BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 420

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
2024 Transition Adjustment Mechanism.	)
	)

REBUTTAL TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE

ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED)

August 16, 2023

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EXHIBIT LIST

AWEC/201 – Mullins Proposed NPC Forecast

AWEC/202 – 2022 Actual NPC

AWEC/203 – Update Production Tax Credit Rate Forecast

I. INTRODUCTION AND SUMMARY

Q. ARE YOU THE SAME WITNESS THAT FILED OPENING TESTIMONY IN THIS MATTER?

A. Yes. I previously filed Opening Testimony on behalf of the Alliance of Western Energy Consumers ("AWEC") discussing the 2024 Transition Adjustment Mechanism ("TAM") filing of PacifiCorp dba Pacific Power ("PacifiCorp" or "Company").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I respond to the Reply Testimony of PacifiCorp witnesses Mitchell[1] and Shahumyan.[2] I also discuss proposed modeling changes PacifiCorp submitted in its Reply Testimony, as discussed by Witness Mitchell.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. In **Exhibit AWEC/201**, I present my forecast of net power costs ("NPC") for the 2024 TAM. My forecast produces results of $2.17 billion, which still an increase relative to, but more in-line with, 2022 Actual NPC of $2.04 billion. This is reasonable given the decline in forward curves relative to 2022 actual prices, as discussed more thoroughly below. The differences between my forecast and PacifiCorp's are detailed in **Table 1**, below, followed by brief descriptions of my recommendations.

[1] PAC/400
[2] PAC/600

Table 1
AWEC 2024 TAM NPC Forecast
Whole Dollars

		Total Company	Approx. Oregon Allocated
1	**RMP July Update NPC Forecast**	**2,527,830,432**	**725,522,878**
2	**Modeling Differences:**		
3	Initial Filing Coal Costs	(110,944,033)	(31,842,498)
4	AURORA Model Environment	(553,624)	(158,898)
5	Market Caps - Liquid Markets	(20,389,050)	(5,851,944)
6	Market Caps - 95th Percentile	5,310,124	1,524,080
7	DA/RT - July Update Method Change	(80,037,888)	(22,971,999)
8	DA/RT- Method Simplification	(24,536,188)	(7,042,231)
9	Ozone Transport Rule Wyoming	(27,457,586)	(7,880,713)
10	Washington CCA	(72,706,490)	(20,867,785)
11	**Total Modeling Differences**	**(331,314,737)**	**(95,091,988)**
12	**Mullins NPC Forecast**	**2,196,515,696**	**630,430,890**

Coal Costs Update: I recommend the final update be based on PacifiCorp's initially filed coal costs because the impacts of the update were not represented accurately in Rebuttal Testimony.

Base Period Update: I recommend that the undocumented update of the base period to calendar year 2022 be rejected as inconsistent with the TAM guidelines. This difference is not included Table 1, although I recommend the Commission require PacifiCorp to make this change in its final update.

AURORA Model Environment: I continue to recommend a dollar adjustment to reflect the fact that the AURORA model run on my computer architecture produces a lower modeled NPC than PacifiCorp calculated.

Market Caps: I continue to recommend that hub demands, formerly known as market caps, be modeled consistent with the Commission's decision in Docket No. UE 390 (the 2022 TAM), Order 21-379, including removing sales restrictions from liquid market hubs.

Day-ahead / Real-time ("DA/RT") – July Update Modeling Change: I recommend the DA/RT adjustment modeling change PacifiCorp proposed in Rebuttal Testimony be rejected as procedurally improper and inconsistent with the TAM guidelines.

Day-ahead / Real-time Adjustment ("DA/RT") – Method Simplification: Given the problems caused by the price adjustment on the AURORA model dispatch, I continue to recommend that the DA/RT adjustment be modeled using only the "historical adjustment," which is a spreadsheet adjustment calculated outside of the AURORA model.

Ozone Transport Rule: I continue to recommend that Ozone Transport Rule modeling be removed from the forecast based on the final rule, which does not apply to Wyoming and is under legal review by the US District Court for application within Utah.

Washington Climate Commitment Act ("CCA"): I continue to recommend that Washington CCA compliance costs be removed from NPC.

Arizona Public Service ("APS") Short-Term Transmission: I have discovered that the modeling anomalies leading to a net cost associated with transmission access to Palo Verde was likely a byproduct of PacifiCorp's overly restrictive DA/RT and market cap modeling methods. The modeling anomalies do not exist to the same extent in my forecast, so I am withdrawing this recommendation.

Production Tax Credit ("PTC") Rate: I continue to recommend that the PTC rate be increased to 3.0 cents per kWh, consistent with inflationary trends expected through the end of 2023. This change, which is separate in the NPC forecast above, results in a $9,432,780 reduction to overall TAM revenues on a total-Company basis with $2,707,340 allocated to Oregon.[3]

Collectively, the approximate 8.5% increase that PacifiCorp is proposing in both this case and its Power Cost Adjustment Mechanism ("PCAM") will have a major impact on Oregonians, as well as on the competitiveness of businesses located in PacifiCorp's service territory. This rate increase comes on the heels of a 16.11% combined rate increase approved in the 2022 GRC, the 2023 TAM, and the 2021 PCAM. Given these impacts, it is important for the Commission to closely scrutinize the reasonableness of PacifiCorp's power cost forecast in this case.

[3] PacifiCorp did not provide updated TAM revenue calculations, including PTCs and other items, in its Rebuttal Filing.

II. OVERVIEW OF PACIFICORP'S RUBUTTAL NPC FORECAST

Q. WHAT LEVEL OF NPC HAS PACIFICORP FORECAST IN ITS REBUTTAL NPC?

A. In its Rebuttal Testimony, PacifiCorp presents an updated NPC forecast of $2.53 billion for the 2024 TAM.[4] While this is a reduction from PacifiCorp's filed case, it still represents a significant increase relative to both the final NPC forecast submitted in the 2023 TAM, as well as to actual NPC incurred in 2022. This forecast represents an approximate $550 million total-Company increase relative to the 2023 TAM of $1.98 billion. It also represents an approximate $530 million increase relative to 2022 actual NPC of $2.04 billion.

Q. ARE THE HISTORICAL VARIATIONS BETWEEN THE TAM AND ACTUAL NPC A REASON TO SET NPC AT AN ARBITRARILY HIGH LEVEL?

A. No. PacifiCorp discusses the fact that it has not accurately forecast in prior years,[5] and basically implies that as a result of its poor performance relative to past TAM forecasts, the Commission should take an unprincipled approach to evaluating the modeling methods used and simply use the method that produces the highest level of NPC.[6] I disagree with this implication. To develop a forecast with an overall end result that is reasonable, the forecast must be based on modeling assumptions that are both principled and consistent.

Q. WHAT IS DRIVING THE RECENT NPC VARIANCES?

A. Market conditions in late 2022 and early 2023 were extraordinary, as shown in **Figure 1**, below.

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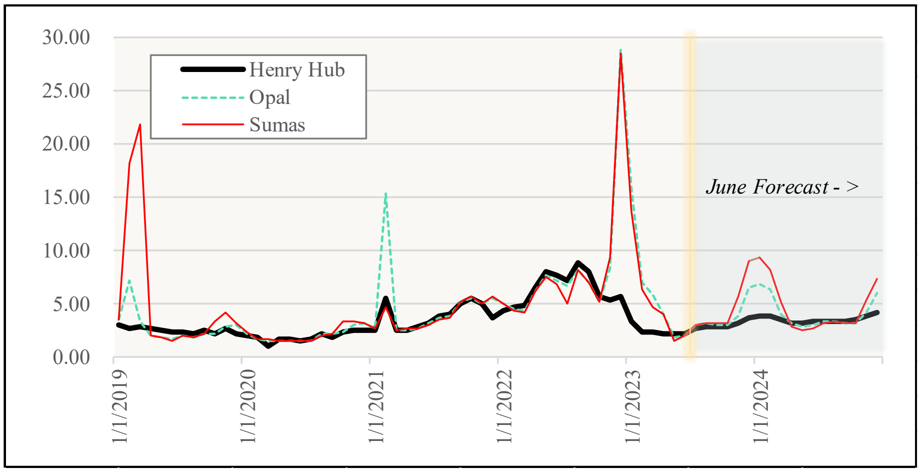
4 PAC/403, Mitchell/5.
5 PAC/400, Mitchell/18:10-12.
6 PAC/400, Mitchell/17:18-21.

Figure 1
Natural Gas Prices 2019 – 2022: Henry Hub, Opal &. Sumas
($/dth)



As can be seen, prices in the West have been materially more volatile and higher than Henry Hub prices, particularly in winter months. Prices at Henry Hub have declined to pre-pandemic levels, although winter price spikes are still being forecast in the West. Thus, the market forecasting issues that PacifiCorp identified in the first six months of 2023 have more to do with the price dynamics discussed above and not its power cost modeling. The 2023 TAM was the first year in which the AURORA model was used to forecast NPC. Accordingly, at this point, little is known about how accurate PacifiCorp's AURORA forecasts will be. While PacifiCorp cites its under-recovery in the first six months of 2023 as a basis for accepting its materially higher NPC forecast,[7] the costs experienced in those months do not provide a reasonable indication of how accurate the AURORA model is because of the extraordinary Western market conditions that occurred during that time period. Moreover, these types of extraordinary events are not intended to be captured in a normalized power cost

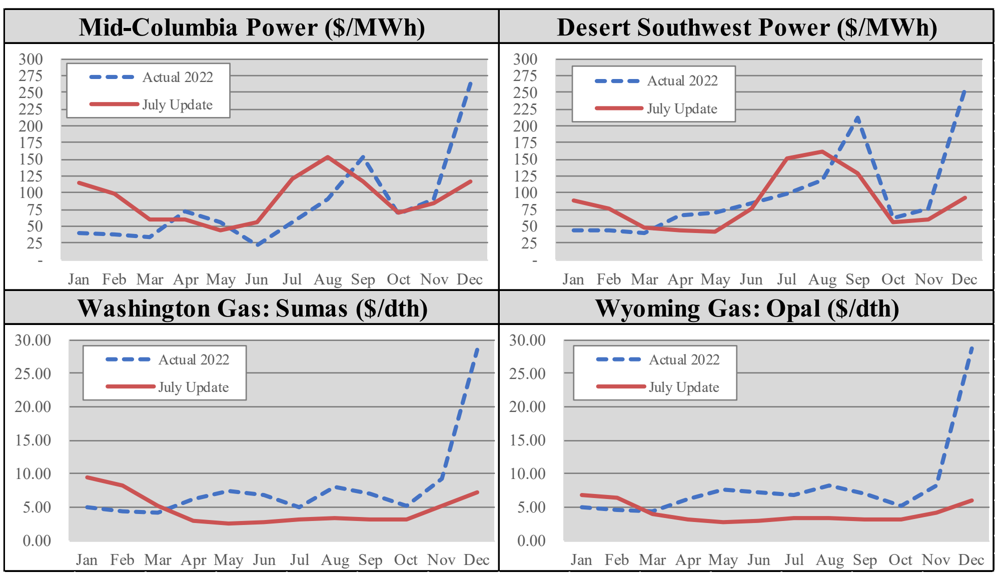
7 PAC/400, Mitchell/15:8-13.

forecast and are precisely why the Commission implemented a PCAM for PacifiCorp in the first place. PacifiCorp's alleged under-recovery for the first six months of 2023 is, therefore, irrelevant to assessing the reasonableness of PacifiCorp's 2024 power cost forecast.

Q. HOW DO FORECAST PRICES COMPARE TO 2022 ACTUAL PRICES?

A. Relative to 2022 actual prices, PacifiCorp's market forecast has declined. This is detailed in **Figure 2**, below.

Figure 2
<u>Change in Western Energy Market Prices: 2022 vs 2024 (forecast)</u>

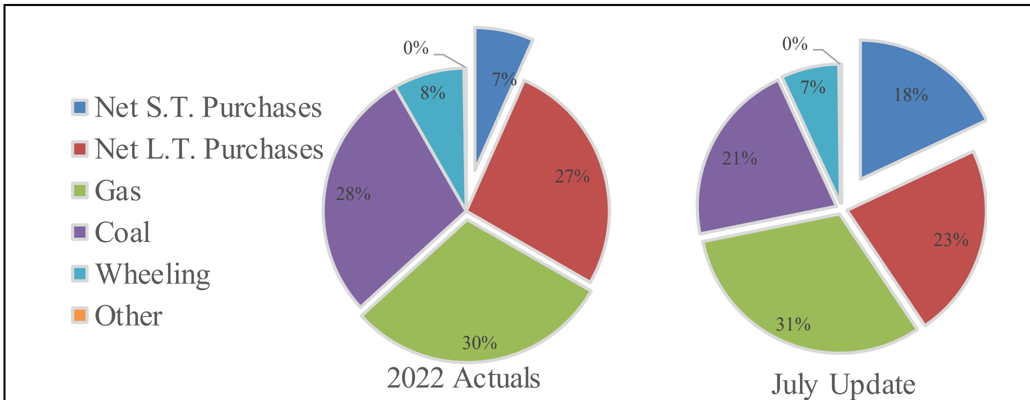


Based on the above, market prices do not justify an increase to forecast NPC relative to NPC that actually incurred in 2022. Sumas gas prices, for example, are forecast to be approximately 20% lower than 2022 levels. The relationship above would otherwise imply that the forecast NPC for the Test Period should be lower than 2022 actuals.

Q. WHAT IS CAUSING PACIFICORP'S FORECAST TO BE HIGHER THAN 2022 ACTUALS?

A. Actual NPC for calendar year 2022 has been attached as **Exhibit AWEC/202.** Below, I provide a comparison between PacifiCorp's Reply Testimony forecast and 2022 actual NPC. For purposes of this analysis, short-term purchases and sales were netted to form an apples-to-apples comparison to the modeled results.

Figure 3
2022 Actual NPC vs. Rebuttal Filing Model Forecast



Category	2022 Actuals	July Update	Variance	%
Net S.T. Purchases	$ 135,625,310	$ 455,720,176	$ 320,094,866	236%
Net L.T. Purchases	544,173,647	569,501,001	25,327,354	5%
Gas	610,525,466	790,277,523	179,752,056	29%
Coal	580,834,961	538,341,964	(42,492,997)	-7%
Wheeling	164,088,727	169,548,867	5,460,140	3%
Other	5,070,191	4,440,902	(629,289)	-12%
Total	**$ 2,040,318,302**	**$ 2,527,830,432**	**$ 487,512,130**	**24%**

In **Figure 3**, it can be observed that the most significant variance between 2022 actual NPC and the Rebuttal Update was the Net Short-Term Purchases category. While market prices declined slightly relative to actuals, PacifiCorp's modeled forecast assumed net short-term purchase that are $320,094,866 higher than 2022 actuals, a variance of 236%. This result is likely being caused in part by some of the modeling techniques discussed below, such as the DA/RT and market cap modeling methods.

Further, another variance can be found in the cost of gas, which increases by 29%. This increase can be attributed in part to gas hedging transactions that offset actual NPC in 2022, which are not included in the Test Period. Further, the conversion of Bridger Units 1 and 2 to a gas fired steam generator is likely another cause of the increase in gas costs. With an increase to gas production, however, one would otherwise expect Net Short-Term Purchases to decline. That, however, is not occurring in the model. Not only is this counterintuitive, but it undermines the economic benefits of the gas conversion, which PacifiCorp represented in its Integrated Resource Plan as substantial.[8]

Q. WHAT ARE YOUR OBSERVATIONS BASED ON THIS COMPARISON?

A. This comparison demonstrates that PacifiCorp's modeling in AURORA is producing an excessive level of NPC. Market prices are forecast to be lower than 2022; therefore, the major increase relative to 2022 levels is concerning. To be clear, there are factors that might lead to increased NPC in the Test Period relative to 2022, including the Jim Bridger Units 1 and 2 gas conversion and expiration of favorable gas hedges. Notwithstanding, my analysis shows that more favorable market conditions discussed above are offsetting to these factors. Based on my modeling, which adopts a different approach to some of the modeling techniques than what PacifiCorp has used, I arrived at a forecast that produces a result that is more consistent with 2022 actual NPC. Before discussing those, however, it is necessary to address problems identified with PacifiCorp's July Update.

