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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF ROCKY MOUNTAIN POWER'S FILING FOR ACKNOWLEDGEMENT OF ITS 2021 INTEGRATED RESOURCE PLAN	**CASE NO. PAC-E-21-19** **COMMENTS OF THE COMMISSION STAFF**

STAFF OF the Idaho Public Utilities Commission, by and through its Attorney of record, Riley Newton, Deputy Attorney General, submits the following comments.

BACKGROUND

On September 1, 2021, PacifiCorp dba Rocky Mountain Power ("Company") filed its 2021 Electric Integrated Resource Plan[1] ("2021 IRP") pursuant to Commission Order No. 22299.

In January 1989, the Commission identified the foundational aspects of the current IRP. Order No. 22299. In 1989, the Commission specified the "Resource Management Report"[2]("RMR") as the way to publicly document the status of a utility's plan for meeting

[1] On September 15, 2021, the Company filed an updated IRP for the purpose of clarifying some changes in the IRP filed on September 1, 2021. *See updated IRP Vol. I* at 1. The updated IRP, as the Company assured, did not "affect the analysis or outcomes of the 2021 IRP." *Id.*
[2] U-1500-165 Order No. 22299 – Page 6

future resource needs. Order No. 22299. This plan was ordered to be developed and completed on a biennial basis to provide a public report documenting a utility's forecasted resource plan to meet its needs over the next 20-year period. The Commission expected RMRs to "*emphasize clarity, understandability, resource capabilities, and planning flexibility.*"[3] This report has evolved and has come to be known as the IRP. Through acknowledgement and compliance with Order No. 22299, the Company recognizes the need to examine and discuss each of the following:[4]

1. Load forecast uncertainties.
2. The effects of known or potential changes to existing resources.
3. Considerations of demand and supply side resource options; and
4. Contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead time, reliability, risk, etc.) as future events unfold.

In the Order, the Commission considered "ongoing comprehensive planning essential to good utility management".[5] The Commission recognized that resource planning is the sole domain of utility executives and that only prudence reviews of the utility's plans are needed. As such, the Commission, in response to a filed IRP, acknowledges that the Company has completed the requirements of the Commission's Order. Recognizing that an IRP is a plan and not a blueprint, the Commission believes the Company has met the requirements of the planning process, and only provides acknowledgment of the IRP, but does not authorize the conclusions or prudence of resources contained in the plan.[6]

[3] U-1500-165 Order No. 22299 – Page 12
[4] Updated 2021 Integrated Resource Plan, Volume II - *Appendix B – IRP Regulatory Compliance*, page 25
[5] Commission Order No. 22299 - Page 6
[6] PAC-E-19-16 Order No. 34780 – Page 12

STAFF REVIEW

Staff recommends the Commission acknowledge the 2021 IRP. Through its review of the Application, participation in stakeholder meetings, and review of responses to production requests, Staff believes the Company's 2021 IRP meets the requirements in Order No. 22299. Staff's overall conclusion is based on its assessment of the four requirements included in the Order as outlined in the Background section above. First, the Company developed a load forecast with load growth considering estimated energy sales and annual peak demand over a 20-year time horizon. This load forecast considered a range of uncertainties related to the econometrics of national and regional growth, weather, seasonal variance, customer usage, and customer behavioral changes. Second, the Company considered changes to existing resources by studying the economics and reliability of coal plant retirement dates, conversion of certain coal units to natural gas fuel, and by verifying the availability of market purchases, referred to as Front Office Transactions ("FOT"). Third, the Company evaluated both demand and supply-side resources in an equivalent manner when selecting them for inclusion in resource portfolios. Finally, the Company considered a wide-range of resource alternatives and resource contingencies in conjunction with a multitude of constraints in its determination of a least-cost, least-risk preferred portfolio over a 20-year time horizon.

While Staff believes the 2021 IRP complies with the requirements of Order No. 22299, Staff also identified the following areas of potential concern and need for future analysis and/or improvement:

1. Differences in cost by selecting the Preferred Portfolio based on the need to meet Washington Clean Energy Transformation Act ("CETA")[7] requirements versus selecting the portfolio on least-cost, least-risk without considering CETA. This difference in cost provides a benchmark for evaluating equity of the Company's Multi-State Protocol ("MSP").
2. Use of a historical fixed 13 percent planning reserve margin ("PRM") may not support the loss-of-load hours reliability target of 2.4 hours per year.

