$10,976	2.803 ¢	$10,974
	465,511		$12,519		$13,194		$13,192
						Change	$673
Schedule 47, Large General Service, Partial Requirements 1,000kW and over							
Primary Voltage							
On-Peak, per on-peak kWh	29,215,751	2.468 ¢	$721,045			2.600 ¢	$759,610
Off-Peak, per off-peak kWh	10,360,384	2.418 ¢	$250,514			2.550 ¢	$264,190
	39,576,135		$971,559		$1,023,800		$1,023,800
						Change	$52,241
Transmission Voltage							
On-Peak, per on-peak kWh	9,059,099	2.318 ¢	$209,990			2.441 ¢	$221,133
Off-Peak, per off-peak kWh	8,675,494	2.268 ¢	$196,760			2.391 ¢	$207,431
	17,734,593		$406,750		$428,564		$428,564
						Change	$21,814

PACIFIC POWER
STATE OF OREGON
TAM Schedule 201 Net Power Costs
Present and Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2018

		Present Schedule 201		Present Rate	Target	Proposed Schedule 201	
Rate Schedule	Forecast Energy	Rates	Revenues	Spread	Revenues	Rates	Revenues
Schedule 48, Large General Service, 1,000kW and over							
Secondary Voltage							
On-Peak, per on-peak kWh	342,725,156	2.661 ¢	$9,119,916	2.6376%	$9,611,951	2.803 ¢	$9,606,586
Off-Peak, per off-peak kWh	188,977,202	2.611 ¢	$4,934,195	1.4270%	$5,200,403	2.753 ¢	$5,202,542
	531,702,358		$14,054,111		$14,812,355		$14,809,128
						Change	$755,017
Primary Voltage							
On-Peak, per on-peak kWh	999,394,124	2.468 ¢	$24,665,047	7.1335%	$25,995,769	2.600 ¢	$25,984,247
Off-Peak, per off-peak kWh	629,750,245	2.418 ¢	$15,227,361	4.4040%	$16,048,904	2.550 ¢	$16,058,631
	1,629,144,369		$39,892,408		$42,044,673		$42,042,878
						Change	$2,150,470
Transmission Voltage							
On-Peak, per on-peak kWh	295,236,621	2.318 ¢	$6,843,585	1.9793%	$7,212,808	2.441 ¢	$7,206,726
Off-Peak, per off-peak kWh	223,948,061	2.268 ¢	$5,079,142	1.4690%	$5,353,171	2.391 ¢	$5,354,598
	519,184,682		$11,922,727		$12,565,979		$12,561,324
						Change	$638,597
Schedule 15, Outdoor Area Lighting Service							
Secondary Voltage							
All kWh, per kWh	9,242,236	2.175 ¢	$200,760	0.0581%	$211,592	2.289 ¢	$211,632
	9,242,236		$200,760		$211,592		$211,632
						Change	$10,871
Schedule 50, Mercury Vapor Street Lighting Service							
Secondary Voltage							
All kWh, per kWh	7,702,924	1.796 ¢	$137,969	0.0399%	$145,413	1.888 ¢	$145,081
	7,702,924		$137,969		$145,413		$145,081
						Change	$7,111
Schedule 51, Street Lighting Service, Company-Owned System							
Secondary Voltage							
All kWh, per kWh	20,115,733	2.827 ¢	$568,005	0.1643%	$598,650	2.976 ¢	$598,627
	20,115,733		$568,005		$598,650		$598,627
						Change	$30,623
Schedule 52, Street Lighting Service, Company-Owned System							
Secondary Voltage							
All kWh, per kWh	403,125	2.163 ¢	$8,720	0.0025%	$9,190	2.280 ¢	$9,191
	403,125		$8,720		$9,190		$9,191
						Change	$472
Schedule 53, Street Lighting Service, Consumer-Owned System							
Secondary Voltage							
All kWh, per kWh	9,695,208	0.922 ¢	$89,390	0.0259%	$94,213	0.972 ¢	$94,237
	9,695,208		$89,390		$94,213		$94,237
						Change	$4,848
Schedule 54, Recreational Field Lighting							
Secondary Voltage							
All kWh, per kWh	1,479,251	1.591 ¢	$23,535	0.0068%	$24,805	1.677 ¢	$24,807
	1,479,251		$23,535		$24,805		$24,807
						Change	$1,272
Total before Employee Discount			**$347,142,582**	100.0000%	$365,871,224		**$365,874,120**
Employee Discount			-$120,128		-$126,619		-$126,619
TOTAL	**12,737,094,377**		**$347,022,454**		$365,744,605		**$365,747,501**
						Change	**$18,725,047**
Schedule 47 Unscheduled kWh	2,540,129						
Total Forecast kWH	12,739,634,506						

Docket No. UE 323
Exhibit PAC/302
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed TAM Adjustment for Other Items

March 2017

PACIFIC POWER
STATE OF OREGON
TAM Schedule 205 - TAM Adjustment for Other Items
Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2018

