

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 294

In the Matter of)
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PORTLAND GENERAL ELECTRIC)
COMPANY)
)
Request for a General Rate Revision)
_____)

**OPENING TESTIMONY OF THE
CITIZENS' UTILITY BOARD OF OREGON**

June 15, 2015



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1 Our names are Bob Jenks and Jaime McGovern, and our qualifications are listed
2 in CUB Exhibit 101.

3 **I. Introduction**

4 CUB participated in settlement discussions and several issues were settled. CUB
5 expects that a stipulation setting forth the settlement agreement will soon be finalized and
6 filed with the Commission. Therefore, we will not address the issues that we anticipate
7 are part of that settlement package.

8 In our Opening Testimony, CUB will make following arguments:

- 9 • PGE has failed to justify its proposed January 1 rate increase;
- 10 • The Residential Exchange Credit is not a rate case issue and should have
11 no impact on this case;
- 12 • PGE has under-forecasted Other Revenue;

- 1 • PGE’s proposal to classify transmission as 100% demand is not
2 reasonable;
- 3 • PGE’s proposal to increase the customer charge should be rejected;
- 4 • PGE’s increase in rate base in recent years requires an increase in the
5 PCAM deadbands; and
- 6 • PGE has failed to examine the benefits of altering its capital structure.

7 **II. PGE has failed to justify its January 1 rate increase.**

8 PGE filed this General Rate Case (GRC) with a rate effective date of January 1,
9 2016. But PGE does not need a rate change on January 1, 2016. According to PGE,
10 without the January increase, PGE’s ROE would be 8.8% before Carty comes online.¹
11 While the Commission authorizes a specific target for ROE, it is generally accepted that
12 there is a range of reasonableness -- just because ROE is above or below the authorized
13 level does not mean that a utility is not earning a reasonable return. And according to the
14 Staff analysis in PGE’s last GRC, an 8.8% ROE is still within the range of
15 reasonableness.²

16 If PGE does not need a rate increase in January to ensure reasonable earnings,
17 why did PGE file this case? The answer is clear. PGE consistently files a general rate
18 case to conclude 2 to 6 months before a major new generating investment is forecast to
19 come online. It has been true for Tucannon³ and Port Westward 2⁴ and it was true for
20 Port Westward 1.⁵ The only exception is Coyote Springs, which came online 9 months

¹ UE 294 - PGE/200/Tooman-Brown/3.

² UE 283 - Staff/200/Muldoon/24.

³ UE 283 - PGE/400/Pope - Lobdell/16.

⁴ UE 283 - PGE/400/Pope - Lobdell/21.

⁵ UE 180 - CUB/200/Jenks-Brown/2.

1 after the last general rate case ended, but PGE had an agreement with OPUC Staff to
2 allow it to bring on Coyote Springs with a tracker filed 90 days before the expected in-
3 service date and an “attestation by a corporate officer” that the plant was operational.⁶

4 PGE has found a way to manage the regulatory system to ensure that it bears no
5 regulatory lag for its capital investments in new generating plants like Carty: file a two
6 stage rate case with the first stage ending within 2 to 6 months of the expected date for
7 the new plant. This allows PGE to get the second plant approved as a second stage to
8 that rate case. This means that approval and a tariff are in place before the plant is
9 operational, so there will not be a single day of regulatory lag.

10 In addition, based on the issues that have been settled in principle, the January
11 increase is getting smaller. While there was no justification for the increase when the
12 Company filed its case, there is certainly no justification now. CUB recommends that no
13 price increase be authorized on January 1, 2016 because the Company’s forecasted
14 earnings do not support such an increase.

15 **III. The Residential Exchange Credit is not a rate case issue and should**
16 **have no impact on this case.**

17 The BPA Residential Exchange Credit (Res Ex Credit) due to PGE’s residential
18 and small farm customers is increasing and PGE includes its affect in its pricing
19 testimony and exhibits:⁷

⁶ OPUC Order No. 95-322, Appendix D, page 3.

⁷ UE 294 -PGE/1400/Cody /2.

Table 1
Estimated Cost of Service Rate Impacts

Schedule	Jan. 1, 2016	Carty	Total
Schedule 7 Residential	-1.2%	4.3%	3.1%
Schedule 32 Small Nonresidential	1.8%	4.2%	6.0%
Schedule 83 31-200 kW	0.4%	5.0%	5.3%
Schedule 85 201-4,000 kW	-1.6%	5.5%	3.9%
Schedule 89 Over 4,000 kW	-2.3%	6.3%	4.0%
Schedule 90 100 MWa	-1.7%	6.6%	4.9%
COS Overall	-0.7%	4.7%	4.0%
COS & DA Overall	-1.0%	4.7%	3.7%

PGE expects that the Res Ex Credit will increase by \$15 million to a total of \$65 million. The Residential Exchange is a requirement of NW Power Act, which requires BPA to exchange power with Investor-Owned Utilities in order to share the benefits of federal hydropower specifically with residential and small farm customers.⁸ Utilities, like PGE, are required to pass this credit through to their residential and small farm customers. PGE has no discretion with how to use this revenue.

To be clear, CUB does not believe that PGE has done anything improper with the Res Ex Credit, but we are concerned with two impacts of including the credit in the pricing exhibits and tables.

First, it hides the real effect of PGE's rate hike on customers. PGE is proposing to increase the rates it charges to residential customers in January, but the rate case filing is telling customers that their rates are going down by 1.2%.

Second, it could affect charges to customers. PGE uses a Customer Impact Offset (CIO) surcharge/sur-credit to protect customer classes with the highest rate increases. PGE will cap increases at a certain level, and the lost revenue will be charged to other classes of customers through a CIO. Typically, such a surcharge will fall on customer

⁸ <http://www.bpa.gov/Finance/ResidentialExchangeProgram/Pages/default.aspx>.

1 classes that are receiving an increase that is less than the average increase. Hence, the
2 relative rate changes between rate classes are what drive the CIO.

