Exh. DRS-3T
Docket UE-210402
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-210402

PACIFICORP

SUPPLEMENTAL TESTIMONY OF DOUGLAS R. STAPLES

September 2021

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ATTACHED EXHIBITS

Q. Are you the same Douglas R. Staples who previously submitted direct testimony in this proceeding on behalf of PacifiCorp dba Pacific Power & Light Company (PacifiCorp or the Company)?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. Why is PacifiCorp filing supplemental testimony?

A. PacifiCorp is filing this testimony at the request of the parties in this docket and to provide a more robust record for the Commission.

Q. What is the purpose of your supplemental testimony?

A. The purpose of my testimony is to:

- Provide an explanation of the Nodal Pricing Model (NPM) including describing the new day-ahead schedules and the costs associated with the NPM;
- Provide an explanation of the transition to Aurora, including how Aurora reflects PacifiCorp's actual operations, and describe the validation process that was used by the Company to evaluate Aurora.

II. NODAL PRICING MODEL

A. Description of the NPM

Q. Will you please briefly describe the NPM?

A. The NPM is a Framework Issue in the 2020 Inter-Jurisdictional Allocation Protocol (2020 Protocol) and is the anticipated future allocation methodology to be used for the inter-jurisdictional allocation of net power costs (NPC). The 2020 Protocol defines NPM as "a method for pricing electricity proposed by the Company that is based on the marginal cost ($/MWh) of serving the next increment of demand at a given pricing node consistent with existing transmission constraints and the performance characteristics of resources."[1] To have the information necessary (*i.e.*, day-ahead, hourly locational marginal prices (LMP)) to allocate actual NPC using the NPM, the Company contracted with the California Independent System Operator (CAISO) to receive optimized day-ahead advisory schedules that are used to inform the Company's day-ahead schedules. In other words, the NPM consists of two components: (1) the operational, "dispatch", or day-ahead schedules from CAISO; and (2) the allocation methodology.

Q. Has PacifiCorp implemented the allocation methodology?

A. No, but PacifiCorp is receiving day-ahead schedules from CAISO. This day-ahead schedules process was implemented in January 2021.

Q. When will the allocation methodology be fully implemented?

A. The NPM is a Framework Issue in the 2020 Protocol and is currently part of the ongoing Multi State Protocol (MSP) negotiations. Though there are still items that need to be resolved in MSP, the 2020 Protocol contemplates that the NPM will be used to set rates beginning in 2024.

Q. Please describe the day-ahead set-up process.

A. Generally speaking, every morning before trading, PacifiCorp's Energy Supply Management group (ESM) runs the Gentrader optimization model to inform day-ahead trading, day-ahead generation schedules, and NPM bids. NPM bids are submitted to CAISO by 10:00 a.m. each morning. Around 1:00 p.m. CAISO provides

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[1] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket No. UE-191024, Exh. EL-3 at 73-74 (Dec. 13, 2019).

ESM with the advisory day-ahead dispatch schedule. ESM will then use these schedules to create the bids for the EIM market. Results are reviewed daily for significant or unexplained discrepancies between NPM and Gentrader and either adjustments in Gentrader are made or if it appears to be a CAISO error, a dispute ticket is created with CAISO.

Q. Please describe the Gentrader optimization model you discuss above.

A. As part of continuous improvements and in coordination with the NPM implementation, ESM transitioned to a new system optimization model called Gentrader, which is owned by Power Costs, Inc. (PCI). During the implementation of NPM, PCI worked closely with CAISO and PacifiCorp to ensure the optimization results from Gentrader were consistent with the NPM. To ensure that the Gentrader optimization was consistent with NPM it was critical to have the topology right. CAISO uses the same proprietary market optimizer for the NPM as it does for its day-ahead market, which is a flow based nodal model or nodal topology that produces a LMP at each node. The Gentrader model uses a zonal topology that is restricted to PacifiCorp's transmission scheduling rights.

Q. With this background, what are the operational benefits of NPM?

A. As the Company has discussed in prior proceedings, the benefits from nodal dispatch and NPM come from having more efficient day-ahead setup.[2] This is the result of the NPM providing ESM more transparency into PacifiCorp's transmission scheduling rights, resulting in a more granular day-ahead setup. Put another way, a more efficient day ahead set-up results in fewer changes between the day-ahead setup and

[2] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket No. UE-191024, Exhibit MGW-1CT at 41 (Dec. 13, 2019).

real-time dispatch, which lowers actual NPC by avoiding those changes. Notably, as the Company has discussed before, this benefit is impossible to track because it is impossible to know what the day-ahead setup would be without NPM.[3] However, this change will serve to improve operational efficiency and allow the Company's transition between day-ahead and real-time to better reflect the sort of efficiency present in its model results.

