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June 11, 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 PACIFICORP, dba PACIFIC POWER
2019 Transition Adjustment Mechanism
Docket No. UE 339

Dear Filing Center:

Please find enclosed the redacted Opening Testimony and Exhibits of Bradley G. Mullins (AWEC/100 – 104) 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. 16-128 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/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the **confidential portions of the Opening 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 this 11th day of June, 2018.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 339

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER,	)
	)
2019 Transition Adjustment Mechanism.	)
	)

OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED VERSION)

June 11, 2018

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Confidential AWEC/103 – Historical Forward Price Curve Forecast Error Analysis 2010 – 2016

AWEC/104 – Response to Discovery Regarding 300 MW Transmission Link

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 PacifiCorp (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 Exhibit AWEC/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my initial review of PacifiCorp's net power cost forecast for 2019. PacifiCorp uses its GRID production cost model to forecast net power costs. Based on the modeling runs in its April 1, 2018 filing, PacifiCorp presents an Oregon-allocated net power costs forecast of $386,898,278. That is a $21,597,951 increase from the $365,300,327 forecast in the final update in Docket No. UE 323, PacifiCorp's 2018 Transition Adjustment Mechanism ("TAM") filing.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Based on my review of the GRID modeling presented in PacifiCorp's filing, I have the following recommendations:

1. **Wind Capacity Factors.** I recommend establishing wind capacity factors using a 75/25 blend between the RFP estimate and actuals. In addition, I also recommend using the production estimates based on PacifiCorp's wind repowering proposal, corresponding to the timing of when those new assets are intended to be placed in service.

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.

3. **Wheeling.** PacifiCorp needs to confirm that it has considered all formula rate updates incorporating H.R.1 of the 115^{th} Congress.

4. **Forward Curve Forecast Error.** I discuss PacifiCorp's forecast of market prices, and ways that the costs and risks of hedging should be shared between ratepayers and shareholders.

5. **Energy Imbalance Market ("EIM") Costs.** These amounts were supposed to be included in the TAM on a temporary basis to address uncertainty in the early stages of the EIM. Now that the EIM is a mature market, I recommend removing these from the TAM and considering them in PacifiCorp's general rates.

6. **Permanent Opt-out.** I recommend the Commission open a docket to reconsider the use of ten years in the calculation of PacifiCorp's long-term cost of service opt-out program, consistent with the 2017 Protocol.

II. PROPOSED MODELING ADJUSTMENTS

a. Wind Capacity Factors

Q. WHAT IS PACIFICORP'S PROPOSAL REGARDING THE WIND CAPACITY FACTORS MODELED IN GRID?

A. Beginning on page 39 of his Direct Testimony, Mr. Wilding describes PacifiCorp's proposal to use 48 months of historical data to forecast the wind capacity factors for owned wind resources in this case. Mr. Wilding reports the Oregon-allocated impact of $4.6 million associated with this change.

Q. IS FOUR YEARS OF HISTORICAL DATA APPROPRIATE FOR FORECASTING WIND PRODUCTION?

A. No. PacifiCorp has not identified any valid reason why the use of four years of data is appropriate when modeling wind production. PacifiCorp uses circular logic by suggesting that, with a forecast based on four years of historical actuals, the forecast will better align with four years of historical production. The objective of the forecast, however, is to align production expected in the long term, not to align the estimate with production over the four-year period. The experience of these wind facilities over such a short amount of time is not necessarily representative of the output expected in the long term. That is why utilities often rely on engineering studies—such as those prepared when a utility conducts a request for proposal ("RFP")—to determine the long-term production potential.

Q. DID PACIFICORP PROVIDE ANY ENGINEERING STUDIES TO SUPPORT USING THE FOUR-YEAR AVERAGE?

A. No. In the prior TAM, PacifiCorp was using a forecast based on a "P50" estimate, meaning there was a 50% likelihood that actual production will be higher or lower than that median value. As I understand, the P50 estimates were based on the assumptions and engineering studies performed when PacifiCorp conducted the RFPs for its various owned wind resources

Q. HOW DO PACIFICORP'S REVISED PRODUCTION ESTIMATES COMPARE TO P50 ESTIMATES?

A. Confidential Table 1, below, compares the new and old estimates:

Confidential Table 1
Impact of Using 4-Year Average for Forecast

Site	Location	[redacted]	4-Year Avg	[redacted]
Dunlap I Wind	E. Wyoming		40%	
Foote Creek I Wind	E. Wyoming		35%	
Glenrock Wind	E. Wyoming		37%	
Glenrock III Wind	E. Wyoming		34%	
High Plains Wind	E.Wyoming		36%	
McFadden Ridge Wind	E. Wyoming		37%	
Rolling Hills Wind*	E. Wyoming			
Seven Mile Wind	E. Wyoming		40%	
Seven Mile II Wind	E. Wyoming		42%	
Goodnoe Wind	Gorge		27%	
Leaning Juniper 1	Gorge		25%	
Marengo I Wind	Gorge		29%	
Marengo II Wind	Gorge		27%	

