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Exh. RJM-1CT
Docket UE-25_____
Witness: Ramon J. Mitchell

BEFORE THE WASHINGTON

UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP dba PACIFIC POWER & LIGHT COMPANY Respondent.	Docket UE-25_____

PACIFICORP

REDACTED DIRECT TESTIMONY OF RAMON J. MITCHELL

April 2025

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ATTACHED EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or Company).

A. My name is Ramon J. Mitchell, and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Director, Net Power Costs.

Q. Please describe your education and professional experience.

A. I received a Master of Business Administration degree from the University of Portland and a Bachelor of Arts degree in Economics from Reed College. I was first employed by the Company in 2015 and during my time at the Company I have held various positions in the regulation, merchant, and transmission departments. After a brief departure from PacifiCorp, in 2022 I returned and now serve as Director, Net Power Costs. In my current role I am responsible for leading and overseeing various efforts associated with the Company's net power costs (NPC) filings.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony to the Washington Utilities and Transportation Commission (Commission), as well as commissions in California, Idaho, Oregon, Utah, and Wyoming.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your direct testimony in this case?

A. My testimony presents the forecast NPC for calendar year (CY) 2026 along with an explanation of the changes since the 2023 general rate case (GRC)[1] and since recent CY 2024 actual NPC. Specifically, my testimony:

[1] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Co.,* Docket Nos. UE-230172 and UE-210852.

- Summarizes forecasted NPC for CY 2026 in this Power Cost Only Rate Case (PCORC) and explains NPC;
- Describes operational and allocation changes since the 2023 GRC as well as changes in comparison to CY 2024 actual NPC that substantially impact the 2026 NPC forecast;
- Explains the drivers behind the decrease in NPC compared to the recent, actual, incurred CY 2024 NPC; and
- Describes modeling changes the Company has made to improve the NPC forecast accuracy since the 2023 GRC.

III. ELEMENTS OF THE PCORC FILING

Q. What NPC elements are being updated in the PCORC filing?

A. The Company's NPC update the forecast for the following Federal Energy Regulatory Commission (FERC) accounts:

Account 447 - Sales for resale, excluding on-system wholesale sales and other revenues that are not modeled in Aurora;

Account 501 - Fuel, steam generation; excluding fuel handling, start-up fuel (gas and diesel fuel, residual disposal) and other costs that are not modeled in Aurora;

Account 503 - Steam from other sources;

Account 509 - Allowances;

Account 547 - Fuel, other generation;

Account 555 - Purchased power, excluding the Bonneville Power Administration (BPA) residential exchange credit pass-through if applicable; and

Account 565 - Transmission of electricity by others.

IV. FORECAST NPC

Q. Please provide an overview of NPC in the Company's filing.

A. The Company's proposed Washington-allocated NPC for the 2026 forecast period is approximately $43.81 per megawatt-hour ($/MWh)[2] under a newly proposed cost allocation methodology paired with resource adequacy requirements, discussed below.[3] Under the prevailing allocation methodology—the Washington Inter-Jurisdictional Allocation Methodology (WIJAM)—Washington-allocated NPC for 2026 would be $53.38/MWh.[4] A report detailing the proposed Washington-allocated NPC forecast is attached to my testimony as Exhibit No. RJM-2. Unless otherwise noted, references to NPC or various individual cost items throughout my testimony are stated in Washington-allocated amounts, before production factor adjustment.

Q. How does the forecast NPC in this proceeding compare to the NPC authorized in the Company's 2023 GRC?

A. As mentioned above—post-resource adequacy—the forecasted Washington-allocated NPC is $43.81/MWh, which is approximately $3.20/MWh, or 8 percent, higher than the $40.60/MWh[5] level calculated for the rate year two (RY2) compliance filing in the 2023 GRC. Pre-resource adequacy, the forecasted Washington-allocated NPC is $40.07/MWh,[6] which is approximately $0.53/MWh, or 1.3 percent, lower than the level calculated for the RY2 compliance filing.[7]

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[2] $194.6 million.
[3] See direct testimony of Company witness Rick T. Link for additional detail on the Company's proposed cost allocation methodology.
[4] $237.1 million.
[5] $184.0 million.
[6] $178.0 million.
[7] Docket No. UE-230172, PacifiCorp's Compliance Filing - Revisions to PacifiCorp's General Tariffs—Rate Year 2 filed March 7, 2025.

Q. How does the forecast NPC in this proceeding compare to 2024 actual NPC?

A. As an initial matter, all references to 2024 actual NPC are either references to historical, actual CY 2024 Washington-allocated NPC, calculated under the WIJAM, and used in the Power Cost Adjustment Mechanism (PCAM), or historical, actual total-company NPC incurred during CY 2024. The forecasted Washington-allocated NPC of $43.81/MWh in this proceeding are approximately $8.57/MWh, or 16 percent, lower than preliminary[8] 2024 *actual* Washington-allocated NPC of $52.38/MWh.[9] The drivers of this cost decrease are described below in my testimony.

Q. Why is 2024 actual NPC relevant?

A. The rate year one (RY1) and RY2 NPC forecasts in the 2023 GRC forecasted some or all of calendar years 2024, 2025 or 2026 and were *estimates* of what would and will occur. However, those estimates were based on multiple known-to-be inaccurate estimates. For example, the load, wind, solar and hydro forecasts were updated in CY 2023 and never refreshed.[10] Now, 2024 actual NPC under the WIJAM—which would flow into the PCAM—are known on a preliminary basis, and these actual NPC are not estimates. They are recorded historical costs and represent current system conditions. Consequently, because these 2024 actual NPC are "grounded in reality," they become the more relevant metrics to compare with the 2026 forecast NPC as it concerns cost drivers, since the 2023 GRC's forecasts are demonstrably not representative of recent system conditions experienced in reality.

[8] The CY 2024 PCAM's WIJAM *actual* NPC is preliminary. The final PCAM will have some variance after regulatory adjustments are calculated.
[9] $234.5 million.
[10] One or more parties in the 2023 GRC objected to a holistic refresh of the forecast's inputs.

Q. What modeling inputs were updated for this filing?

A. All inputs have been updated since the 2023 GRC, including system load, wholesale sales and purchase contracts for electricity, natural gas, and wheeling, market prices for electricity and natural gas also known as the official forward price curve (OFPC), fuel expenses, transmission topology, and the characteristics and availability of the Company's generation facilities.

Q. What is the date of the OFPC that the Company used for its forecast NPC?

A. The forecast NPC use the OFPC dated December 31, 2024.

Q. Please explain how the Company derives total-company NPC.

A. The Company derives NPC for a future test period based on a forecast using Aurora, which is a production cost model. Aurora simulates the operation of the Company's power system on an hourly basis and provides an hourly forecast of NPC for the future test period.

Q. Which version of Aurora was used to prepare this initial filing?

A. The Aurora version used to prepare this initial filing was version 15.0.1016.[11] No other version of Aurora is assured to be able to identically reproduce the NPC proposal in this initial filing.