[7] Washington passed the Clean Energy Transformation Act (CETA), which requires utilities to meet three primary clean energy standards: remove coal-fueled generation from Washington's allocation of electricity by 2025, serve Washington customers with greenhouse gas neutral electricity by 2030, and to serve customers in Washington with 100% renewable and non- emitting electricity by 2045.

3. The Company did not allow new natural gas generating resources for selection as a new resource.
4. Selection of the proposed advanced Natrium nuclear plant. With the amount of uncertainties with the technology, it may pose significant cost and schedule risk.
5. The need to improve clarity regarding FOT Availability Limits.

2021 IRP Overview

The 2021 IRP describes the Company's proposed plan to deliver continuous, reliable electric service to its customers over the next 20 years using an approach that will result in a least-cost, least-risk resource portfolio. In developing this plan, the Company considered a load forecast with varying levels of load growth, future capability and capacity of existing resources, and a wide range of potential future resources before determining the Company's recommended Preferred Portfolio. The Company considered a number of risk variables and constraints in its evaluation to ensure the Preferred Portfolio is least-cost and least-risk in meeting customers' future needs, and can perform well under a reasonable range of possible futures.

Staff believes the 2021 IRP will inform future resource procurements, system upgrades, and economic retirements utilizing a sophisticated analytical framework for modeling and assessing resource investment tradeoffs.

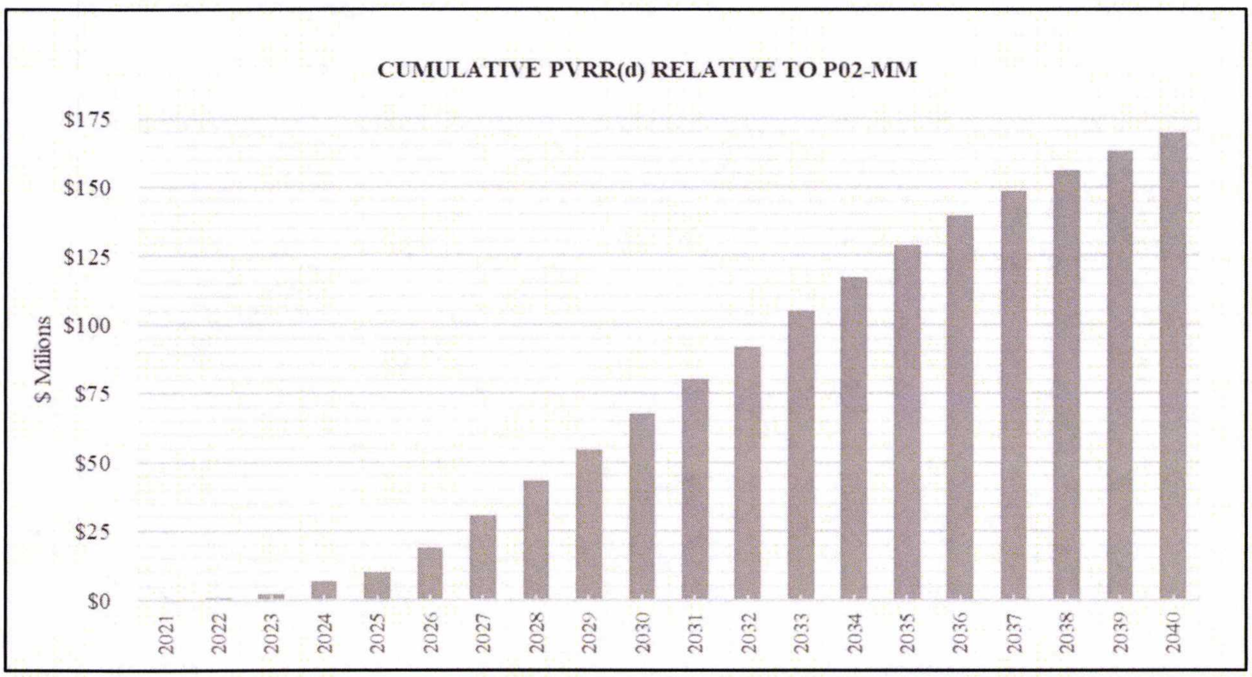
Relative to the 2019 IRP, the 2021 IRP Preferred Portfolio identified the following changes:

