BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 323

In the Matter of PACIFICORP, dba PACIFIC POWER, 2018 Transition Adjustment Mechanism.	COMMISSION STAFF'S CROSS-EXAMINATION EXHIBITS

Pursuant to Administrative Law Judge Rowe's April 26, 2017 Prehearing Conference Memorandum, Commission Staff submits the following cross-examination exhibits in docket UE 323, not previously filed in this case:

Cross-Examination Exhibit	Description
Staff/700	PacifiCorp Response to OPUC DR 27 (attachment confidential)
Staff/701	PacifiCorp Response to OPCU DR 53
Staff/702	PacifiCorp Response to OPCU DR 54
Staff/703	PacifiCorp Response to OPCU DR 55
Staff/704	PacifiCorp Response to OPCU DR 56, including list of workpapers (Confidential)
Staff/705	PacifiCorp Response to OPCU DR 57
Staff/706	PacifiCorp Response to OPCU DR 58 (Confidential)
Staff/707	PacifiCorp Response to OPCU DR 59
Staff/708	PacifiCorp Response to OPCU DR 60
Staff/709	PacifiCorp Response to OPCU DR 61 (Confidential)
Staff/710	PacifiCorp Response to OPUC DR 62

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Staff/711	PacifiCorp Response to OPUC DR 67
Staff/712	Excerpt from PacifiCorp workpaper "_JulyCum ORTAM18 NPC Study CONF," tab "NPC" (Confidential)
Staff/713	PacifiCorp Response to OPUC DR 63
Staff/714	PacifiCorp Response to OPUC DR 65 (attachment confidential)
Staff/715	UE 296 – Direct and Reply Testimony of Brian S. Dickman (excerpts)
Staff/716	UE 296 – Direct Testimony of Frank C. Graves
Staff/717	UE 307 – Direct and Reply Testimony of Brian S. Dickman (excerpts)
Staff/718	Summary Table of GRID Modifications in UE 296
Staff/719	PacifiCorp Response to OPUC DR 76
Staff/720	PacifiCorp Response to OPUC DR 77
Staff/721	PacifiCorp Response to OPUC DR 78
Staff/722	PacifiCorp Response to OPUC DR 79

Confidential exhibits will be mailed in hard copy to those parties that have signed the appropriate protective order in place in this docket.

DATED this 29th day of August, 2017.

Respectfully submitted,

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CERTIFICATE OF SERVICE

UE 323

I certify that I have, this date, served COMMISSION STAFF'S CROSS-EXAMINATION EXHIBITS confidential pages in docket UE 323 upon the parties listed below via first class mail.

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DATED this 24th day of August, 2017.

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OPUC Data Request 27

Energy Imbalance Market (EIM) - Re: Ms. Brown's work paper titled "TAM workbook EIM benefit" tab "2018 Inter regional" and provide the following information:

Please provide all data in an electronic format used to calculate cells C42 and D42.

Response to OPUC Data Request 27

Please refer to Confidential Attachment OPUC 27.

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.

OPUC Data Request 53

Please refer to PAC/400, Wilding/32, lines 12 and 13.

(a) Please provide the NPC forecast of Staff's proposed economic shutdown using the effective outage files provided in Staff's work paper "EOR JB1 60 CH 60.csv" with GRID dispatch and pricing tier coal costs modified to reflect actual coal contracts and average coal costs consistent with the GRID coal use.

(b) Please calculate Cholla coal costs under the assumption that the end of year Cholla coal inventory is the same as the beginning of year Cholla coal inventory.

(c) For all other inputs please use the same assumptions as used in PacifiCorp's July TAM update.

(d) Please include the NPC work papers, including but not limited to system balancing DART calculation work papers and coal cost GRID input work papers. Please only provide work papers that differ from the TAM July Update work papers.

Response to OPUC Data Request 53

The Company objects to this response as overly burdensome. PacifiCorp provides Staff of the Public Utility Commission of Oregon and other parties access to the Company's Generation and regulation Initiative Decision tools model (GRID) as part of the Transition Adjustment Mechanism process.

OPUC Data Request 54

Please refer to PAC/400, Wilding/30, lines 9 to 15.

(a) Please provide the NPC forecast from the July TAM update with the effective outage rate modified to reflect economic shutdowns for the same plants and at the same times as the 2016 reserve shutdowns identified in Staff/502, Kaufman/2.

(b) Please update the dispatch and pricing tier coal cost GRID inputs to reflect actual coal contracts and average coal costs consistent with the GRID coal use.

(c) Please calculate Cholla coal costs under the assumption that the end of year Cholla coal inventory is the same as the beginning of year Cholla coal inventory.

(d) For all other inputs please use the same assumptions as used in PacifiCorp's July TAM update.

(e) Please include the NPC work papers, including but not limited to system balancing DART calculation work papers and coal cost GRID input work papers. Please only provide work papers that differ from the TAM July Update work papers.

Response to OPUC Data Request 54

The Company objects to this response as overly burdensome. PacifiCorp provides Staff of the Public Utility Commission of Oregon and other parties access to the Company's Generation and regulation Initiative Decision tools model (GRID) as part of the Transition Adjustment Mechanism process.

OPUC Data Request 55

Please refer to PAC/400, Wilding/32, lines 17 and 18. Please provide the following:

(a) Details of the APS Exchange including any revenues or power transactions associated with it;

(b) A copy of the APS Exchange agreement;

(c) An explanation of how the APS Exchange is modeled in GRID;

(d) An explanation of why Cholla is included as a dispatchable resource in GRID during the period of the APS Exchange.

Response to OPUC Data Request 55

(a) Please refer to Confidential Attachment OPUC 55 -1, which provides 2016 revenues and power transactions associated with the Arizona Public Service Company (APS) exchange agreement. Please refer to Attachment OPUC 55 -2, which provides a copy of the APS exchange agreement.

(b) Please refer to the Company's response to subpart (a) above.

(c) In the Generation and Regulation Initiative Decision Tool (GRID) the APS Exchange is modeled as an "Energy Limited" contract. "Energy Limited" contracts are contracts for which GRID shapes the delivery or receiving energy against prices within specified constraints. The APS Exchange has 480 MW capacity, which allows the Company to deliver energy to APS starting May 15 to September 15, and receive energy from APS starting October 15 to February 15, under maximum monthly load factor and maximum weekly load factor constraints as determined by the contract. GRID shapes the exchange energy as a call option such that the take occurs in the highest priced hours first, subject to the specified load factor constraints.

(d) Cholla is included as a dispatchable resource in GRID during the period of the APS Exchange as this ensures sufficient resources remain available for summer deliveries under the APS Exchange contract and to serve higher summer time loads.

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.

OPUC Data Request 56

Please refer to ICNU/100, Mullins/6 at lines 1 and 2.

(a) Please provide a detailed description of how the hourly commitment of gas plants is performed outside the GRID model.

(b) Please provide all GRID runs associated with developing the final hourly commitment of gas plants.

(c) Please provide the work papers used as part of the gas screening process.

(d) Please explain why this screening process is only applied to gas plants, and not applied to coal plants.

(e) Please explain what modifications to the screening process are necessary to apply the gas screening process to the coal screening process. For each modification explain why it is necessary.

Response to OPUC Data Request 56

(a) The gas screening process outside the Generation and Regulation Initiative Decision Tool (GRID) determines hourly commitment status of all gas units based on planned outage schedule and comparison of system cost with and without each unit that can cycle on and offline.

Step 1: A GRID run is prepared with all gas-fired units online in all hours (except during annual planned outages).

Step 2: A second GRID run is prepared with highest cost gas unit turned off in all hours.

Step 3: Compare hourly system costs with and without that gas unit, and select operating periods that minimize net system cost, subject to start-up / shutdown time limits, and start-up expenses. This is done in a Microsoft Excel template.

Step 4: Prepare a GRID run with that gas unit "screened" so that it is online only during the selected periods.

Repeat for remaining gas units: "Step 4" becomes the "Step 1" run for the next highest cost gas unit, and the process is repeated.

(b) Please refer to Confidential Attachment OPUC 56.

(c) Please refer to the work papers with the file name starting with "Screen - .....xlsm," for example "Screen - 1 GAD CONF.xlsm" and so on. These files are provided in the 5-day work papers that support the Direct Testimony of Company witness, Michael G. Wilding.

(d) Please refer to the Surrebuttal Testimony of Company witness, Michael G. Wilding (PAC/800, Wilding/46-47).

(e) The Company has not perform any screening process to coal plants. At hypothetical level, the modifications to the gas screening process may potentially include, but not be limited to, the following:

(1) Total system reliability requirement and reserve requirement to meet Federal Energy Regulatory Commission (FERC) and Western Electricity Coordinating Council (WECC) compliances.

(2) Coal plants units start-up cost and start-up time to reflect actual cost of screening coal plants.

(3) The Company actual operation constraints to ensure the Company serve load and other obligations in feasible and effective manner.

(4) Coal supply curve and coal contract minimum take or pay volume requirements to meet any coal contracts obligation and control liquidate damages.

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OPUC Data Request 57

Please refer to PAC/600, Ralston/9 at line 8. Please provide the referenced amended CSA.

Response to OPUC Data Request 57

The requested coal supply agreement (CSA) is considered highly confidential and commercially sensitive. The Company requests special handling. Please contact Natasha Siores at (503) 813-6583 to make arrangements for a review.

OPUC Data Request 58

Please refer to PAC/600, Ralston/8, lines7 and 8. Please also refer to Staff/502, Kaufman/1.

(a) Please identify the size of a coal stockpile that avoids incremental maintenance costs at Cholla.

(b) Please identify the size of a coal stockpile that avoids operational issues and risks associated.

(c) Please describe the types and sources of incremental maintenance costs associated with a large coal stockpile at Cholla.

(d) Please describe the operational issues associated with a small coal stockpile at Cholla.

(e) Please describe the risks associated with a small coal stockpile at Cholla.

(f) For each month beginning January 2013, and ending July 2017, identify the amount of incremental maintenance costs associated with having a large stockpile.

(g) For each month beginning January 2013 and ending July 2017, identify whether PacifiCorp encountered operational issues and risks with having a small stockpile. Please describe the operation issues and risks encountered each month.

Confidential Response to OPUC Data Request 58

(a) PacifiCorp targets a range of approximately [redacted] tons (PacifiCorp share) for the Cholla plant. This represents a coal inventory level of approximately [redacted] days of available consumption. The maximum stockpile size permitted and allowed at the Cholla plant is [redacted] tons. This includes PacifiCorp share and Arizona Public Service Company (APS) share. As the coal inventory stockpile level increases, additional pile grooming and pile maintenance must be performed with dozers to compact the pile to comply with fugitive dust suppression and other requirements. PacifiCorp has not analyzed the incremental costs associated with both increasing and decreasing the pile size.

(b) When the stockpile is reduced to a level below approximately [redacted] days burn or approximately [redacted] tons, the risk of not having coal available for consumption increases. If PacifiCorp had insufficient or no coal available in the stockpile to consume for electricity generation, the cost to customers to purchase power could increase substantially as well as losing opportunities to sell power into the Palo Verde (PV) market.

(c) Please refer to the responses to subparts (a) and (b) above.

(d) Please refer to the responses to subparts (a) and (b) above.

(e) Please refer to the responses to subparts (a) and (b) above.

(f) For the referenced time period, the total (PacifiCorp and APS) coal stockpile level at the Cholla plant remained below levels that would require additional pile grooming and pile maintenance costs associated with having a large stockpile.

(g) For the referenced time period, the total (PacifiCorp and APS) coal stockpile level at the Cholla plant remained above levels where PacifiCorp would have encountered operational issues and risks with having a small stockpile.

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OPUC Data Request 59

Please refer to PAC/600, Ralston/8, lines7 and 8. Please also refer to PAC/600, Ralston/15.

(a) Please describe the analysis performed by PacifiCorp when determining the appropriate level of coal supply or transport contract damages or minimum take levels. If such analysis differs by plant, provide such information separately for each plant.

(b) Please explain how PacifiCorp incorporated the incremental maintenance costs of a large coal pile into its decision to engage in a Cholla supply contract and transportation contract with liquidated damages.

(c) Please explain how PacifiCorp is analyzing and incorporating the risks associated with minimum takes and liquidated damages in the analysis of the Black Butte mine CSA.

Response to OPUC Data Request 59

(a) PacifiCorp's coal supply and stockpile policies, procedures and strategies have previously been provided to the OPUC Staff for review in previous TAM proceedings. This information was provided on May 18, 2016, in docket UE 307 in response to OPUC Data Request 18 as well as on July 9, 2013, in docket UE 264 in response to OPUC Data Request 9.

This analysis takes into consideration the unique circumstances of each plant, which includes targeted coal stockpile levels, forecasted plant capacity and generation levels, rail and truck offloading infrastructure, market price and supplier alternatives, contract pricing thresholds that would trigger price breaks or cost increases, as well as supply and transportation risks, when negotiating minimum take and liquidated damages provisions in contracts. Coal at the minimum take volume is valued under the terms for minimum take that are specified within the contract.

(b) Taking into consideration expected future market prices, plant demand for coal, plant remaining life, environmental and regulatory requirements, coal stockpile targets and costs, and the financial capacity of providers, the Company negotiated the coal supply agreement (CSA) and transportation contracts so as to maximize benefits for customers, while limiting their risks and exposure to changes in economic and regulatory environments. Plant coal inventory stockpiles can frequently be utilized to temporarily absorb surplus coal volumes for consumption in future periods. This facilitates the elimination or mitigation of potential charges for liquidated damages.

(c) Please refer to the Company's response to Sierra Club Data Request 2.3, specifically subpart (a).