Rate Schedule	Forecast Energy	Present Schedule 205 Rates	Generation Based Rate Spread	Proposed Adj. to Schedule 205 for Other Revenues: Rates	Proposed Adj. to Schedule 205 for Other Revenues: Revenues	Total Proposed Schedule 205 Rates
Schedule 4, Residential						
First Block kWh (0-1,000)	3,882,367,724	0.022 ¢	29.2611%	-0.003 ¢	-$116,471	0.019 ¢
Second Block kWh (> 1,000)	1,369,562,218	0.029 ¢	14.1011%	-0.003 ¢	-$41,087	0.026 ¢
	5,251,929,942				-$157,558	
Employee Discount						
First Block kWh (0-1,000)	11,221,813			-0.003 ¢	-$337	
Second Block kWh (> 1,000)	5,282,861			-0.003 ¢	-$158	
	16,504,674				-$495	
Discount					$124	
Schedule 23, Small General Service						
Secondary Voltage						
1st 3,000 kWh, per kWh	886,189,510	0.024 ¢	7.3968%	-0.002 ¢	-$17,724	0.022 ¢
All additional kWh, per kWh	237,590,159	0.018 ¢	1.4712%	-0.002 ¢	-$4,752	0.016 ¢
	1,123,779,669				-$22,476	
Primary Voltage						
1st 3,000 kWh, per kWh	742,993	0.023 ¢	0.0060%	-0.002 ¢	-$15	0.021 ¢
All additional kWh, per kWh	324,975	0.017 ¢	0.0019%	-0.002 ¢	-$6	0.015 ¢
	1,067,968				-$21	
Schedule 28, General Service 31-200kW						
Secondary Voltage						
1st 20,000 kWh, per kWh	1,417,425,049	0.023 ¢	11.5685%	-0.003 ¢	-$42,523	0.020 ¢
All additional kWh, per kWh	578,602,933	0.022 ¢	4.5935%	-0.003 ¢	-$17,358	0.019 ¢
	1,996,027,982				-$59,881	
Primary Voltage						
1st 20,000 kWh, per kWh	9,427,769	0.023 ¢	0.0741%	-0.003 ¢	-$283	0.020 ¢
All additional kWh, per kWh	8,625,555	0.022 ¢	0.0660%	-0.003 ¢	-$259	0.019 ¢
	18,053,324				-$542	
Schedule 30, General Service 201-999kW						
Secondary Voltage						
1st 20,000 kWh, per kWh	180,571,770	0.025 ¢	1.5756%	-0.003 ¢	-$5,417	0.022 ¢
All additional kWh, per kWh	1,067,873,816	0.022 ¢	8.0794%	-0.003 ¢	-$32,036	0.019 ¢
	1,248,445,586				-$37,453	
Primary Voltage						
1st 20,000 kWh, per kWh	12,283,897	0.024 ¢	0.1060%	-0.003 ¢	-$369	0.021 ¢
All additional kWh, per kWh	79,465,238	0.022 ¢	0.5927%	-0.003 ¢	-$2,384	0.019 ¢
	91,749,135				-$2,753	
Schedule 41, Agricultural Pumping Service						
Secondary Voltage						
Winter, 1st 100 kWh/kW, per kWh	2,906,663	0.033 ¢	0.0339%	-0.004 ¢	-$116	0.029 ¢
Winter, All additional kWh, per kWh	2,406,724	0.023 ¢	0.0191%	-0.003 ¢	-$72	0.020 ¢
Summer, All kWh, per kWh	214,281,260	0.023 ¢	1.7018%	-0.003 ¢	-$6,428	0.020 ¢
	219,594,647				-$6,616	
Primary Voltage						
Winter, 1st 100 kWh/kW, per kWh	11,013	0.032 ¢	0.0001%	-0.004 ¢	$0	0.028 ¢
Winter, All additional kWh, per kWh	62,989	0.022 ¢	0.0005%	-0.003 ¢	-$2	0.019 ¢
Summer, All kWh, per kWh	391,509	0.022 ¢	0.0030%	-0.003 ¢	-$12	0.019 ¢
	465,511				-$14	
Schedule 47, Large General Service, Partial Requirements 1,000kW and over						
Primary Voltage						
On-Peak, per on-peak kWh	29,215,751	0.020 ¢		-0.003 ¢	-$876	0.017 ¢
Off-Peak, per off-peak kWh	10,360,384	0.020 ¢		-0.003 ¢	-$311	0.017 ¢
	39,576,135				-$1,187	
Transmission Voltage						
On-Peak, per on-peak kWh	9,059,099	0.018 ¢		-0.002 ¢	-$181	0.016 ¢
Off-Peak, per off-peak kWh	8,675,494	0.018 ¢		-0.002 ¢	-$174	0.016 ¢
	17,734,593				-$355	

PACIFIC POWER
STATE OF OREGON
TAM Schedule 205 - TAM Adjustment for Other Items
Proposed Rates and Revenues
Forecast 12 Months Ending December 31, 2018

