BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 308

In the Matter of PORTLAND GENERAL	)
	)
ELECTRIC COMPANY,	)
	)
2017 Annual Power Cost Update Tariff	)
	)

OPENING TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

June 20, 2016

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Our names are Bob Jenks and Nadine Hanhan, and our qualifications are listed in CUB Exhibit 101.

I. Introduction

On April 1, 2016, PGE ("the Company") filed its 2017 Annual Update Tariff ("AUT"). The Company is proposing an overall Power Cost forecast of $499.8 million, excluding federal production tax credits, resulting in a $32.3 million reduction relative to last year's net variable power cost ("NVPC") forecast.[1] Despite this reduction in cost, CUB has several concerns regarding PGE's 2017 AUT. In its testimony below, CUB discusses three main points: PGE's proposal to rate base natural gas reserves, Energy Imbalance Market (EIM) benefits and costs, and PGE's modeling enhancement related to the wind day-ahead forecast error.

[1] UE 308/PGE/100/Tinker-Sims/1; 11-14.

II. CUB Has Reservations Regarding PGE's Proposal to Rate Base Natural Gas Reserves (Long-Term Hedging)

A. Background

On April 18, 2016, parties in UE 308 participated in a pre-hearing conference call to determine the procedural schedule for the 2017 AUT. In that phone call, CUB expressed concerns about the timeline for reviewing PGE's long-term hedging proposal. PGE's long-term hedging is not representative of traditional hedging. It is unlike the fuel costs that are normally considered in the AUT, and it is much closer to a rate base investment in power generation which is typically reviewed in a general rate case where parties have an extended schedule. In the pre-hearing conference call, parties eventually agreed on a bifurcated schedule, where PGE would file additional testimony and a draft term sheet to give parties an opportunity to conduct specific discovery on PGE's long-term hedging strategy.

While CUB agreed to the bifurcation schedule, and CUB agrees that parties must review the specifics of PGE's proposal, CUB reserved the right to argue that rate basing natural gas reserves does not belong in the AUT filing and that the limited time to review the Company's actual proposal in this docket is inadequate. In this testimony, CUB will not speak to the specifics of PGE's draft term sheet filed on June 3, 2016[2]. As agreed in the bifurcation schedule,[3] CUB will file its testimony as to the specifics of the term sheet testimony on August 12, 2016. In its present testimony, CUB raises the more general question of whether PGE's long-term hedging proposal belongs in the AUT at all and responds to discussion from PGE's Direct Testimony.

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[2] UE 308/PGE/600-602.
[3] UE 308 Prehearing Conference Memorandum. Accessed at http://edocs.puc.state.or.us/efdocs/HDC/ue308hdc14543.pdf.

B. This Rate Base Investment in Gas Reserves is Not a Variable Power Cost Eligible for Recovery in Schedule 125

Throughout its testimony, the Company refers to its proposal as long-term hedging, but, in reality, the Company is specifically proposing to rate base natural gas reserves as an alternative to entering into a long-term financial hedge.[4] The Company is in fact proposing to become a gas producer through acquisition of gas production properties instead of a natural gas purchaser engaged in market transactions.[5]

i. The Historic Purpose of Schedule 125 is Limited to Variable Power Costs

This docket's purpose is to identify the costs that can be recovered under PGE's Schedule 125. This was established in 2002 and was controversial from the start. In the initial case, PGE filed modeling enhancement that CUB believed went beyond the simple cost update CUB expected, and CUB then proposed some rate base adjustments. Staff and PGE opposed CUB's rate base adjustment because this docket was limited to variable power costs.[6] PGE was clear that this is limited to variable power costs:

> PGE contends that the scope of this proceeding is limited under Schedule 125 to the examination of variable power costs. It argues that CUB's proposed adjustments relating to fixed costs are outside the scope of the changes considered in this annual RVM update.[7]

The Commission resolved those disputes by stating that Schedule 125 was limited to variable power costs and updates after April 1st were limited:

> First, the annual update of PGE's RVM should not be the equivalent of a generation rate case. Rather, it should be a proceeding to review PGE's net variable power costs. Second, the company should file proposed model enhancements and data updates for the 2004 RVM adjustment by April 1, 2003, to give interested parties and the Commission sufficient time for review. The only changes allowed after that time should be limited to

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[4] E.g., a fixed-for-float swap.
[5] UE 308/PGE/100/Tinker-Sims/7.
[6] *In re Application for Annual Adjustment to Schedule 125 under the terms of the Resource Valuation Mechanism*, OPUC Docket No. UE 139, Order No.02-772 (Oct. 30, 2002).
[7] *Id*.

> updates for load forecasts, new power purchase or sales contracts, new fuel contracts, and forward prices for electricity and gas.[8]

Schedule 125 is very clear as to its purpose:

> The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs (the Annual Power Cost Update).[9]

In CUB's opinion, PGE's proposal to make a major long-term capital investment in natural gas reserves with a return on that investment does not constitute a variable power cost. Rather, significant capital investments are typically and appropriately reviewed for prudence in general rate cases where parties have more time to complete such a review. Capital investments are not variable costs; instead they are the fixed and predictable cost of return of and return on rate base. If the Commission finds this capital investment to be prudent, then a predictable set of fixed costs will be used to establish rates. This is not a variable power cost. The variable here is not cost, but rather production levels. CUB does not believe that this is eligible under Schedule 125. PGE should bring this rate base investment to the Commission in a general rate case like any other significant rate base investment.

ii. PGE Fails to Explain How This is a Variable Cost

In a data request, CUB asked the Company to explain: 1) how a capital investment in a gas field is a variable power cost and not a fixed cost; 2) what its basis is in including a long-term rate based investment in the AUT; 3) what is the basis in seeking prudence determination of a long-term rate based investment in the AUT; and 4) whether

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[8] *Id.* at 6.
[9] PGE Schedule 125, *see*: https://www.portlandgeneral.com/-/media/public/documents/rate-schedules/sched_125.pdf.

PGE has ever proposed recovery of a rate based asset in its AUT filings.[10] CUB did not find PGE's answers compelling.

As part of its response to the data requests, PGE stated the following:

> PGE's proposal calls for an affiliated entity, Portland General Gas Supply Co. (PGGS) to transact for gas reserves. As a result, PGGS will have a capital investment. PGGS will then sell the produced gas to PGE on a cost-of-service basis in accordance with the terms of the Purchase Gas Agreement, submitted as part of PGE's request in Docket No. UI 371. Because PGE will use this gas as fuel for its gas-fired thermal plants, it is no different than other gas purchases and/or physical hedges, which are appropriately treated as variable power costs and included in PGE's power cost forecast (i.e., AUT filings) and actual power costs (i.e., PCAM filings). As noted in part d, below, the price that PGE pays for these purchases undoubtedly includes a fixed cost component such as return on and of capital.[11]

The Company further stated:

> PGE is seeking a prudence determination for the cost per MMBtu of its proposed long-term gas hedge to be included in AUT filings. We believe this to be very similar to the NW Natural determination in Commission Order No. 11-176, wherein the cost of NW Natural's long-term gas investment will be included in its annual purchased gas adjustment mechanism.[12]

And:

