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September 2, 2016

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Filing Center
Public Utility Commission of Oregon
201 High Street, SE Ste. 100
Salem, OR 97301

RE: UE 308 In the Matter of Portland General Electric Company's 2017 Annual Power Cost Update Tariff (Schedule 125)

Attention Filing Center:

Enclosed for filing in the above referenced matter please find the following:

Rebuttal Testimony of:

- **Brett Sims – Brian Faist – Alex Tooman (PGE / 800-802)**

If you have any questions, please contact me at (503) 464-7580 or Alex Tooman at (503) 464-7623.

Sincerely,

Patrick G. Hager
Manager, Regulatory Affairs

PGH/sp
cc: UE 308 Service List

UE 308 / PGE / 800
Sims – Faist – Tooman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 308

Rebuttal Testimony

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony and Exhibits of

Brett Sims
Brian Faist
Alex Tooman

September 2, 2016

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I. Introduction

Q. Please state your names and positions with PGE.

A. My name is Brett Sims. I am the Director of Origination, Structuring, and Resource Strategy at PGE. My qualifications appear at the end of PGE Exhibit 100.

My name is Brian Faist. I am a Specialist with the Structuring and Origination Department at PGE. My qualifications appear at the end of this testimony.

My name is Alex Tooman. I am a Project Manager with Rates and Regulatory Affairs at PGE. My qualifications appear at the end of PGE Exhibit 300.

Q. Mr. Faist, do you adopt the prior testimony of Mr. Scott Russell?

A. Yes. I adopt all of Mr. Russell's prior testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address the testimonies of the Public Utility Commission of Oregon Staff (OPUC Staff or Staff), the Citizens' Utility Board of Oregon (CUB), and the Industrial Customers of Northwest Utilities (ICNU), (or collectively as "Parties") filed separately in this docket. We appreciate the Parties' participation in this proceeding, which involves a complex topic and the review of considerable amounts of information.

Q. Please summarize your review of Parties' positions.

A. Parties have expressed a number of concerns regarding PGE's proposal for long-term gas hedging. Certain concerns have been expressed by two or more Parties (e.g., PGE's proposed guidelines), while others were expressed individually (e.g., the program's potential effect on PGE's cost of capital by Staff). In response, we address those concerns below, and show that the objections are based on misunderstandings or otherwise not supported. While we understand and appreciate the general nature of the Parties' concerns, when these concerns are put into proper perspective we continue to maintain that the substantial benefits for customers of the proposed transaction outweigh the risks and concerns.

Q. Does PGE believe its proposed transaction is in customers' interest?

A. Yes. PGE continues to believe that the proposed long-term gas hedging is in customers' interest. We do so based on all the testimony and exhibits presented in this proceeding plus the information provided over the past year at five workshops, one special public meeting, regularly scheduled quarterly power supply meetings, and PGE's responses to numerous data requests. We highlight the primary aspects of this as follows:

- Customers and Commissions have indicated a preference for stable prices and have encouraged hedging (see PGE Exhibit 100, Section II, page 4, and Section II, part C, below).
- PGE's proposal represents a cost-of-service supply hedge that would provide greater diversity among PGE's gas resources (see PGE Exhibit 100).
- PGE's proposal would help protect customers from structural shifts in the market price of gas (see PGE Exhibit 100, Section III).
- The proposed transaction is cost effective and [redacted] (see PGE Exhibits 600 and 700).
- The proposed transaction results in fairly level annual costs to effectively eliminate intergenerational inequity (see PGE Exhibit 702C and Section II, part D, below).
- PGE has conducted extensive due diligence and has addressed or mitigated the potential risks associated with the proposed transaction (see PGE Exhibit 300, Section II, part C and Section II, part G, below).

Q. Have you addressed all of the Parties' concerns regarding your proposed transaction?

A. Yes. We believe we sufficiently address the Parties' concerns in the testimony that follows and to the extent possible, have incorporated their feedback into our proposal. This belief is further supported by the Parties who, in spite of their concerns, have provided the following favorable comments regarding PGE's proposed 2017 transaction:

- "CUB has to admit that the price of PGE's investment does make the first year of drilling attractive. If PGE had brought the first year of drilling forward as a unique opportunity, CUB evaluation might have turned out differently" (CUB 200/35).
- "ICNU's concerns … are not based on the specific Transaction that the Company has presented" (ICNU 200/4).

Based on this rebuttal testimony, we present our conclusions in Section VI and suggest alternatives for the Commission to consider in its final order in Docket No. UE 308.

Q. How is your testimony organized?

A. In the next section, we address the common concerns expressed by two or more Parties. We then address the OPUC Staff's individual concerns. Next, we address CUB's and then ICNU's individual concerns. We then provide our conclusions and summarize PGE's proposal to the Commission. In the final section, Mr. Faist provides his qualifications.

II. Response to All Parties

Q. What are the common concerns expressed by two or more Parties?

A. The Parties have stated that the following items are of general concern:

- PGE's proposed guidelines
- PGE's Annual Power Cost Update (i.e., AUT filing) is not the appropriate place to evaluate this type of proposal
- Intergenerational inequity
- Benefit to customers
- Inadequate time to review
- Additional risks that PGE's proposal entails

We address each below.

Q. How do you respond to the concerns expressed over PGE's proposed guidelines?

A. Parties' conclusions regarding PGE's proposed guidelines can be collectively summarized as they are inadequate. No party stated that there should not be any guidelines. Instead, Parties believe that guidelines should encompass additional risks and all of PGE's hedging activities. In response, we note that PGE Exhibit 200, page 3, invited Parties to suggest other guidelines "that we may have overlooked but that may also be meaningful." We realize that establishing guidelines for long-term hedging can be difficult but believe that guidelines are appropriate for such an endeavor. In fact, ICNU notes that PGE "has negotiated terms that fit well within the constraints of the Company's proposed guidelines" (ICNU 200/4).

Q. Have the Parties proposed other guidelines?

A. Parties' have offered certain suggestions regarding guidelines but most of their testimony is focused on the shortcomings of PGE's guidelines. We address each of these categories below.

A. Response to Issues with Specific PGE Guidelines

First Proposed Guideline – Cost Effectiveness

- Staff is "puzzled" that PGE's long-term gas hedge is not intended to beat the market but yet, the cost of an acceptable long-term hedge must be at or below the current long-term market price forecast (Staff 400/5-6). Staff seems to be confusing the long-term price forecast with the short-term spot market. In our initial testimony, we noted[1] that the cost-effectiveness of PGE's proposed transaction would be based on the Long-Term Projected Cost of the investment[2] as compared to the Long-Term Benchmark Price.[3] This guideline would help PGE assess a potential transaction's competitiveness with the long-term gas price forecast. If PGE's long-term gas hedging proposal were to be approved, its subsequent annual costs could then be compared to the corresponding spot market over time to see if it "beat the market". This latter, after-the-fact comparison, however, is precisely the one that PGE claims is not appropriate for long-term hedging.
- ICNU claims that PGE's first guideline "makes the long-term hedging program a [likely bad] bet on the forward price curve used to justify the transaction" (ICNU 200/4). ICNU supports this conclusion with an analysis of PGE's hedging results from 2010 through 2016. We address this particular analysis in Section V below, but note that the

[1] See PGE Exhibit 300, page 17.
[2] Equal to the real, levelized cost of the proposed gas hedge.
[3] Equal to the real, levelized forecast cost of gas as used in PGE's integrated resource planning.

purpose of PGE's long-term hedging proposal is to reduce customer price volatility; it is not intended to beat future market prices.

- CUB argues that the data used to create the Long-Term Benchmark Price are "often stale and should not be used to establish a presumption of cost effectiveness that leads to a presumption of prudence" (CUB 100/22). In reply, we specifically stated that this guideline was based on the "forecast cost of gas as used in PGE's integrated resource *planning*" (PGE 300/17; emphasis added) and not integrated resource *plan*. In addition, PGE stated that "This guideline establishes the cost-effectiveness of the hedge *at the time the hedge is executed*" (PGE 200/4; emphasis added). In other words, PGE plans to use the most current long-term gas price forecast in determining the cost-effectiveness of the hedge, not obsolete or stale forecast data.

Second Proposed Guideline – Maximum Purchase Commitment

- CUB states that the second guideline would "*require* [PGE] to purchase at least 15% and not more than 30% of its gas supply under long term contracts" (CUB 200/3; emphasis added). This is incorrect. PGE did not claim that the guideline creates a requirement. Instead, we proposed a ceiling range within which PGE's long-term hedging would be limited and would evaluate potential transactions within those limits (i.e., the Commission could set the ceiling anywhere from 15% to 30% of PGE's average gas requirement). Further, PGE would only propose transactions if they meet all other guidelines and a normal prudence review. Only a Commission order instructing PGE to achieve certain levels of hedging would create a requirement, and that is not what PGE is proposing.

- Staff finds the second guideline to be insufficient because "In particular, simply prescribing a fixed percentage of a portfolio to be hedged creates a 'lock-and-leave' approach which is at odds with more commonly used hedging strategies, such as the value-at-risk (VaR) approach to hedging" (Staff 400/11). PGE and the Berkley Research Group (BRG) have performed a detailed analysis of the proposed range and provided it in response to CUB Data Request No. 009, Attachment B, and provide it here as PGE Exhibit 801. According to the BRG study, a hedging range of 20% to 60% can be supported depending on the risk metric chosen for decision making (e.g., long-term variability, short-term volatility, or extreme outcome avoidance). We have chosen to work at the bottom of that range.

In addition, PGE believes that Staff's interpretation of the proposed strategy as a "lock and leave" approach is incorrect. The proposed investment in reserves has a declining production curve, with gas supplied in the year of maximum production being less than 10% of PGE's projected annual need. PGE would then have multiple opportunities to evaluate the performance of the contract on an on-going basis, both in terms of price and volume, prior to any subsequent commitment(s) for long-term contracts.

In fact, one of the major findings of a National Regulatory Research Institute (NRRI) survey is that "A number of commissions indicated that long-term contracting could be part of a diversified portfolio that mitigates risk. Many of them recognize that diversification gives a utility more flexibility and protection from unknown future events" (ICNU 202/26). The proposed long-term transaction is a diversification strategy for PGE's operations alongside the current mid-term and short-term strategies.

- PGE's second proposed guideline is specifically silent on the types of hedges to be transacted. Staff considers this to be inadequate and recommends that "A comprehensive set of hedging guidelines would prescribe the hedging activities to be pursued under various market conditions" (Staff 400/12). In reply, we believe that Staff is creating an unrealistic standard that would have PGE attempt to identify all potential future market conditions so we can create a forward-looking guideline to address each of those conditions. If an unpredicted market condition were to arise, PGE believes that the best approach would be to have the flexibility to address it with the tools available at that time rather than be bound by only the hedging tools available or imagined at the time the guideline was created. The advantage of PGE's proposed long-term hedge is that it would provide price protection against structural shifts that impact the longer-term market price for gas at a time when gas prices are very low. In other words, PGE is responding to projected market conditions with a tool available at this time.
- Staff further questions this by stating, "If PGE believes that it is different than other market participants in such a way that it is in a position to procure gas at below market prices through reserve ownership at this time, … PGE should explicitly acknowledge this and explain why it believes it is in such a position, relative to other gas purchasers at this time" (Staff 400/10). PGE never claimed this unique status. In fact, numerous similarly-situated electric utilities are also pursuing long-term gas hedging based on the same conditions PGE is facing. PGE's claim to selecting a cost-effective hedge is based solely on a comparison to the long-term gas price forecast, not short-term spot market prices.

Third Proposed Guideline – Proved and Probable Reserves

- CUB questions the protection afforded by the third guideline by challenging the estimates of potential reserves as determined by PGE's independent consultant. In response, [redacted] In addition, PGE has proposed a mechanism to limit price changes in PGE's AUT filing based on updated production forecasts (i.e., the fourth guideline).

Fourth Proposed Guideline – Limit Price Changes in the AUT

- This guideline places limits on the unit cost of the long-term gas as it would be incorporated into PGE's AUT filing. CUB and Staff dismiss this guideline as: 1) applying to rate-making, 2) having little to do with determining prudence, and 3) not actually placing any restrictions on, nor offer any guidance for, hedging activities (CUB 100/24 and Staff 400/10). Regardless of its guideline or non-guideline label, this proposal significantly mitigates production risk.

B. Response to General Issues with Guidelines

- CUB claims that "There are no guidelines concerning what information PGE needs to document their evaluation of these investments" (CUB 100/21). CUB appears to misunderstand the purpose of the guidelines. The guidelines represent the basis of a prudence review, for which "PGE would still have to demonstrate prudence based on the information available at the time we execute specific transactions" (PGE 200/2). If sufficient documentation is lacking or contrary to the transaction, the Commission can disallow costs, similar to their decision in Docket No. UE 228 to reduce PGE's 2012 net variable power costs (NVPC)[4].

- Staff (400/11-12) argues that PGE's hedging needs to be reviewed more comprehensively and ICNU states that "parties should undertake a more thorough examination of the Company's mid-term strategy in the next AUT" (ICNU 200/18-19). PGE agrees that Parties can raise topics of relevance in proceedings, although we note again that PGE's mid-term strategy was thoroughly reviewed in Docket No. UE 228 in relation to PGE's 2012 AUT. The result of that review was Commission Order 11-432, which stated (also quoted in PGE Exhibit 100):

> We conclude that PGE's overall hedging strategy to be prudently designed. Specifically, we find that the MTS is a reasonable approach to addressing the three-year period between the company's short-term hedges and purchases and the company's long-term resource investment, and agree that the appropriate goal is to address PGE's entire NOP [net open position]. … Based on the testimony and contemporaneous exhibits PGE introduced documenting the design and goals of the MTS, as well as its expectation at the time the MTS was introduced that gas and power market volatility would remain high, we conclude that PGE's MTS is an objectively reasonable strategy. (Page 8).