- Accelerated coal-unit retirements;
- No new fossil-fueled resources;
- Continued growth in energy-efficiency ("EE") programs;
- Incremental new renewable resources;
- Greater reduction in greenhouse gas emissions;
- Increased investment in transmission infrastructure;
- Conversion of two coal units to natural gas peaking units;
- Growth in demand response ("DR") capacity;
- New advanced nuclear resources;
- Increased reliance on energy storage resources; and

- Non-emitting peaking resources using technology requiring further technology development.

Preferred Portfolio

The Company selected portfolio P02-MM-CETA as its Preferred Portfolio. However, the Preferred Portfolio on a risk-adjusted present-value revenue requirement ("PVRR") basis is $164 million higher than the top performing P02-MM portfolio.[8] By comparison, P02-MM-CETA has a risk adjusted PVRR of $26.343 billion compared to the $26.179 billion lower cost P02-MM portfolio. The differences between the two portfolios are the changes in resources needed to the top performing portfolio to meet Washington's CETA requirements. The graph below illustrates the cumulative incremental cost of the P02-MM-CETA portfolio over the P02-MM least-cost least-risk portfolio over the 20-year planning horizon.



Due to the requirements needed to meet Washington's CETA, the Company identified a shortfall in renewable capacity and needed to add incremental wind, solar, and battery storage in Yakima, Washington. The cost difference between the two portfolios provides an indication of

[8] Updated 2021 Integrated Resource Plan, Volume I - Chapter 9 – Modeling and Portfolio Selection Results, page 291

the magnitude of additional cost that the State of Washington should be allocated in the MSP to ensure that Washington legislation does not increase costs to customers in other jurisdictions.

Issues Addressed from the 2019 IRP Staff Comments

Staff comments in Case No. PAC-E-19-16 identified the following concerns that the Company' addressed in the 2021 IRP:

1. Public Utility Regulatory Policies Act of 1978 ("PURPA") Capacity Deficiency Date: In the 2019 IRP, Staff identified the capacity deficiency date based on the IRP Load and Existing Resource Balance ("L&R"). Staff was concerned with including unauthorized early coal plant retirements in the L&R for the IRP. These unauthorized early retirements should not be included for determining the deficit date for assessing avoided cost of capacity in PURPA contracts when the capacity deficiency date filing is submitted after acknowledgment of the IRP. Although the L&R used for IRP purposes and the L&R for PURPA use much of the same information, the purpose of each requires differences in the resources that should be included.

2. Coal Unit Decommissioning Costs: The Company did not use the recently released costs for coal unit decommissioning in the 2019 IRP. Staff was concerned by the Company not including updated coal unit decommissioning cost into the IRP. The Company responded by including the base estimate demolition costs from the 2019 decommissioning study into the 2021 IRP. These costs were limited to the base estimate demolition costs from the study for the coal-fueled generating units that include "take-or-pay" provisions, but do not include contingency reserves as they cannot be reliably estimated at an acceptable level of granularity.

3. Long-run gas cost assumptions: Staff noted that the Company's natural gas cost forecast from its 2019 IRP was significantly higher than the Company's 2017 forecast. In the 2021 IRP response, the Company noted the following:

    a. The 2021 IRP base case forecast for natural gas prices decreased along with a decrease in wholesale power prices for most years relative to those in the 2019 IRP.

b. These forecasts are based on prices observed in the forward market and on projections from third-party experts.

c. The lower power prices observed in the 2021 IRP are primarily driven by the assumption of lower natural gas prices than what was assumed in the 2019 IRP.

d. The 2021 IRP assumed lower natural gas prices than in the 2019 IRP due to additional supply of natural gas available in the market from lower than expected liquefied natural gas ("LNG") exports. LNG exports were limited by pipeline expansions to LNG facilities that did not occur.

