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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR APPROVAL OF THE CAPACITY DEFICIENCY TO BE UTILIZED FOR AVOIDED COST CALCULATIONS	)	**CASE NO. IPC-E-21-09** **AMENDED COMMENTS OF THE COMMISSION STAFF**

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

BACKGROUND

On April 9, 2021, Idaho Power Company ("Company") applied for Commission approval of its capacity deficiency period determination for avoided cost calculations under the Public Utility Regulatory Policies Act of 1978 ("PURPA") and Order Nos. 32697, 33084, 33159, and 34659. Based on its second amended 2019 Integrated Resource Plan ("IRP") the Company asked for Commission approval of the capacity deficiency period with a first deficit occurring in August 2028.

On February 4, 2022, the Company filed a motion and amended application ("Amended Application"), seeking to implement a first capacity deficit of July 2023 for both the Surrogate Avoided Resource ("SAR") method and the IRP method. Idaho Power also requests that the

Commission direct that future capacity deficiency filings for PURPA avoided cost rates be made at the time the IRP is filed, rather than at the time the IRP is acknowledged.

Under PURPA, the Commission has established a surrogate avoided resource ("SAR") method and an IRP method to calculate avoided cost rates for qualifying facilities ("QFs"). Under both methods, a QF receives capacity payments only after the applicable capacity deficit date is reached. Order Nos. 33377, 33159, and 33898. The first deficit date under the IRP method will float to reflect the changes in the QF queue, while the first deficit date under the SAR method will not float to reflect the changes in the QF queue. Order No. 33933.

The capacity deficiency period is determined through the IRP planning process and is submitted to the Commission in a proceeding separate from the IRP docket. The capacity deficit date determined in the IRP process is presumed to be correct as a starting point but will be subject to the outcome of the capacity deficiency case. Order No. 32697.

STAFF REVIEW

Staff reviewed the Load and Current Resource Balance ("L&R") contained in the Company's Amended Application and recommends the following changes be made to the proposed L&R:

- Use the most recent load forecast developed by the Company with Brisbie's load removed and a 15.5% planning reserve margin ("PRM") applied;
- Verify the capacity amounts of Brownlee Hydro and Shoshone Falls Hydro facilities and make sure the correct capacity amounts are used in the L&R;
- Add Energy Efficiency ("EE") Bundles to the L&R as an adjustment to load;
- Assume no renewals for PURPA wind projects unless the Company receives information from the wind qualifying facilities indicating they plan to renew their contract;
- Reflect the expiration date of Path C transmission capacity, unless the Company has renewal rights;
- Remove Boardman to Hemingway ("B2H") and B2H-related transmission capacity; and
- Include the capacity of Western Systems Power Pool ("WSPP") market purchases in the L&R, if not already included.

Staff recommends that the Company file an updated L&R incorporating these changes and update the first capacity deficiency date accordingly. The first capacity deficiency date should be used in both the SAR method and the IRP method. Lastly, Staff recommends that if the Commission decides to re-evaluate when the capacity deficiency date case should be filed, a generic docket should be opened because the decision may need to consider factors affecting all three Idaho electric utilities.

Load Forecast in the L&R

Staff continues to believe that the latest load forecast provides better accuracy for determining the first capacity deficiency date because it is based on the most current information. *See* Staff's comments filed on July 21, 2021. If a more recent load forecast is available, Staff recommends that the Company include it with Brisbie loads removed in an updated L&R with the same 15.5% PRM applied.

The load forecast in the L&R includes Brisbie's forecasted load. *See* page 13 of Mr. Tatum's Direct Testimony in Case No. IPC-E-21-42. Staff believes that Brisbie's load should be removed from the load forecast because Brisbie's load and resource are contingent upon one another. Until the Commission has approved the Brisbie contract, neither the load nor resource should be included in the L&R.

The proposed load forecast includes a 15.5% PRM based on a one day in twenty years (1-in-20) or 0.05 days per year Loss of Load Expectation ("LOLE") reliability target. The Company changed its target from a one-day in ten years (1-in-10) LOLE target to the more stringent target toward the end of the 2021 IRP cycle. According to the Company, this reliability target was changed to account for the extreme weather events that are becoming more frequent and increased uncertainty in year-to-year water availability impacting hydro generation. The Company also stated that Northwest Power and Conservation Council used the same target in its Seventh Power Plan[1] and its Resource Adequacy site.[2] *See* Response to Staff's Production Request No. 15 in Case No. IPC-E-21-43.

