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Kate Brown, Governor

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June 9, 2017

Via Electronic Filing and US Mail (CD)

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 1088
SALEM OR 97302-1088

**RE: Docket No. UE 323 In the Matter of
PACIFICORP, PACIFIC POWER, 2018 Transition Adjustment
Mechanism.**

Enclosed for filing is Staff Opening Testimony in UE 323, Certificate of Service and UE 323 Service List.

Exhibit 100, pages 5, 9 - 12 are confidential.
Attachment to Exhibit 102 to 104 are confidential and provided in electronic format.

Exhibit 200, pages 2, 15 - 16, 19, 21 - 24 and 27 - 28 and Exhibit 204 and 205 are confidential.

Exhibit 300, pages 4, 6 and 7 and Exhibit 303 and 304 are confidential.

Confidential pages and exhibits/attachment (CD) will be provided to parties who have signed Protective Order No. 16-128.

/s/ Kay Barnes
(503) 378-5763
Email: kay.barnes@state.or.us

CERTIFICATE OF SERVICE

UE 323

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 9TH day of June, 2017 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
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UE 323 – SERVICE LIST

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CASE: UE 323
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

<u>REDACTED</u>

June 9, 2017

Q. Please state your name, occupation, and business address.

A. My name is Scott Gibbens. I am a senior economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I present a portion of Staff's review of PacifiCorp's 2018 TAM filing. I will be presenting Staff's recommendation to the Commission regarding the issues covered. I will discuss Staff's analysis of the following issues:

- Energy Imbalance Market (EIM)
- Wholesale market transactions
- Wheeling expense
- Natural Gas Fuel Prices
- Allocation Factors and Load Forecast
- Rate spread and rate design
- TAM Transparency and TAM Guidelines

I also discuss the 2018 TAM filing, the amount it is requesting and how this year's filing is different from previous TAMs.

This Staff testimony reflects our current positions, which may change as a result of review and consideration of other parties' testimony.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared three exhibits not including my witness qualification.

Staff/102: Company's response to Staff DR No. 14
Staff/103: Company's response to Staff DR No. 16
Staff/104: Estimated and Actual Wheeling Expenses
Staff/105: Company's response to Staff DR No. 17

Q. How is your testimony organized?

A. My testimony is organized as follows:

2018 TAM BACKGROUND

Q. Please summarize PacifiCorp's 2018 TAM filing.

A. On a system basis, the Company's initial filing requested a 2018 Net Power Cost (NPC) of approximately $1,545,592,389 without adjustments, which represents a decrease of approximately $20.4 million compared to the 2017 NPC.[1]

Q. What is the effect on an Oregon basis?

A. On an Oregon basis, the 2018 NPC of approximately $380.4 million is higher than the 2017 NPC of $370.7 million.[2] This represents a 1.5 percent increase to overall rates on a net basis.[3] As I will discuss later in my testimony, Oregon's share of the NPC has increased and the reason why the NPC costs for Oregon increased even though total PacifiCorp NPC have decreased.

Q. Does PAC propose any model changes to the 2018 TAM?

A. Yes. PAC proposed changes which stemmed from the TAM workshops held following UE 307. Commission Order No. 16-482 directed the parties involved to participate in workshops covering issues which parties held disagreements on. The issues covered were: Day-ahead/Real-time transactions (DART) adjustment, Energy Imbalance Market (EIM) adjustment, Renewable Energy Credit valuation for direct access, and transparency and filing requirements for the TAM. PacifiCorp proposed to:

1. Utilize 48 months of historical data in the DART adjustment.

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[1] See PAC/101 Wilding/1 line 33 and UE 307 PAC/101 Dickman/1 line 33.
[2] See PAC/100 Wilding/3 lines 7-9.
[3] See PAC/100 Wilding/3 lines 2-5.

2. Remove transmission constraints when calculating EIM benefits.
3. Value REC's as a credit to customers who opt for Direct Access.

PAC proposed no changes to its GRID model which creates the starting estimation of the current year's NPC.

Q. What topics will Staff opening testimony address?

A. Staff discusses the following issues in our opening round of testimony:

(Staff/100 Gibbens)

1. Energy Imbalance Market
2. Wholesale Market Transactions
3. Allocation Factors and Load Forecast
4. Natural Gas Fuel Prices
5. Wheeling Expense
6. Rate Spread/Rate Design
7. TAM Guidelines and Transparency

(Staff/200 Kaufman)

8. Accuracy of PacifiCorp's NPC Forecast Model
9. Day-ahead Real-time Transaction Costs
10. Economic Shutdown of Coal Units
11. Jim Bridger SCR Related Costs
12. Coal costs

(Staff/300 Anderson)

13. Renewable Energy Certificates
14. Qualifying Facilities

15. Avian Adjustment

Q. Please summarize Staff's adjustments in this docket.

A. Below is a table summarizing the Staff adjustments found in Staff testimony:[4]

[BEGIN CONFIDENTIAL]

Adjustment	Amount
EIM net benefits	[redacted]
Day-ahead/Real-time Transactions	[redacted]
Economic Shutdown	[redacted]
Jim Bridger SCR	[redacted]
Coal Costs	[redacted]
Qualifying Facilities	[redacted]
TOTAL	$33,659,393

[END CONFIDENTIAL]

Q. Does Staff have any other recommendations?

A. Yes. As discussed in Dr. Kaufman's testimony, Staff further recommends that the Commission direct PacifiCorp to cooperate with Staff's investigation into the source of PacifiCorp's historic under-recovery of NPC, including performing a back-cast analysis of NPC.

[4] All adjustments are listed on a system basis.

ISSUE 1: ENERGY IMBALANCE MARKET

Q. What is the Energy Imbalance Market?

A. The Energy Imbalance Market (EIM) is an automated dispatch system that allows for efficient balancing of load and generation resources for participants, which provides both reliability and renewable integration benefits to the grid, and economic benefits to participants. The EIM allows for very efficient and automated re-dispatch of generators to precisely and continuously meet load in a sliding, five-minute window. Generation and load must be balanced within strict parameters at all times in order for the electric grid to remain stable. A large sustained imbalance between generation and load will cause both voltage and frequency instability on the grid. This balancing and coordination of generation assets is performed on several time scales, starting from months or weeks ahead with generation unit planning, to next-day planning, and then to real-time balancing.

Q. Who participates in the EIM?

A. The EIM was established by the California Independent System Operator (CAISO) on November 1, 2014, with PacifiCorp as the first external participant. NV Energy in Nevada joined on December 1, 2015. Puget Sound Energy and Arizona Public Service joined in October, 2016. Portland General Electric is planning to join in the last quarter of 2017. Idaho Power Company plans to join the EIM beginning April 2018.

Q. Please explain how PacifiCorp includes EIM costs and benefits in the 2018 TAM.

A. PacifiCorp's 2018 net power cost forecast includes a $27.5 million (total-Company) adjustment to reflect the incremental EIM benefits from inter-regional dispatch and reduced flexibility reserves.[5] Consistent with its position in the 2017 TAM and the Commission's ruling in that proceeding, PacifiCorp has not included an adjustment for intra-regional benefits,[6] but did account for the participation of Idaho Power.[7] In response to feedback in the informal workshops preceding this docket, the Company also adopted CUB's proposal to calculate inter-regional benefits based on available transmission, taking into account the California-Oregon Border (COB) transactions that were already modeled as a reduction to net power costs.[8]

The Company also included EIM-related costs of approximately $6.0 million (total-Company), which 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.[9] Total-Company net benefits related to EIM included in this case are $21.5 million.

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[5] PAC/100, Wilding/24.
[6] PAC/100, Wilding/26.
[7] PAC/100, Wilding/26.
[8] PAC/100, Wilding/29.
[9] PAC/100, Wilding/30.

Q. Does Staff have concerns related to PacifiCorp's EIM costs and benefits?

A. Yes. Staff has one main concern related to PacifiCorp's proposed EIM benefits included in this case. Staff believes that PAC's proposed EIM benefit estimation does not account for a clear upward trend in the historic data. By taking the simple average of the historic benefits, the forecast is under-estimating the EIM benefits. Staff also notes that it has a concern related to the Company's inclusion of EIM capital costs in the PCAM. Because these costs are recovered pursuant to the TAM and this is a new issue related to PacifiCorp's power cost proceedings, Staff will briefly summarize the issue below.

Q. Please describe Staff's issue regarding EIM benefit calculation.

A. Staff is concerned that PAC's methodology for estimating the EIM benefit relies too heavily on the assumption that the benefits are stationary. As evident in Table 3 located on PAC/100 Wilding/25, Inter-regional benefits and total benefits have been increasing each year since PAC joined the EIM in 2015. Some of this is most likely due to new entrants to the EIM, although Staff is not certain that is the only reason. PAC's methodology, which is based entirely on historic averages with small adjustments made for new entrants, could potentially under-perform an estimate based on more forward looking inputs. To test the issue, Staff reviewed how actual EIM benefits have compared to estimated EIM benefits. Confidential Figure 1 below illustrates the comparison.

[BEGIN CONFIDENTIAL]

Figure 1

[redacted] **[END CONFIDENTIAL]** Below, in Figure 2, is the same data with a 12 month lag in the predicted benefit. **[BEGIN CONFIDENTIAL]** [redacted]

[10] See Staff/102 and Staff/103.

Figure 2

[redacted]

[END CONFIDENTIAL]

Q. Did Staff determine why the EIM estimate is low?

A. Staff continues to investigate the reasons behind why the forecast is under-estimating actuals. Staff currently has two theories which have been mentioned. The first is that the model does not accurately account for new participants. When looking at the particular months and quarters following a new entrant into the EIM, Staff found that the forecast did increase, but not by a substantial and conclusive enough amount to clearly point to this cause being the main driver. Staff does believe this plays into the overall problem but is not the only issue with the forecast. Second, Staff believes there is also a general trend in the benefit which may be caused by increases in efficiency of the market and a "learning curve." The presence of this is not accounted for in any way by the current PAC methodology and would explain a chronic under-estimation. Staff does not mean to imply that the learning curve or efficiency increase will not level off at some point, but based on the data available to this point in 2017, Staff believes a significant enough error exists in order to warrant an adjustment in the forecast.