OPUC Data Request 60

Please refer to PAC/600, Ralston/15. Has PacifiCorp determined the minimum rail infrastructure needed to accommodate an increase in Powder River Basin coal delivery? If yes, please describe the infrastructure and explain the costs. If no, why not?

Response to OPUC Data Request 60

The Company objects to this response as not relevant and not reasonably calculated to lead to the discovery of admissible evidence. Any potential future increase to deliveries from the Powder River Basin (PRB) would not affect PacifiCorp's 2018 net power costs (NPC). PacifiCorp's long-term fueling strategy for the Jim Bridger plant is subject to separate, on-going discussions while the Company continues to evaluate all components of that strategy.

OPUC Data Request 61

CONFIDENTIAL REQUEST - Please refer to Staff/502, Kaufman/2.

(a) Please explain why **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**

(b) Please provide all agreements related to **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**

(c) Please provide the price for the **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**

Confidential Response to OPUC Data Request 61

(a) [redacted]

(b) Please refer to Confidential Attachment OPUC 61.

(c) The unit cost for the transfer of [redacted] tons was $[redacted] ($/ton), as computed in the confidential table below. The dollars ($) associated with the transfer are included as part of Total Company Adjusted Actual Net Power Cost (NPC) and are used in computing Total Power Cost Adjustment Mechanism (PCAM) Adjusted Actual Costs.

		Tons	**Dollars ($)**	**Unit Cost ($/ton)**
APS Inventory Transfer	**Estimate Recorded May 2016**	[redacted]	[redacted]	[redacted]
APS Inventory Transfer	**April 2016 Actual Recorded May 2016**	[redacted]	[redacted]	[redacted]
APS Inventory Transfer	**May 2016 True-up Recorded June 2016**	[redacted]	[redacted]	[redacted]
Total		[redacted]	[redacted]	

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OPUC Data Request 62

Energy Imbalance Market (EIM) - Regarding's the Company's response to Staff DR No. 23 (a), specifically in reference to the growth rate which it applies apart from future market entrant considerations:

(a) According to the Company's understanding of its methodology, please provide a quantification of the growth rate which it applies.

(b) How would the Company's forecast change if the growth rate was not applied?

(c) Please provide an example of a forecast which does not incorporate a growth rate but also relies on historical data.

Response to OPUC Data Request 62

(a) Please refer to the Surrebuttal Testimony of Company witness, Kelcey A. Brown, PAC/900, page 2, lines 17-20 for the percentage growth rates of PacifiCorp's estimated inter-regional benefits.

(b) PacifiCorp has not performed the requested analysis. Please refer to Ms. Brown's Reply Testimony, PAC/500, pages 4-5, lines 12-18, and lines 1-14, for a description of how PacifiCorp estimated its energy imbalance market (EIM) benefits.

(c) PacifiCorp has not performed the requested analysis. However, quantitative forecast models that utilize historical data can vary based on the variable that is being forecast and the underlying factors that might influence that variable.

OPUC Data Request 67

Energy Imbalance Market (EIM) - Regarding PAC/900, Brown/2, line 5 and 6: Please describe PacifiCorp's understanding of Staff's treatment of new entrant adjustments (PGE, IPC, and Solar) in its original proposal. Please indicate whether the Company understands Staff to have included PacifiCorp's new entrant adjustment in the base, to which it then applied a trend when calculating its original adjustment proposal. If so, please explain why the Company believes that Staff's original methodology did not amount to double-counting growth forecasts, while Staff's new methodology does.

Response to OPUC Data Request 67

Please refer to Opening Testimony of Public Utility Commission of Oregon (OPUC) witness, Scott Gibbens; specifically Staff/100, Gibbens/10, lines 5-7. PacifiCorp understood from OPUC staff's Opening Testimony that its proposal to utilize a growth rate to forecast energy imbalance market (EIM) benefits was based on an assumption that PacifiCorp's methodology did not adequately account for new entrants. Please refer to the Surrebuttal Testimony of Company witness, Kelcey A. Brown; specifically PAC/900, Brown/5, lines 11-16 for an explanation of PacifiCorp's understanding of OPUC staff's treatment of new entrant adjustments.

Please refer to Ms. Brown's Surrebuttal Testimony; specifically PAC/900, Brown/5, lines 17-19 and PAC/900, Brown/6, lines 1-2 for an explanation as to why the Company believes that OPUC staff's new methodology double counts the impact of new market entrants.

OPUC Data Request 63

Energy Imbalance Market (EIM) - Regarding the Company's response to Staff DR No. 24:

(a) Please explain further how the referenced workbook contains information on the source of year over year increases to EIM benefits. Please include specific references to cells. Please also explain how PAC performed the analysis without reviewing 2015 data.

(b) How did PAC control for variation in weather, natural gas prices, and the impact of other entrants in its analysis?

Response to OPUC Data Request 63

(a) PacifiCorp's response to OPUC Data Request 24, which discussed the increase in benefits relative to Nevada Energy joining the energy imbalance market (EIM) in December 2015, referenced the increase in import and export volumes after December 2015 versus prior to December 2015 wherein PacifiCorp only had import and export capability through PacifiCorp West (PACW). Please refer to the Company's response to OPUC 16 for the 2015 import and export volumes.

The referenced workbook in the Company's response to OPUC Data Request 24 includes a comparison of 2015 actual EIM benefits versus 2016 actual EIM benefits, indicating a growth rate of 56 percent. PacifiCorp utilized 2015 EIM benefit information to calculate the 56 percent growth rate.

(b) As discussed in the Company's response to subpart (a) above, PacifiCorp's response to OPUC Data Request 24 references the change in import and export volumes relative to the entrance of Nevada Energy in 2015. The change in volume is easy to verify as directly attributable to the additional transmission connection with Nevada Energy and subsequently the California Independent System Operator (CAISO) through the PacifiCorp East (PACE) Balancing Area (BA) as this was not available in the EIM prior to December 2015.

OPUC Data Request 65

Energy Imbalance Market (EIM) - Regarding PAC/900, Brown/1, line 19- 21: Please provide the data relied upon and proof of calculation (formula in cell) to calculate the two percentage numbers present (51% and 45%). Please also explain how PacifiCorp accounted for new entrant adjustments in its calculation of forecast and base amounts.

Response to OPUC Data Request 65

Please refer to Confidential Attachment OPUC 65, which provides the calculation of the 51 percent increase in benefits relative to PacifiCorp's initial filing, and a 45 percent increase relative to the most recent 12 months of actual inter-regional benefits.

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Docket No. UE 307
Exhibit PAC/100
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Direct Testimony of Brian S. Dickman

April 2016

DIRECT TESTIMONY OF BRIAN S. DICKMAN

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ATTACHED EXHIBITS

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Exhibit PAC/102—Net Power Costs Report

Exhibit PAC/103—Update to Other Revenues

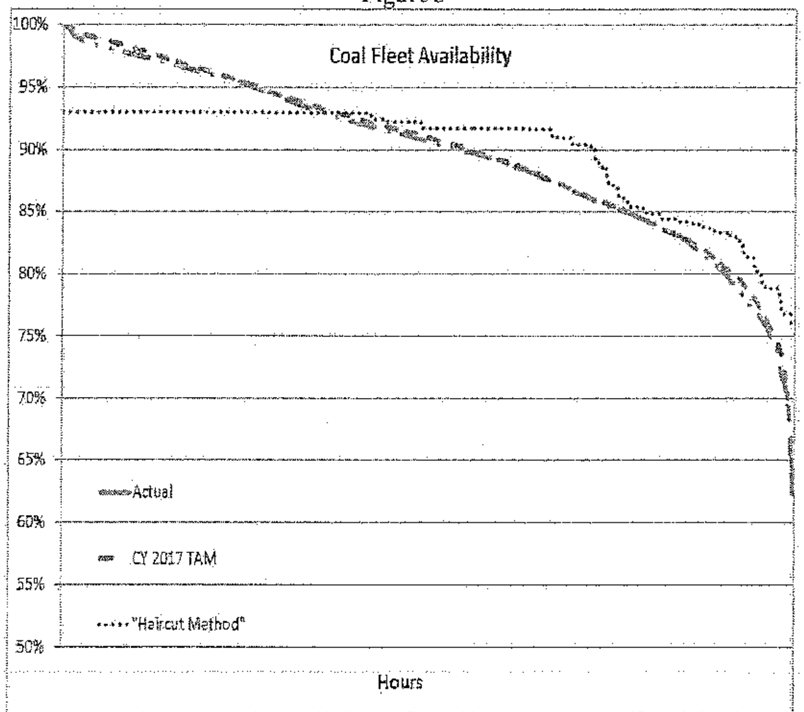
Exhibit PAC/104—Energy Imbalance Market Import and Export Summary

Exhibit PAC/105—Energy Imbalance Market Costs

Exhibit PAC/106 – Update to Renewable Energy Production Tax Credits

Exhibit PAC/107—List of Expected or Known Contract Updates

Figure 3



EIM Costs and Benefits

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

A. The Company adjusted the 2017 NPC forecast from GRID to reflect incremental EIM benefits from inter-regional dispatch (i.e., exports and imports between EIM participants) and reduced flexibility reserves. The 2017 TAM includes approximately $13.9 million of EIM benefits on a total-company basis as a reduction to the NPC forecast. The Company also included $6.4 million of total-company costs related to EIM participation during 2017. Table 2 below summarizes the EIM-related benefits and costs included in the 2017 TAM and shows changes compared to the 2016 TAM.

Table 2
Total-Company EIM-Related Benefits and Costs

$ millions	2016 TAM	2017 TAM
Inter-regional dispatch	$8.4	$11.3
Flexibility Reserves	$1.7	$2.6
Test-period EIM benefits	**$10.1**	**$13.9**
Test-period EIM costs	$5.1	$6.4

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

A. The EIM is a real-time balancing market that optimizes generator dispatch every five and 15 minutes within and between the PacifiCorp and the CAISO balancing authority areas (BAAs). EIM operation went live October 1, 2014, with financially binding operations effective November 1, 2014. By participating in the EIM, the Company's participating generation units are optimally dispatched using the CAISO's computerized security constrained economic dispatch model. The EIM's automated, expanded footprint, co-optimized dispatch replaced the Company's largely isolated and manual dispatch within its two BAAs. Participation in the EIM produces benefits to customers in the form of reduced NPC, partially offset by costs for initial start-up and ongoing operation.

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

A. Participation in the EIM reduces the Company's actual NPC in three ways: (1) optimizing the automated dispatch of participating units in PacifiCorp's BAAs, subject to transmission constraints, using the CAISO's system model; (2) facilitating transactions between CAISO, PacifiCorp, and other EIM participants on a five- and 15-minute basis; and (3) reducing the amount of flexible generating capacity required to be held in reserve by PacifiCorp due to the collective reduction of reserves for the larger and more diversified EIM footprint. Benefits realized for the last two categories are highly dependent on the amount of transfer capacity between EIM participants that is made available for the EIM.

Q. **Does each of these benefits cause a corresponding reduction to the GRID model NPC forecast?**

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

Q. **Please describe the EIM-related costs included in the 2017 TAM.**

A. Consistent with the structure of the settlement reached in the 2015 TAM and the approved 2016 TAM, the Company included $6.4 million of total-company EIM-related costs in the 2017 TAM. These costs consist of the return on net rate base from the capital investment required to participate in the EIM, depreciation expense, and ongoing operations and maintenance (O&M) expenses and transaction fees. A summary of the various cost components is provided as Exhibit PAC/105. Including all EIM-related costs in the 2017 TAM is necessary to ensure that customer rates reflect a proper matching of EIM benefits. This same treatment was approved in the 2016 TAM, and it is consistent with the stipulation in docket UE 287, which first addressed EIM-related costs in the TAM. Rates set in the Company's most recent general rate case, docket UE 263, do not include any EIM-related costs. Until these costs are included in base rates, EIM benefits included in the Company's TAM filings should be net of the ongoing cost of participation.

Q. How is the EIM inter-regional dispatch benefit for transfers to and from CAISO calculated for the forecast period?

A. The export benefits reflect the difference between the Company's revenues from exports to CAISO and the incremental cost of the Company's generation resources that supported the transfer. The export benefit is then expressed in dollars per megawatt-hour of available EIM transfer capability. As in the 2016 TAM, this rate is applied to the available EIM transfer capability in the forecast period. Similarly, the import benefits reflect the difference between the incremental cost of the Company's generation resources that would otherwise have been dispatched, and the costs of imports from CAISO. As in the 2016 TAM, the average import benefit is expressed in dollars per month, and applied to each of the months in the forecast period. Also as in the 2016 TAM, distinct export and import benefits are calculated for two seasons: for the summer period of June through September and for the remaining months of October through May.

Q. Has the EIM inter-regional dispatch benefit for transfers to and from CAISO been updated since the 2016 TAM?

A. Yes. First, the Company's forecast in the 2017 TAM is now based on actual results from January 2015 through December 2015. Second, the Company has now identified the specific incremental resources in each interval of the historical period. In the 2016 TAM, a blend of the incremental costs of the Chehalis, Hermiston, and Jim Bridger was used to approximate the marginal impact of exports and imports.

Q. How does the Company identify the specific incremental resources in each interval of the historical period?

A. Each of the Company's EIM-participating resources submits bids that reflect their cost over their dispatchable range. A unit may have one bid for the entire dispatchable range, or several bids if its heat rate or other operational characteristics create cost variations over that range. The bids are ranked from lowest to highest, and the volume associated with each bid is identified. The resulting supply stack identifies all of the volumes available, and the associated price for each. Starting with the lowest cost unit, EIM dispatches resources up until the total output matches demand for that interval.