Q. Does the Company currently have experience with nodal power flow models?

A. Yes. The Company participates in the Western Energy Imbalance Market (EIM). The market model CAISO uses to optimize the EIM footprint within the hour is a power flow nodal model. There are two main differences between the EIM and NPM power flow nodal models. First is the period for which the optimization occurs, EIM is within the hour and the NPM is the day-ahead. Second is the footprint or area for which the optimization occurs, EIM co-optimizes all EIM participants and the NPM only optimizes PacifiCorp's system.

B. History of the NPM

Q. Has the purpose of the NPM been discussed previously with stakeholders and the Commission?

A. Yes. In the NPM Memorandum of Understanding (MOU), it was clear that the purpose was to track "the costs and benefits associated with different resource portfolios used to serve PacifiCorp's load in each state."[4] In Mr. Wilding's testimony in the Company's last general rate case in Docket UE-191024 (2021 Rate Case), he

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[3] *Id.*

[4] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket No. UE-191024, Exhibit EL-3 at 108 (Dec. 13, 2019).

further described that "[t]he NPM is intended to and is being developed to help preserve the benefit of operating as a single system while providing states the flexibility to have unique resource portfolios that align with a state's energy policy and interests."[5]

Q. What was previously stated about any secondary benefits?

A. PacifiCorp identified that there might be operational cost savings but that "[t]he potential operational cost savings will be the result of a more efficient day-ahead setup and the cost savings will be embedded in the actual NPC. These potential cost savings will be impossible to accurately and precisely track as the calculation of such savings would rely on a counterfactual setup of the system without the NPM."[6]

Q. Did the Parties to the 2020 Protocol determine that the development of NPM was reasonable and prudent?

A. Yes. The NPM MOU states "the Parties affirm support for PacifiCorp's reasonable and prudent investment of related capital funds, related operations and maintenance expenses, and the related ongoing grid management charges to develop and implement an NPM."[7]

Q. Please describe the NPM MOU executed by the Parties and provided as Appendix D to the 2020 Protocol.[8]

A. The NPM MOU sets out the Company's proposal for a third-party day-ahead dispatch model to determine the schedules for each of its generation resources to serve state

[5] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket No. UE-191024, Exhibit MGW-1CT at 41 (Dec. 13, 2019).
[6] *Id.*
[7] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket No. UE-191024, Exhibit EL-3 at 109 (Dec. 13, 2019). The "grid management charge" anticipated in the MOU is a described below as the NPM fee.
[8] *Id.* at 106-111.

loads on a least-cost basis, while tracking costs and benefits associated with the different resource portfolios used to serve PacifiCorp's load in each state. The MOU lists CAISO as the third party that will develop the tool, the scope of work, and costs of the work identified by CAISO, as well as CAISO's estimated costs and benefits of the work. The MOU also provided an explanation of the anticipated benefits, including cost-savings and compliance with state policy directives impacting resource portfolio decisions. Based on the information provided by the Company, parties to the NPM MOU agreed that the Company's decision to invest capital funds and pay an ongoing grid management charge or NPM fee to develop and implement an NPM is reasonable and prudent. The MOU was signed by 17 parties, including the Company, regulatory agencies, consumer advocates, and other interested parties from Idaho, Oregon, Utah, Washington, and Wyoming. No party to date has indicated an objection to the Company's investment to develop the NPM.

Q. Why did PacifiCorp partner with CAISO for the development of the NPM?

A. As the Company implements an NPC allocation methodology based on the NPM solution, partnering with CAISO's existing technology platform reduced both schedule and budget risk. Since the day-ahead market in CAISO is based on the day-ahead LMPs at the nodal level, the Company was able to leverage CAISO's existing day-ahead market model and experience in developing and implementing the NPM. Additionally, partnering with CAISO ensures consistency between the NPM and the EIM dispatch since both are based on the same underlying full network of generation and transmission resources. Even though transfers are not allowed between CAISO and PacifiCorp in the NPM, the day-ahead dispatch for both systems is based on the same model run and potentially results in a more efficient day-ahead setup that takes into consideration a power flow solution.

Lastly, if CAISO offers a day-ahead market to external entities for optional participation, the NPM solution development would allow PacifiCorp to seamlessly participate in the CAISO day-ahead market, if and when PacifiCorp decides to participate in that market.