Rate Schedule	Forecast Energy	Present Schedule 205 Rates	Generation Based Rate Spread	Proposed Adj. to Schedule 205 for Other Revenues Rates	Proposed Adj. to Schedule 205 for Other Revenues Revenues	Total Proposed Schedule 205 Rates
Schedule 48, Large General Service, 1,000kW and over						
Secondary Voltage						
On-Peak, per on-peak kWh	342,725,156	0.022 ¢	2.6376%	-0.003 ¢	-$10,282	0.019 ¢
Off-Peak, per off-peak kWh	188,977,202	0.022 ¢	1.4270%	-0.003 ¢	-$5,669	0.019 ¢
	531,702,358				-$15,951	
Primary Voltage						
On-Peak, per on-peak kWh	999,394,124	0.020 ¢	7.1335%	-0.003 ¢	-$29,982	0.017 ¢
Off-Peak, per off-peak kWh	629,750,245	0.020 ¢	4.4040%	-0.003 ¢	-$18,893	0.017 ¢
	1,629,144,369				-$48,875	
Transmission Voltage						
On-Peak, per on-peak kWh	295,236,621	0.018 ¢	1.9793%	-0.002 ¢	-$5,905	0.016 ¢
Off-Peak, per off-peak kWh	223,948,061	0.018 ¢	1.4690%	-0.002 ¢	-$4,479	0.016 ¢
	519,184,682				-$10,384	
Schedule 15, Outdoor Area Lighting Service						
Secondary Voltage						
All kWh, per kWh	9,242,236	0.018 ¢	0.0581%	-0.002 ¢	-$185	0.016 ¢
	9,242,236				-$185	
Schedule 50, Mercury Vapor Street Lighting Service						
Secondary Voltage						
All kWh, per kWh	7,702,924	0.015 ¢	0.0399%	-0.002 ¢	-$154	0.013 ¢
	7,702,924				-$154	
Schedule 51, Street Lighting Service, Company-Owned System						
Secondary Voltage						
All kWh, per kWh	20,115,733	0.022 ¢	0.1643%	-0.003 ¢	-$603	0.019 ¢
	20,115,733				-$603	
Schedule 52, Street Lighting Service, Company-Owned System						
Secondary Voltage						
All kWh, per kWh	403,125	0.018 ¢	0.0025%	-0.002 ¢	-$8	0.016 ¢
	403,125				-$8	
Schedule 53, Street Lighting Service, Consumer-Owned System						
Secondary Voltage						
All kWh, per kWh	9,695,208	0.008 ¢	0.0259%	-0.001 ¢	-$97	0.007 ¢
	9,695,208				-$97	
Schedule 54, Recreational Field Lighting						
Secondary Voltage						
All kWh, per kWh	1,479,251	0.012 ¢	0.0068%	-0.002 ¢	-$30	0.010 ¢
	1,479,251				-$30	
Total before Employee Discount			**100.0000%**		**-$365,143**	
Employee Discount					$124	
TOTAL	**12,737,094,377**				**-$365,019**	
Schedule 47 Unscheduled kWh	2,540,129					
Total Forecast kWH	12,739,634,506					

Docket No. UE 323
Exhibit PAC/303
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Proposed Tariff Schedules

March 2017

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Residential Consumers and Nonresidential Consumers who have elected to take Cost-Based Supply Service under this schedule or under Schedules 210, 211, 212, 213 or 247. This service may be taken only in conjunction with the applicable Delivery Service Schedule. Also applicable to Nonresidential Consumers who, based on the announcement date defined in OAR 860-038-275, do not elect to receive standard offer service under Schedule 220 or direct access service under the applicable tariff. In addition, applicable to some Large Nonresidential Consumers on Schedule 400 whose special contracts require prices under the Company's previously applicable Schedule 48T. For Consumers on Schedule 400 who were served on previously applicable Schedule 48T prices under their special contract, this service, in conjunction with Delivery Service Schedule 48, supersedes previous Schedule 48T.

Nonresidential Consumers who had chosen either service under Schedule 220 or who chose to receive direct access service under the applicable tariff may qualify to return to Cost-Based Supply Service under this Schedule after meeting the Returning Service Requirements and making a Returning Service Payment as specified in this Schedule.

Monthly Billing

The Monthly Billing shall be the Energy Charge, as specified below by Delivery Service Schedule.

Delivery Service Schedule No.			**Delivery Voltage**			
			Secondary	**Primary**	**Transmission**	
4	Per kWh	0-1000 kWh	2.747¢			(I)
		> 1000 kWh	3.752¢			
5	Per kWh	0-1000 kWh	2.747¢			
		> 1000 kWh	3.752¢			(I)

For Schedules 4 and 5, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).

		Secondary	**Primary**	**Transmission**	
23	First 3,000 kWh, per kWh	3.042¢	2.947¢		(I)
	All additional kWh, per kWh	2.257¢	2.186¢		
28	First 20,000 kWh, per kWh	2.974¢	2.864¢		
	All additional kWh, per kWh	2.893¢	2.788¢		
30	First 20,000 kWh, per kWh	3.180¢	3.145¢		
	All additional kWh, per kWh	2.757¢	2.718¢		
41	Winter, first 100 kWh/kW, per kWh	4.247¢	4.106¢		
	Winter, all additional kWh, per kWh	2.894¢	2.803¢		
	Summer, all kWh, per kWh	2.894¢	2.803¢		(I)

For Schedule 41, Winter is defined as service rendered from December 1 through March 31, Summer is defined as service rendered April 1 through November 30.

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.		Delivery Voltage **Secondary**	**Primary**	**Transmission**	
47/48	Per kWh On-Peak	2.803¢	2.600¢	2.441¢	(I)
	Per kWh, Off-Peak	2.753¢	2.550¢	2.391¢	(I)

For Schedule 47 and Schedule 48, On-Peak hours are from 6:00 a.m. to 10:00 p.m. Monday through Saturday excluding NERC holidays. Off-Peak hours are remaining hours.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November. At such time as updated DST programming is available and has been applied to a Consumer meter, the time periods shown above will apply on all days for that Consumer. Consumers will be notified of their change to updated DST programming in a timely manner.