A 1-in-10 LOLE target is the industry standard for resource planning. *See* Response to Staff's Production Request No. 14 in Case No. IPC-E-21-43 and the North American Electric

[1] https://www.nwcouncil.org/reports/seventh-power-plan
[2] https://www.nwcouncil.org/energy/energy-topics/resource-adequacy

Reliability Corporation ("NERC")'s 2021 Long-Term Reliability Assessment.[3] Staff does not agree with the Company's justification used to change the LOLE target in the Company's IRP. The reliability target threshold should be determined independent of the Company's loads and resources and should be a policy decision based on the tolerance of customers and the public to costs, risks, and other impacts related to electricity outages.

Instead of using a more stringent target, Staff believes it is more appropriate to incorporate year-to-year variability in both the Company's load forecast and availability of hydro generation rather than assuming average weather conditions in the IRP. The Company illustrated how weather variability over just a four-year historic period can have a dramatic effect on the resources needed to ensure reliability. By comparing each year's weather effect on 2023 resource requirements to resource requirements based on average weather over those same years, the Company demonstrated shortages could occur in two out of the four years. *See* Response to Production Request No. 20 in Case No. IPC-E-21-32. This indicates that the load forecast may be underestimated, or hydro resource capacity contribution overestimated (or a combination of both) during some years over the IRP time horizon by not accounting for year-to-year variability in weather. Given the resulting 15.5% PRM is close to the 15% PRM used in previous IRPs, Staff believes that using average weather and hydro conditions, but compensating by using a more stringent 1-in-20 LOLE target achieves approximately the same effect.

Resources in the L&R

Staff's evaluation of resources in the L&R is based on the principle of whether a resource is "available" and/or "existing", unless exceptions are justified. Staff's review is focused on (1) Jackpot Solar, (2) the Brownlee Hydro and Shoshone Falls Hydro facilities, (3) EE Bundles, (4) PURPA Wind Renewals, (5) Thermal Plants, (6) Early Coal Plant Retirements, (7) Market Purchases with Secured Third-Party Transmission, and (8) New Contract Changes.

Jackpot Solar

Staff believes that no changes should be made to the proposed L&R due to the delay of Jackpot Solar. The developers of Jackpot Solar informed the Company that global supply chain disruptions have raised concerns regarding Jackpot Solar's ability to achieve commercial

[3] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf

operation by the dates identified in the approved agreement. *See* page 170 of Idaho Power's 2021 IRP. The latest information from the developers indicates that Jackpot currently anticipates a 40-day delay in project completion from the Scheduled Commercial Operation Date of December 1, 2022. *See* Response to Staff's Production Request No. 8 in Case No. IPC-E-21-43.

All the solar resources on the Company's system do not contribute capacity during winter months of December, January, and February[4] in the L&R. A 40-day delay should not affect the project's capacity contribution to the system or the deficit date, especially since the deficit date for the Company's system does not occur until the summer months.

Brownlee Dam and Shoshone Falls

Staff recommends that the Company verify the capacity amounts of Brownlee and Shoshone Falls hydro facilities and make sure the correct capacity amounts are included in the L&R. Page 38 of the 2021 IRP states that the Company has 17 hydroelectric projects with a total nameplate capacity of 1,773 megawatts ("MW"). The nameplate capacity for Brownlee increased by 22.4 MW and the Shoshone Falls nameplate capacity increased by 3.2 MW both due to plant upgrades. Together these changes increased hydro nameplate capacity from 1,773 MW to 1,798.8 MW. *See* Response to Staff's Production Request No. 1 in Case No. IPC-E-21-43.

EE Bundles

Staff recommends that EE Bundles be added to the L&R as an adjustment to the load forecast, even though this would not affect the identification of the first capacity deficiency date. In determining the deficit amount of each year over the planning horizon, the proposed L&R uses the EE amounts determined in the EE Potential Study as an adjustment to load, which includes both the existing and future EE programs deemed to be cost-effective from the Utility Cost Test. *See* Response to Staff's Production Request No. 9 in Case No. IPC-E-21-43. The EE Bundles selected in the preferred portfolio are treated as new resources and are not used to adjust the load forecast. As stated in Staff's first set of comments, all cost-effective EE should be

[4] Response to Staff's Production Request No. 6 in Case No. IPC-E-21-09 states that, for winter months, the system peak hour occurs in the morning before sunrise. Therefore, PURPA solar capacity is zero in winter months of December, January, and February. Staff believes this rationale also explains why Jackpot Solar has zero capacity in the winter months.

included, because utilities are expected to pursue all cost-effective EE pursuant to Order Nos. 32426 and 33917. Therefore, Staff believes that all cost-effective EE, whether identified from the EE Potential Study or from the modeling process, should be included in the L&R. However, this will not affect the determination of the first capacity deficiency date because EE Bundles do not provide capacity until 2039.