C. Costs of the NPM

Q. What are the costs associated with the implementation of NPM?

A. There is an annual NPM fee (referred to as the Nodal Model fee in my workpapers) of $8.0 million that was included in the NPC baseline through the 2021 Rate Case.[9] Additionally, there were $4 million of capital costs and $500,000 of incremental operation and maintenance (O&M) expenses that were included in the Company's revenue requirement in the 2021 Rate Case.

Q. Can you break these costs down on a Washington-allocated basis?

A. Yes. On a Washington-allocated basis, the capital costs are approximately $312,000, and the O&M costs total approximately $39,000.[10]

Q. What are the capital costs and ongoing O&M expense associated with NPM?

A This includes initial capital costs and ongoing O&M expense, such as upgrades for PacifiCorp's information technology hardware and software for both regulatory and accounting purposes. As described above, these were included in the 2021 Rate Case.

[9] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket No. UE-191024, Exhibit MGW-1CT at 43 (Dec. 13, 2019).
[10] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket No. UE-191024, Exhibit SEM-3C at 158 (Dec. 13, 2019).

Q. What is the purpose of the NPM fee?

A. PacifiCorp pays a $2.1 million fee quarterly ($8.3 million annually) for NPM services. CAISO based the fee on its estimated expenses to provide NPM services to PacifiCorp. The basis for the estimated cost is the direct and indirect time and expense necessary for CAISO to perform the nodal pricing model service for PacifiCorp. The NPM services that CAISO provides are the production of separate day-ahead nodal pricing results within PacifiCorp's balancing authority areas. The NPM services include CAISO calculating the credit each generator will receive for their scheduled generation in the day-ahead market and the price which load would pay for its day-ahead schedule.

Q. Was the NPM fee appropriately included in this Power Cost Only Rate Case (PCORC)?

A. No. While the amount was appropriately included in the baseline NPC in the 2021 Rate Case, PacifiCorp has discovered that only $4 million of this fee was included in the proposed PCORC baseline. This is an error, and PacifiCorp would propose that the appropriate amount be reflected in the final baseline NPC from this case. This would raise Washington-allocated NPC by approximately $312,000. The Company will make this revision in its rebuttal filing.[11]

Q. Is PacifiCorp seeking any recovery of any costs beyond those identified above for NPM?

A. No.

[11] In the event that parties reach a settlement agreement before the rebuttal filing, the Company will seek to incorporate the change as part of the settlement.

III. The Transition to AURORA

A. Aurora and the NPM

Q. How does Aurora fit in with NPM?

A. The switch to the Aurora model was necessary to accommodate NPM as contemplated in the 2020 Protocol and perform the allocation of state-specific NPC for ratemaking purposes in the post-interim period. The Aurora model provides a locational pricing output that is not available in the Generation and Regulation Initiative Decision Tool (GRID) but is necessary for regulatory proceedings that use an NPC forecast, such as the PCORC.

Q. In the settlement for the 2021 Rate Case, the Company agreed that the NPC baseline will be updated based on a nodal dispatch in a PCORC in 2021.[12] How was the topology in Aurora built to reflect nodal dispatch?

A. Aurora uses a zonal topology that purpose built to reflect the "nodal dispatch" and to maintain functionality of the model, nodes were aggregated into groups called zones. Zones represent an aggregation of nodes between which there is no transmission congestion. Additionally, with a future allocation methodology in mind, the zones were formed so that a zone only contained load from a single state and to isolate thermal resources into single zones.

Q. Please explain why Aurora does not use a nodal topology.

A. In implementing the Aurora model, the topology was built with the NPM in mind. However, Aurora is not using a nodal topology as it was not feasible for multiple reasons. First, a nodal topology in Aurora is a power flow model that relies on the

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[12] *WUTC v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket No. UE-191024, Final Order 09/07/12, Appendix B at ¶17 (Dec. 14, 2020).

entire Western Electricity Coordinating Council (WECC) nodal topology and allows for the flow of energy for the entire WECC footprint. Additionally, the Aurora run times to produce an annual NPC forecast using a nodal topology are excessive. Furthermore, access to the nodal topology requires Federal Energy Regulatory Commission approval and individuals who are granted access are not able to share the data with others. That creates obvious difficulties in making work papers available in a regulatory context and would also limit the Company's ability to share NPC work papers internally.