Q. How does the change to EIM modeling affect Staff's issue?

A. Staff analyzed the 2018 EIM benefit forecast using both methodologies. The total increase due to the new methodology was **[BEGIN CONFIDENTIAL** [redacted] **[END CONFIDENTIAL]** on a total-Company basis. Staff factors this in to the adjustment noted below.

Q. What is Staff's recommendation for this issue?

A. Staff recommends that the growth rate in inter-regional benefits be taken into account for the EIM forecast. While a change in methodology to an econometric model that is more forward-looking in nature may produce a more accurate forecast, Staff's recommended approach is a more incremental change to the Commission-approved methodology. Staff believes that because a significant forecast error exists, there is ample reason to warrant an adjustment. Staff's adjustment would include 50% of the year/year growth rate in inter-regional benefits over the last 12 months of data which is currently available. Due to the fact that the forecast has previously been marginally accurate at forecasting benefits with a year lag, this would potentially remove some of the forecast error. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**

Q. Please describe Staff's concern regarding inclusion of capital costs in the PCAM.

A. PacifiCorp includes recovery of its capital costs associated with entering the EIM in its TAM.[11] Power costs collected pursuant to rates set in the TAM are subject to the Power Cost Adjustment Mechanism (PCAM), which requires the application of a deadband, sharing band, and earnings test prior to a rate change associated with the over- or under-recovery of net power costs. As will be discussed more fully in the Company's PCAM proceeding, Staff believes that the inclusion of the return on capital investment related to EIM costs in the PCAM is improper. The Commission approves an authorized rate of return and aims to provide the utility with the opportunity to earn up to its authorized rate. When setting rates, this is the amount calculated into rates so that should the utility perform in an efficient manner, it will earn its authorized rate of return. However, the Commission does not guarantee that the utility will earn this rate of return on investments. Guaranteeing a return on investment would remove all incentive for the utility to operate in an efficient manner. Staff understands the deadband and other mechanisms in the PCAM promote efficient

[11] See Staff/105, PAC's response to Staff DR No. 17.

operations, but in the circumstance of an under-collection and subsequent amortization into rates, including the return on capital does not represent an opportunity to achieve an authorized rate, but an entitlement to receive an authorized rate. When taken a step-further Staff contends that the return on EIM investments should not be included in the PCAM cost calculation and should not be considered in the sharing, deadband, or earnings test.

As stated above, Staff has no recommendation to propose in this proceeding, as the forecast of return on net rate base from capital investments related to EIM is appropriate in the TAM.

ISSUE 2: WHOLESALE MARKET TRANSACTIONS

Q. Please provide background on this issue.

A. Compared to the 2017 TAM, purchased power expense in this case decreased by 2,850 GWh mainly due to a decrease in load of 1,712 GWh and an increase in wholesale price.[12] This resulted in a decrease to total company NPC of approximately $69 million.[13] Market sales also decreased, by approximately 3,209 GWh. This resulted in an increase to NPC of $79.2 million (total-Company).[14]

Q. Please describe Staff's analysis of the issue.

A. Staff reviewed the Company's workpapers on purchased power expense. Staff is curious about how load could decrease and prices could increase when market sales also decreased. Staff assumed that as load went down the marginal unit of production would be a more efficient unit. This would make PAC more competitive in the market and able to take advantage of higher market prices. Staff found that part of the reason for the apparent paradox was the decrease in market purchases. This would have an opposite effect on where the marginal unit fell in their generation stack. Staff also found that the cost of self-generation increased slightly from 2017 to 2018, which would help to explain Staff's concern. However, Staff is unsure if these two effects fully explain the issue. Staff found no other issues in the wholesale market transaction data.

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[12] PAC/100, Wilding/10-11, line 14-1.
[13] PAC/100, Wilding/10 (Table 2).
[14] PAC/100, Wilding/10, line 5.

Q. Does Staff have a recommended adjustment?

A. No. While Staff continues to investigate the apparent paradox, GRID is programmed to maximize profits in the wholesale market. Staff found no issues in the data or methodology and will work with the Company to understand the mechanisms at play.

ISSUE 3: ALLOCATION FACTORS AND LOAD FORECAST

Q. Please provide a background to this issue.

A. Oregon's load is estimated to decrease by 1.11 percent from 2017 to 2018, however other states' loads are expected to decrease by a greater amount.[15] Accordingly, Oregon's allocation of load changes from 23.8% to 24.2% from 2017 to 2018.[16] This results in a $7 million increase in NPC for Oregon.[17] The methodology for calculating allocation factors for costs recovered pursuant to the TAM is governed by the 2017 Protocol.[18]

Q. How did Staff analyze this issue?

A. Staff has reviewed all of the customer and industry data which was utilized to forecast loads for each state within PAC's service territory. The forecasts appear reasonable on a short term basis. However, Staff has not performed a detailed statistical analysis of the Company's load forecast. PacifiCorp is currently involved in an Integrated Resource Planning proceeding, and as part of both the TAM and the IRP Staff will continue to evaluate PacifiCorp's Oregon and other state load.

Q. Is there anything else to note related to your load forecast investigation?

A. Staff reviewed the allocation treatment of Oregon and non-Oregon direct access and self-generation load. The treatment continues to appear consistent across PacifiCorp's jurisdictions.

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[15] PAC/100, Wilding/4 (Table 1).
[16] *See* PAC/100, Wilding/4 (Table 1).
[17] PAC/100, Wilding/3, line 22.
[18] *In re PacifiCorp*, OPUC Docket No. UM 1050, Order No. 16-319, Appendix A (Aug. 23, 2016).

Q. What is Staff's recommendation for this issue?

A. Staff has no issues with PacifiCorp's methodology, and therefore has no recommended adjustment.

ISSUE 4: NATURAL GAS FUEL PRICES

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

A. PacifiCorp states that natural gas fuel expenses in 2018 are $25.2 million lower than in 2017.[19] This is an eight percent reduction. It is stated that the reduction is due to lower system load and lower natural gas generation volume. The reduction is partially offset by the higher average cost from natural gas fueled resources. The Company states that the average cost of natural gas generation increases from $24.7/MWh to $24.49/MWh in the current TAM.

Q. How did Staff review this input parameter?

A. Staff compared the natural gas fuel price forecast utilized in GRID with a forecast of natural gas prices available from the U.S. Energy Information Administration (EIA). Staff found the two forecasts to be commensurate.

Q. Does Staff have any proposed adjustment for this issue?

A. No. Staff has no adjustment to propose for this issue.

[19] PAC/100, Wilding/12.

ISSUE 5: WHEELING EXPENSE

Q. Please provide a background for this issue.

A. Wheeling expense is summarily the cost incurred to move power along other utilities' or organizations' transmission lines. In the 2018 TAM, the Company is including an update to wheeling expense due to a rate change in Idaho Power's firm point-to-point wheeling rates.[20] PAC also included Bonneville Power Administration's (BPA) initial rate proposal for the 24-month period beginning October 2017.[21] BPA is set to release its final Record of Decision (ROD) on July 26, 2017, and has stated that it will update NPC based on the information in the ROD. The total impact of these two updates is $386,000 on an Oregon-allocated basis.[22]

Q. How did Staff analyze the increase in wheeling expense?

A. Staff reviewed BPA's initial rate proposal and Idaho Power's rate change. Staff also reviewed the wheeling expense estimation workpapers made available by PAC. Staff then performed a five-year trend analysis of the wheeling expense included in the TAM to discern any pattern emerging. Figure 4, below, shows Staff's findings. As evidenced, the increase in forecasted wheeling expense is not abnormal over the last five years, the last major increase from 2013 to 2014 being due mainly to another BPA transmission rate increase. Staff feels comfortable with the wheeling expense forecast and believes that the stated reasoning warrants an increase to the projection.

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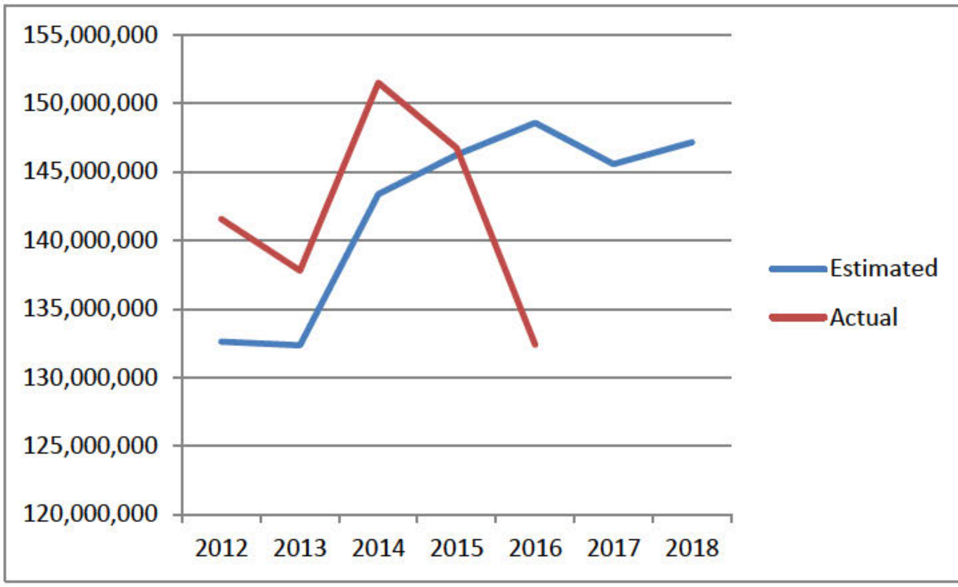
[20] PAC/100, Wilding/12.
[21] PAC/100, Wilding/12-13.
[22] PAC/100, Wilding/13.

Figure 3



[23]

Q. What is Staff's recommendation for this issue?

A. Staff has no adjustment and recommends the Commission approve the estimated wheeling expense.

[23] See Staff/104.

