BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

	) MOTION FOR OFFICIAL NOTICE OF
In the Matter of	) THE NORTHWEST AND
NORTHWEST AND INTERMOUNTAIN	) INTERMOUNTAIN POWER
POWER PRODUCERS COALITION	) PRODUCERS COALITION
	)
Petition for an Investigation Regarding	)
Competitive Bidding	)
	)

Pursuant to OAR 860-001-420 and OAR 860-001-460, the Northwest and Intermountain Power Producers Coalition ("NIPPC") respectfully moves the Public Utility Commission of Oregon ("OPUC" or "Commission") to take official notice of the following documents:

- *Report of the Independent Evaluator, Accion Group, Portland General Electric Company's 2012 Capacity and Energy Power Supply Resources RFP*, OPUC Docket No. UM 1535 (Jan. 30, 2013) (*hereinafter: UM 1535 IE Report*);[1]

- Direct Testimony of Portland General Electric Company witnesses Mike Niman and Terri Peschka, Exhibit 400, OPUC Docket No. UE 262 (Feb. 15, 2013) (*hereinafter:* UE 262 PGE/400).

These documents are subject to official notice because they were made a part of the Commission's files in the regular course of performing the Commission's duties. *See* OAR 860-001-460(1)(d). For the convenience of the Commission and the parties, NIPPC has provided these documents as Attachments 1 and 2 to this motion.

[1] For reasons discussed below, NIPPC only moves for official notice of the non-confidential portion of this document.

LEGAL STANDARD

The Oregon courts have long encouraged liberal use of official notice in Commission proceedings. *See Pierce Auto Freight Lines, Inc. v. Flagg*, 177 Or. 1, 40, 159 P.2d 162 (1945). Judicial notice or official notice allows for reliance on the noticed facts or the contents of the noticed documents. *See State of Oregon v. Bellah*, 242 Or.App. 73, 82, 252 P.3d 357, 362 (2011); *In Re PacifiCorp dba Pacific Power: 2013 Transition Adjustment Mechanism*, OPUC Docket No. UE 245, Order No. 09-409, at 12 (2012) (taking official notice and relying upon contents of documents filed in other proceedings).

"The Commission or ALJ may take official notice of the following: . . . . (d) Documents and records in the files of the Commission that have been made a part of the files in the regular course of performing the Commission's duties." OAR 860-001-460(1)(d). The Commission rules further provide:

> The Commission or the ALJ must notify the parties when official notice is taken. The notice may be given on the record during the hearing, in an ALJ ruling, or in a Commission order. A party may object to the fact noticed within 15 days of the hearing during which notice was given, the ALJ ruling, or the Commission order. The objecting party may explain or rebut the noticed fact.

OAR 860-001-460(2).

ARGUMENT

The Commission should take official notice of the *UM 1535 IE Report* and the PGE rate case testimony (UE 262 PGE/400). The contents of both documents are officially noticeable because they are documents "in the files of the Commission that have been made a part of the files in the regular course of performing the Commission's duties." OAR 860-001-460(1)(d).

PGE has itself argued that the Commission should take official notice of documents filed in other Commission dockets. *See PGE's Prehearing Brief* at 34 n.3.

Both documents are also relevant to the proceedings in this case. The *UM 1535 IE Report* is the most recently produced Oregon IE Report. It therefore provides the most recent example of an IE's analysis of the unique risks and advantages of independent power producer bids and utility-ownership bids in Oregon request for proposals, as called for in Guideline 10(d). NIPPC does not move for official notice of the confidential attachments to the *UM 1535 IE Report.* The protective order in UM 1535 requires PGE's written consent for other parties to use confidential portions of the *UM 1535 IE Report* in this docket, and PGE has not granted NIPPC's request for such written consent. However, NIPPC did not intend to discuss the contents of the confidential attachments to the *UM 1535 IE Report.* Thus official notice of the non-confidential portions of *UM 1535 IE Report* is warranted.

The other document, UE 262 PGE/400, is a contemporaneous example of a request to increase power supply expenses resulting from an inaccurate wind forecast at a utility-owned plant. *See* UE 262 PGE/400, Niman-Peschka/9-10. The contents of this document produced by PGE for purposes of rate recovery are relevant to the question in this generic investigation of whether a risk adjustment to wind capacity factor forecasts is necessary at the time of resource selection. *See, e.g., NIPPC Pre-Hearing Brief* at 15-17.

CONCLUSION

NIPPC respectfully requests official notice of the documents referenced herein.

RESPECTFULLY SUBMITTED this 11th day of March 2013.

RICHARDSON & O'LEARY, PLLC

/s/ *Gregory M. Adams*

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Intermountain Power Producers Coalition

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MOTION FOR OFFICIAL NOTICE OF THE NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION

ATTACHMENT 1

ELLEN F. ROSENBLUM
Attorney General

MARY H. WILLIAMS
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

January 31, 2013

Attention: Filing Center
Public Utility Commission of Oregon
550 Capitol Street NE, #215
PO Box 2148
Salem, OR 97308-2148
puc.filingcenter@state.or.us

Re: *In the Matter of PORTLAND GENERAL ELECTRIC Request for Proposals for Capacity and Baseload Energy Resources*
PUC Docket No.: UM 1535

Enclosed are an original and one copy of Report of the Independent Evaluator for PGE 2012 Capacity Power Supply Resources RFP.

Sincerely,

Stephanie S. Andrus
Senior Assistant Attorney General
Business Activities Section

SSA:mme/#3972241
c: UM 1535 Service List

1162 Court Street NE, Salem, OR 97301-4096
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REPORT OF THE INDEPENDENT EVALUATOR

Portland General Electric Company's
2012 Capacity and Energy Power Supply Resources RFP

January 30, 2013

Submitted by:

ACCION GROUP, INC.
244 North Main Street
Concord, New Hampshire 03301
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Table of Contents

I. Executive Summary

Accion Group, Inc. ("Accion Group" or "Accion") was selected by the Oregon Public Utility Commission ("OPUC" or "Commission") to serve as the Independent Evaluator ("IE") for Portland General Electric Company's ("PGE" or "Company") 2011 Request for Proposals ("RFP"). This report of the IE addresses the combined 2012 Capacity and Energy RFP, which is the result of the OPUC decision of September 27, 2011: Order No. 11 371.

Accion Group believes that PGE has acted in good faith with all Bidders, and created protocols and documents that permitted the RFP to be conducted in a fair and transparent manner. The protocols adopted and employed throughout the RFP were applied to all Bidders, regardless of whether they were from an independent developer or from the PGE Self-Build Team. We are unaware of any instance where the protocols for separation of PGE personnel were violated. Further, we are unaware of any instance where any Bidder was given separate access to PGE personnel, or was provided with information about the RFP other than through the Stakeholders Conference or the RFP Website (http://portlandgeneralrfp.accionpower.com).

The IE believes this RFP was conducted in a fair and unbiased manner and that the Final Short List accurately identified the Bids with the most value for PGE customers. Further, the IE believes PGE successfully separated the evaluation personnel from the PGE personnel supporting the benchmark proposals, and that the evaluation modeling and RFP protocols prevented the benchmark proposals from being treated any differently than bids from third party bidders.

II. Background and Process

The RFP process began in April 2011, when PGE personnel delivered the draft RFP documents to the IE for review. The RFP website was released to the public on April 21, 2011. At that time the anticipated the process would be open to bidding in July 2011.

The RFP provided a variety of products for which bids would be accepted. For flexible capacity, the target capacity was 200 MW, with a minimum required bid of 25 MW. Baseload bids needed to offer at least 100 MW with the maximum bid size of 500 MW. Seasonal products were accepted with the bid minimum being 25 MW and the maximum being 200 MW, expect winder-only seasonal bids could be as large as 350 MW. The RFP established the preferred in-service delivery to begin in 2014 for peaking resources and 2015 for baseload resources. The RFP was open to supplies from existing or as yet to be built generating facilities, and permitted bids to supply as a long-term contractual obligation, or through the purchase of the asset by PGE. As originally designed, the RFP sought bids from third party sites, that is, other than sites presently owned by PGE. Certain interested parties requested that the

Commission require PGE to open Company-owned sites to construction and siting of generation owned and operated by third parties. In response to these requests the Commission encouraged the Company to accept bids for third parties to build new generation on the two existing stations PGE previously identified as future development sites.

When the Commission encouraged PGE to restart the RFP to include Bids for Engineering Procurement Construction (“EPC”) agreements, the IE worked with PGE personnel to devise a process that permitted access to the PGE site-specific data and permit Bidders to build on the PGE sites. This required the development of comprehensive design/build documentation, a revised procedural schedule, and the development of protocols to separate the EPC RFP process and documents from the Capacity and Energy RFP. A separate and parallel process was developed for reviewing information related to the EPC/Build Own Transfer (“BOT”) proposals simultaneously with the Capacity and Energy RFP. This was necessary because all of these Bids were competing to provide the identified energy and capacity need. This approach also permitted EPC and BOT Bidders to have access to site-specific data that was not provided to persons bidding to provide the needed resource via a PPA. This process was explained during the Stakeholders workshop and the Bidders workshop on January 18, 2012, and no participant raised concerns at that time. The separate EPC RFP portion of the RFP website was released on January 18, 2012, and made available to qualified bidders.

A. EPC and BOT bidding Process

On May 11, 2012, the IE filed a report with the Commission detailing the review conducted by the IE of the design/build specifications prepared by PGE and the site-specific review completed by the IE. In that report the IE confirmed that the documentation was adequate to permit a qualified firm to generate a complete Bid to construct on either of the PGE sites. Further, the IE confirmed that the specifications were provided in detail and that the allocation of responsibilities between what would be Bid and constructed by a Bidder, and what would be provided by PGE was appropriate and presented in clear fashion. Two electric power generating plant sites were identified by PGE as potential locations of new generation. One of the sites, Port Westward II, is at an existing PGE facility; the other, Carty, is adjacent to the PGE facility at Boardman.

PGE established a process for qualifying Bidders to participate in the EPC/BOT process. The process required Bidders to pre-qualify by establishing creditworthiness, experience with projects of this size and an experienced development team. The IE reviewed the pre-qualification standards and found them to be appropriate. During the pre-qualification phase PGE notified the IE of the Company’s position on each proposed registrant. The IE reviewed each decision made by PGE and found them to be appropriate and the standards to be applied without bias. During the process two prospective Bidders failed to meet the pre-qualification standards; one because they proposed to Bid a non-conforming, renewable technology and the other because the first attempt to pre-qualify was made two days before the Bid date and the firm was unable to provide the necessary NDAs.

The Carty Generation Station location available for development is a distinct 90 acres tract owned by PGE and adjacent to the Boardman facility. The Carty site boundary (the perimeter of the site of the energy facility, its related or supporting facilities, all temporary staging areas, and all corridors) is 2,400 acres. 1,400 acres of which is the transmission right of way. The energy facility is on approximately 90 acres and is discretely identified as part of the RFP documentation.

The Carty station is physically separated from the existing generating station. Accordingly, the design/build specifications provided for a stand-alone construction project that could be built without significant disruption of the ongoing operation of the existing plant. PGE identified the preferred technology for the site, but committed to evaluate other technologies proposed by Bidders.

The Port Westward site is located within the Port Westward Industrial complex in Columbia County, Oregon. PGE currently owns and operates Port Westward Unit 1. Unit 1 is a natural gas fueled, 425 MW, 1 on 1 (one high efficiency CTG and one HRSG). The site is constrained by the limited size of the site. PGE prepared design/build specifications for two technology options, and invited Bidders to Bid to either or both options. The options were clearly identified in the RFP and in the design/build specifications that were provided to qualified Bidders. Bidders were provided with detailed information on the installation requirements for each of the technologies, along with manufacturer information about each technology. Engineers on the IE team reviewed the specifications and found them to appropriately detail the requirements for installation of each technology on the Port Westward site.

The sufficiency of documentation provided by PGE was unchallenged by Bidders. As the following chart depicts, the documentation was voluminous. All Bidders, whether a third party or PGE, were invited to request additional information, either during the site visits or through the RFP Website.

	Total Documents	Total Pages	Total Size (KB)
Port Westward II	153	2,109	678,6899
Carty	84	5,875	301,823,761

The process did not permit Bids for a third party to build on either the Carty or Port Westward sites and retain ownership of the generating asset. Instead the process required engineering, procurement and construction of the project with the title to the turbines and associated equipment transferred to PGE upon satisfactory completion of construction. Title to the site will remain with PGE throughout the process.

Because of the sensitivity of the data, a separate section of the RFP Website was created through which the EPC and BOT Bids were managed. The EPC website was accessible to qualified Bidders only. The design/build specifications developed for the PGE sites and were provided to qualified EPC and BOT Bidders as part of the RFP documents on the RFP Website. This provided the opportunity for Bidders to have the same information as the PGE Self-Build Team, with all bidders – including the PGE Self-Build Team being required to address the same design/build specifications and requirements.

The PGE site-specific data for both the Carty and the Port Westward sites was separated and made available on the RFP Website to Bidders based on the Bidder's decision to have information for one or both of the sites. Qualified Bidders were given access to the PGE site-specific data, such as the design/build specifications, and permitted to attend the site walk at each site without being required to commit to build on a PGE site. Once a Bidder committed to only Bid to build on a PGE site, and not present a bid from a third party site, the Bidder was provided access to the site-specific cost assumptions developed by PGE. Bidders were given access to the design specifications, and were allowed to visit the sites before having to make the decision on whether to also receive the cost data. If the Bidder proceeded to receive the cost data, they were required to acknowledge that they would be excluded from participating in a Bid from other sites. The IE agreed that this was appropriate to avoid the prospect of a bidder "gaming" the process by receiving competitive information, including pricing information, and then submitting a bid for a facility constructed on a site owned by a third party.

IE engineers reviewed the design specifications and the cost data before the information was released to Bidders. As noted, the IE provided a written report to the Commission affirming our belief that the information was sufficiently detailed and that report will not be repeated herein. The IE review established, after some modification, that the data provided sufficient detail for an experienced firm to develop a Bid and, if selected, complete the project.

IE engineers also reviewed the transmission services and found the information supplied sufficient to assure a winning Bidder that service would be provided, through agreements arranged by PGE, to permit a new unit to go into service, and be interconnected to the transmission network. The Bidder was not required to arrange transmission services. Rather, transmission was designated as a responsibility of PGE, regardless of whether the Carty or Port

Westward project went forward as a self-build project, or as an EPC contract with a third party Bidder.

The IE worked with PGE personnel to review and confirm what costs were appropriately classified as owner's costs, and which were to be included in Bids. The IE found the final list of Owner's Costs to be the appropriate allocation between what a third party Bidder could reasonably be expected to develop, and what PGE should be obligated to provide. Natural gas supply, gas lateral permitting, gas lateral costs and transport costs placeholders were identified and disclosed as owner's costs. The electric transmission and substation costs were listed as owner's costs. Other owner's costs include:

- site development costs;
- initial fills and material purchases;
- initial capital spares (operational);
- initial capital spares for long-term service agreement ("LTSA");
- environmental mitigation;
- outside services and testing;
- carbon offset payments;
- regulatory licenses and fees;
- permanent plant equipment and tools;
- Boardman Co-Owners payments for the Carty project;
- pre-COD LTSA costs, owner's contingency; and
- "placeholders" for builders' risk insurance.