Q. What reports does the Aurora model produce?

A. The major output from the Aurora model is the NPC report. Electronic versions are included in the workpapers accompanying the Company's filing. Those NPC reports include monthly data detailing major NPC components.

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[11] Specifically, Aurora version 15.0.1016.9052 released on December 13, 2024.

Q. How are Washington allocated NPC calculated?

A. The NPC are calculated under a newly proposed cost allocation methodology—the Washington 2026 Protocol (2026 Protocol)—described and explained in detail by Company witness Rick T. Link. The 2026 Protocol is a change from the prior cost allocation method—the WIJAM.

Q. What is the WIJAM and its relevance to NPC?

A. The WIJAM is the currently approved cost allocation methodology for Washington and is used to allocate system costs of providing retail service to Washington customers through retail rates. The WIJAM impacted the NPC forecast as follows:

- Inclusion of all power generation resources on the Company's system,[12] with an adjustment to exclude the costs and benefits of emitting resources that are not electrically located in the PacifiCorp Balancing Authority Area West (PACW)[13] and non-Washington qualifying facilities (QF);
- Inclusion of system transmission on both a firm and non-firm basis;
- Inclusion of the new transmission incremental to the existing transmission system; and
- Inclusion of Western Energy Imbalance Market (WEIM) benefits on a system basis.

Q. How does the 2026 Protocol change the treatment of NPC relative to the WIJAM?

A. The 2026 Protocol layers on the following changes to the WIJAM:

- System allocation factors are calculated as a four-year historical average;
- The Chehalis natural gas power plant is allocated on a situs basis;

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[12] At system allocation, except for emitting resources which were at western control area allocation.
[13] Except for the Jim Bridger plant, which *was* electrically located in PACW.

- The Jim Bridger power plant's natural gas units are system allocated;
- Oregon's system share of the Rolling Hills wind facility is allocated to Washington, incremental to Washington's system share;
- Hermiston is removed from Washington rates; and
- Coal generation is removed from Washington rates.

Q. How does compliance with the Clean Energy Transformation Act (CETA) change the treatment of NPC relative to the 2026 Protocol?

A. Because of CETA and the associated requirements:

- Washington's market price exposure is hedged separately from the rest of the system on an energy basis, using CETA compliant market products; and
- Washington's market supply exposure is hedged separately from the rest of the system on a resource adequacy basis, using CETA compliant market products.

Q. Does the Company propose any further updates to the NPC forecast?

A. Yes. The Company proposes to update the NPC forecast in the required compliance filing.[14] Specifically, this update will be based on the most recent OFPC available and will also reflect the Company's latest electric and gas hedging and contract positions. The purpose of this update is to use the latest and most accurate information to set the baseline going forward and is identical to the compliance filing updates from the 2023 GRC and the 2022 PCORC.[15]

[14] WAC 480-07-880.
[15] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Co.,* Docket No. UE-210402.

Q. Can you please describe in detail the steps that are necessary to complete the update?

A. First, forward prices for natural gas and electricity will be updated. In addition, hedge positions for power and gas will be updated based on the most recent month-end hedge positions available, and any mark-to-market values will be updated to reflect the use of the same OFPC that was described in the first step. Any new power purchase agreements or QF contracts will be included in the model, and any required updates to contracts that were previously included will be made. Finally, WEIM inter-regional transfer benefits will be re-forecast, also based on the same OFPC, to synchronize the model inputs for the most accurate output.

V. NPC VALIDATION

Q. What are the proposed *<u>total-Company</u>* NPC for CY 2026?

A. The proposed NPC for CY 2026 are $36.33/MWh *on a total-Company basis*.

Q. Why is the *total-Company* NPC forecast of 2026 relevant to Washington?

A. Washington allocated NPC begins with the total-Company NPC forecast, which is then allocated to Washington through the 2026 Protocol. NPC under the 2026 Protocol are allocated using a spreadsheet method that reflects assets included in Washington rates. This method, based on relatively simple ratios and formulas, is driven first and primarily by the total-Company forecast and then by the 2026 Protocol specific allocations. Consequently, it is important to first understand the drivers of NPC at the total-Company level and then explore the layered adjustments made under the 2026 Protocol to arrive at an understanding of Washington-allocated NPC.

Q. Is $36.33/MWh a reasonably accurate forecast for *total-Company* NPC?

A. Yes. *At the total-Company level*, actual 2024 NPC was $42.34/MWh. *At the total-Company level*, forecast 2026 NPC is $36.33/MWh. From the perspective of market prices: (1) 2026 Pacific Northwest summer and winter peak power prices **decrease** by two percent and Desert Southwest summer and winter peak power prices **increase** by 45 percent; (2) 2026 Pacific Northwest summer and winter natural gas prices **increase** by 111 percent and Rocky Mountain region summer and winter natural gas prices **increase** by 120 percent; and (3) resource adequacy requirements demonstrate capacity deficits that must be cured with incremental supply-risk based power hedges—discussed in further detail below.

These fundamentals—higher average power and gas prices—indicate that 2026 *forecast* total-Company NPC would be higher than 2024 *actual* total-Company NPC, all else equal. However, commodity price increases are offset by: (1) new battery energy storage systems which allow for intra-day price arbitrage opportunities, and provide dispatchable capacity, ultimately lowering NPC; (2) an estimated increase of approximately one million megawatt-hours (MWh) in Company owned wind generation; (3) increased coal supply relative to 2024; and (4) the removal of the Chehalis dispatch adder associated with the Climate Commitment Act. Altogether, these changes to market fundamentals—and more—combine to reduce total-Company NPC as compared to the actuals observed in 2024.

Q. Is $43.81/MWh a reasonably accurate forecast for *Washington* NPC?

A. Yes. *At the Washington-allocated level*, 2024 actual NPC was $52.38/MWh. *At the Washington-allocated level*, post-resource adequacy 2026 forecast NPC is

$43.81/MWh. Incremental to the total-Company fundamentals discussed above, and relative to the pre-resource adequacy 2026 forecast NPC of $40.07/MWh, the following changes present themselves:

1) Washington's resource composition has changed under the 2026 protocol, along with other details discussed by Company witness Link;
2) From the perspective of hedges: CETA requires special products to hedge Washington—by virtue of forbidding coal from being a component of customer rates. Therefore, Washington's price risk is hedged separately. Furthermore, these products are sold at a premium to the OFPC; and
3) From the perspective of resource adequacy: the system is kept resource adequate, however CETA forbids coal from being a component of customer rates. Therefore, Washington's resource adequacy—and the associated supply risk power hedges—is maintained separately.

The first change results in the pre-resource adequacy forecast and the last two changes offset the decrease to NPC observed in the pre-resource adequacy NPC forecast. That is to say, relative to 2024 actual NPC there is still a decrease to NPC. However, that decrease is diminished by the CETA prohibition on coal which induces separate hedging for Washington. This separate "book-keeping" for Washington is the practice that was identified as uneconomic in the 2022 PCAM.[16] Details on price risk and supply risk hedges are discussed below.

