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May 24, 2018

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PORTLAND GENERAL ELECTRIC CO.
2018 Request for a General Rate Revision
Docket No. UE 335

Dear Filing Center:

Please find enclosed the redacted Opening Power Cost Testimony and Exhibits of Bradley G. Mullins (AWEC/100 – 103) on behalf of the Alliance of Western Energy Consumers in the above-referenced docket.

The confidential portions of Mr. Mullins' testimony and exhibits are being handled in accordance with Order No. 18-047 and will follow to the Commission via Federal Express.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Haley M. Thomas
Haley M. Thomas

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the **confidential portions of the Opening Power Cost Testimony and Exhibits of Bradley G. Mullins** upon the parties shown below by mailing copies via First Class U.S. Mail, postage prepaid, and by sharing copies via the Huddle workspace in this docket.

Dated at Portland, Oregon, this 24th day of May, 2018

Sincerely,

/s/ Haley M. Thomas
Haley M. Thomas

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 335

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

OPENING POWER COST TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED VERSION)

May 24, 2018

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I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 1750 SW Harbor Way, Ste 450, Portland, Oregon 97201.

Q. PLEASE STATE YOUR OCCUPATION AND IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an independent consultant who represents utility customers before state regulatory commissions, with a primary focus in the Pacific Northwest. I am appearing on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users served by electric and gas utilities located throughout the West, including customers that receive electrical services from Portland General Electric Company ("PGE" or "Company"). AWEC was formed as a result of the merger of the Northwest Industrial Gas Users into the Industrial Customers of Northwest Utilities on April 1, 2018.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. A summary of my education and work experience can be found at AWEC/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY.

A. I discuss my initial review of PGE's net power cost forecast for 2019. PGE uses its MONET production cost model to forecast net power costs. Based on the modeling runs in its March 30, 2018 update filing, PGE presents a net power costs forecast of $379,647,300. That is an approximate $44 million increase from the $335,998,800 forecast in the final update in UE 319.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Based on my review of the MONET modeling presented in PGE's filing, I recommend the following adjustments to PGE's power cost filing.

1. **Wind Capacity Factors.** I recommend establishing wind capacity factors using a 75/25 blend between the RFP estimate and actuals. This adjustment reduces power costs by $7,187,300.

2. **Production Tax Credit Rate.** The increasing inflationary escalator associated with the production tax credit ("PTC") will cause the production tax credit rate to increase to 2.5 ¢/kWh in 2019. This adjustment reduces power costs by $3,614,100.

3. **BPA Wheeling.** It is premature to assume a rate increase associated with the BP-20 rate proceeding in this matter. Eliminating the rate increase reduces power costs by $928,400.

4. **Forward Curve Forecast Error.** I discuss PGE's forecast of market prices, and ways that the costs and risks of hedging should be shared between ratepayers and shareholders. To account for PGE's propensity to over-forecast market prices, I propose an adjustment of $9,707,400.

5. **Qualifying Facilities.** PGE proposes to include in its power cost forecast all QFs with a contract commercial operation date in 2019, despite the fact that many QFs do not reach their contract commercial operation date. Accordingly, I recommend that PGE use the same method of forecasting QF online dates that the Commission ordered for PacifiCorp in that utility's 2018 Transition Adjustment Mechanism.

II. PROPOSED MODELING ADJUSTMENTS

a. Wind Capacity Factors

Q. PLEASE SUMMARIZE YOUR CONCERN WITH THE WIND CAPACITY FACTORS PGE HAS MODELED IN MONET.

A. In recent annual update tariff ("AUT") filings, PGE has made several downward adjustments to the capacity factors it assumes for owned wind resources: Biglow Phase 1, Biglow Phase 2, Biglow Phase 3, and Tucannon River. This docket is no exception, as PGE's March 30 update filing proposes to reduce the production estimates for these resources by approximately 4% in aggregate. From a ratepayer perspective, reducing the capacity factor assumed for ratemaking is an unfair result, particularly when one considers representations made in the respective request for proposal ("RFP") processes that led PGE to develop these wind resources. For purposes of modeling the capacity factor of wind resources in MONET, I recommend PGE use a production estimate that is a blend of the estimate assumed when the resources were selected in the respective RFPs and the actual production.

Q. HOW DO PGE'S PROPOSED PRODUCTION ESTIMATES COMPARE TO THE CAPACITY FACTORS ASSUMED IN THE RESPECTIVE RFPs?

A. That information is provided in Table 1, below.

TABLE 1

RFP vs. Historical Average Capacity Factor of PGE Owned Wind Plant[1/]

	-- Historical Capacity Factors --					
	2012	2013	2014	2015	2016	2017
Biglow 1	30.6%	32.8%	31.1%	28.9%	29.5%	24.4%
Biglow 2	28.6%	31.0%	29.4%	26.9%	27.2%	23.5%
Biglow 3	25.5%	27.5%	26.9%	24.3%	24.3%	20.7%
Tucannon	38 2% *	38 2% *	38 2% *	32.6%	37.3%	30.5%

