REDACTED
Exh. DRS-1CT
Docket UE-21____
Witness: Douglas R. Staples

BEFORE THE WASHINGTON

UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP dba PACIFIC POWER & LIGHT COMPANY Respondent.	Docket UE-21____

PACIFICORP

REDACTED DIRECT TESTIMONY OF DOUGLAS R. STAPLES

June 2021

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Q. Please state your name, business address, and present position with PacifiCorp.

A. My name is Douglas R. Staples and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. I am currently employed as a Net Power Cost Specialist in the Net Power Costs Group. I am testifying for PacifiCorp dba Pacific Power & Light Company (PacifiCorp or Company).

QUALIFICATIONS

Q. Please describe your education and professional experience.

A. I received a Bachelor of Science degree with a focus on finance from the University of South Florida. I have been employed by PacifiCorp since 2015. During my tenure at the Company, I have worked as a risk management analyst and I currently work as a net power cost specialist, leading on various regulatory projects including general rate cases and net power cost filings. Before my time with PacifiCorp, I spent seven years working as a senior risk analyst and a supervisor of the risk management group at NextEra Energy Power Marketing, where I designed reports, provided validation and troubleshooting of risk metrics, and oversaw the quarterly validation of valuation assumptions used in mark to market accounting for financial statements. Prior to that, I worked as a principal business analyst for San Diego Gas & Electric. In that role, I was a part of the acting arm of the risk management committee, providing oversight to both San Diego Gas & Electric and Southern California Gas Company.

PURPOSE OF TESTIMONY

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

A. My testimony presents the forecast net power costs (NPC) for the test period and provides an overview of the modeling changes that have been implemented to provide more accurate forecast NPC.

Q. Can you please provide a summary of your testimony?

A. Yes. My testimony supports a $7.4 million decrease in baseline NPC. These lower NPC are supported by an NPC study conducted in the AURORA model instead of the previously used Generation and Regulation Initiative Decision (GRID) model. I also describe the inputs into the NPC model including the Official Forward Price Curve (OFPC) and the adjustments that are necessary under the recently approved Washington Inter-Jurisdictional Allocation Methodology (WIJAM). Additionally, I explain how Energy Imbalance Market (EIM) benefits and the Day-Ahead/Real-Time (DA/RT) adjustment are incorporated into NPC. Finally, my testimony summarizes the coal costs that are forecast for the Jim Bridger and Colstrip power plants.

ELEMENTS OF THE PCORC FILING

Q. Why is PacifiCorp filing a Power Cost Only Rate Case (PCORC)?

A. As part of the stipulation that was adopted by the Washington Utilities and Transportation Commission (Commission) in PacifiCorp's most recent general rate case in Docket UE-191024 (2021 GRC), the Company agreed to file a PCORC that would update the NPC baseline in 2021.[1]

Q. What is the scope of the PCORC filing?

A. The scope of the PCORC filing includes three elements:

1. Reset the NPC baseline using a calendar year 2022 forecast based on the nodal pricing dispatch that the Company is currently implementing.

[1] *WUTC v. Pac. Power & Light Co.*, Docket Nos. UE-191024, UE-190750, UE-190929, UE-190981, and UE-180778, Final Order 09 / 07 / 12, Appendix B at ¶17 (Dec. 14, 2020).

2. Review the deferred accounting treatment for major maintenance expense at Colstrip Unit 4 for inclusion in the next general rate case.
3. Incorporate the change in the NPC baseline into base rates.

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

A. PacifiCorp's NPC specifically updates 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 AURORA;

Account 503 - Steam from other sources;

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.

Q. Does the PCORC filing include recovery of any capital costs?

A. No.

Q. Please identify the other witnesses submitting direct testimony on behalf of PacifiCorp.

A. Mr. Charles (Chuck) L. Tack, Managing Director of Generation Support, testifies regarding the deferral of certain major maintenance expenses at Colstrip Unit 4.

Mr. Robert M. Meredith, Director, Pricing and Cost of Service, presents the Company's proposed prices and tariffs and provides a comparison of existing and estimated customer rates.

FORECAST NPC

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

A. The Washington NPC are approximately $114.8 million. NPC are determined using forecast expenses and revenues for the calendar year 2022. A report detailing the Washington-allocated NPC forecast is attached to my testimony as Confidential Exhibit No. DRS-2C.