[8] PacifiCorp 2021 Integrated Resource Plan at 269.

III. JULY UPDATE

Q. WHAT PROCESS HAS THE COMMISSION ADOPTED FOR PACIFICORP TO MAKE UPDATES IN ITS REBUTTAL TESTIMONY?

A. Pursuant to Commission Order 09-274, the Items that PacifiCorp may update in Rebuttal Update includes the following:

> **"C. Rebuttal Update Filing**
>
> At the time Pacific Power makes its rebuttal filing, it will include an update to forecast net power costs consistent with the following provisions:
>
> 1. The Company will update the following net power cost components, subject to the TAM guidelines:
>   a. Most recent official forward price curve.
>   b. New power, fuel and transportation contracts, both physical and financial, and updates to existing contracts.
> 2. The Company may make corrections to, or address omissions in, the components included in the Company's Initial Filing.
> 3. Parties reserve procedural rights related to the correction of the Rebuttal Update filing.
> 4. The Company will provide workpapers and other supporting documents as specified in Attachment B to the Stipulation."[9]

Notably, modeling changes are not allowed in a Rebuttal Update, since parties otherwise have limited opportunity to review and evaluate such changes in their sur-rebuttal testimony. Further, wholesale updates to the historical, base period data used to forecast NPC are also not allowed.

9 Docket No. UE 199, Order 09-274 at 4 (July 16, 2009).

Q. DID PACIFICORP'S REBUTTAL UPDATE COMPLY WITH THE REQUIREMENTS FROM ORDER 09-274?

A. No. Foremost, PacifiCorp made a wholesale change to the DA/RT method, which it labels as a correction but which is actually a modeling change; modeling changes are not permissible in a Rebuttal Update Filing. PacifiCorp also updated the historical base period data to be based on calendar year 2022, rather than based the year ending June 2022, a change which is also not allowed. There are also several changes that PacifiCorp made that were not properly documented in its filing and were not discussed in Rebuttal Testimony, such as the impact of the coal supply update, as well as updating the base period to calendar year 2022. These deviations from the TAM guidelines are concerning, and given the magnitude of the rate increase being proposed, it is of heightened importance to comply with the procedural framework that has been established for these proceedings.

a. <u>DA/RT Method Change</u>

Q. WHAT "CORRECTION" DID PACIFICORP ALLEGE THAT IT MADE WITH RESPECT TO THE DA/RT METHOD?

A. PacifiCorp's rebuttal testimony states that it "corrected an error in the DA/RT adjustment by removing unsupported artificial arbitrage revenue."[10] While PacifiCorp identified these changes as a correction, that characterization was not accurate. The changes represented a modification to the DA/RT method—a change in the way that the DA/RT modeling was being performed. Characterizing the change as a correction was misleading at best. Consistent with the TAM guidelines, it was improper for PacifiCorp to introduce such a material change to the

[10] PAC/400, Mitchell/11:3-4.

DA/RT method in Rebuttal Testimony. This modeling change represented a $60,740,729 increase to total-Company NPC.[11]

While I discuss this change further below, Witness Mitchell supports this alleged correction by making several vague and unsupported statements such as "arbitrage revenue present in the Initial Filing was above the levels supported by the historical data."[12] In this context, however, it is not clear if Witness Mitchell fully understands the mechanics of the DA/RT adjustment, since the historical adjustment (a.k.a., the volume adjustment) was in no way related to arbitrage revenues—arbitrage revenues have been removed from NPC for over ten years beginning in the 2013 TAM.[13] Although, to the extent arbitrage revenues are included in the historical data, as Witness Mitchell represents, that may be a reason to reevaluate the arbitrage revenue adjustment from the 2008 TAM.[14] In summary, this change is a one-sided attempt for PacifiCorp to offset what would have otherwise been a major reduction to NPC in its Reply Testimony as a result of a declining forward price curve and a new interpretation of the Ozone Transport Rules. This change should be rejected.

b. Coal Cost Update

Q. WHAT DID PACIFICORP REPRESENT THE IMPACT OF ITS COAL SUPPLY UPDATE TO BE?

A. PacifiCorp represented that the impact of its coal supply update was a $1,281,503 reduction to PacifiCorp's forecast NPC on a total-Company basis.[15]

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11 PAC/401, Mitchell/1.
12 PAC/400, Mitchell/11:5-6.
13 Docket No. UE 245, Order No. 12-409 at 9 (Oct. 29, 2012).
14 Docket No. UE 191, Order No. 07-446 at 10-11 (Oct. 17, 2007).
15 PAC/401, Mitchell/1.

Q. DID THAT CALCULATION ACCURATELY PORTRAY THE IMPACTS OF THE COAL SUPPLY UPDATE?

A. No. Based on my AURORA model runs, the coal supply update increased PacifiCorp's forecast NPC by $110,944,033. Based on the discussion in Rebuttal Testimony, it was impossible to know that the coal cost update had such a significant impact since PacifiCorp did not report the true impact of the update.

Q. HOW WAS THE COST OF THE COAL SUPPLY UPDATE MISREPRESENTED?

A. When calculating the impact, PacifiCorp compared back to a scenario that included different coal costs than those included in its initial filing. Coal costs are input into the AURORA model in the Resources Table, with different values depending on the year. I compared the values included in the initial filing to the comparison scenario that PacifiCorp used to calculate its alleged impact of the coal supply update. The values for almost every single coal unit were not the same. Thus, by comparing back to different coal costs than those included in the initial filing, the update impacts that PacifiCorp identified in Rebuttal Testimony were fictional. When I input the initial filing coal costs and rerun the comparison, I calculate a completely different result.

Q. GIVEN THIS MATERIAL VARIANCE, WHAT DO YOU RECOMMEND?

A. Since PacifiCorp did not accurately portray or document the coal supply update, I recommend that the coal supply costs be calculated consistent with PacifiCorp's initial filing. If, as PacifiCorp represents, the coal supply update reduces the NPC forecast, PacifiCorp should have no objection to this change.

c. Base Period Update

Q. DID PACIFICORP UPDATE THE HISTORICAL BASE PERIOD INCLUDED IN THE TAM UPDATE?

A. Yes. In its initial filing, PacifiCorp used a historical base period corresponding to the 48-months ending June 30, 2022. In its update filing, PacifiCorp updated the base period to the 48-months ending on December 31, 2022. For example, PacifiCorp updated the calculation of market caps to be based on the 12-months ending December 31, 2022 and the DA/RT price adders to be based on the 48-months ending December 31, 2022. In past proceedings, PacifiCorp has not updated the base period in its Rebuttal Update or its Final Update. Such a change is not permitted by the TAM guidelines.

Q. DID PACIFICORP MENTION THIS CHANGE IN ITS REBUTTAL TESTIMONY?

A. No. This change is concerning because PacifiCorp did not mention it nor document the impact in Rebuttal Testimony. This undocumented change may be one of the drivers of the largely unexplained $108,807,111 System Balancing Adjustment included in the July Update.[16] In any case, such a change is not permitted in Rebuttal Testimony, and therefore, should be rejected by the Commission.

Q. HAS AWEC RECOMMENDED THAT THE HISTORICAL BASE PERIOD BE UPDATED IN THE PAST?

A. Yes. Just last year, in Docket No. UE 399, I recommended modifying the TAM guidelines such that the base period would be based on the calendar year immediately prior to the TAM filing.[17]

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16 PAC/401, Mitchell/1

17 Docket No. UE 399, AWEC/100, Mullins/33:15-21.

Q. DID PACIFICORP AGREE WITH THAT RECOMMENDATION?

A. No. PacifiCorp disagreed with my recommendation, stating that updating the base period to the calendar year immediately prior to the filing "would delay the TAM's initial filing to July 1st."[18]

Q. HOW WAS THE PROPOSED CHANGE TO THE TAM GUIDELINES RESOLVED?

A. In Docket No. UE 399, the Commission approved a Third Partial Stipulation, in which parties agreed to continue using a base period corresponding to June 30 of the year prior to the TAM filing, not the calendar year immediately prior to the TAM filing. Paragraph 20 of the Third Partial Stipulation stated "[t]he Stipulating Parties agree to withdraw all recommendations on changes to PacifiCorp's TAM (and TAM Guidelines)."[19] This withdrawal included AWEC's recommendation to use a base period corresponding to the calendar year prior to the TAM filing.

Q. HOW HAS THE COMMISSION EVALUATED CHANGES TO THE TAM GUIDELINES?

A. As noted in Order 20-473 in Docket No. UE 374, the Commission has been hesitant to make changes to the TAM guidelines absent consensus among the parties:

> We also decline to adopt any changes to the TAM Guidelines, as requested by PacifiCorp and the parties. The TAM Guidelines are a set of rules that largely govern the company and parties' behind-the-scenes deadlines and filings. We hesitate to make changes to the guidelines absent consensus.[20]

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18 Docket No. UE 399, PAC/1500, Wilding/30:12-23.
19 Docket No. UE 399, Third Partial Stipulation ¶ 20.
20 Docket No. UE 374, Order 20-473 at 130.

Q. WOULD YOU SUPPORT A CHANGE TO THE TAM GUIDELINES IN THIS CASE?

A. No. The current framework requires PacifiCorp to use a base period composed of the 48-months ending in June on the year prior to the TAM filing. While AWEC would support making a change to the TAM guidelines to be based on the calendar year prior to the TAM filing, that change would need to occur in the context of a general rate case. Further, such a change would inherently need to be considered in PacifiCorp's initial TAM filing to provide parties adequate opportunity to review.

Q. WAS PACIFICORP REQUIRED TO HOLD COLLABORATIVE DISCUSSIONS WITH THE PARTIES DISCUSSING CHANGES TO THE TAM GUIDELINES?

A. Yes. Pursuant to Paragraph 20 of the Third Partial Stipulation in Docket No. UE 399, PacifiCorp agreed to "hold collaborative discussions and provide recommendations or report back to the Commission on the following issues associated with PacifiCorp's power costs by December 31, 2023." To date, however, no such collaborative discussions have occurred. Instead, PacifiCorp chose to unilaterally deviate from the TAM guidelines with no explanation.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE BASE PERIOD UPDATE?

A. Since PacifiCorp did not specify that it had updated the base period, and due to the fact that updating the base period is not consistent with the TAM guidelines, I recommend the base period update be rejected. I recommend that the base period data used in PacifiCorp's initial filing be retained in the final NPC update filed in November.

Q. HAVE YOU MODELED THE IMPACT OF THIS CHANGE?

A. No. Given the multitude of inputs implicated by the change, I was unable to revert to the original filing base period in my AURORA model runs. Notwithstanding, I recommend the Commission direct PacifiCorp to do so in its final update.

IV. MODELING DISCUSSION

a. Market Caps

Q. WHAT WAS YOUR RECOMMENDATION RELATED TO MARKET CAPS?

A. I recommended the Commission-approved method be used, including the 75th percentile approach and the removal of market caps from liquid market hubs.

Q. HOW DID PACIFICORP RESPOND?

A. Witness Mitchell discusses his continued opposition to using the Commission-approved 75th percentile approach. For example, Witness Mitchell makes statements such as "Aurora would therefore allow unlimited off-system sales at every market at any time of the day or night—an assumption that is very different from PacifiCorp's actual, historical experience."[21]

Q. IS WITNESS MITCHELL CORRECT THAT AURORA WILL MAKE UNLIMITED SALES IN THE ABSENCE OF MARKET CAPS?

A. No. Witness Mitchell's statement about AURORA making unlimited sales is not correct. Witness Mitchell may not recognize that the ability of AURORA to make sales at any particular market hub is limited by transmission constraints in the model. Based on these constraints, AURORA can only transact up to the amount of transmission assumed to a particular market hub. These transmission constraints are consistent with the real-world transmission constraints that PacifiCorp otherwise faces in actual operations. The market cap limit on these liquid markets would reduce the capability to sell at such markets below the transmission limitation, which may not be consistent with PacifiCorp's actual ability to make sales at such markets. Witness Mitchell is therefore mistaken about this fundamental aspect of

21 PAC/400, Mitchell/50:9-11.

the AURORA model, and therefore, his further views on the market capacity limitations should be given little weight.

Q. HOW DID PACIFICORP RESPOND TO YOUR RECOMMENDATION TO REMOVE THE MARKET CAP LIMITS FROM LIQUID MARKETS?

A. In my testimony, I recommended that the method approved in the 2022 TAM[22] be used in this case, including removing the market cap restriction from liquid markets. PacifiCorp did not address this issue in Reply Testimony.

Q. WHY IS IT NOT NECESSARY TO APPLY A MARKET CAP LIMITATION ON LIQUID MARKETS?

A. As PacifiCorp explained in its Opening Brief in the 2022 TAM, "[t]he Company does not apply market caps to Palo Verde (by far its largest trading hub) or Mid-C because these hubs are liquid markets."[23] PacifiCorp further explained "PacifiCorp does not apply market caps to two of its liquid trading hubs, including Palo Verde, where the Company has made almost six times as many sales compared to other hubs."[24] Further, PacifiCorp affirmatively committed that it would continue this practice of excluding liquid markets when transitioning to AURORA, stating "Aurora will need market caps to control sales at <u>non-liquid hubs</u>."[25]

The assumption of excluding market caps from liquid markets has been in place for a long time and was discussed in detail in the Direct Testimony of Gregory N. Duvall in the Wyoming 2014 GRC, at the time when PacifiCorp originally proposed removing market caps for the Mid-Columbia and Palo Verde markets. As PacifiCorp Witness Duvall stated, "sales

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22 Docket No. UE 375.
23 UE 390, PacifiCorp Opening Brief at 8.
24 *Id.* at 10-11
25 *Id.* at 11 (emphasis added).

restrictions on the Mid-Columbia and Palo Verde markets have been removed."[26] PacifiCorp presented several reasons for excluding a market cap limitation on these markets. First, the markets were liquid, with robust forward markets. PacifiCorp stated that "markets have many participants and are often used to balance the Company's load and resource position on a forward basis."[27] The level of sales at these markets is also more dependent on the level of its generation, rather than liquidity in the market. PacifiCorp Witness Duvall stated, "the Company's historical sales at the Mid-Columbia and Palo Verde markets may be more strongly aligned with the Company's resource position, rather than the position of the other counterparties in the market."[28]

Q. IS THERE ANY VALID REASON TO DEVIATE FROM THE PAST TREATMENT IN THIS DOCKET?

A. No. For the reasons PacifiCorp discussed in the 2022 TAM and the Wyoming 2014 GRC, I continue to recommend that market caps not be applied to liquid market hubs.

Q. HOW HAVE YOU MODELED LIQUID MARKETS IN YOUR FORECAST?

A. In my analysis, I model liquid markets to include the Mid-Columbia market hub, the Palo Verde market hub, *and* the Four-Corners market hub.

Q. WHY HAVE YOU INCLUDED THE FOUR-CORNERS MARKET HUB AS A LIQUID MARKET?

A. The forward and bilateral markets at Four-Corners are more robust than they were nine years ago when PacifiCorp first proposed to remove liquid markets from the market cap calculation. Four-Corners is now traded on the liquid Intercontinental Exchange platform, with robust

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26 AWEC/102 at 2 (Wyoming PSC Docket No. 20000-446-ER-14, Direct Testimony of Gregory N. Duvall ("Duvall Direct") at 14:21-22).
27 AWEC/102 at 6 (Duvall Direct at 19:15-16).
28 AWEC/102 at 6 (Duvall Direct at 19:17-20).

forward market pricing.[29] Further, PacifiCorp no longer has firm transmission access to the Palo Verde market following the retirement of Cholla Unit 4, and accordingly, is increasingly relying on the Four-Corners market to make sales in the Desert Southwest. In 2022, for example, PacifiCorp made [redacted] MWh of short-term sales at the Four-Corners market, which was [redacted]. In comparison, short-term sales at the Mid-Columbia market in 2022 were [redacted] MWh and short-term sales at the Palo Verde market were [redacted] MWh. The relative level of short-term sales transactions indicates that the market liquidity at the Four-Corners market hub must be at least comparable to, if not greater than, the other two market hubs. In **Confidential Table 2,** below, I detail the actual sales at each market hub in 2022, along with a comparison to the corresponding sales levels modeled by AURORA.