4. Transmission Planning: In the Company's 2019 IRP, Staff was concerned that the relatively high natural gas price forecast disadvantaged natural gas plants and transmission resources compared to new renewable resources. According to the response in the 2021 IRP, the Company believes that by implementing the Plexos software, it can now evaluate new transmission topologies with new resource additions, simultaneously. Staff agrees that this is a major improvement in modeling capability and can lead to portfolio options that may not have been considered in past IRPs; however, Staff does not believe its concern was addressed, especially given that new natural gas resources were not included as resources that could be selected by the model.

5. Demand-Side Management ("DSM") and Time-of-Use Rates: Staff identified the need for the Company to continue its efforts to expand its DSM resources and time-of-use rate structures. The Company responded that it continues to evaluate new DSM opportunities, both energy efficiency ("EE") and direct load control programs as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios within the IRP and that DSM resources continue to play a key role in its resource mix. The Company did not respond to the use of time-of-use rate structures as a DSM measure.

Improved Modeling Capabilities

The 2021 IRP made several improvements to the quality of the IRP results. In 2021, the Company began using Plexos, a more advanced third-party software developed by Energy Exemplar, replacing System Optimizer (capacity expansion model) and Planning and Risk (production cost model). Instead, Plexos performs much of the same functions, but uses a combination of Long-term ("LT"), Medium-term ("MT"), and Short-term ("ST") models all of which use a common database and are designed into an integrated platform.

The Plexos software solved problems that existed with the Company's previous modeling software, which required the Company to perform a number of process steps outside of the models in order to get valid results. Plexos also greatly reduced the volume of individual portfolios needed to evaluate the impacts of varying resource decisions and has built-in capabilities to model future resources and system designs that require future evaluation. Plexos allows the Company to evaluate the timing of plant retirements, gas conversions of coal plants, carbon capture and sequestration, retrofits to coal units, battery optimization, and alternative transmission topologies. Portfolio performance measurement is also improved, allowing the Company to calculate forecasted locational marginal prices for a given zone within the Western Interconnect.

2021 IRP Process

The IRP process is used to assess the comparative cost, risk, and reliability characteristics of different resource portfolios while meeting reliability requirements. The Company's models allow the Company to evaluate the net present value revenue requirement ("NPVRR") for each portfolio over the 20-year planning horizon and by further evaluating the portfolios by performing stochastic Monte Carlo simulations so that a risk-adjusted NPVRR can be determined. The risk-adjusted NPVRR results indicate how robustly a portfolio performs under uncertain future conditions so that meaningful comparisons can be made.[9]

[9] To determine a risk-adjusted NPVRR, the Company performs a stochastic analysis using Monte Carlo simulations of each portfolio. This is done by first identifying model input assumptions or risk variables that exhibit future uncertainty, such as load, natural gas prices, wholesale electricity prices, hydro-generation, and forced outages. The models are then run 50 times by sampling values from statistical distributions for each of the risk variables for each model run. The results of these Monte Carlo runs produces a distribution of NPVRR results for each portfolio so that a risk-adjusted NPVRR can be determined and compared between each of the portfolios.

The Company developed its 2021 IRP through the following planning steps:

1. Develop Key Inputs and Assumptions
2. Model a Range of Resource Portfolios
3. Analyze Variants to the Top Performing Resource Portfolios
4. Select a Preferred Portfolio
5. Identify Next Steps within the Action Plan

First, the Company prepared a L&R study comparing forecasted loads to existing resource capacity over a 20-year time horizon. The L&R study highlights deficiencies in capacity that occur over the planning horizon. The Company considered a wide range of factors including natural gas and wholesale power prices, along with regulatory, environmental, and public policy issues. These factors, and additional inputs from stakeholders, were bundled into a set of input assumptions that formed the basis of each unique planning case.

The Company then ran each case through the LT capacity expansion functionality within Plexos. These runs produced a unique resource portfolio for each case optimized for cost that had sufficient capacity to meet the load forecast plus a PRM across the 20-year planning horizon. The set of selected resources also needed to meet other constraints including reliability, state and federal environmental policies, resource limitations, etc. Each portfolio is unique regarding the type, timing, location, and amount of new resources.