PURPA Wind Renewals

The Company's assumption that wind QFs will not renew their ESAs has been in place for several IRP cycles. *See* Idaho Power's Reply Comments in Case No. IPC-E-19-19. Staff believes it is reasonable to assume no renewals for PURPA wind projects absent receipt of information from the wind qualifying facilities indicating intent to renew. Therefore, Staff recommends that the Company remove the 25% renewal rate in the proposed L&R and include only the capacity for wind projects that have indicated intent to renew contracts upon expiration.

Staff has three reasons to support its recommendation. First, the obstacles to wind renewals still exist, which include the high cost of repowering wind facilities, reductions and/or elimination of tax credits, and integration costs for wind. Second, a wind project will either renew in total or not renew its contract; it is unlikely that only 25% of a wind project will renew after a contract expires. Finally, the Company's communication with wind project owners did not provide a positive indication of their intent to renew. *See* Response to Staff's Production Request No. 7 in Case No. IPC-E-21-43.

Because the Company has established communication with wind developers and because of difficulties for renewals, Staff believes that the inclusion of renewal contracts should be based on an indication that a project will renew its contract on a case-by-case basis.

Thermal Plants

Staff believes the capacity of thermal plants included in the L&R is reasonable. Compared to the original L&R included within the Application on April 9, 2021, the updated L&R in the Amended Application updated the capacity amounts of Bridger, Valmy, Bennet Mountain, and Danskin plants due to methodology changes to determine capacity contribution in the 2021 IRP. The method used in the updated L&R incorporates Effective Forced Outage Rates ("EFOR") and the refinement of Effective Load Carrying Capability ("ELCC"). There are also small refinements made to the peaking capabilities of coal and gas units. *See* Response to Staff's Production Request No. 9 in Case No. IPC-E-21-43. After a detailed review of the Company's methods for predicting capacity contribution of thermal resources, Staff believes that they are accurate and reasonable.

Early Coal Plant Retirements

Other than a planned exit of Valmy Unit 2 at the end of year 2025, there are no early coal plant exits in the L&R. *See* Response to Staff's Production Request No. 33 in Case No. IPC-E-21-09. Staff believes this treatment in the L&R is reasonable. As stated in Staff's July 21, 2021, comments, existing resources should reflect their authorized useful life unless early retirements are authorized; until then, any resource decision not authorized by the Commission is speculative.

In Avista's early exit of Colstrip Units 3 and 4, the Commission stated Avista's decision to include the 2025 exit of Colstrip Units 3 and 4 is presumptuous and ignored that the Commission had not addressed the economic retirement date for those units. Order No. 34981. Further Order No. 34981 stated that until the Commission had an opportunity to evaluate and determine a proper exit date, it was unreasonable to utilize Avista's updated first capacity deficiency date.

Given these criteria, Staff believes that Valmy Unit 2 should be included until the end of 2025. Valmy started operation in 1985 with a 50-year useful life. However, in the Settlement resulting in Case No. IPC-E-16-24, the parties agreed Idaho Power will negotiate with co-owner NV Energy to accomplish a permanent end to coal-burning operations of Valmy Unit 1 by December 31, 2019, and of Valmy Unit 2 by December 31, 2025. Or, alternatively, the parties agreed that Idaho Power will use prudent and commercially reasonable efforts to end its participation in the operation of Valmy Unit 1 by December 31, 2019, and Valmy Unit 2 by December 31, 2025. The Settlement was approved in Order No. 33771. Therefore, Staff believes it is reasonable to reflect retirement of Valmy Unit 2 in the L&R based on the approved Settlement.

Market Purchases with Secured Third-Party Transmission

In its review of Market Purchases with Secured Third-Party Transmission, Staff focused on four components: (1) Capacity Benefit Margin ("CBM"), (2) Idaho-NV Energy Path, (3) Path C, and (4) B2H assumptions.

