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June 2, 2017

Via Electronic Filing and US Mail

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

RE: Docket No. UE 319–In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.
(Net Variable Power Costs (NVPC))

Enclosed for filing is Staff Opening Testimony (NVPC) in UE 319, together with a Certificate of Service and UE 319 Service List.

Exhibit 100, pages 5 and 15 are confidential.

Exhibit 200, pages 2, 5-6, 9-19, 21-24, 26-28 and 30-32 are confidential.
Exhibit 203, 204, 205, 208, 209, 210, 211.

Exhibit 300, pages 4 to 9 are confidential.
Exhibit 303 is confidential.

Confidential pages and exhibits (CD) will be provided to parties who have signed Protective Order No. 17-057.

/s/ Kay Barnes
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UE 319 – SERVICE LIST

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CERTIFICATE OF SERVICE

UE 319

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

Dated this 2nd day of June, 2017 at Salem, Oregon

Kay Barnes

Kay Barnes
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CASE: UE 319
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 100

Opening Testimony
(Net Variable Power Costs)

June 2, 2017

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

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

Q. Please describe your educational background and work experience.

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

Q. What is the purpose of your testimony?

A. I provide a summary of Portland General Electric Company (PGE)'s 2018 Automatic Update Tariff (AUT) filing, discuss the impact of PGE's renewable resource integration choice (BPA VERBS, wind integration costs) on 2018 NVPC, Staff's analysis of PGE's decision to participate in Western Energy Imbalance Market (EIM) on Net Variable Power Costs (NVPC), and an issue related to the Portland Hydro Project.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared a witness qualification statement labeled exhibit Staff/101, and three other exhibits:

Staff/102	PGE Wind Integration Study Phase 4
Staff/103	PGE response to Staff DR No. 600
Staff/104	PGE response to Staff DR No. 319

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF STAFF'S REVIEW OF PGE'S 2018 NVPC FILING

Q. Please explain PGE's 2018 NVPC filing.

A. Commission Order No. 08-505 authorized PGE's AUT, which allows for an annual adjustment to PGE's rates that accounts for the forecasted changes in the coming year's NVPC. When filed as a stand-alone case, the AUT is filed by April 1 of the preceding year and includes updates to a pre-specified set of data parameters. Since PGE has filed its 2018 NVPC filing concurrently with a general rate case (GRC) proceeding, the Company has included in its filing, not only the parameter revisions allowed under PGE's AUT (Tariff Schedule 125), but also MONET model changes and updates.

Q. What model changes and updates does the company propose in its initial filing?

A. To update its 2017 NVPC for 2018, PGE:

1. Removes the Bonneville Power Administration (BPA) 30/15 Variable Energy Resource Balancing Service (VERBS) costs beginning April 1, 2018;
2. Updates wind integration modeling to reflect full self-integration of PGE's wind resources;
3. Updates the wind Day-Ahead Forecast Error (DAFE) cost and methodology;
4. Includes an estimated NVPC benefit based on PGE's full participation in the Western EIM;
5. Includes the estimated Portland Hydro Project refund;

6. Updates the forecast of transmission resale net revenue;
7. Updates performance parameters for the Port Westward 1 plant; and
8. Replaces the current Mist Gas Storage and Gap Services contract with the North Mist Expansion Project contract costs.

Q. What topics will Staff testimony address?

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

(Staff/100 Gibbens)

1. VERBS
2. Wind Integration Costs
3. Day-ahead Forecast Error Cost Methodology
4. Western EIM
5. Portland Hyrdo Project

(Staff/200 Kaufman)

6. Transmission Resale Revenue
7. Mid-Columbia/California-Oregon Border Trading Margins
8. Wind Resource Capacity Factors
9. Carty Gas Supply Costs
10. Wells PPA
11. Carty Emissions
12. Load Forecast
13. Major Maintenance Expense

(Anderson)

14. Port Westward 1 Performance Parameters
15. North Mist Expansion Project
16. Boardman Biomass
17. Coyote Springs Forced Outage Rate
18. Transmission Expense
19. The Minimum Filing Requirements (MFRs) required of PGE in accordance with Commission Order No. 08-505.

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

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

Adjustment	Amount
EIM net benefits	$1,100,000
COB Trading Margins	[redacted]
Wind Resource Capacity Factor	[redacted]
Carty Gas Supply Cost	[redacted]
Transmission Revenue	[redacted]
Wells PPA	[redacted]
North Mist Expansion Project	$97,200
Coyote Springs FOR	$3,000,000
TOTAL	$30,160,144

ISSUE 1: VARIABLE ENERGY RESOURCE BALANCING SERVICE (VERBS)

Q. What is VERBS?

A. Variable Energy Resource Balancing Service (VERBS) is a Control Area Service offered by Bonneville Power Administration (BPA) for Variable Energy Resources (VERs) that are within BPA's Balancing Authority Area (BAA).[1] PGE's Biglow Canyon and Tucannon River Wind Farms, which provide a variable amount of power at any given moment based on wind speed and direction, are located in BPA's BAA. BPA offers utilities the option to select a VERBS product to balance the variable energy at four different levels based on the frequency of energy schedules submitted and the generation signal persistence used to calculate the schedules. The products currently offered are referred to as "30/60", "40/15", "30/15", and "Uncommitted", where the first number is the number of minutes preceding the scheduling period for which the persistence value (one-minute average of the actual generation) is calculated, and the second number is the length of the scheduling period.[2] Under the Uncommitted Scheduling, a party can either 1) use the BPA supplied wind generation forecast as the schedule, or 2) they can opt to use a different forecast for an additional fee.

Q. Is PGE currently taking VERBS?

---

[1] See https://transmission.bpa.gov/ts_business_practices/mobile/Advanced/Content/8_Ancillary_and_Control_Area_Services/Balancing_Serv_Elect._VERBS.htm

[2] *Ibid*.

A. PGE currently is utilizing the 30/15 VERBS product.[3] The fifteen minute scheduling means that the Company provides four wind schedules per hour to BPA. This is the lowest cost VERBS product available from BPA. PGE and BPA have agreed to transfer PGE's two wind farms out of BPA's BAA by April 1, 2018.[4] At that time, PGE will become fully self-integrated and be responsible for balancing its own authority area.

Q. How is the transition out of BPA's BAA handled in the 2018 AUT?

A. PGE has included the cost of VERBS for the first three months of 2018. Beginning on April 1, they remove the cost of VERBS and realize a savings of $4.6 million to the 2018 NVPC forecast.

Q. What is Staff's position on the handling of VERBS in the 2018 AUT?

A. Staff reviewed PGE's decision to discontinue VERBS in favor of self-integration and whether the costs and benefits of this switch are appropriately included in PGE's 2018 NVPC. Staff reviewed PGE's actions in the process of requesting a dynamic transfer of its wind resources out of BPA's BAA. Staff's review of the process began in the 2017 AUT in which PGE requested a transfer date that would coincide with their October 2017 enrollment into the Western EIM.[5] At that time, and in all of the information provided since, PGE and BPA have been forthcoming with the fact that the process could be protracted. Staff finds that the Company has acted in a timely manner and understands that the amount of work to be done to move the wind resources out of BPA is time consuming.

[3] See UE 319/PGE/300 Niman-Peschka-Rodehorst/10, lines 14-19.
[4] See UE 319/PGE/300 Niman-Peshka-Rodehorst/11, line 7.
[5] See UE 319/PGE/300 Niman-Peschka-Rodehorst/11, line 20.

Staff's review of PGE's NVPC reflects that PGE has reasonably predicted the actual transfer date out of BPA's BAA. The adjustment itself is simply a summation of the costs associated with VERBS from April-December. Staff believes that at this time, based on the information available, an April 1 date is the most reasonable estimate as it is the date to which BPA has committed to complete the transfer. As PGE has stated, should an update occur throughout the process of this filing, PGE will make a subsequent change to its NVPC forecast.

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

A. Staff recommends that the Commission make no adjustment to the VERBS cost included in the 2018 AUT.

ISSUE 2: WIND INTEGRATION COSTS

Q. Please provide background on this issue.

A. By opting out of VERBS, PGE will be required to hold larger reserves in order to fully self-integrate their wind resources. Under the BPA's 30/15 VERBS program, BPA handled the reserve requirements within each 15-minute schedule. Once PGE becomes its own BAA, it will be required to hold reserves for all aspects of wind integration: imbalance, following, and regulation. PGE also updated the ROM model to provide a more granular and precise forecast of day-ahead forecast error (DAFE).

Q. What are Staff's finding regarding the DAFE model change?

A. Staff has no issues with the DAFE model change. The ROM model is an approved methodology for forecasting DAFE for wind costs and the changes improve the accuracy of the forecast. With PGE becoming fully self-integrated the need to account for sub-fifteen minute time frames is more necessary. Additional granularity in the inputs provides the model with a better ability to forecast the error.

Q. What are Staff's concerns of the reserves model change?

A. One of Staff's main concerns is that the Phase Four Wind Integration Study was performed before PGE had finalized plans to enter into the CAISO based EIM. As stated on page D-27 of the study:

> *PGE will consider modifying a future Wind Integration Study to calculate system costs should PGE have the opportunity to participate in an EIM. However, it should be noted that wind*

integration costs for an entity operating within an EIM would be highly dependent on market structures that have not yet been finalized for either of the two main efforts and that the current system operation model may need to be significantly enhanced to accurately represent these market structures.[6]

It was not clear from PGE's testimony whether PGE considered the market structure of Western EIM and updated the ROM methodology based on this new variable. Staff sent discovery requests to PGE to ensure that PGE had considered the market structure of the Western EIM and updated its ROM. PGE responded to this concern in Staff DR No. 600 and stated:

PGE has updated its wind integration study since the release of Phase 4. See PGE's 2016 IRP filed on November 15, 2016 in OPUC Docket No. LC 66, beginning at page 199. The Phase 5 Study described in PGE's 2016 IRP implements (as a model assumption) a liquid, sub-hourly market with 15-minute dispatch. PGE does not have the necessary information to design a more detailed market structure. PGE's Resource Optimization Model limits its system topology to PGE's system and generation resources. A more detailed market structure design would require PGE to model the system topologies and generating resources of other EIM entities and the WECC more broadly. This additional data requirement would be significant and likely not feasible for

[6] See Staff/102, PGE Wind Integration Study Phase 4.

> *implementation, because it would significantly add to software run times and require additional resources for data and software maintenance.*[7]

Staff reviewed the updated methodology provided by the Company in the MFR's and the Phase five study. While no sweeping changes were made to the approved methodology in order to fully model the EIM, the methodology accurately reflects PGE's operational requirements for full self-integration (FSI) in 2018.

Q. What is Staff's recommendation for the Wind Integration Cost change?

A. Staff recommends no adjustment. The $2.5 million increase is a reasonable estimate of the added cost of FSI.

[7] See Staff/103, PGE response to Staff DR No. 600.

ISSUE 3: WESTERN EIM

Q. Please provide a background of this issue.

A. PGE is set to join the Western EIM on October 1, 2017. The EIM is a market aimed at providing a more efficient means of meeting short term imbalances in load. MONET estimates the costs of meeting PGE's load without the benefit of the EIM. As such, the benefits and costs are estimated separately and an adjustment is made to net NVPC.

Q. What are Staff's concerns with the EIM adjustment?

A. Staff is concerned that the costs of PGE's voluntary involvement in the EIM outweigh the benefits. The EIM is meant to lower costs by providing lower cost resources to meet load and provide flexible reserve savings by providing economies of scale. However, PGE's test year forecast of the costs of EIM participation in the test year exceed PGE's test year forecast of benefits.

Q. PGE's testimony states that the EIM provides a $1 million savings, why does Staff believe this is untrue?

A. PGE has included the costs and benefits of FSI in its net benefit calculation in Table 1 of PGE/300. The savings associated with VERBS and the subsequent costs of wind integration or not direct benefits of the EIM. These costs and benefits would be realized with or without PGE's involvement in the EIM. PGE is required to be completely balanced when it bids into the EIM, and the costs included in MONET reflect that. When the savings associated with VERBs and FSI are excluded from the analysis, the forecasted cost of EIM participation exceeds the benefits by $1.1 million. Accordingly, the true net impact of the EIM to PGE's cost is -$1.1 million.

Q. If participation in the Western EIM is supposed to result in cost savings, why does PGE expect its spending for the Western EIM to exceed the expected benefits?

A. In reviewing the EIM related information, Staff found two possible reasons for a negative value associated with EIM participation: excess costs and under-estimation of benefits.

Q. Why does Staff believe PGE might have overspent to be in the EIM?

A. Comparing PGE's EIM related costs to PacifiCorp's (PAC), another Oregon regulated utility that is part of the EIM, PGE's costs are $300,000 greater, even though PAC's total load is roughly three times larger than PGE's.[8] Due to greater size, PAC is able to realize nearly six times the benefit from EIM participation than PGE's estimate at a lower cost.[9] Staff does note however that upgrade costs could be different based on the system each utility was operating prior to enrollment in the EIM.

Q. Why does Staff believe PGE's estimate of benefits might be low?

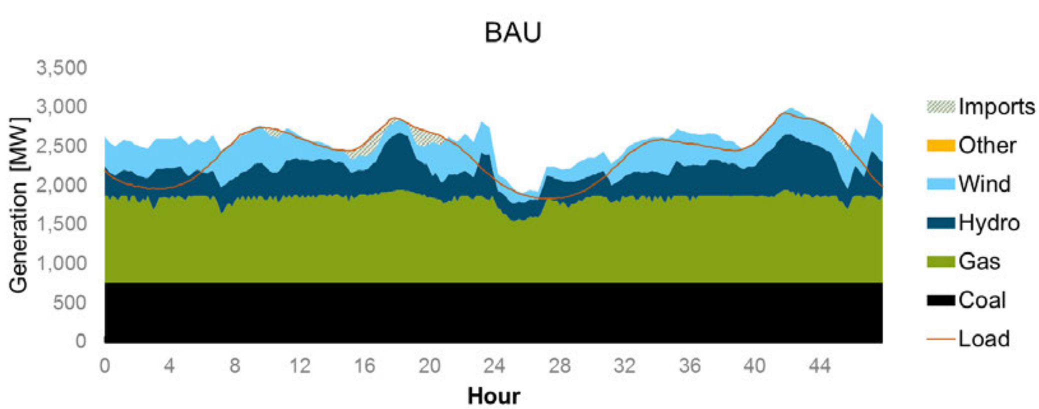
A. PGE has utilized an updated E3 study to estimate the savings associated with joining the EIM. E3 however did not utilize a model that reflects the same granularity as MONET in estimating market purchases and sales. In response to Staff DR. No. 319 PGE stated:

[8] See UE 323 PAC/100, Wilding/30 line 3 and PUC Statbook 2015 page 18.
[9] See UE 323 PAC/100, Wilding/25 table 3.

PGE's power cost model, MONET, uses a more in-depth set of input assumptions than PLEXOS. While MONET is limited to PGE's portfolio of resources, PLEXOS is a Western Electricity Coordinating Council (WECC)-wide production cost model that requires input assumptions for plants and transmission lines across the WECC, not just PGE. In general, this additional level of data requirement (which is significant) necessitates a less in-depth set of input assumptions for PLEXOS.[10]

In order to analyze if this loss of granularity had an impact on the benefit estimation, Staff utilized a chart in the E3 study that shows an estimation of PGE's dispatch without involvement in the EIM. Ideally, this estimation would closely mirror the actual PGE dispatch and the MONET estimation. Below is E3's dispatch estimation for December 12th and 13th of 2018, followed by 2016's actual dispatch for those days and MONET's estimation of the same days in 2018.

Figure 1



[10] See Staff/104, PGE's response to Staff DR No. 319.

Figure 2

[redacted]

Figure 3

[redacted]

[BEGIN CONFIDENTIAL] [redacted] **[BEGIN CONFIDENTIAL]** It is important to note that all transactions made in the EIM result in a reduction to NVPC. If the E3 study under-estimates the amount of transactions it will under-estimate the benefit of the EIM.

Q. What is Staff's recommendation for costs for EIM participation in the 2018 AUT?

A. Staff believes that the benefits should be set to match costs. Until PGE has historical data to get a better idea of the actual costs and benefits of the EIM, customers should not have to bear forecasted net costs for a voluntary program. The E3 study, while informative, does not provide a reliable estimation to justify charging customers for a voluntary program. Application of Staff's adjustment results in a $1.1 million decrease to NVPC.

ISSUE 4: PORTLAND HYDRO

Q. What is the Portland Hydroelectric Project (PHP)?

A. The PHP is a hydroelectric power generating facility located in the Bull Run watershed owned by the City of Portland. The project was completed and commercial generation began in 1982. The City sells the power output to PGE who operates and maintains the facilities.

Q. Please describe the issue related to the PHP Power Purchase Agreement (PPA).

A. The PPA between the City of Portland and PGE expires August 31, 2017. Under that PPA, PGE could receive a disbursement in 2017 from a Renewal and Replacement (R&R) Fund created under the PPA. PGE's receipt of a disbursement is not certain however, and therefore not included in PGE's forecasted NVPC.

Q. How is the PHP refund modeled in the 2018 AUT?

A. In PGE's 2017 AUT, PGE stipulated with parties that it would include a $9.4 million decrease to its NVPC forecast for 2018 in anticipation of the refund. PGE has included this decrease in its 2018 NVPC forecast and has agreed to update this amount in this proceeding should new information come forth.

Q. Does Staff agree with PGE proposed adjustment?

A. Yes, Staff believes that estimate and proposal is reasonable.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 319
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statements

June 2, 2017

WITNESS QUALIFICATION STATEMENT

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

CASE: UE 319
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

June 2, 2017

Appendix D

PGE Wind Integration Study Phase 4

I. Executive Summary: Wind Integration Study Phase 4

In 2007, given projections for a significant increase in wind generating resources, Portland General Electric (PGE) began efforts to forecast costs associated with self-integration of wind generation. This effort entailed developing detailed (hourly) data and optimization modeling of PGE's system using mixed integer programming (MIP). This study was intended as the initial phase of an ongoing process to estimate wind integration costs, and refine the associated model.

In October 2009, PGE began Phase 2 of its Wind Integration Study and contracted for additional participation from EnerNex (a leading resource for electric power research, plus engineering and consulting services to government, utilities, industry, and private institutions), who provided input data and guidance for Phase 1. A significant driver of Phase 2 was the expectation that the cost for wind integration services, as currently provided by the Bonneville Power Administration (BPA), would increase significantly as growing wind capacity in the Pacific Northwest would exceed the potential of BPA's finite supply of wind-following resources. In addition, it is PGE's contention that BPA's variable energy services rate and subsequent generation imbalance charges represent only a portion of the total cost to integrate wind, as calculated in Phase 2.

In the interim between Phase 2 and Phase 4, PGE conducted a Phase 3 internal study to inform the decision for the BPA FY 2014-2015 election period for wind integration services. The result of the study was a PGE election to contract with BPA to provide regulation, load following and imbalance (30 minute persistence forecast for a 60 minute schedule) services for Biglow Canyon for the term of the 2014-2015 election period.

A significant goal for Phase 4 of the Wind Integration Study was to include additional refinements (some of the enhancements were suggested in the "Next Steps" section of Phase 2) for estimating PGE's additional system operating costs incurred by the self-integration of its wind resources and to determine the sensitivity of the wind integration cost to gas price variability. As in Phases 1-3 of the Wind Integration Study, the Phase 4 effort has also included seeking input, deliverables, and feedback from a Technical Review Committee (TRC) and other external consultants. Since launching Phase 4, PGE has reprogrammed and refined the wind integration model, updated the study, and also held a public methodological workshop to discuss progress and modeling details. The public methodological workshop was attended by staff from the Oregon Public Utility Commission (OPUC), the Oregon Department of Energy (ODOE) and other interested parties that have participated in PGE's 2013 Integrated Resource Planning proceeding (IRP – OPUC Docket No. LC 56). In addition to this public review, the Phase 4 data and methodology have been carefully evaluated by the TRC, who provided valuable insight and information associated with wind integration modeling.

The Phase 4 model employs mixed integer programming implemented using the General Algebraic Modeling System (GAMS) programming and a Gurobi optimizer. The Phase 4 model incorporates the improvements made in Phase 2 including:

- Three-stage scheduling optimization with separate Day-Ahead, Hour-Ahead, and Within-Hour calculations;
- Refined estimates of PGE's reserve requirements.

The additional model improvements incorporated in Phase 4 include:

- Separate increasing ("INC") and decreasing ("DEC") reserve requirement formulations for regulation, load following and imbalance reserves;
- Gas supply constraints limiting gas plant fuel usage to the Day-Ahead nomination levels +/- drafting and packing limits on the pipeline;
- Ability to economically feather wind resources; and
- Implementation of the dynamic transfer constraint to allow for limited intra-hour dynamic capacity provision for Boardman, Coyote and Carty.

The results of the study indicate that PGE's estimated self-integration costs (in 2018$) at the reference gas price case is $3.99 per MWh, the high gas price case is $4.24 per MWh, and the low gas price case is $3.57 per MWh. These prices fall within the range calculated by other utilities in the region. **Note: PGE's estimated self-integration costs are exclusive of the necessary investment required in software automation tools, generation control systems, communications/IT infrastructure, and the potential need for personnel additions to manage the self-integration of variable energy resources.** Specific model assumptions are detailed below but, in short, reflect a potential 2018 state in which PGE seeks to integrate almost 717 MW of wind (to physically meet the 2015 Oregon RPS requirement) using existing PGE resources, and future balancing resources acquired in the 2011 RFP, subject to associated operating limitations. As the supply of variable energy resources and the associated demand for flexible balancing resources increases over time, subsequent phases of the Wind Integration Study will assess the effects of these changes.