3 In Oregon, costs are functionally allocated (generation on generation marginal
4 cost, distribution on distribution marginal cost, etc.). Because of this, as the revenue
5 requirement changes so does the relative rate changes among rate classes. A rate class
6 that is currently receiving an increase that is larger than the average increase could end up
7 with an increase that is below the average increase. So while PGE is not proposing to
8 charge a CIO to residential customers in its initial filing, this could change as the case
9 progresses. It would be inappropriate to include the Res Ex Credit in any analysis that
10 triggered a CIO. The Res Ex Credit should be applied after the application of the CIO.
11 It isn't merely a matter of aesthetics. Incorporating the Res Ex Credit into the rate change
12 before the CIO calculation could create a material (possibly adverse) impact for the
13 customers who are supposed to receive the benefit of the Res Ex Credit from BPA via
14 PGE, its custodian. One could imagine a circumstance where residential customers have
15 an increase that is greater than average before the application of the Res Ex Credit, so
16 without the credit, it is clear that the CIO would not be charged to residential customers.
17 However, after the Res Ex Credit, residential customers could have one of the lower rate
18 increases, causing them to have to pay a CIO. In effect, the Res Ex Credit would trigger
19 the CIO and residential customers would then receive less than the full benefit of the Res
20 Ex Credit.

21 While PGE is currently not proposing that residential customers pay a CIO, CUB
22 nevertheless recommends that PGE clearly state its rate impact both with and without the
23 Res Ex Credit and that it should be applied only after the CIO.

1 **IV. PGE has Under-Forecasted Other Revenue.**

2 In addition to revenue from customers established through rates set by this
 3 Commission, PGE has several other relatively small sources of revenue from things like
 4 steam sales and pole attachments. These are classified as “Other Revenue” and act as an
 5 offset to revenue requirement before the revenue requirement is charged to customers. In
 6 UE 283, PGE forecasted 2014 Other Revenue as \$22.6 million.⁹ In this current rate
 7 filing, PGE’s exhibits show that the actual amount of other revenue in 2014 was \$27.5
 8 million.¹⁰ This is a differential of \$4.9 million. This means that almost \$5 million of
 9 revenue requirement that was charged to customers should have been offset by Other
 10 Revenue.

11 CUB went back over PGE’s last several rate cases to examine PGE’s forecasts of
 12 Other Revenue to see how accurate they were. CUB Exhibit 102 shows the results of that
 13 examination. Since 2006, CUB identified 7 years where PGE forecasted Other Revenue
 14 in a rate case and later, in another rate case, provided actual results:¹¹

Year	Forecast (in millions)	Actual (in millions)	Differential
2006	17.7	17.3	-0.4
2008	17.8	20.6	2.8
2010	19.9	26.2	6.3
2011	21.0	22.4	1.4
2012	21.4	24.7	3.3
2013	23.0	24.9	1.9
2014	22.6	27.5	4.9

15
 16 This chart shows that PGE regularly under forecasts Other Revenue. The year
 17 2006 was the last time the Company over-forecasted. While the most recent forecast was

⁹ UE 294 - CUB Exhibit 102.

¹⁰ UE 294 - PGE/202/Tooman-Brown/1.

¹¹ *Ibid.*

1 off by \$4.9 million, on average, PGE has under forecasted Other Revenue by \$3.0 million
2 over the past 8 years. CUB recommends that PGE's Other Revenue be adjusted based on
3 this historical forecast error: \$3.0 million should be added to PGE's forecast of Other
4 Revenue, reducing the amount of Revenue Requirement that is allocated to customers.

5 **V. PGE's proposal to classify transmission as 100% demand is not**
6 **reasonable.**

7 PGE is proposing to recover its transmission revenue requirement entirely through
8 demand--or capacity--related charges by assigning the revenue requirement to a 12 month
9 coincident peak basis:

10 I allocate the transmission revenue requirement consistent with how PGE's
11 FERC transmission prices are determined, therefore on a twelve coincident
12 peak basis (12-CP).¹²

13 This is a significant change from PGE's proposal in the last rate case;

14 I also allocate the transmission revenue requirement consistent with how
15 UE 262 prices were established, 65% based on capacity, and 35% based
16 on energy.¹³

17 PGE offers little to support this change, other than offering the fact that it is
18 consistent with its FERC prices. However, PGE's generation and transmission systems
19 demonstrate that this change is not justified.

20 Consider PGE's two coal plants: Boardman and Colstrip. Boardman was
21 authorized in 1975¹⁴ and, while not in PGE's service territory, was built near PGE's
22 service territory, meaning that relatively minimal additional transmission rights were
23 required. There is no coal production near the plant, and therefore the plant's fuel supply

¹² UE 294 – PGE/1400/Cody/5.

¹³ UE 283 - PGE/1400/Cody/9.

¹⁴ https://en.wikipedia.org/wiki/Boardman_Coal_Plant.

1 must be transported by rail. PGE's investment in Colstrip came nearly a decade after its
2 investment in Boardman.¹⁵ Colstrip was built in eastern Montana, more than 1000 miles
3 from Portland,¹⁶ and is located near coal mines that have been in operation since 1924.¹⁷
4 Transmission is required to get Colstrip's power from eastern Montana to PGE's service
5 territory.

6 With Boardman, PGE believed the right resource strategy was to build a coal
7 plant near its service territory and transport the coal by rail. With Colstrip, PGE believed
8 the right resource strategy was to build a coal plant 1000 miles away, near coal mines,
9 and transport the electricity by wire. The difference in these resource strategies is
10 probably explained by the Staggers Rail Act of 1980, which largely deregulated the US
11 rail industry.¹⁸ Key among its provisions was allowing rail owners to charge any rate
12 they wanted unless the Interstate Commerce Commission found that there was no
13 effective competition to that rail service.¹⁹ The Staggers Rail Act changed the economics
14 of shipping coal by rail.

15 But these two coal plants show that rail transport of coal and transmission
16 transport of electricity are substitutes for each other. With no significant coal resources
17 near its service territory, when building a coal plant, PGE had a choice to transport coal
18 by rail or to transport electricity by wire.