29 *See, e.g.,* Intercontinental Exchange, Four Corners 345 Physical Peak (bilateral) Product Specification. Available at https://www.ice.com/products/1067/Four-Corners-345-Physical-Peak-bilateral.

Confidential Table 2

2022 Sales by Market MWh and Comparison to PacifiCorp Market Cap Modeling

[redacted]

As can be seen, Four-Corners is the most liquid market in the historical data, yet in PacifiCorp's market cap modeling, only a fraction of the sales relative to the 2022 levels are being made. This is a clear indication that Four-Corners needs to be treated consistent with the Mid-Columbia and Palo Verde hubs.

Q. HOW DID THE REMOVAL OF SALES RESTRICTIONS ON THESE LIQUID MARKET HUBS IMPACT YOUR FORECAST?

A. Relative to PacifiCorp's forecast, removal of sales restrictions on liquid market hubs produced a $20,389,050 reduction to my forecast, with approximately $5,851,944 allocated to Oregon.

Q. IS IT APPROPRIATE TO USE AN AVERAGE OF AVERAGES TO CALCULATE MARKET DEPTH?

A. No. By definition, using an average to set a maximum level of sales will result in a level of sales that is less than the historical average. An average of a diverse set of data is always less than the maximum. This phenomenon is clearly demonstrated in **Confidential Table 2**, above, where using the average to model a maximum resulted in sales far below historical levels. This is a major problem with PacifiCorp's use of an average of averages level for market caps. Another problem has to do with the use of a small sample size. PacifiCorp's method relies on monthly values over the four-year period. For any particular period, it results in only four values being considered in the summary statistic. A sample size of four data points, however, is not sufficient to form any statistical conclusions about market depth.

Q. HOW HAVE YOU ADDRESSED MARKET CAPS FOR NON-LIQUID MARKETS IN YOUR FORECAST?

A. While there are likely more refined approaches to address these issues, I recommend that the Commission-approved method be used based on the modal 75th percentile approach of the four average values for each monthly diurnal period in the 48-month period, subject to further review in the next TAM. PacifiCorp has not established that the current method is inadequate, particularly in the context of the AURORA model which is not optimizing sales the same as GRID was.

Q. WHAT IS THE IMPACT OF THE COMMISSION-APPROVED MODAL 75TH PERCENTILE METHOD?

A. Modifying the calculation to be based on the 75th percentile method results in an *increase* of $5,310,124 to my forecast of total-Company NPC, with $1,524,080 allocated to Oregon. Note that this increase is a further indication that the AURORA model optimization is producing unintended results. Increasing market capacity would not otherwise be expected to increase NPC. Based on my recommendation to use the Commission-approved method, however, I continue to support this change.

Q. DOES YOUR METHOD PRODUCE A MORE ACCURATE LEVEL OF WHOLESALES SALES?

A. Yes. In **Confidential Figure 4**, below, I provide a comparison between the sales modeled by the AURORA model, under both my approach and the Company's, and the level of actual wholesale sales made over the five-year period 2018 through 2022.

Confidential Figure 4
<u>Market Cap Methods vs. Historical Sales Volumes</u>
<u>GWh</u>

[redacted]

As can be seen, the Commission-approved method is clearly more in line with the historical data. While there are a few ways to compare the modeled output of AURORA to historical sales volumes, any valid way the analysis is performed shows that PacifiCorp's market cap method is materially understating sales volumes relative to historical actuals. The left chart in **Confidential Figure 4** is, in my opinion, the more accurate way to perform the comparison. It compares the level of sales generated directly in the AURORA model to the level of sales included in PacifiCorp's actual NPC report. As can be seen, PacifiCorp's market cap method results in AURORA producing just [redacted] MWh of wholesale sales transactions compared to an average of approximately [redacted] MWh in the historical period. That is a variance of -70%. In contrast, the method that I used resulted in AURORA modeled sales of [redacted] MWh, which is still below the average.

Q. WHY HAVE YOU ALSO PERFORMED A COMPARISON INCLUDING BOOKOUT TRANSACTIONS?

A. In actual NPC, there are a large number of transaction volumes that are "booked-out" and are not reported in sales volumes in the actual NPC report. The accounting for these bookout transactions is complicated, but generally, they occur when a simultaneous sale and purchase transaction occur at the same market hub. Utilities enter into large volumes of bookout transactions at market hubs, which are reported separately on FERC Form 1. The FERC Rules surrounding bookouts may be found in 18 CFR 35 and I have included a citation to a Federal Register notice that describes the FERC-approved treatment.[30]

AURORA, on the other hand, does not model bookout transactions. In PacifiCorp's DA/RT method, however, it included offsetting sales and purchases as a spreadsheet adjustment, which I discussed above. While bookouts and the DA/RT volumes are not necessarily precisely the same, I prepared a second chart in **Confidential Figure 4** that compares the actual historical sales levels with all offsetting transactions, including both bookouts and the offsetting DA/RT volumes. If offsetting transactions are to be considered in the analysis, they need to be considered on both sides of the comparison. Due to the nature of

[30] Filing Requirements for Electric Utility Service Agreements; Electricity Market Transparency; Revisions to Electric Quarterly Report Filing Process; Electric Quarterly Reports, 81 Fed. Reg. 69731 (Oct. 7, 2017).

the DA/RT adjustment, I view that analysis to be a less accurate representation of sales transactions. If the DA/RT volumes are leading to an excessive level of sales, for example, that means that the DA/RT volumes are being overstated, not that the AURORA model is producing inaccurate sales levels. Notwithstanding, even considering the offsetting DA/RT volumes, the analysis still shows that PacifiCorp sales are materially understated relative to the historical average. As noted, I did not include any DA/RT volumes in my study, so my results are well below the historical average if bookouts are considered in the historical data.

In other words, however the comparison is performed, it shows that PacifiCorp's market cap method, as applied in the AURORA model, is overly restrictive, resulting in sales levels that are too low relative to historical levels. In contrast, my method produces results that are in line with the historical data.

Q. DID PACIFICORP WITNESS MITCHELL ACCURATELY COMPARE THE AURORA OUTPUT TO HISTORICAL SALES LEVELS IN HIS CONFIDENTIAL TABLE 5?

A. No. Witness Mitchell presents a false comparison by mixing up the DA/RT volumes and bookout transactions.[31] His analysis excludes bookout transaction volumes from the historical data, but includes the offsetting DA/RT volumes added in the spreadsheet when comparing back to AURORA. As noted above, this leads to an apples-to-oranges comparison, and therefore, has zero merit.

[31] PAC/400, Mitchell/55.

b. Day-Ahead / Real-Time Method

Q. WHAT WAS YOUR RECOMMENDATION RELATED TO THE DA/RT METHOD?

A. I recommended simplifying the DA/RT method by using the historically calculated DA/RT impacts as a spreadsheet adjustment to NPC. This "just use the historical average" approach does away with all the modeling convolutions and inconsistent modeling constraints PacifiCorp has implemented in AURORA while still capturing 100% of the DA/RT adjustment.

Q. HOW DID PACIFICORP RESPOND?

A. PacifiCorp Witness Mitchell resorts to mischaracterizing my testimony in prior cases.[32]

Q. TO CLARIFY, WHAT IS THE DA/RT METHOD AND HOW DOES IT FUNCTION?

A. To clarify, in the initial filing, the DA/RT method had two aspects: 1) an adjustment to hourly market prices input into the GRID model, and 2) a spreadsheet adjustment made outside of the GRID model after the simulation is performed.

Q. PLEASE DESCRIBE IS THE FIRST ADJUSTMENT MADE TO HOURLY MARKET PRICES IN AURORA.

A. First, PacifiCorp modeled a price spread between hourly sales and purchase prices in the GRID model. This made the cost of purchases more expensive and reduced the revenues from wholesale sales. The intention of this change was to produce modeled results that aligned with historical transaction patterns, in which PacifiCorp purchased more in high priced hours and sold more in low priced hours. This first step is sometimes referred to as the "price adjustment" of the modeling method.

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32 PAC/400, Mitchell/45:19-46:26.

Q. WHAT WAS THE SECOND SPREADSHEET ADJUSTMENT?

A. In GRID, after incorporating price spreads, the modeled transaction still produced results that were more optimal than the historical transaction pattern. Accordingly, PacifiCorp applied a second adjustment outside of the GRID model that tied the overall model impact to the historical impact of the DA/RT adjustment, as calculated over a four-year period. As PacifiCorp has explained, the purpose of this second adjustment was to ensure that "the overall cost of the Company's day-ahead and real-time balancing transactions relative to the forecasted monthly market prices [was] equal to the historical average."[33] PacifiCorp has continued to apply this second step with respect to AURORA. Effectively, this second step served as a plug, which tied the modeled DA/RT impacts back to the historical DA/RT impact levels. As I noted in Opening Testimony, with this second step, the first step became perfunctory, except to the extent that it modified the way thermal plants were dispatched. PacifiCorp Witness Mitchell does not appear to recognize the perfunctory nature of this part of the DA/RT method.[34] In this second step, PacifiCorp also added additional sales and purchase volumes into NPC, although the net impact of these volumes on NPC was zero; they were directly offsetting and produce no impact. Note that these volumes are also perfunctory because they do not have any impact on NPC; they are equal and offsetting and like bookouts, are not necessary to be considered in deriving the NPC forecast. Again, PacifiCorp Witness Mitchell does not appear to recognize the perfunctory nature of this aspect of the adjustment either.[35]

33 Docket No. UE 296, PAC/100, Dickman/30:1-3.
34 PAC/400, Mitchell/45.
35 PAC/400, Mitchell/45:19-46:2.

In a way, this second part of the DA/RT method is somewhat arbitrary because it loosely connects the part of the adjustment tying back to the historical DA/RT impacts to incremental offsetting volumes. PacifiCorp refers to this second, spreadsheet adjustment as the "volume adjustment," although that is a misnomer because, insofar as the cost impacts are concerned, it relates more to tying the DA/RT price adjustment results back to the historical DA/RT price impacts, not the perfunctory volumes. Accordingly, for purposes of this testimony and elsewhere, I refer to the spreadsheet adjustment as the "historical adjustment."

Q. DID PACIFICORP MAKE WHOLESALE CHANGES TO THE WAY IT PERFORMED THE DA/RT METHOD IN ITS REBUTTAL TESTIMONY?

A. Yes. In its July Update, PacifiCorp added an entirely new modeling adjustment to the DA/RT method. After applying the price adjustment and after applying the historical adjustment, PacifiCorp made an entirely new, third DA/RT adjustment. This adjustment was another spreadsheet adjustment performed outside of the AURORA model which, in PacifiCorp's modeling, resulted in an additional DA/RT cost of $60,740,729 on a total-Company basis.[36] When I evaluated it in my forecast, the impact of that adjustment was even larger, equating to $80,037,888 on a total-Company basis, which was due to the interrelated impacts of other modeling adjustments I have proposed. To put the magnitude of this change into context, the total NPC impact of the DA/RT adjustment, prior to this third adjustment, was $56,888,016. Thus, this unexplained third adjustment introduced in Rebuttal Testimony more than doubles the overall impact of the DA/RT adjustment.

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36 PAC/401, Mitchell/1

Q. DID PACIFICORP EXPLAIN WHY IT ADDED THE THIRD DA/RT ADJUSTMENT?

A. Only vaguely. For example, Witness Mitchell states "on further investigation [...] the Company discovered that the volume component of the DA/RT adjustment was not functioning as the Commission intended when the adjustment was approved."[37] PacifiCorp reached this newfound discovery based on the realization that the historical adjustment "was substantially *decreasing* NPC,"[38] as opposed to increasing it. In the July Update, the historical adjustment reduced NPC by $[redacted]. In other words, PacifiCorp did not like that the historical adjustment was now reducing NPC and decided to make an ad hoc modeling change in the spreadsheet where it added back $60,740,729, thereby eliminating the historical adjustment, albeit in a roundabout and opaque way.

Q. DID PACIFICORP PROVIDE ANY OTHER JUSTIFICATION FOR THIS NEW MODELING CHANGE?

A. When explaining why a change to the DA/RT method is necessary, Witness Mitchell states "the revenues from the sales volume was allowed to be greater than the costs from the purchase volumes producing artificial arbitrage within the NPC forecast."[39] He also states, "the DA/RT volume component bought a certain volume of energy at a low price and then sold the same volume of energy at a high price in the same time period."[40] These statements, however, are entirely fictional. The volumes added in the DA/RT adjustment are added in by the Company, not due to some sort of optimization in the DA/RT adjustment. They are set at equal and offsetting levels. There is no buying at low prices and selling at high prices assumed in these

37 PAC/400, Mitchell/47:8-10.
38 PAC/400, Mitchell/47:11.
39 PAC/400, Mitchell/48:13-15.
40 PAC/400, Mitchell/48:15-17.

volumes applied in the historical adjustment. Other than the impact of tying the DA/RT price impacts back to the historical values, the perfunctory offsetting volumes and their associated revenues are equal and offsetting, and therefore it is unclear how Witness Mitchell is concluding that this part of the historical adjustment is somehow engaging in arbitrage trading.

Q. IS PACIFICORP'S CHANGE CONSISTENT WITH THE COMMISSION-APPROVED DA/RT METHOD?

A. No. At the end of his analysis, Witness Mitchell makes a particularly concerning statement. He states that this new proposal "to remove artificial arbitrage opportunity is identical to the adjustment calculated in the DA/RT price component since its inception in the 2016 TAM."[41] This is factually inaccurate. There has never been any a discussion of arbitrage revenues included in the historical adjustment in the DA/RT adjustment. In summary, I urge the Commission to reject this unprecedented and unsupported modeling change PacifiCorp submitted in Rebuttal Testimony, both because it is unsupported by the facts and because it violates the TAM Guidelines as a modeling change introduced on Rebuttal, as discussed earlier in my testimony.

Q. TURNING TO YOUR PRIMARY RECOMMENDATION, DO YOU CONTINUE TO SUPPORT SIMPLIFYING THE DA/RT?

A. Yes. Applying the DA/RT method based solely on the historical averages will greatly simplify the modeling while capturing 100% of the DA/RT impacts. Other than mischaracterizing my testimony, and its own adjustment, PacifiCorp provides no substantive rebuttal as to why it is not reasonable to just use the historical average.

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41 PAC/400, Mitchell/49:8-12.

Q. OTHER THAN SIMPLICITY, WHY IS IT MORE REASONABLE TO USE THE HISTORICAL AVERAGE?

A. Applying the price adjustment in AURORA is leading to skewed dispatch results. The AURORA model is producing levels of short-term purchase transactions that are inconsistent with historical levels. In other words, AURORA is purchasing more and selling less. In **Confidential Figure 5**, below, I provide a comparison of actual net short-term purchases over the period 2018 through 2022 to the levels forecast in PacifiCorp's AURORA modeling.

Confidential Figure 5
Comparison of Aurora and Historical Net Short Term Purchases

[redacted]

While the levels of net short-term purchases vary year-to-year both in terms of volumes and cost, it is apparent that the AURORA model is modeling excessive levels of net short-term purchases both in terms of dollars and volumes. From this, it can be ascertained that the AURORA model is not optimizing short-term sales and purchase transactions at the same level as GRID and in a manner that is less efficient than experienced historically. This historical disconnect is further shown in **Figure 3** in the Background section above. This is an indication that the DA/RT method, as PacifiCorp has implemented it, is not necessary for the AURORA model.

Q. HOW DOES THE DA/RT ADJUSTMENT IMPACT AURORA?

A. It can be observed that the implied DA/RT price adjustment in AURORA is significantly higher than the historical DA/RT adjustment. In **Confidential Figure 6**, below, I compare the historical DA/RT impacts (i.e., the difference between the effective rate for sales and purchases and monthly market prices) to the modeled DA/RT impacts in AURORA, inclusive of the DA/RT method price adjustments, but excluding the second step where the costs are tied to the historical averages.