II. INTRODUCTION

i. REASONS FOR THE PHASE 4 WIND INTEGRATION STUDY

Since the Phase 2 Study, there have been significant changes in the capabilities and inputs to the model. The additional capabilities of the PGE Wind Integration Model were developed in response to public suggestion and internal requests. In addition, gas prices fell off dramatically due to the increased availability of shale gas. As a result of the 2011 RFP process PGE added 266.5 MW at Tucannon River Wind Project, 220 MW flexible gas generators, Port Westward 2, and 440 MW baseload combined cycle gas generator at the Carty Reservoir site. In 2018, PGE loses some of its most flexible capacity on its system with the falling off of some Mid-C contracts. Given the aforementioned changes, it seemed appropriate to update the Phase 2 Study.

ii. STUDY ASSUMPTIONS

Phase 4 of the Wind Integration Study is based on existing PGE owned and contracted resources (as of 2018) plus the 2011 RFP resources which are all planned to be commercially available by 2018. By 2018, PGE will have a varied mix of generation consisting of 2,496 MW of thermal generation (670 MW coal-fired and 1,826 MW gas-fired), 489 MW of PGE-owned hydro generation, approximately 147 MW of long-term hydro power purchase agreements, and 817 MW of wind generation. (One-hundred MW of the wind plant receives long-term third-party wind integration and is not included for this study.) Because PGE is currently a "short" utility, the remainder of its load is covered by market transactions – term contracts and spot market purchases.

Additional assumptions within the model include:

- 2018 is the Wind Integration Study year.
- 2005 actual data was used for hydro flows, wind generation, and load forecast errors.
- 2018 Mid-Columbia (Mid-C) electricity market prices (as used for economic dispatch in the wind integration model) were simulated with AURORAxmp. This is the model used in the Integrated Resource Plan (as discussed in Section 5.3.2, below.
- PGE's 450 MW Biglow Canyon Wind Farm, located in Sherman County, Oregon, is self-integrated.
- PGE's 266.5 MW of Tucannon River Wind Project, located in Columbia County, Washington, is self-integrated.

PGE resources available to provide ancillary services:

- PGE's contractual share of Mid-Columbia hydro generation, which diminishes over time;
- Two-thirds of Pelton-Round Butte hydro generation
- Beaver gas-powered generation, in both combined cycle and simple cycle modes.
- Coyote Springs gas-powered generation
- Port Westward 2 gas-powered generation

PGE resources not available to provide ancillary services:

- Port Westward gas-powered generation
- Carty gas-powered generation
- Boardman coal-powered generation
- Colstrip coal-powered generation

Specific details of PGE's resources and their effective uses for ancillary services are provided in Section V.iv, below.

In Section III of this report, we summarize the public process and third-party review undertaken to ensure that PGE has accomplished its goal of developing an accurate representation of its potential for self-integration using base-line assumptions and robust modeling techniques. In Section IV, we describe the regional wind characteristics used to establish PGE's integration requirements during Day-Ahead, Hour-Ahead, and Within-Hour time frames. In Section V, we provide a detailed description of PGE's wind integration methodology including the programming tools, data assumptions, modeling approach, and calculations for reserves and other variables. In Section VI, we provide a summary of the results and conclusions of our findings. Section VII provides appendices of supporting detail and documentation.

III. PUBLIC PROCESS AND REVIEWS

As with Phase 2 of the Wind Integration Study, Phase 4 sought to assure a robust review by external parties of the logic, assumptions, and data within the model to ensure their accuracy and thereby comply with the Commission directive to have a "wind integration study that has been vetted by regional stakeholders." (Commission Order No. 10-457). To achieve this, several groups were invited to participate in PGE's efforts.

iii. TECHNICAL REVIEW COMMITTEE (TRC)

PGE's TRC consisted of the following members:

- J. Charles Smith, Executive Director, Utility Variable-Generation Integration Group (UVIG)
- Michael Milligan, Ph.D., Principal Analyst, National Renewable Energy Laboratory (NREL)
- Brendan Kirby, P.E., Consultant with NREL
- Michael Goggin, Manager of Transmission Policy, American Wind Energy Association (AWEA)
- Bob Zavadil, E.E., Executive VP of Power Systems Consulting, EnerNex Corporation

The constitution, functions and requirements of the TRC were determined in accordance with UVIG's "Principles for Technical Review Committee (TRC) Involvement in Studies of Wind Integration into Electric Power Systems" as provided in Appendix A.

In accordance with UWIG's TRC Principles agreement, PGE's TRC, in a joint letter displayed in Attachment 1, "endorses the study methodology, execution, and this final report" of PGE's Phase 4 Wind Integration Study.

iv. PROGRAMMING CONSULTANTS

In Phase 4, PGE employed one outside subject matter expert, Jennifer Hodgdon, Ph.D, to assist in the enhancement of the mixed integer programming (MIP) based optimization model that PGE used to calculate costs associated with integrating wind into the PGE system. Dr. Hodgdon helped develop and implement the GAMS and Visual Basic utilized in enhancing the capabilities of the model developed in Phase 2.

Jennifer Hodgdon is owner and Principal Consultant for Poplar ProductivityWare, Seattle and Spokane, WA. She received her Ph.D. degree from Cornell in 1993 and has more than fifteen years of experience as a professional software developer, using a variety of languages and operating systems for many different applications and in various industries.

v. PUBLIC MEETINGS

PGE held two public regional stakeholder meetings in which all members of the service list from PGE's 2013 IRP (OPUC docket LC 56) were invited to attend and provided the opportunity to examine in detail, the methodology of the study and the results. The meetings were held on August 8 and August 29, 2013, and attended by OPUC staff and other interested parties.

During these meetings, PGE provided detailed explanations of the enhancements to the modeling approach, methodology, data inputs, assumptions, bases for cost breakdowns and reserves, and the actual integration costs. PGE also answered numerous questions and engaged in extensive discussion regarding details of the Wind Integration Study.

IV. WIND INTEGRATION ISSUES & METHODOLOGY – OVERVIEW

i. WIND DATA SOURCE

The development of wind power capacity factors and shapes representative of wind generation operations was established initially by using the NREL Western Wind Resource Database (WWRD). The database is a result of 3TIER Group's modeling of wind resources across the entire western United States to generate a consistent wind dataset at a 2-km, 10-minute resolution based on actual wind measurements for the years 2004, 2005 and 2006. The NREL database converted wind to power based on the power curve for Vestas V90 3 MW (Biglow Phase 1), Siemens 141 SWT 2.3 MW turbines (Biglow Phase 2 and 3), and Siemens 108 SWT 2.3 MW turbines (Tucannon River).

The WWRD database provided the following wind data for the study:

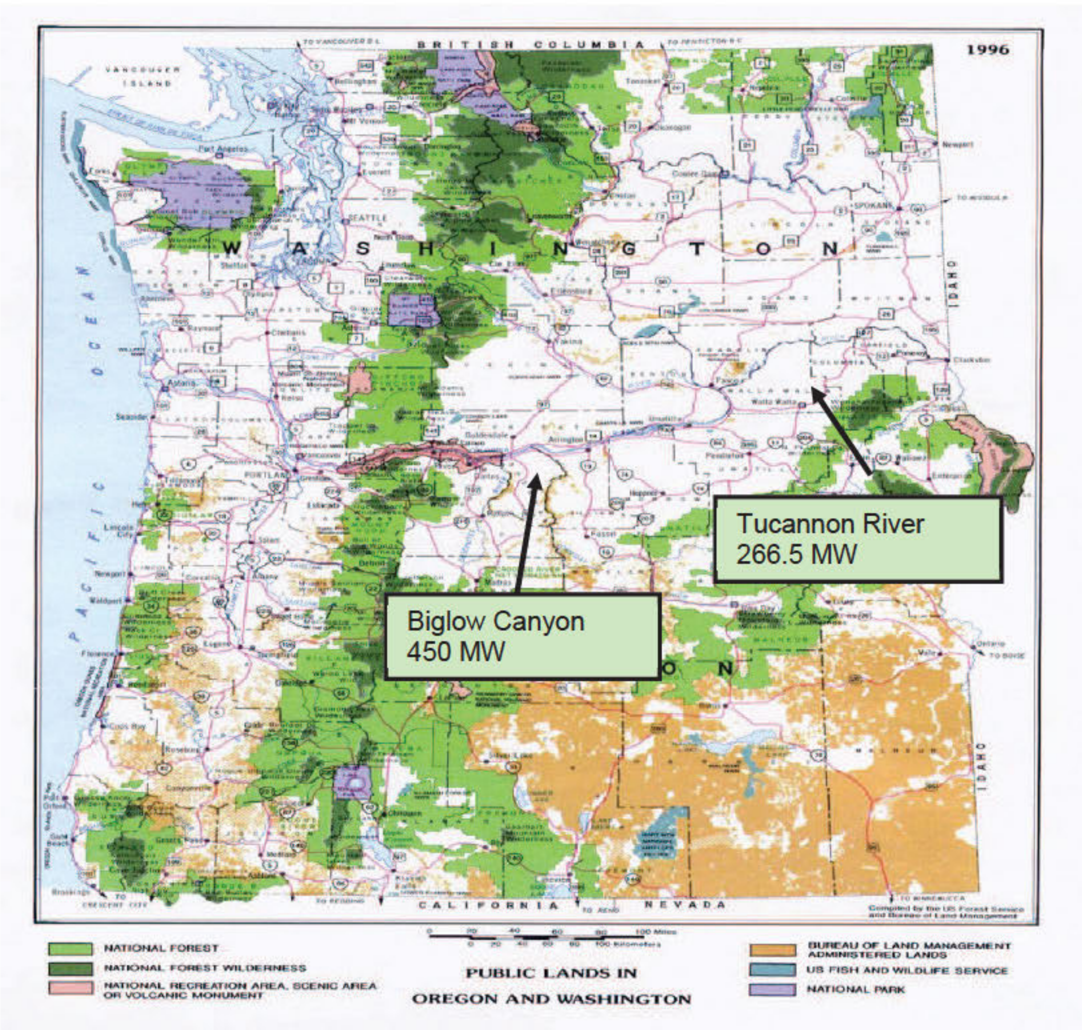
- Date and time (mm/dd/yyyy hh:mm:ss.sss)[1]
- Wind speed (mph)
- Actual wind power output in MW at 1 minute and 10 minute intervals
- Day-Ahead forecast power in MW at 1 hour intervals
- Years 2004, 2005 and 2006

[1] The time stamp hh:mm:ss.sss conveys hours, minutes, seconds and fractional seconds.

- Site Id
- Site location (Longitude, Latitude)

ii. WIND SITE POWER OUTPUT

Virtual wind farms of 266.5 MW in Columbia County on the Tucannon River site and 450 MW in Sherman County on the Biglow Canyon site (see Figure 1, below) in the Columbia River Gorge were developed by selecting multiple wind sites and aggregating the wind site outputs from the NREL database. Capacity factors for the 266.5 MW and 450 MW wind farms based on the 2005 NREL data were 34.4% and 29.6%, respectively.



iii. *WIND SITE FORECASTS*

PGE methodology for performing forecasts is unchanged from the Phase 2 study[2].

V. WIND INTEGRATION METHODOLOGY

i. *OVERVIEW*

Phase 4 of the Wind Integration Study seeks to determine the effect on system operating costs resulting from the introduction of wind resources on PGE's system; specifically, of PGE employing its own generating resources to integrate 716.5 MW of wind capacity in 2018. The system operating costs of wind integration at different gas price levels are calculated by modeling total system costs with and without the additional reserve requirements due to wind. The costs of wind integration in this study are measured as the savings in system operating costs that would result if wind placed no incremental requirements on system operations. The cost savings are conditional on the ability of a given set of generation resources to adjust for the variability and uncertainty of wind generation. In the remaining sections of this chapter, we will discuss:

- The need for Dynamic Capacity in PGE's portfolio (Section V.ii.)
- The modeling tools used by PGE in implementing the study (Section V.iii.)
- Data sources, data generation, and modeling assumptions (Section V.iv.)
- The logic and structure of the modeling approach (Section V.v.)
- Methods for calculating incremental reserves for integrating wind (Section V.vi.)

ii. *THE NEED FOR DYNAMIC CAPACITY*

One of the challenges that PGE faces as a system operator is that we are required to match our system generation to our system load while that load is constantly changing. As PGE adds more variable generation, such as wind, to its portfolio of resources, that challenge becomes more demanding as both generation and load can change moment-to moment. Addressing the challenge of matching total generation with load in real time requires flexible generation that can change production levels over a significant range of operations, and do so in a short time frame. The challenge facing scheduling entities in the Pacific Northwest is that power, predominantly from trades, is currently scheduled for no less than one hour blocks[3]. In 2018, there may or may not be significant and reliable amounts of fast-acting demand response. Therefore, the majority of the responses to changes to load or variable generation must be managed with generators over which

[2] See PGE Phase 2 Wind Integration Report, pp. 13-15 for details of the forecasting methodology.
[3] While there has been some significant movement in the region towards regional imbalance or intra-hour market solutions, at the time of the study there was a large amount of uncertainty about the structure of the market and when/how access to that market might be available.

PGE has physical control and that have been scheduled to allow for intra-hour dynamic generation changes.[4]

As discussed in the Wind Integration Study Phase 2, the reserve requirements for which dynamic capacity must be set aside are as follows: Load Following, Regulation and Contingency Reserves (Spinning and Non-Spinning). Each of these reserves has an independent capacity requirement. Load following and regulation also have an energy requirement that must be assigned to the generator carrying the services.

Contingency Reserves have requirements for storage (for hydro plants) or fuel (for thermal plants). For hydro plants providing contingency reserves, the pond must have sufficient water to produce energy associated with having the spinning or non-spinning reserve called up during the hour. Thermal plants providing contingency reserves have similar fuel reservation requirements.

Increasing and Decreasing Reserve Requirement Model Enhancement

In Wind Integration Phase 2 Reserve calculations, an assumption was made, for simplicity, to make reserve requirements with associated energy (load following and regulation), and increasing and decreasing (INC/DEC) components symmetric. In other words, half of the range of system movement required to account for a particular reserve would be assumed to fulfill the increasing (INC) requirement and half would be assumed to fulfill the decreasing requirement. This symmetry between INC/DEC reserves created simple formulations of reserve requirements and also allowed for a simple accounting of energy and capacity in the constraints supplied to GAMS (two equations per reserve-providing plant). The INC and DEC range requirements are assumed to be the maximum movement above and below the average load net wind for the hour.

In operations, it is observed that the range requirements for load and wind INC and DEC reserves are not usually the same for a particular hour, and inputting independently formulated INC and DEC reserve requirements to the PGE model would better capture system needs for flexibility within an hour. Consider the following examples relating to load following reserve requirements below:

1. Example 1 is a simple example showing if there is just one load net wind movement that is basically equivalent to looking at 2 half hour load net wind blocks that are equally above and below the average load net wind for the hour.
2. Example 2 shows a situation where load net wind decreases steadily over the hour.

[4] For further description of the types of generators required to provide dynamic capacity and a preliminary discussion of reserve range and associated energy please refer to Wind Integration Study Phase 2 pp. 17-19

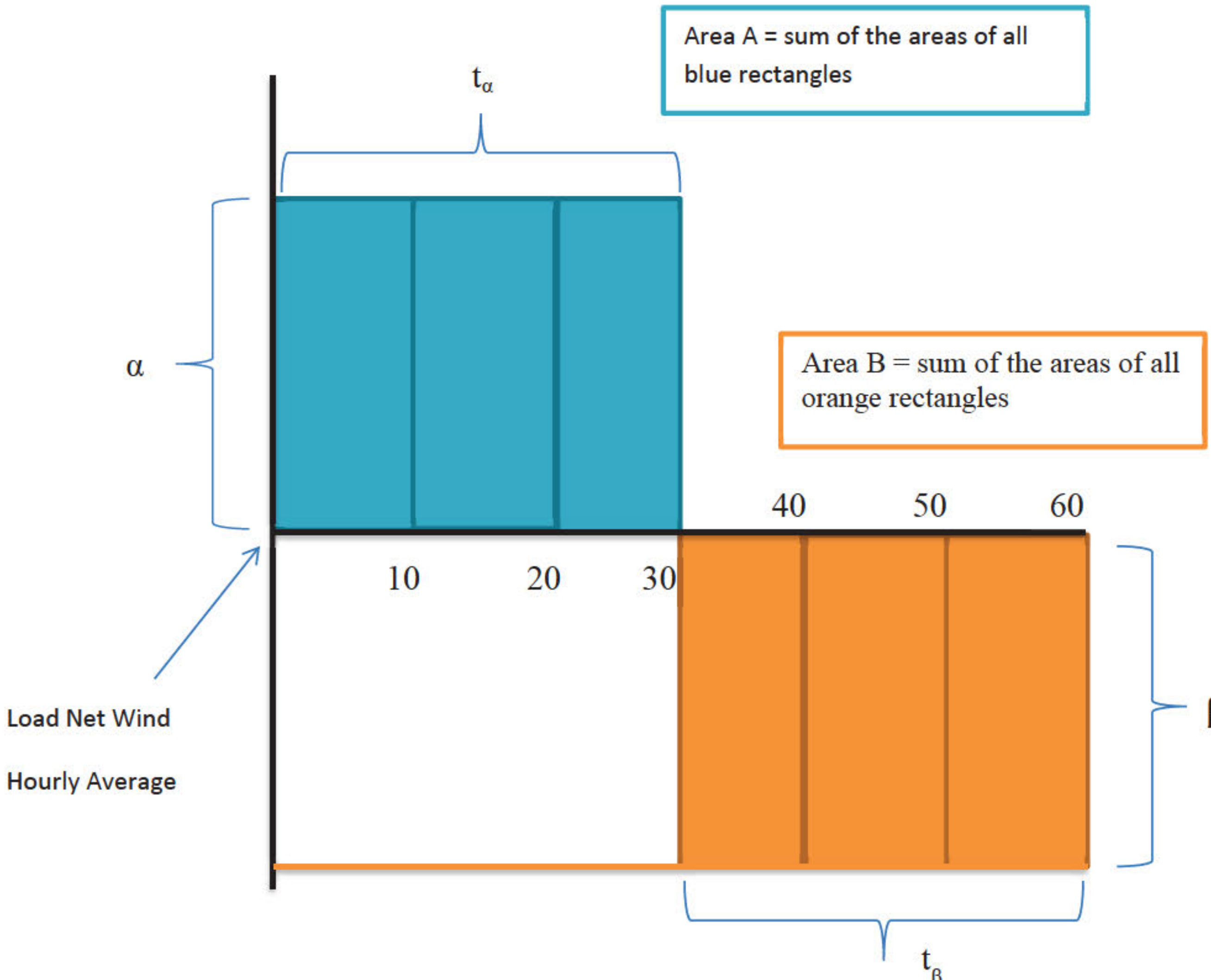


Figure 1: Load net wind direction decreases once within the hour: Equal INC and DEC capacity requirements, $\alpha = \beta$ and $t_\alpha = t_\beta$

The range and duration of required INC and DEC load following reserves are of equal and opposite sign (i.e. $\alpha = \beta$ and $t_\alpha = t_\beta$). In addition, for the formulation to be correct, the energy accounting must reflect the following equality: Area(A) = Area(B). Note that in this case it is also true that Area(A) = β*j - Area(B), where j is the number of time steps in the period, which implies that the energy produced by the reserve providing unit is equal for INC and DEC. This is a simple example of an assumed shape where the INC and DEC reserve requirement shape and the energy associated with providing both reserves are equal and opposite.
Now, consider another example where the intra-hour shape is more complex:

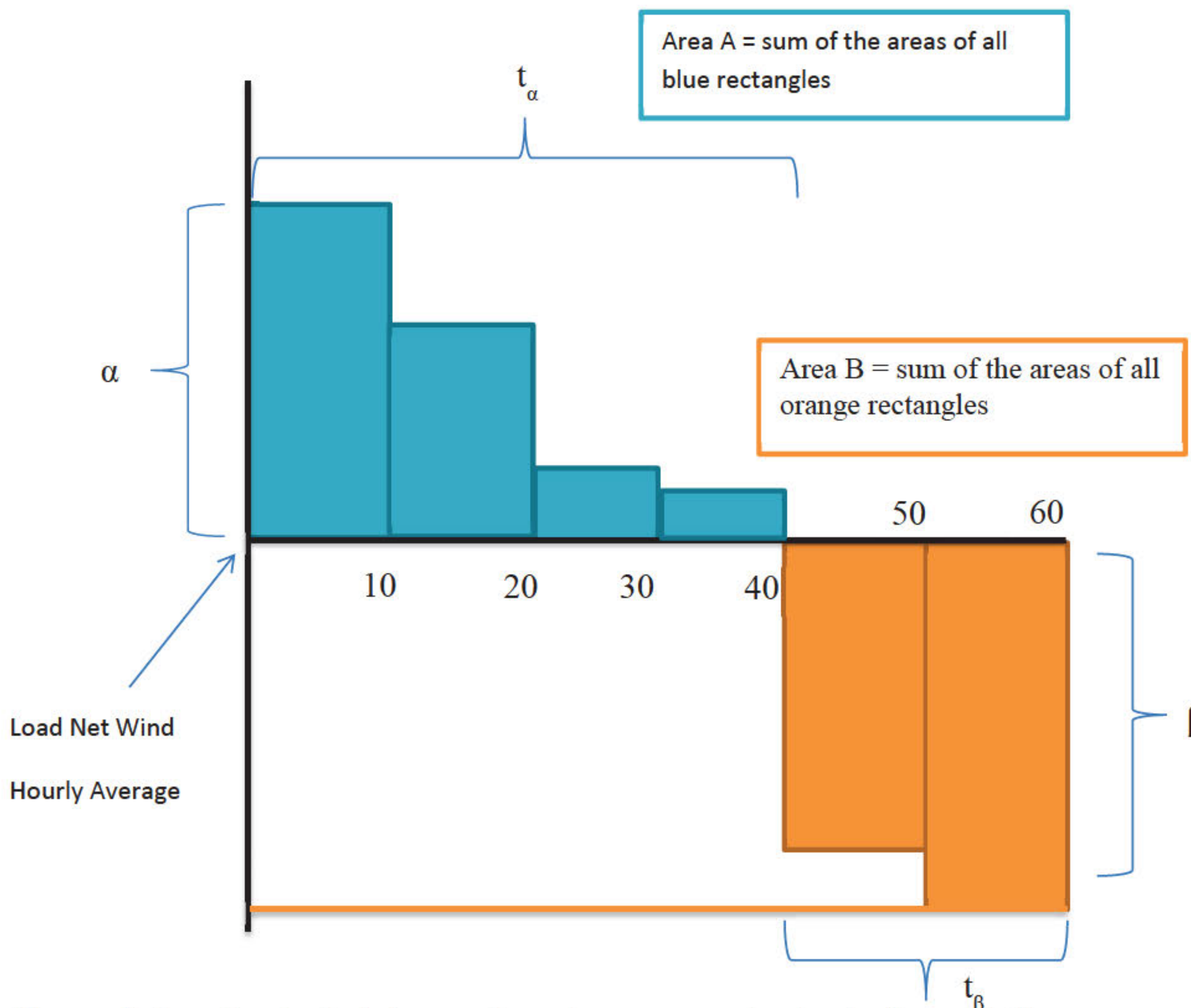


Figure 2: Load net wind decreasing at a non-constant rate through the hour: Equal INC and DEC capacity requirements, $\alpha < \beta$ and $t_\alpha > t_\beta$

The range and duration of required INC and DEC load following reserves are not of equal and opposite sign (in this case $\alpha < \beta$, but $t_\alpha > t_\beta$). However, again, for the formulation to be correct, the energy accounting must reflect the following equality: Area(A) = Area(B). Note that in this case it is NOT true that Area(A) = β*j - Area(B), where j is the number of time steps in the period. In the Phase 4 study, the reserve requirement ranges for load and wind in each hour are considered as above. Once the total reserve requirement ranges and associated energy to provide reserve over that range for Load Following INC, Load Following DEC, Regulation INC and Regulation DEC have been calculated, then the model chooses how to apportion those requirements throughout the portfolio by assigning a percentage to each available plant capable of providing such reserves.