19 Under PGE's proposed transmission rate recovery, the recovery of costs for these
20 two substitutes would be dramatically different. The transportation for Colstrip (electric

¹⁵ http://www.sourcewatch.org/index.php?title=Colstrip_Steam_Plant

¹⁶ <https://search.yahoo.com/yhs/search?p=distance+from+Colstrip+Montana+to+Portland+Oregon&ei=UTF-8&hspart=mozilla&hsimp=yhs-001>

¹⁷ https://en.wikipedia.org/wiki/Colstrip,_Montana

¹⁸ https://en.wikipedia.org/wiki/Staggers_Rail_Act

¹⁹ *Ibid.*

1 transmission) would be recovered entirely from capacity. However, the transportation for
2 Boardman (coal by rail) would be recovered as an energy charge.²⁰

3 IRP Guideline 5 states:

4 Portfolio analysis should include costs to the utility for the fuel
5 transportation and electric transmission required for each resource being
6 considered. In addition, utilities should consider fuel transportation and
7 electric transmission facilities as resource options, taking into account
8 their value for making additional purchases and sales, accessing less costly
9 resources in remote locations, acquiring alternative fuel supplies, and
10 improving reliability.²¹

11 CUB believes that assigning transmission to capacity 100 percent fails to acknowledge
12 that transmission and fuel transportation are substitutes.

13 CUB recommends that the Commission reject PGE's proposal to switch the
14 transmission revenue requirement entirely to demand. Instead, the Commission should
15 require PGE to continue to allocate 65% of the costs of transmission to capacity and 35%
16 to energy. CUB is supportive of PGE's approach of collecting the capacity based on a 12
17 CP approach.

18 **VI. PGE's proposal to increase the customer charge should be rejected**

19 PGE is proposing to increase the fixed customer charge to residential customers
20 from \$10 to \$11.²² PGE supports this increase by referencing its marginal cost study:

²⁰ UE 250 – PGE/200/Macfarlane - Gariety/4.

²¹ OPUC Order No. 07-002 at 13.

²² UE 294 - PGE/1400/Cody/10.

1 Although the embedded customer costs suggest a Basic Charge of
2 approximately \$22, and the marginal customer costs sum to more than
3 \$13, I propose to increase the Basic Charge by one dollar, to \$11 in order
4 to better match prices to costs, consistent with the principle discussed
5 above.²³

6 However, PGE Exhibit 1301 shows that the marginal customer cost for residential
7 customers is \$68.88 or \$5.74/month.²⁴ Even when the cost of the meter (\$20.22) is added
8 to the customer cost, it still only brings the cost to \$7.43 per month.

9 During the 1990s, there were a series of contested proceedings, including one that
10 was a generic review of the use of marginal cost studies. During this time, CUB's
11 perception was that rate design in Oregon was based on a set of principles. While CUB is
12 unaware of any order that carefully lays out these principles, CUB believes that they have
13 been the basis for marginal cost and rate design decisions and two of them are important
14 in this case:

- 15 1) Rate Design should be done in a manner that encourages conservation.
16 This is accomplished by charging most costs to customers as variable
17 charges and using an inclining rate block that ensures that the benefit of
18 conservation is greater than the average energy charge.
- 19 2) Fixed cost recovery is limited to the direct costs of a particular
20 customer: the line drop, the meter and billing, etc. Costs that are shared
21 by customers, whether those costs are line transformers, conductors, or
22 the call center, should not be included in a fixed monthly charge.

23 CUB recommends that the Commission reject PGE's request to increase the fixed
24 customer charge.

²³ *Ibid.*

²⁴ UE 294 - PGE/1301/Macfarlane-Werner /3.

1 **VII.PGE’s increase in rate base in recent years requires an increase in**
2 **the PCAM deadbands.**

3 PGE has been on a capital spending spree in recent years. In 2009, PGE’s total
4 rate base was \$2.37 billion.²⁵ PGE forecasts two different figures for rate base in this
5 filing. Before Carty, PGE will have a rate base of \$3.99 billion, and after Carty will have
6 a rate base of \$4.47 billion.²⁶ This is nearly double what it was in 2009.

7 CUB believes that this increase in rate base requires a reexamination and
8 adjustment of the deadband in PGE’s PCAM mechanism.

9 **A. Original PCAM Order.**

10 The original PCAM was designed by the PUC after a contested case where PGE,
11 Staff and CUB all proposed different versions of a PCAM. The Commission was clear
12 that a PCAM needed to have an earnings test and an ROE deadband:

13 We conclude that a PCAM should be adopted to capture power
14 cost variations that exceed those considered part of normal business risk.
15 In this case, normal business risk for PGE includes all of the
16 circumstances to which it is exposed, such as hydro variability.

17 First, the Commission will apply an earnings test to determine
18 whether the utility is earning an acceptable rate of return. An earnings test
19 serves to protect customers from paying for higher-than-expected power
20 costs when the utility’s earnings are reasonable, while it protects the
21 Company from refunding power cost savings when it is underearning...
22 Second, we will set a deadband so that PGE will absorb some normal
23 variation of power costs. We are persuaded by CUB’s arguments, in this
24 case and in dockets UE 165 and UM 1187, that an asymmetric deadband is
25 necessary to ensure that the PCAM is revenue neutral. *See* UE 165/UM
26 1187, Order No. 05-1261, 10. The deadband for the power cost variation
27 will be range from 75 basis points ROE below the base level of NVPC
28 included in rates, to 150 basis points ROE above. As we noted in AR 499,
29 we are well aware of the double whammy effect on SB 408, *see* Order No.
30 06- 532, 10, and we have considered that impact in the design of this

²⁵ UE 197 - PGE/209/Tooman-Tinker/ 1.

²⁶ UE 294 - PGE/209/Tooman-Brown/1-2.

1 mechanism. Further, **we agree with Staff that the ability to absorb**
2 **power cost increases depends on a utility's total rate base**, and that this
3 PCAM is narrowly tailored to suit PGE; therefore, we decline to accept
4 PGE's arguments that a deadband should focus on a return on generation
5 assets only. The ROE deadband should be calculated based on PGE's
6 overall rate base. If the power cost variation is within this deadband, there
7 will be no power cost rate adjustment.²⁷

8 The Commission was clear that the PCAM was designed to recover power costs
9 that were outside of the normal business risk and that the way to identify the normal
10 business risk is through an ROE deadband. The ROE deadband meant that the
11 mechanism was concerned with the earnings impact of a power cost variance. Rather
12 than focus on the size of a power cost variance (\$10 million, \$20 million, \$30 million,
13 \$40 million, etc.), the key issue was the impact that that variation had on earnings.