> PGE proposes to include cost-of-service gas in its AUT filings as described in PGE Exhibit 300, Section IV. Specifically, the AUT inputs to PGE's MONET model will include the cost per MMBtu and average daily gas volume. These amounts are appropriate to include in PGE's AUT filing because Schedule 125-1 specifies that the following updates "will be made in each of the Annual Power Cost Update filings":
>
> •Contracts for the purchase or sale of power and fuel.
> •Changes in hedges, options, and other financial instruments used to serve retail load.[13]

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[10] See CUB Exhibit 102..
[11] *Id.*
[12] *Id.*
[13] *Id.*

Importantly, 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. UM 1520 was not an annual docket designed to consider variable costs. In addition, UM 1520 demonstrates why capital investments are more typically handled in a general rate case. First, it required updating the cost of capital. One of the problems with determining the ratemaking treatment of capital investments outside of a general rate case is that there are two parts to a capital investment: the investment and the financing of that investment. The only time ratemaking looks at financing costs is in a general rate case. This led to an unusual provision in UM 1520 that required NWN to file a general rate case and required an update to the capital costs with a full refund to customers if the cost of financing was below what had been forecast in NWN's previous general rate case:[14]

Second, there was recognition in UM 1520 that the short timeline of the docket limited review, and this might require a revisiting of the prudence determination:

[14] *In re Application for Deferred Accounting Order Regarding Purchase of Natural Gas Reserves*, OPUC Docket No. UM 1520,Order No. 11-176 at4 (May 25, 2011).

> [T]he Parties agree that given the unique nature of the Proposed Transaction, the Commission should make a finding of prudence at this time based upon the information the Parties have reviewed. However, the Parties recognize that the review in this case has been expedited and that, if in the future, new information, not made available to Staff and the intervening parties, arises which demonstrates that NW Natural knew, or should have known, something of consequence to the Proposed Transaction at the time of the Proposed Transaction, Staff and the intervening parties can then use that information to challenge the prudence of the Transaction.[15]

CUB Exhibit 102 contains PGE's complete explanation for why this is a variable power cost and why the prudence of a significant capital investment should be included in the AUT, which examines variable power costs. Beyond pointing to UM 1520,[16] which was a single-issue ratemaking docket created to examine the prudence of a capital investment by NWN in gas reserves, there is no explanation there.

CUB does not agree with PGE's characterization of acquisition of gas production properties that they are "no different than other gas purchases."[17] Contracts for the purchase or sale of power and fuel and changes in hedges, options, and financial instrument mean purchasing directly from the market, and prudence can be demonstrated by comparing these purchases to other market options. This is a rate base investment, and prudence must be determined by examining PGE's examination of the various risks associated with this specific deal, including risks associated with environmental liability, royalties, future regulation, and production levels. CUB does not believe that this is a variable power cost that is eligible for recovery under Schedule 125.

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[15] *Ibid*. Appendix A, page 6 of 24
[16] *i.e.*, Order No. 11-176.
[17] See CUB Exhibit 102.

C. There is Not Enough Time in This Proceeding

In support of including reserve hedging in its AUT, the Company states: "based on our research and evaluations conducted to date, a non-operating working interest appears to provide the best long-term value for PGE's customers."[18] However, CUB does not necessarily agree that this is in the best interest of customers because CUB does not, nor will it, have enough time to review the proposal for prudence. Consider that PGE filed its draft term sheet on June 3, which is not yet a signed contract.[19] The only opportunity for parties to submit testimony on the bifurcated long-term hedging proposal is August 12 2016, a mere two months after seeing a *draft* of the term sheet. Ultimately, this means is that parties will have less than two months to conduct discovery, receive data responses, and draft testimony on a contract that has not yet been signed. CUB has great concerns about the pace of this process, especially regarding the opportunity for prudence review, and CUB is not comfortable agreeing to this issue on such a short timeline.

i. UM 1520

A prudence review within a limited timeframe for a long-term gas proposal is a concern CUB has previously raised. CUB had similar concerns in its UM 1520 testimony—a single-issue docket that addressed NWN's long-term gas supply agreement with a company called Encana. In that docket, parties were also on a short timeline to review discovery and relevant documents, and while CUB recommended that the Commission approve the Encana deal with specific caveats, it was a challenging docket that required 1) that the Company make independent consultants (KPMG, ENVIRON,

[18] UE 308/PGE/300/Russell-Tooman/12.
[19] UE 308/PGE/600/Russell-Tooman/1-2.

NSAI) available for stakeholders; and 2) that the Company fund an independent legal counsel (Lear & Lear) to advise intervenors on the examination of a significant number of risks in such a short period of time.[20] CUB's testimony included the following disclaimer:

> It is the shortness of the docket that concerns CUB the most. As of Saturday March 26, 2011, CUB, NWIGU, and their expert witnesses were still receiving new documents for review. This means that the experts hired by NW Natural (KPMG, ENVIRON, NSAI etc.) and experts retained by CUB and NWIGU (Lear & Lear, Salt Lake City, Utah) to review this matter also frequently lacked access to final documents. As of Tuesday, March 29, 2011, the parties were still receiving responses to data requests. Also as of Tuesday, March 29, 2011, many data request responses were yet to be updated from pre-finalized contract document references to post contract finalization references, making it very hard for the intervenors to assess this case. It is with these caveats that we rely on the statements of all of the experts made in the course of reviewing this transaction. [21]

ii. NW Natural IRP

In Oregon, there have been other precedents for caution regarding long-term hedging. In one important case, NWN's 2014 Integrated Resource Plan (IRP), CUB and Staff submitted comments regarding its concerns with NW Natural's long-term hedging proposal.[22] In that docket, NWN proposed a long-term reserve hedging strategy that would increase its long-term hedging resources from 10% of supply to 25%.[23] Though the Action Item pertaining to long-term gas hedging was not specifically fleshed out, in its IRP NW Natural stated:

> The final step in Long-Term hedging is deciding on the appropriate transaction. Financial derivatives would be considered as long as additional "insurance" (such as a credit facility) is included in the evaluation to protect against counterparty default. Ownership of the gas, such as through a gas

[20] UM 1520/CUB/100/Jenks/10.
[21] *Ibid, page 11.*
[22] See LC 60, CUB Opening Comments and Staff Initial Comments.
[23] Docket No. LC 60, NW Natural 2014 IRP, pg. 1.21, Action Item 4.1.