	Initial Filing Average 2012-2016	Mar. 30 Update Average 2013-2017	**(a) RFP Capacity Factor ****	(b) Average 2012-2017	AWEC Proposed 75/25 Blend (a)/(b)
Biglow 1	30.6%	29.4%	**31.0%**	29.6%	30.59%
Biglow 2	28.6%	27.6%	**31.0%**	27.8%	30.15%
Biglow 3	25.7%	24.7%	**31.0%**	24.9%	29.43%
Tucannon	36.9%	35.4%	**38.4%**	35.8%	37.64%

* PGE uses the forecast from the 2016 GRC prior to the online date of Tucannon

** Per AWEC Data Req. 112

Table 1 compares the historical capacity factors, which PGE uses as an input into MONET. In its initial filing, the production forecast for owned wind resources was based on

1/ Historical production is available through FERC Form 1.

the average over the period 2012-2016. In its March 30, 2018 update, PGE updated the capacity factors to be based on the averages over the period 2013 through 2017. As can be seen, the updated production estimates declined materially relative to estimates in PGE's initial filing. The reduction was due to the fact that 2017 was a particularly bad year for wind generation in the northwest, as indicated by the color scales applied to the historical capacity factors in Table 1.

Further, Table 1 details the capacity factor assumed in the respective wind RFPs. As can be noted in Table 1, the production estimates PGE proposes, based on recent historical data, are significantly lower than the estimates that were made at the time these resources were selected for procurement. Based on the reductions to the capacity factors, the projects are not providing nearly the level of benefits in rates as PGE represented in the RFP processes.

Q. WHY ARE THESE REDUCED CAPACITY FACTORS PROBLEMATIC FROM A RATEMAKING PERSPECTIVE?

A. The expected capacity factors are extraordinarily impactful when making decisions about whether to acquire a utility-owned resource in the RFP. Had PGE's assessment of these capacity factors been more in line with actual experience, PGE may have made a different resource decision. Of course, the Commission cannot now revisit the prudence determination it made before it knew what the actual production levels of PGE's wind resources would be. From a ratepayer perspective, that is an unfair result because investors are recognizing all of the equity returns associated with PGE's wind facilities, while ratepayers are bearing all of the risk of the benefits of the investment failing to materialize at the level promised when the investment was made.

It is critical that utilities bear some risk that the wind might not blow at the level forecast when wind resources are selected in an RFP process. Other resource options were available in the RFPs. Accordingly, the initial production estimates are significant because if wind output fails to materialize at the level forecast in the RFP, ratepayers might have preferred another resource alternative, such as a power purchase agreement.

Q. IS FIVE YEARS OF HISTORICAL WIND GENERATION SUFFICIENT TO BE USED AS A FORECAST?

A. No. Like hydro resources, the output from wind resources is variable year to year. While wind output has tended to be less variable than hydro variability, five years is not a sufficient amount of time to make long-term conclusions about the capacity factor expected from PGE's wind resources. When measuring the capacity factors over such a short time frame there is the potential for a few bad years to drive down the five-year average capacity factor such that it is not consistent with the capacity factor expected in the long term. Or, in contrast, a few good years may drive the average capacity factor up, causing it to exceed the expected long-term production. Given the low production levels in 2017, it is not known, for example, if the experience in 2017 is an outcome to be expected once every five years, or once every eighty years.

Q. WHAT IS A REASONABLE WAY TO DEAL WITH THE CAPACITY FACTOR RISK WITH PGE'S OWNED WIND RESOURCES?

A. For ratemaking purposes, using a blend of the RFP estimate and actuals is a reasonable way to ensure that the risks associated with the capacity factors of utility-owned wind resources are fairly shared between investors and ratepayers. In circumstances such as this, where the generating facilities have failed to perform at the level assumed when the investment decision was made, it is appropriate for both ratepayers and shareholders to bear the cost of the failure.

The RFP estimates also better represent the long-term expectation for PGE's wind resource, in contrast to the five-year window that PGE is using.

Q. WHAT DO YOU RECOMMEND?

A. I recommend using a 75/25 blend between the RFP estimate and actuals when modeling the production of owned wind resources in the MONET model.

Q. SHOULD PGE'S INVESTORS BEAR ALL OF THE RISK ASSOCIATED WITH ITS PRODUCTION ESTIMATES?

A. PGE cannot control the wind, or how much it blows. Further, while it is expected that PGE will make its best efforts to develop a reasonable forecast, no forecast is perfect. Accordingly, it is reasonable for ratepayers to share some of the production risk associated with PGE's wind resources. In weighing the considerations of both consumers and shareholders, I arrived at the conclusion that the most reasonable approach is to use a weighted blend of the RFP estimate and actual capacity factors, as described above, to assign some of the production risk to customers while recognizing that it was PGE's decision to pursue these resources and PGE was the entity that had all of the information to determine which resources to select. Thus, PGE should bear a majority of the risk associated with the capacity factors of its wind resources.