* Excluded from Oregon rates

As can be noted in the table, there is a wide range of variances between the P50 forecast and the four-year average. Wind sites located in Eastern Wyoming generally overperformed relative to the long-term estimate and wind sites located in the Columbia Gorge have tended to underperform relative to the long-term production estimate.

Q. IS FOUR 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 output, four years is not a sufficient amount of time to make long-term conclusions about the capacity factor expected from PacifiCorp's wind. When measuring the capacity factors over such a short time frame there is the potential for a few bad years to drive down the four-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 up the average capacity factor, causing it to exceed the expected long-term production. In my Direct Power Cost Testimony in Docket No. UE 335, I noted that Columbia Gorge wind experienced historically low capacity factors in 2017.[1/] It is not known, for example, if the experience in 2017 is an outcome to be expected once every four years, or once every eighty years. When modeling hydro, it is not uncommon for utilities to use eighty years of data to assess expected output.

Q. WHY IS THE USE OF HISTORICAL CAPACITY FACTORS PROBLEMATIC FROM A RATEMAKING PERSPECTIVE?

A. The expected capacity factors are extraordinarily impactful when making the decisions about whether to acquire a utility-owned resource in the RFP. Had PacifiCorp's assessment of these capacity factors been more in line with actual experience, PacifiCorp 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 PacifiCorp'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 PacifiCorp'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.

[1/] Docket UE 335, AWEC/100 at 4:4-6.

Q. WHAT IS A REASONABLE WAY TO DEAL WITH THE CAPACITY FACTOR RISK WITH PACIFICORP'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 some of 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. Further, where a resource out-performs the estimate, ratepayers and shareholders share in the benefit. The RFP estimates also are designed to represent the long-term expectation for PacifiCorp's wind resource, in contrast to the four-year window that PacifiCorp is using.

Q. WHAT DO YOU RECOMMEND?

A. I recommend using a 75/25 blend between the P50 estimate and actuals when modeling the production of owned wind resources in the GRID model.

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

A. PacifiCorp cannot control the wind, or how much it blows. Further, while it is expected that PacifiCorp will make its best efforts to develop a reasonable forecast, no forecast is perfect. Accordingly, it is not unreasonable for ratepayers to share some of the production risk associated with PacifiCorp's wind resources, given the circumstances under which those resources were acquired. 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 PacifiCorp's decision to pursue these resources, and PacifiCorp was the entity that had all of the information to determine which resources to select. Thus, PacifiCorp should bear a majority of the risk associated with the capacity factors of its wind resources.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS WITH PACIFICORP'S WIND PRODUCTION ESTIMATES?

A. Yes. The production estimates PacifiCorp has proposed do not take into consideration the effects of its repowering project. The repowering project was a major component of PacifiCorp's 2017 IRP and, assuming that PacifiCorp proceeds with that project, it will result in increasing the capacity factors for owned wind resources that are being replaced as a part of the program.

Q. HAVE ANY COMMISSIONS PRE-APPROVED THE WIND REPOWERING PROPOSAL?

A. The Utah, Wyoming, and Idaho commissions have all formally approved PacifiCorp's wind repowering proposal, although Utah did not approve of the proposal with respect to Leaning Juniper.[2/] In addition, while not pre-approval, this Commission acknowledged the repowering proposal as part of PacifiCorp's IRP Action Plan.[3/]

Q. DID PACIFICORP CONDUCT ENGINEERING STUDIES TO ASSESS THE LONG-TERM OUTPUT ASSOCIATED WITH ITS REPOWERING PROPOSAL?

A. My understanding is that the capacity factors assumed in the repowering proposal were the result of engineering studies that were based on the most recent data available to PacifiCorp. Thus, there is no reason to doubt the accuracy of those assessments in the long term. These capacity factors have been summarized in Table 2, below.

2/ Ut.PSC Docket 17-035-039, Report and Order (May 25, 2018).
3/ Docket LC 67, Order No. 18-138 (Apr. 27, 2018).

