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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO ACQUIRE RESOURCES TO BE ONLINE IN BOTH 2024 AND 2025 AND FOR APPROVAL OF AN ENERGY STORAGE AGREEMENT WITH KUNA BESS LLC	)))))))	**CASE NO. IPC-E-23-20** **COMMENTS OF THE COMMISSION STAFF**

COMMISSION STAFF ("STAFF") OF the Idaho Public Utilities Commission, by and through its Attorney of record, Chris Burdin, Deputy Attorney General, submits the following comments.

BACKGROUND

On May 26, 2023, Idaho Power Company ("Company"), filed an application ("Application") with the Idaho Public Utilities Commission ("Commission") requesting an order: (1) granting the Company a Certificate of Public Convenience and Necessity ("CPCN") to acquire a total of 101 megawatts ("MW") of new dispatchable energy storage to meet identified capacity deficiencies in both 2024 and 2025; (2) approving the 20-year Energy Storage Agreement ("ESA") between Kuna BESS LLC ("Kuna BESS" or "Seller") and the Company for 150 MW of dispatchable energy storage capacity; and (3) acknowledging the lease accounting necessary to facilitate the transaction, and that the resulting expenses associated with the ESA are prudently incurred for ratemaking purposes. The Company asserts approval of the Application is necessary "to position the Company to meet its obligation to provide safe, reliable service to its customers." Application at 2.

The Company represents that several converging factors, including limited third-party transmission capacity, load growth, and a decline in the peak serving effectiveness of certain supply-side and demand-side resources have caused the Company to rapidly move to a near-term capacity deficiency starting in 2023. *Id.* at 5. The Company states that these dynamic circumstances led the Company to file a request for a CPCN to acquire resources to be online in 2023, as well as a CPCN to acquire resources to be online in 2024, and the Company expects to acquire additional resources each year thereafter through 2027. *Id.*

The Company represents that it must acquire additional dispatchable resources to meet identified capacity deficits on its system to comply with its continuing obligation to serve customers. *Id.* at 3. The Company states that the proposed acquisition represents a cost-effective means of providing adequate and reliable service to the customers in the Company's certificated service territory. *Id.*

The Company represents that it conducted a competitive solicitation through a Request for Proposals ("RFP") seeking to acquire energy and capacity to help meet the Company's previously identified capacity needs of 85 MW to be online by June of 2024, and an incremental 115 MW in 2025. *Id.* at 6.

The Company represents that the RFP process resulted in the selection of a 150 MW energy storage project, consisting of a 20-year ESA for a 150 MW battery storage facility, 77 MW of Company-owned battery storage to meet the 2025 capacity deficiency, and an additional 24 MW of Company-owned battery storage for the 2024 capacity need. *Id.*

The Company represents that the ESA acts as a type of lease through which Kuna BESS will develop, design, construct, own, and operate the battery storage system in accordance with the terms of the Agreement. *Id.* at 7. The Company will supply the charging energy for the system and have the exclusive right to dispatch and use the charging and discharging energy in exchange for a monthly payment. *Id.*

The ESA has a Scheduled Commercial Operation Date of June 1, 2025, prior to the Company's projected capacity deficit in July of 2025. *Id.* at 7-8. The ESA also provides for a

Guaranteed Commercial Operation Date, which is 180 days after the Scheduled Commercial Operation Date. *Id.* at 8. The ESA also requires Kuna BESS to post and maintain Credit Support which secures payment of the Termination Payment for an Event of Default by Seller, Delay Damages for Seller's failure to achieve Commercial Operation Date by the Expected Commercial Operation Date, and any other Seller liabilities under the ESA. *Id.*

The Company represents that the 77 MW battery storage facility will be located at the Happy Valley station, and that the Company can address the 2024 capacity deficiency economically and efficiently by adding 24 MW of battery storage at the Hemingway substation. *Id.* at 9-10. The Company states that it intends on executing a Battery Energy Supply Agreement for the 24 MW battery storage with Powin Energy Corporation. *Id.*

The Company represents that it is not requesting binding ratemaking treatment for the 101 MW of battery storage in this case. The Company will make a future filing to address the cost recovery associated with these projects. *Id.* at 11-12.