14 It is much more expensive to finance capital investment through equity than it is
15 through debt (see discussion on capital structure below). But equity has an advantage.
16 The cost of debt – the interest on a loan – must be paid or the debt will be in default. But
17 equity returns are a projection, with the recognition that actual earnings will be higher or
18 lower than the projection. An event that causes equity returns to fall a bit is well within
19 the normal risk variation associated with investing in a utility. Through a series of
20 deferral dockets in the early part the last decade, the Commission began using 250 basis
21 points as a deadband for normal business risk. This was during and after the Western
22 Power crisis when wholesale power prices were at their highest level and during a series
23 of bad water years for NW hydro conditions. There was a great deal of discussion
24 concerning the normal business risk for a utility.

²⁷ OPUC Order No. 07-015, pages 26-27 (emphasis added).

1 **B. UM 995.**

2 Docket UM 995 addressed a deferral related to high purchased power costs that
3 PacifiCorp incurred after a catastrophic failure of a coal unit during the Western Power
4 Crisis. In that docket, the PUC set up a tiered approach to deadbands and sharing:

5 Using the baseline the Commission established in Order No. 01-683,
6 PacifiCorp incurred approximately \$786.7 million in excess net power
7 costs on a total company basis during the deferral period. The sharing
8 mechanism established in Order No. 01-420 works on the total company
9 level and set a deadband for power cost changes equivalent to +/- 250
10 basis points return on equity around the baseline (a band in which the
11 utility bears all the cost and receives all the benefit); a 50/50 sharing band
12 for power cost changes equivalent to between 250 and 400 basis points
13 (basis point threshold established before the effect of sharing is
14 calculated); and for power cost changes equivalent to more than 400 basis
15 points, a sharing in which customers bear 75 percent and the company
16 bears 25 percent. Order No. 01-420 at 5, 29. Applying the sharing
17 mechanism to the \$786.7 million in excess power costs (of which
18 approximately \$259 million is the Oregon share) yields approximately
19 \$160 million at issue on an Oregon basis. Pursuant to Order No. 02-410,
20 PacifiCorp is currently amortizing deferred power costs through August
21 31, 2002.²⁸

22 **C. UM 1071.**

23 In UM 1071, PGE requested a deferral because of poor hydro conditions. The
24 PUC order discussed the issue of what constitutes the normal business risk and rejected
25 PGE's request because it was not outside of the normal business risk:

²⁸ OPUC Order No. 02-469, page 3.

1 Staff has established a distinction between the risks that can be predicted
2 as part of the normal course of events and those that are not susceptible to
3 prediction and quantification. Staff calls the former stochastic risks and
4 the latter, paradigm or scenario risks. An example of a stochastic risk is
5 variation in hydro availability over time. An example of a scenario risk is
6 the “perfect storm” of 2000-2001, a cascade of effects that included poor
7 hydro conditions, cold weather, and extremely volatile power markets
8 (UM 995).⁵ We find this distinction useful to characterize the type of risk
9 we consider appropriate for deferral.

10 We agree with Staff that risks normally included in modeling power costs
11 (stochastic risks) are not appropriate for deferred accounting, as long as
12 those risks are reasonably predictable and quantifiable and have no
13 substantial financial impact on the utility. Here, hydro variability has been
14 included and modeled to set PGE’s base rates. The hydro year on which
15 PGE bases its application is, as CUB points out, a 1 in 4.5 year event. This
16 cause is not extraordinary enough to justify deferred accounting.

17 The magnitude of the financial effect on the utility is also a factor in our
18 consideration under the discretionary stage of the decision process. For a
19 stochastic risk to justify deferred accounting, the financial impact must be
20 substantial. Although we decline to set a numerical criterion, we can give
21 negative and positive examples. In UM 995, for instance, we established a
22 deadband around PacifiCorp’s baseline of 250 basis points of return on
23 equity.⁷ We allowed no recovery of costs or refunds to customers within
24 that deadband, reasoning that the band represented risks assumed, or
25 rewards gained, in the course of the utility business. In the Idaho Power
26 cases, discussed below, we allowed partial recovery for a financial impact
27 that represented approximately 700 basis points of Idaho Power’s return
28 on equity...

29 In the present application, PGE claims that it has incurred \$31.6 million in
30 excess NVPC, only some of which is attributable to hydro replacement
31 costs. PGE asserts that this excess NVPC amounts to 172 basis points of
32 return on equity. This is well short of the 250 basis points of return on
33 equity within which we allowed no recovery in UM 995. Moreover, Staff
34 estimates the hydro related excess NVPC to be about \$17.5 million,
35 which, by extension, amounts to about 95 basis points of return on equity.
36 That figure is about 55 percent of PGE’s \$31.6 million. Finally, we note
37 that PGE claims that without deferral, its return on equity will drop to 8
38 percent. That is far from a dire figure. We find that the impact of excess
39 hydro costs is not significant enough in this case to warrant a deferral.

40 Ultimately, these deferral dockets were highly contested and time consuming.

41 CUB supported a PCAM, because the PCAM would allow us to eliminate the contested

1 deferrals and, instead, pre-establish the rules for cost recovery when power costs are
2 outside of the normal business risk.

3 **D. UE 180/UE 181/UE 184.**

4 The original PCAM was designed by the Commission after receiving
5 recommened PCAMs from PGE, Staff and CUB. The Commission ultimately
6 established the deadbands based on basis points of ROE and stated that they should grow
7 with ROE:

8 Second, we will set a deadband so that PGE will absorb some normal
9 variation of power costs. We are persuaded by CUB's arguments, in this
10 case and in dockets UE 165 and UM 1187, that an asymmetric deadband is
11 necessary to ensure that the PCAM is revenue neutral. See UE 165/UM
12 1187, Order No. 05-1261, 10. The deadband for the power cost variation
13 will be range from 75 basis points ROE below the base level of NVPC
14 included in rates, to 150 basis points ROE above. As we noted in AR 499,
15 we are well aware of the double whammy effect on SB 408, see Order No.
16 06-532, 10, and we have considered that impact in the design of this
17 mechanism. Further, we agree with Staff that the ability to absorb power
18 cost increases depends on a utility's total rate base, and that this PCAM is
19 narrowly tailored to suit PGE; therefore, we decline to accept PGE's
20 arguments that a deadband should focus on a return on generation assets
21 only. The ROE deadband should be calculated based on PGE's overall rate
22 base. If the power cost variation is within this deadband, there will be no
23 power cost rate adjustment.²⁹

24 **E. UE 215.**

25 The Commission originally designed PGE's deadbands around rate base. The
26 deadbands were established at 150 basis points above authorized ROE and 75 basis
27 points below ROE.³⁰ That was modified in UE 215 when the parties to the case
28 stipulated to the current deadband of \$30 million above forecasted amounts and \$15
29 million below forecasted amounts, which approximated the 2009 ROE deadband.³¹ That

²⁹ OPUC Order No. 07-15.