ISSUE 6: RATE SPREAD AND RATE DESIGN

Q. Please provide a background for this issue.

A. PacifiCorp's proposed rate spread and rate design is based on the TAM Guidelines and the stipulated agreement from PAC's last general rate case (GRC), updated for a change in load.[24] During that proceeding, parties held disagreements on the methodology of the marginal cost study calculation but agreed to functionalized revenue requirement allocation factors. Commission Order No. 13-474 and the attached stipulation state that this spread is to be used in all future rate dockets including the 2014 and 2015 TAM until the Company's next GRC. The TAM utilizes the generation based allocation factors for each different schedule in order to calculate the rate spread.

Q. How did Staff review the rate spread methodology?

A. Staff reviewed the marginal cost study performed for UE 263, PAC's most recent general rate case. Staff then verified the 2018 TAM's proposed rate spread for compliance with Order 13-474. After verification of the allocation factors, Staff reviewed Company witness Ridnour's workpapers to check the rate calculation.

Q. Does Staff have any issues following its analysis?

A. No. The rate calculation is based on current loads using information relative to generation revenues across schedules and thus calculated correctly. PacifiCorp has applied the TAM guidelines and the Commission Order in the 2018 filing. Due to this, Staff has no proposed adjustments for this issue.

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[24] PAC/300, Ridenour/2.

ISSUE 7: TAM GUIDELINES AND TRANSPARENCY

Q. Please provide the background for this issue.

A. Pursuant to the Commission's direction in Order 16-482, the parties to the 2017 TAM discussed in workshops the parties' concerns regarding the lack of transparency in the Company's TAM filings. Specifically, CUB expressed concerns about the Company's "continuous tinkering" with the models underlying the forecast of net power costs—that they are "constantly in motion and that the Company regularly fails to notify parties as it changes models, even where the TAM Guidelines require such notice or even when the Commission has expressly told the Company not to make changes in modeling."[25]

Q. Has PacifiCorp taken steps to address these concerns?

A. In response to concerns raised by CUB at the January 24, 2017 public meeting, and based on feedback at workshops, PacifiCorp agreed to create and maintain a step-log of model and input changes that include changes to the NVPC and transition adjustment estimation process that is not considered a standard annual update, and that the Company will provide a summary of input and model changes in filed testimony.[26]

[25] January 23, 2017 Letter from Bob Jenks, on behalf of CUB, regarding Pacific Power TAM Workshops (Item 2, January 24, 2017 Public Meeting). Accessed at http://edocs.puc.state.or.us/efdocs/HAC/ue307hac134558.pdf.

[26] UE 307 Staff Report of the Commission ordered TAM workshops (March 14, 2017) for March 21, 2017 public meeting; PAC/100, Wilding/18.

Q. Does Staff have additional recommendations to make to the Commission regarding this issue?

A. No, Staff has no additional recommendations to propose at this time.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 323
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 101

Witness Qualifications Statement

June 9, 2017

WITNESS QUALIFICATION STATEMENT

NAME:	Scott Gibbens
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates, Finance and Audit
ADDRESS:	201 High St. SE Ste. 100 Salem, OR 97301-3612
EDUCATION:	Bachelor of Science, Economics, University of Oregon Masters of Science, Economics, University of Oregon
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include analysis and technical support for electric power cost recovery proceedings with a focus in model evaluation. I also handle analysis and decision making of affiliated interest and property sale filings, rate spread and rate design, as well as operational auditing and evaluation. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management.

CASE: UE 323
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

June 9, 2017

UE 323 / PacifiCorp
May 30, 2017
OPUC Data Request 14

OPUC Data Request 14

Please provide TAM estimated EIM benefits and costs by month from 2015 through current in an excel file with formulae intact in a format similar to "ORTAM18W_EIM Benefits ORTAM17 (CY2016) CONF (EIM)" tab Historical EIM results.

Response to OPUC Data Request 14

The Company objects to this request as overly broad and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving these objections, the Company responds as follows:

Please refer to Confidential Attachment OPUC 14, which provides the Transition Adjustment Mechanism (TAM) estimate of energy imbalance market (EIM) benefits and costs from 2015 through 2017.

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

Confidential Exhibit 102

Is

Provided in electronic format

CASE: UE 323
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Opening Testimony

June 9, 2017

OPUC Data Request 16

Please provide actual EIM benefits realized by PAC for 2017 YTD by month in an excel file with formulae intact in a format similar to "ORTAM18W_EIM Benefits ORTAM17 (CY2016) CONF (EIM)" tab Historical EIM results.

Response to OPUC Data Request 16

The Company objects to this request as overly broad and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving these objections, the Company responds as follows:

Please refer to Confidential Attachment OPUC 16.

Note: the energy imbalance market (EIM) benefits in the provided attachment are preliminary – subject to change - and will be updated in the transition adjustment mechanism (TAM) update.

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

Confidential Exhibit 103

Is

Provided in electronic format

CASE: UE 323
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
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OREGON

STAFF EXHIBIT 104

Exhibits in Support
Of Opening Testimony

June 9, 2017

Staff Exhibit 104 is confidential and

Is subject to Protective Order No.16-128

(Provided in electronic format)

CASE: UE 323
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 105

Exhibits in Support
Of Opening Testimony

June 9, 2017

OPUC Data Request 17

Please describe how capital costs associated with the EIM are treated in the PCAM.

Response to OPUC Data Request 17

The Company objects to this request as overly broad and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving these objections, the Company responds as follows:

Non-net power costs (NPC) energy imbalance market (EIM) costs are included in the Transition Adjustment Mechanism (TAM) filing and trued-up to actual non-NPC EIM costs in the Power Cost Adjustment Mechanism (PCAM) subject to the deadband, sharing band, and earnings test. Non-NPC EIM costs include the pre-tax return on rate base, ongoing operation and maintenance (O&M) expense, and depreciation. Capital investment costs are used to calculate the pre-tax return on rate base.

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WITNESS: LANCE KAUFMAN

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OREGON

STAFF EXHIBIT 200

Opening Testimony

June 9, 2017

Q. Please state your name, occupation, and business address.

A. My name is Dr. Lance Kaufman. I am a Senior Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit Staff/201.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize Staff's analysis and recommendations regarding PacifiCorp's 2018 Transition Adjustment Mechanism filing, Docket No. UE 323.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared exhibit the following exhibits:

Staff/201: Witness Qualification Statement
Staff/202: Response to OPUC Data Request 2
Staff/203: Response to OPUC Data 207 Filed in Docket No. UE 307
Staff/204: PacifiCorp Coal Unit Economic Shutdown Data
Staff/205: Calculation of Cholla Liquidated Damages

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. What adjustments do you propose in this testimony?

A. I propose the following adjustments:

[BEGIN CONFIDENTIAL]

	System Allocated
Day Ahead Real Time	[redacted]
Economic Shutdown	
Jim Bridger SCR	
Coal Costs	
Total	($18,725,320)

[END CONFIDENTIAL]

ISSUE 1: ACCURACY OF PACIFICORP'S NPC FORECAST MODEL

Q. Please summarize this issue and Staff's recommendation.

A. PacifiCorp recently observed that the Company has persistently under-forecasted net variable power costs, and has used this observation as the basis for its Day-Ahead Real-Time (DART) adjustment.[1] As described more fully below, Staff is concerned that the Company is relying on extra-model adjustments to address the forecast error, rather than analyzing and refining the GRID model. Table 1, below, demonstrates that since 2008 the average forecast error has been about 8.4 percent.[2]

Table 1.

Year	Collected in Rates	Actual NPC	Under Recovery	Percentage Error
2008	$252,556,048	$286,401,464	$33,845,416	11.8%
2009	$248,429,624	$261,335,991	$12,906,367	4.9%
2010	$241,238,092	$276,837,681	$35,599,589	12.9%
2011	$301,662,279	$333,544,838	$31,882,559	9.6%
2012	$336,201,734	$351,814,366	$15,612,632	4.4%
2013	$348,474,235	$382,126,867	$33,652,632	8.8%
2014	$341,351,338	$377,421,181	$36,069,843	9.6%
2015	$343,993,011	$362,384,220	$18,391,209	5.1%
Average				8.4%

Rather than relying on the DART adjustment to address the alleged forecast error for PacifiCorp's net power costs, Staff has proposed that PacifiCorp identify the source of this forecast error by replicating historic forecasts using actual market and demand inputs in place of the originally forecasted inputs. The benefit of this analysis is that it will allow parties to identify the sources of

[1] UE 307 - PAC/400, Dickman/400.
[2] Based on the difference between collections and expenses. This approach to calculating forecast error compensates for variation related to retail energy sales. The data in this table are from Docket No. UE 307 - PAC/400, Dickman/6.

PacifiCorp's historic forecast error.[3] PacifiCorp has declined Staff's request to perform this analysis, but PacifiCorp has provided the data necessary to perform this analysis.[4] Staff is in the process of performing this analysis independently; however, PacifiCorp's familiarity with the GRID model makes PacifiCorp uniquely situated to efficiently perform this analysis. Staff recommends that the Commission direct PacifiCorp to cooperate with Staff's investigation into the source of PacifiCorp's historic under-recovery of net variable power costs.

Q. Should the Commission be concerned that PacifiCorp has had such large and persistent under-recovery?

A. Not necessarily. First, PacifiCorp has recovered a portion of this under-recovery through the subsequent true-up mechanisms, in which customers share 90 percent of the forecast error.[5] Second, there is no conclusive evidence that PacifiCorp's model is subject to statistical bias. If PacifiCorp's model is not biased, than parties can expect that PacifiCorp will experience error in the opposite direction and that over time, the over and under forecasts will balance.

[3] Staff has in past proceedings referred to this process as a back-cast. However, the technical definition of a back-cast differs slightly from what Staff proposes. Staff's proposed analysis is more accurately referred to as a within sample test, which is quite common in statistical based models, but does not appear to be as commonly applied in engineering based models. For consistency across proceedings, Staff will continue to refer to the proposed analysis as a back-cast.
[4] Staff/202, PacifiCorp's response to OPUC DR 2. See also Staff/203, Docket No. UE 307 PacifiCorp's response to OPUC DR 270.
[5] Subject to a dead band and earnings test.