An asymmetrical sharing of power forecasting risks is also consistent with Commission policy, which has found this to be necessary to ensure revenue neutrality. PGE's power cost adjustment mechanism ("PCAM") includes dead bands in which the Company absorbs up to $30 million in excess power costs and retains up to $15 million in lower-than-anticipated power costs. The Commission's orders approving this arrangement relied specifically on the fact that this asymmetry was necessary because the cost of purchasing replacement power in years when forecasts of plant output are higher than realized outweighs the power cost benefits when forecasts of plant output are lower than realized (because market prices will be correspondingly lower).[2/]

In addition, it is important to recognize my proposal is purely a forecasting approach used for ratemaking purposes. I am not proposing to use these capacity factors in PGE's PCAM. Thus, PGE will still have the opportunity to recover its prudently incurred actual power costs through the power cost adjustment mechanism.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Applying my recommended ratemaking will result in a $7,960,400 reduction to net power costs. To calculate this adjustment, I changed the capacity factor estimates in the PC Input tab of MONET. I did not adjust any of the scaling factors used to establish hourly wind profiles.

b. <u>Production Tax Credits</u>

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO THE PRODUCTION TAX CREDIT RATE PGE ASSUMED IN THE MONET MODEL?

A. In its MONET model, PGE includes an assumption of 2.4 ¢/kWh for the production tax credit rate for 2019. In its workpapers, PGE indicates that this assumption was based off the production tax credit rate published for 2017. Notwithstanding, if inflation continues at its current rate in 2018, the inflation adjusted production tax credit rate will increase to 2.5 ¢/kWh in 2019.

Q. WHAT CAUSES THE PRODUCTION TAX CREDIT RATE TO CHANGE FROM YEAR-TO-YEAR?

A. The production tax credit rate is established at a baseline at 1.5 ¢/kWh, which was established when the production tax credit was first created in 1993. To account for inflation, the IRS

[2/] UE 215, Order No. 10-478 at 10 (Dec. 17, 2010); UE 180/UE 181/UE 184, Order No. 07-015 at 26 (Jan. 12, 2007); UE 165/UM 1187, Order No. 05-1261 at 10 (Dec. 21, 2005).

adjusts the production tax credit each year using an inflation adjustment factor. The IRS publishes the inflation adjustment factor on or around April 1st each year. Thus, the inflation adjustment factor for the 2019 tax year will be published on or around April 1, 2019. When applying the inflation adjustment factor, the credit rate is rounded to the nearest multiple of 0.1 ¢/kWh. Consequently, while the inflation adjustment factor increases every year, the production tax credit does not necessarily change each year.

Q. WHY IS THE PRODUCTION TAX CREDIT RATE LIKELY TO INCREASE IN 2019?

A. Based on the current inflation adjustment factor, one additional year of inflation at current levels will cause the production tax credit rate to round up to 2.5 ¢/kWh in 2019. This is demonstrated in Table 2, below.

TABLE 2
2019 Production Tax Credit Rate

Year	Inflation Adjust. Factor	Adj. PTC Rate ¢/KWh	Implied Inflation
1993 (Base)	1.0000	1.5	
...			
2012	1.4799	2.2	
2013	1.5063	2.3	1.78%
2014	1.5088	2.3	0.17%
2015	1.5336	2.3	1.64%
2016	1.5556	2.3	1.43%
2017	1.5792	2.4	1.52%
2018	1.6072	2.4	1.77%
2019 (Forecast)	1.6356	2.5	1.77%

Q. PLEASE PROVIDE AN OVERVIEW OF TABLE 2.

A. Table 2 details the historical production tax credit rates along with the respective inflation adjustment factor published by the IRS for each tax year. The production tax credit rate is determined each year by multiplying the 1993 (base) 1.5 ¢/kWh rate by the inflation adjustment factor. Along the right, I have detailed the rate of inflation implied by the inflation adjustment factor. Finally, at the bottom, I detail the calculation of the 2019 production tax credit rate. That calculation assumes that the IRS uses the same inflation rate for 2019 as it did for 2018, and shows that the production tax credit rate will round up to 2.5 ¢/kWh. As long as the inflationary rate for 2018 exceeds 1.63%, the PTC rate will round up to 2.5 ¢/kWh.

Q. IS IT POSSIBLE THAT THE PRODUCTION TAX CREDIT RATE WILL NOT INCREASE IN 2019?

A. Yes, but it is unlikely. If the rate of inflation declines in the coming year, relative to current levels, the production tax credit might remain at 2.4 ¢/kWh for another year. Notwithstanding, given current inflationary indications, my assessment is that the inflation rate for 2018 will exceed the 1.63% rate necessary to trigger an increase to the production tax credit rate.

Q. WHAT RATE OF INFLATION DID PGE ASSUME IN THE MONET MODEL?

A. For everything other than production tax credits, PGE assumes an inflation rate of 2.5%. Thus, the inflation rate PGE forecast far exceeds the 1.63% necessary to trigger an increase to the production tax credit rate.