52	For dusk to dawn operation, per kWh	2.280¢	(I)
	For dusk to midnight operation, per kWh	2.280¢	(I)
54	Per kWh	1.677¢	(I)

15	**Type of Luminaire**	**Nominal Rating**	**Monthly kWh**	**RatePer Luminaire**	
	Mercury Vapor	7,000	76	$ 1.74	(I)
	Mercury Vapor	21,000	172	$ 3.94	
	Mercury Vapor	55,000	412	$ 9.43	
	High Pressure Sodium	5,800	31	$ 0.71	
	High Pressure Sodium	22,000	85	$ 1.95	
	High Pressure Sodium	50,000	176	$ 4.03	(I)

50 **A. Company-owned Overhead System**
Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
Horizontal, per lamp	$1.43	$3.25	$7.78	(I)
Vertical, per lamp	$1.43	$3.25		(I)

Street lights supported on distribution type metal poles: Mercury Vapor Lamps.

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.43			(I)
On 26-foot poles, vertical, per lamp	$1.43			
On 30-foot poles, horizontal, per lamp		$3.25		
On 30-foot poles, vertical, per lamp		$3.25		
On 33-foot poles, horizontal, per lamp			$7.78	(I)

(continued)

Monthly Billing (continued)

Delivery Service Schedule No.

50 **B. Company-owned Underground System**

Nominal Lumen Rating	**7,000** (Monthly 76 kWh)	**21,000** (Monthly 172 kWh)	**55,000** (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$1.43			(I)
On 26-foot poles, vertical, per lamp	$1.43			
On 30-foot poles, horizontal, per lamp		$3.25		
On 30-foot poles, vertical, per lamp		$3.25		
On 33-foot poles, horizontal, per lamp			$7.78	(I)

51

Types of Luminaire	**Nominal rating**	**Watts**	**Monthly kWh**	**Rate Per Luminaire**	
LED	4,000	100 (comp)		$0.57	(I)
LED	6,200	150 (comp)		$0.80	
LED	13,000	250 (comp)		$1.52	
LED	16,800	400 (comp)		$2.05	
High Pressure Sodium	5,800	70	31	$0.92	
High Pressure Sodium	9,500	100	44	$1.31	
High Pressure Sodium	16,000	150	64	$1.90	
High Pressure Sodium	22,000	200	85	$2.53	
High Pressure Sodium	27,500	250	115	$3.42	
High Pressure Sodium	50,000	400	176	$5.24	
Metal Halide	12,000	175	68	$2.02	
Metal Halide	19,500	250	94	$2.80	(I)

53

Types of Luminaire	**Nominal rating**	**Watts**	**Monthly kWh**	**Rate Per Luminaire**	
High Pressure Sodium	5,800	70	31	$0.30	(I)
High Pressure Sodium	9,500	100	44	$0.43	
High Pressure Sodium	16,000	150	64	$0.62	
High Pressure Sodium	22,000	200	85	$0.83	
High Pressure Sodium	27,500	250	115	$1.12	
High Pressure Sodium	50,000	400	176	$1.71	
Metal Halide	9,000	100	39	$0.38	
Metal Halide	12,000	175	68	$0.66	
Metal Halide	19,500	250	94	$0.91	
Metal Halide	32,000	400	149	$1.45	
Metal Halide	107,800	1,000	354	$3.44	(I)

Non-Listed Luminaire, per kWh 0.972¢ (I)

(continued)

Purpose

This schedule recovers the costs deferred for renewable resources as authorized by the Commission.

Applicable

To all Residential consumers and Nonresidential consumers except consumers who elected (C)
service under the five-year cost of service opt-out program described in Schedule 296 before (C)
November 2017. (C)

Energy Charge

The adjustment rate is listed below by Delivery Service Schedule.

Schedule	Charge
4	0.005 cents per kWh
5	0.005 cents per kWh
15	0.004 cents per kWh
23, 723	0.005 cents per kWh
28, 728	0.005 cents per kWh
30, 730	0.005 cents per kWh
41, 741	0.005 cents per kWh
47, 747	0.005 cents per kWh
48, 748	0.005 cents per kWh
50	0.003 cents per kWh
51, 751	0.005 cents per kWh
52, 752	0.004 cents per kWh
53, 753	0.002 cents per kWh
54, 754	0.003 cents per kWh

Purpose

This schedule adjusts rates for Other Revenues as authorized by Order No. 10-363.

Applicable

To all Residential Consumers and Nonresidential Consumers.

Energy Charge

The adjustment rate is listed below by Delivery Service Schedule and Direct Access Delivery Service Schedule.

Delivery Service Schedule No.			**Delivery Voltage** Secondary	Primary	Transmission	
4	Per kWh	0-1000 kWh	0.019¢			(R)
		> 1000 kWh	0.026¢			(R)
5	Per kWh	0-1000 kWh	0.019¢			(R)
		> 1000 kWh	0.026¢			(R)

For Schedules 4 and 5, the kilowatt-hour blocks listed above are based on an average month of approximately 30.42 days. Residential kilowatt-hour blocks shall be prorated to the nearest whole kilowatt-hour based upon the number of whole days in the billing period (see Rule 10 for details).

Schedule		Secondary	Primary	Transmission	
23, 723	First 3,000 kWh, per kWh	0.022¢	0.021¢		(R)
	All additional kWh, per kWh	0.016¢	0.015¢		(R)
28, 728	First 20,000 kWh, per kWh	0.020¢	0.020¢		(R)
	All additional kWh, per kWh	0.019¢	0.019¢		(R)
30, 730	First 20,000 kWh, per kWh	0.022¢	0.021¢		(R)
	All additional kWh, per kWh	0.019¢	0.019¢		(R)
41, 741	Winter, first 100 kWh/kW, per kWh	0.029¢	0.028¢		
	Winter, all additional kWh, per kWh	0.020¢	0.019¢		(R)
	Summer, all kWh, per kWh	0.020¢	0.019¢		(R)
					(R)

For Schedule 41, Winter is defined as service rendered from December 1 through March 31, Summer is defined as service rendered April 1 through November 30.