Confidential Figure 6
Historical DA/RT Impact vs. Initial Filing AURORA
$Millions

[redacted]

In PacifiCorp's AURORA model, the DA/RT price adjustment produced an effective DA/RT adjustment value of $[redacted]. This does not consider the $[redacted] DA/RT method modeling change presented in the July Update, which increases the cost to $[redacted]. This compares to a historical value of $[redacted] over the 48 months ending December 31, 2022. Thus, the impact of the DA/RT adjustment as applied to the market prices in AURORA results in PacifiCorp materially overstating its cost relative to the historical average.

Q. WHAT IS THE DA/RT IMPACT IF THE PRICE ADJUSTMENT IS REMOVED COMPLETELY?

A. In my modeling, if the DA/RT price adjustment is removed completely, the AURORA model produced an implicit DA/RT adjustment of $29,193,395, which is more in line with the historical data. This means that the AURORA model is already capturing the impact of buying more during high priced hours and selling more during low priced hours and that a DA/RT adjustment in AURORA is largely unnecessary. In contrast, continuing to use the price adjustment in AURORA is producing a skewed dispatch and inaccurate results.

Q. HOW HAVE YOU MODELED THE DA/RT ADJUSTMENT IN YOUR FORECAST?

A. Considering that the price adjustments PacifiCorp included in AURORA were producing impacts that were materially greater than the historical averages, I removed the in-model price adjustments from my forecast. Notwithstanding, in order to recognize the slight variance between the historical DA/RT impacts and the implicit modeled DA/RT impacts, I still retained the historical adjustment in the NPC spreadsheet to tie the modeled impacts back to the $[redacted] historical average. By doing the modeling this way, I avoided all the inconsistent results discussed above, while still capturing the full impact of the DA/RT adjustment. I also avoided any of the modeling convolutions which might be attributed to the "artificial arbitrage revenues" that PacifiCorp modified in the July Update. Finally, since the out-of-model volumes included in the NPC report were perfunctory, and had no impact on NPC, I also removed those from my modeling. Note that the historical DA/RT impacts was one of the things PacifiCorp updated when it changed the base period to calendar year 2022. My calculation was based on the July Update. Accordingly, reverting to the initially filed base period will impact the historical adjustment in my proposed method.

Q. HOW DID YOUR MODELING APPROACH IMPACT NPC?

A. While the end result of the modeling on the DA/RT adjustment tied back to the historical average, it resulted in more accurate thermal plant dispatch, which reduced NPC. As noted in **Table 1** of my introduction, this subtle change lowered the NPC forecast by $24,536,188, with $7,042,231 allocated to Oregon. Note that these impacts do not consider the impact of removing the new spreadsheet adjustment PacifiCorp included in its July Update, which I also removed and stated separately in **Table 1**. That adjustment amounts to a reduction to forecast NPC of $80,037,888 on a total-Company basis and $22,971,999 on an Oregon-allocated basis.

c. <u>Ozone Transport Rules</u>

Q. HOW DID PACIFICORP RESPOND TO YOUR RECOMMENDATION TO REMOVE THE OZONE TRANSPORT RULE MODELING?

A. While PacifiCorp acknowledged that the Ozone Transport Rules will not apply to Wyoming, it continued to insist on including limitations on both Utah and Wyoming coal plants.

Q. HOW DID PACIFICORP MODEL THE RULE?

A. It modeled the Ozone Transport Rule as an annual limit on the amount of nitrogen oxide emissions from gas and coal facilities in both Utah and Wyoming, although the rule only applies to the months of May through September.

Q. DOES THE RULE CONTINUE TO RESULT IN MATERIAL COSTS?

A. Yes. While PacifiCorp has changed the way it modeled the rule, it is still resulting in material costs. Since it is known that the Ozone Transport Rules will not apply to Wyoming and the application to Utah is still uncertain, I continue to recommend the modeling of the Ozone Transport Rule be removed from NPC. This change reduces my forecast of NPC by $24,536,188, or $7,042,231 on an Oregon-allocated basis.

d. Washington CCA

Q. DID PACIFICORP RESPOND TO YOUR RECOMMENDATION TO REMOVE WASHINGTON CCA ALLOWANCES FROM THE TAM?

A. No. While Witness Shahumyan discusses the CCA in Reply Testimony, that testimony does not address AWEC's recommendations to remove the CCA costs from NPC nor does it explain why it is reasonable for CCA allowance costs to be considered in Oregon customers' rates.[42]

Q. IS THERE NOW BETTER INFORMATION ABOUT HOW MUCH CCA ALLOWANCES WILL COST?

A. Yes. So far, two CCA allowance auctions have taken place. The first auction occurred on February 28, 2023, and resulted in an allowance price of $48.50/MTCO2.[43] Total revenues generated from the first auction was $299,983,267. The second auction occurred on May 31, 2023, and resulted in an allowance price of $56.01/MTCO2. Total revenues generated from the second auction were $557,089,850.[44] Based on these results, Washington is on track to

42 PAC/600.

43 Ecology, Washington Cap-and-Invest Program Auction #1 February 2023 Public Proceeds Report (Mar. 7, 2023). Available at https://apps.ecology.wa.gov/publications/documents/2302022.pdf.

44 Ecology, Washington Cap-and-Invest Program Auction #2 May 2023 Public Proceeds Report (Jun. 28, 2023). Available at https://apps.ecology.wa.gov/publications/documents/2302058.pdf.

generate proceeds of approximately $1,971,252,817 in the first year of the CCA's operation.[45] The next auction will occur on August 31, 2023.

Q. HOW MUCH CCA COST DID PACIFICORP INCLUDE IN ITS JULY UPDATE?

A. In AURORA, PacifiCorp has modeled a requirement to purchase CCA allowances as an addition to the fuel cost for the Chehalis gas-fired generating facility. Relative to my forecast, the impact of this assumption was a $72,706,490 increase to NPC on a total-Company basis, with approximately $20,867,785 of the increase allocated to Oregon customers. This impact includes both the cost of allowances, as well as the cost associated with a less efficient generation profile from the Chehalis power plant. On a total-Company basis, the cost of allowances contributed to $65,278,427 of the forecast cost, while the cost of uneconomic dispatch contributed to $7,428,063. Interestingly, in the model, the addition of the CCA costs for Chehalis resulted in increases to the dispatch of other gas plants, and thus, not introducing carbon savings for Oregon customers.

Q. HOW IS PACIFICORP REQUIRED TO ACCOUNT FOR CCA ALLOWANCES?

A. Environmental allowances are treated as an inventoriable item in FERC Account 158.1 - Allowance Inventory and expensed to FERC Account 509 - Allowances.[46] Environmental allowances have been expensed to FERC Account 509 since 1993,[47] although the account language formerly referenced sulfur dioxide allowances and was recently modified to be more

45 Based on an assumption that the third and fourth quarter auctions generate the same level of revenues as the second quarter auction. Calculated as $299,983,267 + 3 × $557,089,850.

46 18 CFR 101.

47 *See* FERC Order 52, 62 FERC ¶ 61,299 (1993).

generic, removing the reference to sulfur dioxide and adding new sub accounts related to renewable energy certificates, which are also recorded to FERC Account 509.[48]

Q. DID PACIFICORP FOLLOW THE APPROVED FERC ACCOUNTING IN ITS JULY UPDATE?

A. No. PacifiCorp included the cost of CCA allowances as a cost of fuel for Chehalis in FERC Account 447- Fuel. This accounting resulted in the inclusion of the CCA allowances in the TAM. This accounting, however, is not in compliance with FERC requirements since CCA allowances must be expensed to FERC Account 509 - Allowances, not to FERC Account 447 - Fuel.

Q. IS FERC ACCOUNT 509 – ALLOWANCES A PART OF NPC OR THE TAM?

A. No. PacifiCorp has not proposed any modification to the TAM to include FERC Account 509 in NPC. Therefore, accounting for the CCA allowances as a fuel cost and in the TAM was improper accounting.

Q. WHAT IS THE VALUE OF THE FREE ALLOWANCES PROVIDED TO WASHINGTON?

A. PacifiCorp Witness Shahumyan discussed the no-cost allowances PacifiCorp has been awarded to date.[49] The volume no-cost allowances were detailed in Exhibit AWEC/103 in AWEC Data Requests 38 through 42.[50] As can be seen, the Company is expected to receive 7,699,149 no-cost allowances over the period 2023-2026 for the benefit of Washington customers. Based on the most recent auction price, that volume of free allowances amounts to a $431,229,335

48 *See* 180 FERC ¶ 61,050 (2022).
49 PAC/600, Shahumyan/5
50 AWEC/103, Mullins/1-5.

benefit provided to only PacifiCorp's Washington customers, which is not equally provided to Oregon customers.

Q. DO YOU CONTINUE TO RECOMMEND REMOVING CCA ALLOWANCES FROM THE NPC FORECAST?

A. Yes. The allowances are not an NPC item and it is not reasonable to include them in Oregon rates.

e. <u>APS Short-Term Firm Transmission</u>

Q. WHAT DID YOU RECOMMEND FOR APS SHORT-TERM FIRM TRANSMISSION IN YOUR OPENING TESTIMONY?

A. I recommended that both the costs and benefits of APS short-term firm transmission be removed from the AURORA model. I proposed this change not due to an expectation that PacifiCorp will not purchase short-term firm transmission to the Palo Verde market. Rather, I made this change based on the premise that PacifiCorp will only use short-term firm transmission to access the Palo Verde market when it is economically beneficial to do so. Because the cost of the short-term firm transmission purchases exceeded the benefits of the short-term firm transmission in AURORA, I recommended a modeling assumption removing both the costs and the benefits. I viewed this as a reasonable modeling assumption because when PacifiCorp uses APS short-term firm transmission in actual practice, it will reduce power costs, whereas my modeling sets the net benefits of that transmission to zero.

Q. HOW DID PACIFICORP RESPOND TO YOUR INITIAL RECOMMENDATION?

A. PacifiCorp attributed the variance between costs and benefits of the APS transmission as the result of sub-optimal dispatch calculated by the AURORA model. PacifiCorp stated that this sub-optimal dispatch should be disregarded because "small NPC impacts are simply noise in the multi-billion-dollar NPC forecast and this forecast and this noise results from that within-threshold-optimality."[51]

Q. IS IT REASONABLE TO EXCLUDE THE BENEFITS OF APS SHORT-TERM FIRM TRANSMISSION AS NOISE?

A. No. Attributing the variance between the costs and benefits of the APS short-term firm transmission in AURORA to noise confutes any argument PacifiCorp may have about those rights. If PacifiCorp views the difference as noise, and not meaningful, then it would be appropriate to accept my proposed adjustment.

Q. DID YOU STATE THAT PACIFICORP WILL NOT PURCHASE SHORT-TERM FIRM TRANSMISSION TO PALO VERDE IN THE RATE PERIOD?

A. No. PacifiCorp Witness Mitchell mischaracterizes my testimony in this regard by making inaccurate statements such as "AWEC argues that since the closure of the Cholla plant and the expiration of the Public Service Company of Colorado (PSCo) exchange agreement, the Company is unlikely to acquire short-term firm transmission enabling access to Palo Verde in 2024."[52] To be clear, I fully expect PacifiCorp to purchase short-term firm transmission to Palo Verde in the Test Period when it is economic to do so. Palo Verde is one of the most liquid markets in the West; therefore, accessing that market provides great value to ratepayers. Notwithstanding, it is the expectation that accessing the market will provide a net benefit to ratepayers, not a net cost as modeled in AURORA.

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51 PAC/400, Mitchell/115:17-19.

52 PAC/400, Mitchell/111:7-10.

Q. WHY DID YOU REMOVE BOTH THE COSTS AND BENEFITS OF THE TRANSMISSION?

A. Since the AURORA model resulted in a net cost to ratepayers from the access to Palo Verde, it was clear that the model was not adequately valuing the short-term firm transmission in its dispatch. Accordingly, I performed an out of model adjustment to correct this.

Q. HAVE YOU FURTHER REVIEWED THE CAUSE OF THIS MODELING ANOMALY?

A. Yes. Based on the modeling I have performed, including changes to the DA/RT and market caps, however, the model does not produce the same results with respect to the APS transmission. In my modeling, the APS transmission produces a slight net benefit of approximately $2 million. I therefore attribute the modeling anomaly to the overly restrictive modeling assumptions imposed by the DA/RT price adders and market caps. Accordingly, subject to my recommendations above, I am no longer recommending a change to remove the costs and benefits of APS short-term transmission to Palo Verde.

f. AURORA Model Environment

Q. PLEASE EXPLAIN THE DIFFERENCE RELATED TO THE AURORA MODELING ENVIRONMENT?

A. In Opening Testimony, I noted differences between my AURORA model results and PacifiCorp's. I had attributed this to my use of a different AURORA model version. Accordingly, PacifiCorp updated its AURORA model version in Reply Testimony. Notwithstanding, the differences persist.

Q. WHAT DO YOU NOW BELIEVE TO BE THE CAUSE OF THIS DIFFERENCE?

A. The difference appears to be driven by architectural differences between my computer and PacifiCorp's. Depending on the computer architecture where the model is run, it appears that

AURORA will produce slightly different results. Different hardware utilizes different levels of precision and rounding points. Different randomization techniques, which are commonly used in optimization algorithms, may also lead to different results. While these differences are small, they can add up over the course of a large simulation. When I run PacifiCorp's July Update on my computer architecture, for example, the AURORA model produces an NPC forecast that is $553,624 lower than PacifiCorp's forecast on a total-Company basis, which I have documented in **Table 1** of my Introduction.

Q. HAVE YOU INCLUDED THIS ADJUSTMENT IN YOUR OVERALL RECOMMENDATION?

A. Yes. To achieve an accurate NPC forecast based on how the AURORA model runs on my computer, I have included an adjustment to capture the overall results.

V. PRODUCTION TAX CREDIT RATE

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO THE PRODUCTION TAX CREDIT RATE.

A. In Opening Testimony, I recommended increasing the PTC rate to 30 cents per KWh. In response, PacifiCorp states that "(1) the inflation adjustment factor has only exceeded year-on-year growth of 4.0 percent or more twice in the past 30 years, and (2) the needed growth to achieve a 2024 PTC rate of 3.0 cents per kilowatt-hour is well in excess of the historic average."[53]

[53] PAC/400, Mitchell/118:1-6.

Q. DO YOU HAVE ANY CORRECTIONS TO THE IMPACT OF THIS ADJUSTMENT FROM YOUR OPENING TESTIMONY?

A. Yes. In Table 1 of my Opening Testimony, I inadvertently used the Oregon-allocated value as the total-Company value for this adjustment, resulting in a misstatement of the impact of my recommendation. The corrected impact is a $9,432,780 reduction to TAM revenues on a total-Company basis with $2,707,340 allocated to Oregon.

Q. IS THE HISTORICAL AVERAGE RELEVANT?

A. No. PacifiCorp focuses on the historical change to the PTC rate, not the actual mechanics of how the PTC rate changes from year to year. The PTC rate does not escalate based on historical levels of growth as PacifiCorp implies. As I mentioned in Opening Testimony, it escalates based on changes in the GDP implicit price deflator, as published by the Bureau of Economic Analysis. PacifiCorp presented no competing analysis to demonstrate that my analysis was incorrect.