Each portfolio was then evaluated in the ST modeling functionality to determine the system costs for each portfolio over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a present-value revenue requirement ("PVRR"), which served as the basis for adjustments of risk in the next step of the process.

Once the portfolios were developed through the LT models, and then ran through the ST modeling functionality, the Company then utilized the Plexos MT modeling functionality to determine a risk adjustment to the system cost results determined in the previous step. Each portfolio was evaluated for cost and risk among three natural gas price scenarios (low, medium, and high) and three carbon dioxide (CO2) price scenarios (zero, medium, high). An additional CO2 policy scenario was developed to evaluate performance of the portfolios that included a social cost of greenhouse gases. Taken together and using a bookend approach, the Company modeled five distinct price-policy scenarios (medium gas/medium CO2, medium gas/zero CO2, high gas/high CO2, low gas/zero CO2, and the social cost of greenhouse gases) in the 2021 IRP.

Informed by comprehensive modeling, the Company's Preferred Portfolio selection process involved evaluating cost and risk metrics reported from the ST and MT models, and comparing resource portfolios based on expected costs, low-probability high-cost outcomes, reliability, CO2 emissions, and other criteria.

Finally, after the Company selected the Preferred Portfolio, the Company developed an action plan that it will use to implement the IRP during the first 3 to 5 years of the planning horizon.

Reliability Assessment

As described above, the Plexos LT functionality develops initial portfolios at a granularity level of 4-block data per month, using a minimum of 13 percent PRM. Subsequently, the initial portfolios are simulated in the ST model to quantify reliability shortfalls at an hourly level and additional resources are added into the portfolios to resolve any shortfalls. Staff has two major issues with the methods the Company uses to ensure adequate reliability of its portfolios: (1) the use of a minimum of 13 percent PRM, and (2) whether the Company ensures that the reliability target, measured in Loss of Load Hours ("LOLH"), was met.

Use of Minimum of 13 percent PRM

The 13 percent PRM was determined in the PRM Study in the 2019 IRP. *See* Response to Staff's Production Request No. 19. However, many inputs, parameters, and assumptions have changed in the 2021 IRP, such as the load forecast and the FOT Availability Limits, which were used to determine the 13 percent PRM in the 2019 IRP. *See* Appendix I – Planning Reserve Margin Study of the 2019 IRP. Staff is concerned that the 13 percent PRM determined in the 2019 IRP may not be appropriate for the 2021 IRP. Ideally Staff believes that each IRP should determine its own PRM based on the inputs, parameters, and assumptions specific to each IRP. If a dated PRM is used, the Company needs to justify why the Company believes the old planning margin is still appropriate.

The footnote on page 146 of the PRM Study in the 2019 IRP states:

> PacifiCorp must hold approximately six percent of its resources in reserve to meet contingency reserve requirements and an estimated additional 4.5 percent to 5.5 percent of its resources in reserve, depending upon system conditions at the time of peak load, as regulating margin. This sums to 10.5 percent to 11.5 percent of operating reserves before even considering longer-term uncertainties such as extended outages (transmission or generation) and customer load growth.

The Company states that the footnote still applies in the 2021 IRP. *See* Response to Staff's Production Request No. 19 (b). Staff believes this footnote justifies a PRM floor of 11.5 percent, but it does not sufficiently justify the 13 percent PRM. Staff believes the estimated 11.5 percent threshold existed before the 2019 PRM study was even conducted, which examined a range of PRM from 11 to 18 percent and ultimately chose 13 percent.

<u>Verification of LOLH Reliability Target</u>

The 13 percent PRM was selected to meet a LOLH reliability target of 2.4 hours per year, which equates to one day in ten years, a common reliability target in the industry. As such, a PRM goal is not a reliability target in and of itself. It is an interim adjustment factor to increase the amount of load that the resource plan must meet; however, without a process to verify whether the portfolios actually met the LOLH target is unclear.

Staff believes a reliability target should be established prior to the start of the modeling process. A reliability target is a policy decision and should be based on what the public and ratepayers can tolerate considering societal cost of outages. Once the target is established, the Company needs to demonstrate that the PRM was derived from the target. After the portfolios have been developed, the Company should be able to verify whether the resulting portfolios met the original target as a feedback loop. This feedback loop and final verification step is important because portfolios with a significant amount of variable resources will require a higher PRM than a portfolio with a higher concentration of dispatchable resources for a given reliability target. Staff recommends that the Company provide greater clarity relative to these expectations in future IRPs.