The Company represents that with respect to the ESA, under Generally Accepted Accounting Principles ("GAAP"), any contract that provides the right to control an identified asset over a period of time is considered a capital lease. *Id.* at 12. The Company requests that the Commission acknowledge that the lease accounting is necessary to facilitate the transaction, and that the Commission find that the expenses associated with the ESA are prudently incurred expenses for ratemaking treatment. *Id.* The Company states that it will address any regulatory accounting necessary and required under GAAP in a later proceeding closer to commencement of operation of the battery storage facility. *Id.*

The Company represents that in 2013, the Commission directed the Company to follow the RFP guidelines applicable to its Oregon service territory, which were later codified into the administrative rules of the Public Utility Commission of Oregon ("OPUC Resource Procurement Rules"). *Id.* at 13-14. The Company states that coincident to filing this Application, the Company filed an exception request with the OPUC and is currently compliant with the OPUC resource acquisition process. *Id.*

The Company represents that it intends to finance the 101 MW of energy storage with a combination of available cash and operating cash flow; available facilities and borrowing and debt issuances; and potential future equity issuances by IDACORP. *Id.* at 14-15.

STAFF ANALYSIS

Staff's review focused on the capacity deficiency in 2024 and 2025, the RFP process, the turn-key costs of the 24 MW of Battery Energy Storage System ("BESS") capacity, the turn-key costs of the 77 MW of BESS capacity, and the 20-year ESA. Staff believes that the proposed projects are the least-cost, least-risk projects among all the final shortlisted projects. However, Staff believes that due to the issues associated with the resource selection process, the bid pool could have been larger and there could have been additional shortlisted projects. Therefore, Staff recommends that the Commission establish a soft cap for the 24 MW BESS, the 77 MW BESS, and the 150 MW ESA. Specifically, Staff recommends:

1. Approval of the CPCN to acquire 24 MW and 77 MW of BESS capacity to meet the 2024 and 2025 capacity deficiencies, respectively;
2. Setting a soft cap for the turn-key costs of the 24 MW and 77 MW BESS projects at the amounts specified in Paragraph 1 and 2, respectively, of Confidential Attachment A, unless the Company presents sufficient evidence that amounts over the cap are justified when the Company seeks cost recovery;
3. The additional overbuild capacity of 5.8 MW for the 24 MW BESS and the 17.25 MW for the 77 MW BESS be subject to a full prudence review if the Company seeks recovery and after the overbuild capacity becomes used and useful;
4. Declaration that the expenses associated with the ESA, as proposed, are prudently incurred for ratemaking purposes;
5. The Company seek a prudence determination of incremental expenses outside of the contracted prices in the ESA as listed in Exhibit No. 6 of Hackett's Direct Testimony, if any, when the project becomes operational;
6. Approval of the ESA, conditioned on the Parties updating Section 19.3 of the ESA to reflect the significance of Commission approval;
7. Acknowledgement that lease accounting is necessary to facilitate the transaction of the ESA; and
8. The Company address the issues Staff identified in the resource selection process in future RFPs, regardless of whether the Company files an exception with the Oregon Public Utilities Commission ("OPUC").

I. Procurement Guidelines and Requirements

The Commission directed the Company to follow Oregon's procurement guidelines, which Staff used as a basis to evaluate the Company's RFP process. Order No. 32745 at 2. Although the Company is filing an exception request with the Oregon Public Utilities Commission (Application at 14), Staff believes the procurement guidelines exist for a reason and should be followed to the greatest extent possible, only relaxing requirements with justification directly tied to the specific reasons for filing an exception.

II. Prudence of Projects based on Company's Need for Capacity

Staff recommends: (1) approval of the CPCNs for the 24 MW BESS based on the Company's need for capacity in 2024, and (2) approval of the CPCN for the 77 MW BESS and of the 150 MW ESA based on the Company's need for capacity in 2025.