> reserves acquisition, eliminates that particular source of risk but potentially introduces other risks that similarly must be accounted for in the evaluation. Gas reserve ownership does have an additional benefit in that the natural decline over time that is associated with production wells fits very well with the concept of a hedging strategy that declines in percentage over time.[24]

NWN goes on to talk about the Encana deal in its 2014 IRP:

> During the first 10 years of the agreement, the Company projected the volume of gas under the Encana transaction to be approximately 8-10% of the Company's average annual requirements for its utility operations, with a peak of about 15% in the years during the height of the drilling program. It expected its investment to result in the eventual total availability of about 93 billion cubic feet (Bcf) of gas, assuming the development of the contemplated 102 wells, at a highly competitive price as compared to equivalent gas supply purchase alternatives over the same term.
>
> Recently though, on March 31, 2014, Encana announced the sale of its interest in the Jonah field to an affiliate of TPG Capital (Jonah Energy LLC), with a transition to be completed by year-end 2014. The Jonah field is overwhelmingly "dry" gas and this sale is part of a strategic move by Encana to refocus on "wet", i.e., liquids-rich gas plays.[25]

As a result of that agreement, customers have been consistently paying more than $5/MMbtu for gas out of the Encana deal[26] when, as of this filing, gas prices are under $2.30/MMbtu.[27]

In NW Natural's IRP, CUB and Staff submitted comments highlighting concerns about long-term hedging. Consider Staff's position in its Initial Comments:

> NWN is requesting acknowledgement of its revised hedging strategy intended to increase its long-term hedged position of gas requirements from the current level of approximately 10 percent up to 25 percent. At a Commissioner workshop on November 4, 2014, Commissioners stated that this is an important issue and indicated that there may be interest in bifurcation of the hedging consideration from the Company's 2014 IRP.

[24] Docket No. LC 60, NW Natural 2014 IRP, pg. 3.41.
[25] Docket No. LC 60, NW Natural 2014 IRP, pg. 3.42.
[26] UG 278. Exhibit B, p. 7.
[27] EIA. "Natural Gas." See "Spot prices table." Retrieved from http://www.eia.gov/naturalgas/weekly/#tabs-prices-2. Accessed June 9, 2016.

> Staff continues to explore the possibility of investigating NWN's proposed hedging strategy in a separate docket with the Company and IRP participants.
>
> NWN's responses to Staff data requests DR 51 to DR 55 show that overall, NWN's hedging strategy has resulted in substantial losses for its customers for the period 2009 to 2014. Staff intends to request more data from the Company in order to make a more informed assessment of the rate impact of its hedging strategy. For NWN to increase its long-term hedge position of gas requirements from 10 percent up to 25 percent, the Company should also make a showing that its customers will be protected against unreasonable losses as a result of the increased long-term hedges. Staff will be interested in a hedging strategy that provides the right incentives for the Company but at the same time protect its customers from gas price volatility and unreasonable losses.[28]

CUB agrees that it is a Company's responsibility to show that its customers should be protected against unreasonable losses as a result of long-term hedges. The Commission also agreed with this position in its LC 60 order when it adopted Staff's recommendation that the long-term hedging Action Item be removed from the Action Plan.[29] The Commission also opened a bifurcated schedule to examine NWN's long-term hedging policy.[30] The order was signed on March 15, 2015.[31] The IRP was filed on August 29, 2014,[32] and as of this filing, NWN has yet to host its third workshop pertaining to long-term hedging in docket UM 1720, a docket in which PGE has intervened.[33] This means stakeholders have had nearly two years to review NWN's long-term hedging strategy, and this has still not been adequate time for the Company to demonstrate to parties the prudence of the hedging policy. However, in PGE's 2017

[28] LC 60. Staff's Initial Comments, pg. 2.
[29] *In re 2014 Integrated Resource Plan,* OPUC Docket No. LC 60, Order No. 15-064 (March 5, 2015).
[30] *Id*.
[31] *Id*.
[32] *See* LC 60, Initial Filing.
[33] *See* UM 1720 Actions. Accessed at http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19453.

AUT, PGE is expecting stakeholders to support its long-term gas reserve contract with hardly two months of review.

iii. UE 308

In this docket, CUB reviewed the lists of risks that were considered in UM 1520 and asked PGE whether it reviewed the following risks:[34]

- Water
- Ozone
- Greenhouse gas
- Spills
- Royalty risks
- Tax litigation risk
- Dry hole risk
- Pre-existing liens
- Bankruptcy risk
- Ownership change risk

PGE's response to these requests was that it has not yet investigated these risks, but that it will "conduct reasonable due diligence."[35] As of this filing, CUB has not seen any updates to this data request. Relevantly, these were the same risks that parties investigated in the Encana deal, docket UM 1520.[36] At the very least, these or similar risks should be investigated in the AUT filing, and parties should have ample time to ensure PGE is indeed doing its due diligence. It is not possible to weigh the costs and benefits of various approaches for meeting customer needs without quantification of risks. Moreover, it is not appropriate to dismiss one type of risk without proper assessment and analysis. CUB feels that the risks listed above and other risks are not being given proper weight.

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[34] *See* CUB Exhibit 103.
[35] *See* CUB Exhibit 103.
[36] *See* UM 1520/CUB/100.

CUB has serious reservations about agreeing to PGE's long-term hedging proposal on such a short timeline. PGE points to docket UM 1520,[37] but that docket was rushed and has led to natural gas that is overpriced in today's market, which led CUB to raise concerns in LC 60.[38] The Commission agreed to open a separate investigation to investigate such a long term hedging strategy,[39] and CUB is currently participating in UM 1720, the PUC's long-term hedging investigation, which has yet to conclude. Thus, CUB is puzzled as to why PGE should receive cost recovery of gas reserve hedging assets on shorter notice, with less opportunity for a prudence review, and no obvious precedent of including a rate base asset in a net variable power cost filing. In addition, CUB reiterates that PGE's proposal has not yet been signed, but even if it had, CUB would only have two months to review the contract. There is not enough opportunity to fully vet the risks.

D. CUB is Not Convinced that Reserve Hedging is the Ideal Long-Term Hedging Strategy

CUB has argued in other dockets, particularly in NWN's 2014 IRP, that we are interested in seeing more than rate based investments as a long-term solution to securing low gas prices.[40] In CUB's experience, there is no industry standard for "long-term." Rather, "long-term" can range anywhere from 3 years to 30 years, whereas short- to medium-term tend to be below that range. A long-term hedge does not need to last for multiple decades and subject customers to risks for 30 years.

In another data request to PGE, CUB asked the Company about the cost of the long-term hedging proposal.[41] In its response, the Company stated that "based on

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[37] *See* CUB Exhibit 102.
[38] LC 60, CUB's Opening Comments, pp 2-8.
[39] *See In re 2014 Integrated Resource Plan,* OPUC Docket No. LC 60, Order No. 15-064 (March 5, 2015).
[40] *See* LC 60, CUB's Initial Comments.
[41] *See* CUB Exhibit 104.

preliminary discussions with one of PGE's potential counterparties and because, at that time and to date, cost-effective, long-term alternatives to a non-operating working interest have not been available."[42] PGE's testimony says that "[b]ased on our research and evaluations conducted to date, a non-operating working interest appears to provide the best long-term value for PGE's customers."[43] PGE also provides an attachment to CUB's data request that demonstrates its belief that another long-term alternative it analyzed, a [redacted][44] is not cost effective.

However, even though PGE's example of a long-term alternative is not feasible, this does not mean that other options do not exist somewhere. In docket UM 1720, NWN produced a ten-year hedge quote. CUB Exhibit 106[45] reveals that hedge quotes starting at $2/MMBtu and ending at less than $4/MMBtu for 10 years are possible. This does not extend to thirty years, it does not require a capital investment, and it does not expose customers to so many risks. CUB recognizes that the same agreements may not be available to PGE, but CUB cannot ignore the fact that NW Natural's example is [redacted].[46] This illustrates that there are indeed other alternatives to rate basing hedging investments.