The IE is unaware of any disagreement from any Bidder as to the allocation of costs between that which was the responsibility of the Bidder, and that which would be provided by PGE.

The RFP Website provided a separate section dedicated to the EPC data and Bid form. Bidders had access to the design/build specifications by completing a pre-qualification form providing confirmation of experience and financial capability to construct a generation unit and execution of the Non-disclosure Agreement ("NDA") provided by PGE (RFP Appendix S - 7). A Bidder was required to execute a second and different NDA in order to gain access to the site-specific cost data developed by PGE (RFP Appendix S – 8). Those executing the second NDA were also required to commit that they would not participate in a Bid from a site that is owned by an entity other than PGE. As noted before, Bidders were given access to the design/build specification and review of the construction site before having to decide whether to also receive the cost estimates developed by PGE.

To avoid disclosure of site-specific details, EPC Bidders were provided a unique Q&A section on the website, with access limited to those who executed the requisite NDA. This also made it possible for all EPC Bidders to have access to the same information at the same time. Communication through the website was the only avenue provided to Bidders for requesting additional information about the process, the sites and the design/build requirements because the process as designed prohibited PGE personnel from accepting emails or other contact from Bidders. The IE is unaware of any Bidder attempting to violate this protocol, or of PGE personnel associated with the RFP process having contact with any Bidder outside of the proscribed process.

The IE worked closely with PGE personnel in the review of information and the format for disclosure. Every suggestion made by the IE was given full consideration and in most instances was accepted and incorporated in the documentation that was released. The IE is satisfied that in instances where a suggestion was not adopted wholesale, PGE was right in explaining the format for disclosing the necessary data.

The IE believes the structure for access with tiers for access to increasingly sensitive information was appropriate. The process permitted Bidders to review enough information at each step to determine whether to move forward, without having to commit to a particular course before having full knowledge from which to make an informed decision. Separating the EPC from the RFP bidding process prevented confusion among Bidders and also minimized the risk of unintentional disclosure of proprietary information. The IE is unaware of any instance when the PGE self-build personnel were given information or access that was not also provided to EPC Bidders.

The IE attended each site visit accompanied by at least one IE engineer. The IE was also available to Bidders throughout the process, with contact information available on every page of the RFP Website. There were no complaints from the Bidders as to the quality and scope of the design/build information that was provided. Likewise, the IE did not receive any challenges to the division of costs between what was the responsibility of a Bidder, and what was designated as a cost to be met by PGE.

In summary, the Bid requirements were as follows:

Carty

- The Carty site is approximately 2,400 acres, and physically separated from the existing Boardman plant. The units would then share some common facilities, once the construction is completed. [1] The physical separation of the Carty site provided Bidders with few logistical complications when considering the design/build requirements. If it ever rained at the site it could be referred to as a green field project, but instead it is more of a sagebrush and dust field development site.

- The Energy Facility Siting Council permitted the facility to include:
  - 900 MW natural gas fueled combined-cycle generating plant. [2]
  - two blocks consisting of one each:
    - one or more high efficiency combustion turbine generator(s) ("CTG"),
    - a heat recovery generator(s) ("HRSG"), a steam turbine generator(s) ("STG"),
  - one (1) combined cycle plant (Unit 1), with provisions for an additional combined cycle plant of equal size.
  - nominal rating for the units will be 300 to 500 MW with gas duct firing.
  - Generator transformers would be constructed to step the voltage to 500-kilovolts (kV).
  - Approximately 0.75 miles of transmission and eight (8) transmission towers would be constructed.
  - Two (2) mechanical draft-cooling towers would be constructed using the existing Carty Reservoir to dispose of waste heat.
  - Natural gas fuel would be supplied to the plant from an existing pipeline operated by Gas Transmission Northwest Corporation ("GTN"). A proposed GTN gas lateral approximately 24 mile, 20" diameter pipe will connect the Carty station to GTN's mainline.
  - The identified preferred combustion turbine was "F" class or higher technology. [3]

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[1] Of the entire 2,400 acres, 1,400 acres are designated for the transmission right of way, with 90 acres identified as the site for the energy facility.

[2] While permitted for 900 MW, the RFP sought baseload capacity bids of 300 MW to a maximum of 500 MW.

[3] The RFP clearly stated that the combustion turbine shall be a heavy duty, industrial steam cooled or air cooled unit. The combustion turbine shall be "F" class or higher, high efficiency machine. Gas turbines supplied by both General Electric and Mitsubishi Power Systems would be considered, however, Bidders were permitted to submit Bids proposing a different combustion turbine.

Port Westward II

The Port Westward Unit 2 system operating design for the RFP, in summary, required the following:

- Two configurations were identified as acceptable.
  - 12 Wartsila reciprocating engine generators rated at 18.7 MW, or
  - 2 General Electric ("GE") LMS 100 Combustion Turbines
- Load following and supply system balance capability during the operation of wind turbines.
- Each aero-derivative combustion turbine is to have a net capacity of 100 MW
- The reciprocating electric power generators are required to startup in ten minutes or less and meet a thirty-minute emission compliance guarantee.
- Compatibility and integration into the existing shared system
- The 12 reciprocating generators are to meet the 200 MW (net) system need.

B. Confidentiality and Non-Disclosure Agreement Process

Bidders were required to complete and execute NDAs. The RFP stated that in order to establish a uniform procedure to safeguard all confidential information and accommodate a potential large number of Bidders, the NDA's could not be edited or revised. One Bidder added a clause when submitting its NDA, however, PGE, through the IE advised the Bidder it was unacceptable, and that a corrected NDA could still be submitted by the deadline. No changes to the forms in the approved RFP were accepted by PGE. Three Confidentiality and Non-Disclosure Agreements were available to Bidders for completion on the RFP Website, and additionally included in Appendices P and S of the RFP. The NDAs were designed to provide Bidders with access to ever increasing layers of information, with the initial level being the least proprietary. With this approach, only Bidders who executed the final (Appendix S, Attachment 8 – Owner's Costs) NDA were restricted in being able to participate in Bids from a third party site.

The IE found that PGE provided a clear and consistent procedure that was used by the Company. To ensure proper processing of the NDAs, the IE was the conduit through which the NDA's were processed.

1. All Bidders were required to submit a general NDA, *Appendix P - Bid Information.* This bilateral NDA protects the confidentiality of the Bidder's confidential information submitted to PGE, and PGE's confidential information submitted to the Bidder. Appendix P was required prior to the Bid receipt date.

Upon receipt of the General NDA, *Appendix P*, Accion forwarded it to pre-determined PGE personnel for execution. Accion additionally confirmed that each NDA was forwarded to PGE for execution and returned to the respective Bidder within two weeks.

2. Bidders who wanted access to PGE's site specifications were required to submit *Appendix S, Attachment 7 – Owner's Site Specifications.* This NDA protects confidential information contained in PGE's site specifications. Additionally, only Bidders submitting Bids backed by new resources could obtain access to the site specifications, and only after executing and returning this NDA.

Upon Accion's receipt of *Appendix S, Attachment 7,* Accion forwarded the NDA to PGE and responded to the party submitting the NDA as follows:

> Thank you for your signed submission of the Non-Disclosure Agreement requesting access to Site Specifications for Portland General Electric Company's (PGE) proposed (Carty, Port Westward II) site *(PGE Site Specification NDA Appendix S, Attachment 7).* By submitting this request you acknowledge that you will only submit a new build alternative to meet PGE's (Baseload Energy, Flexible Capacity) need. Accion will forward your request to PGE personnel who will verify your registration information. Upon verification, PGE will notify Accion. We will then provide you with login and password information to access the confidential data. Please note – you must submit two signed hard copies of the NDA to PGE within seven days or access to confidential information will be suspended.
>
> Note: PGE address was provided here.
>
> Also, if you have not already completed General NDA Appendix P- Bid Information, please submit that as well. Thank you.

3. Bidders who intended to solely Bid on PGE's sites were required to execute and return Appendix S, Attachment 8 – Owner's Costs, which protects the confidentiality of PGE's costs. PGE only accepted Bids for EPC's on PGE's sites from Bidders who were pre-qualified by PGE and additionally, signed the NDA.

Upon Accion's receipt of *Appendix S, Attachment 8,* the protocol was the same as for *Appendix S, Attachment 7,* above. Again, the address for submitting the hardcopies was provided. For this NDA, submitters were informed that the General NDA and/or the PGE Site Specification were also required prior to being granted access to the confidential data.

PGE notified Accion once pre-qualification requirements had been met and the submitting party was approved to review confidential information related to the proposed sites. Next, Accion set the user permission on the Website for access to specific information as granted by PGE, the submitting party was notified by the IE and login and password information was provided in order access the confidential data. If a submitted NDA was deficient, the IE notified the Submitter of the missing information so they could re-submit a corrected NDA. This was most often due to missing signatures, or the site for which they were submitting the NDA was not indicated on the form. PGE notified the IE when a Submitting Party did not pre-qualify, and therefore was denied access; the IE notified the individual of PGE's determination.

One Bidder submitted an edited NDA, two Bidders submitted NDA's that were missing information or had the wrong information, and one Bidder did not provide rating information for the parent Company on its Pre-Qualification Form. In all instances, PGE notified the IE and the NDA's were re-submitted with corrections.

The two other circumstances that needed to be addressed were Bidders who submitted NDA's with no previous registration, and Bidders whose registration were approved, but no NDA's were submitted. In both instances, once identified by PGE, the IE reached out to the individuals to let them know that they must re-register and submit NDA's in order to be approved for access to confidential information.

The IE found this approach to be effective in ensuring that only qualified Bidders received the proprietary information. At the same time, the IE did not encounter any situation where PGE declined to authorize access for a Bidder who was qualified to receive the design/build specifications or the owners cost data.

C. Separation of the Evaluation Team

The IE reviewed PGE's plan for separating personnel between the Evaluation Team and the Self-Build Team before the RFP process was commenced in April 2011. When the RFP was expanded to include EPC bids the IE again reviewed the separation of PGE personnel to confirm protocols were in place for the PGE evaluation team to be independent of the benchmark bid team. The introduction of EPC bidding complicated the planning for personnel because the Evaluation Team required engineering expertise to determine that an EPC Bid met the EPC design/build requirements. The IE and PGE agreed to a structure with a PGE engineer assigned to the Evaluation Team until the completion of evaluation for EPC and Build-Own-Transfer Bids. The designated engineer had no responsibility or involvement with the Self-Build team, other than as part of the RFP process and within protocols. [4] The PGE Evaluation Team also retained the services of an independent engineering firm, Zachry Engineering Corporation, ("Zachry"), which had no other concurrent relationship with PGE, to advise the Evaluation Team on design/build requirements. The IE's engineers worked separately with the Evaluation Team and the Self-Build Team to confirm the design/build specifications.

As noted in an earlier report, Accion established protocols for receipt of self-build proposals by the IE, and to hold that information apart from other Bids, until the IE performed analysis of the Self-Build proposals and completed a "lock down" of those Bids. The IE has

[4] For example, the evaluation team engineer attended the site visits that were available to qualified bidders, including members of the Self-Build team.

employed this approach in other jurisdictions with success, and used it with prior RFPs in Oregon as well. The process worked well in this RFP. The self-build proposals were received on the RFP Website and the IE released the self-build information to the PGE Evaluation Team at COB on August 1, 2012, afterward the website automatically closed the Self-Build Bid form. The Self-Build proposals were reviewed by the IE and the PGE Evaluation Team for sufficiency, scored by both parties, and then "locked down" as complete on August 17, 2012. Third party bids were received on the RFP Website by COB August 8, 2012, but were not released to the PGE evaluation team until the IE was satisfied that all required data was collected. The complexity and volume of the bid materials required the PGE evaluation team and the IE to invest considerable effort to confirm the conformity of the Self-Build proposals. Only at that point were the PGE Evaluation Team personnel given access to the third party Bids.

III. Evaluation Process

A. Product Design Impact on Evaluation

One of the roles of the IE in this RFP is to ensure fair and appropriate evaluation of all Bids. Because of the complexity of the products sought in this RFP, the process of ensuring fairness and appropriateness began well before the RFP was ever issued. The first product sought was a flexible capacity resource designed to assist in integrating wind and in meeting other short-term flexibility needs. To meet these flexibility needs, the desired resource had to provide a number of unique features including quick start and ramping capability, gas storage and intraday scheduling rights, low minimum output requirements, and dynamic transfer capability.

While the IE agreed with the product design and associated necessary flexibility, both the IE and PGE recognized that it would be difficult for many projects to meet all of these qualifications. Despite the product constraints, the IE worked with Commission Staff and PGE to ensure the RFP was designed to maximize the number of Bids received. During the initial release of the flexible capacity RFP, several intervenors challenged the particular qualifications arguing that imposing them would give PGE a distinct advantage since PGE already had a plan to meet all of them at their Port Westward site. The following sections address the reasonableness of the qualifications.

Gas Storage and Intraday Scheduling

The intermittency of wind energy, which is included in PGE's portfolio, can result in the need to drastically change production schedules intra-hour, and, in turn, gas scheduling would be modified intra-day. Without significant gas scheduling flexibility, the new resource would not be able to meet this need. In order to have significant gas scheduling flexibility, the new resource must have access to both gas storage and the pipeline capacity to transport that stored gas when needed. The IE and PGE recognized that this flexibility requirement could be met with gas storage directly connected to the site, or with remote gas storage with associated firm transportation service on the pipeline path to the site, or with firm transportation with no-notice service. The OPUC concurred with this assessment and ruled in Order No. 11-371 that:

> We are convinced that a natural gas fueled generating resource can only provide the flexibility needed to integrate intermittent or variable energy resources if it is located near a gas storage facility and has intraday scheduling capacity with a pipeline. We agree with PGE that Bidders must demonstrate that they have a plan to acquire gas storage and intraday scheduling to be eligible to participate in the RFP for flexible capacity.

Dynamic Transfer Capability

The flexibility requirements of the desired product also extended to transmission scheduling rights. In order to meet load following needs of intermittent resources, the new resource may need to change output dramatically over the course of each hour. Without highly flexible transmission rights, this would not be possible. The OPUC concurred with this assessment in Order No. 11-371 stating:

> "We are convinced that a capacity resource can only provide the flexibility needed to integrate intermittent or variable energy resources if it is located in PGE's Balancing Authority or has dynamic transfer capability."

The OPUC also ruled however that PGE should not consider this component in the initial scoring of Bids to allow for additional consideration of how to meet this requirement.

Eligibility of Frame SCCT Technology

During its design of the flexible capacity RFP, PGE performed a review of potentially eligible technologies. As part of that review PGE determined that frame SCCT technology would not meet the flexibility requirements of the RFP. While the IE believed that frame SCCT units should not be entirely excluded as some of these units could possibly meet the ramping requirements of the RFP, their operating costs would likely be higher than more flexible types of resources and other flexibility related deficiencies of frame SCCT units may make them uncompetitive. The OPUC ruled in Order No. 11-371 that:

> PGE has stated that it will not exclude from bidding any technology that has been commercially deployed and has demonstrated that it can meet the dispatchability, ramp rate, or other performance requirements needed

for this project. We accept this rationale and accept PGE's and the IE's assertions that recent models of both modified and unmodified frame unit simple cycle combustion turbines are not likely to meet PGE's needs.