Q. HAVE YOU UPDATED YOUR ANALYSIS TO REFLECT FURTHER INFORMATION?

A. Yes. Exhibit AWEC/203 provides an updated PTC forecast. Since filing Opening Testimony, the Bureau of Economic Analysis published its GDP implicit price deflator for the second quarter of 2023. Based on that publication, it can be determined that the PTC rate will increase to 3.0 cents per kWh in 2024 so long as inflation equals or exceeds 4.0% on an annualized basis for 2023, as measured by the GDP implicit price deflator. Given recent indications, it is likely that inflation will exceed this level for the year. For example, the annualized inflation rates, using the GDP implicit price deflator for calendar years 2021 and 2022, were 6.418% and 6.409% respectively. Recent Federal Reserve projections published on June 14, 2023, for example, forecast Core Personal Consumption Expenditures ("PCE") Inflation of 3.7% to 4.2%

in calendar year 2023, and historically Core PCE Inflation has been approximately 1.6% less than the inflation rate measured using the GDP implicit price deflator.[54] Thus, these levels of Core PCI Inflation would imply inflation measured by the GDP implicit price deflator of 5.3% to 5.8%. Further information surrounding the actual inflation rates for 2023, however, will become available as this proceeding progresses. While it is not certain to increase in 2024, I believe it is more likely than not that it will. Accordingly, I continue to recommend using a 3.0 cents per KWh rate for the PTC.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

54 Federal Reserve Open Market Committee, June 14, 2023: FOMC Projections, Summary of Economic Projections at 2. *See also* https://www.federalreserve.gov/monetarypolicy/fomcprojtabl20230614.htm (accessed Aug. 8, 2023).

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 420

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
2024 Transition Adjustment Mechanism.	)
	)

EXHIBIT AWEC/201

MULLINS PROPOSED NPC FORECAST

_2024__NPC_Report

	Total	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
							$						
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hurricane Sale	$ 2,271	$ 2,271	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Leaning Juniper Reven	$ 324,744	$ 21,949	$ 21,007	$ 21,312	$ 16,865	$ 16,681	$ 22,511	$ 50,638	$ 54,348	$ 35,959	$ 20,405	$ 18,100	$ 24,970
PSCo_Sale	$ 14,045,296	$ 1,001,710	$ 942,025	$ 1,003,664	$ 713,460	$ 746,240	$ 950,064	$ 881,326	$ 2,979,360	$ 2,821,866	$ 627,973	$ 767,568	$ 610,040
Total Long Term Firm Sal	$ 14,372,310	$ 1,025,929	$ 963,031	$ 1,024,976	$ 730,325	$ 762,921	$ 972,575	$ 931,964	$ 3,033,708	$ 2,857,825	$ 648,378	$ 785,669	$ 635,010
Short Term Firm Sales													
Borah	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
COB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Colorado	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Four Corners	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Idaho	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mead	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mid Columbia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mona	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NOB	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Palo Verde	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SP15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Utah	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Washington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
West Main	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Wyoming	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Short Term Firm Sa	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
System Balancing Sales													
COB	$ 143,864,342	$ 10,929,961	$ 8,274,549	$ 6,064,394	$ 4,129,969	$ 4,417,169	$ 9,427,036	$ 12,828,319	$ 19,320,204	$ 28,279,177	$ 11,363,133	$ 13,016,087	$ 15,814,342
Four Corners	$ 206,605,075	$ 7,898,954	$ 3,406,279	$ 8,073,889	$ 6,958,634	$ 9,696,335	$ 19,224,348	$ 26,750,886	$ 48,222,076	$ 37,212,247	$ 14,922,930	$ 15,235,958	$ 9,002,541
Mead	$ 92,474,980	$ 8,692,240	$ 6,855,151	$ 4,258,913	$ 2,374,337	$ 2,356,553	$ 6,860,290	$ 13,813,659	$ 15,201,599	$ 13,694,296	$ 5,201,119	$ 5,967,651	$ 7,199,171
Mid Columbia	$ 227,440,057	$ 26,572,031	$ 19,852,914	$ 13,581,337	$ 13,303,513	$ 11,047,746	$ 12,106,710	$ 20,700,178	$ 36,087,816	$ 25,367,258	$ 13,069,205	$ 13,391,644	$ 22,359,706
Mona	$ 25,392,559	$ 1,019,096	$ 560,836	$ 1,304,055	$ 879,785	$ 861,810	$ 1,798,603	$ 3,429,049	$ 6,067,216	$ 5,218,300	$ 976,977	$ 1,414,365	$ 1,862,468
NOB	$ 26,039,912	$ 3,185,018	$ 1,382,010	$ 1,812,125	$ 1,572,256	$ 1,061,308	$ 2,384,024	$ 2,657,469	$ 4,358,465	$ 2,808,504	$ 1,152,279	$ 1,233,819	$ 2,432,635
Palo Verde	$ 5,894,934	$ 681,787	$ 339,855	$ 246,204	$ 220,326	$ 205,842	$ 362,047	$ 454,365	$ 688,861	$ 1,385,632	$ 322,383	$ 329,230	$ 658,402
Trapped Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total System Balancing S	$ 727,711,861	$ 58,979,087	$ 40,671,596	$ 35,340,918	$ 29,438,822	$ 29,646,761	$ 52,163,058	$ 80,633,925	$ 129,946,238	$ 113,965,413	$ 47,008,026	$ 50,588,754	$ 59,329,264
Total Special Sales For Resa	$ 742,084,171	$ 60,005,016	$ 41,634,627	$ 36,365,893	$ 30,169,147	$ 30,409,682	$ 53,135,633	$ 81,565,888	$ 132,979,946	$ 116,823,238	$ 47,656,404	$ 51,374,422	$ 59,964,274

Purchased Power & Net Interchange

<u>*Long Term Firm Purchases*</u>

Appaloosa 1A Solar	$ 10,365,204	$ 562,535	$ 617,749	$ 910,879	$ 983,631	$ 1,151,786	$ 1,216,593	$ 1,065,782	$ 1,038,366	$ 979,390	$ 779,343	$ 579,150	$ 479,999
Appaloosa 1B Solar	$ 6,910,136	$ 375,023	$ 411,832	$ 607,253	$ 655,754	$ 767,857	$ 811,062	$ 710,522	$ 692,244	$ 652,927	$ 519,562	$ 386,100	$ 319,999
Castle Solar UoU	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Castle Solar IHC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cedar Springs Wind	$ 11,764,725	$ 1,348,848	$ 1,136,654	$ 1,032,244	$ 1,016,035	$ 830,825	$ 743,881	$ 742,782	$ 585,990	$ 827,498	$ 1,090,534	$ 1,068,343	$ 1,341,093
Cedar Springs Wind III	$ 8,939,587	$ 1,025,293	$ 863,560	$ 784,236	$ 772,111	$ 631,271	$ 565,347	$ 564,366	$ 445,199	$ 628,829	$ 828,668	$ 811,823	$ 1,018,881
Cedar Springs Wind IV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Combine Hills Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cove Mountain Solar	$ 3,824,831	$ 183,114	$ 199,253	$ 335,342	$ 365,062	$ 420,185	$ 451,894	$ 438,350	$ 414,770	$ 355,679	$ 286,322	$ 205,725	$ 169,135
Cove Mountain Solar II	$ 9,457,003	$ 453,001	$ 492,928	$ 829,598	$ 903,121	$ 1,039,489	$ 1,117,932	$ 1,084,426	$ 1,026,092	$ 879,908	$ 708,326	$ 506,098	$ 416,084
Deseret Purchase	$ 27,312,976	$ 3,228,408	$ 3,115,246	$ 2,944,088	$ 2,880,434	$ 2,774,345	$ 2,719,178	$ 3,228,408	$ 3,228,408	$ 3,194,459	$ -	$ -	$ -
Eagle Mountain - UAMF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elektron Solar 20yr	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Elektron Solar 25yr	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gemstate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Graphite Solar	$ 6,247,480	$ 311,883	$ 365,922	$ 557,963	$ 612,332	$ 686,777	$ 704,723	$ 687,351	$ 642,989	$ 576,256	$ 480,478	$ 355,140	$ 265,665
Hermiston Purchase	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Horseshoe Solar	$ 6,115,081	$ 268,027	$ 344,622	$ 502,043	$ 568,585	$ 677,881	$ 750,557	$ 737,711	$ 699,020	$ 581,446	$ 467,167	$ 288,744	$ 229,279
Hunter Solar	$ 7,031,207	$ 369,331	$ 433,652	$ 637,866	$ 665,722	$ 759,120	$ 785,546	$ 746,797	$ 702,015	$ 654,578	$ 558,601	$ 396,190	$ 321,788
Hurricane Purchase	$ 46,925	$ 46,925	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MagCorp Buythru	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MagCorp Reserves	$ 3,264,140	$ 272,680	$ 264,660	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680	$ 272,680
Milican Solar	$ 2,898,880	$ 95,313	$ 150,647	$ 222,859	$ 280,511	$ 332,937	$ 362,395	$ 408,109	$ 360,617	$ 290,222	$ 190,032	$ 121,715	$ 83,523
Milford Solar	$ 6,937,492	$ 350,630	$ 418,195	$ 595,592	$ 662,485	$ 778,851	$ 821,177	$ 731,293	$ 704,005	$ 656,707	$ 529,625	$ 385,321	$ 303,612
Nucor	$ 7,129,800	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150	$ 594,150
Old Mill Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Monsanto Reserves	$ 20,600,000	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667	$ 1,716,667
Pavant III Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PGE Cove	$ 164,065	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672	$ 13,672
Prineville Solar	$ 1,931,376	$ 65,430	$ 103,415	$ 148,062	$ 186,364	$ 221,194	$ 240,766	$ 271,137	$ 239,584	$ 192,816	$ 126,252	$ 80,864	$ 55,491
Rocket Solar	$ 6,518,690	$ 295,778	$ 369,445	$ 537,993	$ 609,687	$ 712,494	$ 800,701	$ 820,796	$ 742,700	$ 624,428	$ 474,844	$ 290,098	$ 239,725
Sigurd Solar	$ 5,900,441	$ 308,030	$ 356,200	$ 507,232	$ 553,807	$ 636,517	$ 699,580	$ 650,415	$ 596,230	$ 556,646	$ 451,695	$ 317,435	$ 266,651
Skysol Solar	$ 5,812,019	$ 277,872	$ 373,145	$ 461,040	$ 572,773	$ 517,340	$ 856,561	$ 908,497	$ 531,387	$ 416,253	$ 406,349	$ 251,550	$ 239,252
Small Purchases east	$ 56,994	$ 5,531	$ 5,198	$ 6,394	$ 4,636	$ 3,869	$ 3,916	$ 3,691	$ 4,013	$ 5,487	$ 4,428	$ 4,478	$ 5,355
Small Purchases west	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Soda Lake Geothermal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Three Buttes Wind	$ 20,638,860	$ 2,782,809	$ 1,915,027	$ 2,129,777	$ 1,611,562	$ 1,423,643	$ 1,202,365	$ 803,345	$ 946,962	$ 1,181,835	$ 1,730,465	$ 2,346,165	$ 2,564,905
Top of the World Wind	$ 37,921,726	$ 3,211,949	$ 3,004,727	$ 3,211,949	$ 3,108,338	$ 3,211,949	$ 3,108,338	$ 3,211,949	$ 3,211,949	$ 3,108,338	$ 3,211,949	$ 3,108,338	$ 3,211,949
Wolverine Creek Wind	$ 10,678,106	$ 789,484	$ 937,544	$ 1,175,634	$ 1,081,742	$ 816,828	$ 877,518	$ 695,099	$ 661,159	$ 780,865	$ 859,564	$ 999,302	$ 1,003,367
Glen Canyon	$ 337,293	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,616	$ 325,678
Rush Lake	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fremont Solar	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Green River Energy Ce	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Anticline Wind	$ 18,483	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,483
Boswell Springs Wind	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Two River Wind LLC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cedar Creek	$ 9,767,806	$ -	$ -	$ -	$ -	$ -	$ 19,440	$ 1,368,669	$ 1,082,327	$ 1,300,232	$ 2,171,667	$ 2,121,175	$ 1,704,296
OR Schedule 126 CSP	$ 4,373,271	$ 226,605	$ 216,386	$ 105,263	$ 349,994	$ 297,608	$ 537,032	$ 673,424	$ 854,450	$ 409,118	$ 302,204	$ 221,442	$ 179,746
UT Schedule Adjustmer	$ (37,466,244)	$ (1,680,691)	$ (2,018,190)	$ (3,360,173)	$ (3,749,047)	$ (4,450,727)	$ (4,535,849)	$ (4,239,494)	$ (3,966,063)	$ (3,437,166)	$ (2,845,889)	$ (1,819,486)	$ (1,363,469)
Long Term Firm Purchase	$ 205,498,351	$ 17,498,298	$ 16,402,306	$ 17,480,305	$ 17,292,807	$ 16,839,210	$ 17,457,822	$ 18,910,595	$ 18,041,583	$ 18,013,922	$ 15,929,356	$ 15,634,494	$ 15,997,654