E. Rate Basing Front-Loaded Costs

PGE's evaluation of rate basing gas reserves is based on the real levelized cost of gas in its IRP.[47] This leads to the back cast that is represented in Figure 4 of its Opening Testimony.

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[42] *See* CUB Exhibit 104.
[43] UE 308/PGE/300/Russell-Tooman/12; 13&14.
[44] *See* CUB Confidential Exhibit 105..
[45] Provided with permission from NWN.
[46] See CUB Confidential Exhibit 107.
[47] UE 308/PGE/100/Tinker-Sims/15.

Q. What does Figure 4 indicate with regard to customers' costs when comparing hedged gas versus non-hedged gas?

A. If we compare the "Market Cost" line to the "Market + 30% LT Hedge" line, where the average difference between them is approximately $4.50/MWh, this difference would represent approximately 7.0% of the average PGE customer's bill for energy charges. Figure 4 also indicates that when market costs are rising, the hedged costs are less than market. Conversely, when market costs are declining, the hedged costs are higher than market.[48]

Unfortunately, this is a misleading discussion of customers' costs. The costs that customers pay for PGE's proposal is not the real levelized cost of gas under the terms of the deal. Like other capital investments, PGE is proposing cost of service rate base treatment for this investment. The costs that customers actually pay are not discussed in PGE's testimony, but are identified in PGE Exhibit 303. CUB summarizes the costs below:[49]

Original Projections
Original Annual Revenue Projected

Year	Revenue Requirement	Volume	Unit Price of Gas
2017	$30,000,000	6,000,000	$ 5.00
2018	$29,000,000	5,900,000	$ 4.92
2019	$28,000,000	5,800,000	$ 4.83
2020	$27,000,000	5,700,000	$ 4.74
2021	$26,000,000	5,600,000	$ 4.64
…			
2046	$1,000,000	3,100,000	$ 0.32

As we can see above, the cost to customers in the first year is $5.00 per therm, and the price in 2046 is $0.32 per therm. This raises serious concerns about intergenerational equity and would change the shape of the revenue requirement associated with a gas plant so it looks more like a wind farm.

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[48] UE 308/PGE/100/Tinker - Sims/17.
[49] *See* UE 308/ PGE/303/Russell-Tooman/1.

i. First, Let's Discuss Why This is Happening

When a capital investment is added to rate base, the utility is allowed to charge customers for the return of the rate base and gets to charge customers a return on its undepreciated investment. In the case of a 30-year gas reserve investment, customers in the first year will be paying PGE a return on the undepreciated investment, which is 29 years. Assuming a 30-year investment that is depreciated in a straight line, customers would pay approximately:

Year 1: (1/30 of the capital investment) + (Pretax ROR) X (29.5/30ths of capital investment)[50]

Year 2: (1/30 of the capital investment) + (Pretax ROR) X (28.5/30ths of the capital investment)

Year 3: (1/30 of the capital investment) + (Pretax ROR) X (27.5/30ths of the capital investment)

…

Year 30: (1/30th of the capital investment)+(Pretax ROR) X (0.5/30ths of the capital investment)

ii. This Means Gas Will Almost Always Be Above Market in Early Years and Below Market in Latter Years

PGE proposes that rate base investments be considered cost effective if the real, levelized cost is at or below the forward price curve from the IRP.[51] This means that on average, over the life of the production, the cost will, on average be at or below the current forward price. But shown above, on the back end when this investment is nearly fully depreciated, it will cost well below what it does in the early years, and in the early years it will cost many times what it does at the end of its depreciation.

But markets do not follow that depreciation curve. This means that gas in the early years will be above market and gas in the latter years will be below market.

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[50] 29.5 is based on the average rate base return over the 1st year.

[51] UE 308/PGE/200 Sims – Outama/4,

iii. This Revenue Requirement Shape Creates Inter-generational Concerns

Rate basing gas reserves under PGE's proposed structure will require current customers to buy gas at above market rates so customers in later years can purchase gas at below market rates. PGE claims that the purpose is not to beat the market,[52] so the purpose of this is not to get lower costs over the course of the capital investment. This raises concerns over why current customers should pay above-market rates. What are customers getting for this value? PGE claims that customers are getting price stability,[53] but a cost that goes from $5 to less than $1 is not stable, it is fixed and declining.

iv. PGE Identifies Avoiding Structural Shifts as a Benefit

PGE is proposing that this investment be considered a hedge against the "potential for longer-term structural shifts due to fundamental changes in supply and demand."[54] PGE includes graphs[55] to show the monthly changes in gas prices to highlight the volatility of gas prices.[56] But only twice since February 2010 have gas prices been above $5.00 per MMBtu – in December 2013 and in February 2014.

There is little evidence in their analysis to support charging current customers $5/mmBtu to protect against market volatility and structural shifts.

F. Current Gas Prices are Well Below $5/MMBtu.

The revenue requirement cost of this investment begins at $5/MMBtu. This is well above the cost of natural gas in today's market.

Average Natural Gas Prices ($/MMBtu)[57]

	Th.,06/02	**Tue.,06/07**	**Th.,06/09**
Henry Hub	2.30	2.29	2.32

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[52] UE 308/PGE/100/Tinker – Sims/17,
[53] *Ibid.*
[54] UE 308/PGE/ 100/Tinker - Sims / 10.
[55] UE 308/PGE/ 100/Tinker - Sims / 13.
[56] Actual numbers behind the graph are in PGE's workpapers.
[57] Clearing Up, June 10, 2016, No. 1752, Page 6.

Sumas	1.92	1.69	1.30
Alberta	1.17	1.28	1.01
Malin	2.22	2.13	2.15
Opal/Kern	2.15	2.09	2.10
Stanfield	2.12	1.99	1.97
PG&E CityGate	2.42	2.35	2.34
SoCal Border	2.28	2.18	2.19
EP-Permian	2.14	2.10	2.12
EP-San Juan	2.15	2.11	2.13

G. Front-Loading the Cost of Fuel Gives a Gas Plant a Revenue Requirement Shape Associated With a Wind Plant

Above, CUB discusses the impact of front-load rate base. Because customers pay both a return of the capital investment and a return on all the future undepreciated investment, the revenue requirement impact of that rate base falls heavily on the customers in the early years.

In looking at generation resources, renewable projects have no ongoing fuel costs, but are nearly entirely capital investment. They tend to have the most front-loaded revenue requirement. While the capital investment associated with a gas plant is also front-loaded, that gas plant also has fuel costs. Because fuel costs tend to rise over time – therefore offsetting the declining rate base revenue requirement – gas plants tend to have a more levelized revenue requirement than renewable projects.

By front-loading some of the fuel supply of that gas plant, PGE is changing the revenue requirement shape of the plant so it starts to look more like a renewable resource. CUB is skeptical that this is a good idea. Having a diversity of resources with different revenue requirement shapes seems to be helpful in managing risk.