We also note that PGE did not intend for the proposed guidelines to be an outline for a comprehensive approach to hedging. Rather, the purpose of the guidelines is to "establish a framework around which prudence can be measured for the proposed *long-term gas hedging strategy* and specific transactions pursuant to that strategy" (PGE 200/2, emphasis added) In summary, we continue to believe that guidelines are an appropriate element to help PGE enter into strategies that reduce gas price volatility for customers, and we see little benefit in re-litigating UE 228. Finally, we address ICNU's primary issue with hedging (i.e., risk premium in forward gas markets) in Section V, below.

[4] Commission Order No. 11-432 reduced PGE's 2012 NVPC by $2.6 million based on a lack of documentation and analysis.

C. AUT Not an Appropriate Proceeding

Q. Please summarize the Parties' position as to whether the AUT is an appropriate proceeding for PGE's proposed transaction.

A. Staff (400/8) agrees with CUB (100/3-8) that the AUT is not an appropriate proceeding to address PGE's proposed transaction. Because CUB expressed specific concerns due to the rate base nature of PGE's investment, we address CUB's arguments, below.

Q. Please summarize CUB's issue regarding rate base.

A. CUB's objection is that the proposed gas cost would result from an investment by PGE's affiliate, Portland General Gas Supply Company (PGGS). This investment would then be treated as rate base in PGGS's revenue requirement, which provides the price of gas to be paid by PGE, as described in PGE Exhibit 300, Section IV, and PGE Exhibit 304.

Q. Would this revenue requirement be charged as a fixed cost to PGE's customers similar to other rate base?

A. No. It would be unitized based on the volume of gas produced and then incorporated into PGE's MONET power cost forecasting model similar to other gas hedges. The dissimilarity with other gas hedges is that PGE's proposal is based on cost-of-service gas as described in PGE Exhibit 100. Because PGE's proposal is a gas hedge, it falls within the updates specified by Schedule 125 (as previously listed in PGE Exhibit 300, page 16, line 19, through page 17, line 2), and listed again as follows:

- Contracts for the purchase or sale of power and fuel.
- Changes in hedges, options, and other financial instruments used to serve retail load.

Q. Has PGE provided any additional support to include the investment as part of its NVPC?

A. Yes. In PGE's response to CUB Data Request No. 025 (provided as CUB Exhibit 102), PGE observed the similarity between: 1) PGE's proposal to include the cost per MMBtu of its proposed long-term gas hedge in our AUT filings; and 2) NW Natural's long-term gas investment being included as a cost per MMBtu in its annual purchased gas adjustment mechanism.

Q. Does CUB agree with this observation?

A. No. In CUB's view, "Order No. 11-176 was the Encana order for UM 1520. UM 1520 was not the PGA but was an unusual single-issue ratemaking docket established for the sole purpose of examining the prudence of Northwest Natural's ("NWN") rate based investment in gas reserves" (CUB/100, page 7, lines 1-4).

Q. How do you respond to CUB's characterization of Commission Order No. 11-176?

A. Commission Order No. 11-176 explicitly states that "The costs of the Proposed Transaction will be tracked and recovered on an annual basis through NW Natural's PGA mechanism" (page 11). This was PGE's point in our response to CUB Data Request No. 025; the Commission Order speaks for itself.

Q. CUB also states that PGE is being inconsistent based on their reference to PGE's 2003 Resource Valuation Mechanism, Docket No. UE 139. Do you agree with this observation?

A. No, for the following reasons:

- In UE 139, CUB specifically proposed to include production rate base and fixed production operations and maintenance costs in PGE's NVPC, while at the same time objecting to PGE's proposals to update its NVPC modeling. These types of fixed costs do not fall under any definition of NVPC, which is why the OPUC Staff opposed CUB's proposal along with PGE.

- If PGE were to purchase long-term gas from a third party, its price would also include fixed costs such as "return of" and "return on" investment.

D. Intergenerational Inequity

Q. Please describe the Parties' concerns regarding intergenerational inequity.

A. Because Parties have raised variations of this topic, we address them separately below.

Q. Does the proposed transaction address CUB's concerns with intergenerational inequity expressed earlier in this docket?

A. Yes. CUB Exhibit 100 expressed concerns that current customers would incur the costs associated with PGE's proposal and that later customers would realize the benefits, resulting in intergenerational inequity. CUB Exhibit 100 also notes that the timing of costs versus benefits is too similar to those of renewable resources. These concerns were based on PGE's initial UE 308 exhibits and work papers filed on April 1, 2016. In more recent testimony, CUB observes that "PGE has done a good job of negotiating a deal that reduces the front loading of costs. The generic deal PGE proposed in Opening Testimony had loaded costs beginning at $5 and declining over time. *This new contract avoids that*" (CUB 200/34; emphasis added).

Q. What are ICNU's concerns regarding intergenerational inequity?

A. Unlike CUB, ICNU maintains that the current proposal does entail front-loaded costs so as to create intergenerational inequity. ICNU attributes this "primarily … with the *return on* component of the Transaction revenue requirement" (ICNU 200/16; emphasis not added).

Q. Do you agree with ICNU's assertions?

A. No. ICNU supports its assertions by drawing a distinction between 1) *return of* investment (i.e., depletion), which corresponds to the timing of when gas is produced and 2) *return on* investment, which provides "a fixed return on [the utility's] investment each year based on the amount of net plant reflected on [the utility's] books" (ICNU 200/16). ICNU further states that "Because the investment will deplete over time, the return [on] component is the largest at the beginning of the investment's useful life, and gradually declines as the investment in the gas reservoir depletes. In other words, today's customers will pay more per unit of gas to achieve lower cost gas for tomorrow's customers" (ICNU 200/16). Finally, ICNU concludes by noting that "depletion accounting is used is to properly align the timing of cost recovery expense with the timing of when the benefits associated with the investment, in the form of gas withdrawals, are recognized" (ICNU 200/16-17).

Q. Are ICNU's statements accurate?

A. No. ICNU appears to miss its own point because the higher "return on" component, during the early years of the investment, *is timed* with the higher gas production levels just like the "return of". This occurs because the "return of" expense translates to accumulated depletion, which in turn reduces the *net* rate base on which the "return on" is calculated. Consequently, there is no mismatch of timing, which explains why the projected costs of the proposed transaction as listed in PGE Exhibits 602 and 702 are fairly level throughout most of the investment's life. CUB understood this; hence their comment noted above.

Q. Please summarize Staff's position on intergenerational inequity.

A. Staff claims that "the annual cost of the investment will exceed the benefits in the first six years of the project" (Staff 500/19). Staff then proposes a rate making solution as follows (Staff 500/20):

> Rather than a cost of service contract, the annual contract price should be shaped so that there is no inter-temporal cost shifting. The price should also be fixed so that the contract results in NPV gas costs $4 million below what would be achieved with the current forward price curve.

Q. How does PGE respond to Staff's proposal?

A. PGE has significant reservations about Staff's rate making proposal because it does not provide specific detail as to how the levelized price is calculated or how PGE's capital carrying cost are treated within that calculation. Unfortunately, there is not enough detail in Staff's proposal to provide a comprehensive response. Ultimately, however, PGE notes that our previous update summarized in PGE Exhibit 702, shows that only years two through five show estimated costs exceeding projected benefits. All other years, plus the overall project, show a net benefit. As noted above, intergenerational inequity is not an issue.

E. Benefit to Customers

Q. What is the primary benefit to customers of PGE's proposal and how do Parties respond to that benefit?

A. As stated in PGE Exhibit 100, the benefit of the proposed hedging program is to limit electric price variability for customers by reducing gas cost volatility. Parties address this benefit as follows:

- Staff addresses this by quoting the NRRI "that the justification of long-term hedging ought to require the utility to 'provide evidence, other than conjecture, that customers are <u>willing to pay</u> something for more stable prices over the long term' [emphasis added]" (Staff 400/6).
- ICNU adds to Staff's comments by noting that large customers operate in regional and national markets and are better served by "allow[ing] rates to fluctuate in the long-term in response to market conditions, as large customer will have greater

certainty that it will be neither harmed, nor benefitted, relative to its existing competitive position" (ICNU 200/12).

- Staff also states that long-term hedging can interfere with customers receiving appropriate market price signals (Staff 400/2-3).

Q. What is your reply to the Parties regarding customers preferring more stable prices?

A. PGE Exhibit 100, page 4, cites several sources that address customers' preference for price stability. Rather than just repeat them here, we provide specific examples below:

- PGE's 2007 Integrated Resource Plan (IRP):
  - Business focus group participants expressed a strong preference for cost predictability and indicated that they would be willing to pay more for a particular resource or mix of resources if they could be assured long-term price predictability. (Page 138)
  - … nine of ten Key Account customers said they preferred higher, more predictable rates as opposed to lower but potentially unstable rates. (Appendix F)
- The results of a customer survey provided as PGE Exhibit 402 in Docket No. UE 228 (and again here as PGE Exhibit 802) showed that in every customer group, 50% or more of the respondents expressed a preference for predictable price increases.
- ICNU witness in Docket No. UE 228 stated, "I would say most people, as a general rule, like more stable rates, predictable, but that always comes at a price" (Deposition of Donald W. Schoenbeck, pages 126, lines 6–8).

Q. How do you respond to Staff's comments regarding appropriate price signals?

A. Utility regulation is currently based on cost-of-service pricing with costs ranging from both short-term to long-term. Some costs can only be short-term such as office supplies, while other costs can only be long-term such as the capital carrying costs for long-lived distribution and transmission facilities (e.g., poles, conductor, and transformers). Yet other costs can involve tradeoffs between both types. For example, when PGE was an energy-short utility, we had a large open position and those costs reflected the significant short-term nature of energy market purchases. With the addition of the renewable and gas-fired generation described in Section IV, part C, below, PGE effectively replaced short-term costs with a combination of long-term fixed plant costs and short-term fuel costs. These costs are all reflected in PGE's revenue requirement and are the basis for PGE's cost-of-service prices.

Staff's testimony, however, suggests that short-term costs are the most relevant for price signals: "By insulating customers from market price volatility, natural gas hedging alters the information that customers receive (via price signals) regarding the social value of natural gas in different areas and during different time periods." (Staff 400/3) PGE disagrees with this position for the following reasons:

- Customer prices should reflect all aspects of the cost-of-service revenue requirement and not arbitrarily favor short-term costs.
- If effectively hedging market energy with fixed plant is appropriate, then so should hedging a portion of the fuel costs for that plant (if cost effective).
- The Commission has specifically instructed energy utilities to consider risk and uncertainty and select a portfolio of resources with the best combination of expected costs and associated risks (Commission Order No. 14-415, page 1).

Q. Do you have any additional comments regarding customer benefits?

A. Yes. Staff correctly identifies the fact that gas hedging has the potential to reduce volatility in customer rates implying rate stability and predictability. While Staff points out that intra-year rate volatility as a result of power cost variation is minimal under the current system in Oregon, they fail to identify that customers do bear the risk of any inter-year power cost increases. The AUT resets power costs annually and does not protect customers from market increases. The proposed transaction will help limit but not eliminate inter-year price risk and volatility.

F. Inadequate Time to Review

Q. How do you respond to Parties' claim that there has been insufficient time to evaluate PGE's proposal, documentation, and associated risks?

A. As noted in Section I, PGE appreciates the Parties' efforts to evaluate the considerable information presented as part of our proposal. We also acknowledge that it entails significant complexity and is outside of PGE's normal business operations. In fact, PGE is also concerned about these issues and we hired a number of expert consultants to review and provide guidance regarding all facets of our proposal. We address Parties' specific concerns with the additional risks in the next section, below.

Ultimately, there is an admitted tension between the timeframe for transactions in the market for gas reserves (typically 60 to 90 days) and the typical regulatory timeline (six to ten months for major proceedings). Nevertheless, because the benefits to customers for this type of transaction are so compelling, we pursued this transaction and sought to obtain contractual terms that enabled the Parties and Commission sufficient opportunity to review the proposal. To address this potential tension between typical transactions in this industry and regulatory review, PGE has transacted with a counterparty willing to accommodate PGE's regulatory requirements and we have pressed our expert consultants to complete their evaluations within the timeframe of the AUT. In addition, PGE has provided information to Parties as soon as it became available to give them as much time for review as the commercial schedule would allow.

In the past year, PGE also held five workshops and presented at a special public meeting to keep the Parties fully informed regarding our progress toward completing a long-term gas hedging transaction. As part of those workshops, PGE presented information on the types of long-term hedges we would examine/pursue, including the value, risks and mitigations associated with each type of transaction or strategy. Although this still resulted in expedited review, we believe it has been adequate given the existing constraints and the benefits of the transaction.

Q. What would be the effect on such a transaction by following CUB's suggestions that it be evaluated first in PGE's IRP and then included in a general rate case?

A. This would have the effect of taking an approximate six-month process and expanding it to several years. No actual transaction would be available for that long. In addition, a generic transaction would be virtually meaningless given the amount that the market could change in that period of time and the availability of willing counterparties. For example, PGE's actual transaction as presented with the draft term sheet on June 3rd had changed considerably from the pro forma transaction as included in the initial AUT filing on April 1st. While CUB's suggestion seems perfectly logical, unfortunately, many long-term transactions that would be beneficial to customers are not commercially available or viable within such an inflexible framework.

G. Additional Risks

Q. How do you respond to the Parties' concerns regarding the additional risks that PGE's proposed investment would entail?

A. To address the additional risks, PGE has performed appropriate due diligence in order to mitigate them as much as possible. [redacted] To be more specific, however, we address individual risks below.

Environmental Risk

Q. Please summarize the Parties' comments regarding environmental risk.

A. CUB 200/20-26 identified a number of environmental issues that it believes pose risks based on the due diligence reports that PGE submitted on July 22nd (PGE's first supplemental response to CUB Data Request No. 043, Attachment C). We first summarize PGE's approach to due diligence and then we address CUB's specific concerns.