[16] *In the Matter of PacifiCorp d/b/a Pacific Power & Light Company, 2022 PCAM Report*, Docket No. UE-230482, Order 07 at ¶ 123 (Oct. 30, 2024).

VI. HEDGING

A. CETA Compliance

Q. Washington state legislation requires that unspecified-source power market purchases with a delivery duration longer than a month be compliant with CETA.[17] How does this impact NPC?

A. Since the bilateral power markets primarily offer forward energy products as unspecified and in quarterly blocks, Washington's energy obligations can no longer be hedged with those products. Instead, the Company will have to execute custom—CETA compliant—deals with individual counterparties. These CETA compliant deals impose additional requirements on the counterparty, as compared to traditional quarterly, unspecified energy deliveries, and therefore are sold at a premium.

Q. How has this premium been accounted for in the NPC forecast?

A. Through observations of CETA compliant bilateral market product pricing, observations of resource specific bilateral market product pricing, observations on the value/pricing of greenhouse gas emissions, renewable energy credits, and various other clean energy attributes, along with analysis of internal calculations, the implied premium for a CETA compliant energy product is approximately 80 percent. To account for uncertainty, the Company chose a conservative premium of 50 percent on top of the costs of traditional quarterly power hedge blocks and applied that premium to all forward transactions in the NPC forecast.

[17] RCW 19.405.030(1)(a); RCW 19.405.020(7)(b)(i).

Q. House Bill (HB) 1329[18] and Senate Bill (SB) 5401[19] in the Washington state legislature both propose to allow for non-CETA compliant (unspecified) quarterly energy products to be allowed in customer rates. How do these bills factor into the NPC forecast?

A. Neither bill has passed (as of the preparation of this testimony). Therefore, the current law[20] is assumed to be in effect for the 2026 test period. If the law is changed to allow a portion of unspecified quarterly energy products in rates (as currently contemplated by the bills), then the Company proposes that the 50 percent premium on supply risk (resource adequacy) hedges be re-evaluated since those types of hedges, under certain conditions, can be unspecified. Price risk hedges, unrelated to resource adequacy, may still require CETA compliant products under certain scenarios in the proposed bills.

B. <u>Hedging Practices and Procedures</u>

Q. Please briefly provide an overview of the Company's power hedging practices and procedures going forward.

A. As referenced in the direct testimony of Company witness Michael G. Wilding:

> The Company proposes to create two separate power and gas hedge books […] Additionally, the risk management policy will be updated to create risk limits to address the resource adequacy position and the average energy position of the two power hedge books. This will allow the Company to manage risk to net power costs (NPC) on behalf of Washington customers, while ensuring compliance with all relevant state laws.

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[18] WASHINGTON STATE LEGISLATURE, HB 1329 - 2025-26, https://app.leg.wa.gov/billsummary?BillNumber=1329&Year=2025 (last visited Mar. 26, 2025).
[19] WASHINGTON STATE LEGISLATURE, SB 5401 - 2025-26, https://app.leg.wa.gov/billsummary?BillNumber=5401&Chamber=Senate&Year=2025 (last visited Mar. 26, 2025).
[20] RCW 19.405.030(1)(a); RCW 19.405.020(7)(b)(i).

> The Company will create a monthly Washington resource adequacy position based on Washington load plus a [planning reserve margin (PRM)] and generation resources. [redacted]
>
> In addition to ensuring resource and energy adequacy, the Company will also calculate an average on- and off-peak position for the purpose of managing risk to NPC. The Company will run [a production cost model] on a total-Company basis, then apply the 2026 Protocol allocation factors to the generating resources, contracts, and QFs that are included in Washington rates. The generation output of the Washington generation portfolio will be compared to the Washington load forecast (also by month and peak type) to determine the Washington open position. [redacted][21]

Company witness Wilding goes on to provide further detail on managing risk for Washington customers under a CETA compliant framework in his direct testimony.

Q. Are these new hedge practices subject to the Day-Ahead/Real-Time (DA/RT) price component?

A. No. The prices used in the DA/RT price component[22] are created in recognition of the fact that, in actual operations, the Company purchases at prices above the OFPC and sells at prices below the OFPC in the spot market (i.e., the day-ahead and real-time

[21] Direct testimony of Michael G. Wilding at 11-13.
[22] Explained in Confidential Exhibit No. RJM-6C.

trading horizons); and Aurora's optimization is fundamentally a spot market simulation. Because this modeling update is intended to simulate forward transactions, the prices for the simulated hedges are added to the model with no price adjustment. This is reflective of the Company's transaction history, which indicates that forward hedges are executed at or about the prevailing market price at the time of execution, on average.

Q. Based on what has been described in Company witness Wilding's testimony, how does the NPC forecast with both price risk and supply risk hedges compare to the NPC forecast without?

A. The Washington-allocated NPC impact of this change is an increase of \$3.10/MWh or \$13.8 million. This change is incremental to the Company's current hedging policy, details of which are discussed below in Section IX(C).

VII. NPC OVERVIEW – 2026 PROTOCOL v WIJAM

Q. Please describe Washington's 2026 market exposure under the 2026 Protocol.

A. Starting with the total-Company NPC, Washington-allocated NPC are determined by comparing Washington load to the generation and market transactions (resources) that are allocated to Washington (*i.e.*, the resources that the 2026 Protocol provide for Washington), this creates a rate-making energy position. In this filing, Washington resources **exceed** Washington load on an annual basis—by 239,973 MWh, or five percent of load (**surplus**). This is an elimination of market exposure in the context of allocations and results in an allocated surplus of energy on a net annual basis. The energy position is calculated monthly and then rebalanced at the monthly level in the 2026 Protocol spreadsheet to arrive at the Washington-allocated NPC. *Surplus* rebalancing is done by first eliminating system balancing purchases. If there are not sufficient system balancing purchases to eliminate, an amount of system balancing sales are imputed that allow the 2026 Protocol to maintain supply-demand balance. Any system balancing purchases that are eliminated or system balancing sales that are imputed in the rebalancing adjustment are done using the average price of either the system balancing purchases or system balancing sales. The rebalancing adjustment *reduces* Washington NPC by $3.78/MWh or $16.8 million.

Q. Please describe Washington's 2026 market exposure under the WIJAM.

A. Like the 2026 Protocol, starting with the total-Company NPC, Washington-allocated NPC are determined by comparing Washington load to the generation and market transactions that are allocated to Washington, this creates a rate-making energy position. Under the WIJAM, Washington resources **fall short of** Washington load on an annual basis—by 1,433,831 MWh, or 32 percent of load (**deficit**). This is a shortfall of energy that creates a substantial amount of market exposure. The energy position is calculated monthly and then rebalanced at the monthly level in the WIJAM spreadsheet to arrive at the Washington-allocated NPC. *Shortfall* rebalancing is done by first eliminating system balancing sales. If there are not sufficient system balancing sales to eliminate, an amount of system balancing purchases are imputed that allows the WIJAM to maintain supply-demand balance. Any system balancing sales that are eliminated or system balancing purchases that are imputed in the rebalancing adjustment are done using the average price of either the system balancing sales or system balancing purchases. This rebalancing adjustment under the WIJAM increases Washington NPC by $24.23/MWh or $107.6 million.