Because renewables tend to have front-loaded revenue requirements, having gas plants with more levelized revenue requirements helps keep rate affordable and avoids rate shock. CUB is not convinced there is a compelling reason to change this revenue requirement shape.

i. The Revenue Requirement Shape Could Change by Changing the Depreciation Schedule, but This is Problematic

The front-loading of rate base is caused by the fact that the Company gets to charge customers for both the investment and the return on the investment. Exhibit 303 demonstrates that this is how PGE intends to collect the revenue requirement associated with this capital investment.[58] The effect of this, however, could be reduced by changing the depreciation schedule so more of the investment is paid off later. A home mortgage, for example, is not front-loaded. In the early years of a home mortgage a homeowner is paying significant interest and very little principle. Over time this changes, and by the end a small share of the monthly payment is going to interest.

By changing the depreciation schedule so we collect less of the capital investment early, we can attempt to change the revenue requirement shape of a capital investment so it is more levelized, but this is problematic for a couple of reasons:

- It increases the financing charges that customers pay. The interest that customers pay to utilities for investments is significantly higher than the interest rate on a mortgage. And, instead of a tax write-off, the equity share of this "interest payment" has to be grossed up by 40% to account for the income taxes the utility has to pay. This means shifting the capital investment so more of it is recovered in later years adds millions of dollars of additional financing costs.
- It increases the risk of stranded costs. Generally, the depreciation schedule for an asset should relate to how fast that asset is utilized. CUB's understanding, is that once drilled, natural gas wells see declining volumes of gas produced.[59] This means production in the first year is much greater than production in the 10th year, or the 30th

[58] UE 308/PGE/303/Russell - Tooman/1.
[59] *Id*.

year. The more that we are shifting costs onto those latter years, where there is less production, the greater risk we are placing on cost recovery. For example, if we adopted a depreciation schedule where half the capital costs were going to be recovered with the last ¼ of the gas produced, there could be a cost recovery problem if the depletion rate of the well is greater than we expected and its useful life is 25 rather than 30 years.

H. PGE's Proposed Guidelines for Long-Term Hedging Should be Rejected

PGE proposes four guidelines and states:

> [If] PGE proposes a transaction within approved guidelines (and with appropriate documentation), the presumption is that the transaction is prudent subject to Commission determination that new circumstances or evidence demonstrates otherwise.[60]

CUB believes that PGE's guidelines are flawed and meeting PGE's guidelines are not nearly enough to provide a presumption of prudence.

PGE's Four Guidelines

Guideline (1): Establish that the "Long-Term Projected Cost" must be at or below the comparable "Long-Term Benchmark Price."
Guideline (2): Establish a maximum gas purchase commitment.
Guideline (3): Enter into transactions for properties that contain "Proved Reserves" or "Probable Reserves".
Guideline (4): Establish limits within which the unit cost of the long-term gas is incorporated into PGE's annual power cost update (i.e., AUT filing).[61]

There are no guidelines concerning the due diligence PGE should undertake to ensure that there are limited risks to this investment. There are no guidelines concerning what information PGE needs to document their evaluation of these investments. Guideline 3 shows that these guidelines only relate to rate basing natural gas reserves and

[60] UE 308 /PGE/200/Sims - Outama/ 2.
[61] UE 308 /PGE/200/Sims - Outama/ 3.

do not apply to alternative methods for securing long term hedges. There is no guideline that the utility consider other long-term hedges that are not rate based investments. Instead all we have is these simple four guidelines. And, these guidelines themselves offer little protection to customers.

i. Guideline (1): Establish That the "Long-Term Projected Cost" Must Be at or Below the Comparable "Long-Term Benchmark Price"

PGE is attempting to establish a basis to determine whether an investment is cost effective. But the Long-Term Benchmark Price is defined as the real levelized cost used in PGE's IRP[62]. PGE does one IRP every two years. In PGE's 2009 IRP, by the time the IRP decision reached the Commission, Staff, and NWEC were arguing that the natural gas forecast was out of date and inaccurate.[63]

The IRP natural gas forecast is often stale and should not be used to establish a presumption of cost effectiveness that leads to a presumption of prudence. This guideline should be rejected.

ii. Guideline (2): Establish a Maximum Gas Purchase Commitment

While PGE identifies this guideline as establishing a maximum, all the discussion of the guideline is about a requirement that PGE engage in long-term hedging for a minimum of 15% of its gas supply and a maximum of 30%.[64] CUB objects to this guideline. At this point in time, Oregon has limited experience with these kinds of transactions, such as NWN's Encana deal and NWN's Post Carry Wells. Both of these examples have had gas production that is well below was projected in the prudence

[62] UE 308 /PGE/200/Sims – Outama/4.
[63] OPUC Order No. 10-457, page 6.
[64] UE 308/PGE/200/Sims - Outama/4

review.[65] Since there is no experience of customers actually benefiting from a rate base investment in gas reserves in Oregon, CUB recommends that the guideline be rejected. There is no demonstration that customers will benefit from rate basing 15% to 30% of its gas supply.

iii. Guideline (3): Enter into Transactions for Properties that Contain "Proved Reserves" or "Probable Reserves"

Proven reserves are reserves where a consultant believes there is a 90% likelihood that production estimates will be reached. Probable reserves are reserves where a consultant believes there is a 50% likelihood that production estimates reach proven plus probable projections.[66] The consultants that make these projections are professionals but are typically hired by natural gas extraction companies that are drilling thousands or tens of thousands of wells. The risk factor for a utility which does not have internal expertise in drilling and will drill dozens of wells is much greater.

The NWN experience[67] raises concerns about whether this will give customers enough protection. When considering its proposal to rate base natural gas reserves, NWN hired Netheland Sewell and Associates (NSAI) a “respected” firm that provides independent projections of reserves. NSAI determined that the reserves that NWN purchased were classified as “Proved Reserves, which means there is a 90% probability that actual volumes will equal or exceed estimated volumes.”[68] The first set of wells that NWN invested in were called the Carry Wells and there production was lower than the forecast.[69] The second set of wells called the Post Carry Wells was even worse.

[65] OPUC Order No. 15-297 at 3.
[66] UE 308/PGE/200/Sims - Outama / 7.
[67] i.e., in UM 1520.
[68] UM 1520/Joint/100/Zimmerman-Miller-Jenks-Pyron/7-8.
[69] OPUC Order No 15-297, page 3.

Production at those wells "has been materially below expectations. NW Natural now projects that these wells will produce on average 1.1 Bcf - well below its 1 .6 Bcf break-even threshold."[70]

iv. Guideline (4): Establish Limits Within Which the Unit cost of the Long-Term Gas is Incorporated into PGE's Annual Power Cost Update (i.e., AUT filing)

This guideline has little to do with determining prudence and concerns the ratemaking for a project after prudence is determined.

v. Presumption of Prudence in Guidelines

The primary purpose of these guidelines is to allow PGE to go forward and invest potentially hundreds of millions of dollars in rate based natural gas reserves with a presumption of prudence. As such, they offer more protection to shareholders than they do to ratepayers. The Commission should reject these guidelines.

II. Other Issues

A. EIM Benefits Should Not Be Zero

i. PGE's Exhibit Lists a Cost and Benefit Estimate for the Energy Imbalance Market (EIM), but the AUT Filing Projects Zero Benefits and Costs

PGE's testimony outlines specific costs it expects to incur upon entry into EIM. In particular, the Company expects "$11 million in capital, which would represent a revenue requirement of approximately $3.5 million in year one of the project's book life."[71] There is also an estimate of $1.9 million that the Company is expected to incur by October 1, 2017.[72] In addition to these costs, the Company highlights a series of benefits pertaining

[70] *Ibid.* page 4.
[71] UE 308/PGE/400/Niman-Peschka-Hager/20.
[72] *Ibid*.

to entry into EIM, specifically sub-hourly dispatch savings, flexible reserve savings, and reliability benefits.[73] The Company enlisted Energy + Environmental Economics (E3) to do a study of costs and benefits,[74] which PGE includes as Exhibit 402.