(continued)

Energy Charge (continued)

Delivery Service Schedule No.		Delivery Voltage Secondary	Primary	Transmission	
47/48	Per kWh On-Peak	0.019¢	0.017¢	0.016¢	(R)
747/748	Per kWh, Off-Peak	0.019¢	0.017¢	0.016¢	(R)

For Schedule 47 and Schedule 48, On-Peak hours are from 6:00 a.m. to 10:00 p.m. Monday through Saturday excluding NERC holidays. Off-Peak hours are remaining hours.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November. At such time as updated DST programming is available and has been applied to a Consumer meter, the time periods shown above will apply on all days for that Consumer. Consumers will be notified of their change to updated DST programming in a timely manner.

52, 752	For dusk to dawn operation, per kWh	0.016¢	(R)
	For dusk to midnight operation, per kWh	0.016¢	(R)
54,754	Per kWh	0.010¢	(R)

15

Type of Luminaire	Nominal Rating	Monthly kWh	RatePer Luminaire	
Mercury Vapor	7,000	76	$0.01	
Mercury Vapor	21,000	172	$0.03	
Mercury Vapor	55,000	412	$0.07	
High Pressure Sodium	5,800	31	$0.00	(R)
High Pressure Sodium	22,000	85	$0.01	(R)
High Pressure Sodium	50,000	176	$0.03	

50 **A. Company-owned Overhead System**

Street lights supported on distribution type wood poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
Horizontal, per lamp	$0.01	$0.02	$0.05	(R)
Vertical, per lamp	$0.01	$0.02		(R)

Street lights supported on distribution type metal poles: Mercury Vapor Lamps.

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$0.01			
On 26-foot poles, vertical, per lamp	$0.01			
On 30-foot poles, horizontal, per lamp		$0.02		(R)
On 30-foot poles, vertical, per lamp		$0.02		(R)
On 33-foot poles, horizontal, per lamp			$0.05	(R)

(continued)

Energy Charge (continued)

Delivery Service Schedule No.

50 **B. Company-owned Underground System**

Nominal Lumen Rating	7,000 (Monthly 76 kWh)	21,000 (Monthly 172 kWh)	55,000 (Monthly 412 kWh)	
On 26-foot poles, horizontal, per lamp	$0.01			
On 26-foot poles, vertical, per lamp	$0.01			
On 30-foot poles, horizontal, per lamp		$0.02		(R)
On 30-foot poles, vertical, per lamp		$0.02		(R)
On 33-foot poles, horizontal, per lamp			$0.05	(R)

51, 751

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
LED	4,000	100 (comp)		$0.00	
LED	6,200	150 (comp)		$0.01	
LED	13,000	250 (comp)		$0.01	
LED	16,800	400 (comp)		$0.01	(R)
High Pressure Sodium	5,800	70	31	$0.01	
High Pressure Sodium	9,500	100	44	$0.01	
High Pressure Sodium	16,000	150	64	$0.01	
High Pressure Sodium	22,000	200	85	$0.02	
High Pressure Sodium	27,500	250	115	$0.02	(R)
High Pressure Sodium	50,000	400	176	$0.03	(R)
Metal Halide	12,000	175	68	$0.01	
Metal Halide	19,500	250	94	$0.02	

53, 753

Types of Luminaire	Nominal rating	Watts	Monthly kWh	Rate Per Luminaire	
High Pressure Sodium	5,800	70	31	$0.00	
High Pressure Sodium	9,500	100	44	$0.00	
High Pressure Sodium	16,000	150	64	$0.00	(R)
High Pressure Sodium	22,000	200	85	$0.01	
High Pressure Sodium	27,500	250	115	$0.01	
High Pressure Sodium	50,000	400	176	$0.01	
Metal Halide	9,000	100	39	$0.00	
Metal Halide	12,000	175	68	$0.00	(R)
Metal Halide	19,500	250	94	$0.01	
Metal Halide	32,000	400	149	$0.01	
Metal Halide	107,800	1,000	354	$0.02	(R)

Non-Listed Luminaire, per kWh 0.007¢ (R)