Evaluation of IRP Resources

Natural Gas Resources

The Company did not include or consider any new natural gas proxy resources for inclusion in any of the Company's portfolios. The Company considered natural gas resources as a stranded-cost risk due to depreciable lives ranging from 30 to 40 years (i.e., a new gas-fired resource placed in service in 2030 would be depreciated as late as 2070). Given current state policies within the Company's service territory and potential for future federal policies, the Company did not believe it feasible to assume new natural gas resources in the IRP. The Company believed it was unlikely it could obtain the permits to site and operate such a facility in many parts of its service territory. Finally, the Company observed that there is very limited development activity for new natural gas facilities. This phenomenon recently evident in the 2020 all source request for proposal ("2020AS RFP") conducted by the Company did not result in a single bid for new natural gas resources.

Staff believes the Company could have used an alternative approach that allows Plexos to select new natural gas resources but consider the cost of these facilities becoming potential stranded assets. The Company could develop an adder to the cost of new natural gas plants that represents the expected value of the additional cost that customers would incur if the gas plants needed to be retired early due to external factors. The value of this approach would allow the benefits of a fully dispatchable resource that is not time limited, as is the case with battery storage, to be considered.

However, the Company selected the conversion of Bridger Units #1 and #2 to natural gas by June 1, 2024. The cost of conversion is significantly less than installing Selective Catalytic Reduction ("SCR") to comply with Regional Haze federal regulations. Furthermore, the benefits to the system of having two additional dispatchable gas peaker units was shown to be cost effective compared to other alternatives for additional capacity due to the low capital cost of conversions.

Coal Generation

Environmental regulations in Oregon and Washington and at the federal level are driving the early retirement of much of the Company's coal fleet. The table below shows the retirement/exit dates reflected in the Company's Preferred Portfolio:

COAL GENERATION RESOURCE	YEAR
Jim Bridger Units 1-2 Retired/Conversion to Natural Gas Peakers	2023/2024
Naughton Units 1-2 -Retired	2025
Craig Unit 1 - Retired	2025
Colstrip Units 3-4 - Retired	2025
Dave Johnston Units 1-4 - Retired	2027
Hayden Unit 2 - Retired	2027
Craig Unit 2 - Retired	2028
Hayden Unit 1 - Retired	2028
Huntington Units 1-2 - Retired	2036
Jim Bridger Units 3-4 - Retired	2037
Wyodak - Retired	2039

The Company's capacity expansion models selected the dates based on a combination of coal plants that remain economical for the system, the system need for capacity, and current environmental constraints. Coal plant capacity that will be retained beyond 2025 and 2030 due to Washington and Oregon's restrictions on coal plants, will be reassigned to the Company's other jurisdictions through MSP.

Renewables and Energy Storage

The Company's 2021 Preferred Portfolio continued to add substantial new renewables as declining cost of renewables and battery storage occur. As costs decline and technologies improve, renewables and energy storage are displacing traditional fueled generation resources. State renewable portfolio standards and new transmission infrastructure continue to drive the addition of over 6,400 Megawatts ("MW") of new renewable resources by the end of 2023, with nearly 11,000 MW of new renewable resources over the 20-year planning period. These new renewable resources are typically located in remote areas away from load centers. As retirement of coal resources continue, the Company plans to continue to invest in a transmission system to move energy across and between the Company's east and west balancing areas.

Energy storage resources can provide a variety of grid services since they are highly flexible, with the ability to respond to dispatch signals and act as both a load and a resource. This evaluation, refreshed for the 2021 IRP, details how these grid services and energy storage resources can be configured and sited to maximize benefits to the system. With the variability of renewable resources, the Company continues to increase energy storage typically through battery storage technology. But with the selection of the advanced nuclear Natrium™ projects, the Company will utilize significant heat energy storage to support increasing amounts of renewables over the long term.