Q. What was PGE's approach to environmental due diligence?

A. PGE considered potential environmental risks to fall into one of two general categories for the purposes of designing the due diligence efforts:

- Risk of incurring costs for cleanup and damages from releases of harmful substances to the environment; the most significant would be the potential to incur long-term, legacy liability. In general, environmental cleanup regulations consider: 1) the magnitude and characteristics of the substance released; 2) the exposure pathway of the released substance to a receptor;[5] and 3) the sensitivity of the receptor that may be impacted. To assess this type of risk, PGE and our advisors considered the

[5] Ecological receptors include organisms and habitat that could be adversely affected by environmental contaminations resulting by a release at or migration from a site.

project site in a comprehensive fashion to create a risk profile. This profile considered the likelihood of significant releases of contaminants as well as the sensitivity of features that may be impacted in the event of a release. The risk profile included consideration of area land and water use, existing water quality, and ecological habitat. It also considered the operating partner's policies and procedures associated with preventing and responding to any releases that may occur, the [redacted]

- Risks related to the operating partner being non-compliant with applicable regulations, permit stipulations and other requirements, and how these types of risks could impact PGE. Assessment of this type of risk has to consider the operating partner's policies, procedures and level of resources dedicated to environmental compliance, the contract between PGGS and the potential operating partner, and the design of the assets proposed.

Q. What were the results of environmental due diligence efforts as they relate to the cleanup and damage risks?

A. In general, PGE's due diligence efforts indicate that the likelihood of PGE incurring significant costs for cleanup is low. The basis for this is as follows:

- [redacted] In the unlikely event that a significant release of harmful substance occurs at the proposed property, impacts to sensitive receptors would not occur because they are absent.

- Water quality in the area is generally poor and shallow groundwater is likely not present.
- Based on the potential counterparty's spill prevention and response procedures and the proposed construction design of the project, the likelihood of releases occurring that would significantly impact PGE are low. PGE recognizes, however, that any process involving the storage, handling, or transport of liquids or gases includes some potential for releases to occur.

Q. What were the results of environmental due diligence efforts as they relate to the non-compliance risks?

A. PGE's due diligence efforts indicate that potential impacts associated with regulatory compliance should be minimal based on the following:

- The counterparty is responsible for obtaining all permits and complying with all applicable regulations, including those associated with both construction and operation. In the event that new regulations become effective, the counterparty may have to employ additional permitting staff to satisfy regulatory requirements, such as more stringent record keeping, data submittals, reporting, inspection, and maintenance. [redacted]
- [redacted]

[redacted]

- [redacted] include all equipment necessary to comply with existing Bureau of Land Management and Environmental Protection Agency (EPA) regulations, including emissions regulations and recently enacted EPA regulations that were finalized last May.

Q. Please respond to CUB's concern that there is no water quality data available for the specific property associated with the project (CUB 200/21-22).

A. [redacted]

Q. How do you respond to CUB's concerns regarding [redacted] (CUB 200/22-23)?

---

[6] [redacted]

A. [redacted]

Q. Please address CUB's concern regarding the lack of documentation as to the applicability of new EPA methane regulations (CUB 200/23-24).

A. The referenced regulations were recently enacted by the EPA regarding methane emissions during oil and gas production. [redacted]

[redacted][7] [redacted]

Q. Please discuss CUB's general concerns related to any future regulations associated with methane and other greenhouse gas emissions (CUB 200/24).

A. In the event that future governmental regulations related to climate change were to result in increased production costs in the oil and gas industry, those costs would be passed through to purchasers regardless of where in the supply chain the purchase is made. In other words, the cost increase would be wide spread and would not impact just PGE's proposed production. The net result is that PGE's costs would increase, but we would expect market gas prices and the gas price forecast to reflect the corresponding increase as well.

Q. How do you respond to CUB's reference to spills and the potential impact of cultural materials (CUB 200/25-26)?

A. PGE is puzzled as to why these are not listed with the risks for which CUB is satisfied with the due diligence. CUB's testimony did not raise specific concerns or issues regarding these risks or cite any perceived short comings to PGE's due diligence.

Counterparty Risk

Q. What concerns have Parties' expressed regarding risks related to PGE's counterparty?

A. CUB notes the possibility that PGE's "drilling partner could go bankrupt or would want to sell its interest in these reserves is very real" (CUB 200/30), although they do not explicitly

[7] One of the purposes of all environmental due diligence is to identify specific information that was and was not available during the due diligence effort.

state what risks would be associated with this possibility. Staff 500/8 claims that "In the event that Production Partner ceases to operate the wells, PGE will have to renegotiate a new contract, at potentially unfavorable terms." Staff, however, also states that "the counterparty to a hedge may not be able to uphold their commitment (i.e., counterparty performance and credit risk). Utilities are typically aware of these risks and experienced in assessing them and contracting to mitigate them" (Staff 400/5).

Q. How does PGE respond to CUB's and Staff's concerns regarding counterparty risk?

A. At the outset, it is important to observe that these concerns are not based on evidence or specific reasons for concerns regarding the counterparty or the transactions but generalized fears about potential scenarios. For example, concerns about bankruptcy, non-performance, or changes in ownership are unsupported by any specific evidence regarding the counterparty or transaction. Moreover, if a bankruptcy or change in ownership were to occur, we do not believe that it would present significant risks because PGGS has a property interest that is not subject to an owner's bankruptcy. [redacted]. PGE addresses bankruptcy risk in Section III, below.

Q. What would happen if the counterparty decides to no longer operate the wells or chooses to sell to another party?

A. [redacted].

[redacted]

Production Risk

Q. Please summarize the issues Parties have raised regarding production risk.

A. Parties recognize that the guidelines [redacted] mitigate much of the production risk, but note that it is not eliminated altogether. Because CUB has identified the most explicit concerns regarding production risk, we respond to them as follows:

- “[redacted] (CUB 200/28)

  [redacted]

[redacted].

- [redacted] (CUB 200/28). [redacted].
- “[redacted] (CUB 200/29). [redacted]
- “[redacted] (CUB 200/29). [redacted]

[redacted][8] [redacted]

Q. Is there any opportunity for PGGS to engage in opportunistic or self-dealing behavior?

A. No. The affiliate agreement is designed to provide only cost of service to PGE. The affiliate has no incentive or ability to increase these costs or engage in opportunistic or self-dealing behavior. In addition, all such costs would be reviewed in future AUT filings.

Commodity Risk

Q. What are the Parties' concerns regarding commodity risk.

A. ICNU observes that PGE's forecast includes a revenue credit for oil and non-gas liquids (NGLs), which "would expose ratepayers to markets to which they are not exposed today. To the extent the Company's assumptions with respect to these revenues do not conform to the reality of future prices, it could result in material, unexpected costs to ratepayers" (ICNU 200/13-14). Staff claims that PGE's proposal has an optimistic view of commodity prices (Staff 500/4).

Q. How do you respond to ICNU?

[8] As discussed in PGE Exhibit 300, Section IV.

A. The proposed transaction does provide customers with the revenue from oil condensate and NGLs as a reduction to the cost-of-service gas supply. [redacted]. PGE believes the market forecast for both byproducts to be developed prudently and is currently examining hedging strategies to lock in these forecasted prices.

Q. Why does Staff claim that the proposal has an optimistic view of commodity prices?

A. Staff bases its claim on the fact that PGE transitions "from a future's market based forecast to a subjective McKenzie Woods [*sic*] forecast."

Q. Is this a reasonable observation?

A. No, we disagree with this characterization. PGE's long-term market price forecast consists of the following elements:

- Years 2017-2020 are the current market natural gas forward price curve.
- Year 2021 is interpolated between the two data sources (i.e., current market natural gas forward price curve and Wood Mackenzie update).
- Years 2022-2035 are the long-term gas price forecast from Wood Mackenzie's annual update.
- Years 2035-2046 are derived from escalating the end of the Wood Mackenzie price forecast.

PGE uses the Wood Mackenzie forecast because it is accepted by all parties as an input to PGE's IRP analyses and because the gas forward curve only addresses the near term. More importantly, the Wood Mackenzie forecast is quite conservative with respect to the referenced commodity prices. For example, if PGE were to use the US Energy Information

Administration's 2016 Annual Energy Outlook instead of Wood Mackenzie, the net present value of PGE's proposal would double.

Cost Risk

Q. Please describe the Parties' concerns regarding cost risk?

A. CUB states that "[redacted], [redacted] (CUB 200/32).

Q. How have you mitigated CUB's concerns?

A. [redacted] Limits on other costs are discussed in Section III, below.

III. Response to the OPUC Staff

Q. What issues did the OPUC Staff raise individually?

A. Staff raises the following five individual issues:

- Transaction cost economics (TCE) indicates that gas hedging is not an efficient alternative for vertical integration.
- The value of the proposed investment is uncertain.
- The proposal would add to PGE's cost of capital.
- The proposed transaction is very similar to purchasing stock in a gas production firm.

A. TCE and Vertical Integration

Q. Please summarize Staff's comments regarding TCE.

A. Staff quotes an NRRI study that cites TCE as predicting "the market conditions under which vertical integration is a preferred institutional arrangement over long-term contracting and spot market transactions" (Staff 400/8; provided in full text as ICNU Exhibit 202). Staff then concludes that these conditions are not present for natural gas (Staff 400/9).

Q. How do you respond to Staff's assertions?

A. TCE has both advocates and critics. We note that one criticism of TCE as discussed by Ghosal and Moran[9] observes that "… TCE can, at best, only explain a very minimal level of cooperation and, consequently, can account for only a small portion of the potential efficiency gains; …"[10] As Ghosal and Moran explain, TCE emphasizes individual opportunism over collaborative behavior and that "the advantage of organizations over

[9] S. Ghosal, P. Moran (1996) "Bad For Practice: A Critique of the Transaction Cost Theory." *Academy of Management Review, Vol. 21* (No. 1) 13-47.
[10] Ibid., 25

markets may lie … in leveraging the human ability to take initiative, to cooperate, and to learn."[11] In summary:

> Although the pursuit of static efficiency can provide the resources to fuel investments for achieving dynamic efficiency, it is not likely to guide the direction of those investments. Further, because dynamic efficiency is more difficult to measure than static efficiency, in their effort to lock in the latter, firms that follow [TCE] will lose sight of the former.[12]

Q. What does this mean with regard to PGE's proposed transaction?

A. It means that Staff uses the NRRI article and TCE to effectively preclude consideration of the proposed transaction. The Ghosal-Moran article, in contrast, would support PGE's proposal by recognizing that the cost efficiencies achieved by the cooperation between PGE and the counterparty justify its consideration.[13]

B. Value of the Proposed Transaction

Q. Why does Staff conclude that the value of the proposed investment is uncertain?

A. First, Staff notes that "The mechanics of [PGE's] revenue requirement model are sound" (Staff 500/5). This revenue requirement is the basis of PGE's analysis comparing the "Long-Term Projected Cost" of the investment to the current "Long-Term Benchmark Price" to determine the cost-effectiveness of the investment (see PGE Exhibit 300/17). Staff then evaluates potential impacts to the revenue requirement from low production, low commodity prices, and unexpected expenses and concludes that by adjusting them all by 10% in combination, they would produce significant losses for each dollar of PGE's investment.

Q. Do you agree with Staff's analysis and conclusions?

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[11] Ibid., 42
[12] Ibid., 39-40
[13] Based on PGE's proposed first guideline.

A. No. A 10% increase from unexpected expenses is not a realistic assumption because [redacted]

- [redacted]
- [redacted]
- All of the truly variable expenses are contingent on the amount of production. If these expenses increase, it would occur because the proposed transaction is producing more than forecasted.

[redacted]

The only other types of costs that could increase would be market-wide impacts resulting from events like the implementation of new environmental regulations. These, in turn, would impact the entire gas market and customers would either pay for these incremental costs through higher market gas prices or an increased cost-of-service supply.

Q. Are there any other reasons you disagree with Staff regarding their testimony on the value of the investment?

A. Yes. Staff primarily focuses on potential negative impacts to the investment and does not provide the combined results from positive impacts or offsetting impacts, which are just as likely. [redacted] Finally, PGE bears the intra-year risk of such impacts, because the costs or benefits would flow through PGE's Power Cost Adjustment Mechanism, which is specifically designed to trigger infrequently.

C. PGE's Cost of Capital

Q. Please summarize Staff's position regarding PGE's cost of capital.

A. Staff concludes that PGE's cost of capital would increase as a result of the proposed transaction based on: 1) the financial weakness of PGE's counterparty, and 2) the rating agencies' view of PGE after its affiliate becomes involved with the exploration and production (E&P) of natural gas.

Q. Is Staff correct in their characterization of PGE's counterparty?

A. No. Publicly available information reveals significant differences with Staff's claims regarding the counterparty. We list these differences below:

[redacted]

[redacted]

Q. [redacted]

A. [redacted]

- [redacted]
- [redacted]

Q. Is the counterparty at risk of going bankrupt?

A. [redacted]

- [redacted]
- [redacted]
  - [redacted]
  - [redacted]

---

14 [redacted]

[redacted] Ibid., 30

[redacted]

- o [redacted]
- o [redacted]

Q. How does Staff claim that the counterparty's financial soundness would affect PGE's credit rating?

A. Staff's testimony does not make that clear. Instead, Staff concludes that "the vast majority of the value of the Proposed Investment could be hedged with a 10 year financial hedging instrument" (Staff 500/15).