The E3 study estimates that the startup cost of PGE entering EIM would be around $645,000, with ongoing costs of $ 400,000-500,000 a year.[75] Importantly, E3 also provided the Company with a range of benefit estimates, seen below:[76]

Table 1. Annual Savings to PGE from Participation in Western EIM or NWPP SCED (2015 $million)

Scenario	Western EIM Savings	NWPP SCED Savings
Sub-hourly Dispatch Savings only		
Base Case	$2.7	$4.6
High Gas Price	$5.8	$6.4
Alt. Transmission Transfer[7]	$3.0	N/A
High RPS Case	**$6.1**	**$7.2**

In addition to this range, E3 estimates the following:[77]

Table 2. PGE's diversity benefit from Western-EIM and NWPP-SCED

Scenario	Western EIM Savings	NWPP SCED Savings
Sub-hourly Dispatch Savings only		
Base Scenario	$2.7	$4.6
Dispatch and Reserve savings		
Base Scenario with Reserve Pooling	$3.5	$5.3

The tables show a range of benefits from $2.7 million to $7.2 million, based on various assumptions, but the base case scenario is well above the yearly estimated cost of $500,000 a year, and also above PGE's estimated start-up cost of $1.9 million.

[73] UE 308/PGE/400/Niman-Peschka-Hager/17.
[74] *Id.*
[75] UE 308/PGE/402/Niman-Peschka-Hager/9.
[76] UE 308/PGE/402/Niman-Peschka-Hager/10.
[77] UE 308/PGE/402/Niman-Peschka-Hager/11.

Presumably, the Company would not be entering into EIM if there was no benefit to doing so. However, the Company is projecting neither costs nor benefits in its AUT filing:

> **Q. Have you included EIM benefits and costs in this case?**
>
> A. No. Due to the uncertainty surrounding the level of benefits that will be achieved and the costs that will be incurred, particularly in the early stages of PGE's participation in the EIM, we propose to set benefits equal to zero in our 2017 forecast.[78]

Moreover, the Company states that it does not "plan to defer costs associated with EIM implementation or participation."[79] According to the way PGE models its forecast, because the benefit forecast is zero, the cost forecast is also zero. The Company states in its testimony that it will enter the EIM market on October 1, 2017.[80] Thus, there are three months of costs and benefits that are not included in PGE's AUT filing.

As an additional note, it is ironic that in PacifiCorp's TAM proceeding, PacifiCorp is forecasting a financial benefit to its customers from PGE joining the EIM and is proposing to pass that benefit through to its customers.[81]

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[78] UE 308/PGE/400/Niman-Peschka-Hager/20; 22-25.
[79] See CUB Exhibit 107.
[80] UE 308/PGE/400/Niman-Peschka-Hager/17; 2.
[81] UE 307 - 2017 Transition Adjustment Mechanism PacifiCorp's List of Corrections or Omissions, http://edocs.puc.state.or.us/efdocs/HAH/ue307hah92148.pdf.

B. By Not Including a Value for EIM Benefits, PGE Is Effectively Forecasting Those Benefits to Be Zero

As CUB explains above, there is clear evidence on the record that zero is not a reasonable forecast for EIM benefits. While CUB is not offering a specific value in this testimony, CUB will be reviewing other Parties' testimony on EIM benefits and will either propose a specific non-zero value for the forecast of benefits or will propose a tracking mechanism to ensure that these benefit flow through to customers.

B. Wind Day-Ahead Forecast Error Cost Update.

PGE recently (June 9, 2016) filed a letter with the parties letting parties know that PGE was changing the methodology used to forecast the Day-Ahead Forecast Error from what was used in the initial filing and this would nearly double the cost from $0.2/MWh to $0.38/MWh.[82] PGE also filed a confidential attachment that provides the ROM summary sheet.

In that letter PGE is clear that the methodology that was used in the initial filing was consistent with the estimate generated in its last general rate case (UE 294) but adjusted for one year of escalation. The update this month was based on "enhancement in the model that now provides sub-hourly (i.e. 15-minute) dispatch capability and more explicit ramp rate constraints."[83]

This modeling enhancement should be rejected. The AUT (previously called the RVM) was controversial for years because of the constant tinkering with the underlying models. Rather than a simple, abbreviated case that simply updates variable power costs, it became a series of annual price adjustments based on modeling changes, not changes in

[82] UEE 308 - Wind Day-Ahead Forecast Error Cost Update. Accessed at http://edocs.puc.state.or.us/efdocs/HAH/ue308hah153758.pdf.
[83] *Ibid*.

costs and revenues. This led to an agreement that modeling enhancements would be limited to the years that PGE filed a General Rate Case. The idea was to lock down the modeling between general rate cases, and focus on actual changes in variable power costs.

This is reflected in the Minimum Filing Requirements ("MFR") that PGE included with its testimony:

> In either an AUT year (April 1 initial filing) or a GRC year (Feb. 28 initial filing), at a minimum the following portion of the Direct Case Filing MFRs will be delivered with the initial filing:
>
> • Summary Documents (Items 1-6)
>
> • Modeling Enhancements and New Item Inputs (Item 14)- not applicable in AUT year.[84]

These MFRs show two problems with PGE's Wind Forecast Error modeling enhancement. First, the filing requirements for model enhancements is not applicable for AUT years because model enhancements are not allowed during AUT years. Second, when modeling enhancements are allowed (GRC years), those enhancements are required to be filed with the Direct Case by February 28. There is no provision that allows PGE to add a modeling enhancement in June of an AUT year. This modeling enhancement should be rejected.

III. Conclusion

In its 2017 AUT filing, PGE has proposed a cost reduction of 32.3 million relative to last year's forecast. However, this does not mean that there aren't significant issues

[84] UE 308/ PGE/ 401/Niman - Peschka - Hager/1.

with the Company's current filing. As CUB has stated above, our main concerns with PGE's proposals are:

- PGE's proposal to rate base gas reserves;
- Energy Imbalance Market (EIM) benefits and costs; and
- PGE's modeling enhancement related to the wind day-ahead forecast error.

CUB's primary concern with PGE's long-term hedging proposal is that it is not a variable cost. It is a rate base asset and there precedents in Oregon that lead CUB to approach this investment with skepticism. These precedents are UM 1520 and LC 60. In addition, there is not enough time in this proceeding to conduct sufficient review for prudence. Both UM 1520 and LC 60 had more time overall to review long-term hedging investments, so CUB believes it is necessary to approach PGE's proposal with the same level of caution. PGE's proposal also changes the traditional the shape of revenue requirement associated with a gas plant, and CUB has concerns about the inter-generational equity issues associated with the investment. CUB also has reservations with PGE's proposed guidelines and believes they should be rejected for reasons stated in Section II.