Docket No. UE 323
Exhibit PAC/304
Witness: Judith M. Ridenour

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Judith M. Ridenour

Estimated Effect of Proposed TAM Price Change

March 2017

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, 2018

					Present Revenues ($000)			Proposed Revenues ($000)			Change				
Line		Sch	No. of		Base		Net	Base		Net	Base Rates		Net Rates		Line
No.	Description	No.	Cust	MWh	Rates	Adders[1]	Rates	Rates	Adders[1]	Rates	($000)	%[2]	($000)	%[2]	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	497,076	5,251,930	$605,609	$5,777	$611,386	$613,555	$5,777	$619,332	$7,946	1.3%	$7,946	1.3%	1
2	**Total Residential**		497,076	5,251,930	$605,609	$5,777	$611,386	$613,555	$5,777	$619,332	$7,946	1.3%	$7,946	1.3%	2
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23	80,346	1,124,848	$124,851	$5,231	$130,082	$126,488	$5,231	$131,719	$1,637	1.3%	$1,637	1.3%	3
4	Gen. Svc. 31 - 200 kW	28	10,280	2,014,081	$184,729	$3,443	$188,172	$187,706	$3,443	$191,149	$2,977	1.6%	$2,977	1.6%	4
5	Gen. Svc. 201 - 999 kW	30	843	1,340,195	$109,222	$1,287	$110,509	$111,112	$1,287	$112,399	$1,890	1.7%	$1,890	1.7%	5
6	Large General Service >= 1,000 kW	48	199	2,680,032	$192,384	($7,585)	$184,799	$195,855	($7,585)	$188,270	$3,471	1.8%	$3,471	1.9%	6
7	Partial Req. Svc. >= 1,000 kW	47	7	59,851	$6,401	($184)	$6,217	$6,473	($184)	$6,289	$72	1.8%	$72	1.9%	7
8	Agricultural Pumping Service	41	9,622	220,060	$25,815	($1,204)	$24,611	$26,136	($1,204)	$24,932	$321	1.2%	$321	1.3%	8
9	**Total Commercial & Industrial**		101,297	7,439,067	$643,402	$988	$644,390	$653,770	$988	$654,758	$10,368	1.6%	$10,368	1.6%	9
	Lighting														
10	Outdoor Area Lighting Service	15	6,414	9,243	$1,190	$221	$1,411	$1,201	$221	$1,422	$11	0.9%	$11	0.8%	10
11	Street Lighting Service	50	230	7,703	$859	$169	$1,028	$866	$169	$1,035	$7	0.8%	$7	0.7%	11
12	Street Lighting Service HPS	51	808	20,116	$3,542	$729	$4,271	$3,572	$729	$4,301	$30	0.9%	$30	0.7%	12
13	Street Lighting Service	52	35	403	$53	$9	$62	$53	$9	$62	$0	0.0%	$0	0.0%	13
14	Street Lighting Service	53	273	9,695	$611	$121	$732	$616	$121	$737	$5	0.8%	$5	0.7%	14
15	Recreational Field Lighting	54	105	1,479	$122	$24	$146	$124	$24	$148	$2	1.6%	$2	1.4%	15
16	**Total Public Street Lighting**		7,865	48,639	$6,377	$1,273	$7,650	$6,432	$1,273	$7,705	$55	0.9%	$55	0.7%	16
17	**Total Sales before Emp. Disc. & AGA**		606,238	12,739,636	$1,255,388	$8,038	$1,263,426	$1,273,757	$8,038	$1,281,795	$18,369	1.5%	$18,369	1.5%	17
18	Employee Discount				($470)	($4)	($474)	($477)	($4)	($481)	($7)		($7)		18
19	**Total Sales with Emp. Disc**		606,238	12,739,636	$1,254,918	$8,034	$1,262,952	$1,273,280	$8,034	$1,281,314	$18,362	1.5%	$18,362	1.5%	19
20	AGA Revenue				$2,439		$2,439	$2,439		$2,439	$0		$0		20
21	**Total Sales**		606,238	12,739,636	$1,257,357	$8,034	$1,265,391	$1,275,719	$8,034	$1,283,753	$18,362	1.5%	$18,362	1.5%	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

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	$20.45	$20.59	$0.14	0.68%
200	$30.25	$30.54	$0.29	0.96%
300	$40.08	$40.50	$0.42	1.05%
400	$49.89	$50.46	$0.57	1.14%
500	$59.71	$60.42	$0.71	1.19%
600	$69.53	$70.39	$0.86	1.24%
700	$79.34	$80.34	$1.00	1.26%
800	$89.17	$90.31	$1.14	1.28%
900	**$98.97**	**$100.25**	**$1.28**	**1.29%**
950	$103.88	$105.24	$1.36	1.31%
1,000	$108.79	$110.22	$1.43	1.31%
1,100	$121.75	$123.36	$1.61	1.32%
1,200	$134.68	$136.49	$1.81	1.34%
1,300	$147.64	$149.64	$2.00	1.35%
1,400	$160.58	$162.78	$2.20	1.37%
1,500	$173.53	$175.93	$2.40	1.38%
1,600	$186.48	$189.07	$2.59	1.39%
2,000	$238.26	$241.63	$3.37	1.41%
3,000	$367.73	$373.05	$5.32	1.45%
4,000	$497.20	$504.46	$7.26	1.46%
5,000	$626.67	$635.88	$9.21	1.47%

* 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	
kW		Present Price		Proposed Price		Difference	
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$72	$81	$73	$82	1.09%	0.99%
	750	$100	$108	$101	$110	1.20%	1.10%
	1,000	$127	$136	$128	$137	1.25%	1.17%
	1,500	$181	$190	$184	$192	1.31%	1.25%
10	1,000	$127	$136	$128	$137	1.25%	1.17%
	2,000	$236	$244	$239	$248	1.35%	1.30%
	3,000	$345	$353	$349	$358	1.38%	1.35%
	4,000	$437	$446	$443	$452	1.36%	1.33%
20	4,000	$464	$473	$470	$478	1.28%	1.25%
	6,000	$648	$657	$656	$665	1.28%	1.26%
	8,000	$833	$841	$843	$852	1.28%	1.26%
	10,000	$1,017	$1,026	$1,030	$1,039	1.28%	1.27%
30	9,000	$979	$988	$991	$999	1.21%	1.20%
	12,000	$1,255	$1,264	$1,271	$1,280	1.22%	1.21%
	15,000	$1,532	$1,541	$1,551	$1,560	1.23%	1.22%
	18,000	$1,809	$1,818	$1,831	$1,840	1.24%	1.23%