Q. How has PacifiCorp structured the topology in Aurora to reflect the switch that is occurring for the NPM?

A. Aurora uses zones that are state-specific to support the future allocation of NPC. The most pronounced modifications were made to allow the model to produce the outputs required to perform allocation of costs and benefits based on states' unique resource portfolios. Those modifications include adding more transmission areas, which are also referred to as zones or bubbles. These additional areas are for the explicit purpose of identifying the load by state and the generation by existing thermal resource.

Q. Why is it important to identify load by state?

A. To use the NPM to set rates in the future (as is contemplated in the framework issues section of the 2020 Protocol), the load is assumed to pay the LMP of the load aggregation point. For operational purposes, there are some load areas that do not have transmission constraints with load areas in a different state. As a result, those load areas are apportioned in a state-specific manner without impacting the dispatch of resources. For example, load in the Company's northern California area may be distinct within the model from the load in the Company's Oregon area, but that distinction will not impact the generation forecast because there is no transmission constraint that can become binding. However, the load in California is split out from the Oregon location in the model so that California and Oregon load can be identified separately for the purpose of future allocation calculations.

Q. Why is it important to have existing thermal resources be in their own areas?

A. In the future, it is expected that existing coal-fired and gas-fired resources will no longer be allocated proportionally to all states. Under the NPM allocation, resources are assumed to be compensated by the LMPs of the areas where they are located. Therefore, an area is set to have only one thermal plant so that the plant can be compensated by the LMP specific to its location.

Q. Would there be additional areas when new resources are added to the Company's system?

A. Most likely. Based on the Company's long-term resource plans, there will be situs resources added for certain states, or states may not have fixed proportional shares of the same resources. To identify the costs and benefits of those resources, additional areas may need to be created to capture the LMPs at the locations of the resources.

Q. Will the advisory schedules from CAISO on NPM allow for PacifiCorp to better view transmission congestion between zones and implement changes to the topology in Aurora if necessary?

A. Yes. The aggregation of various individual nodes into a single transmission area involves an implicit assumption of no congestion between those specific nodes.

However, if the Company observes consistent price differences between nodes that are aggregated into a zone in the NPM model results, that will provide actionable intelligence that transmission congestion exists between those nodes and will allow the Company to modify its topology in Aurora to improve NPC forecast accuracy in the future.

Q. Does Aurora have any other modeling enhancements?

A. Yes. Aurora co-optimizes dispatch and commitment decisions, allowing the model to create a reliable dispatch forecast that satisfies all ancillary service requirements and appropriately reflects the associated costs. This commitment and dispatch feature makes modeling North American Electric Reliability Corporation (NERC) standards for ready and spinning reserves more straightforward. In addition, Aurora is capable of receiving more than one incremental price for the purpose of dispatch forecasting, and has the ability to recognize and optimize around volumetric constraints in each price tier (minimum take volumes, volume limits, etc.). That modeling improvement allows the Company to more easily arrive at an optimized dispatch forecast for plants and units that are subject to volumetric constraints and tiered pricing across a range of consumption levels.

B. Validation Process for Aurora

Q. Are both GRID and Aurora production cost optimization models?

A. Yes. Both GRID and Aurora are production cost optimization models that use linear programming with similar inputs that attempt to forecast and satisfy the Company's load obligation at minimum cost. Aurora may have a few new features, but both models are based on the same underlying economic principles.

Q. What is the process by which PacifiCorp validated the use of Aurora as compared to GRID?

A. The validation process started with the understanding that, generally speaking, no two models will produce the same results. Based on that understanding, the process included steps such as: a) verify if the outputs of non-dispatchable resources match the inputs, and the outputs match between Aurora and GRID; b) refine input parameters in Aurora that are either not available in GRID or have a different impact on optimization; and c) research the reasons why the same dispatchable resources with generally the same inputs produce different results from Aurora and GRID. And, finally, the total NPC from the two models are compared and reviewed for reasonableness.

Q. Why would the same resources produce different results from Aurora and GRID when they have the same inputs?

A. First, the inputs in the two models are not exactly the same because Aurora allows more inputs and some at different levels of granularity. In addition, the optimization logic in the two models is different, where Aurora can co-optimize the commitment and dispatch of resources while GRID does not natively accomplish this. Differences in the optimization logic may lead to different unit availabilities and different dispatch based on the economics at those times.

Q. Can you provide the results of PacifiCorp's validation process?

A. Yes. Please refer to Confidential Exhibits DRS-4C and DRS-5C, which contain the GRID and Aurora NPC Test reports that the Company used to validate the Aurora model. The test reports show that there was a less than 0.8 percent variation between the NPC calculated with GRID as compared to Aurora.

Q. While the overall variation was low, there may have been greater variation in individual resources when comparing the two test reports. Can you comment?