³⁰ *Ibid.*

³¹ OPUC Order No. 10-478, page 10.

1 settlement was for the purposes of that case only, and CUB's expectation was that the
2 deadbands would be revisited on a regular basis as rate base grew.

3 In UE 215 (2010), PGE proposed replacing the ROE deadband with a deadband
4 of \$10 million above or below forecasted power costs.³² This was opposed by CUB,
5 ICNU and Staff.³³ Parties agreed as part of settlement to replace the ROE deadband with
6 the current deadband of \$30 million above the forecasted cost and \$15 million below the
7 forecasted cost. The stipulation makes clear that it was for that rate case only and in
8 future general rate cases, parties could propose updating it. CUB agreed to the change in
9 the deadband because we came to believe that a monetary deadband is easier to
10 understand and might make it easier for PGE to explain the deadband to rating agencies.
11 But the size of the deadband was set at a level that approximated what the ROE deadband
12 had recently been for existing rate base. In addition, CUB agreed on the monetary
13 deadband because the agreement allowed CUB and other parties to request expansion of
14 the deadband as PGE's rate base grew, so we could maintain a deadband that was
15 proportional to the original levels. The stipulation makes clear that it was for that rate
16 case only and in future general rate cases, parties could propose updating it:

³² OPUC Order No. 10-478, page 9.

³³ OPUC Order No. 10-478, page 10.

1 **IV. PCAM.** Effective for power costs beginning January 1, 2011, the
2 power cost variance deadbands in PGE's Annual Power Cost Variance
3 Mechanism tariff, Schedule 126, will be set as follows: The Negative
4 Annual Power Cost Deadband will be \$15 million. The Positive Annual
5 Power Cost Deadband will be \$30 million. The Stipulating Parties agree
6 to no other changes in Schedule 126 in this docket; however, no party is
7 precluded from proposing changes to Schedule 126 in future general rate
8 cases.³⁴

9 In the testimony supporting the stipulation, the parties explain this change:

10 **Please describe the stipulation regarding PGE's PCAM?**

11 The Stipulating Parties agree that deadbands applicable to PGE's PCAM
12 should be modified to fixed amounts of \$30 million when power costs are
13 higher than the base level established in rates, and \$15 million when
14 power costs are lower than the base level established in rates. Other
15 elements of the PCAM, including the earnings test, remain unchanged.
16 This change is for this case only. Parties are free to advocate different
17 deadbands in future general rate cases.

18 **What is the basis for the stipulation regarding PGE's PCAM?**

19 In their filed testimony (ICNU/IOO, Staff/500, CUB/IOO), various parties
20 argued that the current PCAM structure is reasonable. The parties contend
21 that a substantial reduction in the deadbands would constitute an
22 unreasonable shift of risk to customers and that the PCAM was operating
23 consistent with its intended purpose and with principles identified by UE
24 215 Rate Case - Testimony in Support of the Cost of Capital and PCAM
25 Stipulation the Commission in Order 07-015. In opening and rebuttal
26 testimony, PGE supported symmetrical deadbands and narrowing the
27 deadbands to positive and negative \$10 million, along with changes to the
28 earnings test. PGE argued that the current PCAM structure is outside of
29 the mainstream recovery mechanisms operable for most utilities, including
30 those with which PGE competes for capital.

31 The proposed agreement represents a compromise of positions, and the
32 Stipulating Parties believe the modification to the PCAM is reasonable.
33 The Stipulating Parties note that the agreed upon fixed \$30 million and
34 \$15 million deadbands are approximately the same size as the deadbands
35 that actually applied to PGE's power costs for 2009 (as filed in UE 221)
36 which are \$29.4 million and \$14.7 million respectively.³⁵

³⁴ OPUC Order No. 10-478, Appendix D, page 3.

³⁵ UE 215 - Stipulating Parties/500/Johnson - Jenks - Tinker/5.

1 While the parties to that docket agreed to move to a monetary deadband, that
2 deadband was sized to prevent “a substantial reduction in the deadbands” which “would
3 constitute an unreasonable shift of risk to customers.” However, over time, the deadband
4 has shrunk due to the growth in rate base and this has shifted risk to customers. The
5 earnings impact of the \$30 million/\$15 million deadband is approximately half of what it
6 used to be (just as rate base is approximately twice what it used to be).

7 **F. UE 246.**

8 The most recent Commission order establishing a PCAM was the PacifiCorp
9 PCAM. In that case, the Commission established a monetary deadband (\$30 million/\$15
10 million), but specifically noted that the PCAM deadband was tied to the size of rate base,
11 and referred to the precedence that had been set by the Commission with the PGE
12 PCAM:

13 In adopting a PCAM for PGE, we articulated general principles that form
14 the basis of a well-designed PCAM: (1) any adjustment under a PCAM
15 should be limited to unusual events and capture power cost variances that
16 exceed those considered normal business risk for the utility; (2) there
17 should be no adjustments if the utility's overall earnings are reasonable;
18 (3) the PCAM's application should result in revenue neutrality; (4) the
19 PCAM should operate in the long-term to balance the interests of the
20 utility shareholder and ratepayer; and, implicitly, (5) the PCAM should
21 provide an incentive to the utility to manage its costs effectively.

22 Applying those principles, we adopted a PCAM structure for PGE as
23 follows. First, we established a deadband so that PGE would absorb some
24 normal variation of power costs. If the power cost variation fell within the
25 deadband, there would be no power cost rate adjustment. We concluded a
26 power cost deadband should be calculated based on POE's overall rate
27 base. To ensure the PCAM was revenue-neutral, we adopted an
28 asymmetric deadband that did not change rates when excess power costs
29 were less than the equivalent of 150 basis points of authorized ROE or
30 when power cost savings were less than the equivalent of 75 basis points
31 of the utility's ROE...

32 Later, we adopted a stipulation that modified POE's PCAM in one
33 respect-changing the deadband from basis points to a set dollar amount.

1 Under this modification, the negative annual power cost variance
2 deadband was set at \$15 million, and the positive annual power cost
3 variance deadband was set at \$30 million.