When the Company is exporting, the first unit with a bid price that is lower than the transfer price is identified from the supply stack. This represents the last unit the Company dispatched to serve the transfer. The calculation moves down the supply stack until the entire export volume is covered, identifying the prices and volumes of the specific resources the Company would not have dispatched but for the export volume. Similarly, when the Company is importing, the first unit with a bid price that is higher than the transfer price is identified from the supply stack. This represents the next unit the Company would have dispatched to serve its own load, but for the import. The calculation moves up the supply stack until the entire import volume is covered. This identifies the prices and volumes of the specific resources the Company was able to avoid dispatching as they were more expensive than the import cost.

Q. What is the effect of the update to the EIM inter-regional dispatch benefits?

A. Compared to the margins used in the 2016 TAM, the updated EIM inter-regional dispatch margins produce an additional $4.1 million in benefits on a total-company basis.

Q. Has the Company incorporated inter-regional EIM benefits associated with the participation of NV Energy (NVE), Puget Sound Energy (PSE), and Arizona Public Service (APS)?

A. Yes. The methodology for determining these benefits is the same as that utilized in the 2016 TAM. While NVE started participating in EIM in December 2015, at this time the Company has not proposed a change in the associated benefits methodology or incorporated benefits based on the very limited available historical data. PSE and APS are expected to participate in EIM starting in October 2016, so twelve months of benefits from their participation are also included in the 2017 TAM. The Company intends to gather several more months of actual results from NVE's participation which it will incorporate in its reply filing.

Q. Have any other parties expressed interest in joining the EIM in the future?

A. Yes. On November 20, 2015, Portland General Electric (PGE) announced it intends to begin participating in the EIM in October 2017. Initial reports indicate that PGE's participation in the EIM is expected to produce annual inter-regional benefits to existing participants of $2.7 million.[11] The 2017 TAM includes the Company's share of those benefits to existing participants from PGE joining the EIM, based on the same ratio used to account for the participation of APS and PSE in the 2016 TAM.

[11] http://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf.

Q. Does the Company's forecast include flexibility reserve benefits from its participation in the EIM?

A. Yes. The regulating reserve requirement modeled in GRID has been reduced by roughly 68 MW to account for the Company's share of the reserve benefit based on the diversified footprint of the EIM. The methodologies for determining the reduction in reserves associated with CAISO, NVE, APS and PSE participation in the EIM are unchanged from the 2016 TAM. The Company has also included the diversity benefit associated with PGE's participation in the EIM beginning in October 2017, using a comparable methodology to that used for APS and PSE in the 2016 TAM. The overall reduction in the Company's reserve requirement from its participation in EIM decreases NPC by approximately $2.6 million on a total-company basis.

COMPLIANCE WITH TAM GUIDELINES

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

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

Q. Did the Company make changes to GRID in this case?

A. No.

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

A. Yes.

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

A. Yes. Exhibit PAC/107 contains a list of known contracts and other items that could be included in the Company's TAM updates in this case based on the best information available at the time the Company prepared the NPC study.

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

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

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UE 307
Exhibit PAC/104
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Brian S. Dickman

Energy Imbalance Market Import and Export Summary

April 2016

PacifiCorp
Oregon - CY 2017 TAM
EIM Benefits - PacifiCorp - CAISO Imports and Exports

PacifiCorp - CAISO EIM Import and Export Results

	1/1/2015	2/1/2015	3/1/2015	4/1/2015	5/1/2015	6/1/2015	7/1/2015	8/1/2015	9/1/2015	10/1/2015	11/1/2015	12/1/2015	Total	Initial Filing OR TAM CY2017
Export Volume (MWh)	154,281	88,453	93,966	82,893	155,040	195,319	211,647	151,866	87,383	54,672	113,165	134,890	1,523,575	1,045,386
Export Volume (aMW)	207	132	126	115	208	271	284	204	121	73	157	181	174	119
Import Volume (MWh)	20,044	24,757	22,154	19,243	19,505	11,888	9,756	13,859	11,660	20,315	26,508	24,351	224,040	224,040
Import Volume (aMW)	27	37	30	27	26	17	13	19	16	27	37	33	26	26
Transmission Left Open (MWh)	219,389	196,934	192,460	131,104	241,202	265,478	221,797	203,244	197,537	246,422	149,751	148,733	2,414,052	1,632,781
Transmission Left Open (aMW)	295	293	259	182	324	369	298	273	274	331	208	200	276	186
Export Margin	1,222,510	753,588	603,865	537,696	997,371	1,630,360	1,762,451	1,352,010	495,414	444,147	728,625	789,566	$11,317,602	$7,84[illegible]79
Import Margin	44,431	250,959	163,906	150,883	114,615	43,919	54,949	93,655	100,960	(30,292)	104,300	74,906	$1,167,191	$1,16[illegible]191
Export Load Factor	70%	45%	49%	63%	64%	74%	95%	75%	44%	22%	76%	91%	63%	[illegible]4%
Export Margin $/MWh	$7.92	$8.52	$6.43	$6.49	$6.43	$8.35	$8.33	$8.90	$5.67	$8.12	$6.44	$5.85	$7.43	$[illegible].50
Export $/MWh Avail Transmission	$5.57	$3.83	$3.14	$4.10	$4.14	$6.14	$7.95	$6.65	$2.51	$1.80	$4.87	$5.31	$4.69	$[illegible].80
Import $/MWh	$2.22	$10.14	$7.40	$7.84	$5.88	$3.69	$5.63	$6.76	$8.66	-$1.49	$3.93	$3.08	$5.21	$5.2[illegible]
Total Benefit	$1,266,941	$1,004,547	$767,771	$688,579	$1,111,986	$1,674,279	$1,817,400	$1,445,665	$596,374	$413,855	$832,925	$864,472	$12,484,794	$9,00[illegible]07[illegible]

Docket No. UE 307
Exhibit PAC/400
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Brian S. Dickman

August 2016

REPLY TESTIMONY OF BRIAN S. DICKMAN

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adjustment is zero. Second, Mr. Ralston rebuts CUB's argument that coal supply agreements are imprudent for including take-or-pay provisions.

EIM Benefits – General

Q. In the Initial Filing, how did the Company model the benefits resulting from its participation in the EIM?

A. As I described in my direct testimony, the Company's forecast of EIM benefits in the Initial Filing was based on actual results from January 2015 through December 2015. Consistent with the 2016 TAM, the Company's Initial Filing included benefits associated with inter-regional dispatch, which result from transactions between PacifiCorp and the CAISO, and flexibility reserve benefits, which result from a reduced regulating reserve requirement modeled in GRID. These benefits are in addition to the optimized dispatch of the Company's generation within its balancing authority areas (BAA) (*i.e.*, intra-regional dispatch), which can now be achieved in actual operation and which has always been reflected in the GRID model.

Q. Is the Company's calculation of the EIM benefits in the 2017 TAM more refined than in the 2016 TAM?

A. Yes. First, the Company utilized a full year of historical results, as compared to the 10 months of actual results available in the 2016 TAM.[58] Second, the Company refined the calculation of inter-regional dispatch benefits to identify the cost of specific incremental resources that could have facilitated transfers in each interval of the historical period. Generally, the benefit of EIM exports is equal to

[58] In the 2016 TAM, the Company's modeling used actual results from December 2014 through September 2015, which were the most up-to-date results available at that time.

the difference between the revenue received less the expense of generation assumed to supply the transfer. The benefit of EIM imports is equal to the import expense less the avoided expense of the generation that would have otherwise been dispatched. The refined calculation includes a more accurate production cost, resulting in a more accurate calculation of inter-regional benefits.

Q. **Has the Company updated EIM benefits and costs in its Reply Update?**

A. Yes. The EIM benefits in the Company's Initial Filing were derived from actual results from the participation of the Company and the CAISO in EIM, and expected results from the participation of NVE, Puget Sound Energy (PSE), Arizona Public Service (APS), and Portland General Electric (PGE). NVE began participating in EIM in December 2015, and the Company now has six months of actual results reflecting the expanded EIM footprint encompassing the Company, the CAISO, and NVE. To reflect the best information available for the expanded EIM footprint, the Company has based the EIM inter-regional transfer benefits in its Reply Update on the twelve months ending May 2016, with annualizing adjustments to account for the impact of NVE participation. Annualizing the results over a twelve month historical period captures the expected seasonal variation in EIM benefits. The specific annualizing adjustments are as follows:

- The December 2015 through May 2016 results for PACE-NVE imports and exports cover most of the October through May "other" season developed in the 2016 TAM to capture the seasonality of EIM benefits. Therefore the average import and export margin from this period is used for the "other" months not covered by the available data. Because

PacifiCorp and NVE operate the paths interconnecting their transmission systems EIM has greater flexibility to determine the transfers over those paths relative to the transfers between PACW and the CAISO over a path operated by BPA. For instance, all un-scheduled transmission capacity between PACE and NVE becomes available to EIM, including counterflows offsetting the hourly schedules on reserved capacity across the path. This is not the case between PACW and the CAISO. In light of this distinction, the margin on imports and exports between PACE and NVE is calculated as a monthly average, rather than as a function of transmission utilization.

- The available PACE-NVE import and export data does not include any summer months. To estimate the benefits during these months, the Company compared the PACW-CAISO inter-regional transfer margin in the summer to that in "other" months. PACW-CAISO import margin was 54 percent lower in the summer, while the export margin was 103 percent higher. These same percentages have been used to adjust the average PACE-NVE import and export margin during "other" months to levels appropriate to the summer season.
- While the Company has PACW-CAISO import and export data for the full twelve-month history, six of those months did not include NVE participation in EIM, including the entire summer period. Transfers to the CAISO and NVE can both rely on PACE resources. While NVE participation has increased the Company overall inter-regional transfer

margin, when the Company transfers to NVE it may be forgoing lower value transfers to the CAISO. This is evident by comparing the historical results for January through May 2015 to those for January through May 2016, as the Company's PACW-CAISO import and export margins declined by 32 percent and 53 percent, respectively. The PACW-CAISO export margin continues to be expressed as a function of the transmission available for EIM exports, and the Company has refreshed the historical transmission available based on a recent extract from the CAISO's public database.

- The GHG component of the export margin has been updated to include results through May 2016, as well as for prior period adjustments resulting from the CAISO's nine month settlement statements. Because this component is not specifically tied to exports to NVE or the CAISO, it has been included as a separate line item in the results.

Q. What is the total level of EIM benefits and costs now included in the 2017 TAM?

A. The Company's Reply Update includes approximately $23.7 million in total company EIM benefits for inter-regional dispatch and reduced flexibility reserves. Table 2 below compares the total EIM benefits and costs in the Initial Filing and the Reply Update on a total company basis.

Table 2
Total-Company EIM-Related Benefits and Costs

$ millions	2017 TAM - Direct	2017 TAM - Reply
Inter-regional dispatch - Exports	$10.2	$13.9
Inter-regional dispatch - Imports	$1.2	$5.3
Flexibility Reserves	$2.6	$4.5
Test-period EIM benefits	**$13.9**	**$23.7**
Test-period EIM costs	**$6.4**	**$6.2**

Q. Did parties support the Company's approach to modeling EIM dispatch benefits in the Initial Filing?

A. Not entirely. Staff and CUB both proposed adjustments to reduce NPC for intra-regional EIM dispatch benefits. In addition, Staff and CUB each raised separate issues related to the calculation of inter-regional EIM dispatch benefits that they believe need to be addressed or changed. I address each of these below. ICNU did not address EIM benefits in its Opening Testimony.

Q. CUB claims that customers were misled when PacifiCorp entered the EIM, because the benefits are not as high as expected.[59] Do you agree?

A. Absolutely not. CUB claims that EIM benefits are "barely exceeding ongoing costs" and that the benefits "are expected to remain trivial."[60] On the contrary, as noted above, the Company's Reply Update includes $23.7 million of EIM benefits on a total company basis, which is hardly trivial. Moreover, the benefits in this year's TAM are higher than the amount reflected in last year's TAM.

Q. Have Staff and CUB made any general recommendations relating to the modeling of EIM benefits?

[59] CUB/100, McGovern/19-20.
[60] CUB/100, McGovern/20.

A. Yes. Staff recommends a generic investigation into the calculation of EIM benefits, in light of the expected participation of PGE and Idaho Power in the market.[61] CUB recommends that Staff audit the Company's EIM results.[62]

Q. Does the Company object to either recommendation?

A. No. The Company does not object to Staff's proposal for a generic investigation, as long as parties understand that the differences between the operational practices and NPC modeling for the utilities participating in the EIM may not allow for a one-size-fits-all approach. The Company also has no objection to a Staff audit of EIM accounting practices, costs, and benefits, as recommended by CUB.

EIM Benefits – Intra-Regional Benefits

Q. How does the Company reflect the intra-regional benefits resulting from its participation in the EIM?

A. The Company does not include an incremental reduction in its overall NPC calculation to account for intra-regional benefits. The Company's test period NPC are developed using the GRID model, which assumes perfectly efficient operations. Thus, in every hour, the lowest cost resources will be dispatched, subject to transmission constraints. In addition, the Company's gas plant "screening" process optimizes the commitment of each gas unit based on its actual contribution to system costs, accounting for the value at the point of delivery, rather than based on prices at a potentially distant regional market point. Therefore, the Company's NPC already incorporates intra-regional dispatch

[61] Staff/100, Crider/16-17.
[62] CUB/100, McGovern/21.