Eligibility of Battery Technology

The IE worked with PGE personnel and the Staff of the Commission to ensure that all technologies that could meet the established needs were afforded an opportunity to participate in the RFP process. To that end, prior to the formal release of the RFP the IE posted an announcement on the RFP Website advising potential Bidders that technologies that were not already recognized as acceptable would be reviewed by the IE. Any potential Bidder wishing to Bid a technology other than those previously identified in the RFP was advised to contact the IE and provide documentation supporting the contention that the technology could meet the stated requirements. PGE committed to work with the IE to review all submissions and, together, to determine whether the technology meets the flexibility requirements and was commercially proven.

Several potential Bidders with battery technology replied affirmatively. After a review of the technology's conformance with the product design, PGE and the IE agreed that it should be eligible to Bid. However, some restrictions were placed on battery Bids since they have energy limitations and they do not have an extensive record of serving this type of particular need. Battery-backed Bids were required to have enough energy storage to be able to provide 6 hours of operation. Also battery-backed Bids were limited to 25 MW of nameplate capacity value.

Separately, it was important to establish that PGE did not have unfair competitive advantages in the solicitation process.

Access to PGE sites

Several participants in the RFP process argued that PGE had an unfair competitive advantage since their sites already had the requisite access to transmission and fuel supply. To ameliorate this advantage, they requested that PGE make their sites available to Bidders. After reviewing the requests, the Commission did not order PGE to make their site available. However, PGE decided to make the site available to Bidders with a number of caveats. The EPC bidding process is discussed elsewhere in this report.

Allocation of Costs to Self-Build Options

When the RFP was initially proposed, concerns were raised over the possibility of self-build options getting unfair treatment in the evaluation. PGE discussed the construction of the South of Alston transmission line in conjunction with a new project at the Port Westward site in rate case testimony discussing a cost of service study. If the transmission line is necessary to achieve full transmission interconnection of a proposed project, the proper portion of those costs should be allocated to the Bid. PGE, however, did not plan to include the costs of the South of Alston line in its evaluation of the self-build option at Port Westward because the project would be fully deliverable without the upgrade. To the extent that the Port Westward or Carty self-build options have components with costs that PGE may seek to recover in other proceedings, the IE believes that the evaluation process accurately identified which costs were included in Bids and which will be addressed by PGE as owner's costs that were not the responsibility of Bidders. Further, the IE believes the Commission fully addressed this concern in Order No. 12-215, at page 3.

The OPUC Order No. 11-371 addressed the challenges to the initial flexible capacity RFP on September 27, 2011. In the order, the Commission clarified product design requirements and decided that the capacity and energy RFPs should be combined.

B. Evaluation Process Design

Pre-Qualification

The IE worked with PGE to setup Bid requirements that did not restrict competition but still provided clear guidelines for Bidders to provide projects that achieved the goals set out in the Company's 2009 IRP. Those requirements were clearly communicated in the RFP to Bidders. The evaluation process was designed to eliminate Bids that did not meet any of the following specifications: minimal credit standards, Bid quantity, Bid term, commercial operation date, viable technology, site control, fuel supply, and transmission service.

In addition to those requirements, the flexible capacity product had several unique constraints that limited the eligibility of peaking products for this RFP as discussed in previous sections. Bids that did not provide adequate ramping, transmission, or fuel scheduling flexibility would be eliminated.

The price scoring procedures used in this RFP were similar to those employed in previous PGE solicitations. The process was designed such that the final ranking would place significant emphasis on financial terms offered by each Bid. Oregon competitive bidding guidelines require that "the price score should be calculated as the ratio of the Bid's projected total cost per megawatt-hour to forward market prices, using real-levelized or annuity methods". For the energy RFP, application of this principle was simple. However, for both the flexible capacity and seasonal Bids, this was more complex. The flexible capacity and seasonal products sought were not primarily energy. The flexible product was designed to provide capacity, energy and ancillary services. In addition, since battery Bids were eligible; the product could actually consume more energy than it generated. The seasonal product was designed primarily to provide capacity. Comparing financial score for these products based solely on the average price of energy would prove to be difficult.

Since the flexible dispatch product needed to be available to serve a specific ancillary service needs profile and an economic energy dispatch, the modeling was performed outside of the conventional AuroraXMP model used for most production cost simulations. AuroraXMP does not have the capability to simultaneously dispatch for both ancillary services and energy production. In order to accurately compare the individual bid's characteristics an Excel spreadsheet was built by PGE and reviewed by the IE. The Excel spreadsheet uses AuroraXMP prices to dispatch and therefore is consistent with the IRP. Each Bid is first dispatched against a fixed profile (also referred to as 'forced' dispatch) consisting of regulation, load following, spinning and non-spinning needs derived from PGE's Wind Integration Study. The dispatch takes into account ramp rate, minimum uptime, minimum downtime, heat rate, variable operations and maintenance costs (VO&M), minimum operating level, maximum operating level, and startup costs. After the forced dispatch profile is met, the resource can be used to serve load when market prices are higher than the dispatch costs of the unit. The IE performed a number of tests and went through several iterations of the model to ensure it adequately quantified costs and benefits of each unique type of resource.

The price score for each capacity resource was based on the sum of all fixed and variable costs levelized over the term of the Bid on a $/MWh basis (or life of the asset) divided by the market value of all energy delivered. This is the ratio of total costs to market value on a $/MWh basis. This approach converts ancillary services met by this resource are into energy based measures. This approach was also used to assess the battery resource. Batteries are net consumers of energy since they have to draw more energy to fill up their storage reservoir than is generated when releasing energy. For these resources, the consumed energy is equivalent to "fuel costs" and used to calculate the ratio of bid costs over the market equivalent.

Energy and seasonal resources were evaluated using the AuroraXMP model. Each Bid was simulated for its term and all variable costs and values were collected. These costs were added in a financial spreadsheet to the fixed costs of the project to calculate the total revenue requirements of each Bid on a levelized $/MWh basis. This cost was compared to the levelized market value of the energy delivered by the resource. Since seasonal Bids were primarily capacity resources with relatively high heat rates and low capacity factors, the cost-to-value ratio was inadequate for Bid ranking. An approach was developed to compare capacity costs to capacity value and consider energy benefits separately.

Price scoring represents 600 out of a total of 1000 points for the overall evaluation. For all three auctions, the Bid with the lowest ratio of cost to value was given the highest price score of 600 points. For all other Bids, the price score is 1% lower for every 1% higher the price-to-value ratio is as compared to the best-priced Bid. A Bid with a ratio that is 10% higher than the best price Bid would receive 540 points (600 * (1 - .1)=540).

Non-Price Scoring

With any electric resource procurement, qualitative characteristics should be taken into account in the selection process. Similar non-price scoring methodology was employed for this RFP as compared to that of previous RFPs. Development viability, physical characteristics, product characteristics and guarantees, and credit were all assigned discrete point allocations. For the flexible capacity product, several unique components were considered such as minimum generation restrictions, ramp rate, and start time.

In addition to the collaboration between the IE/PGE, the bidders and stakeholders also participated and provided feedback through the public process. And, bidders were also provided a detailed scoring table as part of the RFP release. The implications of the non-price scoring are discussed more in the mock Bid section of this report. Accion concurred that the design of the non-price scoring was appropriate.

Benchmark Scoring

Benchmark scoring was performed using the same methodology for third party Bids. The RFP schedule required Benchmark Bids to be received before other Bids were received. The schedule of the RFP also required both the IE and PGE to independently score these Bids and lock down their evaluation before other Bids were opened.

Of particular concern to the IE during the development of the evaluation methodology was the issue of comparing PPA bids to the Benchmark and other EPC bids that may have different risk profiles. A project without firm pricing guarantees for the construction of the facility has different exposure than a project with set capacity pricing for the term of the proposed agreement. The Oregon Competitive Bidding Guidelines require consideration of these risks in the development of the initial and final short list. However, these risks were accounted for in the design of the RFP since it required fixed pricing for most pre-in service costs of these plants. Additional non-price scoring adjustments were not necessary with this normalization of the risk profiles between PPA and Benchmark or EPC bids.

The risk of costs during plant operation is a distinct consideration. However, since most of the cost exposure during the life of the project for PPAs is passed through to the utility, the risk profile for these costs is similar for both PPAs and Benchmark or EPC projects. Therefore, additional non-price scoring differences to accommodate plant operation cost risks were not necessary. PPAs do frequently provide heat rate and other operational guarantees, but similar to other risk categories, the Benchmark resource or EPC bids have contractual agreements with equipment suppliers that normalize this risk. The IE and the PGE evaluation team worked together during the RFP development and during bid evaluation to ensure that any disparities in risk profiles between the types of resources were considered.

Mock Bids

The purpose of the mock Bid process is to validate PGE evaluation models and scoring methodologies, test the sensitivity of scoring components, and lock down the models before any Bids are received. For the mock Bid analysis, Accion provided PGE with mock Bids for the flexible capacity and base load energy RFPs. A significant focus was put on the flexible capacity evaluation since the dispatch model being used was built by PGE specifically for this evaluation. The base load energy evaluations were simulated using the AuroraXMP mode. AuroraXMP is a full commercial hourly dispatch model that Accion is familiar with and has used in prior experience.

The following two tables summarize the Bids provided by Accion to PGE for the mock Bid process. The information was based on typical generation and expected resources that would be bid into the RFPs. The Bids were developed to stress test the models, and the IE varied Bid structure, terms, fixed costs, and variable costs.

Energy Capacity Resource Mock Bids

	Self-Build	Tolling Service: Combined Cycle	Tolling Service: Combined Cycle with Full Pressure	Tolling Service: Combined Cycle Higher Heat Rate	Build/Own/ Transfer: Combined Cycle
Term	20	20	10	20	20
Asset Purchase	Self-Build	N	N	N	Y
Overnight Capital Costs $/kW	1,280	N/A	N/A	N/A	1,408
Contract Capacity in MW	500	400	480	480	480
Nominal Capacity Charge $/kW-mo	N/A	14.00	18.00	15.75	N/A
Heat Rate at Minimum	8245	8245	8245	9225	8245
Heat Rate at Maximum	7100	7100	7100	7700	7100
VOM rate $/MWh	2.6	2.6	2.6	2.6	2.6
Fixed O&M	3.05	3.05	3.05	3.05	3.05

Flexible Capacity Resource Mock Bids

	Self-Build: Reciprocating Engine	Tolling Service: Aero Derivative	Tolling Service: Aero Derivative	Tolling Service: Reciprocating Engine	Build/Own/ Transfer: Aero Derivative
Term	20	20	10	20	20
Asset Purchase	Self-Build	N	N	N	Y
Overnight Capital Costs $/kW	1,064	N/A	N/A	N/A	1,215
Contract Capacity in MW	200	220	220	220	220
Bid Range	150	110	165	165	165
Bid Min	50	110	55	55	55
Nominal Capacity Charge $/kW-mo		10.00	15.00	12.50	
Heat Rate at Minimum	9413	10413	9413	10413	9413
Heat Rate at Maximum	8475	9475	8475	9475	8475
VOM rate $/MWh	3.72	3.72	3.72	3.72	3.72
Fixed O&M	3.05	3.05	3.05	3.05	3.05

All Bids were simulated by PGE in the evaluation models developed by PGE. The energy Bids behaved as expected and reasonable tradeoffs between fixed costs and variable costs were seen. Given the $/MWh ratio that is used, it was seen that Bids with longer terms did benefit because the market costs escalated substantially due to underlying fundamental assumptions.

For the flexible capacity Bids, several iterations and sensitivities were performed to evaluate the tradeoff between flexibility (capacity range) and heat rate. After these iterations, a modification was made to the $/MWh ratio used for the price scoring. Originally, PGE had planned to use a $/MWh ratio that was slightly different than the energy and seasonal capacity metric. The metric would divide variable costs by total generation but fixed costs by the capacity range of the Bid. The rationale behind this method was that because the resource was meeting a flexible capacity need, the range the resource provided should be the divisor for the fixed costs. Instead of dividing the fixed revenue requirements by the flexible range, the IE and PGE determined that tradeoffs in the analysis were better represented if fixed revenue requirements were divided by total dispatch generation. It was seen that offers with slightly more range but higher variable costs were still ranking higher than a Bid with slightly less range and lower variable costs. Because the non-price scoring already rewards resources that provide additional capacity range, this change in the ratio was warranted and was applied to the flexible capacity evaluation. Also by making this change, the ratio is consistently applied to the flexible capacity, base load energy, and seasonal capacity evaluations.

The mock Bid process is documented in a memo by the IE and is posted on the IE website. Once the mock Bid evaluation was complete, the models were locked down before receiving any information on the Benchmark or other Bids. It should be noted that the mock Bid process did not attempt to analyze the portfolio analysis that will be performed on the Bids that make the initial Short List.

Resource Selection

The initial Short List was determined by the combination of price and non-price scores. PGE planned to identify two to three times the requested amount of each product type in order to ensure a robust final Short List. After the selection of the initial Short List, PGE and the IE refined credit scoring and worked with Bidders to refine transmission plans and fuel supply plans to the extent necessary. Also, a portfolio analysis was performed which calculated total system production costs for as many realistic and competitive combinations of Bids as possible. The portfolio analysis quantified the overall financial attributes of different combinations of Bids and was used in development of the final Short List. The final Short List is comprised of Bids with high price and non-price scores as well as favorable impact on total system costs.

IV. EPC Review

A. Carty Transmission Background

The transmission requests submitted by PGE to the Bonneville Power Administration ("BPA") for the Carty Generating Station could support up to a 500 MW plant that will interconnect to BPA at the BPA Slatt Substation. The IE transmission engineer reviewed the two interconnection requests for the proposed connection. Both requests are supported by facilities studies detailing the connection requirements and the associated cost estimates. The facilities studies were reviewed by the IE transmission engineer and found to be consistent with industry standards as to detail and design. The IE transmission engineer found the upgrade cost estimates to minimal and reasonable in light of the minimal upgrades needed because the connection would be made into an existing substation. Detail of the facility studies and cost estimates are provided as Confidential Information in Confidential Appendix A.

The IE received the system Impact Study prepared by BPA for the interconnection of Carty at the Slatt substation. This study included the results of a load flow for WECC 2015 heavy summer and a 2014 light autumn base case. These flow cases showed no post-contingency thermal overloads and voltage stability, transient stability, closing angle and short circuit results were within limits. These studies show that Carty can successfully connect at Slatt substation without a need for Cascade Crossing.

The IE did not have data to determine whether Cascade Crossing will be required in the future. As noted earlier in this report, the Energy Facility Siting Council approved the addition of 900 MW of new capacity at the Carty site, while this RFP sought EPC bids to meet the first 300 MW to 500 MW of the permitted limit. Accordingly, the IE's review sought to determine whether PGE had sufficient plans to provide transmission to meet the needs of the capacity sought in this RFP. The IE did not determine whether future additions of generation at the Carty site would need additional transmission upgrades. The IE review confirmed that EPC Bidders for the Carty site would not be responsible for transmission upgrades, and that PGE had a sufficient plan to provide transmission services to assure Bidders that upon completion of construction transmission would not be a barrier to acceptance by PGE.