4 After reviewing the factual record and the parties' arguments in this
5 proceeding, we conclude that our reasoning used to establish a PCAM for
6 PGE remains sound and applies equally with respect to establishing a
7 PCAM for Pacific Power.³⁶

8 While the Commission established a monetary deadband of \$30 million/\$15
9 million similar to PGE's deadband, the Commission was clear that the deadband was
10 related to rate base: "***We base our adopted power cost deadband on Pacific Power's***
11 ***authorized rate base, rather than on the utility's net power costs. In determining an***
12 ***appropriate power cost deadband, we look to the size of the utility's rate base and to the***
13 ***utility's authorized ROE.***"³⁷

14 Because the basis for the deadband is tied to rate base and because PGE's ratebase
15 has grown from \$2.4 billion to \$4.4 billion after Carty, CUB proposes to update the
16 deadbands. Based on the rate base ***before*** Carty, and sticking to the 150/75 basis points
17 as the basis of the deadband, 150 basis points would provide a deadband of \$59.8 million,
18 which CUB proposes to round to \$60 million and establish a deadband of \$60 million
19 above forecasted costs and \$30 million below forecasted costs.

³⁶ OPUC Order No. 12-493, pages 13-14.

³⁷ OPUC Order No. 12-493, page 15 (emphasis added).

1 **VIII. PGE has failed to appropriately consider the benefits of altering**
2 **its capital structure.**

3 The Company states that it has a long term financial goal to "maintain our capital
4 structure at 50% equity and 50% debt."³⁸ CUB believes that the prudence of this goal
5 should be investigated and determined.

6 The Company states:

7
8 It is the optimal debt-to-equity ratio for PGE because it offers a balance
9 between the ideal debt-to-equity range and minimizes our cost of capital.
10 The equity portion of PGE's capital structure is important because it
11 represents how PGE finances its cash needs. In addition, the equity portion
12 helps offset the leverage and risk that PGE encounters, in part, as it
13 finishes its large capital expenditure program.³⁹

14 As discussed above, other utilities in other jurisdictions and other utilities under the
15 authority of the Oregon PUC vary from the 50/50 debt equity structure, and while CUB is
16 not recommending that PGE mirror the structure of any other particular utility, we
17 believe that the Company should continue to pursue the most efficient form of raising
18 funds for resources that will be used to serve customers.

19 The Company is vigilant about its ability to attract investor funds and should be
20 active in maintaining solid financial performance. In each of the Company's recent
21 annual rate cases, the Company discusses the role of ratings agencies and their various
22 considerations. Although debt/equity structure is a component, it is not the only
23 component. CUB believes that other favorable factors are at play for the Company and
24 should be considered in the context of determining an appropriate debt/equity structure.
25 As a regulated utility, PGE has characteristics that are unique to its sector.

³⁸ UE 294/PGE/1000/Hagar-Greene/21.

³⁹ *Ibid.*

1 The bonds of regulated utilities have always been solid fixtures in core
2 fixed income portfolios. For good reason – utilities arguably enjoy the
3 most stable business profiles in the corporate bond universe. Their every
4 move is scrutinized by state regulators and cash flows tend to be very
5 predictable.⁴⁰

6 CUB provides perspective and background in our arguments below, and proposes a
7 possible debt equity structure.

8 **A. A least-cost resource can become an overpriced resource with the wrong**
9 **financing.**

10 In the course of the Company’s IRP process, it is required to look forward,
11 identifying resource needs and demonstrating least-cost resource options to fill that need.
12 Once a resource is identified and acknowledged in the context of the IRP, there are still
13 plenty of components that can affect the final cost of the resource to the ratepayers.

14 Imagine that one were to purchase a car, and had the foresight to shop around.
15 Suppose the identical car was available at several dealerships. At dealership A, the car
16 was \$10,000, and at dealership B, the same car was \$12,000. At first glance, it seems
17 obvious that the least-cost approach would be to purchase the car from Dealer A.
18 However, if we understand that Dealer A only allows in-house financing, which will cost
19 25%, then the real cost of the car, if paid back in one year, becomes \$12,500. Dealer B
20 accepts your credit card which currently has a 0% offer. Then, suddenly, the car at
21 Dealer B becomes the more economical approach.

22 CUB does not propose that the Company is able to finance Carty on a credit card.
23 However, the method of funding a purchase can have a material impact on the real cost of

⁴⁰ Another Major Capital Cycle for Utilities: Why We Prefer First Mortgage Bonds, Galliard capital management.

1 the resource. With 30 year treasury rates currently at 3.10%,⁴¹ and the Company's
 2 proposed return on Equity of 9.9%,⁴² there is a significant gap between the after-tax cost
 3 of first mortgage bonds⁴³ and issuance of shareholder equity. The Company can continue
 4 to argue that there are risks to increasing the level of debt above 50/50, and while this is
 5 true, that risk needs to be quantified. In particular, in UE 197, the Company proposed a
 6 50/50 debt/equity structure, while its proposed cost of debt was 6.57%.⁴⁴ Today, the cost
 7 of debt is much lower,⁴⁵ and the Company still proposes the same capital structure.⁴⁶

8 Moreover, one must consider that equity has a tax incidence, and at an
 9 approximate equity tax rate of 40%, the cost to ratepayers for a dollar of capital funded
 10 through equity is 14 cents,⁴⁷ while the same dollars' worth of resource financed through
 11 debt has a cost of approximately 4 cents.⁴⁸

12 Debt is now significantly cheaper than it was several years ago:

13

PGE Long-term Debt Issuance (\$ in millions)			
Amount	Issuance Date	Coupon	Maturity
\$100	8/18/2014	4.39%	2045
\$100	10/15/2014	4.44%	2046
\$80	11/17/2014	3.51%	2024
\$75	1/15/2015	3.55%	2030

14

⁴¹ As of 6/12/15: <http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield>

⁴² UE 294 – PGE/1000/Hager – Greene/1.

⁴³ PGE uses First Mortgage Bonds (FMBs) to finance debt. UE 294/PGE/1000/Hager - Greene/19.

⁴⁴ UE 197 - PGE/900/Hager – Stathis/3.

⁴⁵ Portland General Electric 2014 Annual Report, page 58:

http://files.shareholder.com/downloads/POR/11173558x0x817873/3741d836-468a-4f1b-ab83-e67e1c88511b/PGE_Annual_Report.pdf.