Docket No. UE 307
Exhibit PAC/406
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

EIM Inter-Regional Benefits Reply Filing 2017

August 2016

PacifiCorp
Oregon - CY 2017 TAM
Inter-Regional EIM Benefits - CAISO, PacifiCorp, Nevada Energy

	6/1/2015	7/1/2015	8/1/2015	9/1/2015	10/1/2015	11/1/2015	12/1/2015	1/1/2016	2/1/2016	3/1/2016	4/1/2016	5/1/2016	Total
PACW to CAISO Exports													
Historical Export Volume (MWh)	120,639	127,861	87,325	61,418	43,936	54,756	74,204	61,255	84,342	97,306	82,337	52,332	947,713
Historical Export Volume (aMW)	168	172	117	85	59	76	100	82	121	131	114	70	108
Transmission Left Open MidC to COB (MWh)	197,266	156,426	137,941	130,399	185,106	165,758	193,435	205,369	190,363	215,811	230,237	229,125	2,237,235
Transmission Left Open MidC to COB (aMW)	274	210	185	181	249	230	260	276	274	290	320	308	255
Historical Export Margin	$ 1,808,047	$ 2,089,863	$ 1,290,923	$ 542,647	$ 316,420	$ 1,017,176	$ 707,989	$ 374,227	$ 501,991	$ 633,798	$ 455,793	$ 380,438	$ 10,119,261
Historical Export Margin ($/MWh Avail Trans)	$9.17	$13.36	$9.36	$4.16	$1.71	$6.14	$3.66	$1.82	$2.64	$2.94	$1.98	$1.66	
Adjustment for NVE Participation	47%	47%	47%	47%	47%	47%	100%	100%	100%	100%	100%	100%	
Adjusted Export Margin ($/MWh Avail Trans)	$4.32	$6.30	$4.41	$1.96	$0.81	$2.89	$3.66	$1.82	$2.64	$2.94	$1.98	$1.66	
Seasonal Export Margin ($/MWh Avail Trans)	$4.34	$4.34	$4.34	$4.34	$2.28	$2.28	$2.28	$2.28	$2.28	$2.28	$2.28	$2.28	
2017 TAM Available Transmission (MWh)	198,762	211,734	155,618	81,218	96,669	99,457	140,261	97,679	72,549	52,680	140,857	200,514	1,547,996
2017 TAM Export Margin	**$ 863,217**	**$ 919,555**	**$ 675,844**	**$ 352,727**	**$ 220,411**	**$ 226,769**	**$ 319,803**	**$ 222,714**	**$ 165,416**	**$ 120,113**	**$ 321,162**	**$ 457,185**	**$ 4,864,916**
CAISO to PACW Imports													
Import Volume (MWh)	7,236	5,800	7,790	8,805	11,356	17,126	18,408	34,075	17,528	11,559	11,343	27,872	178,898
Import Volume (aMW)	10	8	10	12	15	24	25	46	25	16	16	37	20
Historical Import Margin	$ 37,372	$ 27,276	$ 71,817	$ 93,800	$ 184,548	$ 63,872	$ 48,616	$ 81,428	$ 83,323	$ 63,651	$ 72,913	$ 69,247	$ 897,864
Adjustment for NVE Participation	68%	68%	68%	68%	68%	68%	100%	100%	100%	100%	100%	100%	
2017 TAM Import Margin	**$ 25,228**	**$ 18,413**	**$ 48,480**	**$ 63,320**	**$ 124,580**	**$ 43,117**	**$ 48,616**	**$ 81,428**	**$ 83,323**	**$ 63,651**	**$ 72,913**	**$ 69,247**	**$ 742,316**
PACE to NVE Exports													
Historical Export Volume (MWh)	-	-	-	-	-	-	38,263	50,036	48,494	45,394	40,342	29,141	251,670
Historical Export Volume (aMW)	-	-	-	-	-	-	51	67	70	61	56	39	57
Historical Export Margin	$ -	$ -	$ -	$ -	$ -	$ -	$ 292,317	$ 432,377	$ 307,669	$ 675,122	$ 685,641	$ 212,382	$ 2,605,508
Historical Average Export Margin	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 434,251	$ 5,211,017
Summer Adjustment	203%	203%	203%	203%									
2017 TAM Export Margin	**$ 881,962**	**$ 881,962**	**$ 881,962**	**$ 881,962**	**$ 434,251**	**$ 434,251**	**$ 434,251**	**$ 434,251**	**$ 434,251**	**$ 434,251**	**$ 434,251**	**$ 434,251**	**$ 7,001,859**
NVE to PACE Imports													
Import Volume (MWh)	-	-	-	-	-	-	50,598	66,998	67,133	90,983	126,718	135,162	537,532
Import Volume (aMW)	-	-	-	-	-	-	68	90	96	122	176	182	122
Historical Import Margin	$ -	$ -	$ -	$ -	$ -	$ -	$ 236,354	$ 211,143	$ 230,511	$ 772,500	$ 810,506	$ 491,830	$ 2,752,844
Historical Average Import Margin	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 458,807	$ 5,505,688
Summer Adjustment	46%	46%	46%	46%									
2017 TAM Import Margin	**$ 212,564**	**$ 212,564**	**$ 212,564**	**$ 212,564**	**$ 458,807**	**$ 458,807**	**$ 458,807**	**$ 458,807**	**$ 458,807**	**$ 458,807**	**$ 458,807**	**$ 458,807**	**$ 4,520,714**

Docket No. UE 296
Exhibit PAC/200
Witness: Frank C. Graves

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED

Direct Testimony of Frank C. Graves

April 2015

DIRECT TESTIMONY OF FRANK C. GRAVES

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ATTACHED EXHIBITS

Exhibit PAC/201—Resume of Frank C. Graves

Exhibit PAC/202—Daily Spot vs. Forward Prices for Mid-Columbia

Q. Please state your name and present position.

A. My name is Frank C. Graves. I am a Principal at the economic consulting firm *The Brattle Group*, where I am also the leader of the utility practice group. I am testifying in this case on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

QUALIFICATIONS

Q. Briefly describe your education and professional experience.

A. I specialize in regulatory and financial economics, especially for electric and gas utilities. I have assisted utilities in forecasting, valuation, and risk analysis of many kinds of long range planning and service design decisions, such as generation and network capacity expansion, supply procurement and cost recovery mechanisms, network flow modeling, renewable asset selection and contracting, and hedging strategies. I have testified before the Federal Energy Regulatory Commission (FERC) and many state regulatory commissions, as well as in state and federal courts, on such matters as integrated resource planning, the prudence of prior investment and contracting decisions, costs and benefits of new services, policy options for industry restructuring, adequacy of market competition, and competitive implications of proposed mergers and acquisitions. I am the author of several publications in risk management. I received an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975. I have included my detailed resume in Exhibit PAC/201.

Q. Have you previously testified on behalf of PacifiCorp regarding its energy cost recovery mechanisms?

A. Yes. I filed testimony on behalf of the Company in Wyoming, Docket No. 20000-405-ER-15 regarding recovery of gains and losses on hedging and whether and how to share hedging gains or losses between customers and the utility. In Docket No. 20000-469-ER-15, I filed testimony supporting changes to the energy cost adjustment mechanism. I also filed testimony in the Company's request for a power cost adjustment mechanism in Utah, Docket No. 09-035-15 and in Docket No. 10-035-124 regarding the recovery of gains and losses from hedging as well as the treatment of option costs.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I have been asked by the Company to review its pattern of systematic under-recovery of net power costs (NPC) that arise largely from system balancing transactions.

SYSTEMATIC NPC UNDER-RECOVERY

Q. Has NPC been under-recovered in Oregon in recent years?

A. Yes. Oregon's load share of incurred total NPC costs above forecasted costs has ranged from $15.6 million to $33.7 million per year during the last three years, or about 5-10 percent of total actuals. Figure 1 below shows the annual details for PacifiCorp.

Figure 1: PacifiCorp's NPC Annual Actual vs. NPC Recovered in Oregon

Year	OR NPC Collected Through Rates	OR Actual NPC	Under-Recovery of OR NPC
2011	$301,662,279	$333,544,839	$31,882,559
2012	$336,201,734	$351,814,385	$15,612,651
2013	$348,474,235	$382,126,867	$33,652,632

Q. Have you identified any consistent drivers of under-recovered NPC in recent years you would consider to be systematic?

A. Yes. These variances between forecasted and actual NPC have occurred largely because the numerous and essential "balancing" wholesale activities of PacifiCorp in the spot market are very large and unpredictable. If these variances tend to "wash out" over time, with some being negative losses to the Company (as above) but others being positive gains, they would merely be a source of noise in company financial performance but not an expected impairment or handicap for the Company. However, these loss patterns have persisted throughout periods of falling and rising power prices and appear to be systematic; they do not wash out.

Q. Please explain why PacifiCorp's NPC variances could occur systematically.

A. A likely reason is that system planning models used to forecast NPC costs do not reflect the extent and cost of realized volatility in prices and demand, nor can they readily capture the way unexpected demands and short-term price changes tend to be correlated, thereby leading to a net adjustment (balancing) cost that is not reflected in the modeling results. These limitations arise because no system planning model cau include all of the uncertain factors that affect actual market operations.

For instance, it is extremely unusual for power systems models to include possible transmission system disruptions, nonstandard generation outages, or load variances due to multi-day persistent abnormal weather. In principle, virtually any one of these kinds of risk factors could be simulated in a Monte Carlo fashion, but doing so would require statistical evidence on their distributions that would be very hard to obtain and verify, and because there are so many such factors, it would be impossible to span all possible combinations of all of them. Importantly, it is also unlikely that such risk factors would occur in isolation, leaving all other expected conditions unchanged. For instance, higher than expected loads may occur in summer because it is hotter than normal, which might be associated with more solar renewable output but perhaps less wind production, while in winter, unexpected loads may correspond to cold snaps that also drive up gas prices. So in order to model these factors, all of their joint interactions would need to be well understood and recurring, at least statistically.

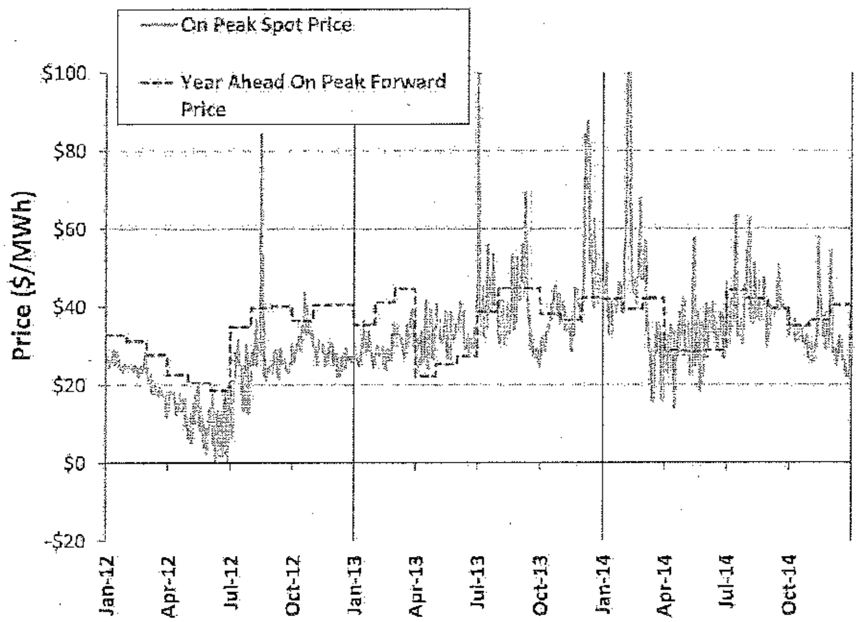
Q. So this is partly a product of practical limitations in forecasting models?

A. Yes, power system planning models tend to be "too smooth" or too perfect, basically only able to simulate how a specific set of assumed future likely conditions affect the costs of system operations if it were optimally deployed for those conditions. These models do not simulate what will happen if those conditions do not materialize, nor how system operators may conditionally manage their systems conservatively to defend against unforeseen circumstances, e.g., committing more fast response resources than would be required if there were no such uncertainties.

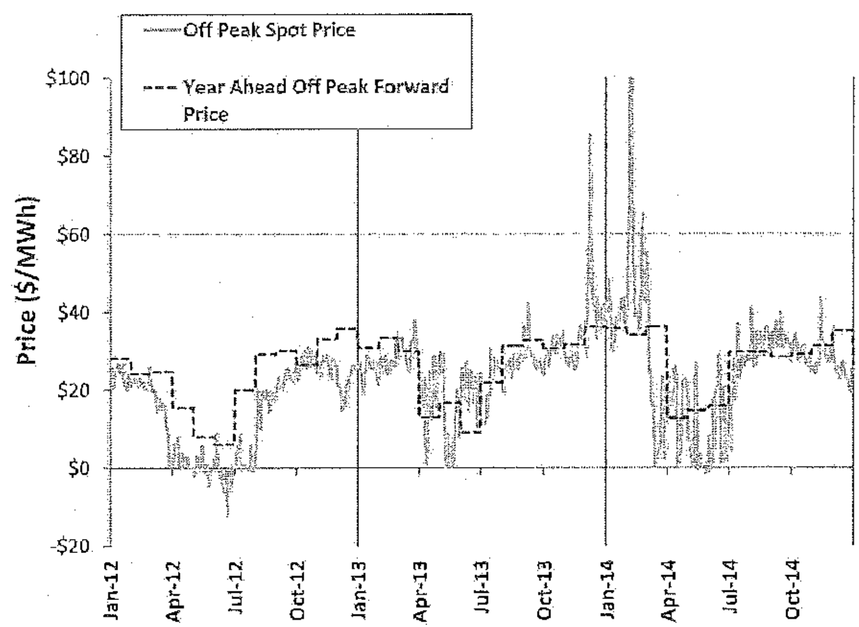
To demonstrate this, Figure 2 below shows that daily average spot prices at Mid-Columbia (Mid-C) are very volatile and have had several recent past dramatic spikes that are several times larger for short periods of time than the year-ahead forward price. Exhibit PAC/202 shows the same data for Palo Verde. Hourly prices within each day can be even more volatile than these daily averages, and balancing transactions often involve only a few hours of purchases or sales each day. While technically not a forecast, the traded forward prices are the market's consensus view of what is reasonable to expect realized spot prices to average, hence are somewhat like a forecast (and many traders may have used a forecasting model to decide what forward prices they were comfortable trading). Thus, the observed daily and annual average variance from forwards is evidence of how difficult it is to accurately forecast the spot price going forward. Moreover, even if you are right on average, you will inevitably be off by a significant amount from day to day and hour to hour. This complexity is part of why the realized NPC always differs from the forecast NPC.