* 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 Difference	
kW		Present Price		Proposed Price			
Load Size	kWh	Single Phase	Three Phase	Single Phase	Three Phase	Single Phase	Three Phase
5	500	$71	$80	$72	$80	1.07%	0.97%
	750	$97	$106	$99	$107	1.19%	1.08%
	1,000	$124	$133	$125	$134	1.24%	1.15%
	1,500	$177	$186	$179	$188	1.30%	1.24%
10	1,000	$124	$133	$125	$134	1.24%	1.15%
	2,000	$230	$239	$233	$242	1.34%	1.29%
	3,000	$336	$345	$341	$349	1.37%	1.34%
	4,000	$426	$435	$432	$440	1.35%	1.32%
20	4,000	$452	$461	$458	$467	1.27%	1.25%
	6,000	$632	$641	$640	$649	1.27%	1.25%
	8,000	$812	$820	$822	$831	1.27%	1.25%
	10,000	$991	$1,000	$1,004	$1,013	1.27%	1.25%
30	9,000	$954	$963	$966	$974	1.19%	1.18%
	12,000	$1,224	$1,232	$1,238	$1,247	1.21%	1.20%
	15,000	$1,493	$1,502	$1,511	$1,520	1.22%	1.21%
	18,000	$1,763	$1,771	$1,784	$1,793	1.23%	1.22%

* 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 Load Size	kWh	Monthly Billing* Present Price	Monthly Billing* Proposed Price	Percent Difference
15	3,000	$353	$357	1.30%
	4,500	$467	$474	1.48%
	7,500	$695	$706	1.66%
31	6,200	$709	$719	1.34%
	9,300	$945	$959	1.51%
	15,500	$1,416	$1,440	1.68%
40	8,000	$910	$922	1.35%
	12,000	$1,214	$1,232	1.52%
	20,000	$1,822	$1,853	1.68%
60	12,000	$1,356	$1,375	1.36%
	18,000	$1,812	$1,840	1.52%
	30,000	$2,708	$2,754	1.69%
80	16,000	$1,796	$1,821	1.37%
	24,000	$2,398	$2,435	1.53%
	40,000	$3,588	$3,648	1.69%
100	20,000	$2,237	$2,268	1.37%
	30,000	$2,980	$3,026	1.53%
	50,000	$4,467	$4,543	1.69%
200	40,000	$4,381	$4,441	1.38%
	60,000	$5,868	$5,958	1.54%
	100,000	$8,841	$8,991	1.70%

* 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	$454	$461	1.47%
	6,000	$558	$567	1.59%
	7,500	$662	$673	1.68%
31	9,300	$912	$925	1.51%
	12,400	$1,127	$1,145	1.63%
	15,500	$1,342	$1,365	1.71%
40	12,000	$1,169	$1,187	1.52%
	16,000	$1,447	$1,471	1.64%
	20,000	$1,725	$1,754	1.72%
60	18,000	$1,743	$1,770	1.53%
	24,000	$2,154	$2,189	1.65%
	30,000	$2,561	$2,605	1.72%
80	24,000	$2,304	$2,339	1.54%
	32,000	$2,847	$2,894	1.65%
	40,000	$3,389	$3,448	1.73%
100	30,000	$2,861	$2,905	1.54%
	40,000	$3,540	$3,598	1.65%
	50,000	$4,218	$4,291	1.73%
200	60,000	$5,612	$5,700	1.56%
	80,000	$6,969	$7,085	1.67%
	100,000	$8,325	$8,470	1.74%

* 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		Monthly Billing*		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
100	20,000	$2,665	$2,698	1.24%
	30,000	$3,265	$3,312	1.44%
	50,000	$4,466	$4,542	1.69%
200	40,000	$4,686	$4,748	1.31%
	60,000	$5,887	$5,977	1.53%
	100,000	$8,288	$8,435	1.77%
300	60,000	$6,877	$6,967	1.31%
	90,000	$8,678	$8,811	1.53%
	150,000	$12,281	$12,498	1.77%
400	80,000	$8,950	$9,068	1.32%
	120,000	$11,352	$11,527	1.54%
	200,000	$16,155	$16,443	1.79%
500	100,000	$11,054	$11,201	1.33%
	150,000	$14,056	$14,273	1.55%
	250,000	$20,059	$20,419	1.79%
600	120,000	$13,158	$13,333	1.33%
	180,000	$16,760	$17,020	1.55%
	300,000	$23,964	$24,395	1.80%
800	160,000	$17,365	$17,597	1.34%
	240,000	$22,168	$22,514	1.56%
	400,000	$31,774	$32,347	1.80%
1000	200,000	$21,573	$21,861	1.34%
	300,000	$27,576	$28,007	1.56%
	500,000	$39,583	$40,298	1.81%

* 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	$3,202	$3,249	1.45%
	40,000	$3,791	$3,852	1.60%
	50,000	$4,380	$4,455	1.70%
200	60,000	$5,776	$5,865	1.53%
	80,000	$6,954	$7,071	1.68%
	100,000	$8,132	$8,277	1.78%
300	90,000	$8,510	$8,640	1.53%
	120,000	$10,277	$10,449	1.68%
	150,000	$12,043	$12,258	1.78%
400	120,000	$11,149	$11,321	1.55%
	160,000	$13,504	$13,733	1.69%
	200,000	$15,860	$16,145	1.80%
500	150,000	$13,800	$14,015	1.56%
	200,000	$16,745	$17,029	1.70%
	250,000	$19,689	$20,044	1.80%
600	180,000	$16,451	$16,708	1.56%
	240,000	$19,985	$20,325	1.70%
	300,000	$23,518	$23,943	1.81%
800	240,000	$21,754	$22,094	1.57%
	320,000	$26,465	$26,918	1.71%
	400,000	$31,176	$31,741	1.81%
1000	300,000	$27,056	$27,481	1.57%
	400,000	$32,945	$33,510	1.71%
	500,000	$38,835	$39,539	1.82%