Q. IS PGE'S OUTLOOK CONSISTENT WITH MARKET EXPECTATIONS?

A. The market expectation is that inflation is on the rise, relative to the rates experienced in prior years. As PGE itself testifies, "the US economy has been growing at an accelerated rate," and the Fed has raised the federal-funds rate by a quarter point three times in 2017, and five times in the past two years.[3/] The Fed has also signaled that further increases are likely.[4/] Moreover,

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[3/] PGE/1000 at 18:6-14.
[4/] Id. at 24:12-14.

according to the Bureau of Labor Statistics, the Consumer Price Index rose 2.4% over the year ending March 2018. Based upon the yield differential between constant maturity and inflation-protected treasury bonds, the five-year break-even inflation rate was 2.2% on May 21, 2018, as published by the St. Louis Federal Reserve Bank. The Federal Reserve Bank of Philadelphia forecast a year-ahead inflation rate of 2.26% on May 11, 2018.

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT THE CALCULATION OF PRODUCTION TAX CREDITS?

A. For Biglow Phase 2, PGE assumes that production tax credits will begin to drop off beginning in June of 2019. Notwithstanding, my understanding is that Biglow Phase 2 was placed into service on August 20, 2009, meaning that production tax credits could be claimed through August 20, 2019. Ratepayers would not have benefited from any production tax credits accrued prior to the in-service date of Biglow Phase 2. For that reason, for ratemaking purposes it is appropriate to assume that credits will be generated for the full 10 years from the in-service date, even though PGE might have been claiming credits prior to the in-service date.

Q. WHAT IS THE IMPACT OF YOUR ADJUSTMENT?

A. The impact of increasing the production tax credit rate to 2.5 ¢/kWh results in a $2,150,600 reduction to power costs. Extending the PTCs for Biglow Phase 2 through August 20, 2019, results in a further reduction of $1,462,500. The total amount of my adjustment related to the production tax credits is $3,614,100. This adjustment assumes the 75/25 weighting of RFP and actual capacity factors discussed in the previous section of my testimony.

c. <u>BP-20 Wheeling Rates</u>

Q. WHAT ASSUMPTION DOES PGE MAKE IN MONET WITH RESPECT TO THE BP-20 RATE PROCEEDING?

A. In MONET, PGE has assumed that the wheeling rates of the Bonneville Power Administration ("BPA" or "Agency") will increase on October 1, 2019, as a result of the BP-20 rate case. This is not based on anything BPA has stated regarding its future transmission rates and instead appears to be based on average historical rate increases.

Q. HAS THE BP-20 RATE CASE STARTED?

A. No. The BP-20 rate case will not be noticed in the Federal Register until November of 2018. Further, a record of decision approving the final rates in the BP-20 rate case will not be issued until the summer of 2019.

Q. ARE THERE ANY INDICATIONS OF WHAT TO EXPECT IN THE BP-20 RATE CASE?

A. No. Prior to the BP-18 rate case, which established rates for BPA's 2018 and 2019 Fiscal Years (Oct 1, 2017 – Sep 30, 2019), BPA conducted a process called Focus 2028, designed to assess the long-term competitiveness of the Agency. In that process, BPA provided some high-level indications of its expectations regarding future rate increases in BP-18. No similar guidance has been provided by BPA regarding the magnitude of the rate increase to be expected for BP-20.

Q. WERE BPA'S INITIAL ESTIMATES ACCURATE IN THE BP-18 RATE CASE?

A. No. In the Focus 2028 process, BPA initially forecast a 4.8% increase to BPA's transmission rates in BP-18. In the final record of decision in BP-18, however, transmission rates actually *declined* for point-to-point customers. Notwithstanding, PGE proposed to use BPA's Focus 2028 estimate in its AUT power cost filing two years ago in 2016. Parties resolved that issue through a settlement, although it is clear that those wheeling costs were overstated in the 2016 AUT initial filing based on PGE's recommendation to assume a 4.8% rate increase for BP-18 using BPA's preliminary estimates.

Q. IS THERE EVEN GREATER UNCERTAINTY ABOUT RATES IN THE BP-20 PROCESS?

A. Yes. BPA is currently undertaking efforts to redesign its transmission tariff. It is unclear how these changes to its tariff might impact rates established through BP-20, but the new tariff imposes an added layer of uncertainty with respect to the ultimate rate change that will be approved through the BP-20 rate case.

Q. WHAT DO YOU RECOMMEND?

A. I recommend assuming no transmission rate increase or rate reduction associated with the BP-20 rate case at this time. It is premature to make any assumptions about how rates might change in the BP-20 rate case, and consequently, the impact is not known and measurable. The impact of this adjustment is a $928,400 reduction to net power costs.

d. Market Price Forecasting

Q. PLEASE SUMMARIZE YOUR OBSERVATIONS WITH RESPECT TO PGE'S MARKET PRICE FORECAST.

A. In the past, I have observed that, when developing power cost forecasts, utilities have had a tendency to overstate market prices relative to the actual market prices observed in the rate period. In PGE's 2016 AUT proceeding, for example, I performed an empirical study where I demonstrated this fact, and I also demonstrated that the over-estimation tended to be greater the further into the future the price forecast was made.[5/]

[5/] Docket No. UE 308, ICNU/200 at 4-11 (Aug. 12, 2016).

In this docket, I was specifically concerned with the accuracy of price forecasts in the near-term timeframe (less than 13 months), corresponding to the forecast period used in developing final AUT updates. My analysis below shows that a similar pattern of over-estimation can be observed even in forecasts prepared only 13 months in advance of the prompt month, although the pattern is not so pronounced as with the long-term price curves.