1. CBM - Staff believes that the CBM contained in the L&R is reasonable. CBM is transmission capacity the Company holds as being unavailable for firm use on its transmission system for the purpose of accessing reserve energy to recover from severe conditions such as unplanned generation outages or energy emergencies. It allows the utility to reduce the amount of reserve generation capacity on its system by providing transmission availability to another market. *See* Response to Staff's Production Request No. 11 in Case No. IPC-E-21-43. If Idaho Power were to replace the emergency reserve provided by CBM with another on-system resource, then the Company would be in the same position for resource planning purposes. Reducing or eliminating CBM moves the need for capacity from one bucket (serving load) to another bucket (PRM), while having no impacts on the Company's overall system capacity need. *See* Idaho Power's Reply Comments in Case No. IPC-E-19-19. Because CBM is used to lower the Company's need for PRM to cover emergencies, Staff believes it should be included in the L&R as the Company proposed.

   The capacity amount of CBM in the proposed L&R is 330 MW for the entire planning horizon, which is based on the Company's most severe single contingency: the loss of two Bridger Units or the loss of the Langley Gulch Plant. *See* Response to Staff's Production Request No. 11 in Case No. IPC-E-21-43. Staff believes that this amount accurately reflects the magnitude of the greatest potential emergency on the Company's system and that the amount of CBM capacity included in the proposed L&R is reasonable.

2. Idaho-NV Energy Path - Staff believes capacity available through the Idaho-NV Energy path is reasonable. The Company uses the Idaho-NV Energy path to import electricity generated at Valmy. However, access to firm transmission south of Valmy currently does not exist. The Company reflects transmission access to Valmy until the Valmy

exit date in the L&R. Staff believes is reasonable and reflects the actual transmission circumstances.

3. Path C - Staff recommends the L&R reflect the expiration date of Path C transmission capacity unless the Company has renewal rights. Despite the Idaho-NV Energy Path, the Company has secured 50 MW of transmission capacity between June and October to access Southwest markets through Path C, which is owned and operated by PacifiCorp. *See* Page 13 of Appendix D of the 2021 IRP. However, this 50 MW is included in the proposed L&R for the entire planning horizon[5] without an expiration date. Staff recommends that the L&R reflect its actual expiration date unless the Company has renewal rights.

4. B2H Assumptions - Staff recommends B2H-related transmission capacity should be removed from the proposed L&R. B2H has not been authorized by the Commission and should not be included in the L&R until there is some regulatory certainty that it will become a resource. Because the B2H project has not been approved by the Commission and the term sheet between the funding parties[6] is non-binding, Staff recommends B2H and B2H-related transmission capacity (i.e. 500-MW BPA transmission service and 200-MW acquisition from PacifiCorp) should be removed from the proposed L&R.

New Contract Changes

Since the development of the proposed L&R, the Company has witnessed three contract changes: (1) a Power Purchase Agreement ("PPA") with Black Mesa Energy, LLC, for a 40-MW solar project, (2) a PPA with Verde Light Community Solar, LLC, for a 2.95-MW solar project under the Oregon Community Solar Program, and (3) a WSPP Schedule C agreement for 76-

[5] The proposed L&R uses transmission capacity forecasts contained in Tab "ATC Backgnd" in the Attachment contained in Response to Staff's Production Request No. 29 in this case. These forecasts cover2021 through 2031, while the L&R covers 2021 through 2040. After 2031, the transmission forecasts used in the proposed L&R repeat the 2031 forecasts.
[6] On January 18, 2022, the three B2H permit funding parties (Idaho Power, PacifiCorp, and Bonneville Power Administration ("BPA")) executed a non-binding term sheet that addresses B2H ownership, transmission service considerations, and asset exchanges. *See* page 1 of Appendix D of the 2021 IRP.

MW market purchases to be delivered to the Company's border June through September in 2022 through 2024, for hours ending 0700-2200 Pacific Prevailing Time. Staff recommends different treatments to these contracts.

As stated earlier, future resources and their corresponding useful lives should be included when authorized, because any resource decision not authorized by the Commission is speculative. The Black Mesa 40-MW solar PPA has not been authorized by the Commission and should be removed from the L&R.

Verde Light's 2.95-MW solar project should not be included in the L&R because the project has not been certified. Although this project has been pre-certified, the project needs to be 50 percent subscribed to receive final certification. *See* page 41 of Oregon Community Solar Program's Program Implementation Manual (Version 20220111).[7] According to the program design, any generation from a pre-certified project that is not sold or finally subscribed will sell to utilities through a 20-year PPA on an "as-available" basis subject to the requirements of PURPA and ORS § 758.505 upon request. "As-available" is considered non-firm and should not be included in the L&R. Therefore, Staff recommends inclusion of Verde Light's subscribed capacity in the L&R once the project is certified.