Q. Please explain, by line item, the changes in Washington-allocated NPC under the 2026 Protocol compared to the WIJAM.

A. As an initial matter, and as discussed above, post-resource adequacy NPC under the 2026 Protocol are $43.81/MWh and under the WIJAM, are $53.38/MWh. Illustrated below in Tables '2026 NPC Price,' '2026 NPC MWh,' and '2026 NPC Dollars' are the line item changes in the components of NPC between the use of the WIJAM and the use of the 2026 Protocol to both forecast 2026 Washington-allocated NPC. The data in the three tables are prices, energy, and dollars, respectively. Below, I expand on the individual line items.

Table '2026 NPC Price'

Net Power Cost Reconciliation			
	WIJAM $/MWh	**2026 Protocol $/MWh**	**Change**
NPC Components			
Wholesale Sales	NA	50.75	NA
Purchased Power	66.12	65.68	(0.44)
Coal Fuel	0.00	0.00	0.00
Natural Gas Fuel	46.14	42.28	(3.85)
Wheeling and Other	21.73	21.73	0.00
2026 Total NPC $/MWh)	**53.38**	**43.81**	(9.58)

Table '2026 NPC MWh'

Net Power Cost Reconciliation (MWh)	
	MWh
WA 2026 PCORC WIJAM	**4,441,744**
	-
Components of Load	
Wholesale Sales	(237,459)
Purchased Power	(1,375,982)
Coal Generation	0
Natural Gas Generation	1,502,927
Wheeling and Other	110,514
Total Change to Load	(0)
WA 2026 PCORC - 2026 Protocol	**4,441,744**

Table '2026 NPC Dollars'

Net Power Cost Reconciliation ($)	
	($ millions)
WA 2026 PCORC WIJAM	**237.1**
	-
Components of NPC ($):	
Wholesale Sales Revenue	(12.04)
Purchased Power Expense	(91.55)
Coal Fuel Expense	0.00
Natural Gas Fuel Expense	59.84
Wheeling and Other Expense	1.20
Total Change to NPC ($)	(42.54)
WA 2026 PCORC – 2026 Protocol	**194.6**

Q. Please explain the increase in wholesale sales revenue.

A. Wholesale sales revenues increase[23] in the 2026 Protocol due to the increase in generation allocated to Washington. This increase in Washington allocated generation eliminates market exposure on an annual basis and therefore reduces the backdown of

[23] The signage for revenues is opposite the signage for costs.

sales (i.e., increases sales) through the rebalancing adjustment, relative to the WIJAM.

Q. Please explain the decrease in purchased power expense.

A. Purchased power expense decreases in the 2026 Protocol due to the increase in generation allocated to Washington. This increase in Washington allocated generation eliminates market exposure on an annual basis and therefore reduces the increase in simulated purchases (i.e., reduces purchases) through the rebalancing adjustment, relative to the WIJAM. This increase is slightly offset by the supply risk resource adequacy hedges.

Q. Please explain the increase in natural gas fuel expense.

A. The net impact of the allocation of Chehalis to Washington on a situs basis along with the system allocation of the Jim Bridger gas units and the removal of Hermiston from rates provides for an approximate doubling of natural gas capacity and associated generation provided for Washington customers. This increased generation increases the natural gas fuel expense.

Q. Please explain the increase in wheeling and other expense.

A. Wheeling expenses increase due to the change in system allocation factors from the WIJAM to the 2026 Protocol.

VIII. NPC OVERVIEW – RECENT ACTUALS

Q. Please generally describe the changes in this Washington-allocated 2026 NPC forecast compared to Washington-allocated preliminary 2024 actual NPC.

A. Tables '2Y NPC Prices,' '2Y NPC Energy,' and '2Y NPC Dollars,' illustrate the changes in NPC by category from the preliminary 2024 actual WIJAM NPC to the 2026 forecast 2026 Protocol NPC.

Table '2Y NPC Price'

Net Power Cost Reconciliation			
	2024 WIJAM $/MWh	**2026 Protocol $/MWh**	**Change**
NPC Components			
Wholesale Sales Revenue	45.13	50.75	5.62
Purchased Power Expense	95.12	65.68	(29.43)
Coal Fuel Expense	34.35	0.00	(34.35)
Natural Gas Fuel Expense	34.63	42.28	7.66
Wheeling and Other Expense	21.82	21.73	(0.08)
Total NPC	**52.38**	**43.81**	(8.57)

Table '2Y NPC MWh'

Net Power Cost Reconciliation	
	MWh
2024 WA Preliminary Actual NPC	**4,476,612**
Change to Load:	
Wholesale Sales Increase	(214,541)
Purchased Power Decrease	(217,075)
Coal Generation Decrease	(807,518)
Natural Gas Generation Increase	1,040,934
Other Generation Increase	163,332
Total Change to Net System Load	**(34,868)**
2026 WA 2026 Protocol Forecast NPC	**4,441,744**

Table '2Y NPC Dollars'

Net Power Cost Reconciliation	
	($ millions)
2024 WA Preliminary Actual NPC	**234.5**
Increase/(Decrease) to NPC:	
Wholesale Sales Revenue	(11.0)
Purchased Power Expense	(59.0)
Coal Fuel Expense	(27.7)
Natural Gas Fuel Expense	54.9
Wheeling and Other Expense	2.9
Total Change to NPC:	**(39.9)**
2026 WA 2026 Protocol Forecast NPC	**194.6**

First, on a *total-Company basis*, the favorable change in 2026 forecast NPC relative to 2024 actual NPC is driven by continued in-model over optimization—within Aurora—of market sales, which artificially increases modeled wholesale sale revenues in 2026, more optimal timing of market purchases resulting from the introduction of battery energy storage systems in 2026, additional coal supply in 2026 relative to 2024, and the construction/acquisition of additional wind resources in 2026.

Second, on a *Washington-allocated basis*, the change in 2026 forecast NPC relative to 2024 actual NPC is first driven by the total-Company changes referenced above and then driven by the change in allocation methodology along with CETA compliant price risk hedges and supply risk resource adequacy hedges. Incremental to the total-Company fundamentals, coal is removed from rates—therefore there is no coal fuel expense. The move from the WIJAM to the 2026 Protocol eliminates market exposure on an annual basis, resulting in an increase in sales revenue and a decrease in purchased power expense, as explained above in Section VII. These decreases to 2026 forecast NPC are offset by the CETA compliant price-risk hedging transactions for Washington, along with the CETA compliant supply-risk resource adequacy hedges, all of which are at a premium to the market. The increase in natural gas market prices concurrent with the increase in natural gas generation allocated to Washington customers results in increased natural gas fuel expense, and the wheeling expense increase reflects a normalization of historical wheeling expenses supporting historical actual purchased power volumes, which have increased over the historical period, along with the change in allocation factors.