Q. WHAT RECOMMENDATION ARE YOU MAKING WITH RESPECT TO FORWARD MARKET PRICES?

A. My recommendation has two parts. First, I recommend that an adjustment be applied to the market prices included in the MONET model to account for historical forecast error. Second, I recommend adopting a policy for all new hedging contracts where PGE shareholders will bear 20% of hedging costs and benefits. Before discussing how I arrived at my recommendation, I will discuss my updated forward curve forecast error analysis applied to the forward price curves used in the final update in past AUT proceedings.

Q. PLEASE PROVIDE AN OVERVIEW OF THE ANALYSIS YOU PERFORMED WITH RESPECT TO PGE'S PREVIOUSLY ISSUED OFFICIAL FORWARD PRICE CURVES ("OFPCs").

A. In Confidential Exhibit AWEC/102, I present an analysis exploring the accuracy of PGE's previously issued OFPCs for both gas and electric markets. These studies specifically study the accuracy over the AUT period, where price curves are issued two to thirteen months in advance of the prompt month. Exhibit AWEC/102 examines the accuracy of OFPCs issued over two different periods: 2005 through 2016 and 2011 through 2016. The analysis considers a long-term period, as well as a shorter period of 2011 through 2017, in order to determine whether structural changes in natural gas and power markets—which occurred generally in the period 2008 through 2010 as a result of advances in directional drilling and fracking technologies and other factors—might have contributed to the over-forecasting observed in the longer-term analysis presented in Exhibit AWEC/102.

Q. WHAT DOES YOUR ANALYSIS SHOW?

A. The analysis in Exhibit AWEC/102 shows that PGE historically tended to overestimate forward prices in past AUT proceedings. In addition, a similar pattern of overestimation can be observed when considering only the curves issued over 2011 through 2016. This indicates that PGE's over-forecasting cannot be explained by the unexpected, rapid decline in natural gas prices that occurred between 2008 and 2010.

The analysis for the Mid-Columbia, On-peak market has been reproduced in Confidential Figure 1, below, based on OFPCs issued over the period 2005 through 2016.

CONFIDENTIAL FIGURE 1
Mid-Columbia On-peak Forecast Error,
For Final AUT OFPCs Issued 2005 to 2016

[redacted]

Q. PLEASE DESCRIBE THE DATA PRESENTED IN CONFIDENTIAL FIGURE 1.

A. Confidential Figure 1 is a plot of the percentage forecast error associated with Mid-Columbia forward prices included in price curves PGE issued over the period 2005 to the end of 2016.

Each dot in the figure represents the percentage difference between a price that was forecast in a forward curve and the ultimate spot price for the given prompt month. To the extent that the error is positive, it means that the price in the forward curve exceeded the ultimate spot price. To the extent that the error is negative, it means that the price in the forward curve was less than the ultimate spot price. Along the x-axis, the set of forecast errors was separated by the number of months before the prompt month for which the forward price was calculated. Thus, a forecast error further to the right indicates the forecast error associated with a price that was forecast further in advance of the prompt month. Similarly, a forecast error on the left side of the x-axis represents a price that was forecast nearer to the prompt month. Overlaid on the figure is the median forecast error based on the number of months in advance of the prompt month that the forward prices were calculated, as well as the interquartile range of the forecast errors.

Q. HOW CAN THE DATA PRESENTED IN CONFIDENTIAL TABLE 1 ABOVE BE USED TO DETERMINE PGE'S ACCURACY IN PREDICTING FORWARD PRICES?

A. If the OFPCs are reasonably accurate, one would expect PGE's price forecast to be an unbiased expectation of future spot prices. That is, forward prices would exceed the ultimate spot price 50% of the time and be less than the spot price 50% of the time. That, however, is clearly not the case. Rather, PGE's projected forward prices have exceeded the ultimate spot price more than [redacted]% of the time in Confidential Figure 1, above.

Q. WHAT DO YOU RECOMMEND TO ACCOUNT FOR THIS ERROR IN PGE's FORECASTING?

A. I recommend that, for purposes of forecasting power costs, a downward adjustment be applied to forecast market prices to account for PGE's forecasting bias. I applied my adjustment by reducing the forecast by the percentages shown in Confidential Table 3, below, which are the median forecast error from the analysis I presented in Exhibit AWEC/102. While the annual values are summarized below, my adjustment is applied on a monthly basis.

CONFIDENTIAL TABLE 3
Median Historical Forecast Error Assumed in AUT Period

[redacted]

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Because of the high volume of hedges entered into by PGE, the impact amounts to a reduction to net power cost of approximately $9,707,400. Incorporating the historical forecast error into the price curves used in MONET resulted in a $18,206,700 reduction to net power cost. That reduction was offset by an increase to power costs in the amount of $8,499,300 associated with updating swap settlements. As PGE enters into more hedges over the course of this proceeding, the corresponding impact of this adjustment should decline.