Need for Capacity in 2024

Staff believes that the additional capacity deficiency in 2024 that drove the need for the 24 MW BESS is justified. Besides the 103 MW of capacity deficiency in 2024 that drove the resources proposed in Case No. IPC-E-23-05, the Company identified an additional 8 MW of capacity deficiency during preparation of the 2023 Integrated Resource Plan ("IRP") in May 2023. Response to Staff Production Request No. 7.

The Company explains that the main factors that contributed to the additional 8 MW capacity deficiency included (1) reduced resource availability associated with the Capacity Benefit Margin ("CBM"), (2) identification of an over-allocation of capacity of a resource in the Loss of Load Expectation ("LOLE") calculation, and (3) the unexpected 20 MW derate at Langley Gulch. Ellsworth, Di. at 18. Staff agrees that the first two reasons have contributed to the existing 103 MW of capacity deficiency addressed in Case No. IPC-E-23-05. Ellsworth, Di. at 14-21 in Case No. IPC-E-23-05. Staff also agrees with the Company that the main factors that contributed to the additional 8 MW capacity deficiency included (1) the unexpected 20 MW derate at Langley Gulch and (2) the updated load forecast that incorporated the 2023 Loss Study. Attachment 1 of Supplemental Response to Staff Production Request No. 36 in Case No. IPC-E-23-05.

Staff performed a thorough review of the inputs and the assumptions used in the Reliability & Capacity Assessment Tool ("R-CAT") model used to determine the 2024 capacity deficit in the Company's system and believes the amount of the deficit is reasonable.

Need for Capacity in 2025

Staff believes that the capacity deficiency in 2025 that drove the need for the 77 MW BESS and the 150 MW ESA is justified. The RFP was issued based on a 115 MW capacity deficiency in 2025, which was identified through the Valmy Unit 2 closure analysis performed as directed in Order No. 34349. Supplemental Response to Staff Production Request No. 3. Subsequently, during the preparation of the 2021 IRP, a 125 MW capacity deficiency was identified for 2025. Supplemental Response to Staff Production Request No. 3. Therefore, the Company issued Addendum No. 3 of the RFP to clarify the updated capacity deficiency. Response to Staff Production Request No. 3. Later, the capacity deficiency grew to 178 MW during preparation of the 2023 IRP in May 2023. Response to Staff Production Request No. 6. The main factors that contributed to the increase included:

1. A change of the LOLE target from 0.05 event-days per year to 0.1 event-days per year;
2. use of a 70th percentile peak load forecast instead of a 50th percentile peak load forecast;
3. adjustments to resource capacities to account for Equivalent Forced Outage Rates during Demand ("EFORd") using a 5-year rolling average from the North American Electric Reliability Corporation ("NERC") Generation Availability Data System ("GADS");
4. reduced resource availability associated with CBM;
5. updated load forecast;
6. inclusion of current transmission reservations;
7. new resource additions;
8. reduced availability of American Falls hydro facility;
9. derates at Langley Gulch; and
10. two solar PURPA projects in Oregon that are uncertain to come online by the summer of 2025.

Ellsworth, Di. at 10-18.

Staff performed a thorough review of the inputs and the assumptions used in the R-CAT model used to determine the amount of the 2025 deficit and believes the amount is reasonable.

III. Prudence of Projects Based on Cost

Staff believes that the proposed projects, without the overbuilds as discussed later, are the least-cost, least-risk projects among all the final shortlisted projects to meet the 2024 and 2025 capacity deficits. Staff based its conclusions on the Long-term Capacity Expansion Model ("LTCE") analysis conducted by the Company.

However, Staff believes that due to the issues associated with the resource selection process, the bid pool could have been larger and there could have been additional final shortlisted projects with lower costs. Because of these reasons, Staff recommends a soft cap for the 24 MW BESS and the 77 MW BESS projects, without the capacity and the cost of the overbuilds, as specified in Paragraph 1 and Paragraph 2 of Confidential Attachment A, respectively, and that the 150 MW ESA be capped at the contract price established in the Application unless the Company presents evidence that any additional costs are justified when the Company seeks cost recovery.