Q. What is the basis of this claim?

A. Staff's claim is based on the declining production levels shown in Staff Figure 2, which Staff also uses to conclude the following:

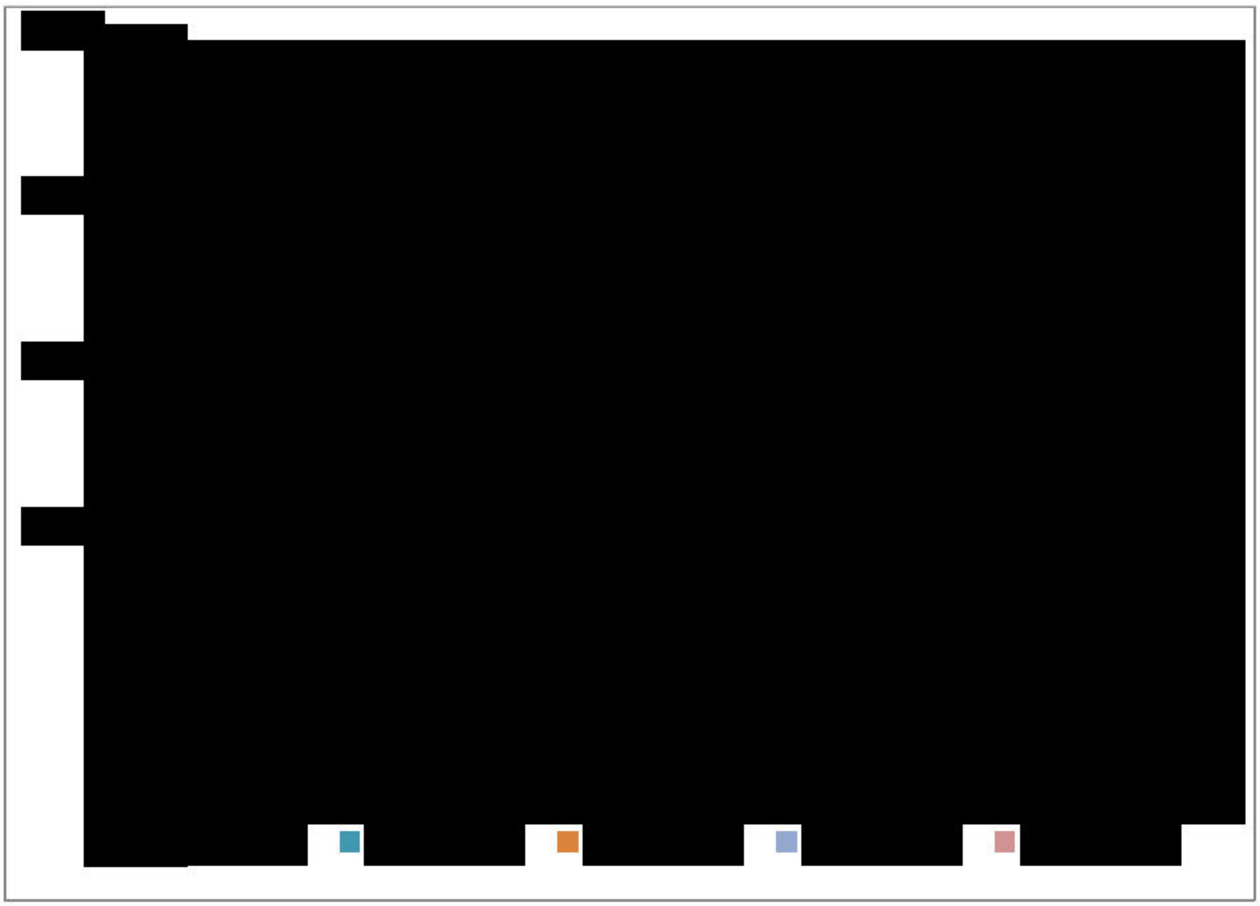
- PGE's proposal "is "a relatively ineffective hedge compared to a traditional financial hedging instrument" (Staff 500/16).
- Because the proposed Investment does not resemble a financial instrument, "It is very similar to simply purchasing stock in a gas production firm. The value of the stock will increase and decrease with the forward gas price curve" (Staff 500/16).

Q. Is Staff correct in claiming that PGE's proposal is a relatively ineffective hedge compared to a traditional financial hedging instrument?

A. No. PGE's proposal is very effective because, as stated in PGE Exhibit 100, page 7, it represents a cost-based price and supply hedge that would last significantly longer than five years, provide protection against longer-term structural shifts in market conditions, as well as provide greater diversity among PGE's gas resources. [redacted]

[redacted]

[redacted]



Q. Has PGE explored the possibility of purchasing a ten-year financial gas hedge as an alternative to the proposed transaction?

A. Yes. However, as stated in Section IV, part A, below, *cost-effective*, ten-year financial gas hedges have not been available. Unless they are cost-effective, they do not represent a viable alternative for long-term gas hedging.

D. Purchasing Stock in a Gas Production Company

Q. Is the proposed transaction very similar to purchasing stock in a gas production company, as Staff claims?

A. No. The proposed transaction does not bear any similarity to purchasing stock in a gas production company. Purchasing such stock would be completely speculative; provide no gas hedge, physical or financial; and would provide no benefit to customers.

Q. What are Staff's conclusions regarding PGE's potential investment in the stock in a gas production company?

A. Staff concludes that "If PGE invests heavily in gas production firms, PGE's cost of capital may increase. Gas production firms have higher costs of capital compared to regulated utility firms" (Staff 500/16). PGE has no intention of investing in gas production firms, let alone "heavily", so Staff's comments on the effect of such a transaction on PGE's cost of capital, are not relevant.

Q. Does Staff make any other claims regarding cost of capital?

A. Yes. Staff claims that if PGE were to form "a natural gas E&P division … rating agencies would be less likely to upgrade PGE, and would likely review PGE for downgrade" (Staff 500/18).

Q. How does Staff support this claim?

A. Staff's support is to cite an article about MDU Resources, which sold its E&P business in 2015 and 2016. There is no indication, however, that Staff evaluated the similarities (or dissimilarities) between PGE and MDU such as: 1) the size of the E&P activities relative to their other business; 2) how their E&P businesses would compare; 3) how their other business is comparable; or 3) what other factors might lead rating agencies to upgrade or downgrade either company.

IV. Response to CUB

Q. Please summarize the issues CUB has raised individually regarding PGE's long-term gas hedging proposal.

A. CUB has expressed the following individual reservations regarding PGE's long-term gas hedging proposal. We respond to them separately below.

- There are other long-term alternatives for gas hedging that are not being given proper consideration.
- The latter years of the proposed investment exceed PGE's planning horizon so the investment is arguably not used or useful during a meaningful portion of its life.
- "There is little reason to believe that a monopoly utility cost-of-service investment will produce lower prices than the competitive wholesale market over the long run." (CUB 200/9)
- "CUB is not sure that the appropriate regulatory solution to a growing dependence on natural gas is to increase the incentive to invest in gas plants." (CUB 200/10)

A. Alternative Transactions

Q. How does CUB support its claim that there are other long-term alternatives for gas hedging available in the market?

A. CUB states that "CUB Exhibit 106 reveals that hedge quotes starting at $2/MMBtu and ending at less than $4/MMBtu for 10 years are possible" (CUB 100/15). CUB Exhibit 106, however, is a slide from a NW Natural presentation, used by permission.

Q. How do you respond to this?

A. PGE cannot respond to a NW Natural slide for which we have no details. We can definitively state, however, that PGE regularly discusses financial gas hedges with institutions that transact them and have not encountered any 10-year hedges that were cost effective in accordance with PGE’s proposed first guideline. If PGE were to find a ten-year financial deal for $2 gas in the current market, we would want to procure it in the customers’ interests.

B. Used and Useful

Q. What arguments does CUB make regarding the “used and usefulness” of the gas production from PGE’s proposed transaction?

A. CUB states that “the contract anticipates a 35-year fuel supply -- extending beyond the life of the current IRP and beyond the life of PGE's generating assets. There is no record relating to PGE's natural gas needs in 2051, so it is difficult to say with any real certainty whether the gas anticipated by this contract will be *fully* used and useful” (CUB 200/5 – emphasis not added).

Q. Is CUB’s statement accurate?

A. Only in part. [redacted] This does exceed the IRP planning horizon, but it does not exceed the expected useful lives of the gas-fired thermal plants that it would serve. In fact, PGE’s gas-fired thermal plants have 45-year useful lives and their depreciation schedules are currently set at this level based on PGE’s most recent depreciation study (Docket No. UM 1679) as approved by Commission order No. 14-297.

C. Market Prices

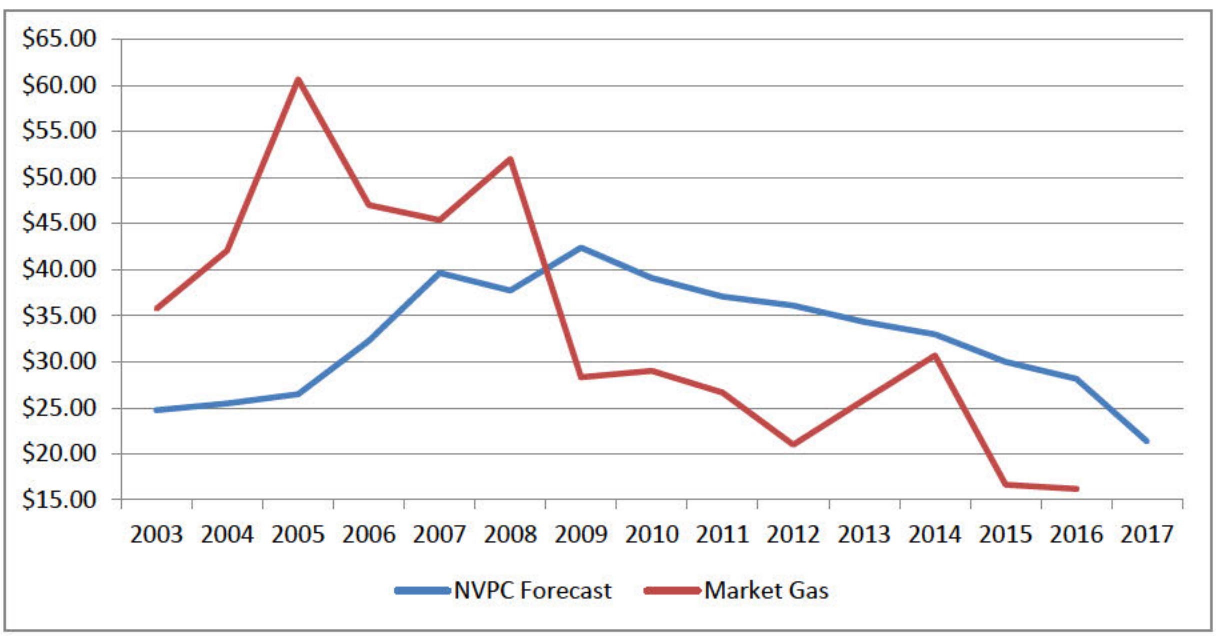
Q. How does CUB conclude that the competitive wholesale market will produce lower prices than a monopoly utility cost-of-service investment over the long run?

A. CUB does so by comparing a graph of market prices for gas (CUB 200/7, which shows increasing and then decreasing prices over the past 20+ years) to a graph of PGE's residential electric prices (CUB 200/8, which have only increased over this period).

Q. Is this a reasonable comparison?

A. No, for two reasons. First, the comparison of market prices for gas to PGE's residential electric prices is not an apples-to-apples approach. There are numerous factors that affect total utility prices per kWh that CUB has not factored out of its comparison. Instead, a more reasonable approach would be to compare PGE's unit NVPC to market gas (both per MWh), which we provide in Figure 2, below.

Figure 2
PGE's NVPC Forecast and Market Gas
$ per MWh



Q. What does Figure 2 show?

A. It shows that over the period of declining gas prices, PGE's unit NVPC have also declined (after a one-year lag). The types of things CUB did not address in the depiction of PGE's residential electric rates for this same period are: 1) the implementation of 717 net MW of wind generation per Oregon's renewable energy standards (RES), 2) significant additional costs to meet the relicensing requirements of PGE's hydro facilities, 3) the implementation of 1,060 net MW of additional gas-fired generation, and 4) a major upgrade at PGE's Coyote plant and pollution controls at PGE's Boardman plant.

Q. Wouldn't the incremental wind generation help bring down the unit NVPC?

A. Yes, but this has been significantly offset by a decline in PGE's overall hydro capacity due to the loss of long-term contracts and the transfer of a portion of the Pelton/Round Butte facility to the tribes.

D. Incentive for Further Investment

Q. Doesn't the additional gas-fired rate base support CUB's argument that the proposed gas hedging would create an additional incentive for more gas-fired generation?

A. No. PGE has proposed a guideline to specifically limit the amount of long-term gas hedging that can be obtained, and 30% was only the upper bound of a proposed range. Further, the increase in gas-fired generation since 2006 has been the result of several factors:

- To reduce PGE's reliance on the power market due to our short position.
- The need to back up intermittent renewable resources, which have been deployed in accordance with the RES.
- The need to replace baseload coal generation that is being terminated.

The addition of gas-fired generation in the future will need to be based on its cost-effectiveness and the reasons why it is both needed and superior to other alternatives, but not based on a perceived PGE bias.

Q. Residential electric prices aside, aren't market prices typically lower than hedged prices?

A. PGE agrees that a premium exists to hedge price certainty into the future and that this premium increases as the length of the transaction grows. We address this issue in reply to ICNU's comments in Section V, below.

V. Response to ICNU

Q. What issues has ICNU raised individually with regard to PGE's long-term gas hedging proposal?

A. ICNU's primary individual concern relates to a risk premium that they have identified as "embedded in forward markets for natural gas over the period 2010 to 2016 and that those risk premiums have been substantial" (ICNU 200/9). ICNU also claims that "there is a positive relationship between the observed risk premiums and how far ahead of the prompt month the forward price is calculated." (ICNU 200/9) ICNU supports both claims with the data presented in its Figure 1 (ICNU 200/7).

Q. Do you agree with ICNU's analysis and conclusions?

A. No. We believe that ICNU's analysis is flawed because it uses only selective information to derive the results. For instance, ICNU states (ICNU 200/8):

> If there is no risk premium present in these forward curves, it would be expected that the forward prices are an unbiased expectation of future spot prices. That is, it should be expected that forward prices exceed the ultimate spot price 50% of the time and are less than the spot price 50% of the time. Stated differently, if there is no risk premium, the median forward curve forecast error should be zero. If, however, the median forecast error exceeds zero, that is an indication of a risk premium.