In addition to concerns about gas reserve hedging, CUB believes that PGE should not be forecasting zero EIM benefits as we believe there is evidence to the contrary.

PGE's day-head wind forecasting modeling enhancement should also be rejected on the grounds that filing requirements for model enhancements are not applicable for AUT years and also because there is no provision that allows PGE to add a modeling enhancement in June of an AUT year.

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

EMPLOYER: Citizens' Utility Board of Oregon

TITLE: Executive Director

ADDRESS: 610 SW Broadway, Suite 400
Portland, OR 97205

EDUCATION: Bachelor of Science, Economics
Willamette University, Salem, OR

EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UE 172, UE 173, UE 207, UE 208, UE 210, UE 233, UE 246, UE 283, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, UM 1355, UM 1635, UM 1633, and UM 1654. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America
Board of Directors (Public Interest Representative), NEEA

WITNESS QUALIFICATION STATEMENT

NAME:	Nadine Hanhan
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EDUCATION:	Master of Science, Applied Economics, 2015 Oregon State University, Corvallis, OR Bachelor of Arts, Economics and Philosophy, 2010 California State University San Bernardino, San Bernardino, CA
WORK EXPERIENCE:	Provided testimony and comments in dockets including LC 55, LC 56, LC 57, LC 58, LC 59, LC 60, LC 61, LC 62, LC 63, UE 264, UE 296, UM 1505, UM 1657, UM 1662, UM 1667, UM 1675, UM 1716, UM 1719, and UM 1746. Also worked at CUB as an analyst on various other dockets, including UE 246, UE 262, UE 263, and UM 1720.

April 29, 2016

TO: Sarah Knox-Ryan
Citizens Utility Board of Oregon (CUB)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 308
PGE Response to CUB Data Request No. 025
Received April 15, 2016

Request:

The AUT is an automatic adjustment clause for variable power costs.

a. Please explain how the capital investment in a gas field is considered a variable power cost and not a fixed cost.
b. What is the basis to seek prudence determination of a long-term rate based investment in the AUT?
c. What is the basis to introduce a long-term rate based investment in an AUT update?
d. Has PGE ever proposed recovery of a rate based asset in the AUT (or its predecessors)?

Response:

a. PGE's proposal calls for an affiliated entity, Portland General Gas Supply Co. (PGGS) to transact for gas reserves. As a result, PGGS will have a capital investment. PGGS will then sell the produced gas to PGE on a cost-of-service basis in accordance with the terms of the Purchase Gas Agreement, submitted as part of PGE's request in Docket No. UI 371. Because PGE will use this gas as fuel for its gas-fired thermal plants, it is no different than other gas purchases and/or physical hedges, which are appropriately treated as variable power costs and included in PGE's power cost forecast (i.e., AUT filings) and actual power costs (i.e., PCAM filings). As noted in part d, below, the price that PGE pays for these purchases undoubtedly includes a fixed cost component such as return on and of capital.

b. PGE is seeking a prudence determination for the cost per MMBtu of its proposed long-term gas hedge to be included in AUT filings. We believe this to be very similar to the NW Natural determination in Commission Order No. 11-176, wherein the cost of NW Natural's long-term gas investment will be included in its annual purchased gas adjustment mechanism.

c. See PGE's response to part a, above. PGE proposes to include cost-of-service gas in its AUT filings as described in PGE Exhibit 300, Section IV. Specifically, the AUT inputs to PGE's MONET model will include the cost per MMBtu and average daily gas volume. These amounts are appropriate to include in PGE's AUT filing because Schedule 125-1 specifies that the following updates "will be made in each of the Annual Power Cost Update filings":

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

d. In its AUT filing, PGE is requesting recovery of cost-of-service gas that will be used to fuel its gas-fired thermal plants. The fact that this cost per MMBtu includes fixed costs is no different than other gas purchased from unaffiliated producers. All gas and energy purchases that are priced at cost or higher (market conditions allowing) will include applicable fixed costs and return on investment.

April 29, 2016

TO: Sarah Knox-Ryan
Citizens Utility Board of Oregon (CUB)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 308
PGE Response to CUB Data Request No. 024
Received April 15, 2016

Request:

See UE 308/PGE/300/Russell-Tooman. With regards to PGE's participation in a non-operating working interest, please explain and document how PGE is evaluating the following risks:

a. Water
b. Ozone
c. Greenhouse gas
d. Spills
e. Royalty risks
f. Tax litigation risk
g. Dry hole risk
h. Pre-existing liens
i. Bankruptcy risk
j. Ownership change risk

Response:

PGE objects to this request on the grounds that it is vague and ambiguous. PGE did not provide this list in testimony or exhibits and the terms and issues are not defined. Without waiving this objection, PGE responds as follows:

a. PGE will conduct reasonable due diligence as described in PGE Exhibit 300, Section II, Part C, pages 7-12, regarding risks associated with water including the potential to contaminate water and potential water supply issues. Following any purchase, regularly scheduled inspections and audits will be conducted to confirm that all practical mitigation efforts are being conducted.

b. PGE will conduct reasonable due diligence as described in PGE Exhibit 300, Section II, Part C, pages 7-12, regarding risks associated with emissions of ozone (smog) forming compounds. Following any purchase, regularly scheduled inspections and audits will be conducted to confirm that all practical mitigation efforts are being conducted.

c. PGE will conduct reasonable due diligence as described in PGE Exhibit 300, Section II, Part C, pages 7-12, regarding risks associated with emissions of greenhouse gases. Following any purchase, regularly scheduled inspections and audits will be conducted to confirm that all practical mitigation efforts are being conducted.

d. PGE will conduct reasonable due diligence as described in PGE Exhibit 300, Section II, Part C, pages 7-12, regarding risks associated with spill prevention. Following any purchase, regularly scheduled inspections and audits will be conducted to confirm that all practical mitigation efforts are being conducted.

e. PGE will conduct reasonable due diligence regarding land and title issues, including a review of the land records, recorded liens, leases and royalty interest holders.

f. PGE will conduct reasonable due diligence regarding any pending litigation and tax implications of the transaction.

g. PGE has retained Netherland Sewell and Associates Inc. (NSAI) to help PGE evaluate resource proposals for both new wells and existing wells that PGE might consider. PGE will work closely with NSAI to evaluate any drilling programs and will factor the statistical likelihood of dry holes into its decision making. Existing wells, however, are actively producing and therefore not considered to be dry holes.

h. See (e) above.

i. PGE will conduct reasonable due diligence regarding the financial condition of any counterparty to assess counter-party and bankruptcy risk. Depending upon the results of such due diligence efforts, the terms and conditions of the final definitive agreement may address and mitigate this risk.

j. The definitive agreements will include assignment provisions governing the assignment of contractual rights and will be subject to negotiation, agreement, and final documentation in the definitive agreements. In addition, the definitive agreements will reflect binding contractual obligations that will be binding upon any assignee or successor entity.

June 9, 2016

TO: Sarah Knox-Ryan
Citizens Utility Board of Oregon (CUB)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 308
PGE Response to CUB Data Request No. 033
Received May 26, 2016

<u>Request:</u>

Please see PGE's data response to CUB data request 17. As part of its response, the Company states, "A decision has not been made. PGE is not exclusively pursuing non-operated working interests." However, the Company [redacted] for long-term hedging costs. Please explain how the [redacted] if a decision has not yet been made.