A. Yes. As I discussed above, there are differences between Aurora and GRID with regards to optimization logic, In addition, each model contemplates different levels of granularity of inputs. Those two in combination will result in different dispatch of resources, and different balancing transaction forecasts. This is why the validation process compared the overall outcome of the NPC test report.

Q. Would running GRID with the inputs used for the PCORC provide additional useful information regarding the validation of the Aurora model?

A. No. As described above, the ability of each model to accept different inputs and the internal optimization logic differs between the models despite the fact that the underlying principles are similar. There is no reasonable expectation that the model results would be the same or would provide additional insight, making the proposed comparison a futile exercise. Additionally, the Company has already benchmarked Aurora against the GRID model and found that the overall NPC results exhibited a tolerable variance between the two models.

C. Inputs and Adjustments in Aurora

Q. Please provide a description of the model data flow in Aurora.

A. Aurora incorporates many of the same inputs that GRID formerly considered in its optimization. As a consequence, many of the same work papers are still in use, but those inputs flow through Aurora input workbooks to be formatted for acceptance by the newer model. For inputs that are quite distinct from their GRID equivalents (coal prices, for example), entirely new modeling approaches were employed to take advantage of the additional flexibility offered by Aurora. There are also inputs that are substantially the same but require slightly modified calculation methodologies to account for the treatment given to those inputs in Aurora. I discuss unit minimums and estimated outage rate (EOR) below, which should serve as examples.

Q. How is output from Aurora incorporated into Washington NPC?

A. The Aurora model results are used to create a total-company NPC forecast. Those results are processed through the Washington Inter-Jurisdictional Allocation Methodology (WIJAM) allocation workbook to arrive at a Washington-allocated NPC forecast.

Q. How was the Day-Ahead/Real-Time Adjustment incorporated into Aurora?

A. The adjustment is unaltered aside from some minor updates to allow the adjustment calculation workbook to process the Aurora output in place of the previous GRID outputs. Fundamentally, the adjustment is calculated in the same fashion and serves the same purpose.

Q. Did your previously filed direct testimony explain why this adjustment was necessary?

A. Yes. I provided testimony in my direct filing explaining why this adjustment was necessary and appropriate.[13]

Q. How is market depth at PacifiCorp's markets modeled in Aurora?

A. Market capacities are unchanged from the way they were calculated in GRID.

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[13] *See* Exhibit DSR-1CT at 16-20.

Q. Please describe any other modeling adjustments that were in GRID and had to be incorporated into Aurora?

A. As mentioned above, Aurora accounts for unit minimums and EOR differently, and both required material updates because of differences in the modeling of unit availabilities. Aurora scales both the unit capacity and the unit minimum in response to a derate. Prior to settling upon a revised approach to the calculation of these inputs, the Company observed many hours where the generation forecast showed output below a unit's minimum stable operating level. A relatively straightforward solution was adopted by the Company that only required the calculation and input of an hourly unit minimum timeseries to account for derates. To avoid the possibility of infeasibilities, another modification was made to the EOR to remove units from service (that is, the EOR was set to 100 percent) whenever the available capacity slipped below the unit minimum.

Q. Is PacifiCorp proposing to change the process for comparing the baseline that is developed through Aurora against the actuals in the PCAM?

A. No. The allocation of actual and baseline NPC will continue to be based on the WIJAM until a new allocation methodology is agreed to in the MSP process and approved by the Commission.

D. Costs of Aurora

Q. Are any of the costs associated with the Aurora implementation included in Washington rates?

A. Yes. PacifiCorp pays an annual license fee to Energy Exemplar for the Company's use of Aurora. Six months, or $89,000, of that annual fee was included in the historical base period for the Company's 2021 Rate Case. This equates to approximately $7,000 on a Washington-allocated basis currently included in Washington rates.

Q. Is PacifiCorp seeking recovery of any of the costs associated with the implementation of Aurora in this proceeding?

A. No.

Q. Is PacifiCorp planning to forecast NPC using Aurora for ratemaking purposes going forward?

A. Yes. While this PCORC is the first time where PacifiCorp has filed an NPC forecast using Aurora, going forward, PacifiCorp is planning to use Aurora (and likely the same zonal topology) to forecast NPC for ratemaking in the annual NPC proceedings or general rate cases. To the extent that any topology modifications are implemented in the future, PacifiCorp anticipates that the modified topology will be used in future filings across all jurisdictions in which the Company does business.

Q. Does this conclude your supplemental testimony?

A. Yes.