Q. How do the forecast NPC in this proceeding compare to the NPC authorized in the Company's 2021 GRC?

A. The forecast Washington NPC in the current proceeding are approximately $7.4 million lower than the level authorized by the Commission in the 2021 GRC, which included use of the power cost adjustment mechanism (PCAM) deferral balance as described later in my testimony.

Q. Is the Company's general approach to forecasting NPC using the AURORA model the same in this case as in the 2021 GRC?

A. Yes. The Company used the GRID model in the 2021 GRC; the Company is now using the AURORA model from Energy Exemplar to forecast NPC. However, both AURORA and GRID are production cost models.

Q. What modeling inputs were updated for this filing?

A. The Company updated inputs to reflect the information available at the time the Company prepared the forecast NPC for the current filing. The updated modeling inputs include:

- Total-Company load;
- Contracts for wholesale sales and purchases of electricity, natural gas and wheeling;
- Market prices for electricity and natural gas or the official forward price curve (OFPC);
- Coal fuel expenses;
- Transmission capability;
- Characteristics of the Company's generation facilities; and
- Planned outages and forced outages of the Company's generation resources.

Q. What reports do the AURORA model produce?

A. The major output from the AURORA model is the NPC report. An electronic version is included in the workpapers accompanying the Company's filing. That NPC report includes monthly data detailing major cost drivers. Additional data with more detailed analyses are also available in hourly and monthly formats.

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

A. The forecast NPC use the OFPC dated March 31, 2021.

Q. Can you please provide an overview for how PacifiCorp derives the OFPC?

A. PacifiCorp's gas and electricity OFPC are developed from a combination of forward market prices on a given quote date and a long-term fundamentals-based price forecast. The first 37 months of the curve are based upon an average of monthly broker quotes for the market period. Months 38 through 49 are an average of the previous year market forward price and the next year's fundamentals price forecast. A fundamentals-based price forecast is used exclusively beyond month 49. As such, the entire test period in this proceeding, calendar year 2022, is based upon broker quotes.

Q. With regards to this OFPC, please explain how broker quotes are incorporated into the OFPC?

A. Power forward prices in the market period are derived from an average of broker quotes received daily from multiple brokers who provide monthly, quarterly, and calendar prices. OFPC monthly prices for which the Company receives broker quotes must be within plus or minus five percentage points of the average broker price for all monthly prices within the market period.

Q. Why does PacifiCorp rely on third party brokers and how do changes in market liquidity affect the accuracy of the OFPC?

A. Brokers provide an important intermediary function between buyers and sellers of power and gas by matching counterparties for both sides of transactions. As a result of this service, brokers enjoy greater insight regarding power and natural gas market prices than the Company, which would otherwise only have visibility into price information based on its own transactions and what traders observe in the market. The OFPC is also used to calculate mark to market value of the forward transactions which appear on the Company's financial statements. Fair value of these instruments is demonstrated to external auditors through observable price quotes provided by independent third parties. Market liquidity refers to market participants' ability to both buy and sell power and natural gas with minimal bid/ask spreads. Reduced market liquidity may result in larger differences between the maximum price that a buyer is willing to pay (bid) and the minimum price a seller is willing to receive (ask). Brokers provide and the Company utilizes mid-market price quotes for its OFPC, so while the bid/ask spreads of these commodities may vary among delivery points and tenors and peak-types, the mid-market price (average of the bid and ask price) remains a consistent and reliable measure of the value of the underlying products.

Q. Can you please explain how PacifiCorp models its hydro resources?

A. PacifiCorp's Energy Supply Management (ESM) department models reservoir operations for the river systems on which the Company owns (e.g., Lewis River) or has an interest (e.g., Priest Rapids Project) in a hydroelectric generating facilities with Vista Decision Support Software (Vista DSS). This modeling is an important component for complying with the FERC license requirements on the hydro projects, including requirements associated with flood management. These projections are then used as inputs to long-term budgeting activities, integrated resource planning, or various power cost analyses. The Company uses 30 years of Vista DSS data to develop realistic and meaningful projections of energy production from modeled hydroelectric projects. These projections are then used as inputs in the AURORA model to develop the forecast NPC used in this proceeding.