⁴⁶ UE 294 - PGE/1000/Hager-Greene/21.

⁴⁷ At the Company's proposed 9.9 ROE, we have .099 x (1+.40) =.14

⁴⁸ The current treasury rate of 3.10+ 100 basis points.

⁴⁹ Portland General Electric 2014 Annual Report, page

58:http://files.shareholder.com/downloads/POR/11173558x0x817873/3741d836-468a-4f1b-ab83-e67e1c88511b/PGE_Annual_Report.pdf.

1 As such, the question must be asked: at what cost of debt is it economical for the
2 Company's shareholders to take on the burden of increased leverage?

3 **B. What is the impact of a shifting debt/equity ratio?**

4 Suppose that a company, which has \$10,000 in assets, is financed with 100%
5 equity. Then the Company, in a market with a 4% price fluctuation risk, absorbs that
6 equity across 100% of its assets. However, if the same company now moves to a 50/50
7 structure, then the same 4% fluctuation is absorbed by the shareholders that hold the 50%
8 equity or \$5,000 worth of assets, because in an unfortunate economic scenario, debt gets
9 paid first and the debt holders shoulder minimal risk. Therefore, that potential 4% price
10 fluctuation becomes magnified to 8% (as long as the size of the company remains
11 constant). This illustrates that companies and regulators must be attentive to the debt
12 equity ratio, because investors, in a market with alternatives, will steer away from a
13 company that is too heavily leveraged, all other things equal. However, all other things
14 are not equal, and changing circumstances must be considered on a company by company
15 basis.

16 **C. PGE has reduced risk because the size of its rate base has doubled.**

17 In 2009, the Company had an average rate base of \$2.3 billion⁵⁰ with a 50/50
18 debt/equity structure and a cost of debt at 6.567%.⁵¹ After Carty, the Company will have
19 twice the amount in rate base at \$4.5 billion. With the same debt/equity structure, the
20 Company's rate base equity has doubled as well. One might also argue that post-
21 recession, the exposure risk that the Company faces, has decreased. In addition, by
22 including load serving resources in rate base, those which used to be in contracts and

⁵⁰ UE 197 – PGE/200/Tooman-Tinker / 24.

⁵¹ OPUC Order No. 09-020 at 3.

1 expenses, the Company has reduced its exposure to fluctuations in the market. Rate base
2 has doubled, and yet Company has approximately the same load to serve.⁵² The
3 Company no longer faces the same risk associated renewal of Mid-C contracts or the
4 large volume of market purchases that it did just a few years ago.⁵³ This larger boat
5 should be expected to weather small storms better and more efficiently.

6 **D. PGE has reduced risk because of its annual rate case filings.**

7 In large part, a capital structure that is not heavily leveraged provides security
8 against risk for shareholders. However, with PGE's recent history of annual rate case
9 filings, the Company faces reduced risk. The risk effect of rate case filings is one-sided.
10 In the near future, after Carty, the Company is not expected to be bringing large assets
11 into rate base, as 94% of its load would then be served by rate base resources.⁵⁴
12 Therefore, if the Company has an authorized rate of return (ROR) that is sufficient to
13 cover its costs, it will not need to come in for a rate case. If, in addition, market factor
14 changes in the Company's favor, it is allowed to keep the financial gain and can choose to
15 extend the time between rate cases. On the other hand, if market conditions change,
16 many mechanisms are in place to reduce the negative impact on shareholders, including,
17 but not limited to the Renewable Adjustment Clause (RAC), authorizing dollar for dollar
18 recovery on renewables, and the PCAM, shifting excess costs of fuel on customers if,
19 say, natural gas prices spike. The Company, if conditions move below acceptable levels,

⁵² The Company expects only 1% load growth in 2015, consistent with recent years - Portland
[http://investors.portlandgeneral.com/common/download/download.cfm?companyid=POR&fileid=815699
&filekey=C9E3CFDB-6CFD-4BDB-A8DC-
C5D40E309FF1&filename=PGE_Investor_Presentation_March_2015_FINAL.pdf](http://investors.portlandgeneral.com/common/download/download.cfm?companyid=POR&fileid=815699&filekey=C9E3CFDB-6CFD-4BDB-A8DC-C5D40E309FF1&filename=PGE_Investor_Presentation_March_2015_FINAL.pdf).

⁵³ UE 294 - CUB/100/Jenks-McGovern/8.

⁵⁴ [http://investors.portlandgeneral.com/common/download/download.cfm?companyid=POR&fileid=815699
&filekey=C9E3CFDB-6CFD-4BDB-A8DC-
C5D40E309FF1&filename=PGE_Investor_Presentation_March_2015_FINAL.pdf](http://investors.portlandgeneral.com/common/download/download.cfm?companyid=POR&fileid=815699&filekey=C9E3CFDB-6CFD-4BDB-A8DC-C5D40E309FF1&filename=PGE_Investor_Presentation_March_2015_FINAL.pdf) pg 28.

1 can file for a general rate increase. In fact, this rate case, excluding Carty, is an example
 2 of a filing by the Company when rates were still sufficient to cover costs while still
 3 allowing for a reasonable rate of return. The Company has demonstrated that it is willing
 4 to file rate cases in close proximity to eliminate risk of under-recovery.

5 **E. PGE has strong financials and can attract capital**

6 As mentioned above, PGE has been steadily building its rate base for the past 5
 7 years. To do so, they have had to attract over a billion dollars in capital.⁵⁵ It is clear to
 8 CUB that a 100% equity position would be unduly rigid and a 100% debt position would
 9 be infeasible. However, CUB does not agree that implies that a 50/50 debt equity capital
 10 structure is sacred. Instead, CUB believes that the Company should revisit its target
 11 structure on a regular basis. Other companies maintain various debt equity ratios in their
 12 capital structure:

Utility	State	Year	Approved Capital	
			Debt	Equity
Sierra Pacific Power ⁵⁶	NV	2013	53.06%	46.94%
PacifiCorp ⁵⁷	WA	2013	50.62%	49.38%
Black Diamond Power Co. ⁵⁸	WV	2012	56.00%	44.0%
Commonwealth Edison ⁵⁹	IL	2012	53.35%	46.12%
National Grid ⁶⁰	RI	2012	51.03%	48.78%
Puget Sound Energy ⁶¹	WA	2012	54.00%	46.00%

⁵⁵<http://investors.portlandgeneral.com/common/download/download.cfm?companyid=POR&fileid=600181&filekey=AD9EA144-57EC-4097-A96D-3F0A925D4643&filename=Official%20PGE%20Investor%20Presentation%20Sept%202012.pdf> pg 19.