Q. DOES PGE'S POOR FORECASTING CALL ITS HEDGING PRACTICES INTO QUESTION?

A. Yes. Given the fact that the forecast tends to be biased, that is an indication that PGE hedging practices are imposing systematic costs on ratepayers.

Q. COULD THE ABOVE ANALYSIS ALSO BE USED TO DETERMINE IF THERE IS A RISK PREMIUM EMBEDDED IN THE FORWARD PRICE CURVE?

A. Yes. Another way to look at PGE's propensity to over-forecast is as a risk premium – an additional cost above the spot market price that PGE is willing to pay, and that the counterparty demands, in order to lock in a fixed price. If there is no risk premium embedded in the OFPC, the median forward curve forecast error in the short term should be zero. If, however, the median forecast error exceeds zero, then that is an indication of a risk premium in the market curves that PGE relies on to develop its OFPC. It makes sense that there would be a risk premium built into forward prices, based on the fact that the curves are typically upsloping, having the attributes of a contango market.[6/] Although, I would also observe that recently the market curves for natural gas have gone inverted and have been trading in backwardation. Backwardation is an indication that market prices in the long term are expected to decline.

Q. WHAT DOES THE DATA IN YOUR ANALYSIS CONFIRM ABOUT THE EXISTENCE OF RISK PREMIUMS IN PGE's FORECASTS?

A. The empirical analysis underlying Confidential Figure 1 indicates that risk premiums have been embedded in the forward curves and that those risk premiums have been substantial. For a transaction executed more than one year in advance of the prompt month, the expected forecast error for Mid-Columbia was approximately [redacted]%. This means that each time PGE purchases a power swap more than one year in advance of the prompt month, ratepayers should statistically expect to pay an amount that is [redacted]% greater than the actual spot price of natural gas. This is particularly concerning given my understanding that PGE hedges 100% of its open position.

Q. HOW DO YOU RECOMMEND DEALING WITH THESE HEDGING COSTS GOING FORWARD?

A. It has been a while since PGE's mid-term hedging strategy was reviewed by the Commission in 2011.[7/] While PGE might have some expectation of consistent treatment for hedging contracts, circumstances have changed since this time. One of PGE's primary arguments in

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6/ Contango means that forward prices exceed the cash market cost at any point in time. Backwardation is the opposite, where forward prices are less than the cash market price.

7/ Docket No. UE 228, Order No. 11-432 (Nov. 2, 2011).

support of its mid-term strategy was that it was a "uniquely 'short' utility because its retail load significantly exceeds its long-term resources."[8/] Since this time, PGE has acquired a baseload combined cycle gas resource (Carty), a flexible peaking capacity resource (Port Westward 2), and an RPS-qualifying wind resource (Tucannon). Today, and especially compared to other utilities in the region, PGE relies relatively little on wholesale markets to meet its resource adequacy requirements.

Nevertheless, PGE has an incentive to continue following its mid-term strategy. PGE's power cost adjustment mechanism, with its dead bands and sharing bands, is intended to balance the risk of market volatility between the Company and its customers. By hedging up to 100% of its open market position, however, PGE significantly reduces its shareholders' exposure to this risk, at great cost to its customers. Therefore, I recommend the Commission apply a policy going forward where, for purposes of establishing power costs in the annual power cost filing, there will be sharing of hedging gains and losses between ratepayers and shareholders using a ratio of 80/20. I recommend that this treatment be applied to all swaps entered into subsequent to the March 30 update in this proceeding.

Q. WHAT IS THE IMPACT OF APPLYING 80/20 SHARING TO ALL HEDGING CONTRACTS IN THIS PROCEEDING?

A. Since I recommend this adjustment only apply to hedges going forward, this part of my proposal has no power cost impact at this point in the proceeding.

[8/] Id. at 6.

e. Qualifying Facilities

Q. HOW DOES PGE MODEL THE IMPACT OF QUALIFYING FACILITIES ("QFs") ON POWER COSTS?

A. PGE assumes that all QFs will reach their expected commercial operation date ("COD") in the contract with the QF. Thus, any QF with an expected COD in 2019 is modeled in the Company's power cost forecast in this proceeding. QFs are small power production facilities from which PGE is required to purchase the output under the Federal Public Utility Regulatory Policies Act.

Q. DO YOU AGREE WITH PGE'S APPROACH TO MODELING QFs?

A. No. It has been well demonstrated that many QFs with an executed contract do not reach their expected COD, either because their online date gets delayed (often through the interconnection process) or the project is canceled altogether. By assuming that every QF with which it contracts will meet the expected COD, PGE is almost certainly over-forecasting the power cost impacts of QFs on its system, to the detriment of customers.

Q. WHAT DO YOU RECOMMEND?

A. The Commission recently adopted a policy with regard to QF forecasting in PacifiCorp's 2018 Transition Adjustment Mechanism ("TAM").[9/] That policy is to use a rolling three-year average of the QF contract delay rate. This method produces an average period over which QFs are expected to be delayed from their contract COD date, which is then applied to QFs forecast to come online in the next year. For the 2019 TAM, the Commission also directed PacifiCorp to weight the contract delay rate by QF size "to more accurately reflect the rate impact of forecast errors."[10/]

9/ UE 323, Order No. 17-444 at 16-17 (Nov. 1, 2017).