IMPACTS OF THE WIJAM ON THE NPC FORECAST

Q. What is the WIJAM?

A. PacifiCorp recovers the costs of providing retail electric service to customers through retail rates established in regulatory proceedings in each state. To ensure states receive the appropriate allocation of costs and benefits from PacifiCorp's integrated system, the collaborative Multi-State Process (MSP) has been used to address allocation issues. This collaborative process has led to the development and adoption of a series of inter-jurisdictional cost allocation methods over time, with the most recent being the 2020 Protocol. Washington has traditionally used a different methodology than PacifiCorp's other jurisdictions, and this methodology was known as the West Control Area Inter-Jurisdictional Allocation Methodology (WCA). Along with the negotiations around the 2020 Protocol, PacifiCorp worked directly with Washington Staff, Public Counsel, and the Packaging Corporation of America to transition from the WCA to the WIJAM. In the order approving the 2021 GRC, the Commission adopted the WIJAM for cost allocations in Washington.[2]

Q. Please describe the WIJAM.

A. The WIJAM has four primary components:

- Costs and benefits associated with PacifiCorp's entire transmission system will use a system allocation.
- Costs and benefits associated with PacifiCorp's existing and new non-emitting, non-qualifying facility (QF) resources will use a system allocation. Non-emitting, non-QF resources include all wind, solar, hydro, and geothermal generating resources.
- NPC will be allocated using a spreadsheet method that reflects assets included in Washington rates, including the allocation of EIM benefits.
- Jim Bridger and Colstrip Unit 4 (Colstrip) will be depreciated by December 31, 2023, in Washington rates.

Q. How does the WIJAM impact the modeling of forecast NPC?

A. The WIJAM changes the following items in the NPC forecast model:

- Inclusion of all power generation resources on the Company's system, with an adjustment to exclude the costs and benefits of emitting resources that are not electrically located in the

[2] *WUTC v. Pac. Power & Light Co*., Docket Nos. UE-191024, UE-190750, UE-190929, UE-190981, and UE-180778, Final Order 09 / 07 / 12 at ¶112 (Dec. 14, 2020).

PacifiCorp Balancing Authority Area West (PACW) and non-Washington QFs;

- Inclusion of system transmission on both a firm and non-firm basis;
- Inclusion of the new transmission incremental to the existing transmission system;
- Inclusion of EIM benefits on a system basis; and
- Modification to certain Commission-ordered adjustments in NPC modeling as described below.

Q. What are the Company adjustments from the WCA that are removed due to the transition to WIJAM?

A. The following items only apply when PACW is treated as one stand-alone entity. They are not applicable under the WIJAM and therefore they were removed from the NPC study:

- An imputed sale from PACW to the PacifiCorp Balancing Authority Area East (PACE), referred to as the Control Area Generation East Sale (CAGE Sale);
- Prorated wheeling expenses for Colstrip based on the transmission capacity from Colstrip to PACW;
- Margin on arbitrage transactions based on the four-year historical average; and
- Excluded non-firm transmission capability and expenses.

Q. Did the Company make these same adjustments in the 2021 GRC?

A. Yes.

Q. Was the WIJAM approved by the Commission?

A. Yes, the WIJAM was approved by the Commission in the Final Order in the Company’s 2021 GRC.

Q. What are the Company adjustments from its last two rate cases, the 2021 GRC and 2014 General Rate Case,[3] that are unchanged?

A. The Company's current filing remains consistent with the Commission's Orders in the 2021 GRC and 2014 General Rate Case, as follows:

- Jim Bridger Coal Costs—Coal supplied by Bridger Coal Company to fuel Jim Bridger is included based on the cost of production during the test period.
- DC Intertie—The cost of transmission rights on the Bonneville Power Administration (BPA) Direct Current (DC) Intertie transmission line is included in NPC, and the related transmission capacity and access to the Nevada-Oregon Border (NOB) market hub are included in the AURORA topology.
- Hedging Costs—Hedging costs are included in NPC, valued using the Company's OFPC.
- Market Caps—Market caps are modeled in AURORA based on the 48-month historical average of short-term firm sales transactions at wholesale market hubs.
- Wheeling Cost—The Idaho Power Company 200 megawatts (MW) point-to-point wheeling contract costs and benefits are all reflected in the NPC study.