Qualifying Facilities													
QF California	$ 1,691,846	$ 144,138	$ 144,080	$ 156,633	$ 157,919	$ 137,956	$ 134,286	$ 135,609	$ 134,441	$ 129,611	$ 135,806	$ 142,268	$ 139,098
QF Idaho	$ 7,384,439	$ 605,201	$ 543,397	$ 628,658	$ 669,151	$ 756,864	$ 745,232	$ 653,778	$ 555,366	$ 520,800	$ 585,228	$ 559,512	$ 561,253
QF Oregon	$ 41,585,975	$ 2,282,896	$ 2,731,056	$ 3,654,769	$ 4,549,011	$ 4,603,695	$ 4,747,221	$ 4,926,335	$ 4,249,316	$ 3,536,881	$ 2,762,393	$ 1,960,706	$ 1,581,696
QF Utah	$ 6,089,886	$ 359,738	$ 403,638	$ 480,494	$ 577,328	$ 633,629	$ 651,580	$ 593,828	$ 598,393	$ 589,272	$ 510,766	$ 383,475	$ 307,746
QF Washington	$ 231,336	$ -	$ -	$ -	$ 22,559	$ 23,311	$ 44,799	$ 46,293	$ 46,293	$ 44,799	$ 3,283	$ -	$ -
QF Wyoming	$ 200,103	$ 24,584	$ 18,617	$ 23,206	$ 19,704	$ 18,046	$ 6,756	$ 10,630	$ 11,984	$ 17,488	$ 16,668	$ 18,738	$ 13,681
Biomass One QF	$ 19,027,178	$ 1,711,538	$ 1,503,454	$ 1,199,705	$ 2,111,478	$ 1,478,210	$ 1,902,825	$ 2,038,896	$ 2,126,630	$ 1,438,118	$ 1,695,483	$ 1,334,022	$ 486,817
Chopin Wind QF	$ 2,052,812	$ 193,044	$ 216,789	$ 168,226	$ 188,753	$ 161,939	$ 177,933	$ 160,795	$ 152,387	$ 133,330	$ 156,651	$ 177,435	$ 165,528
DCFP QF	$ 163,730	$ 3,964	$ 1,547	$ 1,228	$ 2,203	$ 4,118	$ 8,443	$ 46,479	$ 24,151	$ 40,046	$ 10,356	$ 10,241	$ 10,955
Enterprise Solar I QF	$ 11,623,629	$ 559,186	$ 784,934	$ 912,337	$ 992,133	$ 1,110,428	$ 1,198,447	$ 1,221,888	$ 1,550,527	$ 1,196,357	$ 954,053	$ 639,144	$ 504,197
Escalante Solar I QF	$ 10,697,014	$ 507,215	$ 633,209	$ 867,365	$ 1,016,376	$ 1,053,391	$ 1,119,696	$ 1,124,562	$ 1,435,658	$ 1,109,134	$ 783,857	$ 576,262	$ 470,289
Escalante Solar II QF	$ 10,087,243	$ 477,537	$ 671,217	$ 818,048	$ 844,064	$ 998,815	$ 1,252,467	$ 1,416,553	$ 1,026,142	$ 869,153	$ 735,621	$ 539,834	$ 437,791
Escalante Solar III QF	$ 9,317,730	$ 470,848	$ 592,548	$ 793,995	$ 824,329	$ 1,106,663	$ 752,252	$ 1,050,412	$ 1,304,201	$ 852,131	$ 672,504	$ 495,577	$ 402,270
ExxonMobil QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Five Pine Wind QF	$ 9,499,480	$ 616,404	$ 1,029,618	$ 778,256	$ 1,006,333	$ 438,945	$ 730,839	$ 610,749	$ 632,476	$ 814,344	$ 801,144	$ 1,071,362	$ 969,011
Granite Mountain East :	$ 10,171,610	$ 504,709	$ 641,617	$ 825,580	$ 987,453	$ 1,038,919	$ 1,086,439	$ 1,108,137	$ 1,286,199	$ 846,063	$ 807,440	$ 577,538	$ 461,516
Granite Mountain West	$ 6,896,594	$ 333,978	$ 395,130	$ 547,336	$ 655,619	$ 773,111	$ 843,832	$ 733,567	$ 851,083	$ 559,266	$ 516,340	$ 382,161	$ 305,170
Iron Springs Solar QF	$ 10,784,440	$ 585,768	$ 690,867	$ 885,159	$ 1,017,479	$ 1,140,250	$ 1,108,811	$ 1,116,211	$ 1,343,907	$ 1,014,038	$ 814,425	$ 574,405	$ 493,120
Latigo Wind Park QF	$ 9,738,988	$ 901,269	$ 1,044,403	$ 1,201,514	$ 797,152	$ 765,198	$ 635,897	$ 530,489	$ 671,160	$ 689,542	$ 862,310	$ 763,919	$ 876,133
Mountain Wind 1 QF	$ 8,845,656	$ 1,578,013	$ 1,188,132	$ 977,860	$ 754,410	$ 415,181	$ 526,414	$ 342,895	$ 333,320	$ 323,771	$ 547,304	$ 746,558	$ 1,111,799
Mountain Wind 2 QF	$ 13,255,111	$ 2,305,839	$ 1,415,646	$ 1,261,109	$ 1,146,509	$ 829,747	$ 720,730	$ 546,116	$ 491,905	$ 567,403	$ 1,117,317	$ 1,177,108	$ 1,675,681
North Point Wind QF	$ 20,153,704	$ 1,229,960	$ 2,109,016	$ 1,648,060	$ 2,147,894	$ 931,267	$ 1,573,351	$ 1,349,208	$ 1,488,594	$ 1,838,877	$ 1,769,535	$ 2,163,391	$ 1,904,551
Oregon Wind Farm QF	$ 10,790,838	$ 878,406	$ 1,074,544	$ 721,055	$ 882,920	$ 563,584	$ 1,001,622	$ 1,050,261	$ 1,283,619	$ 807,247	$ 537,804	$ 720,121	$ 1,269,655
Orchard Wind 1 QF	$ 1,137,294	$ 63,171	$ 69,701	$ 97,721	$ 124,816	$ 110,803	$ 123,524	$ 123,449	$ 105,362	$ 79,489	$ 84,148	$ 75,107	$ 80,003
Orchard Wind 2 QF	$ 1,137,294	$ 61,356	$ 68,707	$ 91,023	$ 124,993	$ 112,506	$ 123,255	$ 125,420	$ 106,117	$ 79,928	$ 85,657	$ 76,765	$ 81,568
Orchard Wind 3 QF	$ 1,137,294	$ 63,522	$ 66,945	$ 105,763	$ 122,943	$ 112,010	$ 124,350	$ 121,662	$ 105,662	$ 78,908	$ 84,637	$ 72,465	$ 78,427
Orchard Wind 4 QF	$ 1,137,294	$ 63,331	$ 69,219	$ 103,949	$ 122,994	$ 111,676	$ 123,692	$ 122,969	$ 105,683	$ 78,915	$ 82,859	$ 73,472	$ 78,535
Pavant II Solar QF	$ 5,232,788	$ 208,969	$ 266,747	$ 407,283	$ 436,179	$ 499,355	$ 597,409	$ 753,543	$ 758,285	$ 464,865	$ 378,991	$ 254,555	$ 206,606
Pioneer Wind Park I QF	$ 10,499,310	$ 1,229,684	$ 909,112	$ 1,205,792	$ 932,738	$ 642,149	$ 687,075	$ 733,863	$ 566,007	$ 480,518	$ 760,767	$ 1,310,185	$ 1,041,418
Power County North Wi	$ 5,994,693	$ 484,739	$ 635,266	$ 528,277	$ 637,006	$ 311,934	$ 456,535	$ 344,652	$ 373,619	$ 398,911	$ 536,655	$ 626,641	$ 660,459
Power County South W	$ 5,366,134	$ 430,992	$ 562,076	$ 478,423	$ 592,418	$ 268,471	$ 405,970	$ 305,732	$ 349,731	$ 355,859	$ 472,141	$ 568,876	$ 575,445
Roseburg Dillard QF	$ 1,748,686	$ 128,610	$ 238,412	$ 149,346	$ 88,351	$ 220,962	$ 109,492	$ 173,449	$ 234,506	$ 72,911	$ 60,290	$ 89,280	$ 183,076
Sage I Solar QF	$ 2,100,923	$ 73,729	$ 81,622	$ 179,700	$ 189,247	$ 236,861	$ 228,351	$ 344,409	$ 269,460	$ 177,247	$ 154,574	$ 95,460	$ 70,263
Sage II Solar QF	$ 1,995,490	$ 73,825	$ 76,853	$ 179,825	$ 189,507	$ 207,801	$ 228,540	$ 276,890	$ 269,631	$ 177,411	$ 140,723	$ 104,123	$ 70,359
Sage III Solar QF	$ 1,730,069	$ 62,143	$ 63,931	$ 154,399	$ 154,294	$ 170,409	$ 216,080	$ 226,005	$ 277,719	$ 146,563	$ 117,957	$ 80,841	$ 59,728
Spanish Fork Wind 2 Q	$ 3,039,083	$ 258,629	$ 170,236	$ 235,375	$ 155,127	$ 196,716	$ 290,612	$ 249,608	$ 430,373	$ 237,924	$ 292,286	$ 287,993	$ 234,203
Sunnyside QF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sweetwater Solar QF	$ 7,195,776	$ 258,697	$ 347,792	$ 564,672	$ 622,477	$ 727,999	$ 849,575	$ 941,178	$ 1,065,625	$ 710,150	$ 628,643	$ 299,061	$ 179,909
Tesoro QF	$ 309,811	$ 30,784	$ 64,397	$ 46,745	$ 27,813	$ 21,699	$ 4,040	$ 91	$ 3,862	$ 15,221	$ 9,109	$ 17,738	$ 68,310
Three Peaks Solar QF	$ 8,020,002	$ 364,735	$ 502,835	$ 540,336	$ 854,276	$ 730,221	$ 776,895	$ 1,110,291	$ 1,054,827	$ 643,846	$ 685,990	$ 380,673	$ 375,078
Threemile Canyon Winc	$ 1,802,363	$ 82,972	$ 180,579	$ 139,659	$ 183,820	$ 181,293	$ 218,186	$ 208,329	$ 181,311	$ 120,822	$ 125,922	$ 99,256	$ 80,214
Utah Pavant Solar QF	$ 6,733,205	$ 259,763	$ 352,596	$ 546,244	$ 642,550	$ 774,763	$ 736,018	$ 762,807	$ 956,395	$ 617,319	$ 495,467	$ 318,588	$ 270,697
Utah Red Hills Solar QF	$ 10,948,397	$ 425,345	$ 645,241	$ 781,234	$ 932,215	$ 1,040,395	$ 1,262,139	$ 1,600,489	$ 1,513,931	$ 1,040,769	$ 698,090	$ 593,913	$ 414,636
Qualifying Facilities Total	$ 297,555,250	$ 20,899,230	$ 23,205,726	$ 25,086,359	$ 28,504,539	$ 25,661,289	$ 28,531,611	$ 29,338,530	$ 30,325,860	$ 23,915,249	$ 22,691,192	$ 20,438,772	$ 18,956,894
Mid-Columbia Contracts													
Douglas - Wells	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grant Reasonable	$ (9,177,438)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)	$ (764,786)
Grant Meaningful Priorit	$ 75,858,709	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559	$ 6,321,559
Grant Surplus	$ 2,472,617	$ 206,051	$ 206,051	$ 206,051	$ 206,051	$ 206,051	$ 206,051	$ 206,051	$ 206,051	$ 206,051	$ 206,051	$ 206,051	$ 206,051
Mid-Columbia Contracts Tc	$ 69,153,888	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824	$ 5,762,824
Total Long Term Firm Purc	$ 572,207,489	$ 44,160,352	$ 45,370,856	$ 48,329,487	$ 51,560,169	$ 48,263,324	$ 51,752,257	$ 54,011,949	$ 54,130,267	$ 47,691,995	$ 44,383,372	$ 41,836,090	$ 40,717,371

Storage & Exchange													
Rush lake_BESS	-	-	-	-	-	-	-	-	-	-	-	-	-
Fremont Solar_BESS	-	-	-	-	-	-	-	-	-	-	-	-	-
Green River Energy Ce	-	-	-	-	-	-	-	-	-	-	-	-	-
Umpqua Storage Place	-	-	-	-	-	-	-	-	-	-	-	-	-
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
EWEB FC I	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCO FC III	-	-	-	-	-	-	-	-	-	-	-	-	-
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	-	-	-	-	-	-	-	-	-	-	-	-	-
Short Term Firm Purchases													
COB	54,195,300	6,325,800	6,082,500	6,325,800	-	-	-	11,970,600	12,370,200	11,120,400	-	-	-
Colorado	-	-	-	-	-	-	-	-	-	-	-	-	-
Four Corners	-	-	-	-	-	-	-	-	-	-	-	-	-
Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-
Mead	-	-	-	-	-	-	-	-	-	-	-	-	-
Mid Columbia	33,730,760	1,931,280	1,857,000	1,931,280	3,551,600	3,551,600	4,045,000	5,694,000	5,913,000	5,256,000	-	-	-
Mona	-	-	-	-	-	-	-	-	-	-	-	-	-
NOB	-	-	-	-	-	-	-	-	-	-	-	-	-
Palo Verde	-	-	-	-	-	-	-	-	-	-	-	-	-
SP15	-	-	-	-	-	-	-	-	-	-	-	-	-
Utah	-	-	-	-	-	-	-	-	-	-	-	-	-
Washington	-	-	-	-	-	-	-	-	-	-	-	-	-
West Main	-	-	-	-	-	-	-	-	-	-	-	-	-
Wyoming	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Short Term Firm Purc	87,926,060	8,257,080	7,939,500	8,257,080	3,551,600	3,551,600	4,045,000	17,664,600	18,283,200	16,376,400	-	-	-
System Balancing Purchases													
COB	36,753,658	4,263,969	1,249,671	1,402,866	1,481,292	844,150	3,477,083	6,541,557	4,738,900	4,618,174	1,748,541	2,257,565	4,129,888
Four Corners	93,059,524	6,688,577	4,389,194	4,255,858	3,263,447	2,528,729	7,835,352	16,653,575	17,792,271	10,757,969	5,875,020	5,979,791	7,039,741
Mead	5,429,205	231,179	176,807	315,216	158,514	675,709	329,257	249,916	1,310,611	1,381,263	306,523	150,495	143,716
Mid Columbia	645,149,933	86,184,562	54,976,171	34,834,439	30,352,750	15,393,137	33,495,216	103,196,846	96,440,341	57,813,387	23,582,996	30,266,010	78,614,077
Mona	51,790,334	5,077,823	4,372,876	2,744,941	3,354,453	2,342,206	2,377,565	6,619,221	5,826,205	3,638,780	4,857,323	2,962,549	7,616,391
NOB	86,934,850	7,905,120	3,047,008	3,371,108	6,255,697	1,826,669	6,172,220	17,610,256	18,624,781	12,213,197	2,308,514	2,382,000	5,218,277
Palo Verde	111,556,799	10,911,637	7,955,731	4,914,290	3,457,877	3,187,246	7,260,081	18,061,596	19,706,446	15,193,339	6,035,491	6,474,910	8,398,154
EIM Imports/Exports	(107,981,006)	(11,184,399)	(9,180,912)	(7,491,298)	(6,708,794)	(6,428,175)	(6,655,048)	(11,996,478)	(12,960,242)	(10,544,270)	(6,449,442)	(7,258,941)	(11,123,005)
Emergency Purchases	591,355	23,437	2,262	-	3,667	-	-	455,717	91,949	-	-	-	14,323
Total System Balancing Pu	923,284,653	110,101,904	66,988,808	44,347,420	41,618,905	20,369,671	54,291,727	157,392,207	151,571,261	95,071,840	38,264,967	43,214,380	100,051,563
Total Purchased Power & Net	1,583,418,202	162,519,336	120,299,164	100,933,987	96,730,674	72,184,595	110,088,984	229,068,755	223,984,728	159,140,235	82,648,339	85,050,470	140,768,935
Wheeling & U. of F. Expense													
Firm Wheeling	166,964,094	12,354,670	12,989,372	13,803,474	13,891,817	13,166,465	13,760,055	14,658,565	14,843,837	14,600,528	13,832,764	13,901,636	15,160,910
C&T EIM Admin fee	2,584,773	210,477	192,813	230,652	220,405	231,652	233,135	238,944	221,226	240,569	181,475	188,935	194,490
ST Firm & Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Wheeling & U. of F. Expe	169,548,867	12,565,147	13,182,186	14,034,125	14,112,222	13,398,116	13,993,190	14,897,509	15,065,064	14,841,097	14,014,239	14,090,571	15,355,400