10/ Id. at 17.

There is no reason to believe that QFs selling to PGE will achieve their contract COD more often than those selling to PacifiCorp, and a consistent Commission policy on this issue is beneficial to all parties because it creates a uniform and settled environment with respect to how the impact of new QFs are assumed in customer rates, thus reducing litigation over this issue in the future. Therefore, I recommend that PGE use the same method the Commission ordered for PacifiCorp in the 2018 TAM.

Q. DOES THIS CONCLUDE YOUR OPENING POWER COST TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 335

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
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Request for a General Rate Revision.	)
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EXHIBIT NO. AWEC/101

QUALIFICATION STATEMENT OF BRADLEY G. MULLINS

QUALIFICATION STATEMENT

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I have a Master of Accounting degree from the University of Utah. After obtaining my master's degree, I worked at Deloitte in San Jose, California, where I specialized in performing research and development tax credit studies. I later worked at PacifiCorp as an analyst involved in power cost forecasting. I began performing independent energy and utility consulting in 2013 and currently provide services to utility customers on matters such as revenue requirements, power cost forecasting, and rate design. I have sponsored testimony in several regulatory jurisdictions around the United States, including before the Oregon Public Utility Commission.

Q. PLEASE PROVIDE A LIST OF YOUR REGULATORY APPEARANCES.

A. I have sponsored testimony in the following regulatory proceedings:

- In re NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision, Or.PUC Docket No. UG 344.
- In re Cascade Natural Gas Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-170929.
- In the Matter of Hydro One Limited, Application for Authorization to Exercise Substantial Influence over the Policies and Actions of Avista Corporation, Or.PUC, Docket No. UM 1897.
- In re Pacific Power & Light Company 2016 Power Cost Adjustment Mechanism, Wa.UTC, Docket No. UE-170717.
- In re the Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision and Request to Construct Wind Resource and Transmission Facilities, Ut.PSC, Docket No. 17-035-040.

- In re The Application of PacifiCorp dba Rocky Mountain Power For A Certificate Of Public Convenience and Necessity and Binding Ratemaking Treatment For New Wind And Transmission Facilities, Id.PUC Case No. PAC-E-17-07.

- In re Avista Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-170485 (Cons.).

- Application of Nevada Power Company d/b/a NV Energy for Authority to Adjust its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and For Relief Properly Related Thereto, Nv.PUC, Docket No. 17-06003 (Cons.).

- In the Matter of PacifiCorp, dba Pacific Power, 2016 Power Cost Adjustment Mechanism, Or.PUC, Docket No. UE-327.

- In re the 2018 General Rate Case of Puget Sound Energy, Wa.UTC, Docket No. UE-170033 (Cons.).

- In re PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 323.

- In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 319.

- In re Portland General Electric Company, Application for Transportation Electrification Programs, Or.PUC, UM 1811.

- In re Pacific Power & Light Company, Application for Transportation Electrification Programs, Or.PUC, Docket No. UM 1810.

- In re the Public Utility Commission of Oregon, Investigation to Examine PacifiCorp, dba Pacific Power's Non-Standard Avoided Cost Pricing, Or.PUC, Docket No. UM 1802.

- In re Pacific Power & Light Co., Revisions to Tariff WN U-75, Advice No. 16-05, to modify the Company’s existing tariffs governing permanent disconnection and removal procedures, Wa.UTC, Docket No. UE-161204.

- In re Puget Sound Energy’s Revisions to Tariff WN U-60, Adding Schedule 451, Implementing a New Retail Wheeling Service, Wa.UTC, Docket No. UE-161123.

- 2018 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-18.

- In re Portland General Electric Company Application for Approval of Sale of Harborton Restoration Project Property, Or.PUC, Docket No. UP 334 (Cons.).

- In re An Investigation of Policies Related to Renewable Distributed Electric Generation, Ar.PSC, Matter No. 16-028-U.
- In re Net Metering and the Implementation of Act 827 of 2015, Ar.PSC, Matter No. 16-027-R.
- In re the Application of Rocky Mountain Power for Approval of the 2016 Energy Balancing Account, Ut.PSC, Docket No. 16-035-01
- In re Avista Corporation Request for a General Rate Revision, Wa.UTC, Docket No. UE-160228 (Cons.).
- In re the Application of Rocky Mountain Power to Decrease Current Rates by $2.7 Million to Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 and to Increase Rates by $50 Thousand Pursuant to Tariff Schedule 93, Wy.PSC, Docket No. 20000-292-EA-16.
- In re PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 307.
- In re Portland General Electric Company, 2017 Annual Power Cost Update Tariff (Schedule 125), Or.PUC, Docket No. UE 308.
- In re PacifiCorp, Request to Initiate an Investigation of Multi-Jurisdictional Issues and Approve an Inter-Jurisdictional Cost Allocation Protocol, Or.PUC, UM 1050.
- In re Pacific Power & Light Company, General rate increase for electric services, Wa.UTC, Docket No. UE-152253.
- In The Matter of the Application of Rocky Mountain Power for Authority of a General Rate Increase in Its Retail Electric Utility Service Rates in Wyoming of $32.4 Million Per Year or 4.5 Percent, Wy.PSC, Docket No. 20000-469-ER-15.
- In re Avista Corporation, General Rate Increase for Electric Services, Wa.UTC, Docket No. UE-150204.
- In re the Application of Rocky Mountain Power to Decrease Rates by $17.6 Million to Recover Deferred Net Power Costs Pursuant to Tariff Schedule 95 to Decrease Rates by $4.7 Million Pursuant to Tariff Schedule 93, Wy.PSC, Docket No. 20000-472-EA-15.
- Formal complaint of The Walla Walla Country Club against Pacific Power & Light Company for refusal to provide disconnection under Commission-approved terms and fees, as mandated under Company tariff rules, Wa.UTC, Docket No. UE-143932.