Q. How can parties know whether the model is biased?

A. Parties can perform additional tests and analyses, such as Staff's proposed back-cast, to help determine the sources of the forecast error. These analyses can indicate the presence of bias, and reveal how the ways to improve future forecasts.

Q. What are the potential sources of NPC forecast error?

A. The NPC forecast error has four potential sources:

1. Input errors,
2. Parameter errors,
3. Specification errors, and
4. Stochastic errors.

Q. Please explain what input errors are.

A. Power costs are fundamentally driven by market prices, energy use, weather, and generator performance. For example, the cost of generating electricity using a coal generator depends directly on the cost of coal. A simple forecast model involving one coal generator with no market access would look something like the following:

$$NPC_t = Cost\ per\ BTU\ of\ coal_t * Heat\ Rate * kWh_t$$

In this model, total power cost equals the cost per BTU of coal, times the conversion rate of heat into electricity times the amount of electricity generated. In order to focus on the input error related to the cost of coal, let's make some assumptions that we accurately forecast and calibrate the other parts of the model. Suppose the heat rate is 10,000 BTU per kWh and that the company generates one thousand kWh in period t. With these inputs the model can be expressed as follows:

$$NVPC_t = Cost\ per\ BTU\ of\ coal_t * 10{,}000{,}000\ BTU$$ [6]

If the cost of coal in the time period t is forecasted to be $2 per MMBTU[7] (million BTU), then the total NPC forecast is $20 (and the total power produced is 1000 kWh.)[8] If the actual cost of coal ends up being $2.2 per MMBTU than the actual NPC will be $22, an error of 10 percent. It is not uncommon for year-ahead forecasts of fuel to be off by 10 percent or more. This type of error is not the result of a problem with the forecasting model, it is a result of not being able to perfectly predict all the inputs to the forecasted model.

Q. Please describe what the parameter errors are.

A. Parameters are generally fixed values that define the relationships between model inputs and model outputs. In the simple coal generator example above, the heat rate can be considered a parameter. Parameters are usually estimated from past experience. Because parameters are estimated, and because parameters do occasionally change, a model can be subject to parameter error. Returning to the coal example, suppose now that the coal price was accurately forecasted at $2, but the heat rate was not correctly estimated, and that the true heat rate was 10,500 BTU rather than 10,000. This means that in actual operations, more coal will be burned to generate the 100 kWh than was forecasted, and as a result the actual NPC will increase

[6] The heat rate is expressed in BTU per kWh. When simplifying the model the (per kWh) units cancel the (kWh generated) units, leaving the BTU units.
[7] One MMBTU is 1,000,000 BTU.
[8] Calculated as $2 per 1,000,000 BTU times 10,000,000 BTU, or $2 per MMBTU times 10 MMBTU.

from $2 to $2.05. If the source of model error is related to the model parameters, then the model can be improved by improving the method of estimating the parameters.

Q. Please explain what specification errors are.

A. Specification errors are errors in the model formula. There are two ways that a model formula can have errors:

1. The formula is missing inputs or has the wrong inputs; or
2. The formula has incorrect mathematical relationships between inputs.

For example, in addition to coal costs, there are transportation costs. In the simple coal model, transportation cost would be a missing input. If transportation costs are not included in the model, then the model will not accurately predict generation costs. An example of an error in the mathematical relationship would be if the wrong operator was used, such as addition where multiplication is appropriate. Model specification error can be corrected by including appropriate variables and using appropriate mathematical relationships. However, there is often a trade-off between model complexity and model functionality. A model must by nature be a simplification of reality. It is simply not feasible to accurately incorporate every aspect of real operations into a model and as more aspects are incorporated, developing inputs and operating the model becomes more cumbersome.

Q. Please explain what stochastic errors are.

A. Stochastic errors are errors associated with random and unpredictable aspects of reality. In an ideal model, stochastic error is centered around zero. This means that on average, the stochastic error component should be zero. If actual model errors do not appear to be uniformly distributed around zero, the source of the error is unlikely to be attributable to stochastic error.

Q. Please explain why you propose that the Company's forecast model be evaluated with a back-cast.

A. As mentioned above, the Company recently introduced a modeling technique referred to as Day-Ahead Real-Time (DART). Previous Staff testimony demonstrates that this technique is in fact a model misspecification and has the potential to introduce additional error into PacifiCorp's NPC forecasting process.[9] However, PacifiCorp defends the technique because it appears to remedy PacifiCorp's historic under forecast of power cost. Staff does not believe that the Commission has sufficient information on the source of PacifiCorp's historic model error to verify that PacifiCorp's claim is accurate. For example, if all of PacifiCorp's historic NPC forecast error is due to model inputs rather than model specification, than the appropriate correction would be to improve the accuracy of the inputs.

A back-cast allows parties to partition PacifiCorp's historic error into error due to input error from the other types of errors

Q. Can you explain why PacifiCorp has declined to provide the requested analysis?

A. Staff is not aware of the reason for this. Given that PacifiCorp's historic error has generally reduced shareholder profit, it is surprising to Staff that PacifiCorp

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[9] Docket No. UE 307 Staff/200 Kaufman/5 to 6 and Staff/400 Kaufman/32 to Kaufman/35.

is not investigating the source of the forecast error. Staff is concerned that PacifiCorp has no incentive to address the source of the forecast error so long as the Company is permitted to include a DART adjustment in NPC.

Q. Is it necessary for the Commission to request the Company to cooperate in Staff's analysis?

A. Yes. Staff has been working on this issue for over a year. In PacifiCorp's 2017 TAM (Docket UE 307), Staff requested that PacifiCorp perform this analysis.[10] In the 2017 TAM final order, the Commission directed PacifiCorp to meet with parties to investigate issues related to the DART adjustments.[11] As part of the ordered workshops, Staff again requested that PacifiCorp perform a back-cast of past power costs.[12] PacifiCorp declined again to perform the analysis but committed to considering analyses intended to achieve similar goals.[13] Staff again requested the analysis be performed in this Docket and PacifiCorp has declined to perform the analysis.[14] At this point, the source of PacifiCorp's historic forecast error remains unclear to Staff. Parties cannot determine whether there is in fact a problem with PacifiCorp's modeling approach, if the historic error is due to uncertain inputs, or if the error is simply a result of random variation.

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[10] Staff/203, Docket No. UE 307 PacifiCorp Response to OPUC DR 270.
[11] Order No. 16-482.
[12] Staff's March 14, 2017 Memo, Docket No. UE 307.
[13] Staff's March 14, 2017 Memo, Docket No. UE 307.
[14] Staff/202, PacifiCorp Response to Staff DR 2.

Q. Can you please clarify what Staff's recommendation is regarding this issue?

A. Staff recommends the Commission make a determination that a back-cast analysis as described by Staff in this testimony should be performed to help inform the source of PacifiCorp's historic under-recovery of NPC.

ISSUE 2: DAY-AHEAD REAL-TIME TRANSACTION COSTS

Q. Please summarize this issue and Staff's recommendation.

A. PacifiCorp recently introduced a model change intended to account for costs related to DART.[15] Staff, the Oregon Citizens' Utility Board (CUB), and the Industrial Customers of Northwest Utilities (INCU) have each objected to this model in every case in which PacifiCorp has included it. Generally, the parties have objected to the model because the mechanics of the model do not have a rational basis. PacifiCorp has developed a persuasive story regarding the source of day ahead and real time transaction costs. However, the actual DART adjustment is not a real model. Staff has previously demonstrated that the DART adjustment has almost no relationship with market prices, market transactions, or other power cost inputs.[16] As a result, the DART model really functions as an external, arbitrary cost adder.[17] Staff's previous testimony identified an alternative to the DART model which involves correctly correlating the market price inputs and the PacifiCorp retail sales forecast inputs. PacifiCorp acknowledged that this alternative has merits.[18] The Commission ordered PacifiCorp to discuss alternative modeling approaches with parties.[19] PacifiCorp has had a year to develop and implement Staff's recommendation. However, PacifiCorp continues to rely on the DART adjustment.

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[15] PAC/100, Wilding/19.
[16] Docket No. UE 307 Staff/400, Kaufman/32.
[17] Docket No. UE 307 Staff/400, Kaufman/32.
[18] Docket No. UE 307 PAC/800, Dickman/34 line16.
[19] Order No. 16-482 at page 14.

As described more fully below, Staff recommends that Commission replace the price adder component of DART with Staff's approach to correcting the model inputs. Staff also recommends adjusting the system balancing component of DART to account for the value of arbitrage transactions and for the residual value of block energy purchases.

Q. Please explain what you mean when you say that the mechanics of the model do not have a rational basis.

A. The DART adjustment consists of two parts. The first part involves adjusting the NPC market price inputs. However, rather than making the inputs more accurate and representative of the expected values, PacifiCorp modifies the inputs to be less accurate and less representative of the actual inputs. The DART price adders reduce the price spread across market hubs for every hour and every hub. This unequivocally reduces the ability for GRID to make economic cross-hub arbitrage transactions below the ability that the Company has in actual operations. As a result, PacifiCorp's approach incorporates additional input error into the forecast.

The second part of the DART adjustment involves grossing up final net power costs by the difference between a historic calculation involving market transactions and the same calculation performed using GRID model sales. The impact of the second component of the DART calculation is that it makes the total impact of the DART adjustment relatively independent of the impact of the first part of the DART adjustment.