Q. Are any Washington QF contracts currently included in rates?

A. Yes. One Washington QF contract is currently included in this study at an average price of $60.67/megawatt-hour (MWh).

DISCUSSION OF COST DRIVERS IN NPC

Q. Please generally describe the changes in NPC compared to the 2021 GRC.

A. Figure 1 illustrates the change in Washington-allocated NPC under the WIJAM from the NPC included in the 2021 GRC. The NPC in the test period under the WIJAM is

[3] *WUTC v. Pac. Power & Light Co*., Docket No. UE-130043, Order 05 (Dec. 4, 2013).

$7.4 million lower than the NPC in the 2021 GRC. The decrease in NPC is driven by reductions in purchased power expenses, and coal fuel expenses, partially offset by a decrease in wholesale sales revenue and increases in natural gas fuel expenses, and wheeling and other expenses.

Figure 1
Net Power Cost Reconciliation

	Washington Allocated ($ millions)
2021 Rate Case (WA)	**$122.2**
Increase/(Decrease) to NPC:	
Wholesale Sales Revenue	$2.0
Purchased Power Expense	($12.1)
Coal Fuel Expense	($2.0)
Natural Gas Fuel Expense	$2.7
Wheeling and Other Expense	$2.0
Total Increase/(Decrease) to NPC	**($7.4)**
2022 PCORC (WA)	**$114.8**

Q. Please summarize the major drivers in this case?

A. The most significant driver of the variance in NPC between this proceeding and the final update from the Company's 2021 GRC is the decline in purchased power expense. Additionally, there is a decline in coal fuel expense. These declines are offset by a decline in wholesale sales revenue, and increases in natural gas fuel expense, wheeling and other expense.

Q. Please explain the $2.0 million decrease in wholesale sales revenue.

A. One of the drivers of sales revenue is short-term firm sales, which represents actual transactions that have already been executed by the Company. The short-term firm revenue in this filing is at a lower level than what is reflected in the final update of the

2021 GRC. The Company hedges on a rolling 36-month horizon but most of the trading activity is for the next 12 months. Therefore, the final 2021 GRC study filed in October exhibited larger volumes of short-term firm sales than this filing, which is taking place earlier in the year. The volume of short-term firm sales for a forward test period will typically increase as the current year progresses.

Q. Why did purchased power expense decrease by $12.1 million?

A. The decrease in purchased power expense is related to the spreadsheet method used to determine Washington-allocated NPC by excluding the costs and benefits of certain resources not included in Washington rates. Starting with the AURORA total system NPC, the Washington-allocated NPC are determined by comparing the Washington load to the generation and market activity that is allocated to Washington. In this case the Washington load exceeded Washington resources, including market activity, this is shown as the "Shortfall Pre-Balancing" in Figure 2 below. This shortfall is calculated on a monthly basis and "rebalanced" to arrive at the Washington-allocated NPC. In the event of a shortfall, the rebalancing is done by first reducing system balancing sales. If there are not sufficient system balancing sales to remove, system balancing purchases are then added in the amount needed for Washington to be "balanced". Any system balancing sales that are removed or system balancing purchases that are added in the rebalancing adjustment are done using a weighted average of either the system balancing sales or purchases. Figure 2 below shows WIJAM balancing adjustment in both the 2021 GRC and the current proceeding.

Figure 2

WIJAM Balancing		
(MWh)	2022 PCORC	2021 WAGRC
Sales Pre-Balancing	450,229	400,478
Remaining Sales	**14,225**	**3,780**
Shortfall Pre-Balancing	(797,638)	(1,244,437)
Sale Reduction	436,005	396,698
Increased Purchases	361,633	847,740
Net Open	-	-

Q. Please explain the $2.0 million decrease in coal expense in the current proceeding.

A. Total coal fuel expense is $2.0 million lower than the 2021 GRC primarily due to slightly lower coal generation volumes at the Company's coal generation facilities. In addition, average coal prices are $0.60/MWh lower than the prices in the 2021 GRC. Please refer to the detailed discussion of forecast coal costs further below.

Q. Please discuss the $2.7 million increase in natural gas fuel expense compared to the 2021 GRC.

A. Natural gas fuel expense in the test period is a $2.7 million increase in natural gas fuel expense as compared to the 2021 GRC study. The increase in natural gas fuel expense is attributed to higher gas plant generation volume driven partially by lower gas prices as compared to average coal costs. However, this increase in generation is also offset by those lower gas generation prices. The average cost of natural gas generation decreased from $30.18/MWh in the 2021 GRC to $25.10/MWh, a decrease of 17 percent.