Figure 2: Daily Spot vs. Forward Prices

(a) Mid-Columbia, On Peak



(b) Mid-Columbia, Off-Peak



Notes:

[1] Calculated based on data compiled by Ventyx, the Velocity Suite and SNL (as of March 23, 2015).
[2] Spot prices reflect day-ahead prices.
[3] Forward prices are as of the beginning of each month, and held constant throughout the month.

The typical forecasting model does not capture the volatility illustrated in Figure 2, so inherently the realized prices will exhibit greater volatility than the forecasted prices. Further, models typically do not simulate any kind of intra-hour constraints or uncertainty (including the GRID model used by PacifiCorp). Yet, intra-hour constraints and uncertainty cause many of the daily average spikes in Figure 2 above. The short time frames have recently become increasingly important to actual power system operations in the past decade (and will be even more so in the future) because of the increasing reliance on intermittent, renewable resources that are subject to rapid, very short-term changes in performance (if the wind or sunshine should change, as is common).[1]

As a result, even the most detailed of power industry simulation models typically underestimate short-term price and load volatility, though they may forecast average prices and loads over longer time periods fairly well.

Q. Are these volatility forecasting limitations to blame for the underestimation of NPC?

A. Not by themselves. Forecasting limitations in capturing volatility are not a source of persistent (or expected) cost shortfalls <u>unless</u> there is a pattern in the unforeseen price and volume variances from the model projections that causes those variances to have an additional, expected cost. That can arise if there is a consistent relationship between the direction of unexpected (not forecasted) demand and corresponding movements in spot prices of power or fuel relative to

[1] In the past two to three years, a new generation of system planning models have been developed that do simulate very short-term operating horizons and corresponding renewable resource performance uncertainty (or forecasting error). However, these are new and sometimes very cumbersome, and the data they require to capture these short-term effects is voluminous and not yet widely or conveniently available.

expectations. Specifically, if the relationship between movements in the unforeseen demand and spot prices is positive, then the variability in net purchase and sale revenues will tend to be both greater than the apparent price or volume volatilities by themselves, and there will tend to be a systematic, expected cost (above forecasts) as well. This occurs because these balancing transactions tend to involve a loss whether they are purchases or sales:

- If purchases, they tend to occur because demand is higher than expected (or renewable output is lower than expected) and prices are correspondingly higher than forecasted.
- If they are unplanned sales (because retail demand is unexpectedly low), the realized price tends to be depressed and below the forwards, again resulting in a loss relative to closing the expected volumes at the expected or forward price.

Q. Do PacifiCorp's balancing transactions tend to involve a pattern of losses?

A. Yes. Company studies of short-term transactions (less than one week in duration of committed volumes) at trading hubs in the last three years indicate this situation is occurring. At every trading hub, and for both on and off peak purchases and sales, in nearly every month for 36 months, it has been the case that purchases tend to cost more per MWh than average spot prices and sales tend to have occurred below the average monthly spot price (ignoring volumetric causes of revenue variance, i.e. just focusing on the price effects even if realized sales volumes had been known with certainty).

These average annual deviations are shown below in Confidential

Figure 3, by trading hub, for short-term transactions in July 2011 through June 2014. In this figure the MWh purchased each month at a given hub was multiplied by the historical average spot price at the respective hub and month. This amount was summed for the period starting July 2011 and ending June 2014. This total was then subtracted from the total actual dollar amount purchased at the same hub. Finally, this resulting difference was divided by the total amount of MWh purchased in the same time interval to yield a volume weighted average price deviation for all purchases at a given hub. The analogous calculation was performed for sales. Finally, the figure shows the transacted volume, which shows that while the volume-weighted price variation per MWh is large at, for example, Mona, the trading volume is small.

Confidential Figure 3: NPC Variability Breakdown

[redacted]

This graph shows that purchases have occurred at a premium to average prices and sales at a discount per MWh. When looking at the month-by-month source data for this graph, a somewhat more complex pattern emerges that is partly seasonal and varies by trading hub, and that is erratic year on year in absolute magnitudes. However, on average there is a monthly balancing price error of a few $/MWh in each direction, with purchases tending to occur at prices above the monthly average and sales below, to an extent not foreseen in the NPC forecasting models (even if they had been completely accurate about monthly average prices). Collectively, these balancing price variances seem to explain an average of about $27.8 million of PacifiCorp's annual shortfalls.

Q. Is there any way for the Company to avoid the types of transactions causing these systematic losses?

A. No. There is no possibility of operating in the complex power markets without unforecasted transactions to balance the Company's system on an hourly basis, and these must be done at whatever prices are then available in the market, subject to WECC market practices that dictate buying in 25MW blocks on a forward basis. This constraint on discrete block sizes further contributes to some unavoidable volume variances. That is, as described in Mr. Brian S. Dickman's testimony, the balancing transactions done on a forward basis utilize standard block products that are not a perfect match for the Company's hourly position shortfalls or slack snpply. On a real-time basis the company must transact to balance then-current requirements (load) with available resources, including balancing positions taken previously on a week- or day-ahead forward basis.

Q. Why doesn't the Company leave all of its balancing to the hour-ahead market?

A. On a day-ahead basis, counterparties can nominate gas and bring additional gas generation online. Similarly, many hydro projects have flow and ramping constraints that limit hour to hour changes in output. Likewise, generation and transmission outage scheduling may be adjusted based on prices in the daily and monthly markets. Each of these results in lower resource flexibility on an hour-ahead basis than over longer time frames, and that reduced flexibility results in greater price premiums on purchases and reduced revenues on sales.

Q. How does this systematic pattern of losses on balancing transactions affect the Company financially?

A. These shortfalls unduly harm the Company and also imply that the NPC price in base rates is under-estimating true costs. As a result, the company proposes to reduce its expected exposure to this kind of systematic losses on balancing transactions by applying forecasting adjustment factors based on the monthly hub shortfalls observed over the past three years in average balancing prices per MWh. Assuming that this degree of bias persists, this correction will roughly restore base NPC rates to being fair estimates of actual average costs per MWh. This will also make overall variances much closer to zero, hence less burdensome on customers to absorb lagged over/under cost allocations. Thus, there are two advantages to this approach: (1) it makes base rates a better predictor of actual average costs per MWh and hence avoids customer surprises; and (2) it makes PacifiCorp's recovery of NPC more timely and accurate, requiring less true-up.

Of course, these factors have not been precisely stable in the past three years. They vary considerably from year to year in this historical period from which they are estimated, and they are unlikely to perfectly echo their history in the next few years, so there will still be variances.

Q. **Could PacifiCorp reduce its exposure to these variances with better or alternative hedging?**

A. No. First, most hedging takes place over longer time frames (weeks to months or years).[2] Nor could different hedge targets eliminate the persistent shortfalls for which remedy is sought here. Imbalances are inevitable at any level of target hedging—e.g., if peak demand was fully hedged, there would be a need to sell off when the peak was not reached; if the average need was hedged, the realized load would vary about that level and there would be a need for both purchases and sales. There also are no hedges available for the elements of balancing costs that are incurred, such as marginal losses, ancillary services for procuring or using spot market reserves, load uncertainty. In addition, PacifiCorp's hedging practices have been debated and modified over the past few years in settings that aired and compared customer needs and concerns with practical limitations on hedging analysis and reporting, and I believe those arrangements should be left in place.

Q. **Does this conclude your direct testimony?**

A. Yes.

[2] Day-ahead transactions are technically a hedge on day-of, real time operations, but their prices are subject to considerable variability, and most planning models do not consider real time differences from day-ahead prices, so the day-ahead prices are essentially expected spot prices for planning purposes.

Docket No. UE 296
Exhibit PAC/100
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Direct Testimony of Brian S. Dickman

April 2015

DIRECT TESTIMONY OF BRIAN S. DICKMAN

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Confidential Exhibit PAC/105—Energy Imbalance Market Import and Export Summary

Exhibit PAC/106—List of Expected or Known Contract Updates plans to update the BPA wheeling expense during the proceeding to reflect the final ROD. Inter-hour wind integration charges also increased due to higher wind generation in the 2016 TAM and the updated costs included in the 2014 Wind Integration Study.

EIM COSTS AND BENEFITS

Summary and Background

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

A. The Company adjusted the NPC forecast for 2016 to reflect EIM benefits from inter-regional dispatch (i.e., exports and imports between PacifiCorp and CAISO) and reduced flexibility reserves. The Company included approximately $9.4 million of benefits on a total-company basis as a reduction to the NPC forecast. The Company also included $5.1 million of total-company costs related to EIM participation during 2016. Table 2 below summarizes the EIM-related benefits and costs included in the 2016 TAM and shows the increase in EIM benefits and decrease in EIM costs compared to the 2015 TAM.

Table 2
Total-Company EIM-Related Benefits and Costs

<table>
<tr><th>$ millions</th><th>UE 287/UM 1689</th><th>2016 TAM</th></tr>
<tr><td>Inter-regional dispatch</td><td rowspan="4">Not specified</td><td>$8.4</td></tr>
<tr><td>Intra-regional dispatch</td><td>N/A</td></tr>
<tr><td>Flexibility Reserves</td><td>$1.0</td></tr>
<tr><td>Within-hour dispatch</td><td>N/A</td></tr>
<tr><td>Test-period EIM benefits</td><td>$6.7</td><td>$9.4</td></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td>Test-period EIM costs</td><td>$6.7</td><td>$5.1</td></tr>
</table>

Q. Did the Company confer with parties to the 2015 TAM in developing its approach to reflecting EIM costs and benefits in rates?

A. Yes. Before filing the 2016 TAM, the Company participated in two workshops with parties to the 2015 TAM to discuss operation of the EIM, the methodology for calculating EIM-related benefits, and potential options for addressing EIM-related costs and benefits from January 1, 2016, forward.[4]

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

A. The EIM is a real-time balancing market that optimizes generator dispatch every five and 15 minutes within and between the PacifiCorp and the CAISO balancing authority areas (BAAs). EIM operation went live October 1, 2014, with financially binding operations effective November 1, 2014. By participating in the EIM, the Company's participating generation units are optimally dispatched using the CAISO's computerized security constrained economic dispatch model. The EIM's automated, expanded footprint, co-optimized dispatch replaces the Company's largely isolated and manual dispatch within its two BAAs. Participation in the EIM produces benefits to customers in the form of reduced NPC, partially offset by costs for initial start-up and ongoing operation.

Q. What is the primary change in the Company's day-to-day operations as a result of EIM?

A. Before EIM operation, the Company manually dispatched most of its regulating resources to balance the system within the hour, generally via phone calls to plant personnel. As a result, requests would typically be sent to the fastest responding

[4] The two workshops were held in accordance with the stipulation in the 2015 TAM. Order No. 14-331, Appendix A at 6, ¶ 12.

and most flexible units first, to ensure system balance and reliability was maintained. As the balance returned to normal, additional requests would be sent to dispatch up lower-cost units and dispatch down higher-cost units. This approach could result in dispatch of higher cost units than strictly necessary in a computer-optimized world. Under EIM, dispatch instructions are automatically sent to all participating resources every five minutes. This helps minimize costs by ensuring the lowest cost resources that are available are dispatched.

The changes in Company operations align with how the Company forecasts NPC. The GRID model has always assumed perfectly optimized hourly dispatch within PacifiCorp's BAAs (i.e., intra-regional dispatch) and does not reflect any intra-hour imbalance or intra-hour dispatch costs (i.e., within-hour dispatch).

Q. **Does EIM help to reduce another aspect of the Company's intra-hour imbalance costs?**

A. Yes. Before joining the EIM, the Company was dependent on its own resources for all intra-hour balancing. Under the EIM, the CAISO's resources can also be used for intra-hour balancing. In the past, if the Company's loads were less than expected (or if wind generation unexpectedly increased) the Company would work to dispatch down its most expensive available resource. Now, if the highest cost CAISO resource currently dispatched is more expensive than the highest cost Company resource, then the CAISO will back that resource down and the Company will export the output of its most expensive resource to the CAISO (subject to the availability of transmission capacity between PacifiCorp and

CAISO). The same is true in reverse if PacifiCorp has an unexpected need for resources (because, for example, load increases or wind generation decreases).

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

A. Participation in EIM is expected to reduce the Company's actual NPC in three ways: (1) optimizing the automated dispatch of participating units in PacifiCorp's BAAs, subject to transmission constraints, using the CAISO's system model; (2) facilitating transactions between the CAISO and PacifiCorp BAAs on a five- and 15-minute basis, using PacifiCorp's transmission rights between CAISO and PacifiCorp on the California Oregon Intertie (COI); and (3) reducing the amount of flexible generating capacity required to be held in reserve by PacifiCorp due to the collective reduction of reserves for the larger and more diversified EIM footprint rather than the individual sum of reserves for the independent CAISO and PacifiCorp BAAs. Benefits realized for the last two categories are highly dependent on the amount of transfer capacity between CAISO and PacifiCorp at the COI available for EIM. Each of these elements is described in more detail below.