The following is a derivation of the above percentage assignation of reserve requirement.

Let α_k be the amount of inc reserve and let β_k be the amount of DEC reserve provided by plant k. Then let $\sum_k(\alpha_k) = \alpha$ and $\sum_k(\beta_k) = \beta$ in a particular hour i. Let j be the number of data points over which Areas A and B are evaluated. In addition, let the following equations allow the energy accounting depend on the capacity reserved by a particular plant:

$E_\alpha^k = (\alpha_k / \alpha)*(Area(A))/j$ *(energy created by holding out inc reserve on plant k)*

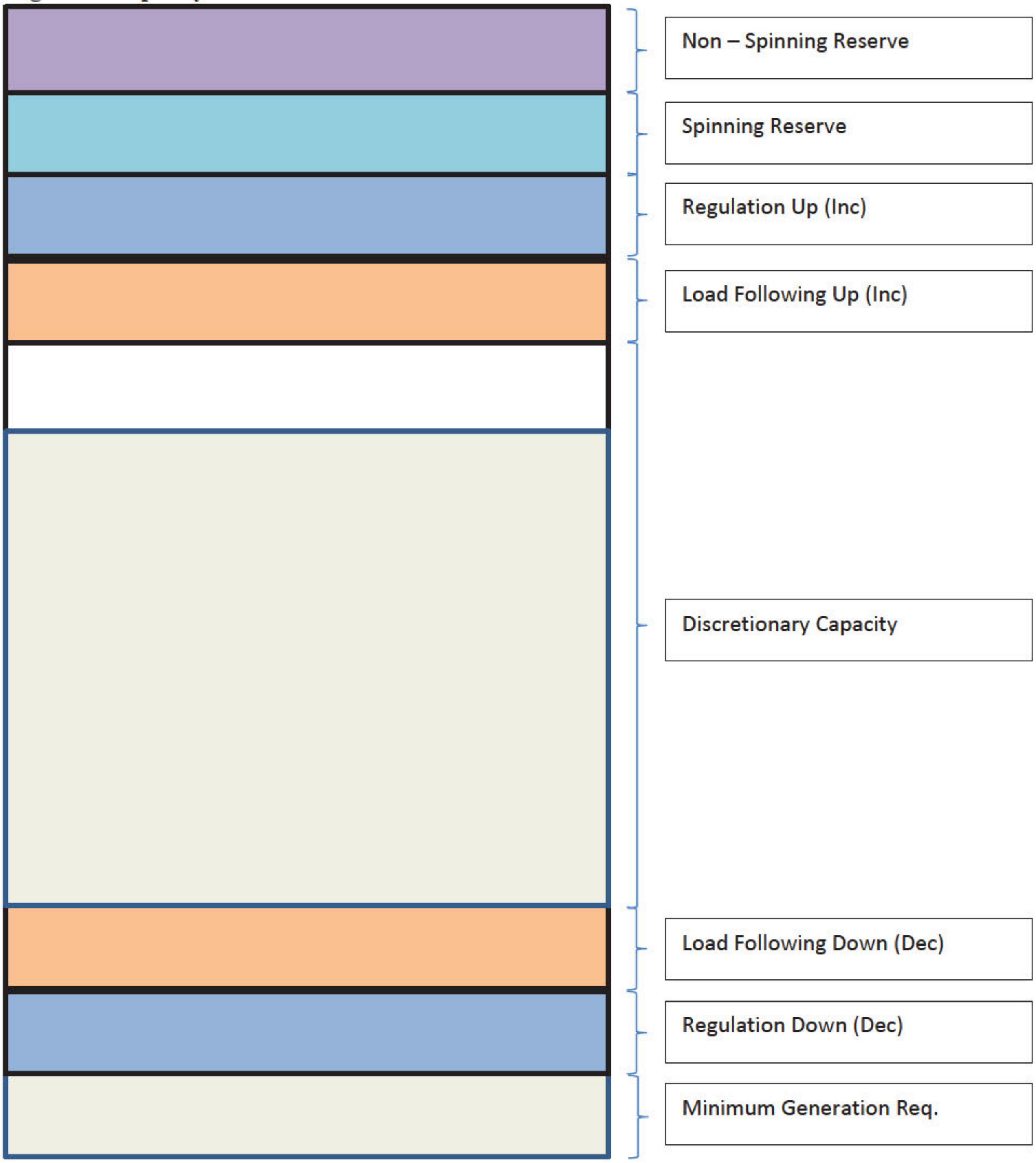
$E_\beta^k = (\beta_k / \beta)*(\beta*j - Area(B))/j$ *(energy created by holding out DEC reserve on plant k)*

In this case, α_k and β_k will be determined be the model, but Area(A), Area(B), α and β will computed outboard and input into the model for each time increment (hourly, sub-hourly).

When the model considers what percentage of the reserve requirements (regulation, load following, spinning, and non-spinning reserves) should be assigned to the plant also must consider other range limitations: minimum generation levels and discretionary energy dispatch. A plant's minimum generation is required to provide almost all reserves (non-spinning can be provided without minimum generation in some cases). The cost of this minimum generation is often the hurdle for a plant's provision of reserves.

In Figures 3 and 4 below, a plant's operating range is assigned all of the discussed reserve components, and minimum generation and discretionary energy. Note that the plant has some unused discretionary range because that is theoretically possible, however in practice, if the plant is generally dispatched for discretionary energy production it is usually because it is in the money and thus would use all of its discretionary range.

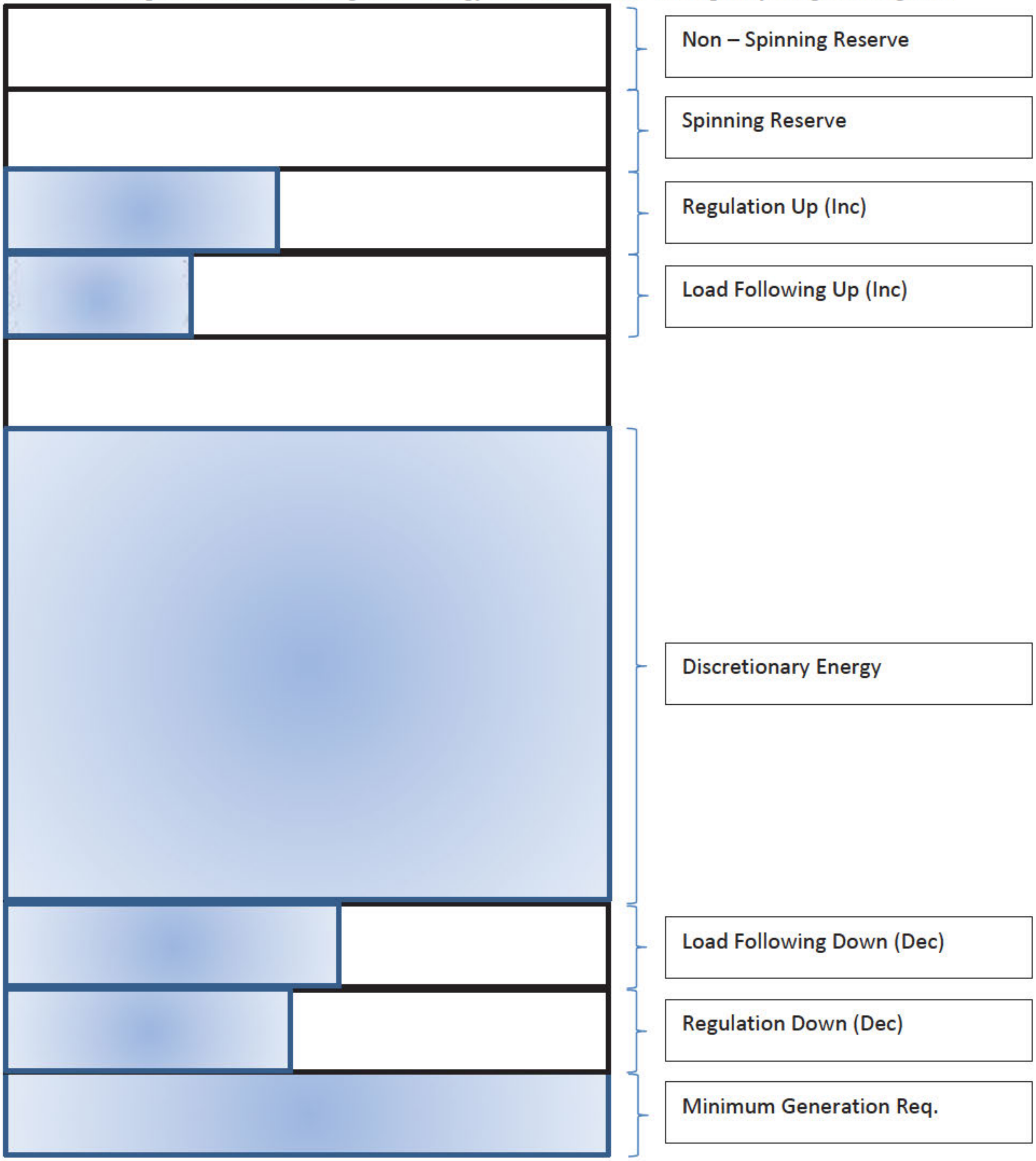
Figure 3: Capacity Reservation on a Generator[5]



[5] Note that this does not necessarily represent the energy produced by reserving a range of the generator for capacity purposes, for more detail on the associated energy see Figure 4 below.

Figure 4: Example of Energy Produced by allocating capacities as in Figure 3

- Add up the blue blocks to get the energy associated with the capacity ranges in Figure 3



Energy production is equal to the capacity provision of the discretionary range that is selected by economic dispatch and the minimum generation requirement[6]. In contrast, there is no energy production directly connected to the provision of contingency reserves (spinning and non-spinning)[7]. The load following capacity reservation[8] is required to cover the largest deviation by the ten-minute average data from the average energy produced over the appropriate dispatch time period. The regulation capacity reservation[9] is required to cover the largest deviation of the one-minute data from the ten-minute average data. By definition, the energy associated with providing those load following and regulation reserves (INC or DEC) must be less than the capacity reserved to meet that requirement. Another way of thinking about this is that for every bit of range of the plant that is reserved for contingency reserves, load following and/or regulation there is foregone opportunity for the plant to have used that range to produce baseload generation over the ENTIRE dispatch period.

iii. MODELING TOOLS

System Optimization

PGE has developed an economic dispatch model to estimate operating costs for the PGE system. This is the principal model used in the Wind Integration Study. The model has a cost minimization objective function and a set of equations/inequalities which detail constraints on the operation of PGE's system. This model was constructed using three commercially available software products: GAMS, Gurobi, and Microsoft Excel. GAMS is used to program/compile the objective function and operating constraint equations. Gurobi is used to solve the resulting constrained optimization problem. Excel (and associated VBA code) is used for data input, reporting model results, and overall model control.

GAMS is a high-level modeling system for mathematical programming and optimization. It consists of a language compiler and a set of integrated high-performance solvers. GAMS is tailored for complex, large-scale modeling applications, and facilitates the construction of large maintainable models that can be quickly adapted to new situations.

The Gurobi Optimizer is a state-of-the-art solver for linear programming (LP), quadratic programming (QP), and mixed-integer linear/quadratic programming (MILP and MIQP). It was designed to exploit modern multi-core processors. For MILP and MIQP models, the Gurobi Optimizer incorporates the latest methods including cutting planes and powerful solution heuristics. Models benefit from advanced presolve methods to simplify models and reduce solve times.

Aurora Model

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[6] In other words, the entire capacity of the range reserved is dispatched over the entire dispatch period.
[7] In the model there is no energy produced even though a portion of the plant is reserved for contingency reserves. In real operation, these reserves will be dispatched only during regional contingencies, and once the contingency situation has been stabilized they need to be re-allocated and maintained without associated generation.
[8] The way load following is defined in the Wind Integration Model.
[9] The way regulation is defined in the Wind Integration Model.

PGE relies on the AURORAxmp Electric Market Model in its IRP for developing the long-term forecast of wholesale electricity prices and for portfolio analysis, as detailed in Chapter 9 of PGE's 2013 Integrated Resource Plan. AURORAxmp is a model that simulates electricity markets by NERC (North American Electric Reliability Corporation) area, detailing: 1) resources by geographical area, fuel, and technology; 2) load by area; and 3) transmission links between areas. As stated in the IRP, PGE uses it to conduct fundamental supply-demand analysis in the Western Electric Coordinating Council (WECC). AURORAxmp is also used to forecast 2018 hourly electricity prices for the Pacific Northwest. These hourly electric prices and the corresponding gas prices, were then input into the Wind Integration Model.

iv. Data Assumptions

Plants Available for Integration

As noted in Section II.ii, above, PGE has a varied mix of generating resources but only a subset of these resources has the capability to provide the Dynamic Capacity required for wind integration. Specifically, we do not use the following thermal resources as part of our modeling:

Port Westward (excluding the duct burner) – plant technology was not designed to provide Dynamic Capacity.

Boardman – this baseload coal plant has a limited dynamic range. It is not allowed to provide dynamic capacity products until a Wear and Tear study better quantifies the risks of operating the plant more flexibly.

Colstrip – PGE does not directly control the operation of this baseload coal plant.

As described in Section V.ii above, for resources that are able to provide ancillary services, only the portion not used for discretionary energy production is available for Dynamic Capacity. A summary of PGE's resources and their specific ancillary services capabilities is provided in Table 1, below.

Table 1: PGE's 2018 Portfolio (does not include Tucannon River or Biglow Canyon Wind Farms)

	Reserve Type	Mid-C	Round Butte	Pelton	Westside Hydro	Boardman	Colstrip	Port Westward	Port Westward Duct Burner	Coyote	Beaver – Simple Cycle	Beaver Combined Cycle	Carty	Carty Duct Burner	Port Westward 2	Distributed Standby Generation
Energy		X	X	X	X	X	X	X	X	X	X	X	X	X	X	
Capacity	Load Following	X	X	X					X	X	X	X		X	X	
	Regulation	X	X	X							X				X	
	Spinning Reserve	X	X	X					X	X	X	X		X	X	
	Non-Spinning Reserve	X	X	X					X	X	X	X		X	X	X

Fuel Prices

PGE relies on independent third-party sources to project fuel prices. Specifically, to be consistent with our IRP methodology, Wood-Mckenzie provided reference, high and low case gas forecasts for 2018. Variable transportation costs are summed with gas commodity price to compute the delivered cost of the fuel, which, along with variable O&M, is used in the dispatch decision. PGE used the most recent available fuel forecast, which was May 2013.

Regional Wholesale Electric Prices

As in the Wind Integration Study Phase 2, PGE used AURORAxmp to generate the wholesale electricity prices used in the wind integration model for the dispatch of PGE generating resources. AURORAxmp simulates the fundamentals of supply and demand in the WECC and is the model used in PGE's 2013 IRP. Macroeconomic assumptions and modeling setup are those described in the

2013 IRP draft (as filed in November 2013) with minor changes not materially affecting electricity prices:

Carbon regulation

It was assumed that no specific carbon regulation is in place by 2018.

Wind shapes

Wind shapes for the WECC are those of the default 2012 AURORAxmp data base. EPIS (the developer of the Aurora market model) developed wind shapes for each area in the WECC using this NREL data. These were calculated by averaging the three years of NREL data (2004-2006), selecting sites/areas as typical of a region, computing a typical-week wind generation for every region and month with hourly detail (168 hours for each month), and reintroducing some of the variability in hourly generation lost in averaging .

For new plants in the Pacific Northwest, PGE computed a typical hourly shape (8760) representing the aggregate wind generation in the BPA balancing authority. We chose 2011 as the year that best fits the historical behavior of wind in the PNW and used the computed hourly shape from the BPA wind generation in 2011 to model any other generic wind plant in the PNW.

Resulting electric prices

The resulting average 2018 wholesale electricity price is $41.26 per MWh ($46.83 on-peak and $30.12 off-peak). In the Pacific Northwest, prices tend to peak in winter, when PNW load peaks, and in July-August, when California's load is peaking. Spring is typically a low price season, because of the abundance of hydro. Hydro is a major driver of prices in the Pacific Northwest. For modeling purposes we assume average hydro conditions.

Loads and Load Forecast Error

For Phase 4 of the Wind Integration Study, PGE projected its 2018 load data by employing a three-step process using 2005 actual load and 2005 Day-Ahead and Hour-Ahead load forecast data. The wind data is based on 10-minute intervals for the necessary Within-Hour granularity.

<u>Step 1. Realign Days of Week</u>
PGE developed the 2018 load data from 2005 load data by first aligning the 2005 actual load data days of the week with the 2018 days of the week. Because January 1, 2005 fell on a Saturday and January 1, 2015 falls on a Monday, we used the first Monday of January 2005 (January 3rd, 2005) for Monday, January 1st, 2018. Tuesday, January 4th, 2005 was then used for Tuesday, Jan. 2nd, 2018, and so on. This step is important because the load and wind data must correspond to the same days for consistency in deriving the "load net wind" concept.

<u>Step 2. Escalate 2005 to 2018</u>
The realigned 2005 data was then scaled up to 2018 levels by an escalation factor equal to the percentage increase from PGE's 2005 average annual actual load to PGE's 2018 average annual

forecast load. The realigned and scaled data was then used to develop the projected 2018 real-time load data in the model.

Step 3. Develop Hour-Ahead and Day-Ahead Forecast Loads
PGE's 2018 Hour-Ahead and Day-Ahead forecast load data was derived by summing the 2018 forecasted-actual load data (derived in steps 1 and 2 above) with the corresponding 2018 Hour-Ahead or Day-Ahead load forecast error data. Specifically, the 2018 Hour-Ahead and Day-Ahead load forecast error data was created by: 1) taking the difference between the respective forecasted and actual 2005 loads, and then realigning to the matching day of the week, and 2) scaling the actual 2005 Hour-Ahead and Day-Ahead forecast errors in the same way the 2005 actual load data was escalated to 2018 forecast load data (described in step 2, above).

Water Year

PGE selected 2005 hydro flows for use in the wind integration model as a proxy for 2018 hydro flows. Of the three years (2004-2006) of NREL wind data used in the Western Wind and Solar Integration Study (from which EnerNex derived the wind energy data), 2005 was nearest to a normal hydro year for the Pacific Northwest. PGE did not use a 3-year hydro average of those years because the resulting hourly averages would mask the interactive effect of localized weather on hydro flows and wind speeds. The inputs of the wind integration model are temporally aligned to try to capture the effect of weather creating volatility in loads, wind, and hydro, and the resulting effect on the system trying to provide the Dynamic Capacity to meet the reserve needs of such volatility.

Specific hydro data used in the wind integration model includes:

- Mid-Columbia hydro energy – this is treated as one resource in the model, so historical (2005) flows from Chief Joseph were used.
- Deschutes hydro project inflows – USGS daily average inflows from 2005 were the assumed inflows for Round Butte.
- Hourly energy for PGE's run-of-river hydro – PGE historical PSAS (Power Scheduling and Accounting System) data from 2005 was used as proxy hourly energy data for Oak Grove, North Fork, Sullivan, Faraday, River Mill, and PGE's portion of Portland Hydro Project. (These hydro facilities do not provide ancillary services for wind integration.)