<u>Market Purchases and FOT Availability</u>

FOTs play a specific role in the IRP for fulfilling capacity requirements throughout the 20-year planning horizon. The Company first determines FOT Availability Limits based on firm transmission capacity and market liquidity and depth. Once the limits have been determined, FOTs are used as a slack amount of capacity to fill short positions up to the limit for each time period. If the market purchase needs exceed what the market can provide, the deficit triggers an incremental amount of generation resources that needs to be added to the system.

The 2021 IRP assumes that the FOT availability limits are 500 MW for summer and 1,000 MW for winter, which are significantly reduced from the 1,425 MW for summer and 1,425 MW for winter used in the 2019 IRP. Staff has identified issues with the FOT Availability Limits involving improving transparency of methods used to determine the limits, issues where the Company appears to exceed its Availability Limits, and whether the contingency adder required for market sellers is capacity available for use by the Company to meet load.

Transparency of Methodology for determining FOT Availability Limits

Staff believes that the Company should improve the transparency of the methodology for determining FOT Availability Limits in the next IRP by describing the steps and the assumptions used in the overall methodology. The Company uses regional studies, physical delivery constraints, market liquidity, and market depth to make the determinations, but does not provide any specificity for how the limits are determined.

FOT Availability Limit Exceedance

In Table 6.11 (Summer Peak – System Capacity Loads and Resources without Resource Additions), the "Uncommitted FOTs to meet remaining Need" amounts are significantly greater than "Available Front Office Transactions" amounts in the summers of 2021, 2022, and 2023. The Company stated that it will be reliant on a higher level of FOTs in the near term. *See* Response to Staff's Production Request No. 21 (b). Staff believes it likely that during these early years, the Plexos model is constrained by resource acquisition lead times, and the only recourse if these deficits actually occur, is to resort to the market.

However, this issue has implications for the First Capacity Deficit Date used for setting PURPA rates. It is unclear whether the FOTs in the L&R above the Availability Limit are properly reflected and can be counted upon to provide the stated amount of capacity. Staff recommends that the Company provide greater clarity on this issue in the upcoming first deficit year filing and in the next IRP.

Contingency Adder for FOT Availability Limits

The L&R in the 2019 IRP increases the FOT Availability limits by 3 percent, while the 2021 IRP does not include these increases. According to the Company, the 3 percent adder is for contingency reserves that firm energy sellers are required to hold. *See* Response to Staff Production Request No. 19 in Case No. PAC-E-20-13 and Supplemental Response to Staff Production Request No. 18 in Case No. IPC-E-21-19. However, it is not clear whether this additional amount of contingency held by a seller is available to the Company in order to meet its load for firm market purchases. The answer to this question will determine whether the additional 3 percent should be included in the L&R. Staff recommends that the Company provide clarification of this issue in the upcoming first deficit year filing and in the next IRP.

<u>Private Generation</u>

Page 149 of Volume I of the 2021 IRP states that the hourly system load is reduced by hourly private generation projections to determine the net system coincident peak load for each of the first ten years (2021-2030) of the planning horizon. The reference to "the first ten years (2021-2030) of the planning horizon" is incorrectly stated. According to the Company, the hourly system load is reduced by hourly private generation projections for the 20 years of the IRP planning horizon (2021 through 2040). See Response to Staff's Production Request No. 25. Staff also verified that the amount of private generation was included in the L&R for the entire planning horizon.

DSM

The Company has a mature portfolio of EE and DR programs it effectively deploys to reduce and reshape loads. Because these programs are cost-effective, they reduce the cost the Company incurs to serve customers.

EE Programs

In the Company's Preferred Portfolio, the Company's EE resource selections show a decline in resource selections in 2022, dropping to 12,824 Megawatt-hours ("MWh") from 17,590 MWh in 2021. However, by 2025 resource selections begin to increase again and reach near 2021 levels with 17,289 MWh of first-year EE savings. Despite EE resource selections declining early in the planning horizon, Staff encourages the Company to continue pursuing all cost-effective DSM resources.