Q. Does each of these benefits cause a corresponding reduction to the GRID NPC forecast?

A. No. The GRID NPC forecast already reflects the optimized (i.e., lowest cost) dispatch of PacifiCorp's generating units within its two BAAs, so there are no additional benefits from EIM optimized dispatch (i.e., intra-regional and within-hour dispatch benefits). The other two NPC benefits—inter-regional transactions with CAISO and reduced flexibility reserves—do produce NPC savings relative to the optimized GRID NPC forecast.

Q. Did the Company use actual EIM operations to develop the forecasted EIM benefits applicable to the 2016 TAM?

A. Yes. The Company based its forecast of EIM benefits on actual results from December 2014 and January 2015 because this was the most recent, representative actual data available at the time NPC was prepared. These actual results flow readily from data generated by the operation of the EIM and provide a good baseline for quantification of EIM benefits. The EIM benefit estimates and data to support those estimates will be improved with additional experience, and the Company intends to update the calculations during this case to include more historical results.

The results from December 2014 and January 2015 demonstrate several factors which are critical to calculate benefits realized through EIM. The results should be derived from actual data for five- and 15-minute intervals, reflect contemporaneous actual market prices for electricity and natural gas, and reflect contemporaneous generation and transmission capabilities and constraints. During periods of transmission congestion on the COI, even if the Company has economic resources and transmission available to the California-Oregon Border (COB), the CAISO may not be able to import EIM volumes. Such operational details are difficult to account for in a model but are captured in the actual results.

Recognizing that December and January are only two months during the winter season, the Company expects additional operational data to provide insight into the benefits that can be achieved in other months. For example, during the spring runoff period the Company expects additional congestion on the COI as power moves from hydro units in the northwest to the California market. This congestion will limit the availability of transmission for use in EIM, and updating the 2016 TAM with this data as it becomes available will produce the most accurate forecast possible.

Q. Why didn't the Company use November 2014 results given that financially binding transactions began in November?

A. The Company did not use data from November 2014 because of data integration and modeling errors that were discovered during that month. The CAISO has tools in its tariff to correct prices after the fact for identified software and data errors and has also received additional accommodations from the Federal Energy Regulatory Commission to mitigate anomalous prices for special circumstances associated with the start-up of the EIM.

Q. On February 11, 2015, the CAISO published a report quantifying the estimated EIM benefits during November and December 2014.[5] What were the results of that report?

A. The CAISO report indicated that total EIM benefits during November and December 2014 were approximately $5.97 million for the CAISO and PacifiCorp, or approximately $4.73 million for PacifiCorp. The CAISO indicated its calculation included the impact of more efficient dispatch, both inter- and intra-

[5] http://www.caiso.com/Documents/PacifiCorp_ISO_EIMBenefitsReportQ4_2014.pdf.

regional, and reduced renewable energy curtailment (applicable to the CAISO). The report did not include benefits from reduced flexibility reserves.

Q. Are the benefits in the CAISO report comparable to the EIM benefits in the GRID NPC forecast?

A. No. The report issued by the CAISO is intended to quantify the EIM benefits realized by the CAISO and PacifiCorp relative to a counterfactual scenario that mimics system operation before EIM implementation. As a result, the CAISO report includes the benefit of improved PacifiCorp system dispatch compared to the more manual dispatch used before EIM. As noted, because this benefit is already reflected in the GRID model, the CAISO report overstates EIM benefits compared to PacifiCorp's GRID NPC forecast.

Q. Are the benefits from the CAISO report directly comparable to the actual NPC included in the Company's power cost adjustment mechanism (PCAM)?

A. Yes. The benefits reported by the CAISO are reflected in the Company's actual NPC included in the PCAM beginning November 2014.

Q. Please describe the EIM-related costs included in the 2016 TAM.

A. Consistent with the structure of the settlement reached in the 2015 TAM (which matched costs and benefits of EIM participation), the Company included $5.1 million of total-company EIM-related costs in the 2016 TAM. These costs consist of the return on net rate base from the capital investment required to participate in EIM, depreciation expense, and ongoing operations and maintenance (O&M) expenses. A summary of the various cost components is provided as Exhibit PAC/104. Including all EIM-related costs in the 2016 TAM is necessary to ensure that customer rates reflect a proper matching of EIM benefits and costs. Rates set in the Company's most recent general rate case, docket UE 263, do not include any EIM-related costs. Until these costs are included in base rates, EIM benefits included in the Company's TAM filings should be net of the ongoing cost of participation.

Inter-Regional Dispatch Benefits

Q. Did the Company adjust the GRID NPC forecast in the 2016 TAM to reflect savings from exporting and importing energy between PacifiCorp's and the CAISO's BAAs?

A. Yes. The costs and benefits associated with EIM exports and imports are relatively direct, with known historical transaction prices and volumes, and those volumes can be tied to the Company resources that are on the margin. The export benefit is the difference between the export revenue and the expense of the Company generation that was dispatched to support the transaction. The import benefit is the difference between the import expense and the expense of the Company generation that would have been dispatched but for the transaction.

Q. Are the benefits of transacting with the CAISO affected by transmission constraints?

A. Yes. The southbound transfer capability between the Company's west balancing authority area (PACW) and the CAISO has a significant impact on the available benefits. The transmission available for EIM use is limited by two factors. First, the COI path rating is influenced by the status of a large number of interdependent components and is frequently de-rated due to forced and planned outages. Second, the Company's forward transactions delivered at COB also use the Company's available transmission rights—if the Company has scheduled forward transactions that use COI capacity, there is less transfer capacity available for EIM transactions.

Even if transmission is available for the EIM, actual historical data shows that not all of the capacity is used to support exports from the Company to the CAISO. In some periods, the Company imports from the CAISO and exports are zero. In other periods, the Company may not have sufficient resources that are economic at the CAISO market price to fill the entire available path.

Q. How is the EIM export benefit calculated for the forecast period?

A. As noted above, the Company's forecast EIM export benefit is derived from the results of EIM operation during December 2014 and January 2015 as reflected in the CAISO invoices and the cost of the Company's resources that were expected to be on the margin.

Q. Please provide detail on the EIM export benefits included in the 2016 TAM.

A. As shown in Confidential Exhibit PAC/105, the Company's EIM exports in December 2014 and January 2015 averaged 115 megawatts (MW) and had an estimated margin (transaction revenue minus generation expense) totaling approximately $1.3 million. The transmission available to EIM averaged 278 MW. This works out to benefits of $7.81 per megawatt-hour exported or $3.22 per megawatt-hour of transmission available to EIM.

The transmission available to EIM in the forecast period is based on the

Company's COI transmission rights, after accounting for path de-rates, and hourly volumes delivered to COB as calculated by GRID. The COI capacity remaining unused after de-rates and after accounting for forward sales at COB is available to EIM and is valued at $3.22 per megawatt-hour of available transmission. The resulting EIM export benefits total $7.5 million (total-company) for the test period. The Company included these benefits as incremental wholesale sales revenue to the GRID results.

Q. How is the EIM import benefit calculated for the 2016 TAM?

A. The Company's forecasted EIM import benefit is derived in a manner similar to that for exports, based on the results from December 2014 and January 2015, and the Company plans to update its analysis of imports based on additional months of operation during this case. The Company's EIM imports in December 2014 and January 2015 averaged 18 MW and had an estimated margin (avoided generation expense minus transaction expense) totaling approximately $162,000.

Prices in the CAISO BAA are normally higher than in the Company's BAAs, resulting from higher natural gas prices along with a carbon tax. As a result, southbound flows on the COI are typical and face constraints, but northbound counter-flows are not normally constrained. This indicates that transmission may not be a limiting factor for EIM imports. Instead, the relatively infrequent periods when prices in the CAISO BAA are lower than in PACW are likely driven by rapid increases in wind or solar output in the CAISO BAA. Because transmission availability does not appear to be a factor in south to north transfers, the 2016 TAM NPC forecast includes EIM import benefits equal to the average of the benefits in December 2014 and January 2015 multiplied by twelve. Total EIM import benefits in 2016 are $1.0 million (total-company), which is included as a rednction to pnrchase expense.

Flexibility Reserve Benefits

Q. Does the Company's forecast include flexibility reserve benefits from its participation in EIM?

A. Yes. The Company reduced the regulating reserve requirement modeled in GRID to account for the Company's share of the reserve benefit based on the larger and more diversified footprint of the EIM. Flexibility reserve benefits are a function of the transmission available for EIM dispatch, similar to the EIM export benefit. During December 2014, the Company's share of the reserve diversity benefit amounted to approximately six MW of reserves per 100 MW of EIM transfer capability, as calculated by the CAISO. During the forecast period this amounts to a reserve reduction of roughly 12 MW. Similar to imports and exports, the Company plans to update its analysis of diversity benefits to improve forecast accuracy based on additional months of operation.

Q. How does the CAISO calculate the reduction in flexibility reserves?

A. The CAISO calculates the reduction in ramp reserves for the combined CASIO and PacifiCorp system as compared to the stand-alone ramp reserve need for the CAISO and PacifiCorp separately.

Q. What are ramp reserves?

A. Ramp reserves measure the expected change in load net wind from the beginning of the hour to the end of the hour.

Q. Why are ramp reserves of the combined systems of the CAISO and PacifiCorp lower than the sum of the separate ramp reserves of the CAISO and PacifiCorp?

A. Because of the diversity of the combined load net wind.

Q. Did the Company include additional diversity benefits as a result of NV Energy joining the EIM in October 2015?

A. Yes. The Company's share of this incremental diversity benefit is estimated to amount to three MW of reserves per 100 MW of EIM transfer capability over the COI. During the forecast period this amounts to an additional reserve reduction of roughly six MW. In total, the flexible reserve benefit in the forecast period associated with NV Energy joining the EIM reduces total-company NPC $1.0 million.

Q. Will the addition of NV Energy result in incremental EIM import or export benefits?

A. The impact of NV Energy on the Company's EIM import and exports is uncertain at this time. In the E3 Study of NV Energy's EIM benefits, no direct connection was assumed between the Company and NV Energy, so any benefits would have to flow through the CAISO system.[6]

Q. Have any other parties expressed interest in joining the EIM in the future?

A. Yes. On March 5, 2015, Puget Sound Energy (PSE) announced it intends to begin participating in the EIM in October 2016. Initial reports indicate that PSE's participation in EIM is expected to produce annual benefits to existing

[6] http://www.caiso.com/Documents/NV_Energy-ISO-EnergyImbalanceMarketEconomicAssessment.pdf.

participants (including PacifiCorp and CAISO) ranging from $3.5 million to $4.2 million.[7] The Company's share of these benefits during the 2016 test year is expected to be minimal and, as a result, no adjustment was made to the 2016 TAM. If PSE does begin participating in EIM as planned, any incremental benefits to Oregon customers in 2016 would flow through the PCAM.

GRID MODELING CHANGES TO IMPROVE NPC FORECAST ACCURACY

Q. Did the Company make any changes to improve the accuracy of its NPC modeling since the OR TAM 2015?

A. Yes. The Company made various modifications to the GRID inputs to improve the accuracy of forecast NPC, including changes to reflect:

- Previously unrecognized costs related to day-ahead and real-time balancing transactions;
- Thermal plant forced outage events (heat rate and minimum capacity de-rate);
- Natural gas unit start-up costs and energy;
- Hourly regulation reserve requirements;
- Compliance curtailment of certain Company-owned wind facilities for avian protection; and
- Actual performance of wind PPAs.

Details supporting each modeling change are provided below.

Q. Why is the Company proposing changes to NPC modeling in this case?

A. In previous cases, the Public Utility Commission of Oregon (Commission) has encouraged improvements to NPC modeling to improve forecast accuracy. The Company's proposed modeling changes capture costs and benefits that have not

[7] http://pse.com/aboutpse/EnergySupply/Documents/PSE-ISO_EIM_Report_wb.pdf.

been recognized in the Company's past NPC forecasts. Mr. Graves supports the need for NPC modeling changes, testifying that modifications are needed so that rates reflect the real costs of balancing PacifiCorp's system.

Q. Does the Company's past under-recovery of NPC support the need for changes in its NPC modeling?

A. Yes. Since at least 2007, the Company's actual NPC required to serve customers have exceeded the forecast included in TAM filings.[8] Recovery of any excess actual NPC required to serve customers is limited and, to date, the Company has not recovered any of its prudently incurred excess NPC because of the restrictions on NPC recovery in the PCAM design. A more accurate NPC forecast will minimize this under-recovery and send appropriate price signals to customers so they can make informed decisions regarding their energy consumption, balancing the interests of the Company and customers.

Q. Did the Company provide advance notice to the parties regarding the modeling changes proposed in this case?

A. Yes. In compliance with the TAM Guidelines, the Company provided notice of substantial changes to the Company's modeling of NPC in the 2016 TAM. This notice was provided on February 27, 2015.

Day-Ahead and Real-Time Balancing Transactions

Q. Please summarize the Company's proposal to more accurately model system balancing transactions in GRID NPC.

A. To more accurately model system balancing transactions, the Company adjusted

[8] *See In the Matter of PacifiCorp d/b/a Pacific Power Request for a General Rate Revision*, Docket No. UE 246, Direct Testimony of Gregory N. Duvall, PAC/900, Duvall/16 (Mar. 1, 2012).

forward market prices to reflect historical variations from average actual market prices for purchases and sales. The Company also adjusted system balancing transaction volume to reflect transacting on a forward basis using standard block products, balanced on an hourly basis in the real-time markets.