Table 2
Repowering Capacity Factors[4/]

	Repower Cap. Fact.	Repower Date
Dunlap I Wind	49.0%	12/1/2020
Foote Creek I Wind	Not Repowered	
Glenrock Wind	42.6%	10/1/2019
Glenrock III Wind	40.1%	10/1/2019
High Plains Wind	44.1%	11/1/2019
McFadden Ridge Wind	46.7%	11/1/2019
Rolling Hills Wind*	36.8%	10/1/2019
Seven Mile Wind	48.1%	7/1/2019
Seven Mile II Wind	51.2%	7/1/2019
Goodnoe Wind	34.5%	10/1/2019
Leaning Juniper 1**	33.7%	10/1/2019
Marengo I Wind	35.7%	11/1/2019
Marengo II Wind	34.0%	11/1/2019

* Not in OR Rates **Not approved by Utah PSC

Q. IS IT APPROPRIATE TO CONSIDER THE REPOWERING ENERGY IN SOME OTHER FORUM?

A. No. Absent a holistic review of power costs, it is not possible to arrive at a reasoned estimate of the system value of the incremental repowering generation. While PacifiCorp will likely propose to include both the costs and benefits of repowering in its renewable adjustment clause ("RAC") tariff, Schedule 202, unlike capital costs it is not possible to forecast the energy benefits of resources in isolation absent a comprehensive review of the Company's total power costs. Thus, these benefits would only be estimates if incorporated into a RAC filing.

Q. WHY IS A COMPREHENSIVE REVIEW OF PACIFICORP'S POWER COSTS NECESSARY TO ACCURATELY FORECAST THE BENEFITS OF REPOWERING?

A. In PacifiCorp's forecast, there are many factors which influence power costs. As the additional wind energy is introduced into the system, that will cause overall power costs to decline. The

4/ Source: Ut.PSC Docket 17-035-39 Exhibit RMP___(RTL-1SD).

reduction to power cost, however, may come from incremental market sales, reduced market purchases, displaced generation, or other factors. Absent a comprehensive modeling of power costs, these offsetting impacts are difficult, if not impossible, to determine for any particular wind resource. Accordingly, it is preferable to consider all of the power impacts of the repowering in a single power cost run, rather than trying to carve out the impacts of that generation.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE REPOWERING?

A. I recommend that, beginning on the date that the repowering is expected to be completed for each wind project, the repowering capacity factor be used to forecast net power costs. As actual data is developed, the repowering capacity factor should be reconsidered once four years of data is available using the 75/25 ratio discussed above.

b. Production Tax Credits

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO THE PRODUCTION TAX CREDIT RATE PACIFICORP ASSUMED IN ITS FILING?

A. In its filing, PacifiCorp includes an assumption of 2.4 ¢/kWh for the production tax credit rate for 2019. This assumption is consistent with the production tax credit rate published for 2018. 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 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 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 3, below.

TABLE 3
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 3.

A. Table 3 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. Current expectations are that inflation will exceed that level in 2018.

Q. WHAT RATE OF INFLATION DID PACIFICORP ASSUME IN THE GRID MODEL?

A. For everything other than production tax credits, PacifiCorp assumes an inflation rate of [redacted]% for 2019. Thus, the inflation rate PacifiCorp forecast far exceeds the 1.63% necessary to trigger an increase to the production tax credit rate.

Q. IS PACIFICORP'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. The Fed has raised the federal-funds rate by a quarter point three times in 2017, and five times in the past two years. The Fed has also signaled that further increases are likely.[5/] Moreover, according to the Bureau of Labor Statistics, the Consumer Price Index rose 2.5% over the year ending April 2018.[6/] 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.[7/] The Federal Reserve Bank of Philadelphia forecast a year-ahead inflation rate of 2.26% on May 11, 2018.[8/]

5/ Federal Reserve Issues Federal Open Market Committee Statement (December 13, 2017). Available at: https://www.federalreserve.gov/newsevents/pressreleases/monetary20171213a.htm

6/ See https://www.bls.gov/opub/ted/2018/consumer-prices-up-2-point-5-percent-over-year-ended-april-2018.htm

7/ Federal Reserve Bank of St. Louis, FRED Economic Data, 5-Year Breakeven Inflation Rate. Available at: https://fred.stlouisfed.org/series/T5YIE

8/ Federal Reserve Bank of Philadelphia, Short-Term and Long-Term Inflation Forecasts: Survey of Professional Forecasters. Available at: https://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/historical-data/inflation-forecasts

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 IS THE IMPACT OF YOUR ADJUSTMENT?