IX. MODELING IMPROVEMENTS TO THE NPC FORECAST

Q. Why are modeling improvements necessary?

A. Modeling improvements are needed to align the NPC forecast to operational realities for the purpose of increasing the reasonableness and accuracy of the NPC forecast. In the 2023 GRC compliance filing submitted in March 2024 the Company forecasted *total-Company* NPC for *CY* 2024 at $37.88/MWh (absent production factor adjustment). Actual NPC for CY 2024 was recorded at $42.34/MWh. This is an *under-forecast* of $4.46/MWh, or 11 percent, and demonstrates the need for modeling improvements.

Q. In addition to the modeling improvements proposed in the 2023 GRC, has the Company incorporated any additional modeling improvements into this 2026 PCORC?

A. Yes. The Company is proposing the following modeling improvements:

- An updated WEIM benefits methodology;

- An EDAM benefits methodology;
- The NPC forecast will simulate power hedging transactions to maintain compliance with PacifiCorp's current Energy Risk Management Policy;
- An update to market sales capacity limits to remove double counting of hedges; and
- Use of Unspecified Purchased Power to satisfy ramp and capacity deficits in addition to energy deficits.

A. <u>WEIM Benefits Methodology</u>

Q. What change is the Company proposing for WEIM benefits?

A. Please refer to Exhibit No. RJM-9 for details. The Washington-allocated NPC impact of this change is a decrease of $2.6 million.

B. <u>EDAM Benefits Methodology</u>

Q. What is the EDAM?

A. The EDAM is a market that allows for limited[24] regional, centralized scheduling and commitment of electricity on a day-ahead basis. This market aims to enhance the efficiency and reliability of electricity supply by optimizing the use of resources across a broader geographic area. EDAM participation can help utilities like the Company manage their NPC more effectively and integrate renewable energy sources more efficiently.

The current WEIM optimizes the energy imbalances throughout the West by transferring energy between participants in 15-minute and 5-minute intervals throughout the day. The EDAM builds on this real-time market by extending

[24] Based on number of EDAM participants in the first year.

optimization to hourly intervals on a day-ahead basis while keeping the 15-minute and 5-minute optimizations.

Q. Since the EDAM is scheduled for implementation in 2026, how has the Company incorporated this market into this 2026 NPC forecast?

A. As an initial matter, there are three foundational elements of the EDAM that must be outlined before any discussion of EDAM benefits.

Q. What is the first foundational element?

A. **First**. It is only after one-third of the year has passed, in May 2026—assuming no delays—that the EDAM is anticipated to be implemented with the only participants being the Company and the California Independent System Operator (CAISO). In October 2026, Portland General Electric (PGE) is then scheduled to join the EDAM. After PGE, no further participants are scheduled for EDAM entrance in 2026. This dilutes EDAM benefits due to the limited EDAM time to be experienced in 2026, along with the lengthy learning curve required to become familiar with and proficient in this new market.

Q. What is the second foundational element?

A. **Second**. On implementation, the transfer capability within the EDAM will be one transmission path between PACW and the CAISO, which is the same transmission path used today in the WEIM. It is anticipated that this paradigm will continue when PGE joins the EDAM. That is to say, the transmission paths used today in the WEIM to connect the Company and PGE will be the same transmission paths used to connect the Company and PGE in the EDAM. This dilutes EDAM benefits because these are not new connections between entities. Since transmission capacity is static, one of the functional impacts of the EDAM upon implementation will be a movement of benefits out of the intra-day horizon of the WEIM and into the day-ahead horizon of the EDAM, along with improvement to unit commitment.

Since the EDAM benefits shown in this 2026 NPC forecast are incremental to "business as usual," which includes the current WEIM, and since the WEIM benefits in this forecast have not been adjusted downwards to account for cannibalization of WEIM benefits by the EDAM, the EDAM benefits in this 2026 NPC forecast are present both in the calculation described further below, and in the WEIM benefits that currently exist. Presented further below are only the portion of EDAM benefits that are *not* currently embedded in the WEIM benefits. Quantification of the portion of EDAM benefits that *are* currently embedded in the WEIM benefits has not been performed.

Q. What is the third foundational element?

A. **Third**. Although the conceptual market design is known, the way EDAM participants—including the Company—will operate within the confines of the actual market design across pivotal market elements is mostly unknown. Examples of these mostly unknown pivotal market elements are: (1) amount of transmission donated; (2) use of price taker self-schedules versus standard economic bids; (3) potential restrictions on market based commitment; (4) methods to mitigate the misalignment between gas delivery versus power delivery start times; (5) interaction with third party utilities that exist within an EDAM entity's balancing authority area; (6) market bidding strategies; (7) impact of market power mitigation rules; and (8) multiple other issues. Furthermore, as it concerns the operations of non-Company EDAM participants, many of these pivotal market elements of operation will never be fully known.

Q. How do these three foundational elements above relate to incorporating EDAM benefits into this 2026 NPC forecast?

A. If the Company's system and associated footprint were smaller in size, it may have been possible to simulate a rough and generally accurate approximation of a simplistic, bifurcated, dual market system, with both the EDAM and the pre-existing bilateral markets co-existing—however this is not the case. The EDAM cannot currently be modeled by the Company within a production cost model—at bare minimum—until the market accumulates some history of operations. However, the Brattle Group, Inc. (Brattle), a well-respected consulting practice, has in its possession, preliminary information on tentatively speculative market operations expectations as it concerns the Company, the CAISO, PGE, and six other balancing authority areas—provided to Brattle by those balancing authority areas. Brattle used that utility-confidential data to simulate EDAM benefits incremental to the current status quo for CY 2030.[25] The Company has pro-rated those EDAM benefits to CY 2026 and applied the resulting amount as an out-of-model adjustment.

Q. Please elaborate.

A. Brattle modeled PacifiCorp's EDAM benefits to be $359 million total-company in 2030. These benefits are incremental to the status quo of the bilateral markets and the WEIM. Along with those benefits, the total annual gigawatt-hour (GWh) transfers between each of the nine assumed EDAM participants, as of 2030, (displayed below

[25] Confidential Exhibit PAC/112.

in Confidential Figure 'EDAM Transfers') were derived. From these values, the Company extracted transfers between the Company and both the CAISO and PGE to prorate the benefits downward to CY 2026, and then further prorated the benefits downwards to account for each entity's EDAM implementation date.