Q. Please describe the $2.0 million increase in the wheeling and other expense category.

A. Expenses in this category are higher due to the removal of the 2021 GRC settlement adjustment of approximately $1.4 million. In addition, firm wheeling expenses increased by approximately $0.6 million

MODELING CHANGES TO IMPROVE NPC FORECAST ACCURACY

AURORA Model

Q. Why is PacifiCorp filing this PCORC with the AURORA model?

A. As part of the resolution to PacifiCorp's 2021 GRC, the Company committed to filing the PCORC with the AURORA model.[4] PacifiCorp has used the GRID model since it was deployed by the Company in 2008. Moving to the AURORA model, which is produced by Energy Exemplar, provides some additional functionality, increases usability, and compatibility with Company IT technology.

Q. How does the AURORA model work?

A. AURORA is designed to model the competitive wholesale electricity market and produce hourly market prices to meet load requirements at various locations (referred to as "zones"). This is accomplished by simulating the dispatch of available resources, both supply-side and demand-side, within physical and economic constraints of the resources, as well as profiles of the load requirements. These simulations determine the resources at the margin in each hour to serve the next

[4] *WUTC v. Pac. Power & Light Co*., Docket Nos. UE-191024, UE-190750, UE-190929, UE-190981, and UE-180778, Bench Request No. 7 (Nov. 10, 2020).

incremental amount of load requirements of the zones and the costs of the resources at the margin, which set the market prices of the zones.

Q. How does AURORA compare to GRID?

A. The model logic is generally the same between AURORA and GRID; both models minimize costs to serve obligations, under various constraints. While the categories of inputs are generally the same between the two models, AURORA has more parameters to model resources and more flexibility to model different types of resources.

EIM Benefits

Q. Please summarize the EIM benefits included in this case.

A. In the current test period, the Company continues to include EIM benefits in the base NPC in the same manner as the 2021 GRC. PacifiCorp's 2021 NPC forecast from GRID includes an adjustment to reflect incremental EIM inter-regional benefits and greenhouse gas (GHG) marginal revenues in this case. The test period includes approximately [redacted] of inter-regional benefits and [redacted] of GHG benefits on a total-Company basis as a reduction to the NPC forecast.

Q. How did the Company calculate the historical EIM inter-regional benefits?

A. The inter-regional benefits reflect the value PacifiCorp receives when it economically exports energy to the EIM and when it imports energy from the EIM that allows it to displace a more expensive resource.

Generally, the benefit of EIM exports is equal to the revenue received less the production cost of generation assumed to supply the transfer. The production cost used in the Company's calculation of EIM benefits is the marginal cost to produce an additional MWh at a given resource. The Company's production costs used to calculate EIM benefits are equal to the resource bids submitted to the EIM. The benefit of EIM imports is equal to the import expense less the avoided expense of the generation that would have otherwise been dispatched.

Q. How did the Company forecast the inter-regional EIM benefits in the test period?

A. Using EIM benefits by month, a linear regression model was developed using the following four independent variables: electric market prices, natural gas market prices, EIM transfer capability, and spring oversupply conditions. The linear regression model with multiple independent variables will reflect market conditions which drive EIM benefits, resulting in a reasonable forecast.

Q. What are GHG benefits, and how much are included in this case?

A. GHG benefits are realized when the GHG revenue is higher than the Company's resulting compliance obligation. The total-Company GHG benefits for the forecast year 2022 is about [redacted]

Day-Ahead and Real-Time System Balancing Transactions

Q. Please describe the DA/RT adjustment.

A. PacifiCorp incurs system balancing costs that are not reflected in the Company's forward price curve or modeled in AURORA, because, much like GRID, AURORA is a deterministic production cost model that optimizes the system perfectly in a single step. To address this the Company proposes the DA/RT adjustment to more accurately model system balancing transaction prices and volumes.

