Office of the Secretary
Service Date
December 27, 2022

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 BY 2023 TO SECURE ADEQUATE AND RELIABLE SERVICE TO ITS CUSTOMERS	**CASE NO. IPC-E-22-13** **ORDER NO. 35643**

On April 29, 2022, Idaho Power Company ("Company" or "Idaho Power") applied for a Certificate of Public Convenience and Necessity ("CPCN") to acquire 120 megawatt(s) ("MW(s)") of dispatchable energy storage. The Company filed the Direct Testimony of Timothy E. Tatum, Jared L. Ellsworth, and Eric Hackett in support of the Application.

On May 25, 2022, the Commission issued a Notice of Application and Notice of Intervention Deadline. Order No. 35417.

Industrial Customers of Idaho Power ("ICIP"), Idaho Hydroelectric Power Producers Trust d/b/a IdaHydro, Micron Technology, Inc. ("Micron"), and Idaho Conservation League ("ICL") intervened in the case. Order Nos. 35407, 35413, and 35449.

On July 27, 2022, the Commission issued a Notice of Modified Procedure, and set public comment and Company reply comment deadlines. Order No. 35470.

ICL and Commission Staff ("Staff") filed comments to which the Company timely filed a reply. No other comments were received. With this Order, as set forth below, we approve the Company's request for a CPCN.

APPLICATION

The Company explained what a CPCN is, what it does, and why it needs one from the Commission for this particular investment. The Company next explained its need to acquire additional resources to meet its demand, what resources it selected to meet this demand, and the process it used to select these resources. The Company stated that it complied with the Oregon procurement rules, which the Commission adopted in Case No. IPC-E-10-03, to procure 120 MWs of dispatchable energy resources. Finally, the Company clarified that it was not seeking ratemaking treatment in this case to recover the costs of the resources.

A. CPCN

The Company requested the Commission find the public convenience and necessity required the Commission to order the Company to acquire "additional dispatchable resources" to meet its identified capacity deficit and reliably serve all customers. Application at 3. The Company explained its statutory obligation to serve all customers with safe and reliable service. The Company cited *Idaho Code* § 61-508 for the proposition that the Commission "has the express authority to order a utility to build new structures, or to upgrade and/or improve existing plant and structures, to secure adequate service or facilities." *Id.* at 3. A CPCN, as the Company explained, represents the Commission's "fundamental power and authority to, at the most basic level, authorize and direct a public utility to serve in the public interest" and is required anytime the Company wants to build a new generation resource or plant. *Id.* at 4.

B. Resource Need

The Company stated that in May 2021, while developing its Integrated Resource Plan ("IRP"), it identified a 78 MW capacity deficiency that would grow incrementally until the estimated construction of the Boardman to Hemingway transmission line in 2026. And, when the Company filed the 2021 IRP on December 31, 2021, it anticipated the capacity deficiency would be approximately 101 MW by June 2023. The Company explained that the "rapid change in deficit position was caused by several dynamic and evolving factors" related to transmission, planning, population growth, emerging demands, and diminished effectiveness of demand response and variable resources. *Id.* at 5. Ultimately, because it expected increased and sustained load growth, and to address the looming deficiency, the Company stated it needed to acquire "new dispatchable resources, fully controlled by the Company, to meet peak summer demand." *Id.*

C. Resources

On June 30, 2021, the Company issued a Request for Proposals ("RFP") "seeking to acquire up to 80 MWs of Idaho Power owned resources, to be online by June of 2023." *Id.* at 5,7. Simultaneously with the RFP, the Company investigated "different configurations of Company-owned and constructed battery storage systems." *Id*. at 7.

The Company explained that the selected bidder in the Company's RFP was the 40 MW solar photovoltaic ("PV") Black Mesa project Power Purchase Agreement ("PPA")[1] plus a 40 MW

[1]The Company obtained Commission approval of the 40 MW PV PPA—the Black Mesa PPA—in Case No. IPC-E-22-06. The Black Mesa PPA is intended to provide power to Micron under a special contract between Micron and the Company.

battery energy storage system ("BESS") project. *Id.* at 7. The Company stated that the developer of the successful bid did not agree to a build-transfer agreement ("BTA")—a requirement of the RFP. *Id.* The developer did agree, however, to coordinate with the Company "on a battery storage facility that the Company would procure on its own and locate adjacent to the developer's solar PV site" if the 40 MW PV PPA was approved. *Id.*

The Company also identified, in an independent review, an 80 MW BESS as the other resource to satisfy its capacity deficiency requirements. The Company envisioned co-locating the 40 MW BESS at the site of the Black Mesa solar PV project and would potentially install the 80 MW BESS at the Hemingway substation but indicated it was flexible on the final siting locations.