Q. Can you provide an example of what you mean?

A. Yes. The basic DART concept relies on calculating the difference between the value of wholesale power transactions at the market price and the value at the monthly average price. The formula for this is as follows:

$$Sales\ Value - Volume\ of\ Sales * Average\ Price$$

The above formula is repeated for purchases and applied to each high load hour (HLH)[20] – light load hour (LLH)[21] group of transactions in each month for each market hub. Now as an example, let us review how the Company's model works using some simple numbers. Suppose the historic 5-year average calculation using the above formula is $100 for January HLH. This means that during January HLH, more of the Company's actual purchases occur when the market price is higher than average. This simply means that there is a correlation between when it is economical for the Company to purchase and when market prices are high. Based on this observation, the Company manipulates the inputs to GRID to try and force GRID to make purchases when the market price is higher than average. The Company then evaluates the forecasted GRID purchases using the same formula that generated the $100, and finds that GRID only models January HLH sales at $15 above the average price. The second part of the DART adjustment is calculated as follows:

[20] High Load Hour revers to the hours of 7 am through 10 pm Monday through Saturday.
[21] Low Load Hour refers to the remaining non-HLH hours.

$$\$100 - \$15 = \$85$$

Notice that the second DART adjustment, plus the first DART adjustment equals the original historical value of $100. Suppose that instead of $15, the first component of the DART adjustment changed the average pricing differential by $20, the second part of the adjustment reduces to $80, and the two components added together is still $100.

Q. Are you saying that the DART adjustment is essentially a fixed cost adder layered on top of the GRID model?

A. Yes. There are some minor dispatch impacts associated with the first part of changing GRID inputs. In general, purchases and sales reduce and self-generation increases. However, in Staff's experience with DART, these impacts are minor compared to the basic fixed cost adder.

Q. Is Staff's primary objection to DART that it is effectively a fixed cost adder?

A. No, this is not Staff's main concern. Staff's main concern relates to the original formula, which in the example above calculated the $100. The Commission has in the past accepted that the $100 represents an incremental power cost that is not accounted for in GRID. However, PacifiCorp has not presented compelling evidence to Staff that this formula is calculating a real cost that is incremental to the costs included in GRID. Staff has supported fixed cost adjustments in other proceedings, but only when they have a rational basis, and usually only as a temporary measure, not an ongoing adjustment. Staff's primary concern is that PacifiCorp's calculation of the historic DART costs is not a real incremental cost to those included in the base GRID model. The DART adjustment is power-cost equivalent of single-issue ratemaking. PacifiCorp is calculating historic values without acknowledging that there are many other components to power costs.

Q. Can you give some examples of how PacifiCorp's historic calculations may not represent a real cost, incremental to the costs already modeled in GRID?

A. As an example, consider PacifiCorp's ability to take advantage of market price differentials across trading hubs. When the price at Mid-C is below the price at Palo Verde, and the Company has excess transmission, the Company can reduce power costs by purchasing at Mid-C.

Q. What evidence is there that PacifiCorp's historic day ahead and real time transactions should not be modeled independently from other factors?

A. Staff provides the following two examples, using actual PacifiCorp data, to demonstrate that PacifiCorp's approach is not accurate:

1. In 2016, PacifiCorp made net sales of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** across all hubs, at a net revenue of **[BEGIN CONFIDENTIAL]** [redacted].[22] **[END CONFIDENTIAL]**PacifiCorp's average sale price, after accounting for cross hub transactions, was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per megawatt hour. However, the forward price curve for 2016 showed an average price of only

[22] Calculated from PacifiCorp data provided in response to OPUC DR 5 and 6.

[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]** per megawatt hour. This means that on average, PacifiCorp was able to sell energy for **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** the market price.

2. PacifiCorp transactions often occur in simultaneous pairs across hubs. For example, consider the following transaction:

[redacted]

This transaction was a day ahead transaction that is included in the calculation of the DART adjustment. The transactions were executed at the same time and have zero net energy. This pair of transaction is purely an economic transaction, and yielded a profit of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** However, these transactions also add around $2,145 to the NPC forecast for the each TAM in the next four years.

Staff also notes that PacifiCorp does not account for the residual value of monthly contracts. PacifiCorp performs a large number of monthly transactions. Because these are monthly transactions, the actual price is the monthly price. PacifiCorp then re-transacts the low value components of these monthly products. Because PacifiCorp is transacting the low value daily and hourly components, PacifiCorp ends up transacting at a disadvantageous price. PacifiCorp's model is focused on these disadvantageous transactions, and ignores the fact that PacifiCorp retains the high value components.

Q. Can you please clarify the concepts in your explanation using some simplified numbers?

A. Yes. When a monthly energy product is sold, there is usually a fixed delivery rate over a fixed period of time for a fixed value. For example, a standard, 25 megawatt high load hour block will provide 25 MW of electricity, Monday through Saturday between 7 am and 10 pm, every week of the month. This transaction will occur at a fixed price. Now consider a month with 400 high load hours and a forecasted average high load price of $20 per MWh. The monthly product will sell for $20 per MWh * 400 hours * 25 MW = $200,000. Now suppose for simplicity that on half the days, the daily HLH market price is $10 and on the other half of the days the daily HLH market price is $30. These prices result in an average monthly price of $20, and the value of the monthly contract is still $200,000. PacifiCorp's claim in support of the DART has two parts. One part is that PacifiCorp buys monthly products in order to meet its forecasted real time transactions. But for many days, the monthly product is not needed, and PacifiCorp resells the energy. PacifiCorp has demonstrated that this resale of energy occurs when prices are lower than average.

So returning to the example, PacifiCorp would sell half of the MWh from the monthly contract at $10. The residual energy from the monthly contract delivers energy to PacifiCorp during the high value time periods. So, to summarize:

1. PacifiCorp buys a monthly product with 10,000 MWh valued at $20 per MWh for a total of $200,000.
2. PacifiCorp sells 5,000 MWh in daily products priced at $10 per MWh, for a total revenue of $50,000.
3. PacifiCorp keeps the remaining 5,000 MWh in daily products which are valued at $30 per MWh, for a total value of $150,000.

The DART adjustment only evaluates part 2 of this transaction, the sale below the monthly average price. This creates what looks like an un-accounted for cost, because in GRID there is not an appropriate correlation between demand and sales. However, GRID also does not perform monthly transactions, and so GRID cannot capture the benefit that appears in part 3 above, namely where, via the monthly transaction, PacifiCorp has acquired a substantial amount of high value energy at the monthly average price.

Q. What is Staff's recommendation regarding the DART transaction?

A. Staff continues to find that both the price adder and the balancing transactions components of the DART adjustment be eliminated; however Staff understands that the Commission has in the past been hesitant to eliminate these adjustments in the face of the substantial uncertainty regarding the source of PacifiCorp's historic NPC forecast error. The Commission's previous guidance regarding the DART indicated an interest in adopting improvements to the DART that would make the adjustment more representative of actual operations.

Staff recommends that the DART adjustment be modified in the following manner:

1. The price adder component be modified back to a single market price per hub, with a monthly price shape that is correlated with PacifiCorp's retail load input. The correlation would match the five year historic correlation between actual load and market prices.
2. The day and month ahead components of the DART be modified to account for the value of historic arbitrage transactions and the value of residual monthly and daily purchase contracts.

Staff proposes that the value of arbitrage transactions be calculated by summing the net value of profitable within-hub and cross-hub offsetting market transactions. Staff also proposes that the historic arbitrage value be reduced by the arbitrage value in the GRID model results to prevent double counting. Staff proposes that the residual value of monthly and daily purchase contracts be valued by multiplying the real time actual hourly price of the residual hours by the residual hourly volumes, and subtracting the residual cost of the contracts. Staff has not calculated a dollar adjustment associated with these adjustments at this time, but will provide an update on the impact of these recommendations in its subsequent round of testimony.

Q. What is the impact of Staff's recommendation on the 2018 NPC forecast?

A. Staff's preliminary estimate is **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** This is calculated as the portion of PacifiCorp's 2016 net sales revenue that exceeds the revenue at the annual average price. This estimate does not include the residual value of monthly and daily contracts.

ISSUE 3: ECONOMIC SHUTDOWN OF COAL UNITS

Q. Please summarize this issue and Staff's recommendation.

A. **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

Q. Please describe PacifiCorp's historic economic shutdowns.

A. **[BEGIN CONFIDENTIAL]** [redacted][23] **[END CONFIDENTIAL]**

Q. What type of error does PacifiCorp introduce by not allowing for economic shutdowns?

A. PacifiCorp's approach results in model specification error. This is because preventing economic shutdowns is the equivalent of specifying a constraint

[23] *See* Staff/204, which includes plant outage data from PacifiCorp's workpapers and NERC's definition of the outage term "Reserve Shutdown."

equation. The effect of a constraint is that, if it is binding, it prevents the model from achieving a global optimization. The constraint is binding when GRID dispatches the coal plants at the minimum level. In this situation, because the constraint is not consistent with actual operations, it should be removed.

Q. Please explain how you incorporated economic shutdowns into the GRID model.

A. I model economic shutdowns using the following process:

1. Review PacifiCorp's filed GRID model results to identify periods of low coal generation.
2. Review PacifiCorp's filed GRID model results to identify coal plants with high fuel costs per MWh of generation.
3. Select a continuous block of time with low MWh of coal generation and select one unit with high fuel cost to economically shutdown.
4. Modify the GRID input file "ORTAM18_EOR CONF.csv" to have a 100 percent effective outage rate for the selected plant during the selected time.
5. Run the base GRID model as filed by PacifiCorp but adjusted to replace the effective forced outage rate input with the modified version of ""ORTAM18_EOR CONF.csv".
6. Incorporate the GRID model results into the NPC excel models.
7. Compare new NPC results with the original filed NPC results.

Staff performed two iterations of the process outlined above. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**

Q. Please summarize the results of your two economic shutdown scenarios.

A. The results of my scenarios are presented in the table below.

[redacted]

Q. Is it possible that there are economic shutdown scenarios that have lower costs than the ones that you analyzed?

A. Yes, Staff concedes that is possible and intends to perform further shutdown analysis. Staff will present its updated analysis in subsequent testimony, as appropriate.

Q. If market prices or other GRID inputs change as PacifiCorp updates the NPC forecast, what will happen to the optimal shutdown strategy?

A. It is difficult to predict how future GRID updates will impact the optimal shutdown strategy. Staff recommends that when PacifiCorp files its final update, PacifiCorp evaluate all of the scenarios tested by Staff to identify the low cost scenario.