For its analysis, however, ICNU only uses data from a period with declining market prices. Based on this, it is not surprising that the results support ICNU's conclusions. Over a longer period of time, which includes both increasing and decreasing prices, however, the data would provide very different results. We also note that the net variance that ICNU identifies is not so much a risk premium as a "beat the market" factor, which hedging is not intended to do.

Q. Can you demonstrate this?

A. Yes. We provided a variation of this in a back cast analysis presented in PGE Exhibit 100, pages 15-19. Based on that information, forward prices are below the spot market during periods of increasing market prices, and above the spot market during periods of decreasing market prices. Using ICNU's approach over the entire back cast period, the results would likely reflect a net variance near zero. As with ICNU's analysis, if we were to only focus on the period with declining market prices, the result would be consistent with ICNU's and show a positive net variance (i.e., premium).

Q. Is PGE stating that there is no risk premium associated with hedging?

A. No. At the conclusion of the previous section, we stated that a premium does exist to hedge price certainty into the future and that this premium increases as the length of the transaction grows. This premium can be observed in the futures market and its value is determined by the forecasted prices at the time of execution. This type of premium also represents the implicit value of price stability and was exactly what PGE's business customers said they were willing to pay during a period when natural gas prices were inflated – see Section II, part E, above.

Q. How does PGE's proposed transaction address the risk premium?

A. It does so by meeting PGE's proposed first guideline, which requires that the Long-Term Projected Cost must be at or below the comparable Long-Term Benchmark Price. This means that there are no inordinate costs in PGE's proposal and that the risk premium is contained.

VI. Summary and Conclusions

Q. Please summarize PGE's rebuttal testimony.

A. Parties have addressed a large number of issues and concerns regarding PGE's proposal for long-term gas hedging and all recommend against Commission approval. We acknowledge the concerns expressed regarding our request and understand the basis for those concerns. In this rebuttal testimony, we have shown that put in proper perspective those concerns are not substantial and are outweighed by the significant benefits the proposed transaction would have for our customers. We identify certain primary points regarding the concerns expressed as follows:

- PGE is not requesting any deviation from normal regulatory policy or practice. Schedule 125 allows updates for hedging and contracts, which PGE's proposal entails.
- The proposal for the 2017 AUT is cost effective within PGE's proposed guidelines.
- [redacted]
- The Parties claim that PGE's proposed guidelines are inadequate but have not proposed specific alternatives. No Party claimed that there should not be any guidelines.
- The timeline for review has been expedited but reflects a significant concession by our counterparty, beyond the industry standard timelines, to accommodate the required regulatory review in this proceeding. We believe the Parties' reply testimonies indicate that they overcame the challenges posed by an expedited review

period. PGE appreciates that effort and the amount of work required of Parties to review the proposed agreements and PGE's due diligence.

Q. Based on all of the testimony provided in this proceeding what do you currently request the Commission to approve?

A. PGE believes that we have proposed a transaction that is cost effective and in the interest of customers. Consequently, we request the Commission approve the following items:

1. Affiliated interest transactions between PGE and PGGS as submitted in Docket No. UI 376.
2. A waiver of the lower-of-cost-or-market rule for the Purchase Gas Agreement between PGE and PGGS (also requested as part of Docket No. UI 376).
3. Proposed guidelines as described in PGE Exhibit 200. Even if the Commission agrees that these guidelines are inadequate, they at least represent a good starting point as additional guidelines can be developed over time.
4. The long-term gas hedging costs to be included in the 2017 AUT per the formulas described in PGE Exhibit 300 and the production collar described in PGE Exhibit 600.

Q. If the Commission approves all the requested items, does this mean that [redacted] beyond 2017 could be automatically included in subsequent AUT fillings without question or review?

A. No. It simply means that all the discussion about the basic appropriateness of including such a transaction does not need to be revisited. It also means that if the transaction falls within approved guidelines (if any), then that aspect of prudence is established. PGE would still have to demonstrate prudence based on the information available at the time we propose and execute the specific transactions.

PGE understands, however, the Parties' desire for caution and that they are hesitant to recommend approval of guidelines. Nevertheless, PGE believes that appropriate guidelines would provide PGE the tools to be commercially agile in order to reduce long-term gas price volatility. In conclusion, PGE would also be receptive to alternative solutions where:

- Only [redacted] (and the cost included in 2017 AUT rates) are approved along with the UI 376 transactions and waiver. [redacted] would be submitted in rate making proceedings as the Commission indicates is acceptable with all prudence to be determined at that time.
- Guidelines (if any) serve as mere commercial guideposts to use when assessing the market.

Finally, in future proceedings, we could use the [redacted] to inform Parties and the Commission on the success of PGE's initial efforts and how those could either: 1) benefit customers with continued activity, or 2) indicate that no additional activity is warranted.

VII. Qualifications

Q. Mr. Faist, please state your educational background and experience

A. I received a Bachelor of Business Administration in Accountancy from the University of Notre Dame in 2006 and a Master of Science in Accountancy from the University of Notre Dame in 2007. I have been with PGE since 2013 and prior to joining the Structuring and Origination Department was a member of the Corporate Tax Department. Prior to joining PGE, I worked for Conway, Inc. and KPMG.

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
801	Insights on Long-Term Natural Gas Hedging Strategies – Analysis of PGE's Proposed Second Guideline
802	Results of Customer Survey

INSIGHTS ON LONG-TERM NATURAL GAS HEDGING STRATEGIES

A REPORT PREPARED FOR
PORTLAND GENERAL ELECTRIC
MAY 2016

GARDNER WILLIAM WALKUP, JR.
DR. ADAM BORISON
DR. GREG HAMM

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1 Executive Summary

1.1 Objectives

1 Natural gas is becoming a more important fuel in PGE's generation mix; consideration of long-term supply and the uncertainty in the cost of this supply is warranted.

2 This report summarizes work done to provide insights as to what levels of hedging are appropriate to reduce PGE's customers' exposure to both long-term variability and short-term volatility in gas-related costs.

3 We have provided multiple approaches and perspectives to help PGE triangulate on the appropriate level of hedging.

1.2 Key Insights

4 Hedging decisions to reduce the exposure of PGE's customers to long-term variability are similar to resource planning decisions.

a) A long-term variability trade-off metric can be derived from planning decisions; this metric indicates that a hedging level of 20%, and likely higher, can be supported. A sensitivity case with zero gas electricity price correlation indicates a maximum of 50% hedging is appropriate.

5 Hedging decisions are typically based on judgments about the avoidance of extreme outcomes; the objective is typically to reduce the probability of a specified extreme outcome to a target probability threshold.

a) A reasonable long-term variability avoidance metric suggests that a hedging level of 60-70% can be supported. Examination of the marginal effectiveness of hedging indicates a 20-50% level.

b) A reasonable short-term volatility avoidance metric suggests that a hedging level of as high as 90% can be supported.

6 While the current analysis provides useful insights and guidelines for the appropriate long-term hedging level, we recommend additional research and refinement. Further analysis is particularly warranted on the maximum hedging level.

a) Key areas of improvement may include further analysis of the relationship between gas and electricity markets – especially with high levels of renewables, more evaluation of the costs and risks of hedging – particularly at high levels, the use of metrics calibrated to peer performance, and improved modeling of plant and market costs.

2 OBJECTIVES OF THIS REPORT

7 The report provides insights, and a review of the supporting analytical work upon which these insights are based, on how much of PGE's anticipated long-term natural gas demand should be hedged.

8 In this context, hedging is defined as the ability to establish a firm price for future natural gas supplied to PGE. The established price is not necessarily constant but can vary with time. Importantly, while the price may vary with time, it is known with certainty for all those volumes of the anticipated demand that are hedged. Natural gas demand not hedged would need to be acquired at the then prevailing market price. Of course, future market prices for natural gas are highly uncertain.

9 Our work has attempted to determine the impact on PGE's customers of different hedging strategies, and insights on appropriate levels of hedging are meant to be determined from the customers' perspective.

10 The specific available mechanisms for implementing the hedging level were not investigated in this work. The insights summarized in this report should be interpreted as applicable to a perfect hedge. The specific alternatives for implementing hedging should be evaluated with these insights in mind.

3 INTRODUCTION

3.1 The objectives of long-term natural gas hedging: The customers' perspective

11 With the addition of PGE's Port Westward 2 (2015) and Carty (2016) power plants, PGE's natural gas-fired generation portfolio totals roughly 1,900 MW of nameplate capacity, representing a mixture of baseload and flexible peaking resources expected to provide approximately 40% of PGE's annual energy requirement by 2017. This translates to approximately 65 Bcf/year (178,000 Dth/d average) of natural gas demand. With gas-fired power plants representing a significant portion of the resource portfolio, managing natural gas supply and associated price risk are key elements of PGE's overall strategy to supply customers with reliable power at reasonable prices.

12 PGE, along with many U.S. utilities, is becoming increasingly gas-intensive. In PGE's recently filed 2013 Integrated Resource Plan (IRP), PGE proposed to perform an assessment of longer term gas supply options. PGE is examining strategies (i.e., costs, risks, etc.) of capturing long-term gas supply sources (e.g., investments with a 30-year life).

13 A key differentiation between different long-term gas supply options is the degree to which the associated natural gas supply is exposed to uncertain future natural gas market prices. A number of studies have noted that electric utility customers and regulators are risk averse and are interested in cost-effective reductions of the uncertainty in future costs (i.e., monthly power bill) that could result from uncertainties like natural gas market prices.[1]

14 The uncertainty in future natural gas prices could create uncertainty in customers' costs in two main ways.

15 The first type of uncertainty in natural gas prices is the variability in the long-run average price. It is generally accepted that natural gas prices are currently at relatively low levels, and are expected to remain at these low levels for quite some time, because of the recent drastic growth in natural gas supply created by the shale revolution.[2] However, it is possible that long-lasting structural changes could significantly increase the long-run average price of natural gas from current expectations. This could be caused by a structural (i.e., long-lasting) increases in demand or because supply levels fall. A full discussion of these scenarios is beyond the scope of this report; however, conventional wisdom is that the greatest risk to natural gas supply would be a disruption to an operator's ability to conduct natural gas supply operations (e.g. drilling, hydraulic fracturing, etc.). Demand growth beyond current expectations would likely be caused by multiple factors including faster than expected GDP growth, a renaissance in manufacturing, technology developments that would create a substantial market for natural gas in

[1] See for example, p 250 in Fereidoon P. Sioshansi, Future of Utilities – Utilities of the Future, Academic Press, 2016
[2] Sieminski,A: "Implications of the U.S. Shale Revolution", http://www.eia.gov/pressroom/presentations/sieminski_10172014.pdf

transportation and a policy shift towards high levels of LNG export (i.e., to support foreign-policy objectives).

16 PGE's customers costs are somewhat shielded from the uncertainty in long-run average prices in natural gas because of the diversity of electricity supply within PGE generation fleet; however, customers' costs retain exposure to this uncertainty particularly given the growth of natural gas-fired generation within PGE fleet.

17 The second main type of uncertainty in natural gas prices that could impact PGE's customers' cost is the short-term volatility in natural gas prices. This includes price swings caused by short-term drivers such as the weather, transportation disruptions, local constraints such as limited pipeline off-take, and many others. These varied forces impact natural gas in different ways and over different time-scale. Historically, natural gas price volatility has been significantly higher than other commodities such as oil.

18 In this study, the objective of hedging is to efficiently reduce the impact of both long-term variability and short-term volatility of natural gas prices on PGE's customers' costs.

3.2 Definition of objective variable: NVPC

19 Future customer costs involve many factors in addition to the price of natural gas, and modeling all these factors is beyond the scope of this study. Consequently, we defined a summary or proxy variable closely related to customers' costs on which the impact of natural gas prices can be estimated efficiently and accurately.

20 In this study, we use NVPC (Net Variable Power Costs) as the relevant proxy for customers' cost to investigate the impact of natural gas hedging. The rationale for using NVPC, as well as, the method of calculating NVPC is described elsewhere.[3]

21 In this report, we assume that changes in NVPC with various levels of long-term natural gas hedging reflect similar changes in customers' costs. Thus, the ranges of hedging determined using NVPC will be appropriate for the customer.

3.3 Structure of this report

22 The remainder of this report describes three key technical issues that must be addressed in order to assess customer exposure at different hedging levels, and to choose the appropriate level:

- Natural gas market prices – gas prices drive operating costs both directly (gas purchases) and indirectly (gas-based electricity purchases and sales); a comprehensive and rigorous forecast of gas prices is important.

[3] PGE White Paper: Long-term Gas Hedging: Analysis and Recommendations', May 2016

- Electricity market prices – electricity prices drive operating costs, and can be closely tied to gas; a comprehensive and rigorous forecast of electricity prices and their relationship to gas prices is important.
- Formal risk metrics – customer exposure with different hedging strategies must be measured and compared rigorously; selection and calculation of formal risk metrics is important.

Following these three technical sections, we describe results and key insights.

4 Natural Gas Market Prices

23 Physical commodities, like natural gas, pose a fundamental financial engineering challenge. The requirement to produce and move physical commodities from source to demand means that it is impossible to execute a sales contract and physical delivery simultaneously. This is in contrast to purely financial products like interest rates, equities or currencies where the execution/liquidation of the contract is coincident with delivery of the underlying asset.

24 As a consequence, physical commodities trade in a forward market where contracts for future delivery are established. Forward markets define current forward contract prices but not expected future spot prices. The financial engineering literature documents various attempts to recover expected future spot prices from a wide-range of information including the forward markets.[4]

25 Regardless of the challenge, elicitation of expected future spot prices is required for decision-making across the energy business. Typically, this involves the incorporation of multiple views either provided internally or from external sources. However, no amount of analysis or expert elicitation will change the simple, inescapable truth that future spot commodity prices are uncertain.