Confidential Figure EDAM Transfers

[redacted]

Q. What is the decrease to NPC resulting from this EDAM benefits methodology?

A. The Washington-allocated NPC impact of EDAM benefits before accounting for the EDAM grid management charge, *and without accounting for the EDAM benefits embedded in the WEIM benefits*, is a decrease of [redacted]. The EDAM grid management charge is expected to be [redacted] in 2026. Therefore, the Washington-allocated net impact of the EDAM on NPC, without accounting for the EDAM benefits embedded in the WEIM benefits, is forecasted to be a decrease of [redacted].

C. <u>Hedging Requirements</u>

Q. Please briefly provide an overview of the Company's current power hedging requirements.

A. The Company revised its Risk Management Policy in 2021 with the specific and stated goal of guiding energy supply management to purchase increasing amounts of power in periods with short positions. This is intended to limit the possibility of being short during periods of peak demand and peak pricing. This revised policy imposes power hedge percentage limits that are applied independently to each side of the system,[26] varying by quarter, and escalating as the time to delivery of power approaches. The most relevant requirement in relation to the Company's NPC forecast is the requirement that positions be hedged at a level where, on average, a minimum of 75 percent of each month's peak hour is hedged in the first quarter of the future (e.g., in December 2024 this would apply to the first quarter of 2025).

Q. In its original form, is the NPC forecast in compliance with the Company's current power hedging requirements?

A. No. Aurora is a forward-looking, optimized, deterministic dispatch model with no knowledge of the Company's hedging requirements or how they evolve over time. While some quarters may be in compliance without this modeling improvement, that is coincidental, not an indication that the model intentionally satisfies the requirements imposed by the Company's risk management policy.

Q. What change was made to align the NPC forecast with the Company's current power hedging requirements?

A. To reflect the fact that the Company will eventually need to hedge each quarter at a minimum average of 75 percent, additional short-term firm transactions are calculated, in <u>quarterly 25 megawatt (MW) energy blocks of heavy or light load hour products</u>, and loaded into the model to ensure that the quarterly average hedge ratio in the peak hour of each month satisfies the policy-dictated minimum requirements for

[26] PacifiCorp West and PacifiCorp East.

the first quarter. In that way, the inputs to the model are created in a manner which recognizes that all four quarters in the test period will eventually be the first quarter in actual operations and the Company will need to execute forward transactions to satisfy its hedging policy requirements.

Q. Does this change conform to the realities of actual operations?

A. Yes. As noted above, each month in the test period will eventually be part of a quarter that needs to be hedged at a minimum average of 75 percent in actual operations, as measured against the peak hour load, by side of system.

Q. Are these simulated hedge volumes subject to the DA/RT price component?

A. No. The prices used in the DA/RT price component are created in recognition of the fact that, in actual operations, the Company purchases at prices above the OFPC and sells at prices below the OFPC *in the spot market*; and Aurora's optimization is fundamentally a spot market simulation. Because this modeling update is intended to simulate forward transactions, the prices for the simulated hedges are added to the model with no price adjustment. This is reflective of the Company's transaction history, which indicates that forward hedges are executed at or about the prevailing market price at the time of execution, on average.

Q. Why was no change made to the NPC forecast for the Company's gas hedging requirements?

A. Because such a change would have no impact to the NPC forecast. Aurora does not physically balance the gas system, and the impact of gas hedges consists entirely of the mark-to-market (MTM) value of those hedges. Were the Company to simulate gas purchases at expected market prices (i.e., the OFPC), they would show no MTM impact and additionally, the associated gas volumes are not modeled in Aurora, so there would be no change to the NPC forecast.

Q. What is the NPC impact of this modeling update?

A. The Washington-allocated NPC impact of this change is an increase of $22.8 million. This change is incremental to having no simulated hedges of any type in the NPC forecast.

D. Market Sales Capacity Limits

Q. Please explain the company's market sales capacity limits adjustment.

A. Now, with the inclusion of simulated hedge volumes—and full compliance with hedge policy—in the NPC forecast, the Company has removed volumes related to hedges from its market sales capacity limits calculation.

Q. Why is the Company proposing to remove hedge volumes from its market sales capacity limits calculation?

A. Under the previous method, market sales capacity limits were first calculated using historical sales volumes inclusive of sales hedge volumes. Then, second, these limits were reduced by executed sales hedge volumes for the test period, in order to provide for a realistic modeled estimate of spot market sales volumes (i.e., sales in the day-ahead and real-time trading horizons) plus *yet-to-be-executed* sales hedge volumes in the modeled NPC. However, since the modeled NPC is now fully hedged with simulated hedge volumes from the 'Hedging Requirements' modeling update discussed above, the modeled market sales volumes in the 2026 forecast NPC now represent only spot market sales volumes. For this reason, the market sales capacity limits *calculation* now includes only spot market sales volumes (i.e., excludes all hedge volumes) in its calculation to avoid potential double counting.

Please refer to Confidential Figure 'Market Sales Down' below, specifically the last column labeled "2026 PCORC (Proposed Method)," for a visualization of the change to total-Company market sales volumes under this method as compared to the prior method, and historical market sales. As illustrated, the prior method, "2026 PCORC (Current Method)," shows a sales volumes forecast that is greater than the four-year average sales volumes and far greater than an expectation of the 2026 sales volumes extrapolated from the downward trend observed in market sales volumes over the past four years.

Confidential Figure Market Sales Down

[redacted]

Q. What is the NPC impact of this modeling update?

A. Removing hedge volumes from the market sales capacity limits calculation results in a Washington-allocated NPC increase of $3.7 million.

Q. In the 2023 GRC, there was an assertion that market hubs at Mid-Columbia (Mid-C), Palo-Verde (PV) and Four Corners do not require any market sales capacity limits.[27] In addition to the supporting testimony in Confidential Exhibit No. RJM-4C, does the Company have any other evidentiary support to offer?

A. Yes. The Company created a 2020 Benchmark Study to validate the accuracy of Aurora by forecasting (back-casting) historical NPC given actual, then-prevailing market inputs. This benchmark study is detailed in Confidential Exhibit No. RJM-5C. Using the benchmark study as a starting point for testing, the Company fixed (set as static and known in the model) all historical sales volumes except for real-time sales volumes (i.e., fixed hedge volumes to day-ahead sales volumes) and then ran the model to observe the in-model (modeled) system balancing sales, which should be representative of historical real-time sales volumes, given the aforementioned fixing of all other sales volumes.

Q. Please explain this simulation of real-time sales volumes in further detail.

A. With modeled system balancing sales as a proxy for historical real-time sales there was a need to adjust the DA/RT price component to account for only historical real-time transactions, instead of historical real-time and day-ahead transactions. Furthermore, the DA/RT volume component was adjusted to remove the inferred daily, 25 MW

[27] Docket Nos. UE-230172 and UE-210852, Order No. 08/06 at ¶ 258 (Mar. 19, 2024).

increment block products that represent products from day-ahead trading. Lastly, the market sales capacity limits were removed to assess their impact.