Q. Please explain how the AURORA model currently balances load and resources on an hourly basis.

A. The AURORA model calculates the least-cost solution to balance the Company's load and resources to fractions of a MW for each hour. The model makes purchases in the wholesale market (labeled as "system balancing purchases" in the NPC report) in the hours for which the Company does not have enough owned- or contracted-resources to meet its load. The model also makes wholesale market sales (labeled as "system balancing sales" in the NPC report) when it has excess resources for a given hour. These system balancing transactions are calculated for each hour independently and are for the precise volume required by the model. Wholesale market prices for the system balancing sales are based on an hourly forward price curve that is developed from monthly heavy load hours (HLH) and light load hours (LLH) prices with hourly scalars applied to transform the monthly prices into a series of hourly prices that, on average, remain equal to the monthly prices. These scalars are identical within a given month for each weekday of that month. The prices are input into the model and do not change based on the volume of the system balancing transactions.

Q. How do actual operations differ from the model logic?

A. In actual operations, the Company continually balances its market position—first with monthly products, then with daily products, and finally with hourly products. The monthly and daily position is calculated as the average for the respective time horizon during HLH and LLH periods; for example, the average HLH position during the month of January or the average LLH position on a given day in February. The monthly and daily products used to balance the Company's position in the wholesale market are available in flat 25 MW blocks. The Company's load and resource balance, however, varies continuously each hour in quantities that may vary widely from a flat 25 MW block. In real-time operations, the Company balances its hourly position in the hourly real-time market. At that point, the Company must transact to maintain a balanced system and, as a result, becomes a price-taker subject to whatever price is available at the time.

Q. How do the system balancing volumes in AURORA compare to the Company's actual volumes?

A. The volume of system balancing transactions generated by AURORA is smaller than the volume of similar transactions in actual results. Because AURORA balances the Company's load and resources to fractions of a MW for each hour in a single step, it avoids the additional purchase and sale transactions that occur in actual operations as the Company progresses through balancing its system on a monthly, daily, and real-time system basis.

For instance, when the Company buys a monthly product that aligns with the Company's average open position for the month, one can expect that roughly half of the days will still have a remaining position to be covered by additional daily purchases. On the other days, the Company will have to make daily sales to unwind the excess volume. The same is true for daily transactions—in some hours the volume acquired will be too low, while in others it will be too high, and additional purchases and sales will be required to cover the Company's actual position.

In addition, buying or selling standard block products for monthly and daily average requirements will not result in a perfect balance of load and resources. This difference then must be closed out in the real-time market where the Company is a price-taker.

Q. Please describe the price component of the DA/RT adjustment.

A. To better reflect the market prices available to the Company when it transacts in the real-time market, PacifiCorp includes separate prices for forecast system balancing sales and purchases in AURORA. These prices account for the historical price differences between the Company's purchases and sales compared to the monthly average market prices.

Q. Why is the DA/RT adjustment needed to differentiate the market prices for purchases and sales?

A. The AURORA model used an hourly price curve developed from monthly HLH and LLH forward market prices. Hourly prices were simply the product of applying a scalar, or shape, to the monthly average prices. These scalars were identical within a given month for each weekday of that month. In addition, the prices were input into the model and did not change regardless of the volume of the system balancing transactions or other system conditions in the model. In reality, however, prices vary within each month and the Company has historically bought more during higher-than-average price periods and sold more during lower-than-average price periods. As a result, the average cost of the Company's daily and hourly short-term firm purchases has been consistently higher than the average actual monthly market price, while the average revenues from its daily and hourly short-term firm sales has been consistently lower than the average actual monthly market price.

Q. Please describe the volume component of the DA/RT adjustment.

A. The Company reflects additional volumes to account for the use of monthly, daily, and hourly products. In actual operations, the Company continually balances its market position—first with monthly products, then with daily products, and finally with hourly products. The products used to balance the Company's forward position in the wholesale market are available in flat 25 MW blocks. The Company's load and resource balance, however, varies continuously each hour in quantities that may vary widely from a flat 25 MW block. Thus, in real world operations, the Company must continuously purchase or sell additional volumes to keep the system in balance.

In contrast, AURORA has perfect foresight and can model wholesale market transactions at whatever volume is necessary to balance the system. Because of AURORA's perfect foresight, it can balance the system with far fewer transactions. The DA/RT adjustment adds additional volumes to NPC to more accurately model the transactions necessary to balance the Company's system.