26 Thus, the fundamental financial engineering challenge is how to accurately express the current range of uncertainty of future spot prices given currently observable information.

27 For this study, any solution to this fundamental engineering challenge must meet the requirement of providing insight on both the long-term variability and the short-term volatility of natural gas prices.

4.1 Natural gas price model selection

28 Early commodity price modelling efforts borrowed heavily from the modeling of financial assets and focused on random-walk methods. Most employed a Brownian Motion model that underpins the famous Black-Scholes formulation of the pricing of options contracts for equities.

29 The essence of these random-walk methods is that at any point in time the price of the commodity is exposed to a random change. The size of this random change is characterized by a volatility term. The bigger the volatility, the bigger the likely change. These random walk models are frequently referred to as single factor models where the single factor is the volatility. In truth, these models have other factors (e.g. drift) but the key driver of uncertainty is the volatility. [5]

[4] For example see: The dynamics of commodity spot and futures markets: A primer Robert S Pinkdyck The Energy Journal; 2001; 22, 3

[5] Paddock, J. L., D. R. Siegel, J. L. Smith. 1988. Option valuation of claims on real assets: The case of offshore petroleum leases.Quart. J. Econom. 103 479–503

30 These random-walk models are extremely useful for short-term decisions, such as pricing short-term options. However, they are not particularly useful for long-term decisions because the uncertainty of future prices grows over time to extremely high levels that are generally viewed as unrealistic and unsupportable.

31 Industry participants understood that extremely high prices would lead to an increase in supply, which in turn would lead to lower prices. And extremely low prices would lead to a decrease in supply, which in turn would lead to higher prices. This mean reversion market dynamic could not be represented by random-walk models. However, the financial engineering community did have other models with this mean-reversion and these were applied to commodity price modeling.[6]

32 These mean-reversion models are intuitively appealing. When commodity prices sharply rise, it is likely that supply will also increase because high-cost sources can be tapped. Conversely, when prices sharply fall, supply will shrink as high-cost producers stop production. There will be a time-lag between price changes and resulting changes in supply; however, the fundamental behavior is consistent with most industry participant's understanding of market dynamics.

33 Commodity prices appear to demonstrate aspects of both random-walk and mean-reverting behavior in practice, and models have been developed to capture both dynamics. Early versions of these models were tied to the conceptually-challenging concept of stochastic convenience yields but Edwardo Schwartz and James E. Smith developed an approach that met the challenge of incorporating both shorter-term random-walk behavior and longer-term mean-reversion dynamics in a user-friendly way.[7,8] We have used this two-factor model in this study.[9]

34 A derivation of the two-factor model is beyond the scope of this paper; however, the original paper is available as are case-studies of applying this model.[10]

4.2 The Two-Factor Model

35 Future spot prices in the two-factor model are calculated as the outcome of two stochastic factors; namely, a short-term deviation process and a long-term equilibrium process. The short-

[6] Dixit, A. K., R. S. Pindyck. 1994. Investment Under Uncertainty. Princeton University Press, Princeton, NJ
[7] Gibson, R., E. S. Schwartz. 1990. Stochastic convenience yield and the pricing of oil contingent claims. J. Finance 45 959–976.
[8] Eduardo Schwartz and James E. Smith. Short-term variations and long-term dynamics in commodity prices. Manage. Sci., 46(7):893–911, 2000.
[9] In reality there are 6 factors in this model that must be estimated
[10] Jafarizadeh, B., & Bratvold, R. B. (2012, January 1). A Two-Factor Price Process for Modeling Uncertainty in Oil Prices. Society of Petroleum Engineers. doi:10.2118/160000-MS

term deviation process is a mean-reverting process controlled by the speed of mean reversion (i.e., mean-reversion half-life) and a Brownian Motion random-walk process (i.e., short-term volatility).[11] The long-term equilibrium process is a standard Brownian Motion/random-walk incorporating long-term volatility and long-term drift. The initial spot price and the initial long-run equilibrium price are inputs. Finally, the two-factor model provides for a correlation between the short-term and long-term volatilities.

36 This formulation of the two-factor model is quite intuitive. Additionally, it provides insight on the two key uncertainties that the hedging strategies that are the central issue of this report. Namely, the nature of both the long-term variability and the short-term volatility of natural gas prices that are addressed by hedging in this report.

4.3 Two-factor model parameterization (AECO forecast only)

37 Parameterization of the two-factor model requires developing estimates for the following model inputs:

- Initial spot price
- Initial equilibrium price
- Short-term volatility
- Mean-reverting half-life
- Equilibrium price volatility
- Drift of equilibrium price

38 The most common method to estimate these parameters is to match the prediction of the model to some data set. The data set used and the method to match can vary. For this report, an estimate of the base-case future prices was provided by PGE. This base-case forecast was developed by the consulting company Wood Mackenzie as described elsewhere.[12] Further, we used the base-case forecast for the AECO market to parameterize the two-factor model. The two-factor simulation runs were used to calculate the prices in other markets as described below.

39 We used Monte-Carlo simulation and manual adjustment of the parameters until the expected value (probability-weighted average outcome) closely matched the base-case.

40 The formulation of the two-factor model does not include the impact of seasonality on natural gas prices but the literature explains how seasonality can be included. We implemented this approach in this model by defining a monthly adjustment factor.[13] The equation for using this adjustment factor is:

[11] This is referred to as a Ornstein-Uhlenbeck process
[12] PGE White Paper: Long-term Gas Hedging: Analysis and Recommendations’, May 2016
[13] Eduardo Schwartz and James E. Smith. Short-term variations and long-term dynamics in commodity prices. Manage. Sci., 46(7):893–911, 2000.

$$(price\ with\ seasonality) = exp(log\ (price\ calculated\ from\ two - factor\ model) + (monthly\ adjustment\ factor))$$

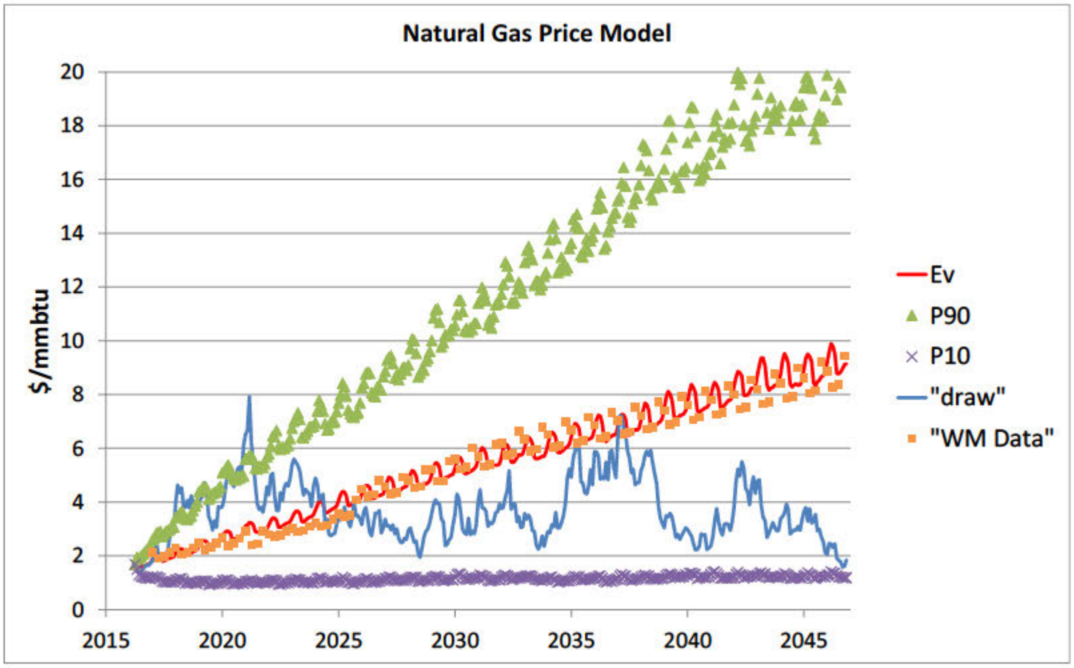
41 The monthly adjustment factors are provided in the table below.

Table 1 – Monthly adjustment factors

Seasonal Adjustment Factors when prices are calculated as $/mmbtu			
Jan	0.0830	Jul	-0.0396
Feb	0.0737	Aug	-0.0338
Mar	0.0454	Sep	-0.0330
Apr	-0.0436	Oct	-0.0252
May	-0.0531	Nov	0.0152
Jun	-0.0473	Dec	0.0578

42 The final match to the base-case data is shown in the figure below based on 10,000 simulation runs. The orange points, labeled WM Data, are the base-case.

Figure 1 - Match of two-factor model to base-case data (AECO)



43 This model has two key features. First, it provides a state-of-the-art view of the range of uncertainty in future natural gas prices. Second, it is calibrated to the WM base case; that is, the expected value matches the WM base case well. It is important to note that we have not independently analyzed or verified this base case.

44 The parameters that resulted from this matching process are shown in the table below.

Table 2 - Two-factor model parameters to match AECO base-case forecast

Parameter	Units	Value
Initial spot price (1 Mar 16)	$/mmbtu	1.6
Initial equilibrium price	$/mmbtu	4.0
Short-term volatility (annual)	%	33%
Mean-reversion half-life	years	7
Equilibrium price volatility (annual)	%	14.3%
Drift of equilibrium price (annual)	%	1.8%
Correlation of short-term and long-term movement	unitless	0

45 The authors have been using this matching approach for over 10 years and have matched the two-factor model to many data sets. The results of the match to the base-case AECO forecast shown in the table above are quite similar to most matches with a one main exception. The values for the short-term and long-term volatilities, the drift of the equilibrium price and the lack of a correlation between short-term and long-term movements are all similar to other matched values in our experience. The mean-reversion half-life is considerable longer than what we have observed in the past. This unusual value is driven in part by the very flat base-case forecast shown in Figure 1 above for the year between 2017 and about 2025.

4.4 Forecasting Other Markets

46 Natural gas is traded at a number of hubs and PGE is active in a number of these hubs. As discussed above, the two-factor model was matched to the AECO market base-case and then used to generate 10,000 independent runs or cases. We need to calculate what the corresponding price would be for each of the 10,000 cases would be for the Sumas and Rocky Mountain hubs.

47 A time-dependent (monthly) basis differential was calculated for these two markets by calculating the difference in the AECO base-case and both the Sumas base-case and the Rocky Mountain base-case. The base-cases for the Sumas and Rocky Mountain hubs, like the base-case for the AECO hub, were developed elsewhere, and we did not independently analyze or verify these base-case assessments.

48 The time-dependent basis calculated for each market was applied to each of the simulation cases calculated from the two-factor model for the AECO market to produce consistent forecasts in each market.

5 Electricity Market Prices

49 To evaluate different long-term gas hedging strategies, we need a suitable model of electricity prices and their relationship to natural gas prices. The relationship between natural gas and electricity prices is complex and highly dependent on the specific characteristics of the electricity market in question, the supply/demand balance as determined by load, generation, regulation and other factors.

50 In some markets at some times, natural-gas fired generation is at the margin and effectively determines the electricity price via the heat rate of the marginal unit. There is essentially a one-to-one correspondence between natural gas and electricity; a 1% increase in gas price leads to a 1% increase in electricity price. In other markets at other times, the electricity price is determined by other forms of generation, such as wind, nuclear or hydro. In these circumstances, the electricity price is only weakly tied, if at all, to the gas price; a 1% increase in gas price may have little, if any, effect on the electricity price.

51 In a typical electricity market, the relationship between gas and electricity varies substantially throughout the day and year. There are different gas-electricity relationships for time-of-day and time-of-year submarkets. The time-of-day is typically characterized with two or three periods: on-peak and off-peak, or super-peak, on-peak and off-peak. The time-of-year is typically characterized by seasons: summer, winter and spring/fall, or quarters. In our work, we chose to consider eight submarkets; on-peak and off-peak times of day, and four quarters during the year.

52 In each submarket, one could assess the relationship between gas and electricity via a correlation coefficient. However, this is purely a statistical approach and ignores the structural relationship between gas and electricity: gas prices effectively cause electricity prices when gas generation is at the margin. A better, well-established approach is the use of regression analysis, a mix of structural and statistical modeling.[14] We chose to develop a linear regression model of spot market electricity price as a function of spot market gas price in each submarket.

5.1 Implementation of the Market Electric Price Model

53 Linear regression describes the relationship between a dependent variable and one or more independent variables. The model can be expressed in the following form:

$$a_1x_1 + a_2x_2 + \cdots a_nx_n + C = y + e$$

In the equation, y is the dependent variable, the x_i are the independent variables, C is a constant, the a_i are the multipliers found in the solution of the problem, and e is the error of the prediction.

[14] See for example, Samantha Azzarello, *Observing the Changing Relationship between Natural Gas Prices and Power Prices*, CME Group, April 2013.

54 To solve the model, we need a number of cases with a variety of values for both the dependent and independent variables. These cases can be expressed as:

$$a_1 x_{1j} + a_2 x_{2j} + \cdots a_n x_{nj} + C = y_j + e_j$$

55 Here the *j*'s represent the different cases. We solve the model by picking the values for a_i that minimize the sum of the squared errors. With a single independent variable, we can visualize this as plotting the x and y variables and drawing a straight line that best fits the data.

56 For the market electric price model, we created four models for on-peak electricity and four models for off-peak electricity. Each model was specific to a quarter of the year. This allowed us to accommodate the different weather and water conditions at different times of the year.

57 We also created two separate sets of models. One based on Aurora predictions of the future relationships between market gas prices and market electric prices, and one based on the historical relationships between gas and electric market prices. The two sets of models allow for incorporation of different views on the strength of the gas-electricity link. With increased gas-based generation, it may become stronger. With higher RPS targets, it may become weaker. Below we discuss these two sets of predictions separately.