B. Port Westward II Transmission Background

The original interconnection request for this proposed project was for a generation facility located in Columbia County, Oregon and connecting to PGE's transmission system with a point of interconnection at PGE's existing Trojan Substation. PGE negotiated and executed an interconnection agreement to supply necessary transmission services. The signed agreement has final transmission costs for this project. Additional details of the interconnection agreement are provided in the Confidential Appendix B.

A system impact study consists of:

- A maximum flow test
- A power flow analysis
- A voltage stability analysis
- A transient stability analysis
- A short circuit analysis

The following outputs are documented in the study results:

- All assumptions
- System impacts including thermal overloads and voltage excursions
- Any impacts on other transmission providers systems
- Any short circuit limits that are exceeded

- List of facility additions and upgrades needed to accommodate the requested transmission service
- An estimate of costs for the needed facility additions and upgrades
- An estimate of the time required to construct the needed facility additions and upgrades

This approach to evaluating transmission service additions is consistent with industry standards and the outputs are those that are expected.

The IE reviewed this system impact study for the transmission service. To test the approach, the data utilized and the outputs, the IE submitted several clarification questions to PGE Transmission and Reliability Services department. The IE is mindful of the fact that the studies conducted by PGE Transmission and Reliability Services are confidential, and provides the following questions to illustrate the scope of the review conducted by the IE transmission engineer. These questions were:

- In the last paragraph on page 4 adjustments to increase loading on transfer paths are discussed. Please further explain the basis for the adjustments and document their magnitude.
- The first paragraph of the Transmission System Maximum Flow Testing on page 7, states that "the new generation added at the specified point of interconnection is offset by decreasing Benchmark Case generation levels across the Northwest region." Please explain the amount of the decrease and how it was applied.
- A footnote at the bottom of page 7 references a WECC document that provides an "Overview of Policies and Procedures for Regional Planning Project review". It would be beneficial if we could review that document.
- Contingencies are discussed on page 9, where it is stated that "thermal line loading increases that are less than 2% over the Benchmark case loadings are not considered significant impact that need to be addressed." Yet in table 1 on page 13 there are several Benchmark results that exceed 102% of the thermal limits. Please clarify.
- Were all of the 340 contingencies listed in Appendix 3, studied as single contingencies?
- Section C, Steady State voltage Stability Analysis, provides for analysis of contingencies. Were multiple contingencies ever studied and if so how were they selected?

All of the questions raised were satisfactorily answered. Thus, we are pleased with both the process of the transmission evaluation for the transmission service request and for the accuracy of the findings.

V. RFP PROCESS

A. Power Purchase Agreement ("PPA") BIDS

Registration

The number of registrants presented in the table below indicates the PGE RFP was well publicized. A total of 319 individuals registered to the Website, with 218, or 68 percent of all individuals, registered as Bidders. There were 36 registered Bidders from Oregon, 24 from Washington, 50 from California and 100 registered Bidders from other states. Additionally there were 7 registered Bidders from Canada and one from Jamaica. Of the 101 registered Non-Bidders, 29 were PGE personnel, 11 were Accion Group individuals, and 7 were Zachry Engineering personnel.

Registration

Website Registration Overview		
Registered Bidders	Registered Non-Bidders	Bidders with Submitted Bids
218	101	12

Questions and Answers

All registered users of the PGE Capacity and Energy Website had the ability to anonymously pose questions via the online Question and Answer ("Q&A") page. Questions and Answers were visible to all public and registered users of the Website immediately after being posted. PGE and the IE automatically received an email notification of the questions posted, without identifying the individual posting the inquiry. PGE responded to Bidders by posting answers to questions on the Website. When a question was posted the individual who posed the question received an automatically generated email from the Website with the answer as did all other registrants.

Screen Capture of the Capacity &Energy PPA/BOT Q&A Page

View All Questions/Answers

			Question		Answer	
Ref #	ID #	Category	Question	Date Asked	Date Answered	Date Modified
247	104	Other	Will notifications to bidders today be to all bidders or only to those selected on the initial short list?	11/20/2012 1:39p	11/21/2012 9:13a	-
246	4	Other	The Calendar shows that on November 20, 2012 PGE selects the Initial Short List. Will bidders be notified if they are on the list?	11/20/2012 12:28p	11/20/2012 12:35p	-
245	61	Other	Would you please publish all of the new calendar dates relevant to this RFP going forward as modified by OPUC Order No. 12-398?	10/26/2012 1:39p	10/29/2012 10:24a	-
244	61	Fueling	How will the IE review all submissions and advise the Commission and PGE as required by Order No. 12-398 on whether sufficient information was provided to permit evaluation of each bid if bidders are only allowed clarification responses that include natural gas as storage and not onsite storage of liquid distillate fuel or other contractual arrangements that may apply?	10/26/2012 1:37p	11/1/2012 3:02p	-
243	61	Fueling	In reference to Order No. 12-398, and a bidders clarification response to scenarios 2 and 3, while the IE has recognized in its answer to Question No. 235 that natural gas storage can be used by a bidder to support its fuel plan for a Flexible Capacity RFP bid, would the IE also clarify that in addition to natural gas storage that storage as used in scenarios 2 and 3 may also include onsite storage of liquid distillate fuel for use in a dual-fuel generating resource?	10/26/2012 1:37p	11/1/2012 3:04p	-
242	61	Fueling	In reference to Questions 104 and 113 answered by PGE and the IE in January and February 2012, if a bidder has relied upon PGEs answers: [1] that [b]ack up fuel on site will receive additional points for firmness of fuel delivery and [2] that [t]he requirement for intra-day scheduling is for the flexible capacity plant to dispatch intra-day, without being restricted by the day-ahead gas procurement decisions and that [a]s long as the on-site stored fuel allows for the autonomous dispatch of the Flexible Capacity resource for its fuel capacity and for any 24 hour period on a no notice basis, the RFP scoring will consider it to have met the intra-day fueling requirement, would the IE also supplement its answer to Question No. 235 that storage includes not only natural gas storage as recognized by the answer to Question 235 but also other contractual arrangements that may provide comparable function?	10/26/2012 1:37p	11/1/2012 3:05p	-

A total of 191 questions were posted on the Q&A page, all questions were answered by PGE or the IE. Most questions were answered within one business day of being posted to the Website. The anonymity of the Q&A page ensured that all Bidders had immediate access to questions and answers that were posted, and that PGE considered questions without regard for the source.

Based upon the IE's prior experience conducting solicitations and using the Website Q&A feature, we found PGE's response time to questions posed was prompt and efficient.

The Website sorted all questions by five categories: Installation, Technology, Transmission, Fueling and Other. Registered individuals asked zero questions relating to Installation, seven questions regarding Technology, 29 questions regarding Transmission, 23 questions relating to Fueling, and 132 questions relating to "Other." The sort feature showed where Bidders had concerns without PGE or the IE having to review them individually and sort by topic.

The questions raised in the RFP provided another opportunity for the IE and PGE to gauge the clarity of the RFP materials, and assist in the development of the Frequently Asked Questions for future RFPs.

The IE believes the public Q&A feature permitted all Bidders to have access to the same information at the same time. PGE personnel referred all inquiries to the Website, and the IE believes PGE personnel did not provide information via email or otherwise to any prospective

Bidder. The IE believes the number of questions reflects the significant interest in the RFP, and that Bidders were fully aware of how to seek additional information via the RFP Website.

Questions and Answers

Website Q&A Overview		
Total Questions Asked	**191**	**(100%)**
Questions answered within 1 business day	143	(74.9 %)
Questions answered within 5 business days	48	(25.1 %)

Alternative Bids

To provide Bidders with greater flexibility, and to encourage greater participation in the Bid submittal process, PGE provided Bidders with the opportunity to submit up to two (2) alternative Bids with their original proposal. This method allowed Bidders to submit their original Bid and two alternatives for only the one Bid fee of $10,000. Acceptable alternative Bids are Bids for the same location, and only differ from the original Bid in any or all of the following: size, technical configuration, term duration, and price. A proposal for a different resource, at a different site, or using a different technology was considered a separate proposal, and therefore subject to a separate Bid fee.

Instructions for submitting alternative Bids were posted on the public Documents page for the review of potential Bidders. The instructions directed Bidders to complete and save all required fields in the Bid form for the alternatives, but to not submit these Bids. Alternative Bids were to be left 'pending' on the Bid Management page. Bidders were also instructed to create a memo in their Bid Book identifying which pending Bids were to be evaluated as alternative Bids.

Bidders who sought further clarification as to whether their proposal would be considered an acceptable alternative Bid used the Q&A page to post questions, and a few called the IE directly.

Bids Received

Bids were due on August 8, 2012. [5] On August 6, 2012, the IE sent a reminder to all Bidders registered on the PGE RFP Website that Bids were due by 4:00 PM (PPT) on August 8, 2012:

> *Bidders are reminded that in order for a Bid to be evaluated, the Bid must be SUBMITTED by 4:00 pm (PPT) on Wednesday, August 8, 2012. Any Bids left as pending at the Bid close time will not be considered for evaluation. You must press the Submit button for each Bid you wish PGE to evaluate.*

In addition, Bidders were sent a blast email on the morning of the Bid date reminding them to submit all Pending Bids if their intent was to submit a Bid to PGE:

> *This is a reminder to all Bidders with pending Bids remaining in their Bid books. As the deadline to submit Bids for the 2012 PGE Capacity and Energy Resources RFP approaches, please note that any Bids left pending will not be considered submitted, and therefore not evaluated. The only exception is for alternative Bids, which remain pending as part of the original Bid submitted. Please be sure to click on the SUBMIT button if that is your intention. You will receive a submittal confirmation email.*

Nineteen (19) Bids and fourteen (14) Alternative Bids were received via the IE Website on August 8, 2012, and were subsequently screened and evaluated.

Bids Received

Bids Received	
Flexible Capacity	
Bids Submitted	8
Alternative Bids	4
Energy	
Bids Submitted	7
Alternative Bids	3
Seasonal Capacity	
Bids Submitted	4
Alternative Bids	5

[5] Benchmark Bids were received via the IE Website on August 1, 2012, with scoring completed prior to PGE's having access to Non-Benchmark Bids received on August 8, 2012.

B. EPC Bids

Registration

A total of sixty-six (66) individuals registered to the Website, with eleven (11) individuals registered as Bidders. There were three (3) registered Bidders from Oregon, one (1) from Washington, two (2) from California, two (2) from Texas and three (3) registered Bidders from other states. Of the fifty-one (51) registered Non-Bidders, twenty-six (26) were PGE personnel, twelve (12) were Accion Group individuals, and five (5) were Zachry Engineering personnel.

Registration

Website Registration Overview		
Registered Bidders	**Registered Non-Bidders**	**Bidders with Submitted Bids**
11	**51**	**5**

Questions and Answers

A total of 46 questions were posted on the Q&A page, all questions were answered by PGE or the IE. Most questions were answered within one business day of being posted to the Website. The anonymity of the Q&A page ensured that all Bidders had immediate access to questions and answers that were posted, and that PGE considered questions without regard for the source.

Based upon the IE's prior experience conducting solicitations and using the Website Q&A feature, we found PGE's response time to questions posed was prompt and efficient.

The Website sorted all questions by four categories: Installation, Technology, Transmission, and Other. Registered individuals asked five questions relating to Installation, six questions regarding Technology, and thirty-five (35) questions relating to "Other." There were no Transmission-related questions. The sort showed where Bidders had concerns without PGE or the IE having to review them individually and sort by topic.

Questions and Answers

Website Q&A Overview		
Total Questions Asked	**46**	**(100%)**
Questions answered within 1 business day	35	(76.1%)
Questions answered within 5 business days	11	(23.9 %)

Additionally, on the EPC Website, Bidders could submit questions regarding confidential Site Specifications and Owners Costs relating to both the Port Westward II and the Carty sites. Access to the confidential Q&A needed pre-approval by PGE upon review of the Bidder's submittal of the appropriate Non-Disclosure. The screen capture below shows the Q&A options available on the EPC Site.

Screen Capture of Q&A Page on EPC Website

- Q&A

- Port Westward II Site Specifications Q&A
- Port Westward II Owners Costs Q&A
- Carty Site Specifications Q&A
- Carty Owners Costs Q&A

Only one question was submitted on the confidential Carty Site Specifications Q&A.

Bids Received

EPC Bid Receipt Summary	
Benchmark Bids Submitted	3
3rd Party Bids Submitted	3
Total Bids Submitted	**6**

C. Gas Supply

Portland General Electric 2012 Capacity and Energy Power Supply Resources RFP

The IE reviewed the gas fuel supply companies and pipeline systems available to serve the needs of the bids in the Portland General Electric 2012 Capacity and Energy Power Supply Resources RFP. The review included interviews with PGE gas procurement representatives, interviews with Northwest Pipeline representatives, GTN representatives and publicly available information for both pipeline companies.

The IE employed the standard established by the Commission in Order No. 12-398 when reviewing gas supply plans of PGE and those identified by Bidders for flexible capacity resources, that one of the following scenarios should be confirmed:

1.) Firm gas transportation of sufficient quantity to fuel the plant for the expected full output 24 hours per day. The firm gas transportation must provide for firm "no notice" service.

2.) Firm gas transportation of sufficient quantity to generate at full output 24 hours per day, with storage capability, along with firm transportation, to accommodate 16 hours of operation at full output. "No-notice" service rights are required with this solution.

3.) Interruptible gas transportation with sufficient storage to ensure dependable operation of the facility. The assessment of sufficient storage will be site specific with respect to transportation alternatives available at each site. For reference, a qualifying bid would have direct interconnection to a storage facility with withdraw capability of 24 hours per day power requirement, for 10 consecutive days before ratcheting.

Order No. 12-398 at 3.

The review was designed to determine availability, accessibility and competitive opportunity for bidders to fairly participate in the PGE 2012 Capacity and Energy Power Resource RFP. The RFP required that bidders demonstrate that they have a plan to acquire gas storage and intraday scheduling to be eligible to participate in the flexible capacity portion of the RFP. Gas supply is required to fuel two electric generating facilities to be constructed for PGE. The Carty Generation Station is located near Boardman, Oregon and the Port Westward site is located within the Port Westward Industrial area in Columbia County, Oregon.

The Carty Generating Station is certificated as a 900 (megawatts) MW natural gas fueled combined-cycle generating plant. This RFP is for 300-500 MW combined cycle generation. The plant will be two combined cycle units consisting of one each; one or more high efficiency combustion turbine generator(s) (CTG), a heat recovery generator(s) (HRSG), a steam turbine generator(s) (STG) and a water cooled condenser. The natural gas fuel would be supplied to the plant from an existing pipeline operated by Gas Transmission Northwest Corporation (GTN). A GTN gas lateral approximately 24 mile, 20” diameter pipe will connect the Carty station to the GTN mainline.