Q. Please explain how the GRID model currently balances load and resources on an hourly basis.

A. The GRID model calculates the least-cost solution to balance the Company's load and resources to fractions of a megawatt for each hour. The model makes purchases in the wholesale market (labeled as "system balancing purchases" in the NPC report) in the hours for which the Company does not have enough owned or contracted resources to meet its load. The model also makes wholesale market sales (labeled as "system balancing sales" in the NPC report) when it has excess resources for a given hour. These system balancing transactions are calculated for each hour independently and are for the precise volume required by the model. Wholesale market prices for the system balancing sales are based on an hourly forward price curve that is developed from monthly HLH and LLH prices with hourly scalars applied. These scalars are identical within a given month for each weekday of that month. The prices are input into the model and do not change based on the volume of the system balancing transactions.

Q. How do actual operations differ from the GRID model logic?

A. In actual operations, the Company continually balances its market position—first with monthly products, then with daily products, and finally with hourly products. The monthly and daily position is calculated as the average for the respective time horizon during HLH and LLH periods; for example, the average HLH position during the month of January or the average LLH position on a given day in February. The monthly and daily products used to balance the Company's position in the wholesale market are available in flat 25 MW blocks. The Company's load and resource balance, however, varies continuously each hour in quantities that may vary widely from a flat 25 MW block. In real-time operations, the Company balances its hourly position in the hourly real-time market. At that point, the Company must transact to maintain a balanced system and, as a result, becomes a price-taker subject to whatever price is available at the time.

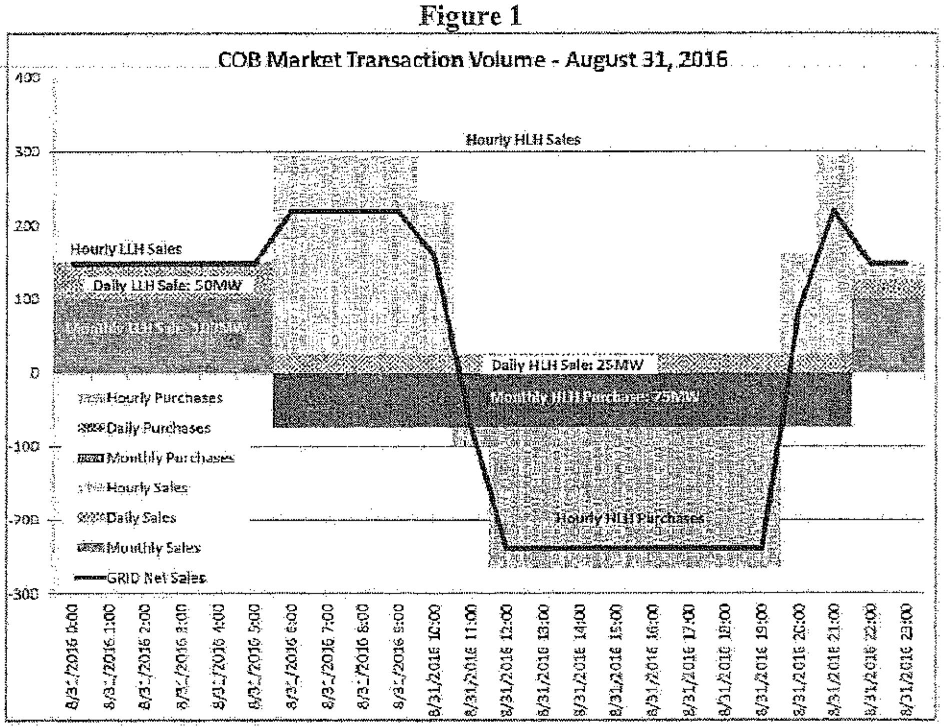
Q. How do the system balancing volumes in GRID compare to the Company's actual volumes?

A. The volume of system balancing transactions generated by GRID is smaller than the volume of similar transactions in actual results. Because GRID balances the Company's load and resources to fractions of a megawatt for each hour in a single step, it avoids the additional purchase and sale transactions that occur in actual operations as the Company progresses through balancing its system on a monthly, daily, and real-time system basis.

For instance, when the Company buys a monthly product that aligns with the Company's average open position for the month, one can expect that roughly half of the days will still have a remaining position to be covered by additional daily purchases. On the other days, the Company will have to make daily sales to unwind the excess volume. The same is true for daily transactions—in some hours the volume acquired will be too low, while in others it will be too high, and additional purchases and sales will be required to cover the Company's actual position.

In addition, buying or selling standard block products for monthly and daily average requirements will not result in a perfect balance of load and resources. This difference then must be closed out in the real-time market where the Company is a price-taker. Figure 1 below illustrates this effect for transactions at the COB market hub during a sample day in the NPC forecast. The solid line represents the hourly sales and purchases generated by the GRID model, and the shaded areas represent monthly and daily standard block products.

Figure 1



Q. Please describe the difference between the hourly price forecast used in GRID and the actual prices for day-ahead and real-time transactions.

A. The GRID model uses an hourly forward price curve that is developed from monthly HLH and LLH prices with hourly scalars applied. These scalars are identical within a given month for each weekday of that month. In reality, prices vary within each month, and the Company has historically bought more during higher-than-average price periods in each month and sold more during lower-than-average price periods. As a result, the average cost of the Company's daily and hourly short-term firm purchases has been consistently higher than the average actual monthly market price, while the average revenues from its daily and hourly short-term firm sales has been consistently lower than the average actual monthly market price.

Q. **Did the Company quantify the impact of this on the Company's past NPC?**

A. Yes. In the 36 months ended June 2014, the Company's day-ahead and real-time transactions increased NPC by an average of $7.1 million per year compared to the historical monthly average market prices. Approximately $4.3 million of this impact was a result of higher-than-average purchase prices, while $2.8 million was due to lower-than-average sales prices.

Q. **How did the Company calculate the impact of higher short-term purchase power costs and lower short-term sales revenues?**

A. The calculation is based on the Company's short-term firm transactions at a given market hub, with deliveries spanning less than one week.[9] The total cost and volume of these transactions is broken down into purchases and sales by month and by HLH or LLH periods. The actual cost of the Company's transactions is then compared against the historical monthly average HLH or LLH market price

[9] Transactions that have deliveries spanning more than a week are excluded because they will contain a price hedging component because both market price and the Company's demand are increasingly uncertain over longer time frames.

at that market. This process is repeated for the other market hubs at which the Company transacts.

Q. Did the price impact of day-ahead and real-time balancing transactions always increase NPC?

A. No. In some periods, the Company was able to sell at higher average prices than it purchased at a given market over the course of a month. The $7.1 million in historical day-ahead and real-time balancing costs is net of $0.8 million from these periods.

Q. Why does the Company buy when prices are high and sell when prices are low?

A. The Company buys when it needs additional resources and sells when it has excess resources. Much of the Company's resource need is determined by its load and wind generation, which vary both throughout the day and throughout the month. The Company's firm loads must be met regardless of price.

The Company's load and wind, which are affected by weather, are correlated with market prices. For instance, during the hottest week in July for the Company's load areas, other market participants are also likely to be experiencing hotter-than-average temperatures and higher-than-average loads. As a result, the marginal cost of the resources other market participants have available is higher than in the coolest week in July, when the Company would likely have extra resources available to sell. The day-ahead and real-time prices the Company experiences during these periods reflect those differences. Similarly, when the wind blows in the Columbia River Gorge and the Company's wind resources generate near their nameplate capacity, the thousands of other turbines in the gorge also generate, pushing down prices in the Mid-Columbia (Mid-C) market. When wind generation in the gorge is low, prices at Mid-C will be higher than average.

Q. **Is some of the unfavorable price impact already reflected in GRID due to the hourly price scalars?**

A. Yes. However, the effect of the price scalars in GRID is significantly smaller than the $7.1 million historical price impact, with costs totaling just $0.5 million in the forecast period. The hourly scalars only capture the costs associated with the Company buying more in the highest load hours around the daily peak, and less in the shoulder hours when loads are well below the peak. They do not capture the impact of buying more on the highest cost days in a month and selling more on the lowest cost days, since every weekday has the same prices.

Q. **How does the Company propose to capture the cost of day-ahead and real-time balancing transactions in the NPC forecast for the test period?**

A. To better reflect the market prices available to the Company when it has volumes to transact in the real-time market, the Company has included in GRID separate prices for purchases and sales. These prices are adjusted to account for the historical price differences between the Company's purchases and sales compared to the average market prices. For instance, the Mid-C HLH price in January is increased by $2.20/MWh for purchases and decreased by $3.45/MWh for sales.

The price adjustment need not be positive for purchases and negative for sales. For instance, the Mid-C LLH price in August is increased by $3.58/MWh for purchases, but is also increased by $0.42/MWh for sales. Thus sales at Mid-C in light load hours in August result in incremental revenue compared with the average market prices, reducing NPC.

As described above, in some periods the Company's average purchase costs were lower than its average sales prices. If the inputs to the GRID model for a single market showed a purchase price that was less than the sales price, then the GRID model would buy and sell arbitrarily large volumes of power under this situation, but in reality the volumes in question would be very limited. To prevent this, when the average monthly sales price exceeds the monthly purchase price in the same market, a single price adjustment is used for both sales and purchases based on the volume-weighted average of the historical sales and purchases.

Q. **Did the Company also calculate a forecast of additional purchase and sale volumes that arise from using monthly, daily, and hourly products to meet the balancing position determined by GRID?**

A. Yes. The system balancing sales volume determined by GRID would need to be increased by 2.6 million MWh, or roughly 28 percent, to account for the use of monthly, daily, and hourly products. System balancing purchase volume would be increased by an equal and offsetting amount as the net position determined by GRID is unchanged.

Q. **Did the Company include these additional volumes in the 2016 TAM NPC forecast?**

A. Yes. The Company added to its NPC forecast the incremental balancing volumes associated with using standard products to cover the open position determined by

GRID. These volumes are priced so the overall cost of the Company's day-ahead and real-time balancing transactions relative to the forecasted monthly market prices is equal to the historical average.

Q. What is the impact to NPC when GRID is adjusted to reflect the historical impact of day-ahead and real-time balancing transactions?

A. When the adjustments to reflect the impact of historical day-ahead and real-time transactions are included in GRID, 2016 TAM NPC increase by approximately $8.0 million.

Q. How does the resulting short-term firm sales volume in the Company's forecast compare to the historical level?

A. The Company's forecast includes 11.7 million MWh of short term wholesale market sales, whereas the Company's 48 month average is 12.0 million MWh per year. In actual operations, the Company's net position is a forecast and varies over time with changes in forecasts of load, wind, hydro, unit outages, and the economics of the Company's thermal fleet compared with market. As these forecasts change, the Company will buy and sell to limit or cover its revised open position.

Thermal Plant Forced Outages

Q. Please summarize the Company's proposal to more accurately model thermal plant forced outages.

A. The Company previously modeled forced outages at thermal units using a percentage de-rate or "haircut" to nameplate capacity in all hours. In this case, the Company modeled forced outages and unit de-rates as discrete events, rather

Docket No. UE 296
Exhibit PAC/101
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Exhibit Accompanying Direct Testimony of Brian S. Dickman

Oregon-Allocated Net Power Costs

April 2015

PacifiCorp
Oregon - CY 2016 TAM

Line no		ACCT.	Total Company UE-287 Final TAM CY 2015	Total Company TAM CY 2016	Factor	Factors CY 2015	Factors CY 2016	Oregon Allocated UE-287 Final TAM CY 2015	Oregon Allocated TAM CY 2016
1	**Sales for Resale**								
2	Existing Firm PPL	447	14,460,450	14,516,623	SG	25.687%	25.464%	3,714,489	3,696,443
3	Existing Firm UPL	447	29,139,801	26,803,485	SG	25.687%	25.464%	7,485,207	6,825,157
4	Post-Merger Firm	447	414,915,695	376,599,095	SG	25.687%	25.464%	106,580,340	95,896,037
5	Non-Firm	447	-	-	SE	24.484%	24.074%	-	-
6	**Total Sales for Resale**		458,515,946	417,919,102				117,780,036	106,417,637
7									
8	**Purchased Power**								
9	Existing Firm Demand PPL	555	3,538,604	4,635,674	SG	25.687%	25.464%	908,969	1,180,414
10	Existing Firm Demand UPL	555	52,672,296	53,565,725	SG	25.687%	25.464%	13,530,052	13,639,812
11	Existing Firm Energy	555	28,521,106	33,338,675	SE	24.484%	24.074%	6,983,099	8,026,082
12	Post-merger Firm	555	537,557,343	535,787,067	SG	25.687%	25.464%	138,083,579	136,431,173
13	Secondary Purchases	555	-	-	SE	24.484%	24.074%	-	-
14	Other Generation Expense	555	3,522,855	6,262,777	SG	25.687%	25.464%	904,924	1,594,734
15	**Total Purchased Power**		625,812,203	633,589,918				160,410,624	160,872,215
16									
17	**Wheeling Expense**								
18	Existing Firm PPL	565	27,165,030	21,064,818	SG	25.687%	25.464%	6,977,943	5,363,880
19	Existing Firm UPL	565	-	-	SG	25.687%	25.464%	-	-
20	Post-merger Firm	565	112,170,725	118,768,709	SG	25.687%	25.464%	28,813,550	30,242,899
21	Non-Firm	565	6,904,205	8,415,001	SE	24.484%	24.074%	1,690,424	2,025,860
22	**Total Wheeling Expense**		146,239,960	148,248,527				37,481,916	37,632,640
23									
24	**Fuel Expense**								
25	Fuel Consumed - Coal	501	760,067,707	766,272,808	SE	24.484%	24.074%	186,094,753	184,475,497
26	Fuel Consumed - Coal (Cholla)	501	60,047,431	58,220,045	SSECH/SE	24.484%	24.074%	14,701,995	14,016,120
27	Fuel Consumed - Gas	501	3,732,974	5,004,816	SE	24.484%	24.074%	913,980	1,204,879
28	Natural Gas Consumed	547	333,797,813	334,547,426	SE	24.484%	24.074%	81,726,958	80,540,249
29	Simple Cycle Comb. Turbines	547	5,273,378	4,853,712	SSECT/SE	24.484%	24.074%	1,291,132	1,168,501
30	Steam from Other Sources	503	4,328,145	4,797,463	SE	24.484%	24.074%	1,059,702	1,154,960
31	**Total Fuel Expense**		1,167,247,450	1,173,696,270				285,786,521	282,560,207
32									
33	**Net Power Cost (Per GRID)**		1,480,783,666	1,537,615,613				365,901,025	374,847,425
34									
35									
36	Settlement Adjustment		(1,300,000)		SG	25.687%	25.464%	(333,934)	
37	EIM Benefits*		(6,700,000)		SG	25.687%	25.464%	(1,721,044)	
38	Oregon Situs Solar Project Benefit		(141,066)	(131,143)	OR	100.000%	100.000%	(141,066)	(131,143)
39	**Total NPC Net of Adjustments**		1,472,642,600	1,537,484,470				363,704,981	374,516,282
40									
41	EIM Costs		6,700,000	4,612,380	SG	25.687%	25.464%	1,721,044	1,174,482
42	**Total TAM Net of Adjustments**		1,479,342,600	1,542,096,849				365,426,026	375,690,764
43									
44	Increase Absent Load Change								10,264,739
45									
46	Oregon-allocated NPC Baseline in Rates from UE-287							$365,426,026	
47	$ Change due to load variance from UE-287 forecast							822,040	
48	2016 Recovery of NPC in Rates							$366,248,066	
49	*EIM Benefits for the 2016 TAM are reflected in net power costs								
50	**Increase Including Load Change**								9,442,698
51									
52	Add Other Revenue Change								2,309,696
53									
54	**Total TAM Increase**								11,752,395