The Resource Selection Process

Staff believes the Company generally conducted a fair and transparent resource selection process. However, there are several key issues that have caused Staff to question whether the Company's RFP process resulted in projects that are least-cost, least-risk resources for Idaho ratepayers. These issues include the limited bid pool, transparency of weighting factors, qualitative evaluations for standalone BESS, and the sequence of events in the final selection process.

Limited Bid Pool

When the Company issued the RFP, the Company limited the size of the bid pool by restricting ownership and resource types, preventing the Company from receiving potential additional bids. Instead, the Company should have allowed all potential resources to bid into the All-Source RFP and should have used scoring metrics and criteria to narrow the bid pool. By limiting the bid pool when the Company first issued its RFP, the Company may have excluded resources that could be obtained at a bargain price to Idaho's ratepayers.

The Company revised the RFP on April 13, 2022, through an addendum to allow respondent ownership of standalone BESS, but respondent ownership of BESS was still not allowed in "Solar + BESS" and "Wind + BESS" projects. Exhibit No. 4 of Hackett's Direct Testimony. Although the Company stated that some respondents still provided bids with PPA-based storage components (Response to Staff Production Request No. 14), additional bids might have been submitted that were lower in overall cost, if ownership was not restricted.

Although the RFP was called "2022 All-Source RFP," certain resource types were not allowed in the RFP. Exhibit No. 4 of Hackett's Direct Testimony. For example, even though gas-fired plants convertible to hydrogen plants were allowed, non-convertible gas-fired plants were not allowed in the RFP. The Company explained that ensuring gas-fired plants could convert to hydrogen would provide greater long-term operational viability of the resources given the uncertainty of future clean energy policies and was consistent with the resource assumptions used in the 2021 IRP. Response to Staff Production Request No. 21 in Case No. IPC-E-23-05. However, Staff believes that by only allowing convertible gas-fired projects to submit bids, it might have discouraged bids from potential non-convertible gas-fired plants that might be available and could be a potential bargain for Idaho ratepayers. Staff also believes the Company should not bias the types of resources based on resources included for selection in the IRP, since they are proxy resources with assumed costs. The purpose of an RFP is to determine potential resources that are available in the market. Until actual bids are received, the availability of certain resources and their costs are unknown.

Transparency of Weighting Factors

Staff believes the Company adequately described the evaluation, negotiation, and approval processes in the RFP and embedded the metrics and criteria used to score each of the bids directly in the forms each bidder submitted to the Company for evaluation. This allowed each bidder to understand how their bids would be evaluated against other competing bids.

However, the Company did not provide the weighting factors for the evaluation metrics and criteria in the bid solicitation materials. Response to Staff Production Request No. 40, Case No. IPC-E-23-05. Although the scoring process was likely conducted in a fair and impartial manner, Staff believes it could lead to questions of bias toward certain projects since the weighting factors were not included upfront when the RFP was issued. Staff recommends that the Company provide the weighting factors upfront in future RFPs to improve transparency.

Qualitative Evaluations for Standalone BESS

In response to Addendum No. 8 of the RFP, several bidders submitted bids for respondent-owned standalone BESS projects. However, the Company did not conduct qualitative evaluations for these projects, because the Company believes that the result of qualitative evaluations would not change as a result of the new ownership structure. Supplemental Response to Staff Production Request No. 13.

First, Staff believes all submitted bids should go through qualitative evaluation, and the Company should not have assumed that the result would remain the same before the evaluation. Second, Staff believes the evaluation result could have changed, because some qualitative factors depend on ownership types. For example, Factor No. 16 (Operation and Maintenance Plan) requires proposals involving Idaho Power ownership to include an Operation and Maintenance Plan, and the evaluation is based on the plan. Another example is Factor No. 20 (Draft Technical Specifications Exceptions), which requires proposals involving Idaho Power ownership to include Technical Specifications of the product with changes requested by the respondent. Exhibit No. 3 of Hackett's Direct Testimony. In these examples, when the ownership changes to respondent-owned, Staff believes the final result could be affected.