Q. Has PacifiCorp previously used the DA/RT adjustment in forecast NPC?

A. PacifiCorp has used the DA/RT adjustment in all filings for all jurisdictions that have included forecast NPC since 2015, including the 2021 GRC.

Q. Has this adjustment changed since the 2021 GRC with the switch from GRID to AURORA?

A. No, this adjustment was also used in the NPC baseline for the 2021 GRC.

Miscellaneous Adjustments Incorporated from the 2021 GRC

Q. Has PacifiCorp's approach to modeling thermal plant forced outages changed since the 2021 GRC?

A. No, the approach has not changed. The Company modeled forced outages and unit de-rates as discrete events, rather than applying a uniform de-rate to the plant operating characteristics across all hours.

Q. Has the Company changed its regulating reserve requirement modeling since the 2021 GRC?

A. No, the Company's regulating reserve requirements continue to be based on the 2019 Flexible Reserve Study that was included in the 2019 Integrated Resource Plan (IRP).[5]

Q. Has the Company changed the forecast capacity factors for owned wind generation and purchased wind generation since the 2021 GRC?

A. No, PacifiCorp continues to calculate the annual capacity factor using a cumulative average methodology for any wind generation with a history of generation longer than four years. For those wind generation facilities with less than four years of history, the project owner's forecast is used for the period until the actual results become available. The capacity factor for all the repowered wind plants will be based on the Company's February 2018 economic analysis for wind repowering (included in the 2017 IRP Update).

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[5] *Pacific Power & Light Company 2019 Integrated Resource Plan*, Docket No. UE-180259, Volume II at Appendix F.

FORECAST COAL COSTS

Q. Has forecast coal expense in the test period decreased from the amount in the 2021 GRC?

A. Yes. As shown in Figure 7 above, forecast coal fuel expense decreased by $2.0 million on a Washington-allocated basis, from [redacted] million in the 2021 GRC to [redacted] million in the test period. Reduced volumes account for an [redacted] million decrease and reduced coal costs account for the remaining [redacted] million.

Q. Please explain why coal consumption decreased in the test period?

A. Increased generation from non-emitting resources and natural gas resources has significantly reduced coal generation in the test period compared to the 2021 GRC.

Q. Please quantify the reduced coal consumption amount in the test period?

A. On a Washington-allocated basis, the test period forecast [redacted] million British Thermal Units (MMBtus) of coal will be consumed, which is [redacted] million MMBtus less than the 2021 GRC. This is a [redacted] percent decrease.

Q. Is the impact of the reduced coal consumption similar at Jim Bridger and Colstrip?

A. No. On a Washington-allocated basis, Jim Bridger is projected to consume [redacted] million MMBtus in the test period, which is [redacted] million MMBtus or [redacted] percent less than in the 2021 GRC. On a Washington-allocated basis, Colstrip is projected to consume [redacted] million MMBtus in the test period, which is [redacted] million MMBtus or [redacted] percent higher than forecast in the 2021 GRC.

Jim Bridger Coal Costs

Q. Please explain the coal supply arrangements for Jim Bridger.

A. Similar to the 2021 GRC, Jim Bridger is expected to be supplied by a combination of coal supplies from Bridger Coal Company (BCC) and the Black Butte mine in the test period.

Q. Can you please quantify the cost decrease at Jim Bridger?

A. Yes. As shown in Confidential Figure 3, Jim Bridger costs decrease [redacted] million on a Washington-allocated basis.

Confidential Figure 3

Jim Bridger Plant Coal Deliveries - PacifiCorp Portion

Supplier	2022 Test Period Tons	Dollars	$ / Ton	2021 Test Period Tons	Dollars	$ / Ton	Variance Tons	Dollars	$ / Ton	WA Allocated Price Variance
Bridger Coal Deliveries	[redacted]									
Black Butte Deliveries										
Total Jim Bridger Plant										

Q. Of the [redacted] million coal cost decrease at Jim Bridger, how much is attributable to BCC?

A. BCC coal costs decreased from [redacted] per ton to [redacted] per ton, or by [redacted] per ton, which resulted in a Washington-allocated price decrease of [redacted] million.