A. The impact of increasing the production tax credit rate to 2.5 ¢/kWh results in a $250,587 reduction to Oregon-allocated net power costs.

c. <u>Wheeling Rates</u>

Q. WHAT ASSUMPTION DOES PACIFICORP MAKE IN GRID WITH RESPECT TO THE BONNEVILLE POWER ADMINISTRATION'S BP-20 RATE PROCEEDING?

A. Unlike Portland General Electric, PacifiCorp has not assumed that wheeling rates of the Bonneville Power Administration will increase on October 1, 2019, as a result of the BP-20 rate case.

Q. DO YOU HAVE CONCERNS WITH PACIFICORP'S ASSUMED WHEELING CHARGES NEVERTHELESS?

A. Yes. PacifiCorp acquires wheeling services from a large set of transmission service providers throughout the west. Many of those entities will be performing formula rate updates, or other updates, which incorporate the impacts of the H.R.1 of the 115th Congress. For example, PacifiCorp's filing did not consider the Arizona Public Service Company's March 7, 2018 Federal Energy Regulatory Commission ("FERC") filing to reduce rates to address federal tax reform.

These updates will likely put downward pressure on wheeling costs in the rate period, and thus need to be appropriately reviewed and updated. It appears that PacifiCorp has generally not considered these tax reform updates, potentially due to the timing of its filing. In past years, however, I have observed large variances between forecast and actual wheeling costs in PacifiCorp's favor. This leads me to believe that some of the wheeling cost updates have slipped through the cracks in prior TAM proceedings.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that PacifiCorp review the wheeling rates applicable to each of its counterparties and report back, in its rebuttal testimony, the impacts of all known transmission rate filings. Further, for those transmission service providers that don't have formula rates and are not presently conducting tariff changes to reduce rates in conjunction with tax reform, PacifiCorp should indicate what efforts it is undertaking at FERC to ensure that those wheeling benefits are returned to ratepayers.

d. Market Price Forecasting

Q. PLEASE SUMMARIZE YOUR OBSERVATIONS WITH RESPECT TO PACIFICORP'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 Portland General Electric'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.[9/] In this docket, I applied the same analysis to PacifiCorp's forward price curve.

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

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 GRID to account for historical forecast error. Second, I recommend adopting a policy for all new hedging contracts where PacifiCorp's 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 PacifiCorp's official forward price curves.

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

A. In Confidential Exhibit AWEC/102 and Confidential Exhibit AWEC/103, I present an analysis exploring the accuracy of PacifiCorp's previously issued OFPCs for both gas and electric markets. Within these studies I was particularly concerned with the period that is two to thirteen months in advance of the prompt month, corresponding to the timing of the final TAM update. Confidential Exhibit AWEC/102 examines the accuracy of OFPCs issued over the period 2007 through 2016. Confidential Exhibit AWEC/103 examines the accuracy of OFPCs issued over the period 2010 through 2016. The analysis considers a long-term period, as well as a shorter period of 2010 through 2016, 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 PacifiCorp historically tended to overestimate forward prices in past TAM proceedings. In addition, a similar pattern of overestimation can be observed when considering only the curves issued over 2010 through 2016. This indicates that PacifiCorp'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 Henry Hub market has been reproduced in Confidential Figure 1, below, based on OFPCs issued over the period 2006 through 2016.

CONFIDENTIAL FIGURE 1
Henry Hub Forecast Error,
For OFPCs Issued 2006 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 PacifiCorp issued over the period 2006 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 FIGURE 1 ABOVE BE USED TO DETERMINE PACIFICORP'S ACCURACY IN PREDICTING FORWARD PRICES?

A. If the OFPCs are reasonably accurate, one would expect PacifiCorp'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, PacifiCorp's projected forward prices 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 PACIFICORP'S FORECASTING?

A. I recommend that, for purposes of forecasting power costs, a downward adjustment be applied to forecast market prices to account for PacifiCorp's forecasting bias. I applied my adjustment by reducing the forecast by the following percentages, which are the median forecast error from the analysis I presented in Exhibit AWEC/103.

CONFIDENTIAL TABLE 4
Median Historical Forecast Error For TAM Period
Natural Log Difference

[redacted]

Q. PLEASE SUMMARIZE HOW THE ABOVE PERCENTAGES ARE APPLIED TO PACIFICORP'S PRICE CURVE.

A. The above forecast error values were calculated using natural log differences. The values in Confidential Table 4 must be applied to forward prices using the *e* constant, i.e.,

$F(e) = F(Pac) * e^{p}$, where
F(e) = Error Adjusted Forecast Price
F(Pac) = PacifiCorp Forecast Price
p = Table 4 Forecast Error %

In addition, the error adjusted monthly forecast would still need to undergo the scaling process to convert the monthly forecast value into the hourly grid model inputs, as well as recalculate forecast hedging settlements. Since working versions of certain workpapers were not provided in PacifiCorp's filing, I did not attempt to perform this modeling.