Bid/Ask Pricing

The wind integration model assumes virtually unlimited access to the energy market in the Day-Ahead and Hour-Ahead schedules. When the model chooses to purchase or sell energy in the Day-Ahead or Hour-Ahead stages to balance generation to load net of wind, there is an assumed bid/ask spread that affects the economics of using the market to meet load.

The Bid/Ask treatment is the same as in Phase 2 of the Wind Integration Study[10].

[10] See pp. 29-30 in the "2011 Update to the 2009 IRP – Appendix A: Wind Integration Study Phase II"

General constraints for Hydro

The hydro modeling methodology is the same as in Phase 2 of the Wind Integration Study[11], and all hydro data is consistent with the Phase 2 study, except PGE's contractual shares of the Mid-Columbia system are decreased in 2018 to reflect the expiration of the Wells contract.

General Constraints for Thermal Plants Providing Ancillary Services

In Phase 4 of the Wind Integration Study, Beaver and Port Westward Duct Burner are available to provide ancillary services as in Phase 2[12]. In addition, 50 MW per hour of intra-hour movement will be allowed on Coyote Springs (natural gas combined cycle cogeneration plant), per PGE's current understanding of the BPA's Dynamic Transfer Capability (DTC) business practice and best assumption of long term availability of DTC from Coyote. The 50 MW of range provided by the duct burner at PGE's future CCCT at Carty Reservoir is also available to provide some ancillary services. The 12 reciprocating engines at PGE's future Port Westward 2 plant are available to provide all ancillary services and are free to move between the min generation (8 MW, emissions constrained) and max generation (18 MW) although the number of engines available in any hour is determined by the designated scheduled outage rate.

<u>Constrained Gas Supply Enhancement</u>

In Phase 2, the wind integration model had no gas supply constraints limiting its nomination of gas to be burned in the day-ahead, hour-ahead and real-time economic dispatches. This modeling simplification over represented, in the Wind Integration Model, the flexibility the PGE system had to supply gas to Beaver, Port Westward and Coyote. Thus, to better represent the system operations, in Phase 4 of the Wind Integration Study, gas supply constraints have been applied to the operations governing Beaver (simple and combined cycle), Coyote, Port Westward (baseload and duct firing), Carty (baseload and duct firing), and Port Westward 2.

In actual operations, there are multiple ways that the gas desk can change the supply of gas after it has been nominated on a day-ahead basis. When there is a market, a portion of nominated gas can be sold at a couple different times after it is nominated. However, our model currently is not set up to capture the time windows in which renomination is available. Due to time constraints, renominating gas will have to be saved for a future enhancement to the model.

The other major way that gas is constrained, but has some flexibility is utilizing storage and/or drafting and packing the pipeline. This constraint is a daily accounting to ensure that a plant has not underused its nomination, and is thus storing unused gas in the pipeline (packing the gas, since it is a compressible fluid); or, overused its nomination, and is thus using more gas than allotted off the pressurized pipe (drafting the gas within appropriate pressure limits).

Beaver and Port Westward 2 can be fueled from a gas storage facility so are allowed a broader range of flexibility within the injection and withdrawal limits of the facility. This gas storage facility has

[11] See pp. 30-32 in the "2011 Update to the 2009 IRP – Appendix A: Wind Integration Study Phase II"
[12] See pp. 32-33 in the "2011 Update to the 2009 IRP – Appendix A: Wind Integration Study Phase II"

an annual maintenance cycle; during this period, the change of gas supply for Beaver and Port Westward 2 dispatch changes after the day-ahead nomination is limited by the drafting/packing limits of the gas pipeline.

Economic Feathering of Wind

In Phase 2 of the Wind Integration Study, the wind output was a static input for each stage (Day-Ahead, Hour-Ahead and Real-Time), and the model had no choice on how the wind plant actually dispatched. This was a simplifying assumption for the Phase 2 study that would underrepresent system flexibility in certain rare situations, since when there is wind blowing, the generation (determined by rotation speed) from the plant can be reduced/stopped by pitching the blades of the wind plant (feathering). PGE's wind plants all have feathering capability (albeit different capabilities between the Vestas and Siemens units), so it makes sense to incorporate that aspect into the optimization.

One of the potential benefits of feathering wind is that it can reduce the additional reserve burden on the system due to wind. PGE does not currently have the methodology refinement required to adjust intra-scheduling period reserves (Load Following, Regulation) dynamically as the wind generation changes. However, the spinning and non-spinning reserve requirements can be dynamically reduced with any feathered generation in the model.

In Phase 4 of the Wind Integration Study, the model can make the decision to feather based on the cost of losing the wind generation. The production tax credit, renewable energy credit, and increased wear and tear cost to the plant caused by feathering wind are explicitly defined as inputs to the model. Replacement energy for the feathered wind generation is implicitly calculated in the model. These are all part of the variable cost calculation considered by the model when determining to feather wind.

v. Modeling Approach

During Phase 2 of the Wind Integration Study, with the assistance of two external consultants, PGE developed a mixed integer programming model to assess the incremental operating (non-capital) costs of integrating wind resources into PGE's system. The model is a "constrained optimization model" with an objective function to minimize total system operating costs given a set of operational constraints. These operational constraints include plant dispatch requirements (minimum plant up-times, minimum plant generation requirements, etc.) and system requirements (Contingency Reserves [Spinning and Non-Spinning], Regulation INC/DEC, Load Following INC/DEC, etc.). The model allocates the total system requirements (e.g., total Spinning Reserve requirements) to the individual generators to minimize overall system costs. Currently, the model optimizes plant dispatch and system operation for a single year (2018). Given the heavy computational requirements, each of the 52 weeks is run separately on an hourly basis although functions for reserve requirements are developed from 10-minute data.

Phase 4 of the Wind Integration Study considers wind integration cost for three gas price sensitivities - reference, high, and low cases. In order to accurately represent system operation, the model is run in three stages corresponding to Day-Ahead, Hour-Ahead, and Within-Hour. At each stage, PGE's system is optimized subject to the operational constraints relevant at that stage. Commitments made in prior stages (e.g., purchase or sale commitments) are carried forward to the next stage as constraints. Total system operating costs at the third stage are used in assessing the costs of wind integration.

The model incorporates explicit reserves (reserved generation capacity) to address:

1) The Hour-Ahead uncertainty of wind INC/DEC;
2) Generation resource requirements for Within-Hour Load Following INC/DEC for wind; and
3) Generation resource requirements for Within-Hour Regulation INC/DEC for wind.

In addition, implicitly, spinning and non-spinning reserves are assigned economically within to generators per the level dictated by portfolio dispatch.

As in Phase 2, no reserves are specified in the model to address Day-Ahead wind uncertainty.

Details of Modeling Approach and Results

As discussed above, the costs of wind integration are identified by comparing total system operating costs, from a model run that incorporates the system requirements for wind integration, to total system operating costs, from a model run that excludes the system requirements for wind integration.

In Phase 4, to capture the system operation costs associated with integrating wind[13] for each of the three gas price sensitivities six model runs are required per Table 2 below. For example the system operation cost for wind integration in the reference gas case requires Run 1 (PGE integrates wind and load) and Run 1 (PGE integrates load only) described in Table 2. The difference between those runs is the systems operations cost associated with the self-integration of wind in the reference gas price case. Similarly, the differences between Runs 3 and 4, and Runs 5 and 6, are the increased system operation costs associated with self-integration of wind in the high and low gas cases respectively.

[13] As mentioned above, "PGE's estimated self-integration costs are exclusive of the necessary investment required in software automation tools, generation control systems, communications/IT infrastructure, and the potential need for personnel additions to manage the self-integration of variable energy resources."

Table 2: Descriptions of the Six Model Runs Required

Note that PGE integrates load in all the runs, the delineation of "PGE integrates" refers specifically to wind.

Identification	Description
RUN 1	**PGE integrates Regulation, Load Following, Hour-Ahead and Day-Ahead Uncertainty (Reference Gas Price)**
RUN 2	**PGE doesn't Integrate Load Following, Regulation, Hour-Ahead and Day-Ahead Uncertainty (Reference Gas Price)**
RUN 3	**PGE integrates Regulation, Load Following, Hour-Ahead and Day-Ahead Uncertainty (High Gas Price)**
RUN 4	**PGE doesn't Integrate Load Following, Regulation, Hour-Ahead and Day-Ahead Uncertainty (High Gas Price)**
RUN 5	**PGE integrates Regulation, Load Following, Hour-Ahead and Day-Ahead Uncertainty (Low Gas Price)**
RUN 6	**PGE doesn't Integrate Load Following, Regulation, Hour-Ahead and Day-Ahead Uncertainty (Low Gas Price)**

vi. Calculation for Reserves and Uncertainty

The wind integration model accounts for three categories of reserves: Regulation, Load Following (including forecast error), and Contingency Reserves. The Contingency Reserve requirement is defined by the WECC (i.e., 5% for hydro and wind, and 7% for thermal resources) with requirements split equally between Spinning and Non-Spinning Contingency Reserves. The model simulates the different reserve requirements as hourly constraints for resource scheduling and dispatch across each of the three time horizons: Day-Ahead scheduling, Hour-Ahead scheduling and Real Time dispatch (Within-Hour). In Phase 2 of the Wind Integration Study, EnerNex provided PGE with a methodology for estimating regulation and load variability parameters for Day-Ahead, Hour-Ahead and Real Time (Within-Hour) scheduling, as well as the Hour-Ahead forecast error. However, PGE currently does not explicitly set aside reserves for Day-Ahead forecast error for either load or wind generation. Specific modeling for the reserves, by category and time frame, are described below.

Reserve Requirement Calculation

The reserve requirements for regulation, load following and forecast error for the Phase 4 study are calculated using the same methodology described in the Phase 2 study[14]. The only difference in reserve calculation is described in detail in Section V.ii: Increasing and Decreasing Reserve Requirement Model Enhancement above.

Day-Ahead Scheduling

In Day-Ahead scheduling, reserve predictions must be made for load variability and regulation for both load and wind generation. The Day-Ahead load forecast is input with a forecast error, but the model does not explicitly hold back reserves to cover the forecast error.

Hour-Ahead Scheduling

For Hour-Ahead scheduling, reserve predictions for the load variability and regulation from the Day-Ahead Scheduling step must be recalibrated to account for the Hour-Ahead load and wind generation forecast. Since PGE explicitly holds back reserves for forecast error in Hour-Ahead scheduling, additional reserves are calculated as follows:

- Reserves to cover the load forecast error are derived from historical PGE information (i.e., 2005 load data escalated to 2018 levels)
- Additional reserves held to cover the wind generation Hour-Ahead forecast error are determined by the EnerNex methodology described in the Phase 2 Study[15].

Plant dispatch is recalibrated from the Day-Ahead schedule to reflect the different reserve, wind generation, and load requirements.

Real-Time Dispatch (Within-Hour)

The forecast error reserve obligations that were established in the preceding Hour-Ahead scheduling step are released (when possible) in the Real Time (Within-Hour) dispatch step, and the reserve requirements for load variability and regulation are recalibrated. Plant dispatch is also recalibrated from the Hour-Ahead schedule to reflect different reserve, wind generation, and load requirements. Consequently, in each stage of the simulation, (i.e., Day-Ahead, Hour-Ahead and Within-Hour), the calculated reserve requirements for Regulation, Load Following, and Contingency Reserves are factored into the model's optimization of dispatching generation, capacity, and market resources.

[14] See pp. 40-42 in the "2011 Update to the 2009 IRP – Appendix A: Wind Integration Study Phase II"
[15] See p. 42 in the "2011 Update to the 2009 IRP – Appendix A: Wind Integration Study Phase II"

VI. Summary and Conclusions

i. Cost Summary

PGE estimates the additional system operation costs incurred to self-integrate almost 717 MW of wind in 2018 would be $3.99 per MWh (in 2018$) at the reference gas price. PGE's estimate of the additional system operation costs to self-integrate the 717 MW in 2018 at the high gas price case is $4.24 per MWh, and at the low gas price case is $3.57 per MWh. It is again important to note that the aforementioned estimated self-integration cost estimates are exclusive of the necessary investment required in software automation tools, generation control systems, communications/IT infrastructure, and the potential need for personnel additions to manage the self-integration of variable energy resources. These results are summarized in Table 3 below.

Table 3: System Operation Costs for PGE Self-Integrating Wind with Gas Price Sensitivities

Identifier	Cost Saving For PGE	Run Delta Measures:	Cost ($/MWh)
A	RUN 2 – RUN 1	Cost saving for Day-Ahead Uncertainty, Hour-Ahead Uncertainty, Load Following and Regulation (Cost of wind integration at **Reference Gas Price**)	$3.99
B	RUN 4 – RUN 3	Cost saving for Day-Ahead Uncertainty, Hour-Ahead Uncertainty, Load Following and Regulation (Cost of wind integration at **High Gas Price**)	$4.24
C	RUN 6 – RUN 5	Cost saving for Day-Ahead Uncertainty, Hour-Ahead Uncertainty, Load Following and Regulation (Cost of wind integration at **Low Gas Price**)	$3.57

ii. Conclusions

PGE believes that Phase 4 of the Wind Integration Study accurately simulates the constraints associated with existing conditions and available resources to estimate the costs attributed to the self-integration of 717 MW of wind generation in 2018. The study has been subject to regular and rigorous reviews from the TRC and major participants in PGE's 2013 IRP, Docket No. LC 56. The TRC considers this study to be technically sound and have provided their unanimous endorsement. Regional stakeholders and PGE's Wind Integration Study Project Team have participated in three detailed public presentations regarding the intricacies of the study. Stakeholders have been provided the opportunity to examine, in detail, the methodology of the study and the results. They have also had the opportunity to comment on the methodology and make recommendations. In short, Phase 4 of the Wind Integration Study has been vetted in accordance with Commission Order No. 10-457.

As shown in the results in Table 4 below, the change in wind integration cost has a direct significant relationship to the price of gas. However, the larger overall effect is due to the net addition of balancing resources and wind diversity. There may be some threshold of gas prices where the effect on system operation cost due to wind integration is more drastic, but this study did not bear evidence to that threshold.

Table 4: Comparison of Gas Plant Portfolio Changes, Gas Price Sensitivities, WI Phase costs[16]

Study Name	Study Year	Gas Plants Capable of Providing Reserves	Plants fueled by Sumas	Plants fueled by AECO	Annual Average Sumas Gas Price	Annual Average AECO Gas Price	Wind Integration Cost
Wind Integration Study Phase 2	2014	Beaver, PW Duct Firing	Beaver, Port Westward	Coyote	$ 5.23	$ 5.17	**$ 11.04**
Wind Integration Study Phase 2	2014	Beaver, PW Duct Firing, **Proxy Port Westward 2**	Beaver, Port Westward, **Proxy Port Westward 2**	Coyote	$ 5.23	$ 5.17	**$ 9.15**
Wind Integration Study Phase 4 (reference)	**2018**	Beaver, PW Duct Firing, **Port Westward 2, Coyote, Carty Duct Firing**	Beaver, Port Westward, **Port Westward 2**	Coyote, **Carty**	$ 5.28	$ 4.89	$ 3.99
Wind Integration Study Phase 4 (high)	**2018**	Beaver, PW Duct Firing, **Port Westward 2, Coyote, Carty Duct Firing**	Beaver, Port Westward, **Port Westward 2**	Coyote, **Carty**	$ 6.05	$ 5.62	$ 4.24
Wind Integration Study Phase 4 (low)	**2018**	Beaver, PW Duct Firing, **Port Westward 2, Coyote, Carty Duct Firing**	Beaver, Port Westward, **Port Westward 2**	Coyote, **Carty**	$ 4.24	$ 3.89	$ 3.57

All evidence points to wind regime diversity between Biglow and Tucannon River as the single most influential factor in the cost estimate decrease from Phase 2 to Phase 4. In the Phase 2 study, the most reasonable site for the next available tranche of wind had a much higher correlation with Biglow than the Tucannon River Wind Project acquired in the 2011 RFP. Thus, the regulation and load following reserve requirements fell slightly and the forecast error dropped considerably. This

[16] Note that the **bold** resources differentiate from the Wind Integration Phase 2 Base Case.

significant reduction in reserve requirements seems to be highly dependent on spatial and temporal diversity between wind sites.

The advent of more available gas balancing resources as was also seen in Phase 2 seems to have a significant mitigating effect on wind integration cost; however, these effects are highly portfolio dependent. Other changes between Phase 2 and Phase 4 that appear to have significant effect on the cost are follows:

(1) Reduction in PGE's contractual share of the Mid-C likely raises system operating costs.
(2) Addition of gas fueling constraints likely raises system operating costs.
(3) Revised understanding of BPA's dynamic transfer constraint which allows some generation movement at Coyote and Carty Duct Firing likely decreases costs.
(4) The model's ability to feather wind when system constraints leave the portfolio flexibility short likely decreases costs.
(5) Ability for the model to assign INC and DEC reserve requirements to units individually allows PGE's portfolio to provide reserves more efficiently and likely decreases costs.

iii. ***Dynamic Dispatch Program***

For PGE to self-integrate wind, join a future energy imbalance market or adopt a hybrid system integration solution, investment is required in software automation tools, generation control systems, and communications/IT infrastructure. There is also the potential need for personnel additions to manage the self-integration of variable energy resources. In addition, to be prepared for a future where units will be used more flexibly, PGE has contracted an in-detail study on the wear and tear costs of increased cycling of PGE's units and the installation of automatic generation control (AGC) systems on the thermal units that will be sent within-hour balancing signals. PGE has currently folded all these efforts into a Dynamic Dispatch Program that will be completed in phases over the next few years.

iv. ***Future Potential Remediation***

Energy Imbalance Market

Currently, PGE is participating in the region's Energy Imbalance Market (EIM) feasibility assessments. An EIM is a hybrid of a bilaterally based market and a centrally cleared market model that seeks to redispatch in real-time, according to transmission availability, the flexible capacity made available to it by market participants. In an EIM, parties must enter the market with sufficient resources to stand-alone, in terms of energy and capacity to meet load and balancing requirements, as the market does not provide flexible reserve capacity to participants. EIM participants demonstrate their resource sufficiency through a combination of scheduled market purchases and identified resource plans for their owned assets. Whether for intentional, or market instructed deviations where a more economic regional redispatch is sought, market participants will either pay or be paid for the difference between their actuals and schedules (i.e., their energy imbalance, paid to or by the EIM) for each EIM flow period.

PGE is actively participating in the formative discussions of two main regional efforts: the Northwest Power Pool Members EIM and the California Independent System Operator EIM proposal with PacifiCorp. While outcomes of each effort are currently unknown, and noting that PGE has limited ability to influence the ultimate outcome of these processes, PGE expects that some form of an EIM has the potential to be made available to entities in the Pacific Northwest within the next few years.

PGE will consider modifying a future Wind Integration Study to calculate system costs should PGE have the opportunity to participate in an EIM. However, it should be noted that wind integration costs for an entity operating within an EIM would be highly dependent on market structures that have not yet been finalized for either of the two main efforts and that the current system operation model may need to be significantly enhanced to accurately represent these market structures.

Additional Flexible Generation

As stated earlier, the cost for wind integration is dependent on the characteristics of the system available to provide the moment-to-moment movement that is required to keep generation and system load in balance. If additional flexible resources are added to the PGE system, then the cost to provide wind integration will likely decrease.

v. Next Steps for PGE's Wind Integration Study

Because variable generation resources place unique demands on system operation and reliability, PGE reiterates that understanding the physical needs and costs of wind integration is an ongoing effort. While PGE has not yet formulated a formal list of next steps, or tried to prioritize them, the following items are presented for further consideration. PGE's Wind Integration Study Project Team welcomes suggestions and feedback from stakeholders regarding prioritization or other study items may not be listed.

Phase 4 incorporated some the changes suggested in Phase 2 including the following:

- Evaluate impact of natural gas price variability
- Assess impact of transmission and gas supply constraints
- Evaluate impact of additional flexible gas generation resources
- Delineate between INC/DEC reserves
- Cost effects of feathering wind

Future Phases of PGE's Wind Integration Study may include:

- Evaluating the net impact of moving to sub-hourly scheduling;
- Evaluating the net impact of developing and operating a regional energy imbalance market;

- Estimating the value of adding additional flexible gas generation;
- Estimating how wind integration costs change with a higher or lower amount of variable resources to integrate;
- Better understanding the impact of a poor water year;
- Exploring the impact of changes to scheduled maintenance outages.

The PGE Wind Integration Study Project Team will continue to evaluate and improve its modeling tools and software, as needed, and will also continue to monitor the industry for Wind Integration Study best practices.

Attachment 1

The Technical Review Committee (TRC), operating under the principles established by the Utility Variable-Generation Integration Group (UVIG) and available at http://variablegen.org/wp-content/uploads/2009/05/TRCPrinciplesJune2012.pdf, wishes to congratulate you and the entire study team on completing the PGE Wind Integration Study Phase IV. The TRC endorses the study methodology, execution, and the final results presented to the TRC. The results naturally depend on the assumptions concerning balancing area and regional grid operating practices and scheduling opportunities which remain in a state of flux in the Pacific Northwest. We have enjoyed working together on this project and feel it has advanced the state of the art in wind integration studies.