⁵⁶ *In re Sierra Pacific Power Company d/b/a NE Energy*, Docket Nos. 13-06002, 13-06003, 13-06004, 2013 Nev. PUC LEXIS 281, 14-15 (Dec. 18, 2013).

⁵⁷ *Washington Utilities and Transportation Commission v. PacifiCorp d/b/a Pacific Power & Light Co.*, 2013 Wash. UTC LEXIS 1010, 5 (Dec. 4, 2013).

⁵⁸ *In re Black Diamond Power Co.*, 2012 W.Va. PUC LEXIS 1169, 35-36 (Jun. 7, 2012).

⁵⁹ *In re Commonwealth Edison Co.*, 2012 Ill. PUC LEXIS 272, 317-318 (May 29, 2012).

⁶⁰ *In re Narragansett Electric Co. d/b/a National Grid*, 2012 WL 1437571 (R.I.P.U.C.), 2 (Apr. 13, 2012).

1 PGE demonstrates improvement in its financial position by increasing dividends from
2 \$1.00 to \$1.09 in the past 5 years.⁶² This hasn't hurt the Company in the eyes of its
3 ratings agencies either, as it "received two upgrades on its long-term debt from Moody's
4 in the past two years."⁶³ To its investors, PGE touts these successes, noting that since the
5 last rate case, earnings per share, return on investment and net income have all
6 increased.⁶⁴ In testimony, PGE expresses its concerns about ongoing risks, such as hydro
7 fluctuations and economic performance, which could affect its financial performance.
8 However, hydro risks have been substantially lessened with the retirement of the Mid-C
9 contracts and their replacement by Carty and economic conditions continue to improve

10 **F. Recommendation**

11 CUB recommends that the Company perform quantitative analysis examining the
12 costs and benefits of alternative capital structures. In addition, CUB recommends with
13 the large increase in rate base and spending trends that the Company currently employs,
14 the large rate base footprint, with approximately the same load and customer size, can
15 absorb existing risk. In particular, CUB recommends that the Company reduce its equity
16 portion by 5% for a 55/45 debt/equity structure. Alternatively, the Commission could
17 penalize the Company, mandating a reduction in equity of 2% for not producing rigorous
18 analysis of capital structure.

⁶¹ *Washington Utilities and Transportation Commission v. Puget Sound Energy, Inc.*, 297 P.U.R. 4th 1, 7-9 (May 7, 2012).

⁶² <http://files.shareholder.com/downloads/POR/11173558x0x40727/42ebd67c-4652-4e6b-8713-a6a961e4bbf4/factsheet.pdf>

⁶³ UE 294 – PGE/1000/Hager – Green/ 5.

⁶⁴ http://investors.portlandgeneral.com/common/download/download.cfm?companyid=POR&fileid=815699&filekey=C9E3CFDB-6CFD-4BDB-A8DC-C5D40E309FF1&filename=PGE_Investor_Presentation_March_2015_FINAL.pdf

1 **IX. Conclusion**

2 In Conclusion, CUB recommends the following:

- 3 • There should be no January 1 rate increase because PGE filed this case
4 even though its expected earnings in January will still be reasonable.
- 5 • The Company should not include the Residential Exchange Credit in its
6 pricing workpapers, and the credit should be applied ex-post of the CIO.
- 7 • The Company has consistently under-forecasted Other Revenue in recent
8 rate cases. This should be corrected using historical forecast error as a
9 guide by increasing Other Revenue by \$3.0 million.
- 10 • The Company has not demonstrated justification for changing the
11 allocation of transmission costs, and should continue to allocate energy
12 costs to both energy and capacity. CUB recommends the Commission
13 allocate 65% of transmission costs to capacity and 35% to energy with the
14 capacity charges being based on a 12 CP approach.
- 15 • PGE's proposal to increase the residential customer charge should be
16 rejected. It is not supported by the filing.
- 17 • The deadbands in PGE's PCAM should be adjusted to account for the fact
18 that its rate base has doubled in the last few years. CUB recommends that
19 the monetary deadbands be updated based on a 150/75 basis point
20 deadband. This would create an asymmetrical deadband of \$60 million
21 and \$30 million.
- 22 • PGE failed to consider whether current interest rates should be reflected
23 by changing its capital structure. CUB recommends that the Commission

1 impose a capital structure of 55% debt/45% equity. As an alternative,
2 CUB recommends that the PUC reduce the equity portion of the capital
3 structure by 2% (from 50% to 48%) to penalize the Company for its
4 failure to provide any analysis to support its capital structure.

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

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EDUCATION: Bachelor of Science, Economics
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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, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, UM 1209, UM 1355, UM 1635, UE 233, UE 246, UE 283, 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
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WITNESS QUALIFICATION STATEMENT

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EDUCATION: PhD, Economics
W.P. Carey School of Business
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EXPERIENCE: Provided testimony or comments in a number of OPUC dockets, including UE 262, UE 283, UM 1633, and UM 1654. Worked as Utility Analyst at the Oregon Public Utility Commission from 2006-2008, providing advice on rate cases, analysis in meetings with the Bonneville Power Administration and performing benchmarking studies regarding telecom and electric competition in the state of Oregon.

Economics professor at Mesa Community College and the State University of New York from 2004–2010.

Other Revenue
(in millions)

<u>Year</u>	<u>Forecast</u>	<u>Actual</u>	<u>Differential</u>		
2006	17.7	17.3	-0.4		
2007		18.7			
2008	17.8	20.6	2.8		
2009	20.2			average differential	2.957143
2010	19.9	26.2	6.3		
2011	21	22.4	1.4		
2012	21.4	24.7	3.3		
2013	22.5	24.9	2.4		
2014	22.6	27.5	4.9		
2015	25.0				
2016	25.1				

sources:

UE 294/PGE/202/Tooman-Brown/1

UE 283/PGE/Exhibit 302/Tooman-Macfarlane/1

UE 262/PGE/Exhibit 302/Tooman-Liddle/1

UE 215/PGE/302/Tooman-Tinker/1