Q. Has Staff considered the impact that economic shutdowns have on coal contract prices?

A. In the previous TAM proceedings, parties were concerned about the impact of contract minimums on PacifiCorp's NPC.[24] However, it is Staff's understanding that PacifiCorp is not currently expecting to have coal contract minimum volumes be a binding constraint in NPC.[25] Staff's analysis assumes that this continues to be the case and Staff does not make an adjustment for the impact of plant shutdowns on fuel prices. Staff recommends that PacifiCorp review the impact of economic shutdowns on average coal costs, and that the final scenario analysis incorporate coal costs specific to each scenario. The coal costs are addressed further Issue 6 of this testimony.

Q. What is Staff's recommendation regarding economic shutdowns?

A. Staff recommends the lowest cost economic shutdown scenario be selected for the NPC forecast. **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

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[24] Order No. 16-482 at page 9.
[25] Based on PacifiCorp statements at the first Docket No. UE 323 TAM workshop held May 15, 2017.

ISSUE 4: JIM BRIDGER SCR RELATED COSTS

Q. Please summarize this issue and Staff's proposal.

A. In Docket No. UE 307, CUB raised a concern related to the impact of PacifiCorp's Jim Bridger SCR investments in NPC.[26] The Commission has not ruled that these investments were prudent, and they were not acknowledged in the Company's most recent IRP.[27] In Docket No. UE 307, PacifiCorp agreed with CUB's proposal to model Jim Bridger without SCRs;[28] however, in this case, PacifiCorp is modeling the operational impacts of the investments in its NPC filings.[29]

Staff finds that CUB's conclusions regarding the modeling of SCRs remains persuasive and recommends that the Commission exclude the impacts associated with the SCRs from both the 2018 TAM and the associated PCAM filing. Staff has not calculated the dollar impact of this recommendation, however Staff notes that the impact in last year's TAM was a reduction to system allocated NPC of $1.6 million.[30] Staff expects that the impact in this case will be similar. Staff will provide a specific dollar impact for this proceeding in subsequent testimony.

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[26] *See* Docket No. UE 307 CUB/100, McGovern/3-7.
[27] *See* Docket No. UE 307 CUB/100, McGovern/6 at lines 9-12.
[28] *See* Docket No. UE 307 PAC/400, Dickman/7 line 21 to Dickman/8 line 1.
[29] *See* Docket No. UE 307 CUB/100, McGovern/6 at lines 12-13.
[30] *See* Docket No. UE 307 PAC/403, Dickman/1.

ISSUE 5: COAL COSTS

Q. Please summarize this issue and Staff's proposal.

A. In Order No. 16-483 the Commission directed PacifiCorp, Staff, and the other parties to Docket No. UE 307 to meet informally to discuss analysis needed to meaningfully evaluate PacifiCorp's long-term fuel supply plan for Jim Bridger, as well as whether additional information and analyses should be provided to Staff and the parties regarding PacifiCorp's fuel plans for any of its other coal fired units. These meetings are on-going, and at this time parties have not settled on an appropriate set of analyses for Jim Bridger's fuel source. Staff has also not yet received consistent and verifiable documentation regarding how the Company sets the appropriate levels for coal plant minimum takes.

At the workshops, Staff understood PacifiCorp to concede that the rail transportation costs used in the Company's Powder River Basin supply alternative was likely too high. However, due to the Company's currently supported long term fuel plan, Staff does not find good reason to test the validity of a market based Jim Bridger coal supply in this case.

Staff continues to seek information on the analysis and decision-making process related to coal contracts at PacifiCorp's other plants. For example, it remains unclear to Staff how PacifiCorp's long-term load forecasts and market prices are incorporated into the coal volume decisions. It is also not clear how the Company weighs the costs and benefits associated with different levels of minimum takes.

At the workshop, Staff presented the following three questions to the Company:

1. What is the range of future coal needs for PAC plants?
2. How does the Company evaluate the benefits of coal supply contracts with large contract minimums?
3. How can stakeholders weight the tradeoffs between the benefits of large contract minimums against the risk of contract damages?

Staff has not obtained sufficient answers to these questions at this time but is continuing to work with the Company to address these questions in future workshops.

Q. Are coal contracts a concern for the current case?

A. Yes. In the current case the Company is modeling liquidated damages for Cholla. Staff finds that the Company's estimated damages are not accurate. The Company states that it expects to incur **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in liquidated damages. This value as based on an assumption that it will receive **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons of coal in 2018. However, the filed NPC forecast indicates that Cholla is forecasted to consume **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** tons. Based on this level of coal use the liquidated damages should only be **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[31]

Q. What is Staff's recommendation with respect to liquidated damages?

A. Staff recommends that liquidated damages be consistent with the final anticipated coal use at Cholla. Based on the initial filing this would **[BEGIN**

[31] Staff/205.

CONFIDENTIAL] [redacted]. **[END CONFIDENTIAL]** Staff is continuing to analyze PacifiCorp's coal contracting process.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UE 323
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

June 9, 2017

WITNESS QUALIFICATIONS STATEMENT

NAME:	Lance Kaufman
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 9730
EDUCATION:	In 2013 I received a Doctorate degree in economics from the University of Oregon. In 2008 I received a Master of Science degree in Economics from the University of Oregon. In 2004 I received a Bachelor of Business Administration in Economics from the University of Alaska Anchorage.
EXPERIENCE:	From March of 2013 to September of 2014 and from September of 2015 to the present I have been employed by the Oregon Public Utility Commission (OPUC). My current responsibilities include analysis of power costs, cost allocations, decoupling mechanisms, and sales forecasts. I have worked on power costs in the following OPUC dockets: IPC UE 301, IPC UE 305, PAC UE 307, and PGE UE 308. From September 2014 to September 2015 I was employed by Regulatory Affairs Public Advocacy group of the Alaska Department of Law. From 2008 to 2012 I was employed by the University of Oregon as an instructor. I taught undergraduate level courses in Microeconomics, Urban Economics, and Public Economics.

CASE: UE 323
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

June 9, 2017

OPUC Data Request 2

Please provide backcast GRID model results and model inputs for 2012, 2013, 2014, 2015, and 2016. In addition to providing the results, please provide parties access to the GRID runs via the online portal. Please use the GRID inputs used in the final approved GRIG forecast for each year with the following exceptions:

(a) Replace market energy prices with actual hourly POWERDEX prices for each hub;

(b) Replace market sale capacity to equal the maximum aggregate hourly transaction size within the year at each hub;

(c) Replace fuel costs with generating unit specific actual fuel costs or fuel cost curves at the most granular time period available to the Company;

(d) Replace load with actual load;

(e) Replace planned outages with actual planned and forced outages;

(f) Eliminate forced outage rate constraints;

(g) Replace heat rate to equal actual heat rate or actual heat rate curve; and

(h) Replace hydro conditions with actual hydro conditions.

Response to OPUC Data Request 2

The Company objects to this request on the basis that it is overly broad and unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. Notwithstanding the foregoing objection, the Company responds as follows:

The Company has not performed any backcast studies for the period of 2012 through 2016 using the Generation and Regulation Initiative Decision Tool (GRID). Please refer to the Company's response to OPUC Data Request 3.

(a) Please refer to the Company's response to Sierra Club Data Request 1.4; specifically Confidential Attachment Sierra Club 1.4, which includes actual hourly market prices for 2012 through 2016. Note: Confidential Attachment Sierra Club 1.4 contains confidential and proprietary third party data which is the property of POWERDEX. The POWERDEX actual hourly market prices are provided subject to the PacifiCorp POWERDEX Subscription Agreement which requires that POWERDEX proprietary data be provided only to persons qualified to receive confidential information under the protective order for this proceeding. Furthermore, parties must return or destroy all POWERDEX data that the Company provides in responses to data requests in this proceeding, and any extracts thereof, following conclusion of this regulatory proceeding.

(b) Please refer to the Company's response to OPUC Data Request 5; specifically Confidential Attachment OPUC 5, and the Company's response to OPUC Data Request 6; specifically Confidential Attachment OPUC 6, which provide short-term firm (STF) market transactions from 2009 through 2016. In addition, please refer to the confidential work paper entitled "ORTAM18_Market Capacity FEB17 CONF", tab entitled "48 month Source" which was included with the five-day work papers supporting the Company's 2018 transition adjustment mechanism (TAM). This work paper provides STF sales transaction for July 2012 through June 2016.

(c) Please refer to the Company's response to ICNU Data Request 011; specifically Attachment ICNU 011 -1, which provides actual net power costs (NPC) reports for 2012 through 2016. Actual fuel costs can be derived by taking the dollars divided by megawatt-hours (MWh) for each unit by month.

(d) Please refer to Confidential Attachment OPUC 2 –1, which provides actual hourly load for 2012 through 2016.

(e) Please refer to Confidential Attachment OPUC 2 –2, which provides actual planned and forced outage data for the Company's owned thermal, hydroelectric and wind generation facilities in the period of 2012 through 2016.

(f) Please refer to the Company's response to subpart (e) above.

(g) Please refer to the confidential work paper entitled "ORTAM18w_HeatRateCurves 16Jun CONF.zip", which was included with the five-day work papers supporting the Company's 2018 TAM.

(h) Please refer to Confidential Attachment OPUC 2 –3, which provides actual hourly owned hydroelectric generation for 2012 through 2016.

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

CASE: UE 323
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Opening Testimony

June 9, 2017

OPUC Data Request 270

Please refer to Figure 1 of PAC/400, Dickman/6. For each year in the referenced table, please provide the GRID results and forecasted NVPC using actual values as inputs to the furthest extent possible, including but not limited to the following inputs:

(a) Fuel costs;

(b) Wholesale electricity prices;

(c) Effective outage rate;

(d) Planned outages;

(e) PPAs;

(f) QFs;

(g) Wholesale electricity capacity;

(h) Heat rate;

(i) Hydro generation; and

(j) Retail load.

Response to OPUC Data Request 270

The Company objects to this request as overly broad, unduly burdensome, and not likely to lead to admissible evidence relevant in this proceeding. Without waiving these objections, the Company responds as follows:

The Company has not performed the requested analysis.