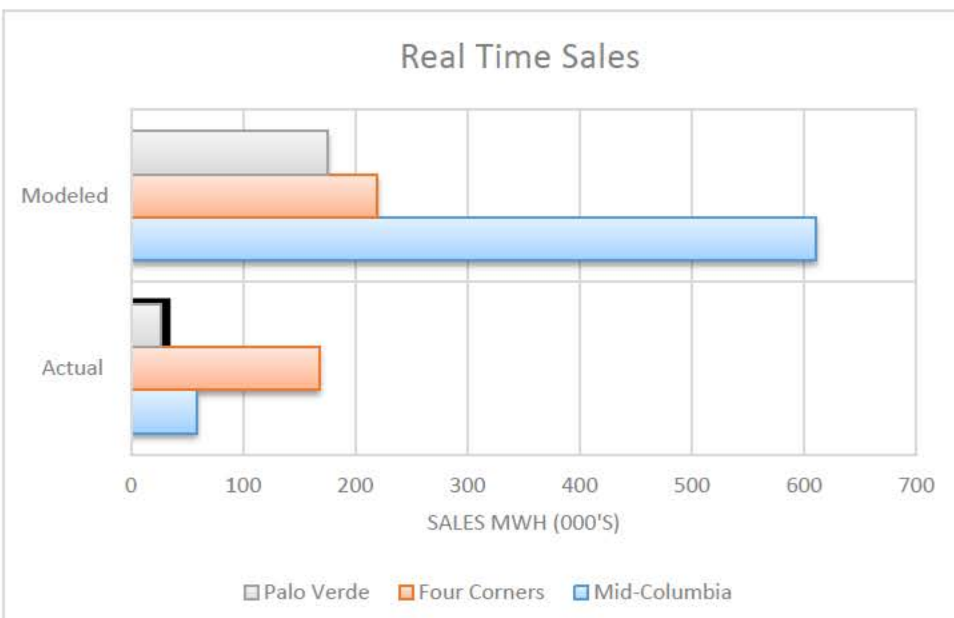
Q. How do the modeled real-time sales compare with the actual, historical real-time sales?

A. Using the Aurora 2020 benchmarking study, the below Table 'RT Sales' and Figure 'RT Sales' shows a comparison between modeled real-time sales volumes and historical real-time sales volumes, in 2020, at the Mid-C, PV, and Four Corners trading hubs.

Table 'RT_Sales'

2020 Real-Time Sales			
	Actual (MWh)	Forecast (MWh)	Percentage Increase (%)
Mid-Columbia	58,622	610,866	942%
Palo Verde	26,432	175,257	563%$
Four Corners	167,6161	219,509	31%

Figure 'RT_Sales'



As can be seen from Table 'RT Sales,' modeled real-time sales volumes at the Mid-C, PV and Four Corners trading hubs are greater than historical real time sales volumes by percentages of approximately 942 percent, 563 percent, and 31 percent respectively. This shows that without market sales capacity limits at these trading hubs, Aurora over-optimizes system balancing sales volumes. This over-optimization and the consequent overstatement of wholesale sales revenue necessitate application of market sales capacity limits to all trading hubs, inclusive of Mid-C, PV, and Four Corners.

Q. Do the increased modeled real time sales volumes reflect an expectation of increased market depth in the test period?

A. No. Please refer to Confidential Figure 'Market Sales Down' above. The modeled real-time sales volumes from this test implies market depth that is contrary to the Company's recent experience.

E. Unspecified Purchased Power

Q. What is unspecified purchased power within the Company's NPC forecast?

A. Unspecified purchased power is a simulation of regular firm purchased power, with the caveat that no modeled transmission is required to move the purchased power to the point of delivery. Unspecified purchased power is primarily designed to remedy energy deficits, ramp capability deficits and capacity deficits with modeled firm purchased power.

Q. How is unspecified purchased power related to the longstanding modeling enhancement known as 'emergency purchases' within the NPC forecast?

A. They are the same. The difference is only in the nomenclature.

Q. If the only change to the feature is a name change, why is it addressed in this section?

A. In the 2022 PCORC, emergency purchases were used to satisfy energy deficits, ramp capability deficits and capacity deficits, just like they are used in this PCORC (albeit with a different name). In the 2023 GRC, emergency purchases were inadvertently deactivated as it relates to the satisfaction of ramp capability deficits and capacity deficits. Now, the feature is restored back to its precedential nature, and the Company discusses its restoration in the interest of transparency.

Q. Why are there energy deficits in the NPC forecast that require the usage of unspecified purchased power as a remedy?

A. The test period short-term transmission capacity modeled in the NPC forecast is based on a four-year average of historical short-term transmission capacity. However, the load and generation in the NPC forecast is based on actual test period expectations (example, includes upcoming new wind and solar resources).

This creates a mismatched scenario wherein there can be more load or generation than there is transmission to fully satisfy the needs of that load or generation. This mismatch occurs because the short-term transmission capacity required in 2026 will be more than the four-year average of historical short-term transmission capacity after accounting for year-over-year growth in load and generation.

Q. Why are there ramp capability deficits and capacity deficits in the NPC forecast that require the usage of unspecified purchased power as a remedy?

A. The need for dispatchable capacity resources to regulate the supply/demand balance is substantially increased as additional amounts of load, wind resources and solar resources are integrated into the Company's system. Increased energy from firm purchased power is required to free up ramp and capacity on existing dispatchable capacity resources to integrate that additional load, wind, or solar. However, the modeled short-term transmission capacity lags behind reasonable expectations of test period short-term transmission capacity needs due to the usage of four-year historical averages.

Q. Please quantify the NPC impact of this modeling improvement.

A. The Washington-allocated NPC impact of this change is a decrease of $0.53 million.

X. ROUTINE UPDATES

A. Non-Precedential Modeling Improvements

Q. How has the Company treated the non-precedential modeling improvements from the 2023 GRC?

A. All non-precedential modeling improvements from the 2023 GRC are included in this filing. Please refer to Confidential Exhibit No. RJM-4C,[28] Confidential Exhibit No. RJM-6C,[29] Exhibit No. RJM-7,[30] Exhibit No. RJM-8,[31] Confidential Exhibit No. RJM-11C,[32] and Exhibit No. RJM-12[33] for supporting testimony.

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[28] Market sales capacity limits for all power trading hubs.
[29] Day-ahead/real-time (DA/RT) price component; DA/RT volume component; DA/RT volume component correction.
[30] DA/RT percentile modifier.
[31] DA/RT volume component correction.
[32] DA/RT percentile modifier; DA/RT volume component correction.
[33] NPC impact of non-precedential changes.

B. Power Trading Hub Mapping

Q. What inputs were updated for this filing?

A. The Company updated all inputs to the 2026 PCORC, including wholesale sales and purchase contracts for electricity and natural gas.

Q. How do wholesale sales and purchase contracts for electricity and natural gas flow into the NPC forecast?

A. First, the Company's commodity management software records all wholesale sales and purchase contracts for electricity and natural gas that are executed in actual operations. This source data then flows into the NPC forecast for calculation of physical power hedges (physical power transactions), physical gas hedges (physical gas transactions), financial gas hedges (financial gas transactions), market sales capacity limits (physical power sale transactions), and day-ahead / real-time transactions (spot market physical power transactions).