* 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	$194	$222	$155	$197	$226	$155	1.54%	1.66%	0.00%
	3,000	$290	$319	$155	$295	$324	$155	1.54%	1.62%	0.00%
	5,000	$484	$513	$155	$492	$521	$155	1.54%	1.59%	0.00%
Three Phase										
20	4,000	$387	$444	$309	$393	$452	$309	1.54%	1.66%	0.00%
	6,000	$581	$638	$309	$590	$648	$309	1.54%	1.63%	0.00%
	10,000	$968	$1,025	$309	$983	$1,042	$309	1.54%	1.59%	0.00%
100	20,000	$1,936	$2,221	$1,349	$1,966	$2,258	$1,349	1.54%	1.66%	0.00%
	30,000	$2,905	$3,190	$1,349	$2,949	$3,241	$1,349	1.54%	1.62%	0.00%
	50,000	$4,841	$5,126	$1,349	$4,916	$5,208	$1,349	1.54%	1.59%	0.00%
300	60,000	$5,809	$6,664	$3,409	$5,899	$6,775	$3,409	1.54%	1.66%	0.00%
	90,000	$8,714	$9,569	$3,409	$8,848	$9,724	$3,409	1.54%	1.62%	0.00%
	150,000	$14,523	$15,378	$3,409	$14,747	$15,623	$3,409	1.54%	1.59%	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	$281	$309	$155	$286	$314	$155	1.54%	1.61%	0.00%
	4,000	$375	$403	$155	$381	$409	$155	1.54%	1.59%	0.00%
	5,000	$469	$496	$155	$476	$504	$155	1.54%	1.58%	0.00%
Three Phase										
20	6,000	$563	$618	$309	$571	$628	$309	1.54%	1.61%	0.00%
	8,000	$750	$805	$309	$762	$818	$309	1.54%	1.59%	0.00%
	10,000	$938	$993	$309	$952	$1,009	$309	1.54%	1.58%	0.00%
100	30,000	$2,813	$3,089	$1,339	$2,856	$3,139	$1,339	1.54%	1.61%	0.00%
	40,000	$3,751	$4,027	$1,339	$3,808	$4,091	$1,339	1.54%	1.59%	0.00%
	50,000	$4,688	$4,964	$1,339	$4,760	$5,043	$1,339	1.54%	1.58%	0.00%
300	90,000	$8,439	$9,267	$3,399	$8,568	$9,416	$3,399	1.54%	1.61%	0.00%
	120,000	$11,252	$12,080	$3,399	$11,425	$12,272	$3,399	1.54%	1.59%	0.00%
	150,000	$14,065	$14,893	$3,399	$14,281	$15,128	$3,399	1.54%	1.58%	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		Monthly Billing		Percent
Load Size	kWh	Present Price	Proposed Price	Difference
1,000	300,000	$26,840	$27,269	1.60%
	500,000	$38,310	$39,026	1.87%
	650,000	$46,912	$47,843	1.98%
2,000	600,000	$53,247	$54,106	1.61%
	1,000,000	$73,997	$75,429	1.93%
	1,300,000	$90,395	$92,256	2.06%
6,000	1,800,000	$154,616	$157,193	1.67%
	3,000,000	$220,208	$224,503	1.95%
	3,900,000	$269,402	$274,986	2.07%
12,000	3,600,000	$307,907	$313,061	1.67%
	6,000,000	$439,092	$447,682	1.96%
	7,800,000	$537,480	$548,647	2.08%

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	$25,388	$25,787	1.57%
	500,000	$36,040	$36,704	1.84%
	650,000	$44,029	$44,893	1.96%
2,000	600,000	$50,302	$51,100	1.58%
	1,000,000	$69,416	$70,745	1.91%
	1,300,000	$84,587	$86,315	2.04%
6,000	1,800,000	$145,380	$147,772	1.65%
	3,000,000	$206,064	$210,051	1.93%
	3,900,000	$251,577	$256,759	2.06%
12,000	3,600,000	$289,406	$294,189	1.65%
	6,000,000	$410,774	$418,746	1.94%
	7,800,000	$501,800	$512,164	2.07%

Notes:

On-Peak kWh	61.34%
Off-Peak kWh	38.66%

* 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	$35,735	$36,358	1.74%
	650,000	$43,175	$43,985	1.88%
2,000	1,000,000	$68,394	$69,640	1.82%
	1,300,000	$82,466	$84,086	1.96%
6,000	3,000,000	$203,172	$206,911	1.84%
	3,900,000	$245,389	$250,250	1.98%
12,000	6,000,000	$404,196	$411,673	1.85%
	7,800,000	$488,631	$498,352	1.99%
50,000	25,000,000	$1,677,346	$1,708,504	1.86%
	32,500,000	$2,029,160	$2,069,665	2.00%

Notes:

On-Peak kWh	56.87%
Off-Peak kWh	43.13%

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