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Dickman/1

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Reply Testimony of Brian S. Dickman

August 2015

REPLY TESTIMONY OF BRIAN S. DICKMAN

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Attached Exhibits

REPLY TESTIMONY

Improved Modeling of Day-Ahead and Real-Time Balancing Transactions

Introduction

Q. Please briefly summarize the Company's proposal in this case to more accurately model day-ahead and real-time system balancing transactions.

A. The Company's NPC reflects important changes to modeling market transactions, defined as non-hedging, system balancing transactions. PacifiCorp developed these modeling refinements to more accurately capture the true cost of balancing its system in the short-term markets.

The Company's system balancing proposal has two components: volumes selected by the GRID model, which includes adjusted prices for purchases and sales and additional volumes which reflect the fact that GRID determines a single transaction volume for each hour, whereas the Company must balance its system with a combination of monthly, daily, and hourly products. For the adjusted prices in GRID, the Company uses the historical differences between the average market prices over each month and actual prices for the Company's day-ahead and real-time balancing transactions in that month for both purchases and sales. This adjustment creates a more accurate forecast of market prices used for system balancing in the GRID model. Previously, GRID model forecasts only included monthly average prices, and the same prices were used for purchases and sales.[3] The pricing component increases the Company's NPC by $4.3 million.

[3] Wholesale market prices for the system balancing transactions in GRID are based on an hourly forward price curve that is developed from monthly heavy-load-hour (HLH) and light-load-hour (LLH) prices with hourly scalars applied. These scalars are identical within a given month for each weekday of that month. The prices are input into the model and do not change based on the volume of the system balancing transactions.

For the additional volume, the Company calculates the system balancing volume which reflects the operational practice of transacting on a monthly basis using standard 25 MW block products, rebalancing on a daily basis using standard 25 MW block products, and finally closing the remaining position on an hourly basis in real-time markets. As designed, the GRID model perfectly balances each hour to the fraction of a megawatt and does not simulate transacting in the market for standard products. The result of the Company's adjustment is to include additional monthly, daily, and hourly transactions, in the form of offsetting sales and purchases representing this balancing process. The Company calculates these volumes outside of the GRID model and prices them to cover the Company's historical average system balancing costs not already captured by the GRID model results. The additional volume component increases the Company's total Company NPC by $3.7 million.

Q. Why did the Company propose these modeling changes?

A. The Company's historical experience demonstrates that it incurs significant expense in the day-ahead and real-time markets to balance its system. As I explain in my direct testimony,[4] the reason that the Company incurs a net expense for these balancing transactions is timing: the Company is generally buying during periods when prices are high and selling during periods when prices are low. This issue is illustrated in Confidential Figure 1 below, which shows actual HLH prices at the Mid-Columbia (Mid-C) market hub during September 2013, along with the actual volume of the Company's Mid-C purchase and sale transactions that month. The

[4] PAC/100, Dickman/27-28.

average HLH market price that month was $38 per megawatt-hour (MWh), but during the month the Company paid an average of $43/MWh when it made market purchases and received an average of $29/MWh when it made market sales.

Confidential Figure 1

[redacted]

Without the Company's proposed modeling refinements, the flat average market price in its GRID NPC forecast results in average Mid-C prices in September 2016 of $37/MWh for purchases and $35/MWh for sales, compared with a market price of $36/MWh. This price difference is much lower than historical levels. The Company's proposal is intended to more accurately match the purchased power costs and sales revenues in the NPC forecast with actual historical experience.

Q. Has the Commission previously invited parties to more closely review how short-term transactions are modeled in the Company's NPC?

A. Yes. In the 2008 TAM, Staff proposed a margin adjustment, which imputed additional short-term transactions into the Company's NPC based on historical transaction levels and assigned a net margin to these transactions. The Commission rejected this adjustment, in part, in Order No. 07-446, concluding that there was no evidence of a net margin on system balancing transactions.[5] But, the Commission added: "We invite the parties to look more closely at the GRID model to examine whether there is a systematic bias in the way it treats short-term wholesale energy transactions, both for system balancing and for arbitrage and trading."[6]

The Company's proposal in this case is based on historical evidence of the Company's system balancing costs, costs which the GRID model does not reflect absent the adjustments proposed by the Company. This systematic understatement of actual costs has contributed to the Company's under recovery of NPC in Oregon. The Company's under recovery of Oregon-Allocated NPC increased from $33 million (or 8.81 percent) in 2013 to $36 million (or 9.56 percent) in 2014, supporting the need for the Company's proposed NPC modeling improvements.

Q. Has the Commission encouraged PacifiCorp to continue to refine its NPC modeling to improve the accuracy of its NPC forecast?

A. Yes, in the 2013 TAM, the Commission specifically directed PacifiCorp "to refine its

[5] *In the Matter of PacifiCorp, d/b/a Pacific Power 2008 Transition Adjustment Mechanism*, Docket No. UE 191, Order No. 07-446 at 10-11 (Oct. 17, 2007). The Commission accepted the adjustment as it related to arbitrage transactions, which the Commission concluded earned a margin. In the Company's 2013 TAM, the Commission removed the arbitrage adjustment after concluding that the Company's revisions to GRID's topology now captured the arbitrage transactions in the model. *In the Matter of PacifiCorp d/b/a Pacific Power 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 9 (Oct. 29, 2012).
[6] *Id.* at 11.

modeling to produce the best possible estimates of all components of net power costs."[7]

Q. Can you provide recent examples where the Commission has approved the Company's NPC modeling changes that, as here, use historical data to improve the accuracy of the NPC forecast?

A. Yes. In the 2012 TAM, the Commission approved a proposal for more realistic pricing of purchase and sales transactions with hourly scalars derived from historical data.[8] The Commission rejected ICNU's argument for the use of less granular scalars, explaining that "a key purpose of the GRID model is to determine the economic dispatch of Pacific Power's resources on an hourly basis," and the "use of hourly scalars is intended to develop results consistent with historical price data."[9]

In the 2014 TAM, the Commission approved a proposal to shape hourly wind profiles based on historical data, stating that: "We agree with Pacific Power that improving the granularity of its modeling by including actual hourly variation will represent a superior forecasting of the dispatch value of wind output than the flat blocks the company has used in previous TAM dockets."[10]

Q. In both of these cases, did parties object to the Company's proposals because they relied on historical data and added complexity to NPC modeling?

A. Yes. In the 2012 TAM, ICNU asked the Commission to reject the use of hourly scalars because, among other things, they were "overly complex" and unnecessarily

[7] *In the Matter of PacifiCorp d/b/a Pacific Power 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 7 (Oct. 29, 2012).
[8] *In the Matter of PacifiCorp d/b/a/ Pacific Power 2012 Transition Adjustment Mechanism*, Docket No. UE 227, Order No. 11-435 (Nov. 4, 2011).
[9] *Id.* at 23.
[10] *In the Matter of PacifiCorp d/b/a Pacific Power 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 at 4 (Oct. 28, 2013).

detailed. Similarly, in the 2014 TAM, Staff and CUB argued that consideration of the wind shaping proposal should be deferred to allow time for additional workshops and review. In both cases, the Commission adopted the Company's proposals, weighing the benefits of improved NPC forecast accuracy over concerns about increased modeling complexity.

Q. Do parties support the Company's proposal in this case?

A. No, the parties object to the Company's approach to modeling system balancing transactions. Staff and CUB propose to revert to the Company's previous modeling, reducing the 2016 TAM by approximately $8 million. ICNU proposes two different adjustments. First, ICNU proposes to remove market caps from the Company's proposal, reducing NPC by approximately $1.6 million. Second, ICNU proposes an entirely new approach that would both eliminate market caps in GRID and apply a $0.50/MWh bid-ask spread to the price of balancing transactions. This adjustment reduces NPC by $9.4 million.

Q. Do any of the parties challenge how the Company has calculated its historical balancing expense or the fact that the timing of purchase and sale transactions can influence their price?

A. No. None of the parties contest how the Company calculated its historical system balancing expense (*i.e.*, the historical difference between total purchases and sales), nor do parties argue that the Company will not incur the same type of expense in the future. ICNU explicitly states that the expected average purchase and sale prices will differ based on timing within a month.[11] And, as discussed below, Staff recognizes

[11] ICNU/100, Mullins/16, lines 15-23.

Docket No. UE 296
Exhibit PAC/506
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

PACIFICORP

Exhibit Accompanying Reply Testimony of Brian S. Dickman

EIM Benefits

August 2015

PacifiCorp
Oregon - CY 2016 TAM
EIM Benefits - PacifiCorp - CAISO Imports and Exports

PacifiCorp - CAISO EIM Import and Export Results

	12/1/2014	1/1/2015	2/1/2015	3/1/2015	4/1/2015	5/1/2015	6/1/2015	Total	Initial Filing OR TAM CY2016	Reply Update OR TAM CY2016
Export Volume (MWh)	98,946	71,737	46,617	51,641	51,937	89,956	119,969	530,803	956,682	913,590
Export Volume (aMW)	133	96	69	69	72	121	167	104	109	104
Import Volume (MWh)	15,611	11,520	19,124	12,630	15,178	13,548	6,815	94,426	162,788.97	144,074.33
Import Volume (aMW)	21	15	28	17	21	18	9	19	19	16
Transmission Left Open (MWh)	194,756	219,389	196,934	192,460	131,104	241,202	265,478	1,441,323	2,321,293	2,341,179
Transmission Left Open (aMW)	262	295	293	259	182	324	369	283	264	267
Export Margin	$527,961	$805,313	$337,132	$399,054	$533,708	$568,676	$1,196,382	$4,368,225	$7,473,033	$8,002,415
Import Margin	$151,027	$10,745	$200,979	$169,202	$145,151	$38,804	$37,008	$752,915	$970,632	$1,102,575
Export Load Factor	51%	33%	24%	27%	40%	37%	45%	37%	41%	39%
Export Margin $/MWh	$5.34	$11.23	$7.23	$7.73	$10.28	$6.32	$9.97	$8.23	$7.81	$8.76
Export $/MWh Avail Transmission	$2.71	$3.67	$1.71	$2.07	$4.07	$2.36	$4.51	$3.03	$3.22	$3.42
Import $/MWh	$9.67	$0.93	$10.51	$13.40	$9.56	$2.86	$5.43	$7.97	$5.96	$7.65
Total Benefit	$678,987	$816,058	$538,111	$568,256	$678,859	$607,480	$1,233,390	$5,121,141	$8,443,665	$9,104,990

UE 323 - Staff/718

UE 296 – GRID Modeling Changes to Improve NPC Forecast Accuracy

GRID modification[1]	Impact to 2016 TAM NPC
Previously unrecognized costs related to day-ahead and real-time balancing transactions	$8.0 million[2]
Thermal plant forced outage events (heat rate and minimum capacity de-rate)	$0.2 million[3]
Natural gas unit start-up costs and energy	$0.3 million[4]
Hourly regulation reserve requirements	$0.5 million[5]
Compliance curtailment of certain Company-owned wind facilities for avian protection	$0.1 million[6]
Actual performance of wind PPAs	$1.5 million[7]

[1] UE 296 – PAC/100, Dickman/21.
[2] UE 296 – PAC/100, Dickman/30.
[3] UE 296 – PAC/100, Dickman/33.
[4] UE 296 – PAC/100, Dickman/37.
[5] UE 296 – PAC/100, Dickman/38.
[6] UE 296 – PAC/100, Dickman/40.
[7] UE 296 – PAC/100, Dickman/41.