Thanks Again

Brendan Kirby

Charlie Smith

Michael Goggin

Michael Milligan

Bob Zavadil

CASE: UE 319
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Opening Testimony

June 2, 2017

May 30, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 600
Dated May 16, 2017

Request:

Phase 4 of PGE's wind integration study states, "PGE will consider modifying a future Wind Integration Study to calculate system costs should PGE have the opportunity to participate in an EIM. However, it should be noted that wind integration costs for an entity operating within an EIM would be highly dependent on market structures that have not yet been finalized for either of the two main efforts and that the current system operation model may need to be significantly enhanced to accurately represent these market structures." Why did PGE ultimately decide not to update its wind integration study once it decided to enter into the EIM? How has PGE accounted for market structures within the CAISO EIM in order to estimate its wind integration costs? Has the integration cost model changed in any other meaningful way since the Phase 4 study?

Response:

PGE has updated its wind integration study since the release of Phase 4. See PGE's 2016 IRP filed on November 15, 2016 in OPUC Docket No. LC 66, beginning at page 199. The Phase 5 Study described in PGE's 2016 IRP implements (as a model assumption) a liquid, sub-hourly market with 15-minute dispatch. PGE does not have the necessary information to design a more detailed market structure. PGE's Resource Optimization Model limits its system topology to PGE's system and generation resources. A more detailed market structure design would require PGE to model the system topologies and generating resources of other EIM entities and the WECC more broadly. This additional data requirement would be significant and likely not feasible for implementation, because it would significantly add to software run times and require additional resources for data and software maintenance.

See also PGE's Response to CUB Data Request No. 025 and pages 15-16 of PGE Exhibit 300. Updates to the Resource Optimization Model (which produces the results reported in PGE's wind integration studies) allow PGE to estimate the amount of reserves needed to fully self-integrate PGE's owned wind resources.

These reserves are used in MONET to estimate the cost impact of the additional balancing requirements from full self-integration. This cost impact is reduced by the flexible reserve savings identified in the E3[1] study included as PGE Exhibit 303.

[1] Energy + Environmental Economics

CASE: UE 319
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

Exhibits in Support
Of Opening Testimony

June 2, 2017

April 6, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 319
Dated March 24, 2017

Request:

Regarding UE 319/PGE/303, Niman et al./8: Is this update to Port Westward 1 performance parameters included in 'Generation updates" as part of the EIM study?

Response:

No. As part of its Western EIM Study for the 2018 test year, PGE did not revisit performance parameters for each plant. PGE's input data modifications of significance are described in PGE Exhibit 303.

Similar to the earlier Western EIM study completed by E3 for PGE, the 2018 test year analysis used production simulation modeling in PLEXOS to estimate PGE's benefits resulting from participation in the Western EIM. With respect to plant performance parameters, PGE's power cost model, MONET, uses a more in-depth set of input assumptions than PLEXOS. While MONET is limited to PGE's portfolio of resources, PLEXOS is a Western Electricity Coordinating Council (WECC)-wide production cost model that requires input assumptions for plants and transmission lines across the WECC, not just PGE. In general, this additional level of data requirement (which is significant) necessitates a less in-depth set of input assumptions for PLEXOS.

See Attachment 319-A for a list of the Port Westward 1 performance parameters assumed in the 2018 Western EIM Study.

Attachment 319-A is protected information subject to Protective Order No. 17-057.

UE 319

Attachment 319-A

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

Port Westward 1 Performance Parameters Assumed in E3 Study

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony
(Net Variable Power Costs)

June 2, 2017

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

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

Q. Please describe your educational background and work experience.

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide facts, analysis, and expert opinions regarding several aspects of Portland General Electric's (PGE) 2018 net variable power cost (NVPC) forecast used to establish rates in PGE's Automatic Update Tariff (AUT). I evaluate eight issues. I itemize these issues below. Issues two through four relate to the competitiveness of PGE's resource acquisition process.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared ten exhibits:

Staff/201	Witness Qualification Statement
Staff/202	PGE responses to data requests
Staff/203	Confidential PGE responses to data requests
Staff/204	Correlation of COB transactions and margins
Staff/205	Staff analysis of on-peak COB transactions
Staff/206	BPA Report on Klondike 3
Staff/207	Carty Generating Station siting documents
Staff/208	Carty Lateral expenses and disallowance
Staff/209	Comparison of prices used to evaluate Wells PPA
Staff/210	Documentation of PGE wind facility investment
Staff/211	PGE workpaper re: transmission resale revenues

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. What adjustments do you propose in your testimony?

A. I propose the following changes to PGE's forecasted NVPC:

[BEGIN CONFIDENTIAL]

- Mid-C COB Trading Margins ([redacted])
- Wind Resource Capacity Factor ([redacted])
- Carty Gas Supply Costs ([redacted])
- Transmission Revenue ([redacted])
- Wells PPA ([redacted])

[END CONFIDENTIAL]
- Total ($26,007,944)

Q. You mention that three of your issues relate to the competitiveness of PGE's resource acquisition process. Can you explain why you are raising competitive bidding as a concern in a NVPC docket?

A. The three issues that I raise all have dollar impacts on PGE's NVPC. I relate the issues to PGE's resource acquisition process because either the issue stems from resource acquisition decisions or the resolution of the issue impacts future resource acquisitions. The Commission is currently in the process of refining the competitive bidding process. The current case provides an opportunity for the Commission to review the outcome of previous resource acquisitions and may provide insight into the appropriate process for future resource acquisitions.

ISSUE 1: MID-C/COB TRADING MARGINS

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

A. PGE's filing undervalues the energy transactions that it expects to make at the COB trading hub. In Order No. 15-356, the Commission ordered PGE to propose a methodology to capture, for purposes of the AUT, the value of benefits PGE obtains through transactions at COB made possible by transmission rights paid for by PGE ratepayers. In the following AUT docket, UE 308, PGE proposed a methodology that utilized historic transaction volumes with a margin value based on forward prices.[1]

Staff's testimony in UE 308 noted a number of problems with PGE's proposal that would likely result in under-valuation of the COB trading margins. However, in UE 308 Staff did not have the opportunity to perform specific analysis of PGE's actual COB trading data, and committed to performing a more thorough analysis in the following AUT proceeding.[2] The issue remained unresolved on an ongoing basis in the UE 308 settlement.[3] As part of the current proceeding, Staff continued to analyze the Company's COB trading data and has developed additional evidence that PGE's proposed methodology does not accurately value the COB transactions.

Q. How does PGE propose to value COB transactions?

A. PGE uses a three step process to value COB transactions. First, PGE calculates a three-year average of COB sales transactions for each month in

[1] Docket No. UE 308 PGE/400, Niman - Peschka - Hager/9-10.
[2] Docket No. UE 308 Staff/300, Kaufman/6 lines 9-12.
[3] Docket No. UE 308 Staff/300, Kaufman/3 at lines 1-4.

the high load hour and low load hour. Then PGE calculates the forecasted difference in Mid-C/COB prices for each month in the high load hour and low load hour periods. In the final step, PGE multiplies the average COB sales by the forecasted Mid-C/COB price differential. For example, the January 2018 COB High Load Hour (HLH) transaction value would be forecasted as follows:

$$(Average\ January\ HLH\ Sales) * (COB\ January\ HLH\ Price\ Forecast - MidC\ January\ HLH\ Price\ Forecast)$$

Q. What is Staff's objection to PGE's method?

A. The most obvious problem with the equation above is that it does not include purchases at COB.[4] However, the absence of purchases is only a symptom of a graver underlying issue. PGE's methodology does not account for **[BEGIN CONFIDENTIAL]** [redacted]

[4] The mechanics of PGE's model within MONET are slightly more complex, and do allow for the possibility of valuing purchases at COB. However, this would only occur if the average price at COB is lower than the price at Mid-C. This is a hypothetical scenario that has not occurred in recent data. If this were ever to occur, than PGE's model switches from valuing only COB sales to valuing only COB purchases. The model will never simultaneously value both purchases and sales in the same month. For simplicity Staff's testimony assumes that the monthly average Mid-C price does not exceed the average COB price.

[5] *See* Exhibit 204, Confidential correlation of price and transactions.

[redacted] **[END CONFIDENTIAL]** One consequence is that customers receive no value for economic COB purchases. A second consequence is that customers receive substantially less value from sales at COB than the company actually achieves.

Q. You mention that PGE's method provides no value for purchases at COB. Is it normal for PGE both buy and sell at COB in the same month?

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

Q. Please provide an illustrative example using simplified numbers that demonstrates why PGE might make both purchases and sales at COB even if the average margin is positive.

A. Assume that in one month there are 15 days where the Mid-C price is $30 per MWh and the COB price is $20 per MWh. This results in a COB margin of minus $10 ($20 - $30 = - $10). Assume on the other 15 days that the Mid-C

6 *See* Exhibit 204. In this figure, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

7 *See* Exhibit 205, Analysis of On Peak COB Transactions.

8 *See* Exhibit 204 which shows positive and negative margins within the same day. In hours 2 and 8 the margin favors Mid-C sufficiently for PGE to purchase at COB rather than sell.

price is $45 per MWh and the COB price is $15 per MWh. This results in a COB margin of $30 per MWh ($45 - $15 = $30). In this hypothetical scenario, there are 15 days where the margin at COB is minus $10 and 15 days where the margin at COB is plus $30. The average margin is $10 per month (15 x (-10) + 15 x 30)/30 = $10). However, even though the monthly average is positive representing an incremental margin at COB, it is economically better to sell at COB half the days in the month and economically better to buy at COB the other half.

The important point is that the Company can realize an incremental benefit on both purchases and sales, within the same month, by arbitraging between the appropriate markets. PGE will likely have profitable 2018 purchases at COB even though the COB forecast price is higher than the Mid-C forecast price. Therefore, excluding normal COB purchases from the valuation of the COB transactions is inappropriate.

Q. Can you give a simple numeric example that compares the Company's proposed treatment with the Company's actual trading pattern?

A. Yes, consider the scenario presented in the Q&A above, where there are 15 days in the month with a negative margin of ($10) per MWh, 15 days in the month with a positive margin of $30 per MWh, and the average margin is $10 per month. Suppose further that there is 1 MWh of transmission available in every day. The table below summarizes the "actual" operations that would minimize power cost.

Table 1 Hypothetical Example of COB Value Using Staff Method

Margin	Transaction	MWh	Profit
-10	Purchase at COB	15	$150
30	Sell at COB	15	$450
		Total Profit	**$600**

Using actual margins, and actual MWh, the total profit is $600. PGE's modeling approach to COB transactions for this example would result in the following estimate.

Table 2 Hypothetical Example of COB Value Using PGE Method

Avg. Margin	Transaction	MWh	Profit
10	Sell at COB	15	$150
		Total Profit	$150

Using monthly average margin and actual MWh results in a total profit of only $150, much less than the actual profit.

Q. Is it possible to compare the Company's proposed approach against the Company's actual transactions?

A. Yes. Similar to the example above, we can use actual data, and compare same two approaches:

- Actual Margin times Actual MWh; and
- Monthly Average Margin times Actual COB sales.

Staff calculated the company's actual COB trading margin for 2014, 2015, and 2016 using the Company's actual transactions and an hourly Mid-C price index. Staff then calculated the value of the Company's actual COB transactions by multiplying the margin for each by the traded volume in each transaction. Table 3 below summarizes the value for each year when using actual margin. Staff also calculated the value of the Company's average margin approach. To do this, Staff calculated the difference in the average price,[9] and multiplied it by monthly purchases. Table 3 below summarizes the value for each year when using average margin. **[BEGIN CONFIDENTIAL]** [redacted][10]

[redacted]

[END CONFIDENTIAL]

Q. What is the difference between actual valuation and average valuation for Low Load Hours?

A. Staff was not able to locate low load hour historical average pricing for COB. Without these data, the exact values cannot be calculated. However, a reasonable estimate can be made by applying the HLH **[BEGIN CONFIDENTIAL]** [redacted]

[9] Average price as reported by SNL Financial.
[10] The detailed monthly calculations underlying this value are presented in Exhibit Staff/205.

[redacted]

[END CONFIDENTIAL]

Q. What is your proposed treatment?

A. Staff considered a complex solution that would be more forward-looking, and a simpler solution that is more backward looking. A forward-looking solution is preferable, but developing consistent treatment may be beyond the scope of this docket and requires collaboration with PGE outside a contested case setting. For this case, given the time constraints, Staff recommends a backward-looking approach.

Staff's proposal is to modify PGE's methodology to account for the average difference between COB transaction values using actual and average margin calculations. This reduces 2018 NVPC by **[BEGIN CONFIDENTIAL]** [redacted].[11] **[END CONFIDENTIAL]**

[11] This value is the sum of the HLH and LLH amounts presented in tables 3 and 4 above.

ISSUE 2: WIND RESOURCE CAPACITY FACTOR

Q. Please summarize this issue and your proposal.

A. PGE may have substantially over-estimated the capacity factors for all three facilities at its Biglow Canyon Wind Farm (Biglow) and for the Tucannon facility. PGE was aware of the risks associated with the forecasted capacity factors when it chose to build these facilities, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and chose not to mitigate these risks. Staff proposes splitting the risk associated with capacity factor forecasting between the utility and the customers. This treatment is appropriate because it incentivizes the utility to appropriately forecast wind capacity factors and it helps to create a competitive environment for the procurement of renewable generation.

Q. What were the forecasted and actual capacity factors for these facilities?

A. The table below provides the forecasted and actual capacity factors for each plant.[12]

[12] The actual value for Tucannon is based on only two years of operations. PGE forecasts Tucannon's capacity in this filing by averaging the first two years of actual data with the originally forecasted wind study. As PGE gains additional Tucannon data, the weight placed on the original forecast decreases.

[redacted]

[redacted]

Q. How did PGE represent the risk associated with the capacity factors of these facilities?

A. PGE asked to include Biglow Phase 1 in rates in Docket No. UE 188. PGE's testimony in Docket No. UE 188 discusses two types of risk, regulatory risk and fire risk. There is no mention of the significant uncertainty related to Biglow's wind output. The only written documentation of PGE's assessment related to Biglow wind output risk is found in Docket No. UP 234. PGE states "... [Developer] Orion is at risk with respect to both PGE's development of the Project and the Project's generation output."[13] PGE's testimony in Docket No. UE 188 does not mention generation risk; however PGE notes that it had the option of owning the project or operating under a power purchase agreement. PGE chose to own the project in order to "gain experience in operating wind turbines."[14] PGE does not appear to have considered generation risk when it made this decision.

[13] *See* Docket No. UP 234, PGE Application for Approval of Asset Purchase and Development Agreement in Sherman County, Oregon, p. 3.
[14] *See* Docket No. UE 188 PGE/200, Tooman – Tinker - Schue /12 at line 9.

[redacted]

[15] *See* Staff/203 Kaufman/5 and 6, PGE Response to Staff DR No. 443.
[16] *See* Staff/202 Kaufman/21, PGE's response to Staff DR No. 567 (indicating PGE did not evaluate the risk factors) Staff/203 Kaufman/6, PGE Response to Staff DR No. 443, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[redacted]

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

[17] *See* Staff/203 Kaufman/3 and 4, PGE response to Staff DR 443.
[18] *See* Staff/202 Kaufman/21, PGE response to DR 567.
[19] *See* Staff/203 Kaufman/6 and 7, PGE response to DR 443.

Q. In addition to the risk involved in the forecasted capacity factors, is there evidence that PGE could have known it was over-forecasting its capacity factors?

A. Yes. Staff notes three separate facts that indicate PGE could have or did know it was over forecasting its capacity factors.

1. PGE was aware that the Garrad Hassan wind study had likely over-estimated the Biglow capacity factors in 2009, before either Biglow 2 or Biglow 3 were in service.[20] Despite this, PGE did not update or revise its forecasted capacity factors.[21]
2. The wind study for Biglow considered **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of wind generation at Biglow.[22] PGE ultimately installed 449.7 MW of wind generation at Biglow.[23] PGE also modified the type and layout of the turbines.[24] PGE admits that turbine type and location affect generation output.[25] Garrad Hassan **[BEGIN CONFIDENTIAL]** [redacted][26] **[END CONFIDENTIAL]** Adding

[20] *See* Staff/202 Kaufman/17, PGE Response to Staff DR 566 (PGE stating "However, between 2009 and 2010 PGE did begin to become aware that the actual wind at Biglow was consistently underperforming the original forecast."). *See* Staff/202 Kaufman/2, PGE Response to Staff DR 442 (PGE stating "... Biglow 2 and 3 ... in-service dates of August 17, 2009 and August 18, 2010 respectively...").
[21] *See* Staff/202 Kaufman/17, PGE Response to DR 566. In the response to DR 566 PGE indicates that the performance of Biglow 1 and 2 prevented PGE from revising the capacity factor of Biglow 3 up. Despite this, PGE did not revise the capacity factor down or perform additional studies on what the Biglow 3 capacity factor would be.
[22] *See* Staff/203 Kaufman/5, PGE Response to Staff DR No. 443.
[23] *See* Staff/203 Kaufman/10, PGE Response to Staff DR No. 566.
[24] *See* Staff/203 Kaufman/11, PGE Response to Staff DR No. 566.
[25] *See* Staff/202 Kaufman/2, PGE Response to Staff DR No. 443.
[26] *See* Staff/203 Kaufman/6 and 8, PGE Response to Staff DR No. 443.

turbines and turbine capacity has the potential to increase wind wake. Wake is a reduction in wind speed caused by the presence of the turbine. The increased wake in turn reduces the generation at the facility. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

3. The Bonneville Power Administration (BPA) made available an assessment of the adjacent Klondike 3 wind facility.[28] The BPA estimated production of the adjacent facility at 30 percent, 5 percent lower than PGE's forecast for the combined Biglow projects.[29] The BPA's analysis is publically available and PGE could have used the BPA projections to vet the Garrad Hassan study.

Q. Does your proposal require that the Commission make a finding regarding PGE's past decisions?

A. No, my proposal is not based on what PGE could have known or did know about the over forecasting of wind capacity factors. The Commission has already determined the prudence of PGE's past wind investments and Staff is not requesting the Commission reconsider those determinations. The purpose of the preceding testimony is to show that PGE could have exercised a greater degree of caution when evaluating the past wind facilities. Staff's proposal

[27] See Staff/203 Kaufman/11, PGE Response to Staff DR No 566.
[28] An extract of the BPA report is provided in Staff Exhibit 206. The full report was accessed from https://www.bpa.gov/power/pgc/wind/KlondikeROD.pdf on May 31, 2017.
[29] *See* Staff/203 Kaufman/5, PGE Response to Staff DR No. 443.

provides PGE incentive to be more diligent in future resource acquisitions. Furthermore, as explained below Staff's proposal will allow ratepayers and PGE to share generation risk.

Q. Please summarize your proposed treatment for Company-owned wind resource capacity factors.

A. Staff proposes the following two alternatives:

1. Calculate NVPC using half of the difference between the original expected capacity factor included as part of the prudence review and the now-current projected output, this translates to a capacity factor of **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** This alternative shares the costs between customers and shareholders.[30]
2. Calculate NVPC using the higher of the *current* expected capacity factor or the *original* 75 percent probability of exceedance capacity factor.

For example the original CF forecast for Biglow 1 was 38 percent,[31] the original 75 percent exceedance CF was **[BEGIN CONFIDENTIAL]** [redacted],[32] **[END CONFIDENTIAL]** and the current forecast is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent.[33] Option 1 would use

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[30] This approach splits the generation value of forecast error evenly between customers and shareholders. Staff finds that an even split of the generation value is fair, given that the company bears none of the production tax credit risk associated with forecast error. However, this mechanism is capable of accomplishing any split of value between customers and shareholders. For example, customers could bear 90 percent of the risk with the following formula: [redacted] **[END CONFIDENTIAL]**

[31] For Biglow 1 this would be 38 percent.

[32] The original 75 percent probability of exceedance for Biglow 1 was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** This was calculated from PGE's Response to Staff DR 443, pp. 18 and 22, and grossed up by PGE's estimated turbine upgrade impact from PGE's Response to Staff DR No. 443.

[33] The actual forecasted capacity factor of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent was provided in PGE's April 14 MONET update.

the estimate of **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** regardless of whether the current forecast is higher or lower. Option 2 would use the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent number. If the actual forecast is revised in the future to be higher than **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** the actual forecast would be used.

Staff also recommends that the PCAM true up mechanism be consistent with the treatment in the AUT.

Q. Please explain why Staff's proposal is fair, just, and reasonable.

A. Staff's proposal has the following benefits:

- Wind generation risk is split between customers and shareholders;
- Utilities are incentivized to accurately forecast wind capacity factor of new projects;
- Allows utility shareholders to share in generation risk will make the RFP process more competitive and improve outcomes for customers;
- PGE's decision to "gain experience in wind generation" [34] benefited PGE shareholders through a return on rate base. Staff's proposal aligns a portion of the risk with shareholders.

Q. How is generation risk split between customers and shareholders?

A. When the actual capacity factor of wind facilities is lower than forecasted, there are two financial impacts: energy value and production tax credit (PTC) value.

[34] See Docket No. UE 188 PGE/200, Tooman – Tinker - Schue/12 at line 9.

Wind generation has little to no marginal cost. When wind production is lower than expended, PGE has to replace that energy with higher cost sources. Staff estimates that dollar value of lost energy associated with over forecasting wind capacity factors is about **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** In addition to the lost energy, PGE does not receive the expected PTCs. Staff estimates that the value of the lost PTCs is about **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Under Staff's proposal, PGE shareholders will bear a portion of the risk associated with the lost energy value, and customers will bear the risk associated with the lost PTC value. This approach appropriately shares the risk associated with ownership of wind resources between the utility shareholders and customers.