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

A. Given the fact that the forecast tends to be biased, that is an indication that PacifiCorp's 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 PacifiCorp's propensity to over-forecast is as a risk premium – an additional cost above the spot market price that PacifiCorp 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 PacifiCorp 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.[10/] 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.

[10/] 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.

Q. WHAT DOES THE DATA IN YOUR ANALYSIS CONFIRM ABOUT THE EXISTENCE OF RISK PREMIUMS IN PACIFICORP'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]% of the ultimate spot price. This means that each time PacifiCorp 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 power.

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

A. It has been a while since PacifiCorp's hedging strategy was last considered by the Commission in 2011.[11/] Additionally, when the Commission last approved this strategy, it was over objections raised by AWEC (then ICNU) that related specifically to PacifiCorp's hedging policy from November 2006. AWEC's witness in that case testified that he had "not performed a thorough analysis of the Company's current hedging strategy and its execution at this time. My recommendation is based on the hedging strategy that was in place at the time certain transactions were executed in 2007 and 2008."[12/] Consequently, in making its decision, the Commission did not have the benefit of an evidentiary record that demonstrates that the Company's hedging strategy is imposing systematic costs on customers. My testimony and exhibits provide this evidence.

11/ Docket UE 227, Order No. 11-435 (Nov. 4, 2011).
12/ Docket UE 227, ICNU/110, Schoenbeck/9:22-24 (Aug. 16, 2011).

Q. DOES PACIFICORP HAVE AN INCENTIVE TO CONTINUE FOLLOWING ITS HEDGING STRATEGY DESPITE THE COSTS IT IMPOSES ON CUSTOMERS?

A. Yes. PacifiCorp'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 its open market position, however, PacifiCorp 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 PacifiCorp's initial filing in this docket.

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.

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT PACIFICORP'S FORWARD PRICE CURVE?

A. Yes. In AWEC Data Request 006, I requested the broker quotes used to develop PacifiCorp's forward price curve. PacifiCorp only provided a comparison dated 12/29/2017 and that analysis only encompassed electric markets. PacifiCorp should supplement its response to AWEC Data Request 006 with the broker quotes that are actually used to support its initial filing. Absent that data, there is no basis to confirm the reasonableness of PacifiCorp's forward curves, even before considering the issues related to hedging and forecast error. This is particularly important due to the rapid way in which those forward markets have been changing in recent months.

e. <u>300 MW Link Jim Bridger -> Walla Walla</u>

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE 300 MW LINK BETWEEN JIM BRIDGER AND WALLA WALLA?

A. I recommend that PacifiCorp conform its modeling of the EIM in this case with the modeling that was used in its recent RFP process involving new wind and transmission. In that case, PacifiCorp included a virtual 300 MW transmission link between the Jim Bridger transmission area to the Walla Walla transmission area.

Q. HOW DO YOU KNOW THAT PACIFICORP USED THIS MODELING TECHNIQUE IN ITS 2017 RFP?

A. Attached as Exhibit AWEC/104 is a discovery request where PacifiCorp confirmed that it used this method in the production cost models that were used in the RFP process.

Q. WHY DID PACIFICORP ASSUME THIS VIRTUAL LINK IN THE RFP PROCESS?

A. The modeling was described on page 13 of PacifiCorp's July 28, 2017, IRP Informational Filing with the Commission in Docket LC 67:

> In its final 2017 IRP resource-portfolio screening process, PacifiCorp described how the Energy Imbalance Market (EIM) can provide potential benefits when incremental energy is added to transmission-constrained areas of Wyoming. Unscheduled or unused transmission from participating EIM entities enables more efficient power flows within the hour. With increasing participation in the EIM, there will be increasing opportunities to move incremental energy from Wyoming to offset higher-priced generation in the PacifiCorp system or other EIM participants' systems. The more efficient use of transmission that is expected with growing participation in the EIM was captured in the updated economic analysis by increasing the transfer capability between the east and west sides of PacifiCorp's system by 300 MW (from the Jim Bridger plant to southcentral Oregon). The ability to more efficiently use intra-hour transmission from a growing list of EIM participants is not driven by the Energy Vision 2020 projects; however, this increased connectivity provides the opportunity to move low-cost incremental energy out of transmission constrained areas of Wyoming.