DR Programs

The 2021 IRP changes how DR is treated in the L&R compared to its treatment in the 2019 IRP. DR programs include residential and small commercial air conditioner load control, irrigation load management, and interruptible contracts. In the 2019 IRP, the interruptible contracts were treated as a DSM resource to reduce load, thus were used in the calculation of the planning margin. However, remaining DR (Class 1 DSM) was treated as a supply-side resource and thus was not used to calculate the planning margin. In the 2021 IRP, all the existing DR programs were treated as DSM resources and thus were all used to calculate the planning margin. The Company decided it was appropriate because DR programs are dispatchable reductions to load, and it was more appropriate to include them in the total amount of obligations. See Response to Staff's Production Request No. 29 (e). Staff believes this change is acceptable given the nature of DR programs.

In the Company's Preferred Portfolio, the Company shows an increase in DR selections in the Company's Idaho territory. Notably, the Company selected 25.8 MW of additional DR in the next ten years and an additional 10 MW by 2024 for DR in the summer. In Case No. PAC-E-22-03, the Company proposed to increase Electric Service Schedule No. 191 to account for an increase in DSM program expenditures for pending DR programs. Staff looks forward to reviewing the Company's proposals for upcoming DR programs.

Advanced Nuclear Projects

The TerraPower advanced nuclear Natrium™ demonstration project selected in the Preferred Portfolio could potentially deliver significant benefits to the Company's electric system, but there could also be significant risks. The 2021 IRP includes 1,500 MW of advanced nuclear Natrium™ peaking resources as part of its least-cost, least-risk Preferred Portfolio. The first 500 MW identified as a demonstration project is shown to come online by the summer of 2028. The portfolio also includes 1,000 MW of additional advanced nuclear generation being added in 2038.

The operating characteristics for the advanced nuclear plants would significantly benefit the Company's system for meeting peak load and reliability needs. The design is based on a molten sodium-cooled nuclear reactor paired with a molten salt thermal energy storage tank. The molten salt energy storage provides significant ramping in meeting the needs for system reliability as increased renewable resources are added to the system. Both the reactor and the molten salt energy storage generate power through a single steam turbine.

Although a facility with these types of performance characteristics would be highly beneficial, Staff believes there are numerous concerns and risks. First, the licensing process by the U.S. Nuclear Regulatory Commission ("NRC") has historically been a source of large delays.[10] Second, there are several technology issues that still require development, if not resolved, could result in substantial delays. Third, the fuel source for this type of plant has yet to be developed. Finally, there are issues related to spent fuel disposal and plant decommissioning, which could add substantial cost, and should be included in the lifecycle cost of the plant.

Because of these risks, Staff requests the Company assess contingencies in future IRPs in case the plant is determined to no longer be viable, or if significant delays are likely.

Non-emitting Peaker Resources

The Company has also included 1,224 MW of non-emitting peaker resources to its Preferred Portfolio starting in year 2033. These are resources that are projected to be hydrogen-fueled. Because the technology for these types of resources is not mature, Staff believes it is appropriate to include them in portfolios during the second half of the 20-year planning horizon

[10] https://www.nrc.gov/reactors/new-reactors/advanced/ongoing-licensing-activities/pre-application-activities/natrium.html (Last Updated June 16, 2021)

beyond lead times of competing resources. The status of the technology can be updated in future IRPs and determined whether they are likely feasible as the addition of these types of resources approach construction lead times.

STAFF RECOMMENDATIONS

Staff recommends that the Commission acknowledge the Company's September 15, 2021, Updated IRP. Staff also recommends the following:

1. The Company provide greater clarity whether Loss of Load Hour reliability target of 2.4 hours per year was achieved by the Company's portfolios.
2. The Company provide greater clarity on: the development of FOT availability limits in future IRPs, whether the inclusion of 3 percent contingency amounts for firm purchases are appropriate to include to meet Company load, and the exceedance of FOT limits in the early years of the planning horizon as it pertains to the first deficit date for purposes of PURPA avoided cost rates.
3. The Company explore an approach to allow for the selection of natural gas resources into a portfolio but provide an adjustment to the cost based on the expected cost risk of becoming a stranded asset.
4. The Company assess the risks of Natrium nuclear plant implementation due to technology viability and potential delays, and plan contingencies accordingly.

Respectfully submitted this 15th day of March 2022.

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i:umisc/comments/pace21.19rnrkksktncttyy comments

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 15TH DAY OF MARCH 2022, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. PAC-E-21-19, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

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Jo Nelson
SECRETARY