Under Staff's approach, customers cover more of the risk than the utility.[36] Some may argue that it would be fairer to split the risk 50-50. However, in Senate Bill 1547 (2015), the Oregon legislature adopted language indicating that the PTC forecast risk is to be borne by customers.[37] Staff's proposal is consistent with this legislation but still shares risk of over forecasting generation between customers and the Company.

Staff's proposal is reasonable because it incentivizes the utility to accurately forecast the capacity factor of utility owned wind generation.

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[35] This was calculated by modifying PGE's Monet model using the originally forecasted capacity factors and splitting out the change in NVPC between PTC value and generation value.
[36] This is because customers cover all of the PTC risk and half of the generation risk.
[37] Senate Bill 1547, Section 18b (2015).

Q. How does Staff's proposal incentivize utilities to accurately forecast wind generation?

A. Under PGE's method, the Company updates the wind capacity factor every year. In addition, actual wind generation is incorporated in the PCAM. The PCAM includes mechanisms that prevent 100 percent of costs passing through to customers. Thus the only exposure the Company has to wind generation forecast risk is through the difference between the year ahead wind forecast and the actual wind generation. Staff's approach makes the Company accountable for its resource decision. Because of this the Company will be more likely to evaluate and vet the wind forecasts.

Staff's alternative no. 1 does benefit the Company in the case of forecasts that are too low. However under both alternatives, customers are guarded against the risk of a low forecast through the competitive bidding process. If the Company under forecasts wind generation, competing bids will be more likely to be selected.

Q. How does allowing utility shareholders to share in generation risk make the RFP process more competitive?

A. PGE's recent generation RFPs have primarily resulted in PGE ownership of new resources. If shareholders are exposed to some of the generation risk associated with ownership, the utilities will incorporate generation risk into their bids. This is a risk that other bidders already bear. Staff's proposal will bring the Company ownership in line with non-company ownership bids. As a result, the competitive bidding process will be more effective.

A more competitive bidding process will benefit customers. PGE's recent self-owned resource acquisitions have faced substantial problems, either with lower than expected benefits or higher than expected costs.

Q. Why is it fair for PGE shareholders to share in the risk of wind generation?

A. PGE has made a substantial investment in its wind facilities. PGE has invested $1.7 billion in wind facilities.[38] At PGE's current capital structure and cost of equity that represents $82 million dollars per year in profit for PGE shareholders.[39] Staff's proposal reduces power costs by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** dollars. This is only a fraction of wind facilities' annual return to PGE shareholders. PGE acknowledges that at the time of the investments it was not experienced in owning or operating wind facilities, and that one purpose of the investment was to gain experience.[40] It is fair that PGE shareholders bear some of the risk that comes with gaining this experience.

Q. How do you propose to address capacity factor in the PCAM?

A. The PCAM includes a sharing mechanism in which PGE recovers a portion of the deviation between forecasted and actual power costs from customers. Staff does not propose any associated adjustment in the PCAM. This means that actual wind generation is used in the PCAM and the PCAM sharing

[38] *See* Staff Exhibit 210 which indicates a Biglow investment of $1.2 billion and a Tucannon investment of $500 million excluding AFUDC.
[39] Calculated as $1.7 billion times 50 percent equity times 9.6 percent cost of equity.
[40] *See* Docket No. UE 188 PGE/200, Tooman – Tinker - Schue /12 at line 9.

mechanism further reduces the impact of Staff's adjustment has on the Company's risk.

Q. What is the impact of your proposal to NVPC?

A. My proposal decreases NVPC by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

ISSUE 3: CARTY GAS SUPPLY COSTS

Q. Please summarize this issue and your proposed treatment.

A. The gas used at PGE's recently acquired natural gas plant, the Carty Generating Station (Carty), is transported through Gas Transition Northwest (GTN) pipeline. PGE contracted with GTN to build, operate and maintain a 25-mile lateral pipeline (Carty Lateral) from the GTN mainline to Carty. This pipeline has more than double the daily capacity that Carty can use. It appears the extra capacity was built by PGE to give PGE a competitive advantage in bids for future gas generation. Accordingly, the extra capacity was built to benefit shareholders and does not provide a current benefit to customers. Staff proposes a disallowance of the portion of the Carty Lateral expense that exceeds Carty needs.

Q. Please provide the background for this issue.

A. PGE fuels Carty with gas purchased from the AECO trading hub in Alberta, Canada. This gas is transported to Carty through TransCanada NOVA Gas Ltd. pipeline system, TransCanada Foothills pipeline system, and the GTN mainline. PGE contracted with GTN to build, operate and maintain a 25-mile lateral pipeline. PGE's engaged in a 175,000 dekatherm per day contract for the Carty Lateral.[41] The annual cost of the Carty Lateral contract is **[BEGIN CONFIDENTIAL]** [redacted][42] **[END CONFIDENTIAL]** However, PGE only secured a 75,000 dekatherm per day contract for capacity to transport gas to

[41] *See* Docket No. UE 294 PGE/400, Niman – Peschka – Hager/10.
[42] *See* Staff/203 Kaufman/12, Attachment A of PGE response to ICNU DR No. 75.

the Carty lateral.[43] This means that the majority of the Carty Lateral capacity is unused, and PGE has no firm plan to use it during 2018.

Based on its heat rate and capacity, Carty is not capable of burning more than **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** dekatherms per day.

Q. Why do you suppose that PGE secured a gas transportation contract that delivered [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL] more gas than Carty can burn?**

A. This contract appears to be in anticipation of the construction of a second generating facility at Carty. PGE's original siting permit for Carty included a second phase. This second phase was for another large gas generator.[45] PGE has since requested a two year extension for the completion of the second phase.[46]

Q. Is there any other evidence that PGE committed to higher expenses for Carty in preparation for a second phase?

A. Yes. As I already mentioned, PGE has engaged in the planning expenses for a second unit at the Carty site. Staff is also investigating the size and design of the Grassland switchyard and the transmission capacity from Carty to customers and other markets.

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[43] *See* Docket No. UE 294 PGE/400, Niman – Peschka – Hager/10.
[44] This is an initial estimate calculated by Staff. At the time of preparing this testimony Staff was waiting for additional data to refine this estimate.
[45] *See* Staff Exhibit 207 page 1, Department of Energy website capture regarding Carty.
[46] *See* Staff Exhibit 207 pages 2 and 3, full amendment available at http://www.oregon.gov/energy/facilities-safety/facilities/Amendments/2016-08-01%20CGS%20Request%20for%20Amendment%201.pdf pages 16 and 40.

Q. Does it make economic sense for PGE to overbuild Grassland Switchyard and the Carty Lateral? This may save money in the long run.

A. There are four alternative outcomes related to the pre-build for a second phase at Carty (Carty 2):

1. Carty 2 is built in a manner such that the pre-build saves some money in the long run.
2. PGE will not build Carty 2, in which case the pre-build was not needed.
3. PGE builds Carty 2 but the final plans will require something different than what was pre-built. For example, if Boardman closes, the extra capacity at the Grassland Switchyard is not necessary, and if Carty Unit 2 is smaller than expected, the full 175,000 dekatherms of capacity on the Carty Lateral may not be needed.
4. PGE builds Carty 2 and utilizes the pre-built facilities, but Carty 2 is delayed for so long that the financial carrying cost, depreciation expense, and operating expense of the pre-build exceeds the savings. PGE has already delayed the expected build for Carty 2 by at least two years.[47]

Only the first of these outcomes would justify the pre-build expenses.

Q. Given the uncertainty in the future, how do you propose to treat Carty Lateral costs that are related to the over-build?

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[47] *See* Staff/207, Kaufman/2-3. http://www.oregon.gov/energy/facilities-safety/facilities/Amendments/2016-08-01%20CGS%20Request%20for%20Amendment%201.pdf pages 16 and 40.

A. Staff proposes to exclude overbuild costs from rate base until such time as the capacity is used. Staff cannot evaluate the prudence of the overbuild until PGE builds another gas plant at Carty.

Q. How does your proposal apply to the Carty lateral, which is a fixed capacity contract?

A. Staff recommends excluding the portion of the Carty lateral that exceeds the cost of the minimum necessary to supply Carty. Staff has not calculated this value yet. As an alternative, the Commission could exclude the proportion of Carty Lateral expenses equal to the ratio of excess capacity to total capacity. Staff has calculated this to be 57.1 percent of the Carty Lateral costs. This is calculated as the current peak daily demand of Carty divided by the capacity of the Carty Lateral. The ratio approach amounts to a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** reduction in NVPC.[48]

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[48] *See* Staff/208.

ISSUE 4: TRANSMISSION REVENUE

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

A. PGE forecasts $2.8 million in 2018 transmission resale revenues. This is substantially lower than PGE's historic transmission resale revenues. Staff modifies transmission revenue forecast to equal the average revenue from 2014, 2015, and 2016. Staff's revenue forecast is **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** This results in reduction to the filed NVPC of **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

Q. How is Staff's transmission revenue adjustment calculated?

A. Table 6 below calculates Staff's adjustment. Lines 1 through 3 provide historic revenues. Staff's forecast is equal to the three year average of revenues. PGE's historic transmission revenues are summarized below. Staff's adjustment equals Staff's forecast less PGE's forecast. PGE's filing includes **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in transmission revenue.[49] This results in an adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

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[49] *See* Staff/211, PGE Workpaper #EM_GMoore_2018TransmissionResale_02062017.pdf

[redacted]

[redacted]

ISSUE 5: WELLS PPA

Q. Please summarize this issue and your proposal.

A. PGE recently renewed a long-term contract to purchase energy from the Wells Hydroelectric Project. This contract was renewed in part based on Commission Order No. 14-415. This order states, "We agree that PGE should seek to renew its expiring hydro-facility contracts to the extent it is cost-effective to do so and acknowledge the company's pursuit of cost effective hydro contract renewals." PGE states that this contract is cost effective. Staff finds that the contract is not cost effective based on market forecasts available to PGE when it executed the contract in March 2017. Staff proposes that the uneconomic portion of the Wells PPA be excluded from NVPC.

Q. Please explain why Staff finds this contract to be not cost effective.

A. PGE provided a financial model of Wells as part of the MONET update filed on April 14, 2017. This model shows that the contract is cost effective, however the model utilizes a power price forecast that is substantially out of date. When Staff updated these prices to reflect data available to the Company when it signed the contract,[50] Staff found that the net present value of the contract diminished.

Q. How do you know that the Wells contract used out of date information?

[50] Staff used prices used by PGE to forecast its 2018 NVPC in its initial filing in Docket No. UE 319 made on February 28, 2017. See Staff/202, p. 13, PGE Response to Staff DR No. 563; Staff/209, Comparison of UE 319 price forecast with 2015 price forecast.

A. PGE provided a data response indicating that the Wells contract valuation model used price data from 2015.[51] PGE signed the contract in March 29, 2017.[52]

Q. How do current prices impact the 2018 value of the contract compared to PGE's initial contract valuation model?

A. PGE's initial contract valuation model forecasted that the market value of the Wells energy was **[BEGIN CONFIDENTIAL]**[redacted] **[END CONFIDENTIAL]** less than the cost of the contract. However, the Monet update in this case shows that the current forecasted value is **[BEGIN CONFIDENTIAL]**[redacted] **[END CONFIDENTIAL]** less than the contract cost. PGE states that the reason for the change is directly related to the updated market price forecast.[55] The out of date prices used to support the Wells contract are an average of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** than the current price forecast.[56]

Q. It looks like PGE's original analysis expected a loss in the first year of the contract. Why did PGE say that the contract was economic?

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

[51] *See* Staff/202 Kaufman/14, Response to DR 563 part e.
[52] *See* PGE/1500, Niman – Outama – Rodehorst/1 at line 13.
[53] *See* Staff/202 Kaufman/14, Response to DR 563.
[54] *See* Staff/202 Kaufman/14, Response to DR 563.
[55] *See* Staff/202 Kaufman/14, Response to DR 563 part e.
[56] *See* Staff/209.

[redacted] **[END CONFIDENTIAL]**

Q. So the contract could still be economic, even with first year losses increasing so much?

A. It is possible; however, when **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** This means that given the information available to the Company when it signed the contract the costs of the project exceeded the benefit of the project.

Q. Can you provide more information about Staff's long-term analysis?

A. Staff used the same valuation model referenced in PGE's testimony to evaluate the project.[57] PGE provided Staff with a 5-year forecast of Mid-C prices.[58] Staff used a time series forecasting model to extend this forecast to the period covered by the contract, and replaced PGE's outdated prices with prices used by PGE in the February 28, 2017 filing for UE 319. This filing was made before PGE signed the Wells contract. The table below summarizes the net present value for the cost of the contract, PGE's original value estimate, and Staff's updated value estimate. Based on the updated estimate the cost of the project exceeds the benefit.

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[57] *See* PGE/1500, Niman – Outama – Rodehorst/4 at lines 14 to 19.

[58] *See* Staff/202 Kaufman/14, Response to DR 563 part d. Staff Exhibit 209 compares the current price forecast with the 2015 price forecast.

Q. Does Staff have any caveats about the analysis showing the contract is not economic?

A. Yes, the model used by PGE to value the contract does not appear to include a value for the capacity contribution of the contract. Staff is continuing to investigate if it is appropriate to include a capacity value, and if that value would impact the results of the analysis. Staff intends to provide an update on this aspect of the issue in following testimony.

Q. What adjustment does Staff propose for the Wells contract?

A. Staff proposes to exclude a portion of the uneconomic costs associated with the Wells contract. Staff calculated an annual disallowance that would make the net present value of the contract zero. The 2018 disallowance is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** If the current market forecast is accurate, and Staff's method is used for the life of the contract, the cost to customers will equal the benefit to customers. The same disallowance should be applied to the AUT and the 2018 PCAM.

[redacted]

ISSUE 6: CARTY EMISSIONS

Q. Please summarize this issue and your proposed treatment.

A. On May 5, 2017 Columbia River Keeper, Oregon Physicians for Social Responsibility, and 350PDX filed comments with the OPUC in Docket No. LC 66. These comments noted that PGE had recently filed a request to modify emissions permits at Carty. The comments also requested that the OPUC investigate the issues that it raised. Staff's investigation of these issues is ongoing. However, Staff's initial review indicates that the emissions permitting issue at Carty has not impacted the requested rates in this filing.

Q. Please provide more detail regarding the emissions permitting issue.

A. When PGE initially filed for Carty emissions permits with the Department of Environmental Quality, PGE did not account for higher volatile organic compounds (VOC) or carbon monoxide (CO) emissions due to cold starts.[59] This information was provided to PGE by the manufacturer after the initial permitting process.[60] PGE has performed more startups of Carty than would be expected from a baseload unit.[61] At this time DEQ has not made a final determination of the modified permits. The DEQ is unlikely to require additional capital investment, or institute emission restrictions that substantially impact PGE's ability to operate Carty.

Q. Why is Staff's investigation ongoing?

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[59] Based on Staff interview of DEQ Environmental Engineer Douglas Welch on May 22, 2017.
[60] Docket No. LC 66, May 5, 2017 Columbia Riverkeeper Comments, Att. 3, p. 1.
[61] Based on Staff interview of DEQ Environmental Engineer Douglas Welch on May 22, 2017.

A. Due to the timing of the Columbia Riverkeeper comments relative to this case, Staff has not had time to fully evaluate all the ramifications of the issues raised in the comments. In addition, the impact of new emissions permitting should be revisited after DEQ has finalized its new emissions permits.

ISSUE 7: LOAD FORECAST

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

A. Staff reviews the Company's proposed load forecast as part of each general rate case and power cost filing. This year, PGE has filed power costs concurrently with the general rate case. Staff will present analysis of the load forecast in the general rate case. Staff recommends that the same load forecast be used in the calculations of net power costs as in the general rate case.

ISSUE 8: MAJOR MAINTENANCE EXPENSE

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

A. PGE currently recovers major maintenance expenses through base rates. Staff has reviewed these expenses and found that, for gas plants, the expenses are directly based on the number of hours of operation. For each gas plant PGE has a service contract with a fixed rate per hour of respective gas plant operation. The Staff proposal is to reflect in NVPC the service contract rate along with the expected hours of operation. In fact, PGE incorporates the major maintenance expense of gas plants into the optimization of plant dispatch decisions. The Staff proposal would result in an increase in NVPC and a decrease in the base rate revenue requirement. Staff will provide additional testimony on this issue in the general rate case opening testimony.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

June 2, 2017

WITNESS QUALIFICATIONS STATEMENT

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

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

June 2, 2017

Staff Exhibit 202 Contents

April 21, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 442
Dated April 7, 2017

Request:

Please provide the following information for each PGE owned wind generation facility:

a. **Please provide the actual generation of the facility by hour from the in-service date to present.**
b. **Please provide the actual generation of the facility that was directed to be curtailed by the BPA if such generation is not included in item a above. Please provide any other economic outages by hour and state the reason for the economic outage.**
c. **Please provide the nameplate capacity for each PGE owned wind generation facility.**
d. **Please provide the capacity factor assumed when PGE evaluated the site, equipment vendor, and construction contractor.**
e. **Please provide the capacity factor provided by PGE to parties in the first rate case which approved inclusion of the facility costs in rates.**

Response:

a. The actual hourly generation for Biglow Canyon 1 from 2008 through 2015 and Biglow Canyon 2 and 3 from 2011 through 2015 can be found in the following files, all located in ***Vol 7 - Wind\Biglow\Energy and Shaping*** of PGE's Minimum Filing Requirement (MFR) documentation submitted on March 7, 2017 in Docket No. UE 319:
    - Biglow 1 from 2008-2011 – Filename: "#BiglowGeneration2008_2011 – Copy.xlsx"
    - Biglow 2 and 3 for 2011 – Filename: "#BiglowGeneration2008_2011 – Copy.xlsx"
    - 2012: – Filename: "#2012BiglowMDMRGenData – Copy.xlsx"

- 2013: – Filename: "#2013BiglowMDMRGenData – Copy.xlsx"
- 2014: – Filename: "#BiglowGen2014 – Copy.xlsx"
- 2015: – Filename: "#Biglow 2015 MDMR – Copy.xlsx"

The 2016 hourly actual generation for Biglow Canyon can be found in PGE's MFRs submitted on April 14, 2017. See ***Step Documentation/Step 13 – Biglow Energy.*** Filename: "#Biglow 2016 MDMR.xlsx".

The 2016 hourly actual generation for Tucannon River Wind Farm (Tucannon) can be found in PGE's MFRs submitted on April 14, 2017. See ***Step Documentation/Step 15 – Tucannon Energy.*** Filename: "#TucannonMeter2016MWh.xlsx".

The 2015 hourly actual generation for Tucannon can be found in ***Vol 7 - Wind\Tucannon\Energy and Shaping*** of PGE's MFR documentation submitted on March 7, 2017. Filename: "#Tucannon_Metered_Gen_2015.xlsx".

Attachment 442-A includes 2014 hourly actual generation for Tucannon from its in-service date of December 15, 2014 through December 31, 2014.

Attachment 442-B includes hourly actual generation for Biglow 1 from its in-service date of December 21, 2007 through December 31, 2007.

Attachment 442-C includes hourly actual generation for Biglow 2 and 3 from their in-service dates of August 17, 2009 and August 18, 2010 respectively through December 31, 2010.

Attachments 442-A through 442-C are protected information and subject to protective Order No. 17-057.

b. PGE objects to this request on the grounds that it is overly burdensome and that it requires new analysis. Without waiving its objection, PGE responds as follows:

   PGE has no means of tracking "actual generation" that was lost due to BPA instructions to reduce wind generation levels. Once instructed, PGE has approximately 10 minutes to reduce the combined output of its wind facilities to a level at or below the target amount issued by BPA. A calculation of the estimate of lost generation would be subjective and dependent on a backcasting methodology that would need to consider weather conditions at or near each turbine, turbine performance (turbine direction, blade pitch, power curve, etc.), turbine and other system outages, and possibly other variables. PGE does not conduct this analysis because of the significant amount of time and potential costs involved.

c. The nameplate capacities for Biglow 1, Biglow 2 and Biglow 3 can be found in PGE's Minimum Filing Requirement (MFR) documentation submitted on March 7, 2017. See ***Vol 7 - Wind\Biglow\Capacity***. Filename: "^_2018GRCBiglowCanyonCapacity.docx".

The nameplate capacity for Tucannon can be found in PGE's Minimum Filing Requirement (MFR) documentation submitted on March 7, 2017. See ***Vol 7 - Wind\Tucannon\Capacity***. Filename: "^_2018GRCTucannonPlantCapacity.docx".

d. See PGE's response to OPUC Data Request No. 443.

e. See PGE's response to OPUC Data Request No. 443.

UE 319

Attachment 442-A

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

Tucannon Hourly Generation from December 15, 2014 through December 31, 2014

UE 319

Attachment 442-B

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

Biglow Hourly Generation from December 21, 2007 through December 31, 2007

UE 319

Attachment 442-C

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

Biglow 2 and 3 Hourly Generation for 2009 and 2010

April 21, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 443
Dated April 7, 2017

Request:

Please provide the following information for each wind facility with a lifetime capacity factor different than the capacity factor provided in response to parts c and d of OPUC DR 442:

- **a. Please explain how the capacity factor was initially estimated or forecasted.**
- **b. Please provide any studies, reports, or analysis supporting the initial capacity factor estimate.**
- **c. Please explain why the actual capacity factor is lower than the estimated or forecasted capacity factor.**

Response:

a. The assumed capacity factor of Biglow Canyon Phase 1 at the time PGE determined to construct the Biglow Canyon facility was 37.3%. At the time of the decision, PGE had not yet identified the preferred wind turbine manufacturer. The assumed capacity factor reflected the Garrad Hassan 2005 wind assessment, which anticipated development of three Biglow Canyon phases with General Electric 1.5 MW SLE turbines. PGE then selected Vestas as the preferred wind turbine manufacturer. The Vestas V82 turbines selected for the project have a greater rotor diameter and were expected to produce more energy than the GE turbines assumed in the Garrad Hassan 2005 wind assessment. Those expected benefits led PGE to increase the Garrad Hassan forecasted capacity factor by approximately two percent to 38.0%, which we used in the first NVPC case for Biglow 1, the 2008 power cost update filing (AUT).