58 In addition, we also examined a sensitivity case where there is no correlation between gas and electricity prices. This reflects a future world where, perhaps because of very high renewable penetration, gas prices and electricity prices are essentially unrelated.

5.2 Aurora Based Predictions

59 The input data for the Aurora based predictions was the WECC ELON (on-peak electric market price), WECC ELOF (off-peak electric market price), and AECO NG (gas) data found on the "Pricing" sheet of the MTS model as of March 16, 2016. The data included quarterly values for 2017 to 2046, a total of 30 data points for each forecast. With MPe representing the electricity price and MPg representing the gas price, the regression results were:

60 On Peak

Q1: MPe = 11.023 + 10.110 MPg + P(0,2.051)

Q2: MPe = 1.919 + 10.736 MPg + P(0,1.880)

Q3: MPe = 15.73 + 9.610 MPg + P(0,2.534)

Q4: MPe = 16.929 + 9.902 MPg + P(0,2.413)

61 Off Peak

Q1: MPe = -2.586 + 11.267 MPg + P(0,2.126)

Q2: MPe = -11.261 + 10.037 MPg + P(0,2.980)

Q3: MPe = -1.600 + 10.931 MPg + P(0,2.057)

Q4: MPe = 1.300 + 10.847 MPg + P(0,2.52)

62 To illustrate the interpretation of these equations, let's review the equation for On-Peak, Quarter 1. MPe is the average market price of electricity in $/MWh. MPg is the average gas price $/mmBtu. P is the random term that accounts for the uncertainty in the gas price. The random term is normally distributed (like a bell curve) and the terms in parentheses are the mean and standard deviation. Assume that the average gas price is $3.00. The predicted market price is 11.023 + 10.110*3.00 + 1.003 = 42.356 $/MWh. To emphasize, the 1.003 is a random term; it can be different in every sample or trial.

63 The fit of this model is extremely good. R-squared is a statistical measure of how well the regression fits the data. Although, other measures should also be examined, it is usually a good indicator of the quality of the model. A 100% R-squared is a perfect fit. R-squares for on-peak and off-peak in all quarters were all 98% or higher. The F statistic is another measure of the quality of the prediction; the F statistic is the probability that the fit is the result of random chance rather than a true relationship. A small F statistic is better. An F statistic of over 5% is considered bad. Our largest F statistic is less than 1E-24, or 24 places to the right of the decimal. This means the odds that the fit is by chance are infinitesimally small. The P statistic is a similar measure for individual components of the prediction. This statistic is very good for all gas components, again many decimal places smaller than considered acceptable. The P statistic for the constant term, off-peak, 4th quarter is 33%. This is quite high and suggests that this term is not accurate. However, this term is small and has little influence on the results.

64 The Aurora-based model does an excellent job of capturing the very strong relationships in the Aurora runs between forecast natural gas and electricity prices.

5.3 Historically Based Predictions

65 The input data for the historically based predictions is from a spreadsheet received from PGE (GasPlantOutputsAndPrices.xlsx) on March 18, 2016. This data covers the period from August 1, 2008 to March 16, 2016. It provides hourly outputs for plants, daily Sumas gas prices, daily peak and off-peak electric prices at the Mid-C market point. It also provides monthly averages of these. This provides us with seven or eight points for each quarter. This is very sparse data for fitting a regression model. The results of the forecasts were:

66 On Peak

Q1: MPe = -2.054 + 8.881 MPg + P(0,3.117)

Q2: MPe = 7.239 + 5.652 MPg + P(0,4.849)

Q3: MPe = 8.872 + 8.315 MPg + P(0,4.104)

Q4: MPe = 1.962 + 8.745 MPg + P(0,2.444)

67 Off Peak

Q1: MPe = -0.842 + 7.236 MPg + P(0,4.589)

Q2: MPe = 10.608 + 0.609 MPg + P(0,7.625)

Q3: MPe = -1.794 + 7.939 MPg + P(0,5.473)

Q4: MPe = 3.729 + 6.815 MPg + P(0,1.220)

68 Definitions of the variables and operations of the model are the same as above.

69 The fit of this model is not as good as the prior model. This is not particularly surprising since the prior model was a fit to another model, and this model is a fit to historical data. First, note that the standard deviation of all the errors terms but one is larger (off-peak, Q4). This means that the outputs of this model will have a larger random component and be less correlated with gas prices. R-squares for this model in Quarters 1, 3, and 4 are over 85% for peak electric prices and over 75% for off-peak electric prices. For Quarter 2, the R-squares are 50% for the peak and near 0% for the off-peak. The F-statistic is similarly good for Quarters 1, 3, and 4; but, is weak for Quarter 2, on-peak at 8% and off-peak at 88% shows a high probability of no correlation between natural gas and electricity market prices. The P-statistic indicates reasonable accuracy in the constant and gas relationships for Quarters 1, 3, and 4. For Quarter 2, on-peak electricity the model is relatively weak but still can be considered predictive. For Quarter 2, off-peak electricity the model shows no statistically significant correlation with gas. We should emphasize that it is hard to interpret the Quarter 2 results with this small sample. They could mean either that gas has little or no influence or that the sample size is just too small to detect the influence. A lack of correlation in Q2 is not surprising given high hydro and wind generation, and low demand, during this time of year.

70 The history-based model reflects the complex, variable and uncertain relationship between gas and electricity prices in the past; it does not capture potential changes in that relationship in the future.

6 RISK METRICS

71 When it comes to electric power costs and rates, customers care both about long-term variability – persistently and substantially high cost scenarios over years - and short-term volatility – unexpected and sizable year to year changes. It is important to measure carefully the impact of hedging on both of these.

6.1 Long-term Variability Trade-off Metric

72 Strictly-speaking, the term “hedging” deals with reducing short-term volatility, uncertainty usually over 3-5 years. There is relatively little discussion of long-term variability, uncertain scenarios of 10, 20 years or more in the hedging context. In the utility industry, the context where long-term variability does come up is integrated resource planning.

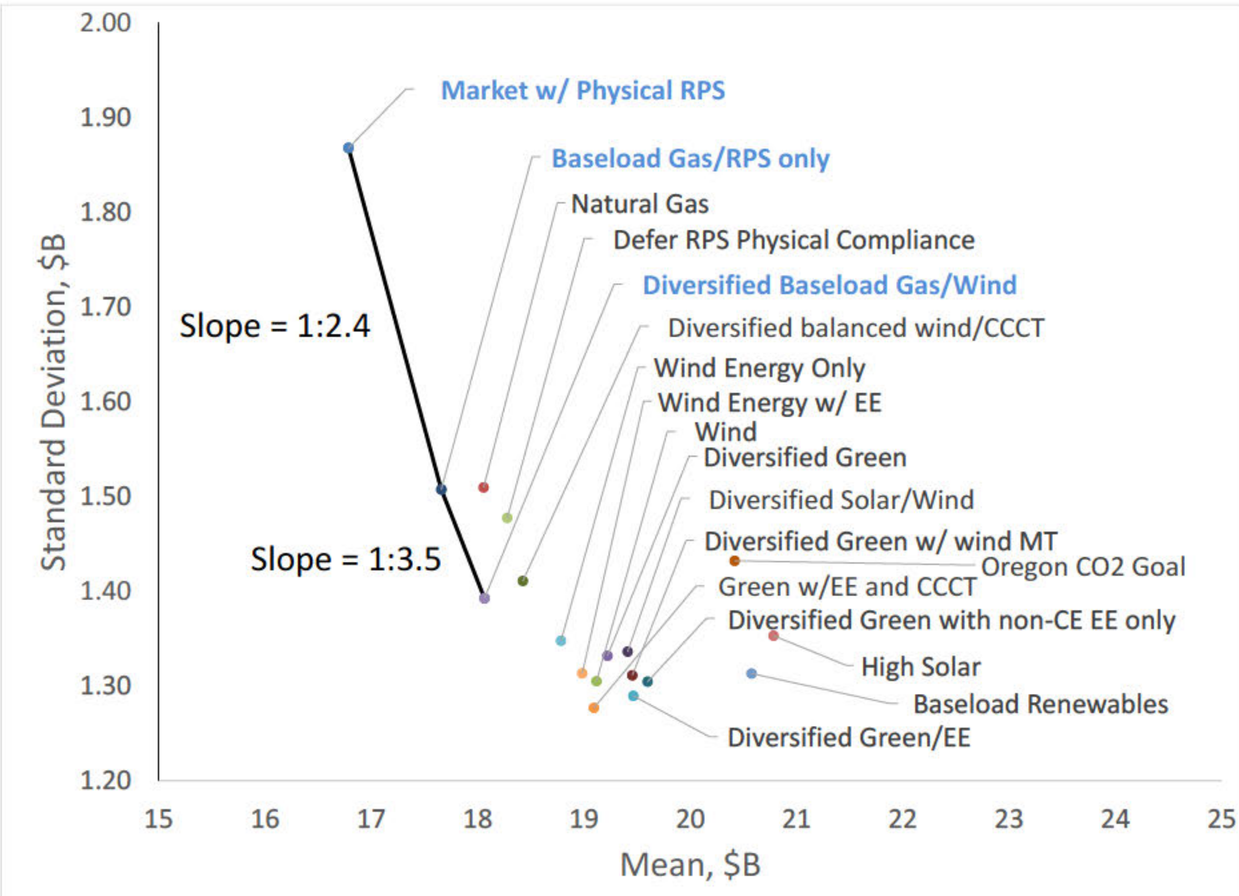
73 Many IRPs, as developed by utilities and as approved by regulators, include detailed descriptions of different plans with different levels of long-term cost (as measured by expected, reference or median cost) and long-term variability (as measured by standard deviation, 90th percentile cost or similar).[15] Often there is a choice between lower-cost plans with higher variability, and higher-cost plans with lower variability and a preferred alternative. Using this information, we can infer the tradeoff that utilities and regulators feel is appropriate when making a choice between strategies with different long-term costs (typically expected cost) and long-term variabilities (typically standard deviation). We chose to use the 2013 Portland General Electric IRP to estimate this tradeoff metric, and apply it to the alternative hedging strategies.[16]

74 PGE’s 2013 IRP provides a straightforward presentation of uncertainty in resource plans. We received data on the mean and standard deviation of each resource plan in the IRP.[17] We then plotted the data on a graph of mean cost and standard deviation. We understand that there are many factors underlying the choice of a preferred plan; nevertheless, this approach provides a rough indication of the acceptable risk-return tradeoff.

75 This plot is below.

[15] See for example Avista, 2015 IRP; Cowlitz PUD, 2014 IRP; Idaho Power, 2015 IRP; Pacificorp, 2015 IRP; Portland General Electric, 2013 IRP; Puget Sound, 2013 IRP; Seattle City Light, 2012 IRP.
[16] See for example, 2013 Integrated Resource Plan, Portland General Electric, p. 6.
[17] 2013 IRP Portfolio costs in various futures.xlsm

Figure 2 – Long-term value metric analysis



76 All else being equal, PGE prefers a lower mean (less expected cost) and a lower standard deviation (less cost variability). That is, they prefer points to the bottom and to the left in this graph. These points form what is known as an efficient frontier of non-dominated alternatives. This frontier is shown by the solid line in the graph. From a mean-standard deviation view point, this suggests the PGE customers are willing to accept $1.00 in increased mean in return for between $0.29 (1/3.5) and $0.42 (1/2.4) in reduced standard deviation.

77 It is important to note that these preferences are based on incremental changes of perhaps $3.5 billion in expected cost and $650 million in standard deviation. For changes outside this range, the willingness to pay may be different.

6.2 Long-term Variability Avoidance Metric

78 Most of the hedging literature focuses not on making cost/risk tradeoffs but on avoidance of extreme outcomes. Much of the discussion about these extreme variations is subjective and qualitative, and most is about short-term volatility rather than long-term variability.

79 Based on a review of the literature and common practice, we suggest that a reasonable starting point may be a long-term variability avoidance metric of limiting the chance of the baseline or unhedged 95th percentile outcome to 2.5%; that is, halving the exceedance probability. Both the definition of the extreme event (unhedged 95th percentile outcome) and the target probability (2.5%) are matters of judgment.

6.3 Short-term Volatility Avoidance Metric

80 As noted above, most of the hedging literature focuses on reducing short-term volatility. For utilities, this typically means avoiding extreme year-to-year variations in costs or rates. Much of the discussion about these extreme variations is subjective and qualitative. But some reports provide quantitative guidance regarding the extreme event target and associated maximum probability.[18] One such report suggests short-term volatility objectives along the following lines:

- Manage the effect of gas price volatility such that the year-over-year increase in retail rates is no higher than 5%, given a 97.5% statistical confidence; and/or
- Manage volatility, with 97.5% confidence, to constrain the potential for unfavorable gas cost outcomes to no worse than $9.00 per MMBtu; and/or
- Limit hedges to assure, with 97.5% confidence, that natural gas costs will not diverge unfavorably from market by more than 2% of Cost-of-Service

81 Based on this guidance, we chose a short-term volatility avoidance metric of limiting the chance that short-term volatility exceeds two times the mean unhedged volatility to 2.5%.

[18] PACE and Vantage Consulting, *Analysis of the Gas Purchasing Practices and Hedging Strategies of the New Jersey Major Gas Distribution Companies*, January 15, 2009.