The Port Westward Generating Plant is located in the Port Westward industrial complex in Columbia County, Oregon. PGE currently owns and operates Port Westward Unit 1. Unit 1 is a natural gas fueled, 425 MW, 1 on 1 (one high efficiency CTG and one HRSG). Unit 2 was bid as one of two technology options – two GE LMS100 turbines and 12 reciprocating engines (Wartsila 18 V50SG) natural gas fueled engine/generators. Each engine/generator has a nominal capacity of 18.7 MW. Total planned installed capacity of Unit 2 is 200 MW net. The natural gas supply will be from one of two separate gas pipelines as noted below. The Port Westward II facility is designed with access to natural gas storage at the Emerald Gas Storage facility. A direct lateral will be constructed to ensure reliable availability.

Northwest Pipeline is a natural gas pipeline network which takes gas from western Canada and the Rocky Mountains and brings it into California, either through Gas Transmission Northwest or Kern River. A small amount of gas goes through the San Juan Basin to El Paso

Natural Gas. It is owned by the Williams Companies. Northwest Pipeline gathers from the Rockies and Canada. Its primary market is the Northwestern states. Its biggest market is the greater Seattle area. Northwest Pipeline has tariffs for firm transport, interruptible transport, firm gas storage, interruptible gas storage, liquefaction storage (firm and interruptible) gas service, firm redelivery transport, deferred exchange of storage gas, park and loan service and firm and interruptible lateral transportation. Northwest Pipeline is a potential transport service provider for a number of the Bidders in the capacity and energy RFPs.

Since significant gas scheduling flexibility is required for the capacity RFP product, and the fuel supply plans of several Bidders were not fully developed, the IE undertook significant research to ascertain whether the Bids would be able to procure sufficient services to meet the fuel needs identified in the capacity RFP. An IE engineer conducted a telephone interview with Northwest Pipeline personnel. The telephone interview with a marketing representative revealed that the firm does not offer a no-notice service. Northwest Pipeline personnel are considering if and how to develop and price a no-notice service. The Northwest marketing representative indicated that if there was a serious request for no-notice service it may be considered. The representative did not share if there had been any request for no-notice service. The Northwest Pipeline marketing representative was aware of the PGE RFP. Due to the confidentiality requirements the marketing representative only disclosed they had been contacted by Bidders to the RFP without naming the companies.

The IE engineer determined that Bids planning to source fuel on the Northwest Pipeline could potentially acquire the flexible fuel scheduling required to meet the requirements of the capacity RFP. Although there is no incremental firm capacity currently available on the system, pipeline representatives indicated to the IE that new requests could be accommodated through expansion or release of existing rights.

The other pipeline on which Bidders proposed projects was that of the Gas Transmission Northwest (GTN). GTN begins at British Columbia-Idaho border, extends through northern Idaho, southeastern Washington and central Oregon, and ends at the Oregon-California border. The GTN system interconnects with TransCanada's BC System at Kingsgate, British Columbia; with Williams (Northwest Pipeline Corporation) at Spokane and Palouse, Wash., and at Stanfield, Oregon; and with Pacific Gas & Electric Company and Tuscarora Gas Transmission Company at Malin, Oregon.

There are multiple taps that connect the GTN System to Avista Corporation and Cascade Natural Gas. Western Canada is the primary source, but the GTN System also receives U.S. domestic gas supplies at Stanfield, Oregon. GTN has a tariff for a parking and lending service. With this provision, customers can store gas in the pipeline and borrow gas from inventory later. GTN will offer a capacity release service where customers can market reserved capacity to other shippers. GTN offers Pacific express, which is an Internet tool used to conduct transactions. GTN also offers “Market Centers” where customers can move gas into and out of their own “paper pools” to increase flexibility in the purchase and sale of gas.

The IE engineer also conducted a telephone interview with GTN personnel. During the telephone interview the marketing representative indicated that GTN does not offer a no-notice service, but did not indicate if there had been a request for no-notice service. The GTN marketing representative was aware of the PGE RFP. The GTN marketing representative indicated contact by Bidders to the PGE RFP. The representative did not disclose the names of Bidders due to confidentiality requirements.

The IE determined that the GTN system has the potential to supply fuel in a structure that meets the requirements of the capacity RFP. If a project on the GTN pipeline was to win the RFP, it is expected that the necessary services could be procured to meet the needs of the capacity RFP even though not all of those services are currently in place. The IE engineer determined that GTN has sufficient pipeline capacity and no adverse system constraints that would disadvantage Bidders’ submitting proposals to the PGE RFP.

The IE concludes there are sufficient regional gas fuel supply and pipeline services available to Bidders to Bid the Portland General Electric 2012 Capacity and Energy Power Supply Resource RFP. The IE’s research convinced the IE that Bidders to the RFP have a fair and equal opportunity to acquire the storage and intraday scheduling required in the RFP through direct negotiation with the pipeline suppliers.

VI. Evaluation Review

A. EPC/Asset Purchase Bid Evaluation

Carty Self-Build

Pursuant to the Oregon Competitive Bidding Guidelines, the IE performed an independent evaluation of the Benchmark resources for the base load energy solicitation. The Self-Build Team submitted one Bid at the Carty Site to meet the base load energy need. It should be noted that when Bids for the Carty site were received, a third party Bidder submitted a conforming Bid using a turbine model of a recognized turbine manufacturer.

The PGE self-build proposal Bid included a different model from the same manufacturer. In both instances the Bidder provided documentation identifying how the turbine included in the Bid would meet the requirements of the energy RFP, and both technologies were determined to be conforming and, thus, were evaluated. The IE and PGE personnel agreed that the technologies that were included in Bids met the RFP requirements and the Bids were included for evaluation. Confidential Appendix A identifies the turbine models and manufacturer.

The evaluation of the technical specification was conducted by the engineering firm retained by the PGE Evaluation Team, Zachry Engineering Corporation, with the direction of the PGE Engineering Team. The IE participated in a site visit, meetings with the Zachry Engineering Corporation team and the PGE engineering team, teleconferences and document exchange sufficient to thoroughly review the conformance of the Bid to the Energy and Capacity Technical Specification. Any exceptions to the technical specification were noted as questions on the IE website and reviewed by the Bidder, Zachry and the IE. The exceptions were resolved to conform to the Energy and Capacity Technical Specification.

The price and non-price scoring of the Carty Self-Build Project was performed using the models already developed by PGE that were finalized during the mock Bid process. All base load energy Bids were simulated using the AuroraXMP model to determine the appropriate dispatch costs and market value. These costs were combined with total fixed costs to calculate the real levelized $/MWh cost to market ratio. The IE reviewed the financial model to ensure all assumptions related to the Carty Project were modeled appropriately. During the Evaluation process, PGE and the IE identified a handful of issues pertaining to the financial models. The issues were minor and had a small impact on results but nevertheless were corrected so that the Benchmark resource and the all other Bids could be evaluated correctly. These issues were documented in the evaluation section of the PGE RFP Website. The IE and PGE conducted a non-price scoring of the Carty Project independently. The IE and PGE posted their respective non-price evaluation spreadsheets to the website and results were compared. A small number of discrepancies were identified and reconciled by both parties. The final reconciled versions of each scoring model were uploaded to the website. The remaining base load energy Bids were not provided to PGE until the Benchmark scoring was completed.

Port Westward Self-Build

The IE performed independent evaluations of the Benchmark resources for the flexible capacity solicitation. The Self-Build Team submitted two Bids at the Port Westward Site to meet the flexible capacity need.

From a technical standpoint, the evaluation was conducted in the same manner as the Carty-Self-Build Project. The IE participated in meetings and teleconferences with the PGE engineering team and Zachry personnel to document and review the conformance of the Port Westward Bid. Any exceptions to the technical specification were noted as questions on the IE website and reviewed by the Bidder, Zachry, and the IE. All exceptions were ultimately resolved to conform to the Energy and Capacity Technical Specification.

The price and non-price scoring was performed using the models developed by PGE which were finalized during the mock Bid process. The IE reviewed the financial model to ensure that both projects were modeled appropriately. During the evaluation process, PGE and the IE identified a handful of issues pertaining to the financial models. Most of the issues were minor and had a small impact on results but nevertheless were corrected so that the Benchmark resource and the all other Bids could be evaluated correctly. These issues were documented in the evaluation section of the PGE RFP Website. The IE and PGE conducted a non-price scoring of the Port Westward Projects independently. The IE and PGE posted their respective non-price evaluation spreadsheets to the website and results were compared. A small number of discrepancies were identified and reconciled by both parties. The final reconciled versions of each scoring model were uploaded to the website. The remaining flexible capacity Bids were not provided to PGE until the Benchmark scoring was completed.

Energy EPC/Asset Purchase

The IE reviewed the evaluations of the one EPC Bid at the Carty site and two Asset Purchase Bids at other sites for the energy solicitation. The IE compared Bid documents to the financial model to ensure inputs were being modeled appropriate. The IE also reviewed and iterated with PGE on the non-price scoring to develop a final non-price score.

B. PPA Bid Evaluation

The IE reviewed all PPA Bids for the flexible capacity, base load energy, and seasonal capacity solicitations. PGE and the IE worked together to determine which offers were conforming vs. non-conforming. If a Bid was non-conforming, then the IE and PGE contacted the Bidder with questions to confirm that the Bid did not meet threshold requirements. As part of the evaluation review, the IE reviewed all financial evaluation models for each PPA to ensure all offers were modeled correctly. The IE and PGE worked together to resolve any modeling issues or complexities that an individual PPA offer provided. The IE also reviewed all non-price evaluations and scored a subset of the Bids independently.

Flexible Capacity Bids

PGE received 12 PPA Bids designed to meet the flexible capacity need. Only one site was within the PGE service territory. Since the flexible capacity resource will be required to closely match changing load and resource output profiles, the electrical and geographical separation from PGE load was a significant concern. Since the RFP design anticipated addressing some of the related uncertainties after Bids were received, PGE and Accion worked with Bidders to attempt to resolve outstanding transmission and fuel supply plan questions.

Fuel Supply Plan Concerns

The most significant issue regarding threshold requirements for the flexible capacity Bids was the natural gas supply requirement. The RFP stated that "Fuel transport and/or gas storage agreements used to support gas thermal Bids submitted for Flexible Capacity must allow for intra-day nomination." None of the third party flexible capacity Bids met this requirement in the initial offers. Because no Bids met the requirement outside of the Benchmark Bid, the IE and PGE determined it was appropriate to allow all Bidders to provide additional information regarding a fuel supply plan. The IE was mindful of Commission Order No. 12,398, as noted earlier, when reviewing fuel supply plans. If a Bidder provided a fuel plan that could potentially meet the threshold requirement, then the Bid moved forward to the evaluation.

During this process, one Bidder asked if liquid distillate fuel storage could be part of an acceptable fuel plan. While PGE was reticent to consider a resource backed by oil, Accion requested that the Bidder supply the information anyway if they were not able to meet the fuel requirements using only natural gas. This particular Bidder submitted multiple alternatives - some of which met the fuel requirements using only natural gas and one, which met the requirements using oil as a backup fuel. After reviewing this Bidders information, Accion agreed with PGE that the oil option was a significant divergence from the desired product, had substantial environmental and regulatory risks, and did not offer enough supplemental value to warrant further consideration. This particular Bidder's other fuel options still resulted in a competitive alternative, which proceeded to the initial Short List.

For Bids based on projects outside the PGE service territory, fuel supply alternatives offered were based on no-notice service on natural gas pipelines. Since this type of service is not yet available on those specific pipelines, both the Bidders and the IE contacted the pipeline to understand whether such service would be available in the future. While this request was answered in the affirmative, pricing and details around the implementation of such service remained vague.

Since there were significant unknowns around fuel supply plans and the requirements laid out in the RFP did not allow for distinction by project, Accion undertook a number of sensitivities to understand how potential changes to the fuel supply might affect the ranking. Since the flexible resource is only expected to operate with a 25% capacity factor, the first assumption that was stress tested was the requirement that the Bids without onsite gas storage supply firm gas transportation rights for 100% capacity factor operation of the unit. While it is conceivable that the resource may be needed for 24 hours in a single day, Accion wanted to explore the risk profile and costs of the resource if only a portion of the potential output had associated fixed gas transportation. Reducing the fixed transportation requirement to 50% capacity factor resulted in a 60 plus point improvement for the Bids, which were supplying fixed gas transportation. However, even with this aggressive assumption, these Bids still ranked significantly lower than the highest ranked Bid. Further, several of the Bids supplied a range of fixed transportation costs. Accion ran a sensitivity analysis with fixed fuel transportation costs at the low end of the range, which was almost 50% less than the high end of the range. Even with this assumption and the lower volume requirements, all of the Bids with fuel supply issues were still scored substantially lower than the bids included on the final short list.

Battery Technology Concerns

There was one battery-backed Bid in the capacity RFP. The Bid was sized to comply with the limitations applicable to the technology. In addition to the flexibility, this resource was able to overcome a number of the challenges faced by other Bids such as fuel supply and transmission concerns. When all costs were considered, the Bid was economically highly competitive. However, this Bid also had a number of drawbacks. The energy limitations affected the dependability of the Bid and in the portfolio evaluation credit was only given for capacity based on a limited number of hours of energy storage. Since the conventional resources bidding into the capacity RFP have little or no energy constraints, they received credit for full nameplate capacity. Therefore, the energy constraints make the battery Bid less economic when considered as part of the entire portfolio. Also, there are a number of qualitative risks inherent in the technology that affected its overall valuation. While batteries are obviously a mature technology, implementations of this size and for this application are nascent. Additional detail about the battery-backed Bid is found in the Confidential Appendix C.

Notwithstanding the ultimate disposition of this bid, battery-backed Bids deserve significant additional consideration. PGE has proposed the consideration of a smaller demonstration sized implementation of battery technology to further explore its potential future role in meeting intermittent resource integration.

Energy Bids

PGE received fourteen (14) PPA Bids designed to meet PGE's energy needs. All of the Bids submitted were combined cycle combustion turbines as requested. Some of the Bids consisted of existing projects.

Seasonal Bids

PGE received nine (9) PPA Bids designed to meet PGE's seasonal needs. PGE anticipated seasonal capacity with limited strike opportunity, high dispatch cost and low capacity cost to fit with the desired portfolio identified in the Company's IRP. While the bids provided met the requirements of the RFP, some product characteristics were different from expectations. Relative to the total cost evaluation of the other resource types, the seasonal Bids were not highly competitive. Since the costs of the bids were higher than expected, the final selection of seasonal resources may differ from the seasonal capacity target in the RFP. Seasonal Bids are further discussed in the Short List development section.

PGE received nine (9) PPA Bids designed to meet PGE's seasonal needs. PGE anticipated seasonal capacity with limited strike opportunity, high dispatch cost and low capacity cost to fit with the desired portfolio identified in the Company's IRP.

VII. SHORT LIST DEVELOPMENT

A. Initial Short List Development

The evaluation process went through a series of iterations as the IE and PGE personnel culled the most advantageous Bids from the array of offers. The initial short list included the technology reviewed in the confidential appendices. Confidential Appendix D captures the initial Short List ranking, scoring, price and non-price considerations for each category of products: Flexible Capacity, Energy and Seasonal Capacity.