The assumed capacity factor of Biglow Canyon Phase 2 at the time PGE determined to construct the Biglow Canyon facility was 35.0% based on the Garrad Hassan 2005 wind assessment and using GE turbines. PGE then selected Siemens as the preferred wind turbine manufacturer. The Siemens SWT 2.3-93 turbines selected for the project have a greater rotor diameter and were expected to produce more energy than the GE turbines assumed in the Garrad Hassan 2005 wind assessment. Those expected benefits led PGE to increase the Garrad Hassan forecasted capacity factor by approximately 3.7% percent to 36.27%, which PGE used in the first NVPC case including Biglow 2, the 2010 AUT.

The assumed capacity factor of Biglow Canyon Phase 3 at the time of PGE's decision to construct the Biglow Canyon facility was 32.87%, based on the Garrad Hassan 2005 wind assessment and using GE turbines. PGE used the 32.87% capacity factor, with no adjustment, in the first NVPC case for Biglow 3, the 2011 general rate case (GRC).

The assumed capacity factor of Tucannon River Wind Farm at the time PGE decided to construct the facility was 38.4%. The assumed capacity factor reflected the Garrad Hassan 2013 wind assessment of Tucannon River Wind Farm. For the initial filing of PGE's first NVPC case for Tucannon, the 2015 AUT/GRC, we used a calculated capacity factor of 36.75% based on a 02/07/2013 Draft Review of Wind Resource and Energy Assessments to Support PGE's Renewable request for proposal (RFP), by DNV/KEMA Energy & Sustainability. This filed capacity factor was then adjusted to 38.2%, pursuant to a stipulated agreement between PGE, the Industrial Customers of Northwest Utilities, the Citizens' Utility Board, and the Public Utility Commission of Oregon Staff.

b. Attachment 443-A includes Garrad Hassan's 2005 wind assessment of Biglow Canyon Wind Farm.

   Attachment 443-B includes GL Garrad Hassan's 2013 wind assessment of Tucannon River Wind Farm.

   Attachment 443-C includes DNV KEMA's 02/07/2013 Draft Review of Wind Resource and Energy Assessments to Support PGE's Renewable RFP.

c. Actual capacity factors are based on the actual generation of the wind turbines and can vary from study information due to a number of uncertainties including but not limited to:
   - Accuracy of wind measurements;
   - Modelling accuracy;
   - Actual variability of wind compared to study information;
   - Turbine technology selected;
   - Actual (vs modeled) location and number of wind turbines built; and
   - In general, many explicit and implicit input and modeling assumptions made in the studies that may or may not accurately represent real-life conditions and operations.

   It is also worth noting that, in determining the initial capacity factors for our wind plants, PGE relied on the expertise of independent industry experts to prepare these forecasts. During the time of PGE's construction and completion of Biglow, wind forecasting was still a relatively new subject area, which had limited expertise or history to draw upon.

This led to the systematic over forecasting of wind capacity factors, not only for Biglow, but throughout the country for large-scale wind projects. Since then and in conjunction with the rapid increase of wind turbine data and experience across the country, the forecasting of wind capacity factors has and continues to be improved.

Attachments 443-A, 443-B and 443-C are protected information and subject to Protective Order No. 17-057.

UE 319

Attachment 443-A

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

Garrad Hassan’s 2005 wind assessment of Biglow Canyon Wind Farm

UE 319

Attachment 443-B

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

GL Garrad Hassan’s 2013 wind assessment of Tucannon River Wind Farm

UE 319

Attachment 443-C

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

DNV KEMA's 02/07/2013 Draft Review of Wind Resource and Energy Assessments to Support PGE's Renewable RFP

May 23, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 563
Dated May 9, 2017

Request:

Please refer to the file "#Wells PPAv2 Updated Model.xlsx" provided as a workpaper for MONET step 61. The forecasted 2018 forecasted costs associated with Wells is [redacted] while the market value of the energy is forecasted to be [redacted]

a. **Please confirm that when PGE Fundamentals and Strategic Support group analyzed this contract they found that the cost of the project in 2018 would [redacted]**
b. **Please explain how cost of capital (Inputs tab, cell B73) is used in this model and why this model utilizes a cost of capital of 6.43 percent.**
c. **Please explain how the prices in the "Prices" tab are calculated.**
d. **Please provide the Mid Columbia forward on and off peak price curve by month for 2018 through 2028 as used in the April 14, 2017 MONET update. If available please provide such data separately for CO2 and no-CO2 scenarios.**
e. **Please refer to the file "#2018GRC-ModelSteps-March31Filing.xlsx" provided in PGE's MONET update. This file indicates that the Wells contract [redacted] Please explain why the MONET estimate of the value of the Wells contract differs from that of the Fundamentals and Strategic Support group.**

Response:

a. Referring to the file "#Wells PPAv2 Updated Model.xlsx", the estimated first year (2018) net cost of the Wells PPA contract, when compared to the No CO_2 market prices, can be calculated by subtracting the value calculated in cell G4 from the value calculated in cell E4. PGE notes that the net present value of the estimated contract cost when compared to the net present value of the estimated revenues under any of the market reference points, over the term of the contract, results in a net benefit to customers.

b. The “#Wells PPAv2 Updated Model.xlsx” file does not actively use the cost of capital, as defined in cell B73 of the “Inputs” worksheet. However, the discount rate, as defined in cell B74 of the “Inputs” worksheet, is used to calculate the net present value of the revenue and payment cash flows in order to calculate the real levelized cost of energy (RLCOE), which is a constant dollar, inflation-adjusted value. The discount rate is based on a capital structure of 50% equity at 9.68% and 50% debt at 4.47%.

c. The prices used for “CO_2” and “No CO_2” scenarios were derived from AURORA in 2015. The “Avoided Cost - Energy Only w/No CO_2” prices were derived from PGE’s 2014 avoided cost modeling by subtracting the capacity component from the total avoided cost to arrive at an energy only component used for comparison purposes

d. The Mid-Columbia market forward price trading curves used in MONET can be found in ***Step Documentation/Step 08 – Electric-Gas Curves*** of PGE’s MFR documentation submitted on April 14, 2017. See the file “#2018EndurCurves-02232017_FA.xlsx”, Columns N and O. Attachment 563-A provides monthly forward price trading curves through 2022, consistent with the February 23, 2017 snapshot date used for PGE’s March 31, 2017 NVPC update filing. PGE’s forward price curves generally span a time series of five to six years, not 10 years. As described in part (c) above, the “Wells PPAv2 Updated Model.xlsx” file uses AURORA prices from 2015 and Avoided Cost based prices from 2014.

Attachment 563-A is protected information and subject to Protective Order No. 17-057.

e. The difference in values is primarily attributable to the prices used in the two models. As explained in part (c) above, the “Wells PPAv2 Updated Model.xlsx” file uses AURORA prices from 2015 and Avoided Cost based prices from 2014. MONET uses forward market curves data February 23, 2017. As explained in part (a) above, the net present value of the estimated contract cost when compared to the net present value of the estimated revenues under any of the market reference points used in the “Wells PPAv2 Updated Model.xlsx” file, over the term of the contract, results in a net benefit to customers.

UE 319

Attachment 563-A

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

2017-2022 Endur Mid-C Forward Price Curve as of February 23, 2017

May 23, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 566
Dated May 9, 2017

<u>Request:</u>

Please refer to PGE's response to DR 443.

a. **When did PGE first become aware that the wind forecast for Biglow was over estimated?**
b. **When PGE chose to increase the size of the wind turbines for Biglow Phase I or II, did PGE consult with Garrad Hassan to determine the impact of larger turbines on Garrad Hassan's estimated the wake effect? If no, why not?**
c. **Please provide the analysis used by PGE to determine that the larger turbines would increase the capacity factor of Biglow Phase I by 2 percent and Phase II by 3.7 percent. If no analysis was performed how did PGE determine the change in capacity factor?**
d. **Please explain why PGE chose not to modify the turbines for Biglow Phase III.**
e. **Please provide the meteorological data provided to Garrad Hasson to support the wind studies in attachments of this DR. Please provide the data for the entire length of time the observations are available, even if the time periods extend beyond that provided to Garrad Hasson.**
f. **Does PGE have evidence that the wind data used in the Biglow or Tucannon wind studies were abnormal and not representative of average wind? If yes, please provide such evidence.**

<u>Response:</u>

PGE objects to this request on the basis that it is unduly burdensome. Subject to and without waiving its objection, PGE replies as follows:

a. With only nine years of actual generation data, PGE has no certainty the overall average of wind at Biglow will continue to come in lower than originally forecasted. However, between 2009 and 2010 PGE did begin to become aware that the actual wind at Biglow was consistently underperforming the original forecast. Additionally, PGE does know that, since completed, actual wind at Biglow has consistently come in lower than originally projected.

b. When making the turbine selection for Biglow Canyon Phase 1 and Phase 2, PGE held discussions with wind resource experts at Orion Renewable Energy Group in order to determine what effects larger rotors and larger blades would have on energy production. As wind farms in the United States were in their infancy, little was known at the time regarding wake effects, so it is likely that this was not discussed.

c. The capacity factors for all three phases of Biglow are primarily based upon the Garrad Hassan 2005 study as provided in PGE's response to OPUC Data Request No. 443, Attachment 443-A. PGE is unable to find a specific analysis at this time supporting the increase in capacity factor for Phase 1 and Phase 2 and the subject matter experts who worked on developing these factors are no longer at PGE. However, the reasons for the increase can be summarized as follows:

   The assumed wind turbine generator used as the basis for the 2005 Garrad Hassan report is the GE 1.5 MW SLE, which is a substantially smaller unit than either the Vestas unit used in Phase 1 or the Siemens SWT 93 unit used in Phase 2. The approximate 2% increase from the 2005 Garrad Hassan study for Phase 1 was based on the Vestas unit having an 82 meter diameter rotor and stronger power curve compared to the 77 meter rotor on the GE unit. The approximate 3.7% increase from the 2005 Garrad Hassan report for Phase 2 was based on the Siemens unit having a 93 meter diameter rotor and a substantially stronger power curve compared to the 77 meter rotor on the GE unit.

d. PGE assumes that part (d) is referring to adjusting the capacity factor from what was assumed in the 2005 Garrad Hassan report. PGE did not adjust the capacity factor for Biglow Phase 3 due primarily to the review of actual data from Phase 1 and Phase 2 and the recognition that actual production seemed to suggest a lower than expected capacity factor even with a larger turbine unit than assumed in the 2005 Garrad Hassan study.

e. PGE cannot locate any additional data beyond that provided in PGE's response to OPUC Data Request No. 443, Attachment A.

f. No. PGE has approximately 15 years of wind data that appears to indicate the study years were high. However, without a larger data set (i.e., 100 plus years) or a full understanding of how natural climate cycles and events or if climate change is affecting the wind regime, PGE cannot definitively state that the 2005 study information was "abnormal". Attachment 566-A provides the 2012 Garrad Hassan reassessment. This study indicates a number of reasons why actual output at Biglow was underperforming the 2005 estimate. One of the sources of the deviation was the wind itself. A discussion of the original study potentially being performed during a high wind period begins on page 67 of Attachment 566-A. However, there is no high quality anemometer data, prior to siting Biglow, that can prove the 2005 study information was from a high-wind, or "abnormal" wind period.

Attachment 566-A is protected information and subject to Protective Order No. 17-057.

UE 319

Attachment 566-A

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 17-057

2012 Garrad Hassan Assessment of Energy Production at Biglow Canyon

May 23, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 567
Dated May 9, 2017

Request:

Please refer to the file produced in response to DR 433 named "OPUC_DR_443_Attach_A_CONF.pdf" at page 9 (page 5 of the report's pagination).

a. **Did Garrad Hassan provide PGE with the numerical impact that including the [Begin Confidential] long term meteorological data [End Confidential] had on forecasted energy output or forecast uncertainty?**
b. **Did PGE ask Garrad Hassan what the impact of including the [Begin Confidential] long term meteorological data [End Confidential] had on the forecasted energy output of the proposed wind projects? If no, why not?**
c. **Please refer to page 19 (15 in report pagination) of the attachment. Did PGE evaluate the risk factors that Garrad Hassan listed and recommended PGE consider carefully?**

Response:

OPUC Staff sent portions of this data request as confidential. PGE does not believe the question itself is confidential and therefore we are including the question as non-confidential.

PGE objects to this request on the basis that it is unduly burdensome and vague. It is unclear to PGE what Staff means by the numerical impact of long-term meteorological data. Additionally, the primary PGE subject matter experts, who directly worked with Garrad Hassan in developing Biglow's wind forecasts, are no longer with PGE. Subject to and without waiving its objection, PGE replies as follows:

a. PGE is unable to locate any supplemental data or analysis from Garrad Hassan directly associated with the 2005 study, (referenced above as PGE's response to OPUC Data Request No. 443, Attachment 443-A).

b. PGE's subject matter experts who directly worked with Garrad Hassan in the development of the 2005 study are no longer with the company and email communications from this period are no longer accessible in PGE's current email archive. Therefore, PGE is unable to determine what questions its experts asked or did not ask Garrad Hassan in regard to the 2005 study.

c. While PGE's subject matter experts who directly worked with Garrad Hassan in the development of the 2005 study are no longer at PGE, a project of this size would have required extensive study and review. As discussed in PGE's response to OPUC Data request No. 443, wind forecasting was a relatively new subject area when PGE determined to build Biglow. PGE had no reasonable basis or historical data to draw upon that could have led PGE to determine a reduction in forecasted energy output was appropriate.

May 9, 2017

TO: Tyler Pepple
Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to ICNU DR No. 075
Dated April 25, 2017

Request:

Please provide actual expenses on a monthly basis over calendar year 2016 associated with the following gas transportation contracts:

- **a. Carty Gas Transp. - TransCanada NGTL**
- **b. Carty Gas Transp. - Foothills**
- **c. Carty Gas Transp. - GTN**
- **d. Carty Gas Transp. - Carty Lateral**

Response:

Attachment 075-A provides the information requested in parts (a) through (d). Please note that the gas transportation costs provided in Attachment 075-A were recorded as a capital cost prior to the date of July 29, 2016, when Carty was placed into service for full commercial operation.

Attachment 075-A is protected information and subject to Protective Order No. 17-057.

UE 319

Attachment 075-A

Provided in Electronic Format only

Protected Information and Subject to Protective Order No. 17-057

2016 Carty Gas Transportation Costs

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Opening Testimony

June 2, 2017

Staff Exhibit 203 is confidential and

Is subject to Protective Order No.17-057.

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Exhibits in Support
Of Opening Testimony

June 2, 2017

Staff Exhibit 204 is confidential and

Is subject to Protective Order No.17-057.

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 205

Exhibits in Support
Of Opening Testimony

June 2, 2017

Staff Exhibit 205 is confidential and

Is subject to Protective Order No.17-057.

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 206

Exhibits in Support
Of Opening Testimony

June 2, 2017

public utility loads in the period after current contracts expire in September 2011. While BPA has not made any final decisions regarding how much, if any, of the 550 aMW will ultimately be required, BPA believes it is likely that some augmentation will be necessary, and that it is prudent to make some limited, cost-effective acquisitions at this time. Furthermore, BPA has identified a potential increase in demand for renewable resources due to Renewables Portfolio Standards ("RPS") recently put in place by the State of Washington ("Energy Independence Act") and Oregon ("Oregon Renewable Energy Act"). These laws require many of BPA's public and investor owned utility customers to meet a certain percentage of their load using renewable resources. For these reasons, BPA began exploring available renewable resources to identify any potential lost opportunity projects that BPA might acquire now to meet the projected power requirements of these customers.

II. The Project and Power Purchase Agreement

Seller, a limited liability company incorporated in the state of Oregon, is an affiliate of PPM Energy, Inc., which in turn is a subsidiary of Scottish Power, plc. Credit support is being provided to BPA by Scottish Power Finance (US), Inc. The Klondike III Wind Project is located adjacent to the Klondike I and II wind projects near the town of Wasco, Sherman County, Oregon. The Project is currently expected to consist of 125 wind turbines and towers, new roads, new maintenance facilities, and a new substation. Several turbines types are currently expected to be used, with capacities ranging from 1.5 MW to 2.4 MW. Project facilities occupy approximately 74 acres of private agricultural land. The total generating capacity of the Project is expected to be 223.6 MW.

The Project is under construction and expected to be completed and ready for commercial operation by December 31, 2007. Such date may be extended by Seller until June 1, 2009, and for up to an additional 180 days in the event of an uncontrollable force, at which time if commercial operation has not been achieved, Seller (with some preconditions) or BPA (unconditionally) may terminate the PPA.

BPA's contractual percentage share of actual Project output is 22.36 percent, or 49.99 MW of the anticipated generating capacity. However, BPA's share of actual output is capped at 50 MW, even in the event that the generating capacity of the Project as finally constructed exceeds 223.6 MW. The balance of the Project's anticipated generating capacity has been sold to other purchasers. Because wind energy is an inherently intermittent resource, the actual projected annual average output of the Project is well below its nameplate capacity. Based on historical performance of similar wind generation resources in the same area, BPA projects that the Project will have an annual average capacity factor of 30 percent (a conservative assumption), which means BPA expects on a planning basis that its annual average output share of Project generation will not exceed 15 aMW.

Under the PPA, Seller is responsible for providing schedules to the transmission provider before each hour, specifying the amount of energy it will deliver to BPA in such hour. BPA is obligated to pay Seller the contract price for the amount of energy actually generated and metered at the metering point. At the end of each month, the hourly metered amounts will be trued-up to the hourly schedules submitted by Seller in such month. Depending on whether Seller

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 207

Exhibits in Support
Of Opening Testimony

June 2, 2017

Carty Generating Station

The certificate holder received approval to construct and operate a 900-megawatt, natural gas-fueled, combined-cycle electric generating plant consisting of two 450-megawatt units (Unit 1 and Unit 2). Unit 1 was fully operational in July 2016. Construction of Unit 2 has not yet begun.

Status: Suspended review/Operating. The certificate holder submitted a request to amend the site certificate in August 2016. In May 2017, the certificate holder requested to suspend review of the amendment request. While the amendment request is still "active" until further notice from the certificate holder, the Department has suspended review and coordination with state and local agencies. If the certificate holder requests to re-initiate review of the amendment request, this webpage will be updated. Also, additional noticing will be issued regarding any changes to the amendment request and next applicable comment period.

Location: Morrow and Gilliam counties (Map) **(/energy/facilities-safety/facilities/Documents/CGS/Carty_map.**gif)

Applicant/Certificate holder: Portland General Electric

ODOE contact: **Sarah Esterson (mailto:sarah.esterson@oregon.gov)**

Application/Certificate holder contact: **Arya Behbehani (mailto:Arya.Behbehani@phn.com)**

4. Proposed Changes and Analysis

A. Proposed Changes

Changes to the Carty Generating Station include modifications to Unit 2, extension of the construction timeline for Unit 2, the addition of Unit 3 and the Carty Solar Farm and associated transmission and other supporting facilities. The major components, structures, and systems of Unit 1 and Unit 2 are described in the Site Certificate. Modifications to Unit 2 are described below, along with a description of Unit 3 and the Carty Solar Farm. All units would be fully integrated into the operations and maintenance of the Carty Generating Station.

Unit 2

There are no proposed substantive changes to the major equipment required for Unit 2 as described in the Site Certificate. Minor changes in the internal design of the unit and improvements in technology since the original design was submitted have resulted in the increased nominal electric generating capacity of Unit 2 from approximately 450 MW described in the ASC to 530 MW (net). Condition 4.3 of the Site Certificate requires that construction of Unit 2 begin no later than five years after the effective date of the Site Certificate. The Site Certificate was countersigned on July 2, 2012; therefore, construction of Unit 2 would have to start construction by July 2, 2017. PGE is requesting an extension to the construction beginning deadline.

Unit 3

The new proposed Unit 3 would consist of a high efficiency CTG in simple cycle with the capability of building out into a combined cycle unit in the future. Unit 3 would be located next to the Boardman boiler building. The following major new equipment required to support the Unit 3 simple cycle CTG and balance of plant additions include:

- One CTG 330 MW net at International Organization for Standardization (ISO) standard reference conditions;
- Fin fan coolers for auxiliary equipment;
- Exhaust system, including exhaust silencer and stack;
- Service water system for new buildings and equipment (this would tie into the existing Boardman system or extend the system from Carty Unit 1);
- All environmental control systems required to meet the emissions and discharge requirements of the facility;
- Compressed air systems, including instrument air;
- Fire detection, alarm, and protection systems;

Additional areas in the vicinity of the proposed Carty Generating Station are provided for construction offices, construction parking, construction staging, and temporary storage of soil displaced during the construction process. Similar temporary construction areas are provided in the vicinity of the Grassland Switchyard~~ and Carty Solar Farm~~.