The Company has established a WSPP market purchase, which typically does not require Commission approval. However, these purchases may not have any impacts on the proposed L&R because the capacity associated with purchases may be covered by *Market Purchases with Secured Third-Party Transmission.* Staff recommends that any impacts of the WSPP market purchases should be reflected in the L&R, if not already included.

<u>Filing Schedule</u>

The Company requests that the Commission direct that future first capacity deficiency date filings for PURPA avoided cost rates be made at the time the IRP is filed. Staff recommends if the Commission decides to re-evaluate its direction for capacity deficiency date case filings, a generic docket should be opened. Staff believes the decision should be made considering relevant factors impacting all three Idaho electric utilities.

[7] https://www.oregoncsp.org/pim/

Currently the Commission requires each Idaho electric utility to submit its capacity deficiency date filing after acknowledgement of its IRP, rather than upon its IRP filing. Order No. 33917. In addition, Order No. 34649 states:

> [T]he Commission determines that it is prudent for the Company to file its first capacity deficit date cases upon IRP acknowledgment. The narrower capacity deficiency review should follow the more in-depth IRP review, thereby providing assurances that the Company is using data and forecasts that have undergone rigorous review before establishing its first capacity deficit date. This is not done for the mere convenience of Commission Staff, as the Company suggests, but to ensure that a review of the Company's data has indeed occurred before using the data to establish QFs rates. The Company's claim that delaying the processing of its first capacity deficit date cases will be to the direct detriment of ratepayers is unpersuasive. This is an anticipated, biennial update that will provide an opportunity for a QF to establish a legally enforceable obligation before the update occurs, regardless of whether the update occurs after the IRP is filed or after the IRP is acknowledged.

Regardless of when the first capacity deficiency date case should be filed, the date should be determined based the latest and most accurate information. The Commission has expressed this expectation in prior orders:

1. "The capacity deficiency determined through the IRP planning process will be the starting point, and will be presumed to be correct subject to the outcome of the proceeding." Order No. 32697.
2. It is appropriate for a utility to use the most updated information available in calculating its capacity deficit date. Order No. 33958.
3. PacifiCorp is required to use the most recent peak-load forecast when its next capacity deficiency case is filed. Order No. 34918.

Further, when complex new methods are introduced in an IRP that affect the first capacity deficiency date, including the methods used to determine the capacity contribution of resources and the determination of the PRM in the 2021 IRP, consideration for the time required to perform the review should be given. As is currently required by Commission orders, this level of review is performed after the review of the IRP, requiring a shorter review period during the deficiency date case filed after IRP acknowledgment. Alternatively, as proposed by the Company, the capacity deficiency date case could be filed at the same time as the IRP so that both cases are processed simultaneously but allow sufficient time during the deficiency date case schedule to ensure any new methods and/or data can be fully vetted.

If the Commission decides to re-evaluate the schedule, Staff recommends the Commission open a generic docket to determine the deficiency date filing schedule in relation to the schedule of the IRP to ensure all three utilities can provide input.

STAFF RECOMMENDATION

Staff recommends that the Company file an updated L&R and a new first capacity deficiency date as a compliance filing that incorporates the following changes:

- Uses the most recent load forecast developed by the Company with Brisbie's load removed and a 15.5% planning margin applied;
- Verifies the capacity amounts of Brownlee Plant and Shoshone Falls Plant and make sure the correct capacity amounts are used in the L&R;
- Adds EE Bundles to the L&R as an adjustment to load;
- Assumes no renewals for PURPA wind projects, unless the Company receives information from the wind qualifying facilities indicating they plan to renew their contracts;
- Reflects the expiration date of Path C transmission capacity, unless the Company has renewal rights;
- Removes B2H and B2H-related transmission capacity; and
- Includes the impacts of WSPP market purchases in the L&R, if there are any impacts on the L&R.

Staff also recommends that, if the Commission decides to re-evaluate when the capacity deficiency case should be filed, a generic docket should be opened to consider impacts to all three Idaho electric utilities.

Respectfully submitted this 31st day of March 2022.

Dayn Hardie
Deputy Attorney General

Technical Staff: Yao Yin

i:umisc/comments/ipce21.9dhyy amended comments

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 31ST DAY OF MARCH 2022, SERVED THE FOREGOING **AMENDED COMMENTS OF THE COMMISSION STAFF,** IN CASE NO. IPC-E-21-09, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

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