B. Final Short List Development

Revised Transmission Assessment

All Initial Short Listed offers were provided an additional opportunity to provide detailed transmission assessment to insure that there were no transmission issues that had not been addressed. As part of this assessment, both price and non-price components were impacted.

Revised Credit Scoring

Credit scoring for all Short Listed offers was updated and non-price scoring was updated accordingly.

Final Scoring

After credit and transmission scores were updated, the final scoring table was developed. The point scores in this table assist in the development of the final rankings, but the portfolio analysis and other project specific risks are also used in the final selection. The final scoring is provided in the Confidential Appendix E.

Portfolio Analysis

All Short Listed offers were simulated in a portfolio analysis. PGE and the IE worked together to develop the portfolio scenarios as the Short List was developed. The IE made sure that all potentially economic portfolios were being captured in the analysis. The modeling included portfolios with flexible capacity, base load energy, and seasonal peaking capacity. PGE and IE also examined long energy portfolios that were made up of only flexible capacity and base load energy and did not include Seasonal products. All portfolios were modeled in PGE's production costing tool (AuroraXMP).

The portfolio analysis was instructive in that several of the Bids were more attractive than the initial scoring indicated. Namely, the long energy portfolios that consisted of the larger baseload resources appeared particularly attractive. This was substantially a function of the relatively uneconomic seasonal Bids since the long energy portfolios did not have this capacity included. Since these portfolios offered some financial benefit, both PGE and the IE performed substantial review of ways to mitigate non-price drawbacks of the energy Bids in these portfolios. While the energy Bids in these portfolios consisted of existing projects, transmission deliverability was a significant issue. Additional information was requested of the Bidder to clarify how the Bid could meet the transmission requirements of the RFP. While some creative suggestions were put forward, PGE and the IE agreed that the substantial remaining risks justified the low non-price scoring of the Bid and commensurately the lower ranking of the Bid in the final selection.

Further, the portfolio analysis showed that when considered as part of the entire resource plan, the battery option was not very competitive. While it performed very well in the individual price and non-price scoring, the energy limitations of this resource required substantial backup by other resources and resulted in high costs in the portfolio analysis. As discussed in other sections, however, battery technology deserves continued evaluation in separate procurement activities.

The results of the portfolio analysis along with the updated non-price scoring evaluations led to the following final Short List rankings. Confidential Appendix E provides detail on the final Short List ranking. The total score includes updates to transmission and credit information submitted in response to inquiries from PGE personnel and the IE by the Bidders between initial and final shortlist. The final ranking reflects updated total scores and portfolio analysis results.

VIII. Conclusions

The RFP lasted far longer than expected and went through a series of changes, such as the expansion to include accepting bids to build on generating sites owned by PGE. Throughout the process the IE worked closely with the PGE evaluation team to develop RFP documents that were fully descriptive and comprehensive. The IE worked closely with PGE personnel to devise RFP protocols that were fair to all bidders, and that gave all bidders access to the same information at the same time. Of primary importance to bidders, the IE and PGE personnel invested considerable time and effort to construct an evaluation model and process that was fair and thorough.

The IE is unaware of any instance where PGE personnel favored any bidder over another, including the treatment of proposals from the PGE Self-Build teams that developed proposals for the Carty site and for Port Westward. To the contrary, the IE believes PGE personnel went to great lengths to treat all bidders equally and without bias. The IE found the PGE personnel to be open to suggestions and cooperative with the requests made by the IE. Responses to bidders were provided promptly and professionally.

Expansion of the RFP to include EPC bids to construct on PGE owned sites complicated the RFP process, and resulted in the need to design a separate and parallel process in order to isolate proprietary information. The EPC process also included additional stakeholder meetings, site visits, and the development of design specifications for dissemination to qualifying bidders. All of these tasks were completed in what the IE believes to be an efficient and well-executed manner. The IE believes that once PGE decided to adopt the Commission's suggestion that the RFP be expanded to allow third party Bids on specific PGE sites, the PGE evaluation team acted appropriately when it retained an independent engineering firm to assist in the evaluation of the sufficiency of Bids intended to meet the design/build specifications. The IE believes the extra investment by PGE further affirms the Company's commitment to complete the RFP while maintaining complete separation of the bid evaluation and the Self-Build teams, and to avoid even the appearance of bias or conflict.

The IE is unaware of any instance where PGE personnel attempted to thwart access to information needed by any qualified bidder. To the contrary, the IE believes PGE viewed each request for information via the website and during the site visits as legitimate, and when the inquiries were ambiguous PGE enlisted the assistance of the IE in having an inquiry clarified so that a meaningful response could be provided.

The IE believes the evaluation of bids was conducted using the evaluation criteria and modeling agreed to by the IE, and was consistent with the outcome of the mock bid evaluation conducted before bids were received. The bids independently scored by the IE were easily reconciled with the scoring by PGE. The IE worked closely with PGE personnel in reviewing each bid and participated in the solicitation of additional information, as needed. In response to inquiries raised by certain bidders the IE conducted independent research and evaluation of the gas supply and transmission access available to bidders. When the short list was, finally, established, the IE agreed that the bids included represent the best value from all the bids received during the RFP process.

The IE believes the RFP was conducted fairly, that all bidders were treated in the same manner and the resulting short list of bids is the product of the evaluation process that was developed by PGE with the participation of the IE being fairly employed. The IE believes the short list includes the bids that are the best value considering both price and non-price factors, from among all bids presented in the RFP.

A summary of the types of bids received, and the distribution of EPC and APSA bids between the Benchmark and third party Bidders is provided in Confidential Appendix F.

CERTIFICATE OF SERVICE

I hereby certify that on the 31st day of January, 2013, I served the foregoing Report of the Independent Evaluator for PGE 2012 Capacity Power Supply Resources RFP upon the persons named on the service list below, who have waived such service by mail, by serving a full, true and correct copy thereof at their e-mail address, as follows.

W Gregory M. Adams **(Confidential)** Richardson & O'Leary greg@richardsonandoleary.com	W J. Laurence Cable Cable Huston Benedict et al lcable@cablehuston.com	W Erik Colville **(Confidential)** OPUC erik.colville@state.or.us
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DATED: January 31, 2013

Stephanie Andrus, OSB #925123
Senior Assistant Attorney General
Of Attorneys for Staff of the Public Utility
Commission of Oregon

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 1182

PHASE 2

MOTION FOR OFFICIAL NOTICE OF THE NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION

ATTACHMENT 2

UE 262 / PGE / 400
Niman – Peschka

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 262

Net Variable Power Cost

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Mike Niman
Terri Peschka

February 15, 2013

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric (PGE).

A. My name is Mike Niman. My position at PGE is Manager, Financial Analysis.

My name is Terri Peschka. My position at PGE is General Manager, Power Operations.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide the initial forecast of PGE's 2014 Net Variable Power Costs (NVPC). We discuss several of the updates to parameters from PGE's NVPC forecast for 2013, as well as modeling changes. We compare our initial 2014 forecast with PGE's final 2013 NVPC forecast and explain why the per-unit expected NVPC have decreased by approximately $0.87 per MWh.

Q. What is PGE's initial net variable power cost forecast?

A. Our initial 2014 NVPC forecast is $639.2 million, based on contracts and forward curves as of December 6, 2012. This initial 2014 NVPC forecast represents a reduction of approximately $11.9 million relative to our final 2013 NVPC forecast filed in the 2013 Annual Update Tariff (AUT) proceeding (Docket No. UE 250).

Q. Will PGE make a separate 2014 test year AUT filing?

A. No. The NVPC portion of this general rate case establishes the basis for recovering these costs and will be the 2014 forecast to which we compare the 2014 actual NVPC pursuant to the provisions of Schedule 126, which implements the Power Cost Adjustment Mechanism (PCAM).

Q. Are there Minimum Filing Requirements (MFRs) associated with PGE's NVPC filings?

A. Yes. Commission Order No. 08-505 adopted a list of MFRs for PGE in AUT filings and GRC proceedings. The MFRs define the documents PGE will provide in conjunction with the NVPC portion of PGE's initial (direct case) and update filings of its GRC and/or AUT proceedings. PGE Exhibit 401 contains the list of required documents as approved by Order No. 08-505. The required MFRs are included as part of our electronic work papers, with the remainder of the MFRs to be submitted within fifteen days of this filing (i.e. March 1, 2013). As with PGE's NVPC filings in the 2013 AUT, the MFR documents are designated as either "confidential" or "non-confidential".

Q. What schedule do you propose for NVPC updates in this docket?

A. We propose the following schedule for our power cost update filing:

- April 1 – Update parameters and forced outage rates; power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; wind resource energy forecasts; load forecast; and any errata corrections to our February 15 initial filing;
- July – Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; wind day-ahead forecast error cost; variable energy integration costs; and loads;
- September – Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned hydro maintenance outages; and loads; and

- November – Two update filings: 1) update gas and electric forward curves; final updates to power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; long-term opt-outs; and 2) final update of gas and electric forward curves.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have six sections:

- Section II: MONET Model;
- Section III: MONET Updates and Modeling Changes;
- Section IV: Comparison with 2013 NVPC Forecast;
- Section V: Qualifications.

II. MONET Model

Q. How did PGE forecast its NVPC for 2014?

A. As in prior dockets, we used our power cost forecasting model, called "MONET" (the Multi-area Optimization Network Energy Transaction model).

Q. Please briefly describe MONET.

A. We built this model in the mid-1990s and have since incorporated several refinements. In brief, MONET models the hourly dispatch of our generating units. Using data inputs, such as forecasted load and forward electric and gas curves, the model minimizes power costs by economically dispatching plants and making market purchases and sales. To do this, the model employs the following data inputs:

- Forecasted retail loads, on an hourly basis;
- Physical and financial contract and market fuel (coal, natural gas, and oil) commodity and transportation costs;
- Thermal plants, with forced outage rates and scheduled maintenance outage days, maximum operating capabilities, heat rates, operating constraints, and any variable operating and maintenance costs (although not part of net variable power costs for ratemaking purposes, except as discussed below);
- Hydroelectric plants, with output reflecting current non-power operating constraints (such as fish issues) and peak, annual, seasonal, and hourly maximum usage capabilities;
- Wind power plants, with peak capacities, annual capacity factors, and monthly and hourly shaping factors;
- Transmission (wheeling) costs;
- Physical and financial electric contract purchases and sales; and

• Forward market curves for gas and electric power purchases and sales.

Using these data inputs, MONET simulates the dispatch of PGE resources to meet customer loads based on the principle of economic dispatch. Generally, any plant is dispatched when it is available and its dispatch cost is below the market electric price. Thermal plants can also be operating in one of various stages – maximum availability, ramping up to its maximum availability, starting up, shutting down, or off-line. Given thermal output, expected hydro and wind generation, and contract purchases and sales, MONET fills any resulting gap between total resource output and PGE's retail load with hypothetical market purchases (or sales) priced at the forward market price curve. In Section III below we discuss enhancements to PGE's MONET power cost model.

Q. How does PGE define NVPC?

A. NVPC include wholesale (physical and financial) power purchases and sales ("purchased power" and "sales for resale"), fuel costs, and other costs that generally change as power output changes. PGE records its net variable power costs to Federal Energy Regulatory Commission (FERC) accounts 447, 501, 547, 555, and 565. Based on prior Commission decisions, we include some fixed power costs, such as excise taxes and transportation charges, because they relate to fuel used to produce electricity. For purposes of FERC accounting, these costs are recorded in a balance sheet account as inventory (FERC 151); this inventory is then expensed as the fuel is consumed. We include certain variable chemical costs in this filing, and discuss this in more detail below. We exclude some variable power costs, such as certain variable operation and maintenance costs (O&M), because they are already included elsewhere in PGE's accounting. However, variable O&M is used to determine the economic dispatch of our thermal plants. The "net" in NVPC refers to net of forecasted wholesale sales of electricity, natural gas, fuel and associated financial instruments.

Q. Do the MFRs provide more detailed information regarding the inputs to MONET?

A. Yes. The MFRs provide detailed work papers supporting the inputs used to develop this initial forecast of 2014 NVPC.

III. MONET Updates and Modeling Changes

Q. Does PGE present both parameter updates and modeling changes in this initial filing?

A. Yes. Because this is a GRC proceeding, we include not only the parameter revisions allowed under PGE's AUT (Tariff Schedule 125), but also model changes and updates.

Q. What load forecast do you use in this initial filing?

A. We use the 2014 retail load forecast described in PGE Exhibit 1300. That forecast is approximately 19,106,397 MWh, or 2,181 MWa, an increase of 16 MWa from the 2013 test year forecast presented in PGE's most recent AUT in Docket No. UE 250.

Q. What updates and model changes do you propose in this docket?

A. In this initial filing we include many of the updates typically included in an April 1 AUT filing. Additional items requiring 2012 data, or for which updated data were not available in a timely manner for this filing, will also be updated in our April 1 filing. Among those items is the update to the thermal forced outage rates. We plan to file an update that includes forced outages rates based on 2009–2012 data by April 1, 2013, consistent with information that would be used in an initial AUT filing for 2014. By that date, we will have processed the 2012 data needed to complete the outage rate calculations. For this filing, we use the same forced outage rates based on 2008–2011 data from UE 250 (2013 AUT). We will continue to update several of the items included under Schedule 125 as this docket proceeds.

We include the following updates and modeling changes in our initial MONET runs:

1. Wind energy forecasts move to five-year rolling average;
2. Coal plants now use MONET's dynamic programming dispatch model, consistent with the dispatch model used for gas-fired resources;

3. Dynamic programming dispatch model now models variable O&M using monthly values;
4. MONET's modeling of ancillary services has been updated;
5. The latest Pacific Northwest Coordination Agreement (PNCA) Headwater Benefits study is now included in our hydro data;
6. The following emissions control chemicals in use at PGE's plants are now included in NVPC rather than O&M for ratemaking purposes:
    - Mercury and sulfur dioxide control chemicals at the Boardman plant;
    - Sulfur dioxide control chemicals at the Colstrip Unit 3 and Unit 4 plants;
    - Nitrogen oxide control chemicals at the Port Westward and Coyote Springs plants;
7. The biomass test burn at the Boardman plant is scheduled for the second quarter of 2014; and,
8. The cost estimate of wind day-ahead forecast error based on PGE's wind integration study will be included as an update in the July filing.

Q. What is the net effect on PGE's initial 2014 NVPC forecast of these updates and modeling changes?

A. The net effect of these updates and modeling changes is a $9.8 million increase in PGE's initial 2014 NVPC forecast. The updates related to emissions control chemicals simply move the chemical costs from PGE's O&M budgets into the NVPC forecast, and, therefore, do not represent an increase in the overall amount that PGE would otherwise be seeking to recover in this proceeding. Excluding these chemical costs, the updates and modeling changes described below result in a $4.7 million increase in PGE's initial 2014 NVPC forecast. We discuss the regulatory treatment of these emissions control chemical costs in more detail below.