Sequence of Events in Final Selection Process

Staff has expressed its concerns about the selection process associated with the 2024 resources in Case No. IPC-E-23-05. Therefore, Staff's review in this case focused on the selection process associated with the 2025 resources. The process for selection used the following sequence:

1. Projects that did not make it to the Final Short List were rejected;
2. Projects in the Final Short List were given an opportunity to update their pricing based on increased capacity deficiency. (Four projects increased pricing, while one project decreased pricing. Hackett, Di. at 25.); and
3. The LTCE analysis was performed with updated 2025 capacity deficiency.

Staff believes that before the Company rejected any project, the Company could have analyzed the capacity position first. Given the new capacity position, the Company could have given all projects an opportunity to update their proposed pricing and their proposed capacity sizes, unless a project does not have available transmission capacity. This would have allowed the Company to identify the least-cost, least-risk resources based on the latest information without rejecting projects prematurely.

LTCE Analysis

The Company conducted a LTCE analysis to identify the least-cost, least-risk resources to meet the 2024 and 2025 capacity deficiencies, which Staff agrees should be used as the basis to determine whether the projects selected are least-cost and used to verify that the selected projects resolve the capacity deficit. The short-listed resources with their specific operating characteristics and levelized costs were allowed to be selected in the LTCE AURORA model as potential resource additions. Hackett Direct at 17 in Case No. IPC-E-23-05. The LTCE model logic selects the resources based on optimizing the cost of the overall portfolio conditioned upon meeting the Company's identified capacity deficiencies and when those resources are available for service. Hackett Direct at 17 in Case No. IPC-E-23-05. The Company modeled different alternative futures to determine if the selected resources in the least-cost portfolio were consistently selected. Hackett, Di at 19. If a resource was consistently selected across different alternative futures, this indicates the resource maintains its cost-effectiveness regardless of changing future conditions and therefore carries less risk.

Selection of Resource for 2024 Deficit

In Case No. IPC-E-23-05, the LTCE modeling resulted in the selection of Project No. 8 as the least-cost, least-risk project, and Project No. 10 as the next least-cost, least-risk project on the final short list. However, Project No. 8 was a 100 MW solar project paired with a 60 MW BESS and was already selected for implementation as a result of the case. Because Project No. 10 was the next least-cost, least-risk project among all the remaining projects, it was selected and was the bid used to establish the 24 MW BESS proposed in this case.

Selection of Resources for 2025 Deficit

In the LTCE analysis, Project No. 31 (the 150 MW ESA) was selected as the most economic resource, and Project No. 15 (the source of the 77 MW BESS) was selected as the second most economic resource. Exhibit No. 5 of Hackett's Direct Testimony. These two projects were consistently selected across different alternative futures. Hackett's Direct at 23. The Company selected both of these projects to fulfill the 2025 capacity deficit. Based on Staff's analysis of the results, it believes that these two projects are the least-cost, least-risk resources on the final short list. In addition, Staff recommends that the Commission acknowledge the expenses incurred for the ESA as prudently incurred for ratemaking treatment conditioned upon expenses not changing as proposed and upon the Company updating Section 19.3 as described below.

Overbuild for BESS Degradation

The Company is overbuilding the 24 MW BESS and the 77 MW BESS by 5.8 MW and 17.25 MW, respectively, even though the amount of capacity that can be dispatched at any given time is limited to 77 MW and 24 MW Supplemental Response to Staff Production Request No. 22. The overbuilds are the Company's solution to address battery degradation due to age and cycling that occur over time in order to maintain the capacity of the projects over their useful life. Staff recommends that a full prudence review of the additional overbuild capacity of 5.8 MW for the 24 MW BESS and the overbuild capacity of 17.25 MW for the 77 MW BESS be determined when the Company seeks recovery and after the over-build capacity is known to become used and useful.