<u>Response:</u>

PGE included the referenced amount as a pro forma estimate based on preliminary discussions with one of PGE's potential counterparties and because, at that time and to date, <u>cost-effective</u>, long-term alternatives to a non-operating working interest have not been available. "Based on our research and evaluations conducted to date, a non-operating working interest appears to provide the best long-term value for PGE's customers" (PGE Exhibit 300, page 12). In addition, PGE included the pro forma estimate with the expectation that it could change significantly as we further evaluated potential counterparties and negotiated possible transactions. See PGE Exhibit 600, page 5, lines 13-18, for the updated cost/MMBtu and volume associated with the term sheet provided as PGE Exhibit 601C.

By way of example, Attachment 033-A provides an analysis of a recent long-term alternative to a non-operating working interest and demonstrates that it is not cost-effective. PGE continually evaluates the market for these types of products and Attachment 033-A is typical in that it is priced at a premium to our long-term market forecast. Attachment 033-A is protected information and subject to Protective Order No. 16-137.

UE 308

Attachment 033-A

Provided in Electronic Format only

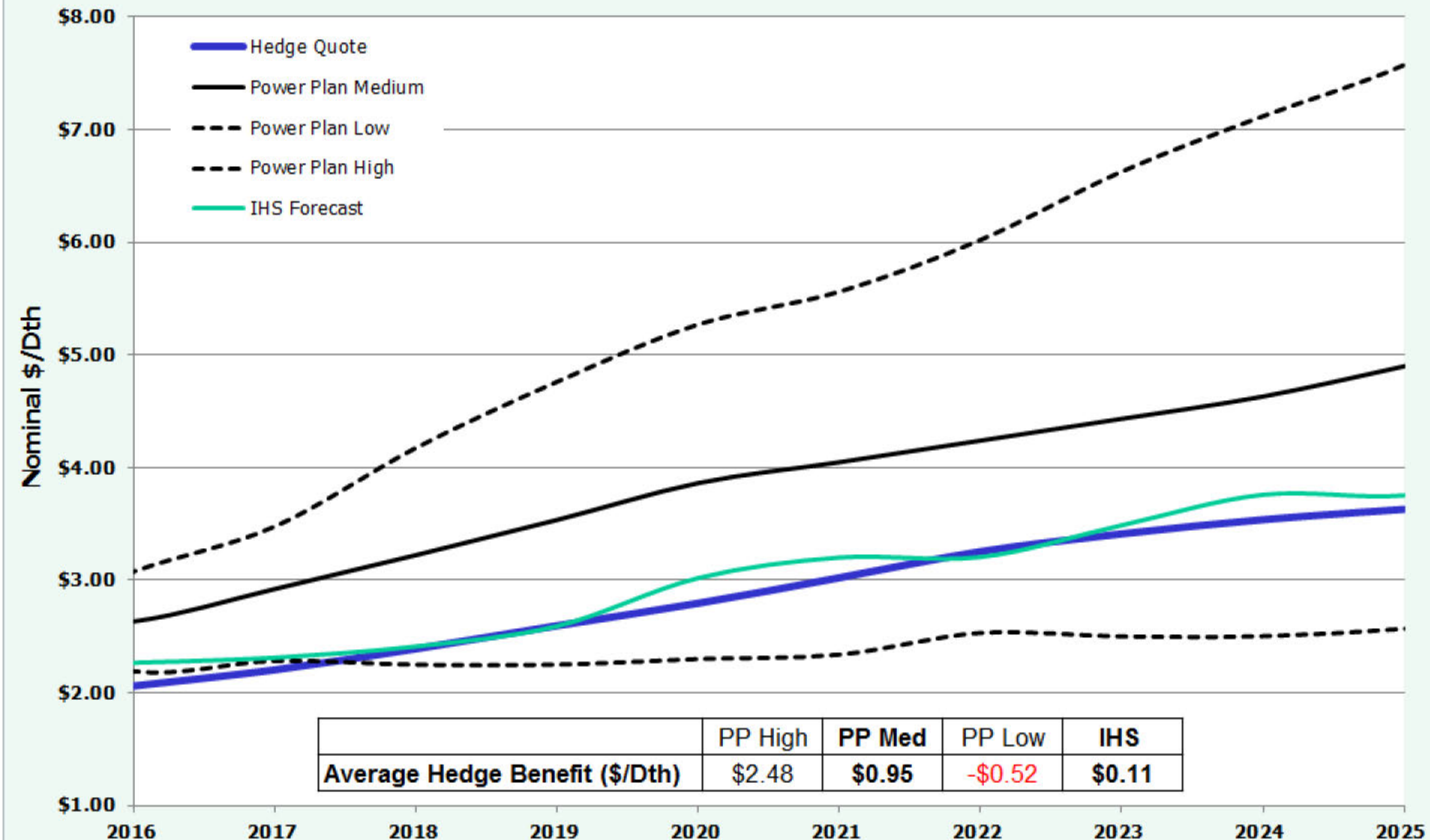
Protected Information Subject to Protective Order No. 16-137

Alternative to Non-Operating Working Interest

CUB Exhibit 105 is confidential and was submitted to each party designated to receive confidential information pursuant to Order 16-137.

NW Natural

Financial Hedge Price vs Price Forecasts- January 2016 Example



	PP High	PP Med	PP Low	IHS
Average Hedge Benefit ($/Dth)	$2.48	$0.95	-$0.52	$0.11

CUB Exhibit 107 is confidential and was submitted to each party designated to receive confidential information pursuant to Order 16-137.

June 14, 2016

TO: Sarah Knox-Ryan
Citizens Utility Board of Oregon (CUB)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 308
PGE Response to CUB Data Request No. 038
Received June 6, 2016

Request:

Is the Company planning on deferring any of the costs of EIM (both start-up costs and otherwise)? If so, please detail and estimate the costs that the Company plans to defer. Please provide a demonstration/explanation of the Company's understanding of prudence/used and usefulness for EIM investments when the Company is forecasting no benefit to customers during the forecasted time period.

Response:

PGE objects to this request to the extent that it seeks a legal opinion from PGE. Without waiving its objection, PGE responds as follows.

No, PGE does not currently plan to defer costs associated with EIM implementation or participation.

With respect to prudence, PGE excluded costs and benefits from its 2017 net variable power cost forecast. Since costs and benefits are excluded, a prudence determination by the Commission in Docket No. UE 308 is not necessary.

PGE believes that its decision to participate in the Western EIM is prudent as part of its efforts to enhance operational efficiency, integrate renewable resources, and optimize PGE's generation portfolio. The key capital projects described in PGE Exhibit 400, pages 19 – 20 will be used to enable PGE's participation in the Western EIM. PGE is preparing for a market entry date of October 1, 2017.

UE 308 – CERTIFICATE OF SERVICE

I hereby certify that, on this 20th day of June, 2016, I served the foregoing **CUB Confidential Testimony & Exhibits** in docket UE 308 upon the Commission and each party designated to receive confidential information pursuant to Order 16-137 by U.S. mail, postage prepaid.

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Respectfully submitted,

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