A. Wind Energy Forecast

1. Biglow Canyon

Q. How was PGE's forecast of Biglow Canyon wind energy developed in recent AUT and GRC proceedings?

A. The Biglow Canyon wind energy forecast previously relied on annual and monthly capacity factors based on a study completed in 2005 for PGE by Garrad Hassan America (GH).

Q. Did PGE have actual experience with the generation from Biglow Canyon at the time the 2005 study was prepared by GH?

A. No. Biglow Canyon Phase I was placed into service in 2007. Biglow Canyon Phase II was placed into service in 2009. Biglow Canyon Phase III was placed into service in 2010. The values provided in the 2005 GH study were based on the best information and techniques available at that time.

Q. Please explain the method used by PGE in this proceeding for forecasting Biglow Canyon energy.

A. The Biglow Canyon energy forecast used in this filing is based on a five-year average using PGE's actual generation history at the facility, coupled with the energy forecast previously used in MONET as established in the UE 215 proceeding (2011 GRC). For this initial filing, full-year actual generation data for each Phase of Biglow Canyon through year-end 2011 are used. The previous MONET energy forecast is then used for the remaining years in order to calculate a five-year average for the entire plant for the 2008–2012 period.

PGE's April 1 update filing in this proceeding will incorporate actual generation data through year-end 2012 into the five-year average.

Q. How will PGE include the most recently available actual Biglow Canyon generation data in the NVPC forecast each year?

A. PGE will update the Biglow Canyon energy forecast to incorporate the most recent year's actual generation data, and include this forecast in the AUT or GRC NVPC forecast, by April 1 each year. The Biglow Canyon energy forecast will be based on a five-year rolling average and will continue to rely on the previous MONET energy forecast where necessary.

Q. Why is this new method based on historical actual generation at Biglow Canyon better than the method used previously?

A. A forecast based on actuals is fair, transparent, reflects changing operational experiences, incorporates the effects of recent environmental conditions, is not tied solely to outdated forecasting techniques, and is consistent with other aspects of PGE's power cost forecast where actuals serve as the basis for the forecasted value (e.g., thermal forced outage rates, generation under certain wind PPAs (Klondike II), and the BPA imbalance premium). The method we propose allows for a smooth transition from the values previously used in MONET to a forecast based on PGE's actual experience.

Q. What effect does the updated Biglow Canyon energy forecast have on PGE's initial 2014 NVPC forecast?

A. The updated Biglow Canyon energy forecast increases PGE's initial 2014 NVPC forecast by approximately $2.7 million.

2. Vansycle Ridge

Q. How was PGE's forecast of the Vansycle Ridge contract wind energy developed in recent AUT and GRC proceedings?

A. The energy forecast for the Vansycle Ridge contract was previously determined based on the average of actual generation over the lifetime of the plant.

Q. How does PGE forecast the wind energy for the Vansycle Ridge contract in this proceeding?

A. In this proceeding, the wind energy forecast for the Vansycle Ridge contract is calculated as an average of the most recently available five years of actual generation. For this initial filing, the five-year average is for the period 2007-2011. In the April filing, the five-year average will be updated to include 2012 data.

Q. Why is PGE using a five-year average for the Vansycle Ridge contract energy forecast?

A. Several factors support PGE's move to a five-year rolling average for the Vansycle Ridge contract energy forecast in this proceeding. The use of a five-year average is consistent with the method proposed for Biglow Canyon. As discussed with respect to Biglow Canyon, the five-year average will reflect the changing operational experiences with the plant, as well as the effects of recent environmental conditions. The use of a five-year average is also consistent with the method that has been used to forecast the energy for the Klondike II wind contract.

Q. What effect does the updated Vansycle Ridge contract energy forecast have on PGE's initial 2014 NVPC forecast?

A. The updated Vansycle Ridge contract energy forecast increases PGE's initial 2014 NVPC forecast by approximately $0.05 million.

B. Coal Plants Switch to Dynamic Programming Dispatch Model

Q. Please provide a brief explanation of the coal plant dispatch model used in recent AUT and GRC NVPC proceedings.

A. Historically, coal plants have been dispatched in MONET by the "non-cycling logic". The non-cycling logic was part of the original MONET design from 1996 and was intended to be a simple and quick approach to modeling unit commitment.

Q. Why does PGE propose to change the coal plant dispatch model in this initial filing?

A. The original non-cycling logic was adequate during periods when the plants were generally "deep in-the-money," and provided for very fast model execution. However, now that the plants dispatch down more frequently in MONET, the model results using the original dispatch logic are becoming less realistic. The dynamic programming dispatch optimization logic currently used in MONET for the combined-cycle combustion turbine plants is much more robust and accurate.

Q. Please explain the enhanced coal plant dispatch model used for this initial filing?

A. For this initial filing, PGE has switched the coal-fired dispatch model from the original non-cycling logic to the existing dynamic programming model. The dynamic programming model achieves dispatch decisions that maximize the plants' value in each period, while accurately incorporating operational constraints. Information regarding the gas-fired plant dispatch model has been provided by PGE in the MFR documents accompanying recent AUT filings, and additional detail will be provided in our work papers and with the MFRs for this filing.

Q. Please briefly describe dynamic programming.

A. Dynamic programming (DP) is a computational approach to multi-stage decision problems. The "stages" in the current problem are the hours for which a decision must be made to dispatch or not dispatch the plant. The DP logic provides the ability to look ahead over the year and optimize the dispatch across all stages by maximizing a "payout" function, subject to plant constraints. This logic is very robust and, for the given inputs, produces an optimal, least-cost dispatch. In-depth discussions of dynamic programming and this specific dispatch model are provided in our work papers and in the MFRs.

Q. How does the DP approach maximize plant value?

A. The objective function of the DP algorithm is to maximize the payoff function for the year. The payoff is calculated as wholesale market revenues, less variable fuel and variable O&M costs. To realistically represent the dispatch decision-making process, the algorithm must consider interdependencies across hours of plant operation; the decision to operate cannot be made on an hour-by-hour basis. The payoff must be maximized over the entire dispatch cycle. To do this, the algorithm must be capable of "looking ahead." The DP model is a "perfect foresight" model; the model takes hourly electricity prices, fuel prices, and variable O&M costs as given and known in advance for the entire year. The algorithm results in the optimal decision; there is no other collection of dispatch sequences that will result in a higher overall payoff for the year.

Q. How does this more accurately reflect plant operational constraints?

A. The DP dispatch algorithm more closely mirrors actual plant operations than the previous dispatch model. The new method takes account of ramp-up and ramp-down constraints, minimum commitment times, start-up costs, and varying heat rates.

Q. Does this enhanced dispatch model affect PGE's initial 2014 NVPC forecast?

A. Yes. Implementing the enhanced coal plant dispatch model reduces PGE's initial 2014 NVPC forecast by $1.0 million.

C. Monthly Variable O&M for Dynamic Programming

Q. What is this enhancement?

A. This enhancement improves the DP logic by allowing for the use of monthly variable O&M values by plant, rather than a one-time study input.

Q. Why did PGE implement this enhancement?

A. Previously, the DP logic used plant variable O&M values that varied with operating state, but were static both across a given year and from one year to the next. Most other input parameters in MONET (such as plant heat rates and capacities) are specified on a monthly basis. The ability to vary plants' variable O&M values by month, rather than use a single study value, results in a more accurate representation of plant operations for the dispatch model, is consistent within MONET, and makes the modeling more flexible.

Q. Does this change affect PGE's initial 2014 NVPC forecast?

A. No. The monthly variable O&M values in the dispatch model for this initial filing are the same as the one-time study values used in the 2013 AUT, so this enhancement has no effect on PGE's initial 2014 NVPC forecast. In our April filing, however, we will update these monthly variable O&M values.

D. Ancillary Services Modeling (Dynamic Capacity)

Q. Please explain the method previously used in MONET to model ancillary services.

A. The provision for ancillary services (load following, regulation, spinning reserves, and non-spinning reserves) was previously addressed in MONET by certain hydro resources. In general, non-spinning reserves were implicitly covered by PGE's Eastside hydro resources, Pelton and Round Butte. Load following, regulation, and spinning reserves were modeled using PGE's Mid-Columbia (Mid-C) resources. Available generation on the Mid-C resources was first allocated to provide the needed ancillary services and the remaining generation was then allocated across the hours in a given month in order to maximize its value. This treatment was first implemented in MONET for the 2005 test year with the introduction of the Mid-C hourly dispatch logic.

Q. Why is a change to the modeling of ancillary services in MONET necessary?

A. A number of operational changes have occurred since the implementation of the Mid-C hourly dispatch logic, most notably, PGE's shares of several Mid-C resources decreased significantly and new generating resources were added to PGE's portfolio. Other issues arising from the old logic were also identified, including the absence of explicit modeling of non-spinning reserves, the inability to track ancillary service needs that remained unmet after the Mid-C dispatch, the inability to model self-integration of wind resources, and the lack of a means by which to model changing WECC operating reserve requirements. Our updated method models ancillary service obligations and capabilities of generating plants, contract resources, wind generation, dispatchable standby generation, and loads.

Q. Please explain the updated method for modeling dynamic capacity in MONET.

A. This enhancement replaces the existing Mid-C hourly dispatch logic with a new methodology. This new Mid-C dispatch includes updated operating constraints for the Mid-C projects, accounts for the implicit ancillary service abilities of PGE's Pelton and Round Butte hydro facilities and contracts, and improves the logic used to allocate ancillary services while optimizing Mid-C generation. This enhancement also includes new functionality that re-dispatches (after the economic dispatch occurs) eligible thermal plants in order to cover ancillary service needs that are unmet by the Mid-C resources for a given hour. Ancillary service needs that remain unmet at this point are assumed to be satisfied by spilling water, which allows for the provision of additional dynamic capacity by reducing hydro generation. In order to provide operating reserves, a plant needs to have the operational ability to operate in the requested manner. It is not simply a matter of adding a plant to the model, but requires ensuring that the necessary system controls, and communications and operational capabilities exist.

Q. What is PGE's goal in implementing this enhancement?

A. The goal is to improve MONET's modeling of hourly hydro generation and ancillary services, including the role of thermal plants and contracts with regard to ancillary services. Additionally, this enhancement provides greater flexibility to address future developments, such as updated reserve requirements and the integration of wind generation. In general, the goal is to more effectively model the role of dynamic capacity on PGE's system.

Q. How does this enhancement more accurately model PGE's resources and ancillary services requirements?

A. This enhancement models PGE's resources and ancillary services needs more accurately and effectively in a number of ways. First, the enhancement results in more accurate dispatch of PGE's Mid-C resources, which reduces PGE's initial 2014 NVPC forecast. Second, ancillary services needs that cannot be provided by PGE's hydro resources will now be allocated to PGE's thermal resources. This reallocation increases the NVPC forecast, but provides a more accurate representation of the uses of PGE's thermal plants. Overall, this modeling enhancement results in a more comprehensive and accurate representation of the uses of our resources for dynamic capacity purposes, which more accurately represents the operational dispatch of our generating plants and the resulting NVPC.

Q. What effect does this enhancement have on PGE's initial 2014 NVPC forecast?

A. The dynamic capacity enhancement reduces PGE's initial 2014 NVPC forecast by approximately $1.9 million.

Q. Will PGE integrate this enhancement into MONET for the April 1 update filing?

A. Yes. For this initial filing, the functionality of the dynamic capacity enhancement exists external from MONET. While modestly increasing the processing time, presenting this enhancement outside of MONET for this initial filing allows the analyst to isolate the effects of dynamic capacity on PGE's system and on the initial 2014 NVPC forecast. In the April 1 filing, this enhancement will be fully-integrated into MONET.

E. Pacific Northwest Coordination Agreement Study Update

Q. Please describe the update to include the new Pacific Northwest Coordination Agreement (PNCA) study.

A. Under the PNCA, the Northwest Power Pool conducts a 70-year regulation study called the Headwater Benefits Study (Study), based on a regulation model whose objective function is to maximize the firm energy load-carrying capability of the Northwest system as a whole. This model considers the loads and thermal resources of regional entities, as well as hydro resources. The model produces a simulated regulation of 70 water years under historical stream flows, which we then use, with a set of adjustments, to develop the average hydro energy inputs to MONET. For this filing, we updated from the 2008–2009 Study to the 2011–2012 Study to establish base average expected outputs for our hydro resources. We then adjusted these base figures using essentially the same adjustment steps used to develop hydro inputs to MONET in prior filings (such as removing PGE hydro maintenance, changing to continuous mode, and adjusting for end-of-study reservoir content).

Q. What effect does the PNCA-related change have on PGE's initial 2014 NVPC forecast?

A. Updating the PNCA study results in NVPC reduction of approximately $0.4 million.

F. Emissions Control Chemicals

Q. Why is it appropriate for PGE to include the costs associated with emissions control chemicals in its NVPC forecast?

A. It is appropriate for these costs to be reviewed in the context of PGE's NVPC because they are directly related to the operation of the respective plants. The forecast of plant operations that is relied upon by PGE to determine its 2014 NVPC forecast will be reviewed by parties to this proceeding. As such, it makes sense for the emissions control chemicals that are directly dependent upon these factors to be reviewed at the same time.

Q. Should these costs be treated in a manner similar to variable O&M?

A. No. O&M is established in a GRC and recovered in base rates. The variable portion of the plants' O&M is included in MONET for dispatch purposes. There is, however, a direct relationship between the plant generation forecast and the expected costs associated with these emissions control chemicals. The best method for forecasting the total chemical cost must rely on the cost driver forecasts, which are included in PGE's NVPC forecast as developed in MONET.

Q. How do these costs differ from variable O&M?

A. These emissions control chemical costs differ because there is no ambiguity as to their causation; there is a direct correlation between the costs incurred to achieve a particular emission target and the quantity and type of fuel used. Given that the quantities and types of fuel expected to be used during 2014 are modeled directly in MONET, the resulting total chemical costs are the best estimates.

Q. What chemicals does PGE move from O&M to NVPC for this initial filing?

A. We move the following chemicals from O&M to NVPC for this initial filing:

1. Activated carbon and calcium bromide for Mercury control at the Boardman plant;
2. Trona for sulfur dioxide control at the Boardman plant;
3. High-calcium lime for sulfur dioxide control at the Colstrip Unit 3 and Unit 4 plants;
4. Ammonia for nitrogen oxide control at the Coyote Springs plant; and
5. Ammonia for nitrogen oxide control at the Port Westward plant.

Q. Are the costs of any of these chemicals included in any other portion of PGE's filing in this docket?

A. No. The costs of these chemicals have been removed from the O&M values presented in PGE Exhibit 300 and are included only in PGE's 2014 NVPC forecast. While their inclusion in NVPC does increase PGE's 2014 NVPC forecast, it does not represent a net increase to PGE's request in this case.

1. Boardman – Mercury control chemicals

Q. Please explain the chemicals included for mercury emission control at Boardman.

A. Activated carbon and calcium bromide are used at Boardman to reduce mercury emissions from the plant. PGE began using the chemicals in 2011 in order to assure that the plant could comply with the Oregon Utility Mercury Rule.