Q. WHY HAS PACIFICORP NOT DEPLOYED THE SAME METHODOLOGY FOR POWER COST FORECASTING?

A. It is not clear. Assuming the methodology involving the use of a modeled 300 MW transmission link between Jim Bridger and Walla Walla was valid to estimate net benefits of a proposed wind facility, it should similarly be a valid way to establish net power cost in a forecasting mechanism such as the TAM. Further, absent this modeling, ratepayers would have no way of recognizing some of the incremental benefits that were promised in the 2017R RFP or with respect to the wind repowering proposal.

III. ENERGY IMBALANCE MARKET COSTS

Q. WHAT AMOUNT OF COSTS HAS PACIFICORP INCLUDED IN THE TAM FOR THE ENERGY IMBALANCE MARKET?

A. As noted in PAC/101, PacifiCorp has included $912,632 in Non-NPC energy imbalance market costs.

Q. ARE EIM COSTS APPROPRIATELY CONSIDERED NET POWER COSTS?

A. No. In UE 199, Order No. 09-274, the Commission adopted a stipulation that specified the net power costs, by FERC account, that PacifiCorp could update in a standalone TAM filing. These are:

- Account 447 – sales for resale, excluding on-system wholesale sales and other revenues that are not modeled in GRID;
- Account 501 – fuel expense, steam generation; excluding fuel handling, start up fuel/gas, diesel fuel, residual disposal and other costs that are not modeled in GRID;
- Account 503 – steam from other sources
- Account 547 – fuel expense, other generation
- Account 555 – purchased power, excluding BPA residential exchange credit pass-through;

- Account 565 – wheeling expense.[13]

By contrast, EIM costs are capital and O&M costs that are tracked by separate FERC accounts and are more appropriately considered in general rates with similar costs.

Q. WHY DOES PACIFICORP INCLUDE EIM COSTS IN ITS FILING?

A. PacifiCorp states that EIM costs are included in order to match EIM benefits.[14] It also notes that this was the original agreement of the parties to UE 287 when PacifiCorp first joined the EIM and proposed to include their costs and benefits in rates.[15]

Q. DO YOU AGREE?

A. I agree that the stipulation in UE 287 did authorize inclusion of EIM costs in the TAM in order to match benefits, and parties have since not challenged this treatment in subsequent TAM proceedings. The stipulation in UE 287, however, did not specify that such treatment would be the practice forever. In fact, the joint testimony in support of this stipulation says precisely the opposite: "The Settling Parties agree that, at this time, the costs and benefits associated with the EIM are difficult to predict with certainty. As an interim approach, the Settling Parties agree that it is reasonable to offset EIM costs and benefits in 2015 NPC. The agreement in the Stipulation resolves the issue of EIM costs and benefits only through December 31, 2015."[16]

Q. WHAT DID THE PARTIES AGREE TO AFTER 2015?

A. The parties agreed "to address EIM-related costs and benefits after December 31, 2015 in the 2016 TAM."[17] After this, PacifiCorp agreed to "participate in one or more workshops with

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[13] Docket No. UE 199, Order No. 09-274, Appen. A at 14 (July 16, 2009).
[14] Exhibit PAC/100, Wilding/6:13-15.
[15] Id. at 6:15-17.
[16] Docket UE 287, Settling Parties/100 at 8:15-19.
[17] Id. at 8:22-23.

Staff and other interested parties to discuss the … potential options for addressing EIM-related costs and benefits from January 1, 2016, forward."[18/]

Q. DID THESE WORKSHOPS RESULT IN AN AGREEMENT OVER HOW TO ADDRESS EIM-RELATED COSTS?

A. No. The Company has simply perpetuated the arrangement parties temporarily agreed to in 2015.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO ENERGY IMBALANCE MARKET COSTS?

A. I recommend that the costs associated with the energy imbalance market be removed from the TAM. As noted above, these costs are outside of the scope of this "narrow" proceeding,[19/] and the rationale for originally including them – the uncertainty associated with both the costs and benefits of the EIM – is no longer present. PacifiCorp is free to file a general rate case to include these costs, and even if it does not, this does not mean those costs will not be recovered. As its most recent results of operations report shows, the Company is exceeding its authorized rate of return and, therefore, recovering its costs as a whole.[20/]

IV. PERMANENT OPT-OUT

Q. PLEASE DESCRIBE PACIFICORP'S PERMANENT OPT-OUT PROGRAM.

A. Like PGE, PacifiCorp has developed a program to allow large non-residential customers to permanently opt-out of its cost-of-service rates under Oregon's direct access law.[21/] The Commission required PacifiCorp to develop this program after PGE's had been in place for

18/ Id. at 8:23-9:3.
19/ Order No. 09-274 at 2.
20/ Docket RE 56, PacifiCorp's Annual Results of Operations Report Ending Dec. 31, 2017 at 1.0 (Apr. 30, 2018).
21/ Pacific Power Schedule 296.

some time.[22/] Unlike PGE's program, however, PacifiCorp requires participating customers to pay transition charges for ten years, rather than the five years PGE's program includes. Transition charges are intended to ensure that a departing customer does not unduly shift costs to remaining customers. Because customers must effectively pay twice as much to leave PacifiCorp's system as PGE customers do, PacifiCorp's permanent direct access program has been largely unsuccessful. My understanding is that only one customer is participating.