Q. How does the NPC forecast account for physical power transactions within the production cost models?

A. Regarding physical power transactions, the Company executes these transactions across many different trading points in the West (western interconnection). These trading points can be categorized as minor trading points or major trading points. For modeling convenience, the NPC forecast models only the major trading points[34] and then maps all transactions at minor trading points to those major trading points. For example, from an electronic tagging (E-Tag) perspective, the energy associated with a physical power hedge transacted with the BPA may be received at the minor trading

[34] Mid-C, California Oregon Border (COB), Nevada Oregon Border (NOB), Mona, Mead, Four Corners, PV.

point known as the Bonneville/PacifiCorp transmission interface (BPAT.PACW). Since the NPC forecast only models major trading hubs, this particular hedge would be mapped to the Mid-C major trading hub.

Q. Why is this mapping process necessary?

A. For accuracy of the NPC forecast all physical power transactions must be accounted for. However, for simplicity of modeling, all trading points across the West are not accounted for in the Company's production cost model. Therefore, all physical power transactions are mapped to one of the major trading points and all major trading points are modeled in the NPC forecast. This ensures that purchases and sales of physical power are fully accounted for in the model, across the historical and future data.

Q. What inconsistencies were observed during the input update process?

A. All physical power hedges and all market sales capacity limits map all physical power transactions to one of the major trading hubs. However, the day-ahead / real-time transaction mapping was incomplete and did not map a substantial portion of the Company's physical power transactions to one of the major trading hubs.

Q. How does this inconsistency impact the NPC forecast?

A. Either the market sales capacity limits are calculated on too many transactions, or the day-ahead / real-time transactions are calculated on too few transactions since there can only be one consistent set of transaction data supporting the NPC forecast. Across both scenarios, the Company's commodity records (source data) for power transactions would effectively reflect two separate official record sources in the same

NPC forecast and therefore this would create a known inaccuracy in that NPC forecast.

Q. What is the remedy for this inaccuracy?

A. All elements of the NPC forecast must calculate from the same set of source data. Therefore, either all power transactions are mapped to major trading points, or only a defined portion of power transactions are mapped to major trading points. The immediate implication is that power hedges and market sales capacity limits should use only a portion of the Company's power transactions to calculate, or the day-ahead / real-time transactions should use all the Company's power transactions to calculate.

Q. The accuracy of the forecasts is of significant importance to setting fair, just and reasonable rates. Which mapping process is more accurate?

A. Using all power transactions in all the NPC forecast calculations and mapping all minor trading points to the major trading points, for all calculations, is the only accurate process when considering that the NPC forecast simulates and attempts to replicate the actual operations of the Company's system as if only major trading points existed and this contrasts with actual operations which has both major and minor trading points. Without mapping all power transactions to the major trading points in the NPC model, the NPC forecast will not accurately simulate the actual operation of the Company's system.

Q. What is the NPC impact of updating the day-ahead / real-time transactions to all Company power transactions?

A. The Washington-allocated NPC impact of this change is an increase of $0.40 million.

Q. How does the 2020 Benchmark Study[35] relate to this mapping process?

A. The results of the 2020 Benchmark Study show Aurora producing 2020 NPC that is $58.7 million total-company (or 3.9 percent) less than 2020 Actual NPC. This benchmark study uses all power transactions in all the NPC forecast calculations and maps all minor trading points to the major trading points for all calculations. When the 2020 Benchmark Study uses only a portion of the Company's power transactions for day-ahead / real-time transactions, (discussed above as the inaccurate method), the 2020 Benchmark Study shows Aurora producing 2020 NPC that is $72.2 million total-company (or 4.8 percent) less than 2020 Actual NPC. This is a worsening of the 2020 Benchmark under-forecast by $13.6 million total-company and validates the Company's update.

XI. MODEL INPUT OPTIMIZATION

Q. What is model input optimization in the context of this testimony?

A. Model input optimization is the increasing usage of native Aurora functionality, as and when possible, to reduce model complexity, reduce model size, or reduce model run times.

Q. By what means did the Company achieve model input optimization?

A. Through ongoing consultation with Energy Exemplar, the Company receives an increasingly in-depth understanding of best practices and techniques in modeling NPC as time progresses. These insights are incorporated into the NPC forecast as and when appropriate.

[35] Confidential Exhibit No. RJM-5C.

Q. How does model input optimization impact the NPC forecast?

A. By simplifying the model, or using native Aurora functionality, Aurora becomes easier or faster to understand or use. However, because Aurora—solved by Gurobi—is based upon a mixed integer-program,[36] using branch and bound techniques,[37] changes in the mathematical problem size or formulation impacts the presence or lack thereof or suboptimality in the model's commitment and dispatch decision.[38] Consequently, changes to the problem size or formulation result in relatively minor NPC variances.

Q. What Aurora model input optimizations have been implemented in this NPC forecast?

A. There are two. First, Aurora was designed with the ability to directly evaluate any MW based ancillary service product. Explicit ancillary service MW based obligations can be inserted into Aurora's optimization through the Ancillary Services table within the software. This table accepts as input any MW reserve requirements by hour and then appropriately evaluates those requirements within the NPC forecast. Considering this, the Company has moved all ancillary service products into the Ancillary Services table to reduce model complexity, whereas before, a portion of the ancillary services were calculated from resources modeled specifically for that purpose.

Second, Aurora was designed with the ability to explicitly resolve supply/demand energy, ramp or capacity deficits. This feature is identical to the

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[36] Confidential Exhibit RJM-10C.

[37] GUROBI OPTIMIZATION, Mixed Integer Programming, A Primer on the Basics, https://www.gurobi.com/resources/mixed-integer-programming-mip-a-primer-on-the-basics/ (last visited Mar. 26, 2025).

[38] LinkedIn, What are the limitations and challenges of branch and bound? https://www.linkedin.com/advice/1/what-limitations-challenges-branch-bound-skills-linear-programming (last visited Mar. 26, 2025).

function of the Company's emergency purchase (unspecified purchased power) resources,[39] except for that it is native Aurora functionality. Considering this, the Company migrated the modeling of emergency purchases into this feature, whereas before, emergency purchases were acquired from resources modeled specifically for that purpose.

Q. What if any impact did these changes have to the NPC forecast?

A. The Washington-allocated NPC impact of these two changes is a decrease of $0.014 million.

XII. CONCLUSION

Q. What actions are you recommending the Commission take?

A. I recommend that the Commission adopt the proposed post-resource adequacy NPC baseline of $43.81/MWh or $194.6 million on a Washington-allocated basis—produced under the 2026 Protocol—and approve the proposed modeling improvements as outlined in my testimony.

Q. Does this conclude your direct testimony?

A. Yes.

[39] See Confidential Exhibit PAC/110.