- In re PacifiCorp, dba Pacific Power, 2016 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 296.

- In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 294.

- In re Portland General Electric Company and PacifiCorp dba Pacific Power, Request for Generic Power Cost Adjustment Mechanism Investigation, Or.PUC, Docket No. UM 1662.

- In re PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction, Or.PUC, Docket No. UM 1712.

- In re Public Utility Commission of Oregon, Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity, Or.PUC, Docket No. UM 1719.

- In re Portland General Electric Company, Application for Deferral Accounting of Excess Pension Costs and Carrying Costs on Cash Contributions, Or.PUC, Docket No. UM 1623.

- 2016 Joint Power and Transmission Rate Proceeding, Bonneville Power Administration, Case No. BP-16.

- In re Puget Sound Energy, Petition to Update Methodologies Used to Allocate Electric Cost of Service and for Electric Rate Design Purposes, Wa.UTC, Docket No. UE-141368.

- In re Pacific Power & Light Company, Request for a General Rate Revision Resulting in an Overall Price Change of 8.5 Percent, or $27.2 Million, Wa.UTC, Docket No. UE-140762.

- In re Puget Sound Energy, Revises the Power Cost Rate in WN U-60, Tariff G, Schedule 95, to reflect a decrease of $9,554,847 in the Company's overall normalized power supply costs, Wa.UTC, Docket No. UE-141141.

- In re the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Wyoming Approximately $36.1 Million Per Year or 5.3 Percent, Wy.PSC, Docket No. 20000-446-ER-14.

- In re Avista Corporation, General Rate Increase for Electric Services, RE, Tariff WN U-28, Which Proposes an Overall Net Electric Billed Increase of 5.5 Percent Effective January 1, 2015, Wa.UTC, Docket No. UE-140188.

- In re PacifiCorp, dba Pacific Power, Application for Deferred Accounting and Prudence Determination Associated with the Energy Imbalance Market, Or.PUC, Docket No. UM 1689.

- In re PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism, Or.PUC, Docket No. UE 287.

- In re Portland General Electric Company, Request for a General Rate Revision, Or.PUC, Docket No. UE 283.

- In re Portland General Electric Company's Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU), Or.PUC, Docket No. UE 286.

- In re Portland General Electric Company 2014 Schedule 145 Boardman Power Plant Operating Adjustment, Or.PUC, Docket No. UE 281.

- In re PacifiCorp, dba Pacific Power, Transition Adjustment, Five-Year Cost of Service Opt-Out (adopting testimony of Donald W. Schoenbeck), Or.PUC, Docket No. UE 267.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 335

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
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Request for a General Rate Revision.	)
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CONFIDENTIAL EXHIBIT NO. AWEC/102

HISTORICAL FORWARD PRICE CURVE FORECAST ERROR ANALYSIS 2005-2016

(REDACTED VERSION)

Exhibit AWEC/102 contains Protected Information and has been redacted in its entirety in accordance with Order No. 18-047.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 335

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC	)
COMPANY,	)
	)
Request for a General Rate Revision.	)
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EXHIBIT NO. AWEC/103

COMPANY RESPONSE TO AWEC DATA REQUEST NO. 112

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 112
Dated May 4, 2018

Request:

For Biglow (1, 2 & 3) and Tucannon, please identify the capacity factor that was assumed in the request for proposals where the respective wind resources were selected.

Response:

A capacity factor was not assumed in the request for proposals (RFPs) that ultimately resulted in the construction of the Biglow Canyon Wind Farm (Biglow) and Tucannon River Wind Farm (Tucannon). The bids provided in response to PGE's RFPs did include a capacity factor for the projects that ultimately resulted in the construction of Biglow 1, 2, and 3 and Tucannon. The project that ultimately became Biglow was bid into PGE's 2004 All-Source RFP as a purchase power agreement wind project with a capacity factor of approximately 31%.

The winning bid in PGE's 2011 Renewable RFP that ultimately became Tucannon provided a capacity factor of 38.4%. However, at the request of the Independent Evaluator, studies from all the submitted bids were reviewed by DNV KEMA, an independent consulting firm. DNV KEMA's study estimated the projected net capacity factor of Tucannon over the first 20 years of operation, based on a probability of exceedance of 50 percent, to be approximately 36.8 percent.