Q. HOW DID PACIFICORP JUSTIFY IMPOSING TEN YEARS OF TRANSITION CHARGES INSTEAD OF FIVE?

A. Among other things, PacifiCorp distinguished itself based on its Multi-State Protocol, which allocates the costs of its system among five of the six states it serves (Washington follows a different allocation methodology). At the time PacifiCorp's permanent opt-out program was under consideration, PacifiCorp adhered to the 2010 Protocol. As it testified in UE 267:

> This cost shifting appears unavoidable under Section X of the Company's approved inter-jurisdictional allocation methodology, the 2010 Protocol, which provides that direct access loads must be included when allocating costs to Oregon. When the adjustment to remove the direct access loads is made for setting rates in Oregon beginning in years six of the [permanent opt-out program], other Oregon customers will absorb the costs that are allocated to Oregon and no longer recovered from these direct access customers …. While PacifiCorp and representatives from all six of its states are currently in discussions regarding the 2010 Protocol, there is no agreement now on changes to Section X.[23/]

Q. WHAT DID THE 2010 PROTOCOL PROVIDE WITH REGARD TO DIRECT ACCESS?

A. Section X stated that "[w]here the Company is no longer required to plan for the load of customers who permanently choose direct access or permanently opt out of New Resources,

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[22/] Docket UM 1587, Order No. 12-500 at 9 (Dec. 30, 2012).
[23/] Docket UE 267, PAC/300, Steward/4:10-20.

such loads will be included in Load-Based Dynamic Allocation Factors for all Existing Resources ….”

Q. WHAT DOES THE 2017 PROTOCOL PROVIDE WITH REGARD TO DIRECT ACCESS?

A. Section X of the 2017 Protocol states that treatment will be consistent with the Commission's final order adopting PacifiCorp's permanent direct access program, including payment of ten years of transition fees. However, it also states that "[t]o the extent Oregon adopts new laws or regulations regarding Oregon's Direct Access Programs, treatment of loads lost to Oregon Direct Access Programs may be re-determined in a manner consistent with the new laws and regulations." Thus, under the 2017 Protocol, the Commission may determine that permanent direct access loads should not be included in the Load-Based Dynamic Allocation Factors that govern cost assignment between states after five years, which would eliminate the basis for requiring ten years of transition charges.

Q. WHAT DO YOU RECOMMEND?

A. I recommend the Commission open a proceeding to reevaluate the use of 10 years in establishing opt-out payments for PacifiCorp. Now that there has been a material change in circumstances underlying one of PacifiCorp's principal justifications for distinguishing its transition adjustment from PGE's, the time is ripe for reconsidering PacifiCorp's transition adjustment.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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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 Utilities Commission.

Q. PLEASE PROVIDE A LIST OF YOUR REGULATORY APPEARANCES.

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

- <u>In re Portland General Electric Company, Request for a General Rate Revision.</u> Or.PUC Docket No UE 335.
- <u>In re Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision,</u> Or.PUC Docket No. UG 344.
- <u>In re Cascade Natural Gas Corporation Request for a General Rate Revision,</u> Wa.UTC, Docket No. UE-170929.
- <u>In the Matter of Hydro One Limited, Application for Authorization to Exercise Substantial Influence over the Policies and Actions of Avista Corporation</u>, Or.PUC, Docket No. UM 1897.
- <u>In re Pacific Power & Light Company 2016 Power Cost Adjustment Mechanism,</u> Wa.UTC, Docket No. 170717.
- <u>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,</u> 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. 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.

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CONFIDENTIAL EXHIBIT NO. AWEC/102

HISTORICAL FORWARD PRICE CURVE FORECAST ERROR ANALYSIS 2007 - 2016

(REDACTED VERSION)

Exhibit AWEC/102 contains Protected Information and has been redacted in its entirety in accordance with Order No. 16-128.