CASE: UE 323
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Exhibits in Support
Of Opening Testimony

June 9, 2017

Staff Exhibit 204 is confidential and

Is subject to Protective Order No.16-128

CASE: UE 323
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 205

Exhibits in Support
Of Opening Testimony

June 9, 2017

Staff Exhibit 205 is confidential and

Is subject to Protective Order No.16-128

CASE: UE 323
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

REDACTED

June 9, 2017

Q. Please state your name, occupation, and business address.

A. My name is Rose Anderson. I am a Utility Analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit Staff/301.

Q. What is the purpose of your testimony?

A. I present Staff's analysis of particular issues in response to PacifiCorp's opening testimony in UE 323. I will discuss the valuation of Renewable Energy Certificates (REC), Qualifying Facilities (QF), and the adjustment to net power costs based on avian curtailment following UE 307.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Staff/301: Witness Qualifications Statement.
Staff/302: PacifiCorp's response to OPUC DR 10 providing names and capacity of QFs in PacifiCorp TAM.
Staff/303: PacifiCorp response to CUB DR 1.
Staff/304: Confidential workpapers of Michael G. Wilding on QF costs

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: RENEWABLE ENERGY CERTIFICATES

Value of Freed-up RECs

Q. Please describe the Renewable Energy Credit (REC) valuation issue.

A. In the two most recent TAM proceedings, Calpine Energy Solutions, LLC (Calpine)[1] argued that one- and three-year direct access customers are paying for RECs that the Company will not ultimately be required to retire on their behalf. As such, Calpine argued that the freed-up RECs result in these customers paying twice for RPS compliance; they pay PacifiCorp through Schedule 203 and must also pay their Electricity Service Supplier (ESS).[2] PacifiCorp argued that there was no reliable basis to value the freed-up RECs and that the net present value of freed-up RECs is *de minimus*.[3]

In PacifiCorp's 2017 TAM (docket UE 307), the Commission declined to adopt Calpine's proposed adjustment, concluding that "[i]n the near term, we see little or no benefit from a reduction in RPS obligations due to the loss of load from direct access" and that "a 'freed-up' REC today simply adds to the surplus of RECs that PacifiCorp already has or will have to comply with the RPS."[4] The Commission also noted, however, that over the long run, there may be benefits to the remaining cost of service customers due to changing the point in time in which PacifiCorp would need to take resource actions to comply with the RPS.[5]

[1] Calpine was previously known as Noble Americas Energy Solutions, LLC (Noble Solutions). The Commission approved the name change, due to a sale of ownership interests in the company, in OPUC Order No. 16-479.
[2] UE 296, Noble Solutions/100, Higgins/4 and UE 307, Noble Solutions/100, Higgins/15.
[3] UE 307 PacifiCorp Opening Brief at 56.
[4] Order 16-482 at 22.
[5] *Ibid.*

The Commission also noted that no party in the proceeding had offered a reliable way to estimate the value of RECs due to loss of load and that "any reasonable estimate of benefits from that time period would be *de minimus* when discounted to today's dollars."[6]

Following its conclusion in UE 307, the Commission ordered PacifiCorp, Staff and other parties to further discuss REC valuation in workshops, "with a focus on the potential benefits that may derive at the time PacifiCorp must take substantive action to comply with its RPS targets."[7]

Accordingly, the parties to UE 307 met and discussed potential methods of valuing RECs. During those meetings, the parties discussed potential methods, but did not agree on how to value RECs for customers moving to PacifiCorp's direct access schedules.

In PacifiCorp's initial filing to UE 323, it has proposed a REC valuation method for all direct access customers.[8]

Q. How does PacifiCorp propose to value RECs for customers transitioning to Direct Access?

A. PacifiCorp proposes to include a credit for the RECs freed up by departing direct access customers in the transition adjustment for those customers.[9] Specifically, PacifiCorp proposes to estimate the value of the RECs as the

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[6] *Ibid.*
[7] *Ibid.*
[8] Staff notes that the Company's proposal is to apply this methodology to the transition adjustments for one-, three-, and five- years direct access programs. PAC/100, Wilding/34. During information discussions with the parties, PacifiCorp had initially proposed that 5-year opt-out customers be ineligible for a REC credit, as these customers do not contribute to the Company's Schedule 203. PAC/107, Wilding/68. In this docket, the Company revised its approach and now proposes permanent direct access customers both contribute to Schedule 203 and receive a REC credit.
[9] PAC/100, Wilding/32.

value of the delay in action required to meet Oregon's Renewable Portfolio Standard, converted from future dollars to present value.[10] PacifiCorp bases the estimate of future REC value on several recent long-term REC purchase contracts.[11] PacifiCorp uses a discount rate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to discount the RECs from 2028 dollars to 2018 dollars, resulting in a REC value of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[12]

Q. What method does Staff recommend for REC valuation?

A. Staff views PacifiCorp's suggested method of REC valuation as one reasonable alternative method of preventing subsidization of cost-of-service customers by direct access customers. A different alternative, that might be considered a bookend, would be to credit permanent direct access customers the current market price of RECs. Staff is continuing to evaluate this position and will respond to methodologies proposed by other parties.

Application of Schedule 203

Q. Please describe PacifiCorp's Schedule 203.

A. PacifiCorp's Schedule 203, the Renewable Resource Deferral Supply Service Adjustment, recovers the costs of RECs that were purchased following the Company's 2016 RFP. In docket UE 313, the Commission

[10] PAC/100, Wilding/32-33.
[11] PAC/100, Wilding/33.
[12] PAC/100, Wilding/33.

determined that only one- and three-year direct access customers would be charged for Schedule 203 amounts at the time that they elect direct access.

Q. Has PacifiCorp proposed changes to its Schedule 203?

A. Yes. PacifiCorp proposes that its Schedule 203 also be applied to new direct access customers on the five year/permanent opt-out program.[13] PacifiCorp argues that because the Commission found in UE 313 that one- and three-year direct access customers are subject to Schedule 203, new five-year direct access customers should also be subject to Schedule 203. The Company argues that because those customers' portions of load were included in PacifiCorp's decision to purchase RECs, they should be subject to REC charges under Schedule 203.[14] Under PacifiCorp's proposal, existing five-year/permanent direct access customers would continue not to be subject to Schedule 203 charges because they were not included in PacifiCorp's REC purchase planning.

Q. Does Staff recommend applying Schedule 203 to new 5-year/permanent direct access customers?

A. Yes, it is consistent for new permanent direct access customers receiving a REC credit to also be charged pursuant to Schedule 203. Furthermore, Schedule 203 should apply to all loads for which the Company has planned.

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[13] PAC/100, Wilding/34-35.
[14] PAC/100, Wilding/35.

ISSUE 2: QUALIFYING FACILITIES

Q. Please describe the role of Qualifying Facilities (QFs) in PacifiCorp's TAM filing.

A. PacifiCorp forecasts an increase of approximately $5.6 million (total-Company) in expense for power purchased from QFs compared to the 2017 TAM.[15] The Company asserts that the increase is attributable to several QFs that are expected to reach commercial operation in 2018.[16]

Q. Is PacifiCorp certain that all QFs projected to come online in 2018 will indeed begin service during the 2018 Test Year?

A. No. Pursuant to the TAM Guidelines, the Company includes new QF contracts in the TAM if the Company can attest that it reasonably expects the QF to reach commercial operation during the test period. PacifiCorp is not certain that the four QFs scheduled to come online in 2018 will indeed begin selling power to PacifiCorp in 2018. However, Staff notes that the Company has several opportunities to adjust its forecast before the January 1 effective date of the TAM, with the final update in the beginning of November 2017.

Q. How accurate was the prediction of the number of QFs to come online in the last TAM?

A. In UE 307, PacifiCorp predicted that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** QFs would come online during 2017 before April 30. Of those facilities, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** are online. Data comparing PacifiCorp's Commercial Operation Date (COD) estimates

[15] PAC/100, Wilding/11.
[16] *Ibid.*

from UE 307 to actual online dates of QFs show that **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** In UE 307, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** QFs that PacifiCorp predicted to begin operation after November 7th, 2016 are still delayed. Currently, there is an average **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for QFs that PacifiCorp predicted would come online after PacifiCorp's final Net Power Cost update in UE 307 on November 8, 2016.[17]

Q. Does Staff have any adjustments to QF expenses in the 2018 Test Year?

A. Yes. Staff proposes to adjust the QF expense to account for uncertainty in the commercial operation dates of facilities planned for 2018. One of the four QFs that are expected to begin operation in 2018 is not scheduled until **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** Based on the Company's confidential workpaper, Staff estimates this will result in a downward adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on a system-basis.[18] [19] [20]

[17] Staff/303, Confidential Attachment 1 to PacifiCorp's response to CUB DR 1.
[18] Confidential workpapers of Michael G. Wilding, "ORTAM18 Testimony Support CONF".
[19] Staff/302 (PacifiCorp's response to Staff DR 10).
[20] Staff/304, Confidential Workpapers of Michael G. Wilding, "ORTAM18 NPC Study CONF_2017 03 21".

ISSUE 3: AVIAN ADJUSTMENT

Q. Please describe the avian curtailment expense.

A. In UE 296, ICNU raised an issue with an adjustment to the GRID power cost model that accounted for reduced output at two wind sites, Glenrock and Seven Mile Hill.[21] The Commission rejected ICNUs argument in that docket; however in UE 307 new evidence showed that the Company constructed the two wind sites in an avian-sensitive area while knowingly violating federal law and ignoring the advice of federal agencies.[22] In UE 307, Staff recommended the Commission reject the model change, resulting in a downward adjustment of approximately $64,000 (Oregon-allocated) to the Company's proposed NPC associated with the loss of energy from avian protection curtailments.[23] The Commission adopted Staff's adjustment based on Staff's presentation of evidence that PacifiCorp knew or should have known at the time of siting that there were relevant U.S. Fish and Wildlife Service (USFWS) guidelines for siting wind in avian-sensitive areas that could impact the output of these facilities.[24] Staff's adjustment sought to hold ratepayers harmless from PacifiCorp's decision to site the wind projects in avian-sensitive areas without accounting for the costs of compliance with federal guidance.