7 Results and Insights

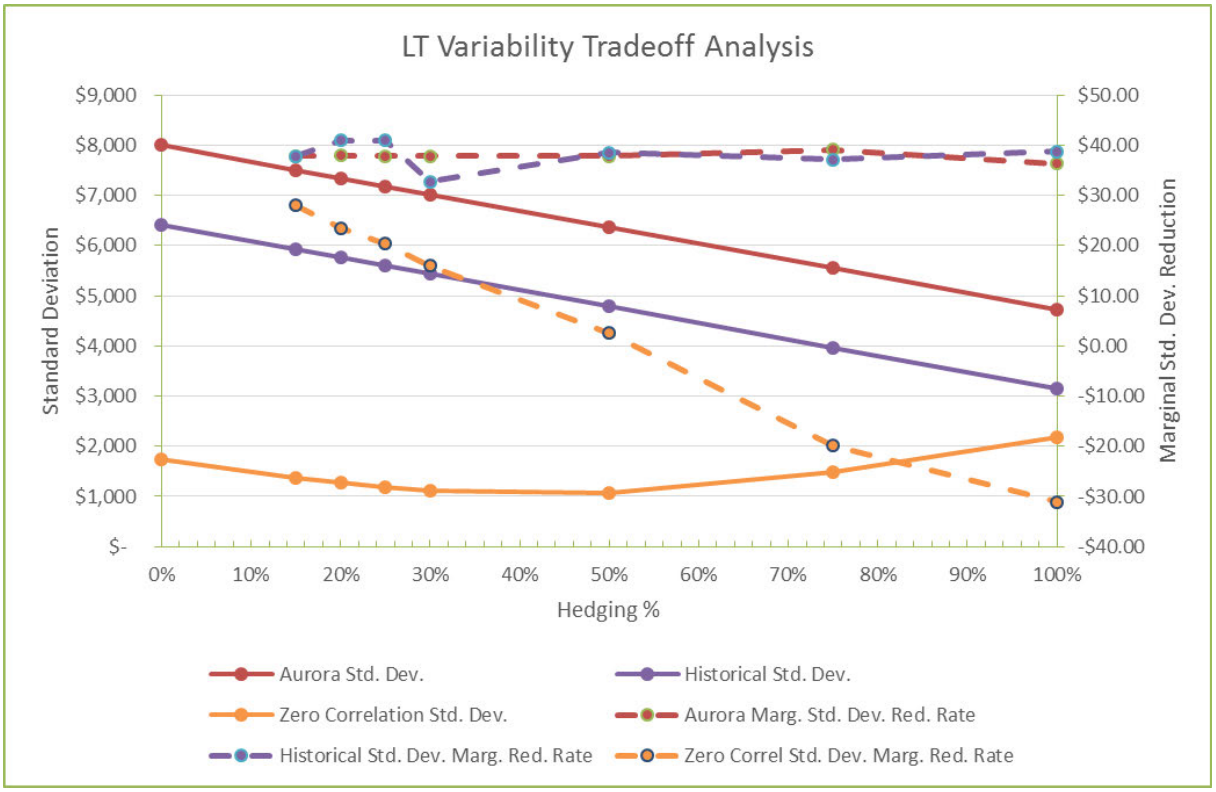
82 Results and insights are discussed below using the three metrics identified above:

- Long-term variability tradeoff metric
- Long-term variability avoidance metric
- Short-term volatility avoidance metric.

7.1 Long-term Variability Tradeoff Metric

83 Figure 3 below compares alternative hedging levels using the long-term variability tradeoff metric. The solid lines show the standard deviation of long-term costs as a function of hedging level, while the dotted lines show the marginal benefit (decrease in standard deviation) per unit of cost (increase in mean) as a function of hedging level.

Figure 3 – Long-term tradeoff analysis



84 As the figure shows, based on both Aurora forecasts and historical data, hedging has a steady risk reducing effect over the entire range. In addition, the marginal rate of risk reduction as hedging increases remains fairly constant at around $38 in standard deviation reduction for each $1 increase in mean. As noted earlier, analysis of the PGE 2013 IRP indicates that customers would need only a reduction of at most $0.42 in standard deviation reduction for each $1

increase in mean, at least for standard deviation reduction on the order of $650 million. The actual rate of reduction is two orders of magnitude better.

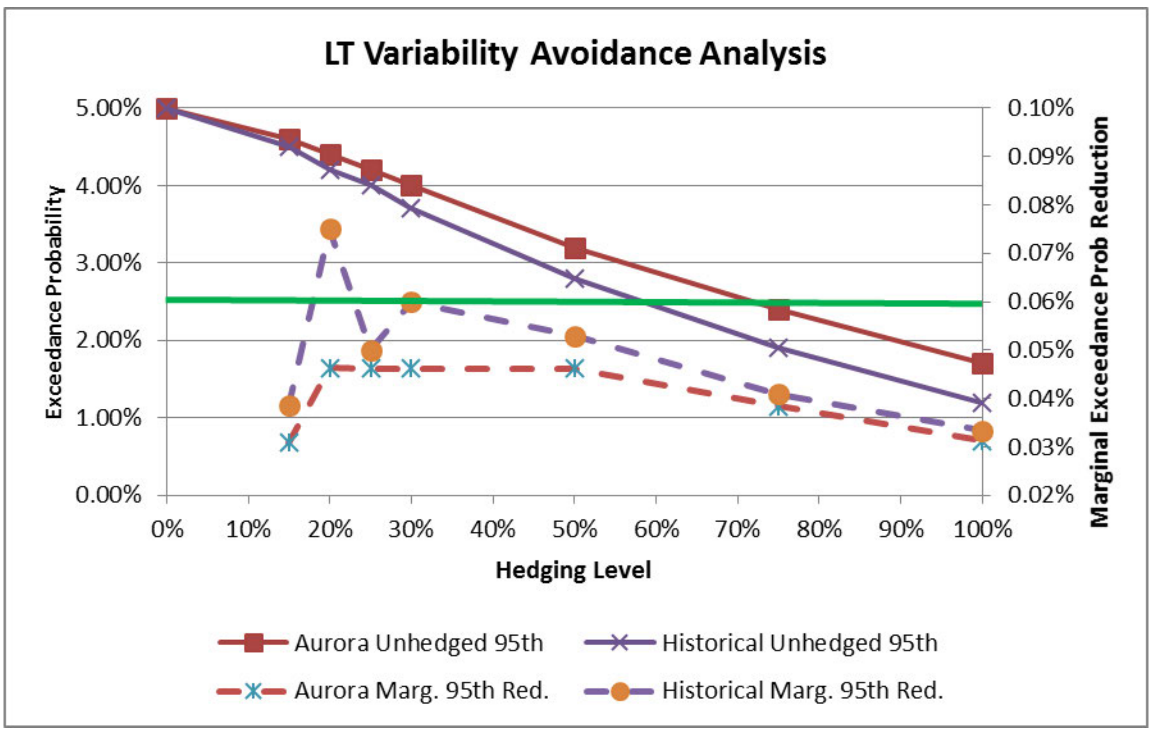
85 $650 million is roughly the risk reduction at 20% hedging. Consequently, this metric indicates that a hedging level of 20%, and likely higher, is appropriate.

86 In the zero correlation sensitivity case, risk as measured by the standard deviation first decreases and then increases as the hedging level increases. The uncorrelated electricity market provides an inherent natural gas price hedge, and the increasing risk at high hedging levels presumably reflects overhedging and market exposure. In the zero correlation case, there is clearly a maximum appropriate hedging level. The marginal risk reduction rate actually turns negative above the 50% hedging level.

7.2 Long-term Variability Avoidance Metric

87 Figure 4 below compares alternative hedging levels using the long-term variability avoidance metric. The solid lines show the probability of exceeding the unhedged 95th percentile outcome as a function of hedging level. The 2.5% target level is shown with a solid green line. The dotted lines show the marginal benefit (reduction in the exceedance probability) per unit of cost (increase in mean) as a function of hedging level.

Figure 4 – Long-term variability avoidance analysis



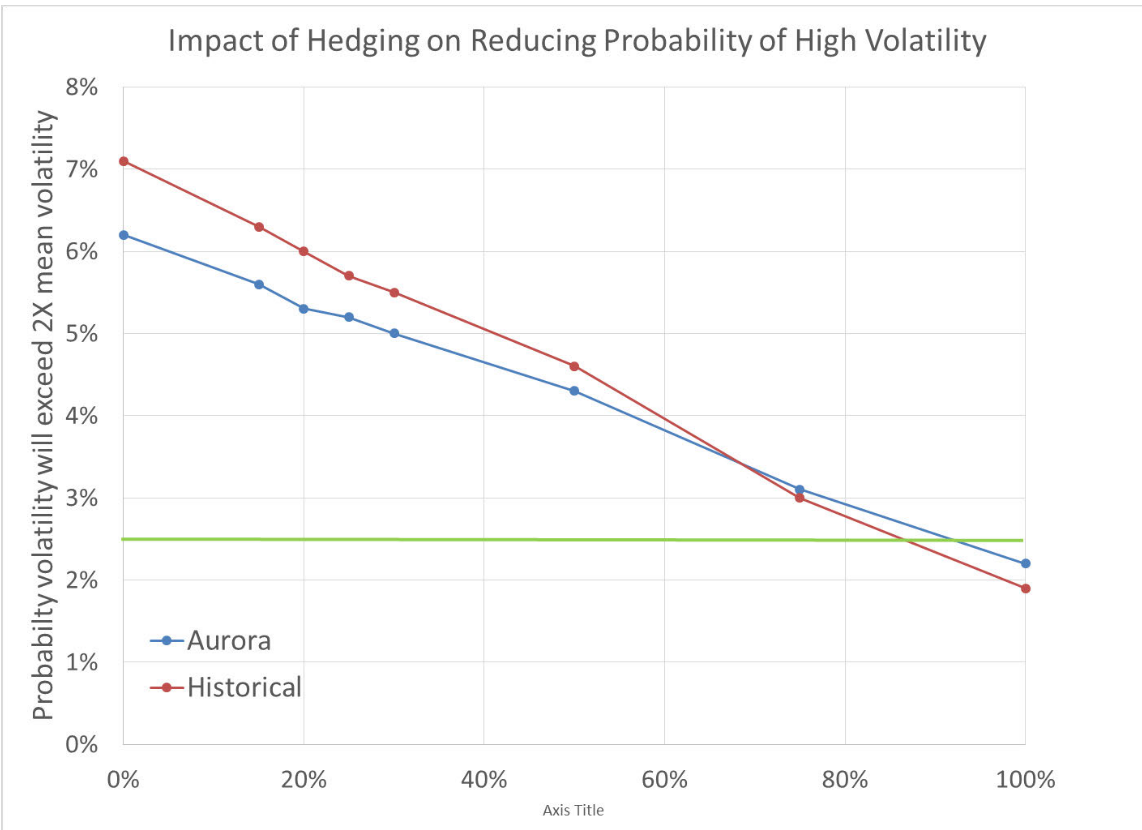
88 As the figure indicates, based on both Aurora forecasts and historical data, hedging has a steady risk reducing effect over the entire range. Based on a metric of reducing the unhedged 95th percentile value exceedance probability to 2.5%, a hedging level of 60% to 70% is indicated. The

dotted lines indicate that the effectiveness of hedging by this long-term variability avoidance metric reaches a maximum between a 20% and 50% hedging level. This is particularly relevant because the costs and risks of high levels of hedging have not been fully evaluated.

7.3 Short-term Volatility Avoidance Metric

89 Figure 5 below compares alternative hedging levels using the short-term volatility avoidance metric.

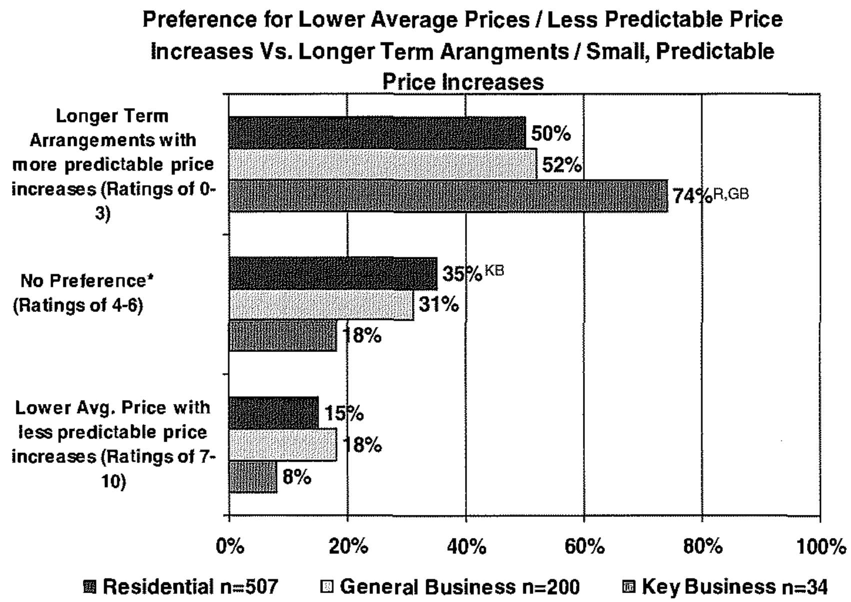
Figure 5 – Impact of Hedging on reducing probability of high volatility



90 As the figure indicates, based on both Aurora forecasts and historical data, hedging has a steady risk reducing effect over the entire % range. Based on a metric of reducing the likelihood of a doubling in volatility to 2.5%, a hedging level as high as 90% is supported.

Momentum Market Intelligence
Predictive Insight

Customers overwhelmingly prefer that PGE pursue longer-term arrangements that focus on making price increases small and predictable, as opposed to pursuing resources that may be lower in average price, but with less predictable fluctuations



- Key business customers express an even stronger preference for long-term arrangements than other PGE segments.

*While "No Preference" was not a point specifically identified on the rating scale, ratings of 4-6 do not indicate a clear preference for one of the two courses of action

Q38c. PGE could guarantee access to electricity supply resources with long-term arrangements that would mean "locking in" small (2-4%), predictable, annual price increases. Alternatively, PGE could access electricity supply resources that might have prices that fluctuate more as market conditions change. With these arrangements, price increases should be lower on average, but would be less predictable, both in terms of how often they occurred and how large they were. In general, would you prefer that PGE pursue longer-term arrangements that focused on making any price increases small and predictable, or pursuing resources that should have lower prices on average, but with price increases that are less predictable? 0=Longer term resource arrangements with small, predictable price increases; 10=Resources with less predictable price increases

R,GB,KB indicates a statistically significant difference between customer segments (R=Residential, B= General Business, KB = Key Business)