Because of the Company's lack of experience in owning and operating BESSs in its system and based on the information provided, Staff does not believe the Company has demonstrated with enough certainty whether overbuilding the project to account for degradation is the least cost method or when the overbuilt capacity will become used and useful, since the manufacturer warranties may also be used for the first several years to mitigate excessive degradation.

Determination of Soft Caps

Although Staff believes all of the projects the Company has proposed for approval in this case are the least cost and least risk projects selected from the Company's 2024 and 2025 final short lists, Staff recommends that they all be subject to a soft cap. A soft cap is a threshold up to which Staff believes that the cost of the project has a high level of certainty that it is justified based on the evidence presented and what is known at this time. However, if the actual cost of any of the resources are higher than the caps, a determination of prudence can be made for the additional amount(s) when the Company files for recovery of the costs if the Company can provide evidence that the increases are justified.

In this case, Staff has a high level of certainty that of the projects that were included in the short list and included in the LTCE analysis, the projects the Company is proposing for approval, were the least-cost, least-risk projects based on the levelized cost assumptions used in the Company's analysis. However, Staff also believes there are sufficient anomalies in the 2024 and 2025 resource selection processes to justify soft caps for all the resources the Company selected.

As explained earlier, the Company will overbuild the 24 MW and 77 MW BESS projects to account for battery degradation, but Staff has recommended a full prudence review of the additional overbuild amounts when the Company seeks recovery due to uncertainties related to cost-effectiveness and when they will become used and useful. For these reasons, Staff has calculated the soft caps to only include the cost and amount of capacity of the two projects without the overbuild amounts by taking the ratio of the 24 MW and 77 MW against the total capacity of the projects with the overbuilds and then multiplying these ratios by the total cost of the projects including the cost of the overbuild. The amount of the caps and the calculations are included in Confidential Attachment A to these comments. If the Company seeks recovery for the cost of the overbuilds, it will need to provide evidence that the overbuilds are used and useful and that the cost of the overbuilds are least-cost.

Similar to the soft caps for the Company-owned BESS projects, Staff recommends that the Company seek a prudence determination of any incremental expenses outside of the contracted prices for the 150 MW ESA listed in Exhibit No. 6 of Hackett's Direct Testimony. If there are incremental expenses beyond the costs included in this Application, the Company would need to seek a prudence determination for the additional cost by justifying it with evidence when the Company seeks cost recovery.

IV. Terms and Conditions of the 150 MW ESA

On April 26, 2023, the Company and Kuna BESS entered into a 20-year ESA for a 150 MW battery storage facility located in Kuna, Idaho. Exhibit No. 6 of Hackett Direct Testimony. The ESA only becomes effective upon Commission approval of all of the terms and provisions of the ESA as well as the accounting and regulatory treatment requested by the Company. Section 3.1 of the ESA. Staff's review of the terms and provisions included a review of the contract price, liquidated damages clauses, and Section 19.3.

Contract Price

The Company has a negotiated contract price per MW of effective capacity that does not have escalation. Hackett Direct at 28; Exhibit No. 6 of Hackett's Direct Testimony at 9. The Company will make fixed payments to the Seller each month based upon the minimum capacity the developer guarantees. Payments above the minimum guaranteed capacity would vary based upon the effective capacity of the project and expensed monthly. Tatum Direct at 10-11 and Exhibit No. 6 of Hackett's Direct Testimony at 21.

Liquidated Damages

The Company has also negotiated various liquidated damages clauses that the Company will recover if conditions of the contract are not met by the Seller. Application at 8; Hackett Direct at 29-30; Exhibit No. 6 of Hackett's Direct Testimony at 17, 23-24, 40. This will ensure that the Company and its customers will be protected financially if the conditions of the ESA are not met.

Section 19.3 of ESA

Section 19.3 of the ESA contains the statement "[n]o amendment, modification or change to this Agreement shall be enforceable unless set forth in writing and executed by both Parties." ESA at 57. Staff believes that this statement neglects the significance of Commission approval and recommends that the statement be updated to reflect the need for Commission approval before any modification becomes valid. For example, the statement can be updated as follows:

No amendment, modification or change to this Agreement shall be enforceable unless set forth in writing and executed by both Parties *and subsequently approved by the Commission.*

V. Accounting Treatment of the 150 MW ESA

The Company requests and Staff recommends that the Commission acknowledge that lease accounting is necessary to facilitate the transaction of the ESA.