Q. Please identify cost reductions that result in a total BCC coal cost decrease of $[redacted] million.

A. The primary driver of the cost decrease from BCC is due to the increase in supplemental coal delivered from BCC for price decrease of [redacted] million. Other decreases for depreciation, depletion and amortization of [redacted] million, and materials and supplies of [redacted] million. These decreases are partially offset by increases to the contributions to the final reclamation trust of [redacted] million, royalties and taxes of [redacted] million, reduced heat content of the coal of [redacted] million and other miscellaneous costs of [redacted] million.

Q. Did the Black Butte coal price increase in the test period compared to the 2021 GRC?

A. Yes. The Black Butte coal price in the test period is based on an estimated amount of [redacted] per ton for 2022 which is [redacted] per ton higher than the [redacted] per ton, free on board (FOB) mine price assumed in the 2021 GRC. Including Union Pacific rail transportation costs from the Black Butte mine to Jim Bridger and application of anti-freeze agent applied to railcars during winter months, the delivered cost of Black Butte coal increased from [redacted] per ton in the 2021 GRC to [redacted] per ton in the test period, or by [redacted] per ton.

Colstrip Coal Costs

Q. Did coal prices increase at Colstrip in the test period compared to the 2021 GRC?

A. Yes. Delivered coal prices increased [redacted] per ton, from [redacted] per ton in the 2021 GRC to [redacted] per ton in the test period, which resulted in a Washington-allocated price increase of [redacted] million. The increase costs are primarily due to an increase in the contract indices and to a lower volume of tier 2 coal being purchased.

Q. Please explain the coal supply arrangements for Colstrip.

A. Colstrip is supplied by coal delivered from the Rosebud Mine owned by Westmoreland Rosebud Mining, LLC.

DEFERRED NPC BASELINE ADJUSTMENT

Q. Please explain what happened in the October Update to NPC in the 2021 GRC.

A. PacifiCorp's October Update to NPC reflected a $17.5 million increase to baseline NPC over the approximately $102 million that was estimated in the initially filed stipulation from July of 2020 (July Stipulation).[6] The stipulation specified that an increase in baseline NPC "as a result of the October Update will be offset by the balance in the deferral account for the PCAM."[7] The increase in the NPC baseline from the October Update was larger than the December 31, 2019 PCAM deferral balance of -$9.5 million.[8] Under the July Stipulation, any increase beyond the PCAM balance would have been allocated to customers on January 1, 2021. This would have resulted in a $7.8 million increase in revenue requirement from this update. When compared to the rates indicated in the July Stipulation, such an increase in the revenue requirement would have resulted in a rate increase for customers on January 1, 2021, instead of the stipulated rate decrease. The magnitude of the increase in the NPC baseline was unexpected and PacifiCorp worked with the parties to the Stipulation to preserve the benefits of the rate decrease for customers. This was accomplished by reflecting the entire increase in the NPC baseline from the October Update in the PCAM balancing account through a monthly adjustment that was called the Deferred NPC Balancing Adjustment (DNBA).

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[6] *WUTC v. Pac. Power & Light Co*., Docket Nos. UE-191024, UE-190750, UE-190929, UE-190981, and UE-180778, Exhibit No. JT-3CT at 1-2 (Nov. 6, 2020).
[7] *Id.*
[8] *In the Matter of PacifiCorp, d/b/a Pac. Power & Light Co., 2019 Power Cost Adjustment Mechanism*, Docket UE-200507, Order 01 at ¶13 (Aug. 27, 2020).

Q. What is the impact of the proposed NPC from this filing on customer rates?

A. While the NPC baseline as proposed in this proceeding is decreasing relative to the October Update, the October Update was never reflected in the Company's revenue requirement that is collected through customer rates. It is instead being reflected through the DNBA in the PCAM balancing account. As a result, the NPC baseline reflected in the Company's revenue requirement is the approximately $102 million from the July Stipulation, which is lower than the NPC baseline that is forecasted in this case. The proposed rate adjustment in this filing is in relation to the revenue requirement that is being collected in customer rates, which results in an increase to revenue requirement of $13.1 million. The effect of this increase on actual customer rates is described in the testimony of Mr. Meredith.

CONCLUSION

Q. What actions are you recommending the Commission take?

A. I recommend that the Commission approve PacifiCorp's proposed $7.4 million decrease in the NPC baseline as described in this testimony because it is just and reasonable.

Q. Does this conclude your direct testimony?

A. Yes.