Q. Please discuss the regulatory treatment of these mercury control chemical costs.

A. Costs incurred by PGE in 2011 and 2012 (treatment of 2013 expenses is expected to be consistent) related to these mercury control chemicals are subject to deferred accounting pursuant to the Orders in Docket Nos. UE 215 (PGE's 2011 test year GRC, Order No. 10-478) and UM 1513 (PGE's application for deferred accounting related to four capital projects, Order Nos. 11-153 and 12-050).

Q. What effect do these chemicals have on PGE's initial 2014 NVPC forecast?

A. The inclusion of the costs associated with these mercury control chemicals in NVPC increases PGE's initial 2014 NVPC forecast by approximately $1.2 million.

2. Boardman – Sulfur dioxide control chemicals

Q. Please explain the chemicals included for sulfur dioxide emission control at Boardman.

A. Trona will be used at Boardman as part of a dry sorbent injection (DSI) system to reduce sulfur dioxide emissions from the plant. Beginning July 1, 2014, the Regional Haze Rules established by the Oregon Department of Environmental Quality ("DEQ") mandate a maximum level of sulfur dioxide emissions that must be achieved at Boardman. The DSI system is being installed to help achieve compliance with those DEQ requirements, and is currently scheduled to be operational in the second-half of 2013 to allow for testing and system optimization prior to the required compliance date. PGE plans for this testing and optimization to occur during 2013 and the first-half of 2014.

Q. What effect do these chemicals have on PGE's initial 2014 NVPC forecast?

A. The inclusion of the costs associated with these sulfur dioxide control chemicals in NVPC increases PGE's initial 2014 NVPC forecast by approximately $1.9 million.

3. Colstrip – Sulfur dioxide control chemicals

Q. Please explain the chemicals included for sulfur dioxide emission control at Colstrip.

A. High-calcium lime is used at Colstrip Unit 3 and Unit 4 to reduce sulfur dioxide emissions to levels that comply with state and federal requirements.

Q. What effect do these chemicals have on PGE's initial 2014 NVPC forecast?

A. The inclusion of the costs associated with these sulfur dioxide control chemicals increases PGE's initial 2014 NVPC forecast by approximately $1.5 million.

4. Coyote Springs – Nitrogen Oxide Control Chemicals

Q. Please explain the chemicals included for nitrogen oxide emission control at Coyote Springs.

A. Coyote Springs uses anhydrous ammonia injected into the Heat Recovery Steam Generator to reduce nitrogen oxide emissions to levels that are compliant with State and Federal requirements.

Q. What effect do these chemicals have on PGE's initial 2014 NVPC forecast?

A. The inclusion of the costs associated with these nitrogen oxide control chemicals increases PGE's initial 2014 NVPC forecast by approximately $0.1 million.

5. Port Westward – Nitrogen oxide control chemicals

Q. Please explain the chemicals included for nitrogen oxide emission control at Port Westward.

A. Port Westward uses aqueous ammonia injected into the Heat Recovery Steam Generator to reduce nitrogen oxide emissions to levels that are compliant with State and Federal requirements.

Q. What effect do these chemicals have on PGE's initial 2014 NVPC forecast?

A. The inclusion of the costs associated with these nitrogen oxide control chemicals increases PGE's initial 2014 NVPC forecast by approximately $0.5 million.

G. Boardman Biomass Test Burn

Q. Please provide an overall description of the Boardman Biomass Project.

A. On April 9, 2010, PGE filed an Addendum to its 2009 IRP that included a revised operating plan for the Boardman power plant. OPUC Order No. 10-457 acknowledged PGE's 2009 IRP Addendum, which included the acknowledgement of PGE's BART III option. Per PGE's BART III option, coal-fired operations at Boardman will cease at the end of 2020. PGE is currently researching the possible substitution of torrefied biomass for coal as the fuel source for the Boardman plant. Since 2011, PGE has been growing and harvesting Arundo donax; a high-yield biomass crop being considered as a potential source of locally-accessible biomass to fuel the Boardman facility. In January 2013, PGE contracted with a vendor to develop design, fabricate, install, commission, and lease a torrefier at the Boardman plant to torrefy PGE's harvested green biomass as well as additional green biomass potentially procured from around the Boardman area. In 2014, PGE expects to perform a test burn using torrefied biomass as fuel. This test will provide data on plant operations, emissions, ash characteristics, and information regarding the effect on existing plant components of the biomass fuel. Boardman powered by biomass after the cessation of coal-fired operations could provide up to 300 MWa of renewable baseload energy (100% power for six months of the year) as well as help PGE meet the renewable portfolio standard of 25% of load by 2025.

Q. What is torrefaction?

A. Torrefaction is a form of pyrolysis where a biomass material is "roasted" in the temperature range of 200 to 350 degrees Celsius in a low oxygen atmosphere. The roasting yields a charred material that will not absorb water and can be stockpiled outdoors in large quantities for long periods of time.

Q. Who is supplying the additional green biomass for the test burn?

A. PGE will purchase additional biomass from around the Boardman area to supplement the Arundo. This additional biomass could include corn stover, wheat straw, and other varieties currently available near Boardman. PGE is also exploring purchasing torrefied briquettes from Canada to supplement the test burn.

Q. What are PGE's expected costs associated with the Boardman Biomass test burn?

A. PGE expects for the biomass used to fuel the test burn to cost approximately $6.0 million, consisting of the following components:

- $1.0 million for the procurement, farming, and harvesting of Arundo donax;
- $2.0 million for the procurement of other biomass sources;
- $2.4 million for acquiring, developing and running a torrefaction unit; and
- $0.60 million for other expected costs.

Q. How does PGE propose to incorporate the Boardman biomass test burn costs into the 2014 test year?

A. The costs associated with the Boardman biomass test burn are included in PGE's net variable power cost forecast for the 2014 test year. This treatment is consistent with Staff's Report in UM 1571 provided in OPUC Order No. 12-141. While opposing PGE's request for the specific accounting order sought in that proceeding, the Staff Report documents the agreement between Staff, PGE, and other parties that torrefied biomass would be, "treated as fuel and run through the Company's AUT" (Order No. 12-141, Appendix A, page 2). The torrefied biomass is a fuel source being burned at Boardman, and will be accounted for as fuel when burned. This fuel expense is directly aligned with the mechanics of the AUT and the PCAM.

Q. What effect does the biomass test burn have on PGE's initial 2014 NVPC forecast?

A. The Boardman biomass test burn increases PGE's initial 2014 NVPC forecast by approximately $5.2 million.

H. Wind Day-Ahead Forecast Error Cost

Q. Please briefly explain the cost of day-ahead forecast error, with respect to wind integration.

A. The cost of day-ahead forecast error is the cost incurred to re-optimize PGE's portfolio in order to account for the difference between the day-ahead and the hour-ahead forecast for wind generation. These costs materialize in the form of market transactions (purchases and sales) and the re-dispatch of available generation resources.

Q. Has an estimate of the cost of day-ahead forecast error been included in PGE's recent power cost proceedings?

A. Yes. An estimate related to the cost of wind integration has been included in the NVPC forecast by PGE since the 2008 test year in Docket No. UE 188. PGE has included the same estimate of this specific cost when developing the final NVPC forecast in each year since the 2009 test year in Docket No. UE 198. In the 2013 AUT (Docket No. UE 250), PGE proposed to update this estimate based on its Wind Integration Study.

Q. What estimate of the cost of day-ahead forecast error does PGE include in this initial 2014 NVPC forecast?

A. In this initial filing, PGE uses the same day-ahead forecast error cost that was used in PGE's final power cost update filing for 2013 in Docket No. UE 250.

Q. Does PGE plan to update this cost estimate for 2014?

A. Yes. The 2013 value will be used for the initial filings in this docket; however, PGE plans to provide an update in the July filing pursuant to the schedule proposed above. It is unlikely for an update to be available prior to that time given the need for consistency with the plant parameters modeled in MONET, which will be presented in our April 1 update filing, and the time- and labor-intensive nature of running PGE's wind integration model.

I. Forthcoming Updates

Q. Are there other items that PGE expects will require updates?

A. PGE currently expects to update several specific items during this proceeding in addition to the general updates listed in Section I above. These items include:

1. The ongoing Bonneville Power Administration (BPA) rate proceeding;
2. PGE's analysis regarding self-integration of variable energy resources;
3. A potential new WECC operating reserve standard; and
4. Potential fuel transport and capacity resource contract updates.

Q. Please discuss the ongoing BPA rate proceeding.

A. BPA is currently holding a rate proceeding to establish power and transmission rates effective October 1, 2013 (2014 fiscal year). The schedule in that proceeding indicates that a Draft Record of Decision will be filed June 13, 2013, and the Final Record of Decision will be filed on July 22, 2013. Our initial filing in this docket includes a portion of the rate increase proposed by BPA for the relevant service.

Q. What is the status of PGE's decision to self-integrate variable energy resources?

A. PGE is currently analyzing the most cost-effective approach to integrate our variable energy resources and will determine whether or not to enter into a contract with BPA for integration services by April 1, 2013, for the period of October 2013 through September 2015. If PGE determines that it will self-integrate the resources, rather than enter into an agreement with BPA, the integration requirements will be updated in the July filing.

Q. Please describe this potential new WECC operating reserve standard.

A. WECC Standard BAL-002-WECC-2 (WECC Bal-002) changes the calculation of operating reserves from 5% of hydro and wind generation, and 7% of thermal generation; to 3% of all generation, plus 3% of control area load.

Q. What is the status of approval of this new standard?

A. WECC-Bal-002 was initially approved by NERC in 2008. The standard was remanded in 2010 by FERC and has undergone revisions since that time. The NERC Board of Trustees adopted the revised standard in November 2012. It is currently awaiting final approval by FERC.

Q. What effect does this new standard have on PGE's initial 2014 NVPC forecast?

A. We have not estimated the effect for this initial filing. PGE will continue to monitor developments related to the approval of this new standard and will provide updates as necessary. The reserve requirements of this standard will be incorporated into MONET by updating certain parameters in the dynamic capacity enhancement described above.

Q. Please discuss the pending fuel transport contract updates.

A. PGE is currently pursuing the execution of new contracts for certain fuel transport services. An estimate of the rates currently expected for 2014 are included in our initial filing, which results in an increase to PGE's initial 2014 NVPC forecast. We expect that new agreements will be reached in time for our final scheduled contract update in November, as described above.

Q. What is the potential capacity resource contract update?

A. PGE's ongoing capacity request for proposals (RFP) seeks bi-seasonal (winter and summer) capacity of 200 MW and 150 MW of winter-only capacity (the capacity RFP is combined with PGE's energy RFP in OPUC Docket No. UM 1535). It is possible that a capacity resource selected from this RFP could be in the form of a power purchase agreement with an effective date in 2014. PGE will continue to evaluate other products available in the market to help fulfill our expected need for capacity resources. In the case that a contract is executed, we will include the contract in an update filing in as timely a manner as possible in order to enable review by parties to this proceeding.

J. Changes to Schedule 125 and Schedule 126

Q. Does PGE propose adjustments to Schedule 125 to reflect the updates discussed above?

A. Yes. PGE's proposed revisions to Schedule 125 reflect the updates to our wind energy forecast methodology and emission control chemical costs we discussed above. We also propose that wind integration costs, such as day-ahead forecast error cost, be updated to reflect the expected test year operating environment.

Q. Does PGE make any other changes to Schedule 125?

A. Yes. We make one additional change to Schedule 125, which clarifies a revision authorized in UE 215 (Commission Order No. 10-410, page 4). In that Order, the Commission adopted the Stipulation in which, "(t)he Stipulating Parties also agreed that the estimated costs of transmission losses will be allowed to change dynamically with the dispatch modeling for the Colstrip and Port Westward plants." Our change to Schedule 125 more accurately reflects that Order.

Q. Does PGE make any other changes to Schedule 126?

A. Yes. Our proposed changes to Schedule 126 update the definition of NVPC for inclusion of costs related to emissions control chemicals, consistent with our proposed changes to Schedule 125.

IV. Comparison with 2013 NVPC Forecast

Q. Please restate PGE's initial 2014 NVPC forecast.

A. The initial forecast is $639.2 million.

Q. How does this 2014 NVPC forecast compare with the 2013 forecast utilized to develop power costs in UE 250 and approved in Commission Order No. 12-397?

A. Based on PGE's final updated MONET run for the 2013 test year, the NVPC forecast was $651.1 million, or $34.32 per MWh. The initial 2014 forecast is $639.2 million, or $33.45 per MWh, which is approximately $0.87 per MWh less than the final forecast for 2013.

Q. What are the primary factors that explain the decrease in NVPC forecast for 2014 versus the NVPC forecast for 2013 in UE 250?

A. As Table 3 demonstrates, multiple factors contribute to the decrease:

Table 3
Factors in Forecast Power Cost Difference 2014 vs. 2013
($ Million)

Element	$ Effect*
Hydro Cost and Performance	1.8
Coal Cost and Performance	29.5
Gas Cost and Performance	-38.1
Wind Cost and Performance	1.9
Contract and Market Purchases	-16.4
Market Purchases for Load Change	4.0
Transmission	8.0
Lower Market Price	-2.7
Total	**-$11.9**

* Numbers may not total due to rounding.

Key among these factors is the significant reduction in power costs related to gas-fired generation. Favorable movements in the market prices for natural gas and power lead to increased dispatch of PGE's gas-fired resources, and a reduction to the NVPC forecast. This reduction relative to PGE's final 2013 NVPC forecast includes mark-to-market on gas financial contracts. Various elements of Boardman operations (including the biomass test burn, the cost of emissions control chemicals, and the expected cost increases associated with certain contracts) increase the cost, and reduce the amount, of generation in this initial filing.

V. Qualifications

Q. Mr. Niman, please describe your qualifications.

A. I received a Bachelor of Science degree in Mechanical Engineering from Carnegie-Mellon University and a Master of Science degree in Mechanical Engineering from the California Institute of Technology. I am a registered Professional Mechanical Engineer in the state of Oregon.

I have been employed at PGE since 1979 in a variety of positions including: Power Operations Engineer, Mechanical Engineer, Power Analyst, Senior Resource Planner, and Project Manager before entering into my current position as Manager, Financial Analysis in 1999. I am responsible for the economic evaluation and analysis of power supply including power cost forecasting, new resource development, least-cost planning, and avoided cost estimates. The Financial Analysis group supports the Power Operations, Business Decision Support, and Rates & Regulatory Affairs groups within PGE.

Q. Ms. Peschka, please state your educational background and experience.

A. I received a Bachelor of Arts degree in Finance from Portland State University. I have been employed at PGE since 1999 in the following positions: Risk Management Analyst, Manager of Risk Management Reporting & Controls, and my current position General Manager of Power Operations. Before joining PGE, I worked at PacifiCorp from 1980-1999 in various retail, wholesale, planning, and mergers and acquisition positions. In my current position, I am responsible for managing the Power Operations group that coordinates the NVPC portfolio over the next five years.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
401	List of MFRs per OPUC Order No. 08-505
402C	February 15 Initial Filing MONET Output Files and Assumptions Summary

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 11th day of March, 2013, a true and correct copy of the within and foregoing **MOTION FOR OFFICIAL NOTICE OF THE NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION IN DOCKET UM 1182** was served as follows:

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Signed ______________
Gregory Adams