Kuna BESS will construct, own, and operate the BESS and supply 150 MW of capacity to the Company's system. Application at 7. The Company, however, will have complete control to dispatch the capacity. Application at 7. Because the Company is not the owner of the BESS, but has the right of control, Staff agrees this contract qualifies as a lease.

The Company states that the lease meets the criteria of being classified as a capital lease. Application at 12. In order for a lease to qualify as a capital lease, a lease must meet at least one of the following criteria. Accounting Standards Codification 842 (a lease accounting standard for entities reporting under U.S. Generally Accepted Accounting Principles).

1. Transfer of title/ownership to the lessee after the lease term;
2. A purchase option the lessee is reasonably certain to exercise;
3. The lease term represents the major part of the asset's useful life (75% is the most common threshold);
4. The present value of the lease payments over the lease term equals or exceeds substantially all of the fair value of the asset (90% is the most common threshold); and
5. The asset is so specialized in nature that it provides no alternate use to the lessor after the lease term.

After analysis, Staff believes that the contract has met two of the five criteria to qualify as a capital lease: Criteria No. 3 and No. 4. First, the lease term of the Kuna BESS is 20 years, and the useful life is estimated to be 20 years. Response to Production Response No. 2(c). This results in the lease term being 100% of the asset's useful life, which exceeds the 75% threshold. Second, the present value of the lease payments over the least term is estimated to be 94% of Kuna BESS' fair value, Response to Production Request No. 2(d). This exceeds the 90% threshold for the capital lease classification. Therefore, Staff agrees that the appropriate way to account for Kuna BESS is as a capital lease.

The Company has stated they are not seeking approval of accounting treatment of the ESA and will address regulatory accounting closer to the commencement date. Tatum Direct at 13. The Company also states that the incremental borrowing rate may differ from the Company's current estimate and will be known around the time that the BESS is placed into service. This will affect the right-of-use value and liability the Company will record to the balance sheet. Tatum Direct at 13. Therefore, Staff agrees to address regulatory accounting related to the ESA at a later date, when the necessary information is known.

STAFF RECOMMENDATION

Staff recommends:

1. Approval of the CPCN to acquire 24 MW and 77 MW of BESS capacity to meet the 2024 and 2025 capacity deficiencies, respectively;
2. Setting a soft cap for the turn-key costs of the 24 MW and 77 MW BESS projects at the amounts specified in Paragraph 1 and 2, respectively, of Confidential Attachment A, unless the Company presents sufficient evidence that amounts over the cap are justified when the Company seeks cost recovery;
3. The additional overbuild capacity of 5.8 MW for the 24 MW BESS and the 17.25 MW for the 77 MW BESS be subject to a full prudence review if the Company seeks recovery and after the overbuild capacity becomes used and useful;
4. Declaration that the expenses associated with the ESA, as proposed, are prudently incurred for ratemaking purposes;
5. The Company seek a prudence determination of incremental expenses beyond the contracted prices in the ESA as listed in Exhibit No. 6 of Hackett's Direct Testimony, if any, when the project becomes operational;
6. Approval of the ESA, conditioned on the Parties updating Section 19.3 of the ESA to reflect the significance of Commission approval;
7. Acknowledgement that lease accounting is necessary to facilitate the transaction of the ESA; and
8. The Company address the issues Staff identified in the resource selection process in future RFPs, regardless of whether the Company files an exception with the Oregon Public Utilities Commission ("OPUC").

Respectfully submitted this 26th day of September 2023.

Chris Burdin
Deputy Attorney General

Technical Staff: Yao Yin
James Chandler
Kevin Keyt

i:umisc/comments/ipce23.20cbyy comments

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 26th DAY OF SEPTEMBER 2023, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF TO IDAHO POWER COMPANY,** IN CASE NO. IPC-E-23-20, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

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