Coal Fuel Burn Expense													
Colstrip	$ 19,381,022	$ 1,313,383	$ 1,662,001	$ 1,706,198	$ 1,469,093	$ 1,216,906	$ 966,600	$ 1,916,696	$ 1,895,550	$ 1,934,769	$ 1,857,228	$ 1,896,141	$ 1,546,457
Craig	$ 23,784,379	$ 1,898,119	$ 1,537,905	$ 1,786,859	$ 1,694,851	$ 1,871,756	$ 2,071,847	$ 1,984,895	$ 2,309,630	$ 2,355,113	$ 2,242,555	$ 2,153,147	$ 1,877,704
Dave Johnston	$ 55,080,089	$ 4,015,974	$ 3,902,616	$ 4,959,131	$ 4,064,425	$ 4,838,865	$ 5,185,962	$ 4,102,767	$ 5,388,946	$ 4,386,075	$ 5,207,280	$ 4,716,134	$ 4,311,913
Hayden	$ 11,294,382	$ 842,494	$ 951,002	$ 812,739	$ 665,052	$ 902,611	$ 955,313	$ 979,461	$ 1,042,139	$ 952,375	$ 1,171,635	$ 1,100,236	$ 919,325
Hunter	$ 157,957,315	$ 20,639,095	$ 15,870,099	$ 6,886,480	$ 9,949,680	$ 6,838,906	$ 9,210,416	$ 19,669,923	$ 16,760,844	$ 11,329,095	$ 9,261,043	$ 12,063,088	$ 19,478,647
Huntington	$ 76,807,783	$ 10,148,035	$ 9,006,293	$ 4,438,004	$ 4,467,864	$ 3,190,281	$ 4,164,093	$ 9,162,326	$ 8,015,309	$ 4,927,618	$ 3,889,014	$ 5,014,727	$ 10,384,217
Jim Bridger	$ 99,127,871	$ 6,639,076	$ 7,917,574	$ 8,206,543	$ 7,572,436	$ 8,336,130	$ 8,725,580	$ 8,337,781	$ 9,288,966	$ 8,831,663	$ 8,937,540	$ 8,859,435	$ 7,475,147
Naughton	$ 38,492,149	$ 2,404,160	$ 2,584,277	$ 3,232,338	$ 2,976,995	$ 3,844,508	$ 3,802,368	$ 3,126,353	$ 4,440,177	$ 3,932,330	$ 3,102,998	$ 3,412,336	$ 1,633,309
Wyodak	$ 24,361,614	$ 2,161,034	$ 1,937,556	$ 1,583,738	$ 2,193,478	$ 2,129,308	$ 2,143,742	$ 1,572,478	$ 2,059,941	$ 2,061,818	$ 2,565,532	$ 1,806,700	$ 2,146,287
Total Coal Fuel Burn Expense	$ 506,286,604	$ 50,061,370	$ 45,369,323	$ 33,612,030	$ 35,053,874	$ 33,169,271	$ 37,225,921	$ 50,852,679	$ 51,201,503	$ 40,710,856	$ 38,234,825	$ 41,021,945	$ 49,773,006
Gas Fuel Burn Expense													
Chehalis	$ 119,217,816	$ 21,225,290	$ 15,941,373	$ 10,656,675	$ 5,449,759	$ 6,317,810	$ 6,246,608	$ 7,765,809	$ 8,046,041	$ 6,588,972	$ 6,382,828	$ 10,032,205	$ 14,564,447
Currant Creek	$ 92,757,192	$ 11,791,417	$ 11,114,896	$ 8,470,328	$ 6,320,000	$ 6,380,055	$ 5,802,165	$ 6,570,799	$ 6,842,456	$ 7,389,779	$ 7,517,548	$ 7,089,672	$ 7,468,078
Gadsby	$ 27,632,171	$ 3,981,850	$ 3,833,919	$ 2,351,155	$ 1,458,513	$ 1,149,813	$ 1,792,489	$ 1,977,215	$ 2,170,737	$ 1,846,021	$ 1,565,541	$ 1,906,971	$ 3,597,947
Gadsby CT	$ 18,848,872	$ 2,700,323	$ 2,404,853	$ 1,501,030	$ 960,985	$ 1,278,650	$ 1,210,090	$ 1,340,704	$ 1,352,158	$ 1,198,384	$ 1,142,750	$ 1,322,695	$ 2,436,250
Hermiston	$ 40,678,880	$ 5,829,723	$ 5,053,002	$ 2,117,870	$ 1,824,317	$ 2,375,213	$ 1,897,459	$ 2,329,136	$ 3,636,724	$ 3,499,257	$ 3,617,922	$ 4,291,457	$ 4,206,800
Jim Bridger - Gas	$ 88,297,821	$ -	$ -	$ 4,462,430	$ 3,348,505	$ 8,989,822	$ 10,267,486	$ 10,055,061	$ 11,620,732	$ 10,595,580	$ 11,225,120	$ 10,841,459	$ 6,891,627
Lake Side 1	$ 103,748,716	$ 12,059,770	$ 12,137,537	$ 8,110,563	$ 5,947,296	$ 7,218,923	$ 7,152,076	$ 7,250,379	$ 8,143,978	$ 8,154,530	$ 7,424,463	$ 9,663,990	$ 10,485,213
Lake Side 2	$ 116,339,001	$ 14,635,888	$ 13,546,042	$ 10,853,382	$ 3,225,589	$ 3,823,721	$ 8,474,088	$ 9,360,247	$ 10,239,989	$ 9,920,189	$ 9,460,645	$ 11,142,242	$ 11,656,980
Naughton - Gas	$ 26,337,289	$ 1,974,148	$ 1,985,228	$ 2,933,960	$ 658,713	$ 2,783,988	$ 3,174,821	$ 2,158,579	$ 2,759,706	$ 2,566,361	$ 1,290,931	$ 2,867,306	$ 1,183,549
Total Gas Fuel Burn	$ 633,857,759	$ 74,198,408	$ 66,016,850	$ 51,457,393	$ 29,193,676	$ 40,317,995	$ 46,017,281	$ 48,807,930	$ 54,812,520	$ 51,759,073	$ 49,627,747	$ 59,157,996	$ 62,490,891
Gas Physical	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gas Swaps	$ (2,173,320)	$ (11,212,855)	$ (7,609,528)	$ 5,974,475	$ 1,206,750	$ 2,136,985	$ 1,584,750	$ 814,254	$ 465,000	$ 1,095,150	$ 3,252,365	$ 3,429,863	$ (3,310,529)
Clay Basin Gas Storage	$ (2,019,909)	$ (775,564)	$ (693,925)	$ (179,008)	$ 52,242	$ 52,242	$ 52,242	$ 52,242	$ 52,242	$ 52,242	$ 52,242	$ (169,614)	$ (567,495)
Pipeline Reservation Fe	$ 45,240,762	$ 3,787,019	$ 3,714,024	$ 3,787,678	$ 3,754,751	$ 3,789,926	$ 3,750,690	$ 3,787,085	$ 3,786,298	$ 3,751,811	$ 3,789,831	$ 3,754,698	$ 3,786,952
Total Gas Fuel Burn Expense	$ 674,905,292	$ 65,997,009	$ 61,427,421	$ 61,040,537	$ 34,207,419	$ 46,297,148	$ 51,404,963	$ 53,461,511	$ 59,116,060	$ 56,658,276	$ 56,722,185	$ 66,172,942	$ 62,399,819
Other Generation Expense													
Blundell	$ 4,440,902	$ 443,392	$ 228,935	$ 88,076	$ 360,802	$ 379,715	$ 391,298	$ 418,061	$ 430,310	$ 413,742	$ 401,326	$ 431,972	$ 453,273
Total Other Generation Expen	$ 4,440,902	$ 443,392	$ 228,935	$ 88,076	$ 360,802	$ 379,715	$ 391,298	$ 418,061	$ 430,310	$ 413,742	$ 401,326	$ 431,972	$ 453,273
Net Power Cost	**$ 2,196,515,696**	**$ 231,581,237**	**$ 198,872,402**	**$ 173,342,863**	**$ 150,295,845**	**$ 135,019,164**	**$ 159,968,724**	**$ 267,132,627**	**$ 216,817,719**	**$ 154,940,969**	**$ 144,364,509**	**$ 155,393,479**	**$ 208,786,158**
Net Power Cost/Net System Lo	32.97	39.67	37.37	32.42	29.82	25.80	28.76	41.81	35.73	28.99	27.57	29.04	35.44

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 420

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
2024 Transition Adjustment Mechanism.	)
	)

EXHIBIT AWEC/202

2022 ACTUAL NPC

PACIFICORP
ACTUAL NET POWER COST REPORT
FOR THE YEAR ENDING DECEMBER 31, 2022

	Total	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
							DOLLARS						
Special Sales For Resale													
Long Term Firm Sales													
Black Hills	$ 8,974,735	$ 786,193	$ 568,783	$ 722,192	$ 754,255	$ 791,733	$ 837,197	$ 859,284	$ 842,378	$ 747,878	$ 708,911	$ 644,716	$ 711,214
Hurricane Sale	22,855	1,495	1,323	1,448	1,546	1,650	1,670	1,775	1,737	2,771	2,511	2,444	2,486
PSCO Craig Sale	1,298,880	-	-	-	-	-	-	-	-	-	-	694,550	604,330
Total Long Term Firm Sales	10,296,471	787,688	570,106	723,640	755,801	793,383	838,867	861,059	844,115	750,649	711,422	1,341,710	1,318,031
Short Term Firm Sales													
Short Term Firm Sales	244,194,101	17,771,151	16,774,575	17,603,392	20,295,183	11,904,900	19,431,495	12,943,944	21,407,431	33,316,220	17,492,682	15,195,389	40,057,740
Other Firm Sales	27,445,397	723,437	584,845	640,039	1,287,221	1,077,820	4,735,566	2,736,791	3,586,784	3,587,176	1,268,087	1,919,339	5,298,293
Total Short Term Firm Sales	271,639,498	18,494,588	17,359,420	18,243,431	21,582,403	12,982,719	24,167,061	15,680,735	24,994,215	36,903,395	18,760,770	17,114,727	45,356,033
Total Secondary Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Special Sales For Resale	**281,935,969**	**19,282,276**	**17,929,525**	**18,967,071**	**22,338,204**	**13,776,102**	**25,005,928**	**16,541,794**	**25,838,330**	**37,654,044**	**19,472,192**	**18,456,437**	**46,674,064**

	Total	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Purchased Power & Net Interchange													
Long Term Firm Purchases													
Amor IX	7,347,934	771,009	666,225	710,110	520,995	644,971	529,933	461,528	475,335	458,549	627,326	741,540	740,414
Cedar Springs Wind	12,726,833	1,544,100	1,335,052	1,334,156	1,247,861	1,039,126	734,064	663,423	561,691	751,140	914,221	1,130,184	1,471,815
Cedar Springs III Wind	10,057,037	1,239,185	1,023,582	1,029,524	940,837	809,592	588,599	537,513	466,561	619,226	697,851	899,054	1,205,513
Combine Hills Wind	4,053,171	205,421	389,927	356,119	456,263	481,634	450,199	310,618	288,805	273,596	322,420	264,351	253,818
Cove Mountain Solar	3,901,856	221,300	266,708	329,959	408,421	777,189	471,354	419,885	499,425	493,908	313,359	217,223	(516,876)
Cove Mountain Solar 2	9,454,940	531,748	636,467	804,784	997,268	1,659,969	1,147,166	1,035,553	1,118,650	1,102,646	744,351	516,933	(840,595)
Deseret Purchase	41,116,580	3,669,272	3,228,764	3,283,186	3,139,551	3,044,783	3,114,112	3,586,595	3,452,638	3,243,947	3,783,371	3,755,191	3,815,169
Eagle Mountain - UAMPS/UMPA	542,109	195,257	181,487	165,365	-	-	-	-	-	-	-	-	-
Gemstate	1,820,447	150,059	150,059	150,059	150,059	150,059	150,059	150,059	150,059	150,059	120,118	174,899	174,899
Graphite Solar	2,825,788	-	-	-	-	-	267,576	592,409	425,937	461,098	507,048	329,407	242,312
Hunter Solar	6,874,903	419,390	490,438	556,046	682,296	759,059	752,575	684,858	646,119	618,131	581,298	397,105	287,589
Hurricane Purchase	287,004	19,600	21,431	17,609	14,518	10,595	11,965	18,511	22,819	50,956	23,400	33,075	42,525
MagCorp Reserves	2,011,735	254,378	199,990	213,973	219,361	210,203	192,984	302,320	228,970	84,972	34,067	35,791	34,726
Milford Solar	6,762,422	378,796	455,961	564,804	703,171	816,713	691,752	721,759	665,947	639,256	549,353	353,537	221,373
Millican Solar	2,678,413	116,522	163,441	165,451	232,295	299,715	316,018	360,426	343,341	259,811	217,930	111,574	91,887
Nucor	8,018,900	609,450	609,450	680,000	680,000	680,000	680,000	680,000	680,000	680,000	680,000	680,000	680,000
Old Mill Solar	583,547	24,753	35,334	49,086	58,620	75,898	71,174	92,726	64,901	47,556	31,409	17,488	14,602
P4 Production	20,974,244	2,090,911	1,716,667	1,716,667	1,716,667	1,716,667	1,716,667	1,716,667	1,716,667	1,716,667	1,716,667	1,716,667	1,716,667
Pavant III Solar	2,430,917	148,152	168,764	220,096	252,860	285,938	264,701	262,013	237,403	221,928	181,865	109,495	77,702
PGE Cove	196,359	16,184	16,379	16,379	16,379	16,379	16,379	16,379	16,379	16,379	16,379	16,379	16,379
Prineville Solar	1,837,081	80,011	111,715	137,888	170,393	198,819	199,750	251,235	228,718	175,833	147,615	74,594	60,509
Sigurd Solar	5,508,554	399,536	440,257	364,803	337,190	595,444	691,918	619,822	528,535	476,059	505,555	324,389	225,047
Small Purchases East	21,389	2,149	3,436	2,625	3,246	1,894	1,968	1,809	2,501	2,196	2,118	1,782	(4,335)
Small Purchases West	-	-	-	-	-	-	-	-	-	-	-	-	-
Three Buttes Wind	20,269,304	2,859,002	2,205,573	1,874,077	1,806,680	1,505,340	1,258,444	974,443	761,344	974,754	1,314,489	1,880,831	2,854,328
Top of the World Wind	41,127,862	5,496,835	4,429,941	3,909,170	3,845,938	3,135,672	2,562,109	1,627,437	1,634,416	2,067,270	2,846,480	3,855,910	5,716,685
Wolverine Creek Wind	9,161,926	438,945	564,321	901,419	1,196,383	1,058,043	876,082	685,882	512,093	668,353	581,852	810,556	867,995
Subtotal Long Term Firm Purchases	222,591,255	21,881,964	19,511,368	19,553,356	19,797,252	19,973,705	17,757,547	16,773,871	15,729,254	16,254,290	17,460,541	18,447,957	19,450,148

	Total	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Qualifying Facilities													
QF California	1,293,829	99,342	220,523	225,315	157,734	117,269	108,216	85,843	9,457	9,310	9,065	100,797	150,958
QF Idaho	5,978,173	409,045	293,907	469,654	416,338	434,695	593,561	625,064	568,166	485,385	571,123	492,328	618,906
QF Oregon	39,738,953	2,372,835	2,572,370	3,026,380	3,713,862	4,575,995	4,632,458	4,597,667	4,269,649	3,749,650	3,000,513	1,782,023	1,445,551
QF Utah	20,103,589	1,334,554	1,628,126	1,791,374	1,963,956	2,161,875	1,965,610	1,801,009	1,641,013	1,812,115	1,848,522	1,300,578	854,858
QF Washington	338,738	-	0	-	8,816	16	25,448	142,602	107,846	45,986	8,026	-	-
QF Wyoming	29,884	2,414	2,821	2,150	2,956	3,472	671	1,712	2,272	2,271	4,779	827	3,540
Biomass One QF	18,506,771	1,734,600	1,549,564	1,738,852	1,608,607	1,095,696	1,078,306	1,612,010	1,714,064	1,759,797	1,870,371	1,863,376	881,528
Chopin Wind QF	1,773,475	138,264	200,147	176,815	185,586	175,582	148,072	111,236	127,732	102,508	141,243	137,135	129,156
Chopin Schumann Wind QF	417,684	-	-	-	-	-	-	-	-	-	42,806	92,392	282,485
DCFP QF	290,235	1,621	790	2,213	6,526	10,009	8,393	33,487	49,783	75,959	26,540	16,389	58,524
Enterprise Solar I QF	12,341,019	728,687	860,913	910,625	1,140,912	1,345,958	1,359,242	1,470,837	1,245,018	1,075,617	977,193	726,378	499,638
Escalante 1 Solar QF	11,158,731	638,178	757,169	811,816	1,013,965	1,161,213	1,237,326	1,360,470	1,219,994	1,085,417	872,042	618,223	382,919
Escalante 2 Solar QF	10,550,951	567,152	697,422	787,836	959,770	1,107,802	1,172,303	1,308,045	1,161,793	1,015,475	820,074	592,553	360,725
Escalante 3 Solar QF	10,241,715	579,186	695,773	680,295	944,691	1,099,846	1,165,430	1,286,033	1,143,562	1,013,341	753,127	538,540	341,892
ExxonMobil QF	28,027	-	-	16,955	0	623	-	-	8,971	24	-	-	1,454
Five Pine Wind QF	7,984,172	452,646	432,170	672,990	858,682	751,924	665,722	581,201	540,014	641,498	559,599	773,929	1,053,796
Granite Mountain East Solar QF	10,599,452	658,718	757,046	838,625	1,031,316	1,188,114	1,243,890	1,226,542	1,011,001	875,391	783,524	576,707	408,579
Granite Mountain West Solar QF	6,333,247	422,333	486,807	557,154	132,606	783,479	775,078	793,931	668,801	559,646	508,620	381,548	263,244
Iron Springs QF	10,913,602	667,975	838,445	876,850	752,842	1,206,574	1,285,216	1,317,146	1,138,795	923,934	845,299	621,431	439,094
Latigo Wind QF	9,325,660	713,583	997,451	988,578	1,068,566	905,829	482,646	453,602	498,494	582,689	528,961	1,007,770	1,097,493
Mountain Wind 1 QF	8,416,551	1,224,559	1,125,001	772,040	813,141	663,645	236,750	483,752	308,366	365,610	544,091	852,100	1,027,497
Mountain Wind 2 QF	13,116,745	1,850,821	1,701,372	1,124,052	1,096,590	942,488	774,339	860,538	460,643	551,879	782,392	1,215,810	1,755,821
North Point Wind QF	16,674,223	844,026	984,449	1,509,605	1,813,769	1,444,007	1,384,879	1,207,542	1,219,583	1,416,973	1,306,389	1,510,053	2,032,947
Oregon Wind Farm QF	9,910,361	428,902	909,222	892,612	1,114,083	1,090,700	986,600	982,184	941,957	756,090	605,199	716,569	486,243
Orchard Wind 1 QF	587,360	29,035	45,645	19,583	87,227	85,940	60,238	60,450	55,076	47,589	30,616	44,008	21,954
Orchard Wind 2 QF	618,586	29,437	46,212	61,409	87,172	71,883	62,238	59,912	52,096	47,019	29,415	44,166	27,627
Orchard Wind 3 QF	628,895	30,074	44,294	66,540	79,980	83,051	56,984	60,322	52,800	45,699	27,721	36,460	44,969
Orchard Wind 4 QF	662,532	32,559	47,753	69,547	80,070	83,761	62,299	61,535	56,614	47,415	33,686	33,688	53,605
Pavant II Solar QF	4,583,486	263,712	304,016	357,527	432,202	467,575	551,175	638,420	565,993	387,831	305,385	189,716	119,934
Pioneer Wind 1 QF	9,170,570	1,357,201	1,009,742	802,211	678,141	587,704	561,939	394,087	383,016	355,168	756,289	982,392	1,302,680
Power County North Wind QF	5,182,408	274,920	501,177	532,503	511,109	467,789	368,760	329,021	307,089	394,426	429,461	455,451	610,702
Power County South Wind QF	4,706,666	295,473	399,056	463,388	478,275	385,189	311,050	304,258	247,976	348,797	368,136	508,649	596,419
Roseburg Dillard QF	3,257,496	213,809	222,700	230,542	195,754	243,503	162,006	224,780	95,306	153,774	52,341	154,959	1,308,022
Sage I Solar QF	2,028,387	82,941	126,570	173,564	164,487	164,265	195,033	304,057	281,672	226,699	162,283	99,712	47,104
Sage II Solar QF	2,008,695	72,536	147,134	164,523	141,190	160,081	220,392	295,073	259,527	208,828	181,492	99,797	58,122
Sage III Solar QF	1,817,124	78,986	108,776	134,149	119,486	130,264	185,633	284,359	260,763	209,269	162,291	88,665	54,484
Spanish Fork Wind 2 QF	2,618,369	256,390	203,654	208,152	150,609	111,800	176,524	313,659	287,621	263,123	250,091	180,043	216,704
Sunnyside QF	33,045,343	2,844,870	2,485,434	2,841,910	1,734,429	3,012,900	3,072,409	3,140,147	3,143,077	3,064,918	1,994,597	3,060,281	2,650,370
Sweetwater Solar QF	8,008,595	426,211	488,190	692,748	718,461	783,422	936,406	1,027,937	941,169	794,461	635,478	328,031	236,081
Tesoro QF	39,763	16,444	10,110	4,056	553	181	54	-	1,041	8	257	330	6,728
Three Peaks Solar QF	9,141,290	550,263	671,793	771,916	907,015	1,042,875	939,466	1,021,027	877,752	753,264	721,719	528,391	355,811
Threemile Canyon Wind QF	1,610,859	54,343	160,564	144,377	187,247	205,831	178,139	160,104	148,530	127,815	94,269	86,138	63,501
Utah Pavant Solar QF	5,469,965	289,435	303,645	384,452	468,471	542,812	636,602	748,728	628,787	537,462	455,604	277,461	196,508
Utah Red Hills Solar QF	11,888,239	575,104	799,801	888,539	705,359	1,636,113	1,290,280	1,432,187	1,252,615	1,344,542	875,780	683,219	404,699
Subtotal Qualifying Facilities	333,140,415	23,643,185	25,837,757	27,884,419	28,732,549	32,533,751	31,357,782	33,202,519	29,955,494	28,264,669	24,976,407	23,799,010	22,952,872