[21] UE 296 - ICNU/100, Mullins/4.
[22] Staff's UE 307 Opening Testimony. Staff/200, Kaufman/18.
[23] Order 16-418 at 2.
[24] Order 16-482 at 19-20.

Q. Has PacifiCorp removed the impact of avian curtailment as directed by the Commission in UE 307?

A. Yes. PacifiCorp states in its initial filing that avian curtailment costs are not included in the 2018 TAM.[25] PacifiCorp confirmed in a response to a Staff Data Request that no avian curtailment adjustment has been included in the 2018 TAM.

Q. Does this conclude your testimony?

A. Yes.

[25] PAC/100, Wilding/38.

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

June 9, 2017

WITNESS QUALIFICATION STATEMENT

NAME:	Rose Anderson
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Master of Science, Agriculture and Resource Economics, University of California Davis, Davis, CA Bachelor of Arts, International Political Economy University of Puget Sound, Tacoma, WA
EXPERIENCE:	I have been employed at the Public Utility Commission of Oregon since September of 2016. My position is Utility Analyst in the Energy Rates, Finance and Audit Division. My current responsibilities include review of Affiliated Interest filings and utility labor cost analysis. Prior to working for the PUC I was a Research Associate at McCullough Research for two years. My responsibilities included economic analysis of energy markets and utilities.

CASE: UE 323
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

June 9, 2017

OPUC Data Request 10

Please provide a list of QFs in the 2018 TAM filing with data indicating:

(a) For any QF that is not yet online, the date at which PacifiCorp expects it will come online,

(b) The capacity of each QF that is already online, or the expected capacity of any QFs that will come online in 2018.

Response to OPUC Data Request 10

(a) Please refer to the file entitled “ORTAM18 Testimony Support CONF,” tab entitled “QF” which was included in the confidential work papers filed concurrently with the Direct Testimony of Company witness, Michael G Wilding.

(b) Please refer to the Attachment OPUC 10.

QF Name	Capacity (MW)
Adams Solar	10.00
Astoria Hydro QF 2015-2029	0.03
Ballard Hog Farms Inc	0.05
Bear Creek Solar	10.00
Beatty Solar	5.00
Bell Mountain Hydro Sorenson	0.28
Bell Mountain Power (Jake Amy)	0.45
Beryl Solar QF	3.00
Biomass One QF	32.50
Birch Creek Hydro 1984	2.65
Black Cap II Solar QF	8.00
BLM-Rawlins Wind	0.10
Bly Solar Center, LLC	8.50
Bogus Creek 1998	0.16
Buckhorn Solar QF	3.00
BYU-Idaho 2015-2017	5.60
Cameron Curtiss	0.08
Cargill Biogas	1.70
CDM Hydro 1984	6.00
C-Drop Hydro	1.10
Cedar Valley Solar QF	3.00
Central Oregon Irrigation District	6.00
Chevron Wind p499335 QF	16.50
Chiloquin Solar QF	9.90
Chopin Wind QF	10.00
City of Albany QF	0.50
City of Buffalo - WY	0.20
COID Juniper Ridge	5.00
COMMERCIAL ENERGY MGMT	0.90
Consolidated Irrigation QF	0.48
Cottonwood Lower - UT	0.85
Cottonwood Upper - UT	0.26
Davis County Waste Managemer	1.60
DCFP p316701 QF	6.25
Deschutes Valley Water District	4.30
Dorena Hydro	6.10
Draper Irrigation Company	0.51
Dry Creek 1986	4.00
Duane Wiggins Hydro	0.02
Eagle Point Irrigation District 198	0.72
eBay Solar	0.52
EBD Hydro	2.99
Elbe Solar Center, LLC	10.00
Enterprise Solar I QF	80.00
Escalante Solar I QF	80.00

Escalante Solar II QF	80.00
Escalante Solar III QF	80.00
Evergreen BioPower p351030 QI	10.00
Ewauna Solar	0.83
ExxonMobil p255042 QF	107.40
Falls Creek 1986	4.10
Farm Power Misty Meadows	0.75
Farmers Irrigation District 1983	4.80
Fery, Loyd - OR	0.07
Fiddler's Canyon 1	3.00
Fiddler's Canyon 2	3.00
Fiddler's Canyon 3	3.00
Finley Bioenergy LLC	4.80
Five Pine Wind QF	39.90
Foote Creek II	1.80
Foote Creek III Wind QF	24.50
Galesville Dam 1982	1.80
Garland Canal	3.00
George DeRuyter and Sons Dairy	1.20
Georgetown Power 1984	0.33
Granite Mountain East Solar QF	80.00
Granite Mountain West Solar QF	50.40
Granite Peak Solar QF	3.00
Greenville Solar QF	2.19
Grow Pro	0.01
Hill Air Force Base	2.46
Ingram Warm Springs Ranch 19	0.95
Iron Springs Solar QF	80.00
Ivory Pine Solar QF	10.00
J Bar 9 Ranch	0.10
James & Sharon Jans	0.23
Kennecott Refinery QF	7.54
Kennecott Smelter QF	31.80
Klamath Falls Solar 2, LLC (Ewai	2.90
Lacomb Irrigation 1998	0.96
Laho Solar QF	3.00
Lake Siskiyou - 5000KW C/I 05/	5.00
Latigo Wind Park QF	60.00
Lower Valley Energy	1.70
Lower Valley Energy Culinary - ID	1.70
Lower Valley Energy Upper-Lowe	1.70
LOYDFERY July 2015 - June 20	0.07
Lucky, Paul 2014	0.05
Mariah Wind, LLC	10.00
Marsh Valley Hydro & Electric Co	1.70
Middlefork Irrigation District	3.70
Milford 2 Solar	2.97

Milford Flat Solar QF	3.00
Mink Creek Hydro 1985	2.70
Monroe Hydro	0.30
Monroe Hydro, LLC (Apple, Inc.)	0.30
Mountain Energy	0.05
Mountain Wind 1 p367721 QF	60.90
Mountain Wind 2 p398449 QF	79.80
Nicholson Sunnybar Ranch 1985	0.35
NORTH FORK SPRAGUE(HDIV)	0.75
North Point Wind QF	79.80
NorWest Energy 2 -Neff Solar	9.90
Norwest Energy 7 LLC (Eagle Po	9.90
Odell Creek - 225KW C/I 12/85	0.23
OJ Power Company 1986	0.26
OM Power I Geothermal QF	10.00
OR Solar 2 LLC - Agate Bay	10.00
OR Solar 3 LLC - Turkey Hill	10.00
OR Solar 5 LLC - Merrill	8.00
OR Solar 6 LLC - Lakeview	10.00
OR Solar 7 LLC - Jacksonville	10.00
OR Solar 8 LLC - Dairy	10.00
OR Solar Land Holding LLC - Co	9.90
Oregon Environmental Industries	3.20
Oregon Institute of Technology .2	0.28
Oregon State University	6.50
Oregon Wind Farm QF	
Oregon Wind Farm QF	1.65
Oregon Wind Farm QF	4.95
Oregon Wind Farm QF	10.00
Oregon Wind Farm QF	10.00
Oregon Wind Farm QF	9.90
Oregon Wind Farm QF	8.25
Oregon Wind Farm QF	9.90
Oregon Wind Farm QF	9.90
Oregon Wind Farm QF	3.30
Oregon Wind Farm QF	6.60
Orem Family Wind, LLC	10.00
Pancheri, Inc - 80KW C/I 05/83	0.08
Pavant II Solar QF	50.00
Pioneer Wind Park I QF	80.00
Portland Water Bureau	0.03
Power County North Wind QF p5	22.50
Power County South Wind QF p5	22.50
Preston City Hydro 1982	0.40
Quichapa 1	3.00
Quichapa 2	3.00
Quichapa 3	3.00

Ralphs Ranch, Inc - 100KW C/I	0.10
RES Ag-Oak Lea Biogas	0.17
Roseburg Dillard QF	20.00
Roseburg Forest Products (Weec	10.00
Roseburg LFG	1.60
Rough and Ready Lumber Bioma	1.28
ROUSH Hydro July 2015 - June 2	0.08
Roush Hydro, Inc - OR	0.08
Santiam Water Control District 1	0.16
SF Phosphates	9.50
Slate Creek 1982	4.20
South Milford Solar QF	2.93
Spanish Fork Wind 2 p311681 QI	18.90
Sprague River Solar	7.00
St. Anthony Hydro	0.50
Stahlbush Island Farm	1.60
Sunderland Dairy 150 KW Bio Ga	0.15
Sunnyside p83997/p59965 QF	53.00
Surprise Valley Electrification Coi	3.65
Swalley Irrigation District	0.75
TATA Chemical	30.00
Tesoro QF	25.00
Thayn Ranch Hydro - UT	0.48
Three Peaks Solar QF	80.00
Three Sister Hydro	0.70
Threemile Canyon Wind QF p500	9.90
TMF Biofuels QF	4.80
Tooele Army Depot (Wind 1)	1.50
Tooele Army Depot (Wind 2)	1.70
Tumbleweed Solar QF	9.90
US Magnesium QF	36.00
Utah Pavant Solar QF	50.00
Utah Red Hills Solar QF	80.00
Wadeland South Biomass	0.13
Walla Walla, City of - 2000KW C	2.00
Weber County Landfill	0.95
Weyerhaeuser QF	45.00
Whitney, A C - 2KW C/I 03/81	0.00
Woodline Solar LLC	8.00
Yakima Tieton Cowiche	1.47
Yakima Tieton Orchard	1.40

New QFs in 2018	Capacity (MW)
Sweetwater Solar QF	80
Norwest Energy 9 LLC (Pendleton)	6.6
Norwest Energy 4 LLC (Bonanza)	4.8
Cypress Creek Renewables - Merr	10

CASE: UE 323
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Exhibits in Support
Of Opening Testimony

June 9, 2017

Staff Exhibit 303 is confidential and

Is subject to Protective Order No.16-128.

CASE: UE 323
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 304

Exhibits in Support
Of Opening Testimony

June 9, 2017

Staff Exhibit 304 is confidential and

Is subject to Protective Order No.16-128.