4.0 GENERAL ADMINISTRATIVE CONDITIONS

4.1. The certificate holder shall begin construction of the facility within three years after the effective date of the site certificate. Under OAR 345-015-0085(9), a site certificate is effective upon execution by the Council Chair and the applicant. The Council may grant an extension of the deadline to begin construction in accordance with OAR 345-027-0030 or any successor rule in effect at the time the request for extension is submitted.
[Final Order III.D.3] [Mandatory Condition OAR 345-027-0020(4)]

4.2. The certificate holder must complete construction of Unit 1 of the facility within three years of beginning construction of ~~Block~~ Unit 1. Construction is complete when: 1) the facility is substantially complete as defined by the certificate holder's construction contract documents; 2) acceptance testing has been satisfactorily completed; and 3) the energy facility is ready to begin continuous operation consistent with the site certificate. The certificate holder shall promptly notify the Department of the date of completion of construction of ~~Block~~ Unit 1. The Council may grant an extension of the deadline for completing construction in accordance with OAR 345-027-0030 or any successor rule in effect at the time the request for extension is submitted.
[Final Order III.D.4] [Mandatory Condition OAR 345-027-0020(4)] [Amendment No. 1]

4.3. The certificate holder must begin construction of ~~Block~~ Unit 2 no later than ~~five three~~July 2, 2019.~~years after the effective date of the site certificate.~~ The certificate holder shall complete construction of ~~the facility~~~~each unit~~Unit 2 within three years of beginning construction~~ of that unit~~~~Block 2~~. Construction is complete when: 1) ~~Block 2~~the unit is substantially complete as defined by the certificate holder's construction contract documents; 2) acceptance testing has been satisfactorily completed; and 3) ~~Block 2~~the unit is ready to begin continuous operation consistent with the site certificate. The certificate holder shall notify the Department when the construction of ~~Block 2~~ Unit 2 begins, and notify the Department of the date of completion of ~~Block 2~~ construction for Unit 2. The Council may grant an extension of the deadline for completing construction in accordance with OAR 345-027-0030 or any successor rule in effect at the time the request for extension is submitted.

The certificate holder must begin construction of Unit 3 no later than five years after the effective date of Amendment No. 1 of the site certificate. The certificate holder shall complete construction of Unit 3 within three years of beginning construction.

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 208

Exhibits in Support
Of Opening Testimony

June 2, 2017

Staff Exhibit 208 is confidential and

Is subject to Protective Order No.17-057.

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 209

Exhibits in Support
Of Opening Testimony

June 2, 2017

Staff Exhibit 209 is confidential and

Is subject to Protective Order No.17-057.

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 210

Exhibits in Support Of Opening Testimony

June 2, 2017

Staff Exhibit 210 is confidential and

Is subject to Protective Order No.17-057.

CASE: UE 319
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 211

Exhibits in Support
Of Opening Testimony

June 2, 2017

Staff Exhibit 211 is confidential and

Is subject to Protective Order No.17-057.

CASE: UE 319
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony
(Net Variable Power Costs)

June 2, 2017

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

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

Q. Please describe your educational background and work experience.

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

Q. What is the purpose of your testimony?

A. I discuss PGE's contract with Northwest Natural Gas Company ("NW Natural") for gas storage service from NW Natural's North Mist Expansion Project, PGE's update to NVPC to account for upgrades at Port Westward 1, PGE's Biomass Project at its Boardman coal plant, the Forced Outage Rate (FOR) at its Coyote Springs natural gas plant, transmission, and PGE's compliance with minimum filing requirements (MFRs).

My testimony and recommendations reflect my analysis to date and my recommendations could change as a result of the review of other parties' testimony filed in this docket.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Exhibit 301 Witness Qualifications Statement

Exhibit 302 PGE Responses to Staff Data Request (DR) No. 524 re: Need for storage capacity for Clatskanie plants

Exhibit 303 NW Natural's Rate Schedule 90 Service Agreement

Exhibit 304 PGE response to Staff DR No. 556 regarding the uses of gas at the North Mist Expansion Project

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: NORTH MIST EXPANSION PROJECT (NMEP)

Q. What is the North Mist Expansion Project (NMEP)?

A. PGE currently has an agreement with NW Natural Gas Company (NW Natural) for firm natural gas storage at NW Natural's Mist gas storage facility near Clatskanie, Oregon (the "Mist Agreement"). PGE uses the storage to augment gas pipeline transportation service to its Beaver and Port Westward Plants. PGE has used the storage service since 2007. Under the Mist Agreement, PGE is allowed to store up to 1.26 million dekatherms and withdraw up to 70,000 dekatherms per day of natural gas.[1] However, the capacity at Mist is subject to recall by NW Natural and NW Natural has decided to use its existing Mist storage to serve its customers.[2]

In 2012, PGE entered into an agreement with NW Natural for long-term no-notice gas storage services from NW Natural's NMEP (the "Precedent Agreement").

Q. What is the current state of construction at NMEP?

A. Construction is still in preliminary stages. NW Natural estimates that construction will be complete by October 2018.

[1] PGE/300, Niman-Peschka-Rodehorst/23.
[2] PGE/300, Niman-Peschka-Rodehorst/23.

Q. Are costs associated with storage service from NMEP included in PGE's NVPC?

A. Yes. PGE anticipates that the NMEP will be in service October 2018.[3] Accordingly, costs for gas storage service from the NMEP are included in NVPC for the months of October-December 2018.[4]

Q. How did Staff perform its analysis of storage service from the NMEP in PGE's NVPC filing?

A. I reviewed the Precedent Agreement and Oregon Storage Service Agreement between PGE and NW Natural. I participated in phone conferences with PGE and NW Natural and reviewed the responses to 13 data requests.

Q. What is the Oregon Storage Agreement?

A. The Oregon Storage Agreement sets forth the terms of PGE's agreement with NW Natural for storage service at the NMEP. Under the Oregon Storage Service Agreement NW Natural will provide no-notice withdrawal firm storage service for 30 years, with possible extensions for a cumulative service term of 80 years.[5] The agreement sets forth the maximum injection, maximum withdrawal (120,000 dekatherms per day), and maximum storage quantities (2.54 million dekatherms) provided to PGE.[6] **[BEGIN CONFIDENTIAL]** [redacted]

[3] PGE/300, Niman-Peschka-Rodehorst/25.
[4] PGE/300, Niman-Peschka-Rodehorst/25.
[5] PGE/300, Niman-Peschka-Rodehorst/26.
[6] PGE/300, Niman-Peschka-Rodehorst/26.

[redacted] **[END CONFIDENTIAL]**

Q. How will PGE be charged for storage service from NMEP?

A. PGE will be charged NW Natural's Schedule 90 rates based on **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

Q. Will the NMEP help PGE provide reliable service to PGE customers?

A. PGE states that NMEP will provide no-notice, flexible gas supply to the three gas plants at Clatskanie, Oregon. PGE has access to 103,305 Dth/day of transmission from the Williams Pipeline. PGE explained in response to a data request that the MONET forecast for 2018 predicts that, during summer months, gas consumption at Clatskanie will be greater than the 103,305 Dth/Day available from the Williams pipeline.[7]

The full generating capacity of the three plants requires 225,000 Dth/day.[8] The 120,000 Dth/Day of gas from NMEP will allow PGE to fuel the entire capacity of its Clatskanie plants. The no-notice availability of NMEP will allow PGE to utilize the plants for load and wind following. NMEP was included in PGE's 2013 Integrated Resource Plan (IRP).

Q. Has PGE considered other options for flexible gas supply at Clatskanie?

A. Yes. PGE considered procuring more pipeline capacity from the NW Pipeline. PGE estimates that this would be more expensive than NMEP and would not provide no-notice service needed for intra-hour generation decisions.[9] Staff's analysis finds that if PGE could procure a lower amount of daily transmission from the NW Pipeline in 2018, the pipeline cost initially would be lower than the cost of NMEP. If PGE purchased **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** at $0.56 per Dth/Day, the annual expense would be **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** In comparison, PGE provided annual cost estimates for storage at NMEP of about **[BEGIN CONFIDENTIAL]** [redacted]

[7] Staff Exhibit 302; PGE Response to Staff DR 524.
[8] PGE's 2013 Integrated Resource Plan, p. 92.
[9] PGE/300, Niman-Peschka-Rodehorst/24, lines 7-11.

[redacted] **[END CONFIDENTIAL].** The cost of pipeline transmission would likely not decrease over time.

Q. Is Staff recommending an adjustment based on its conclusion regarding the cost of capacity from the NW Pipeline compared to PGE's forecasted cost under the Oregon Storage Agreement?

A. No. PGE states that it requires no-notice availability in order to maximize the dispatchability of its gas plants in Clatskanie. This option is not available with additional capacity from the NW Pipeline. Further, although the costs of the NMEP are initially more expensive, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. Will PGE use the gas at NMEP to generate revenue by purchasing when gas prices are low and selling when gas prices are high?

A. No. PGE has explained that PGE cannot physically move gas from NMEP to the Williams NW Pipeline.[10]

Q. Does Staff recommend any adjustments to NMEP expenses in PGE's 2018 NVPC filing?

A. Yes. Staff recommends that PGE reduce the length of overlap between current Mist storage service and service from the NMEP. In PGE's initial filing, an overlap of two months is proposed between current "gap services" at Mist and the start of service from the NMEP. Staff recommends reducing the overlap to one month. This results in a decrease to NVPC of $97,200. Staff believes that a

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[10] Staff/304; PGE Response to Staff DR No. 556.

two month overlap is unnecessary because the consequences of a reduction in the amount of flexible capacity to PGE for a single month during November are relatively small and unlikely. Based on Staff analysis of confidential information provided by PGE in response to Staff Data Request No. 371, Staff determined that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** It is Staff's position that, although in the longer term the NMEP will provide value to ratepayers, if storage service from Mist is unavailable for one month then PGE will have access to other sources of flexible capacity such as PGE's Carty gas plant or market purchases.

With respect to NMEP, Staff has no other adjustments to the 2018 NVPC. The costs for NMEP in PGE's 2018 NVPC filing are fixed. Accordingly, there is little risk that PGE's actual costs may be less than or more than the amount included in NVPC. And Staff believes the amount included in NVPC is reasonable.

Q. Are there any comments you wish to offer for future analysis or review?

A. Yes. In subsequent dockets, Staff will be reviewing PGE actions to see if PGE prudently exercised its contractual rights with NW Natural with regards to NMEP to ensure costs are no higher than necessary. Staff believes PGE should be exercising its oversight of the construction and other activities to ensure the project is prudently managed.

ISSUE 2: PORT WESTWARD PERFORMANCE UPGRADE

Q. What is the Port Westward 1 Performance Upgrade?

A. PGE updated the parameters of the Port Westward 1 gas plant in the MONET model to reflect a higher capacity factor and lower heat rate that resulted from a plant upgrade that took place **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The MONET update resulted in a decrease to PGE's 2018 NVPC forecast of approximately $1.5 million.

Q. How did Staff perform its analysis of the Port Westward 1 Performance Upgrade in PGE's NVPC filing?

A. Staff reviewed PGE's responses to two data requests and checked the implementation of the Port Westward 1 update in PGE's MONET power cost model. Staff spoke on the phone with PGE about the parameter updates and Minimum Filing Requirements for Port Westward 1.

Q. Does Staff find that the Port Westward 1 parameter update provides a fair and reasonable update to Port Westward 1 costs?

A. Yes. The update is implemented as described in the workpapers provided by PGE. The Port Westward 1 operating parameters have been updated to reflect the improved performance of the plant after a performance upgrade.

Q. Does Staff recommend any adjustments to Port Westward 1 expenses in PGE's 2018 NVPC filing?

A. Not at this time.

ISSUE 3: BOARDMAN BIOMASS

Q. What is the Boardman Biomass Project?

A. Since 2010, PGE has attempted to assess the feasibility of displacing coal at its Boardman coal plant with biogenic torrefied biomass. Costs associated with biomass test burns have been included in previous NVPC forecasts.

Q. How did Staff perform its analysis of the Boardman Biomass project?

A. Staff confirmed that no Boardman Biomass expenses were included in the MONET model, consistent with PGE's testimony in this docket.[11] PGE's testimony reflects that after 2017 tests are complete the next step in testing biomass burning at Boardman will be to run multiple-day 100 percent biomass burns to evaluate the longer-term viability of biomass as a fuel source.[12] PGE has stated that it is still determining a fuel source for these tests and evaluating the probability that this could be accomplished in the 2018 timeframe.[13]

Q. Are there any other expenses associated with Boardman Biomass in the 2018 General Rate Case?

A. Yes. PGE included $410,000 of Boardman Biomass R&D in the 2018 Research and Development (R&D) budget.[14] PGE budgeted $110,000 for supply chain development of torrefied biomass, which is intended to develop PGE's knowledge of potential sources of biomass fuel at Boardman.[15] The remaining $300,000 is budgeted for multiple-day biomass test burns that are intended to

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[11] See PGE/300, Niman-Peschka-Rodehorst/32.
[12] PGE/300, Niman – Peschka – Rodehorst /31.
[13] PGE/300, Niman-Peschka-Rodehorst/32.
[14] PGE/604, p.6.
[15] PGE/604, p. 6.

allow PGE to develop its fuel handling, processing, and safety procedures and monitor performance and emissions of biomass fuel at Boardman.[16]

Q. Please summarize your proposed treatment of R&D costs.

A. PGE has included these Boardman fuel supply expenses as part of the current General Rate Case filing. Staff finds that the expenses are appropriately included in NVPC rather than base rates. PGE intends to spend up to perhaps $410,000 in 2018 on R&D relating to the biomass test burns to support evolution of new fuel handling, processing and safety procedures associated with both green and torrefied biomass and a study of Boardman's fuel supply chain management.[17] According to PGE, "the study will help PGE to firm its views of what will be the potential biomass supply chain components sufficient to fire the Plant at 30% to 40% capacity."[18] Costs related to fueling generation are more appropriately recovered through NVPC mechanisms than through base rates. Staff proposes to remove these costs from base rates and incorporate them into the 2018 NVPC.

Q. What adjustment does Staff recommend related to Boardman Biomass?

A. Staff recommends adding $410,000 of costs currently categorized under R&D in base rates to NVPC. Staff believes these costs are more properly classified as power costs. To include these costs in revenue requirement would increase base rates by $410,000 — essentially reflecting a permanent increase in costs

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[16] PGE/604, p. 8.
[17] PGE/604, pp. 6-8.
[18] PGE/604, p. 6.

while these test burns are temporary and likely will not be repeated in future years.

Q. Are there other Staff recommendations on the $410,000 costs related to Boardman Biomass?

A. Yes. Staff recommends that PGE track these costs. Sometimes the scheduled test burns do not occur and are postponed. To the extent any of the $410,000 in costs is not incurred, those costs should be removed from the baseline power costs in any true-up review. If PGE is aware or becomes aware prior to the November Update that some or all of the costs will not be incurred in 2018, then those monies should be excluded from NVPC and base rates. Under these two conditions, Staff is comfortable with and supportive of including the $410,000 in baseline power costs.

ISSUE 4: MINIMUM FILING REQUIREMENTS

Q. Has PGE met the requirements for its Minimum Filing Requirement filing in UE 319?

A. Yes. Staff has reviewed the Minimum Filing Requirements (MFR) as filed by PGE. Staff's analysis has confirmed that the MFR and subsequent updates include all of the elements listed in Order No. 08-505 from Docket UE 198 except the updated Headwater Benefits Study. PGE indicated in a meeting on NVPC and confirmed in a phone call with Staff that the Headwater Benefits Study is undergoing review by the Northwest Power Pool. The current filing includes the Headwater Benefits Study from the PGE's most recent General Rate Case.

ISSUE 5: TRANSMISSION

Q. Please describe transmission transactions in the 2018 NVPC filing.

A. PGE contracts with parties for long-term transmission capacity and participates in short-term transmission purchases and sales with various parties. Accordingly, PGE has both expenses and revenues associated with these transactions.

Q. Please describe Staff's analysis of PGE's transmission transactions.

A. Staff reviewed PGE's responses to data requests as well as the transmission data in PGE's Minimum Filing Requirements.

Q. What adjustments does Staff have regarding transmission expense?

A. Staff has no adjustments to PGE's forecasted transmission expense at this time.

ISSUE 6: COYOTE SPRINGS FORCED OUTAGE RATE

Q. Please describe the Forced Outage Rate (FOR) for a generating plant.

A. A FOR is a measure of the likelihood of a generating plant being unavailable for service due to an unplanned event. The FOR measures the amount of time when a plant should have been available for service, but was unavailable due to an unplanned event such as emergency maintenance.

Q. What methodology has PGE used to calculate the FOR for Coyote Springs?

A. PGE has used a four-year average to calculate the FOR for its Coyote Springs natural gas plant (Coyote) in this filing.

Q. Do you have any concerns regarding PGE's calculation of the Coyote FOR?

A. Yes. As it has in PGE's testimony in previous dockets, the PGE calculation includes the effects of an extremely long outage at Coyote that occurred in 2013.

Q. Did Staff have a similar concern in UE 294?

A. Yes. As Staff testified in UE 294, an extended outage at Coyote in 2013 resulted in the plant being unavailable more than it was available for service.[19] When PGE included this year in the FOR calculation in UE 294, NVPC increased by about $3 million compared to an estimate replacing the 2013 FOR with a value from before the extraordinary 2013 outlier year.

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[19] See UE 294 Staff/100, Crider/2-11.

Q. What did Staff propose in UE 294 to address this 2013 extended outage?

A. Staff proposed using the same method described for coal plant outlier FOR years in Order No. 10-414. This method replaces extreme outlier years with the plant's 20-year rolling average FOR, or the average FOR over the life of the plant if the plant has been in service less than 20 years.

Q. **What method does Staff recommend for calculating the FOR at Coyote Springs for this docket?**

A. Staff recommends the outlier year be treated using the same method proposed by Staff in UE 294. Therefore Staff recommends that the alternative and more appropriate FOR be modeled in MONET and the NVPC updated. In UE 294, Staff estimated that this method would reduce NVPC by roughly $3.0 million. Staff would expect a similar downward adjustment in this case, although the exact number could vary from the $3 million UE 294 amount.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 319
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

June 2, 2017

WITNESS QUALIFICATION STATEMENT

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

CASE: UE 319
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

June 2, 2017

May 8, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 524
Dated April 24, 2017

Request:

Please provide any studies or workpapers demonstrating the need for the North Mist Expansion Project. Please include studies or workpapers showing whether currently available gas supply and storage resources and contracts are being fully utilized by the Port Westward I & II and Beaver plants.

Response:

PGE objects to this question on the basis that it is overly broad. Notwithstanding its objection, PGE replies as follows:

As described on page 23 of PGE Exhibit 300, PGE's existing contract with NW Natural for firm natural gas storage service from Mist storage is not available for renewal. In the future, NW Natural intends to use its existing Mist storage to serve its core customers. Therefore, PGE identified the North Mist Expansion Project as the least-cost option to (1) replace its existing storage service and (2) meet the increased gas fueling needs at the Port Westward / Beaver complex. The increased gas fueling need resulted from the addition of Port Westward Unit 2 to PGE's gas-fired generation portfolio. See PGE's Response to CUB Data Request No. 014 for a description of the alternative gas fueling options PGE evaluated.

In its 2013 Integrated Resource Plan (IRP), PGE identified the Precedent Agreement with NW Natural. PGE also demonstrated that the combination of the North Mist Expansion Project storage and firm transportation rights on the NW Pipeline will be used to meet the fueling needs of the Port Westward / Beaver complex. See Attachment 524-A for the relevant pages of PGE's 2013 IRP. PGE's 2013 IRP was acknowledged on December 2, 2014.

PGE's demonstrated need is based on the capability of the plants at the Port Westward / Beaver complex. PGE's plants (Port Westward 1, Port Westward 2, and Beaver 1-8) are capable of using up to 232,500 Dth/day.[1] This capability is significantly greater than PGE's firm gas transport from the Williams NW pipeline (i.e., 103,305 Dth/day). Without the North Mist Expansion Project storage, PGE would not be able to plan to fuel the full capability of its plants on a firm basis. Reduced firm fuel source options would create reliability risks, because it increases the likelihood that there will be instances where PGE is forced to constrain generation.

In PGE's Response to OPUC Data Request No. 374, PGE also demonstrated that under MONET's expected (i.e., "average") conditions, PGE forecasts gas consumption significantly greater than 103,305 Dth/day on a monthly average basis during the months of July, August, and September. See the "Pipeline – Storage and Plant" worksheet in confidential Attachment 374-A.

[1] The 225,000 Dth/day listed in the 2013 IRP excluded Beaver Unit 8.

UE 319

Attachment 524-A

Provided in Electronic Format only

2013 IRP – Gas Storage and Transportation

CASE: UE 319
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Exhibits in Support
Of Opening Testimony

June 2, 2017

Staff Exhibit 303 is confidential and

Is subject to Protective Order No.17-057.

CASE: UE 319
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 304

Exhibits in Support
Of Opening Testimony

June 2, 2017

May 18, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 556
Dated May 5, 2017

Request:

Please describe, except for storage and fueling the plants at Clatskanie, any way that PGE used the gas stored at Mist during the Base Year ending December 31, 2016 and how each of those other uses benefited customers.

Response:

PGE objects to this request on the basis that it is overly broad. Notwithstanding its objection, PGE replies as follows:

Mist storage provided a reliability benefit in 2016. In addition to fueling the plants at the Port Westward / Beaver complex, Mist storage, in combination with gas pipeline transportation service and delivered gas, ensured that PGE had firm fuel supply equal to the full capability of the plants' fueling needs in 2016. This underpins PGE's efforts to provide reliable service to our customers. Without firm fuel supply, PGE could be forced to constrain generation during a peak demand period or contingency event.

PGE did not sell (or otherwise use) gas from Mist storage in 2016 other than to fuel the plants at Clatskanie. Please note that PGE will not be able to sell gas from the North Mist Expansion Project, because PGE cannot physically move gas from the North Mist pipeline to the Kelso-Beaver pipeline to the Williams NW pipeline.