	Total	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Mid-Columbia Contracts													
Grant Surplus	2,189,840	182,487	182,487	182,487	182,487	182,487	182,487	182,487	182,487	182,487	182,487	182,487	182,487
Grant Reasonable	(7,951,391)	(662,616)	(662,616)	(662,616)	(662,616)	(662,616)	(662,616)	(662,616)	(662,616)	(662,616)	(662,616)	(662,616)	(662,616)
Subtotal Mid-Columbia Contracts	(5,761,551)	(480,129)	(480,129)	(480,129)	(480,129)	(480,129)	(480,129)	(480,129)	(480,129)	(480,129)	(480,129)	(480,129)	(480,129)
Total Long Term Firm Purchases	549,970,118	45,045,020	44,868,996	46,957,645	48,049,673	52,027,327	48,635,200	49,496,261	45,204,618	44,038,830	41,956,819	41,766,838	41,922,891
Storage & Exchange													
Cowlitz Swift	-	-	-	-	-	-	-	-	-	-	-	-	-
PSCo Exchange	4,500,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	-	-
SCL State Line	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Storage & Exchange	4,500,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	-	-
Short Term Firm Purchases													
Short Term Firm Purchases	697,321,949	23,270,056	21,960,308	21,445,028	28,381,334	25,816,927	29,481,186	110,227,479	113,677,203	133,192,256	31,951,740	43,920,499	113,997,932
EIM Settlements	(294,703,565)	(14,209,526)	(11,526,127)	(11,304,956)	(18,147,071)	(24,063,195)	(15,739,318)	(27,334,779)	(40,144,891)	(51,780,067)	(21,154,375)	(21,204,274)	(38,094,987)
Other Firm Purchases	4,646,424	108,933	(49,373)	(212,741)	(156,339)	512,222	232,312	1,398,966	5,296,177	(3,123,639)	1,226,739	(3,712,581)	3,125,747
Total Short Term Firm Purchases	407,264,808	9,169,463	10,384,809	9,927,332	10,077,924	2,265,955	13,974,180	84,291,666	78,828,489	78,288,550	12,024,105	19,003,644	79,028,692
Total Secondary Purchases	0	(0)	(0)	-	(0)	0	0	-	-	-	(0)	(2,303)	2,303
Total Purchased Power & Net Interchange	**961,734,926**	**54,664,483**	**55,703,804**	**57,334,977**	**58,577,597**	**54,743,282**	**63,059,381**	**134,237,927**	**124,483,107**	**122,777,380**	**54,430,924**	**60,768,179**	**120,953,886**

	Total	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Wheeling & U. of F. Expense													
Firm Wheeling	150,448,799	11,381,355	11,919,833	12,607,933	12,582,278	12,211,733	12,266,590	12,739,450	13,002,119	13,008,691	12,469,103	12,640,521	13,619,193
Non-Firm Wheeling	13,639,928	569,005	411,167	449,040	803,826	479,883	1,287,013	2,770,591	1,932,530	1,144,303	675,465	1,623,634	1,493,471
Total Wheeling & U. of F. Expense	**164,088,727**	**11,950,361**	**12,331,000**	**13,056,973**	**13,386,104**	**12,691,616**	**13,553,603**	**15,510,041**	**14,934,648**	**14,152,994**	**13,144,568**	**14,264,155**	**15,112,664**
Coal Fuel Burn Expense													
Colstrip	20,849,027	1,834,186	1,783,709	1,901,841	1,029,683	1,195,514	1,530,689	2,028,320	2,214,606	1,882,631	2,240,892	1,458,558	1,748,399
Craig	24,121,433	2,683,121	785,612	1,772,124	2,674,311	1,565,300	2,408,819	2,118,381	1,801,948	2,856,402	1,489,151	2,363,792	1,602,473
Dave Johnston	45,379,006	3,473,429	3,525,792	4,301,619	2,094,151	2,841,582	2,431,506	5,608,309	4,217,068	4,770,507	4,211,404	4,369,551	3,534,087
Hayden	12,927,652	1,715,645	902,599	987,760	953,295	778,701	822,066	1,159,083	1,269,790	1,093,947	1,054,078	1,136,179	1,054,509
Hunter	106,543,072	11,311,713	8,818,872	5,979,201	7,305,809	10,224,004	11,070,652	12,240,376	12,588,783	9,136,443	4,020,529	5,841,916	8,004,775
Huntington	121,347,519	10,622,080	9,128,732	10,064,687	10,198,629	10,296,416	10,615,745	11,829,854	12,472,142	10,894,417	6,363,371	9,593,055	9,268,393
Jim Bridger	177,053,829	14,694,657	12,570,372	14,969,030	13,332,394	12,637,557	8,704,635	17,652,350	16,386,426	16,250,867	19,547,221	15,361,926	14,946,395
Naughton 1 & 2	50,876,388	6,240,360	2,465,250	2,654,516	2,501,244	3,623,147	2,901,420	5,964,484	4,677,938	5,005,397	5,091,728	4,150,203	5,600,701
Wyodak	21,737,035	1,410,907	1,865,007	2,047,426	1,123,441	40,279	2,325,065	1,668,405	2,630,805	1,943,424	2,531,628	2,081,249	2,069,398
Total Coal Fuel Burn Expense	**580,834,961**	**53,986,099**	**41,845,945**	**44,678,204**	**41,212,957**	**43,202,498**	**42,810,596**	**60,269,561**	**58,259,505**	**53,834,035**	**46,550,001**	**46,356,429**	**47,829,131**
Gas Fuel Burn Expense													
Chehalis	144,499,963	14,664,917	6,653,258	3,750,206	10,652,327	766,625	754,145	8,373,905	11,224,399	11,256,802	15,604,287	20,947,175	39,851,916
Currant Creek	102,455,322	8,246,975	7,565,226	6,298,626	8,922,213	8,631,237	9,297,740	5,497,348	6,802,631	6,248,691	7,579,029	10,977,140	16,388,465
Gadsby	10,693,287	115,610	76,027	(5,523)	258,324	918,113	1,284,553	1,625,613	1,957,907	1,234,386	1,287,701	764,508	1,176,068
Gadsby CT	756,516	90,555	67,038	131,206	53,508	38,346	36,373	59,545	58,728	54,484	32,703	34,063	99,966
Hermiston	76,653,042	4,355,021	4,059,630	4,284,234	6,173,137	6,670,396	5,015,301	4,774,345	5,377,777	4,922,139	(543,202)	8,163,156	23,401,108
Lake Side 1	113,701,691	9,792,529	7,822,306	5,250,067	9,081,981	11,841,059	9,577,969	6,059,095	7,419,623	7,631,436	8,999,656	11,618,145	18,607,824
Lake Side 2	124,095,798	10,000,295	9,230,333	7,277,500	7,989,624	10,025,269	11,631,052	6,576,589	9,150,156	8,424,017	9,594,040	13,471,391	20,725,532
Naughton 3	37,669,848	188,481	185,557	184,574	2,517,179	5,144,382	3,743,479	3,271,393	4,029,802	2,686,195	4,057,022	3,562,304	8,099,480
Total Gas Fuel Burn Expense	**610,525,466**	**47,454,385**	**35,659,375**	**27,170,890**	**45,648,291**	**44,035,428**	**41,340,612**	**36,237,833**	**46,021,024**	**42,458,150**	**46,611,236**	**69,537,883**	**128,350,359**
Other Generation Expense													
Blundell	5,070,191	362,140	405,021	413,835	375,227	368,142	431,917	392,834	365,885	445,010	384,170	656,179	469,831
Total Other Generation Expense	**5,070,191**	**362,140**	**405,021**	**413,835**	**375,227**	**368,142**	**431,917**	**392,834**	**365,885**	**445,010**	**384,170**	**656,179**	**469,831**
NET POWER COST	**$ 2,040,318,303**	**$ 149,135,191**	**$ 128,015,620**	**$ 123,687,809**	**$ 136,861,972**	**$ 141,264,863**	**$ 136,190,181**	**$ 230,106,401**	**$ 218,225,839**	**$ 196,013,525**	**$ 141,648,707**	**$ 173,126,387**	**$ 266,041,806**
Net Power Cost/Net System Load	$ 32.81	$ 27.33	$ 26.23	$ 25.37	$ 29.82	$ 29.96	$ 27.78	$ 36.93	$ 36.28	$ 39.06	$ 30.19	$ 33.84	$ 46.77

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 420

In the Matter of	)
	)
PacifiCorp, dba Pacific Power,	)
	)
2024 Transition Adjustment Mechanism.	)
	)

EXHIBIT AWEC/203

UPDATE PRODUCTION TAX CREDIT RATE FORECAST

PTC Inflation Adjustment Factor Calculations and PTC Rate Forecast

	Year	GDP Implicit Price Deflator Q1	Q2	Q3	Q4	AVG.	1992	Inflation Adjustment Factor Calculated	Actual	Delta	PTC Rate
	1992	119.80	120.60	121.20	121.80	120.90	120.90	1.0000	1.0000	-	1.5
	1993	123.30	124.00	124.50	124.90	124.20	120.90	1.0273	1.0273	-	1.5
	1994	125.00	125.90	126.50	126.90	126.10	120.90	1.0430	1.0430	-	1.6
	1995	106.70	107.30	107.80	108.30	107.50	100.00	1.0750	1.0750	-	1.6
	1996	109.00	109.50	109.90	110.30	109.70	100.00	1.0970	1.0970	-	1.6
	1997	111.71	112.22	112.62	113.05	112.40	100.00	1.1240	1.1240	-	1.7
	1998	112.32	112.56	112.84	113.04	112.69	100.00	1.1269	1.1269	-	1.7
	1999	103.83	104.19	104.46	104.98	104.37	91.70	1.1382	1.1382	-	1.7
	2000	106.10	106.73	107.15	107.65	106.91	91.84	1.1641	1.1641	-	1.7
	2001	108.65	109.21	109.82	109.75	109.36	91.84	1.1908	1.1908	-	1.8
	2002	110.14	110.48	110.76	111.21	110.65	91.84	1.2048	1.2048	-	1.8
	2003	105.15	105.43	105.85	106.16	105.65	86.39	1.2230	1.2230	-	1.8
	2004	107.25	108.09	108.48	109.06	108.22	86.39	1.2528	1.2528	-	1.9
	2005	110.91	111.62	112.53	113.49	112.14	86.39	1.2981	1.2981	-	1.9
	2006	114.95	115.89	116.42	116.89	116.04	86.39	1.3433	1.3433	-	2.0
	2007	118.75	119.52	119.83	120.61	119.68	86.39	1.3854	1.3854	-	2.1
	2008	121.51	121.89	123.06	123.21	122.42	86.39	1.4171	1.4171	-	2.1
	2009	109.69	109.69	109.78	109.88	109.76	76.53	1.4342	1.4342	-	2.2
	2010	109.95	110.49	111.05	111.15	110.66	76.53	1.4459	1.4459	-	2.2
	2011	112.40	113.12	113.84	114.08	113.36	76.60	1.4799	1.4799	-	2.2
	2012	114.60	115.04	115.81	116.07	115.38	76.60	1.5063	1.5063	-	2.3
	2013	106.11	106.26	106.78	107.20	106.59	70.64	1.5088	1.5088	-	2.3
	2014	107.66	108.23	108.60	108.64	108.28	70.57	1.5344	1.5336	0.00	2.3
	2015	109.10	109.67	110.03	110.29	109.77	70.57	1.5555	1.5556	(0.00)	2.3
	2016	110.63	111.26	111.65	112.21	111.44	70.57	1.5791	1.5792	(0.00)	2.4
	2017	112.75	113.03	113.61	114.27	113.42	70.57	1.6072	1.6072	-	2.4
	2018	109.37	110.27	110.68	111.22	110.38	67.33	1.6396	1.6396	-	2.5
	2019	111.47	112.19	112.66	113.04	112.34	67.33	1.6686	1.6687	(0.00)	2.5
	2020	113.42	112.82	113.84	114.37	113.63	67.33	1.6877	1.6878	(0.00)	2.5
	2021	116.12	117.92	119.71	121.71	118.37	67.28	1.7594	1.7593	0.00	2.6
	2022	124.17	126.91	128.27	129.51	127.21	67.28	1.8909			2.8
2023 Forecast	2023	130.8	*131.518*	*132.8135*	*134.1217*	*132.3133*	67.28	1.9667			***3.00***
		1.00%	*0.55%*	*0.99%*	*0.99%*	4.01%					
Zero Inflation	2023	129.508	*129.508*	*129.508*	*129.508*	*129.508*	0.00	1.9250			***2.90***
		0%	*0%*	*0%*	*0%*	0.0%					