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CONFIDENTIAL EXHIBIT NO. AWEC/103
HISTORICAL FORWARD PRICE CURVE FORECAST
ERROR ANALYSIS 2010 – 2016

(REDACTED VERSION)

Exhibit AWEC/103 contains Protected Information and has been redacted in its entirety in accordance with Order No. 16-128.

BEFORE THE PUBLIC UTILITY COMMISSION

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EXHIBIT NO. AWEC/104

RESPONSE TO DISCOVERY REGARDING 300 MW TRANSMISSION LINK

PAC-E-17-07 / Rocky Mountain Power
March 19, 2018
PIIC 5th Set Data Request 29

PIIC Data Request 29

Reference the Rebuttal Testimony of Rick T. Link at 27:17-28:1: Mr. Link states that "[t]he GRID studies and assumptions referred to by Mr. Mullins were used in the 2017 IRP, but not in the economic analysis included in this case".

(a) Does PacifiCorp agree that, in preparing the economic analyses identified in the Second Supplemental Direct Testimony of Rick T. Link, it has incorporated the adjustments underlying the referenced supplemental GRID studies into the System Optimizer and Planning and Risk models?

(b) On what basis, if any, does PacifiCorp conclude that the impacts of the adjustments underlying the supplemental GRID studies have changed materially after being incorporated into System Optimizer and Planning and Risk models? Please provide all studies showing what PacifiCorp believes the impact of those adjustments to be when incorporated into the System Optimizer and Planning and Risk models.

(c) Does PacifiCorp's economic analysis identified in the Second Supplemental Direct Testimony of Rick T. Link still include an assumption where the transfer capability between Jim Bridger and Walla Walla is increased by 300 MW corresponding to growing participation in the Energy Imbalance Market (EIM)? If yes, please provide PacifiCorp's best estimate of the impact of this assumption on the medium gas and medium CO2 scenario. If no, please explain.

(d) Does PacifiCorp's economic analysis identified in the Second Supplemental Direct Testimony of Rick T. Link still include an assumption where the Wyoming loads are reduced to account for purported line loss benefits of the Transmission projects? If yes, please provide PacifiCorp's best estimate of the impact of this assumption on the medium gas and medium CO2 scenario. If no, please explain?

(e) Does PacifiCorp's economic analysis identified in the Second Supplemental Direct Testimony of Rick T. Link still include an assumption to account for reduced de-rates associated with constructing Gateway segment D2? If yes, please provide PacifiCorp's best estimate of the impact of this assumption on the medium gas and medium CO2 scenario. If no, please explain.

Response to PIIC Data Request 29

(a) PacifiCorp does not agree. The line loss, reliability and energy imbalance market (EIM) assumptions adopted in the 2017 Integrated Resource Plan (IRP) were previously evaluated in the Generation and Regulation Initiative Decision Tool (GRID). In the 2017 IRP, PacifiCorp applied the results from these GRID studies into the portfolio costs used to analyze the new wind and transmission projects. In the economic analysis presented in this proceeding, including the economic analysis summarized in the Company's second supplemental direct testimony filing, these assumptions were subsequently incorporated in the System Optimizer model (SO model) and the Planning and Risk (PaR) model. Consequently, no results from GRID have been used in the Company's economic analysis presented in this case.

(b) PacifiCorp has not isolated the incremental impact of referenced assumptions in the SO model and PaR model. Please refer to the following supporting materials:

<u>EIM Benefit</u>
PacifiCorp's estimate of a 300 megawatt (MW) increase in transfer capability was based on historical experience with adjacent entities that have joined the energy imbalance market (EIM) since 2014. Please refer to Attachment PIIC 29-1, which provides the transmission intertie connectivity volumes as of December 2017. In each case that an entity has joined the EIM, total transmission connectivity to PacifiCorp has been greater than or equal to 300 MW. Idaho Power Company (IPC) has not yet finalized its transmission availability to the market, however, it is in each entity's best interest to make its transmission available to the market to maximize EIM benefits.

<u>Line Loss Benefit</u>
Please refer to Confidential Attachment PIIC 29-2, which provides calculations supporting the 11.6 average megawatts (aMW) referenced value.

<u>Reliability Benefit</u>
Please refer to Confidential Attachment PIIC 29-3, which provides calculations supporting the 36.5 average megawatts (aMW) referenced value.

(c) Yes. Please refer to the Company's response to subpart (b) above.

(d) Yes. Please refer to the Company's response to subpart (b) above.

(e) Yes. Please refer to the Company's response to subpart (b) above.

Confidential information is provided subject to the terms and conditions of the protective agreement in this proceeding.

Recordholder: Randy Baker

Sponsor: Rick Link