D. Process

The Company commenced the RFP process by assembling an "interdisciplinary team" and engaging with Black & Veatch, LLC to develop "detailed criteria and a methodology for evaluating both price and qualitative attributes of a proposed resource including . . . 37 factors . . . identified" in the RFP entry form. *Id.* at 8. As stated above, a criterion of the RFP was that any "third-party ownership under a PPA for wind and solar" had to include a BTA for any associated storage resources. [2] *Id.* at 9. The Company explained that the 40 MW BESS was part of the "successful RFP bid . . . ." *Id.* at 7.

The Company explained that it needed to own and operate the "peak capacity storage resource(s)," rather than contract with a third-party under a PPA, as this allowed it to, among other things, retain its:

> ability to configure, reconfigure, maintain, operate, and economically and operationally dispatch the unit . . . [and] . . . focus on price . . . [and] . . . reliability, system operation, long-term operation and maintenance of facilities, financial viability of the utility, long term impacts of imputed debt from PPAs, and the ability to obtain financing for operations, the efficacy of legal remedies, economic dispatch in changing energy markets, and adaptation for environmental policies.

Id. The Company's Application highlighted inherent problems with contracting with a third party for battery storage resources under a PPA. The Company cautioned that, as the Company acquired more PPA generation resources in its portfolio,

> a number of issues are exacerbated: integration of the power becomes more difficult and costly; the utility loses maintenance and control over the facility and its

[2]The Company explained that it focused its solicitation in the RFP on acquiring wind, solar, and energy storage solutions or some combination thereof because it assumed these resources were, due to the short timeline, "the most likely projects to be submitted in response to the RFP." Hackett Direct at 9.

> condition; the utility typically loses the generation resource at a specified contract date short of the useful life of the plant; the utility is relegated to the terms of the contract despite a dynamic energy landscape; curtailment of the facility is limited, expensive, or fraught with potential legal challenges; and cyber and physical security oversight of the facility is diminished.

Id. at 9-10. The Company further explained that remedies for contractual breaches associated with PPAs were insufficient and that the terms of any potential PPA, especially under the time constraints the Company was facing, would not allow the Company any necessary flexibility in the operation of a BESS on its system.

Mainly because of the time constraints, the Company stated it "did not develop a formal benchmark resource in the RFP[,]" but instead relied on "developers to propose potential projects that would meet the criteria outlined to determine the least-cost, least-risk option." *Id.* at 10. In addition, because it did not believe it would not receive timely or adequate responses through the RFP process to meet its capacity deficiency demand, the Company, concurrently with the RFP, evaluated the price and project reasonableness of "self-build options against bids submitted through the RFP responses." *Id.* at 10-11. Through this "parallel investigation," including a request for quotes sent to eight different battery manufacturers, the Company identified the 80 MW BESS project. *Id.* at 11.

The Company stated that it had executed two contracts with Powin Energy Corporation ("Powin") for the 40 MW and 80 MW BESS projects. The Company believed that its procurement process resulted in the least-cost, least-risk resources capable of being operational in time to meet its resource needs beginning "the summer of 2023 and into the future." *Id.* at 12.

E. Ratemaking Treatment

The Company stated that it was only seeking a CPCN in this case for 120 MW of energy storage and, due to ongoing negotiations related to the projects, would make a future filing addressing the cost recovery for these projects in a subsequent case. *Id*. at 12-13.

F. Oregon Procurement Rules

The Company noted that there were no "Idaho-specific procurement guidelines." *Id.* at 13. Thus, pursuant to Commission Order No. 32745, the Company must follow the Oregon Public Utilities Commission ("OPUC") rules applicable to the Company's Oregon service territory when it wants to procure resources to serve its Idaho customers. As the Company explained, the OPUC procurement rules impose competitive bidding requirements for any electric utility seeking to acquire "a resource or contract for more than an aggregate of 80 MW and five years in length." *Id.* Given the timeframe, the Company determined that it would not be able to meet its capacity deficiency by summer 2023 if it engaged in the competitive bidding process under the OPUC rules. Nonetheless, the Company claimed the acquisition of the 120 MW BESS projects constituted "a time-limited opportunity to acquire a resource of unique value to . . . [its] . . . customers" which made it eligible to file for an exception to the OPUC procurement rules on March 18, 2022.[3] *Id.* at 14.

THE COMMENTS

I. Staff

a. Capacity, Selected Resources, Procurement Requirements, Depreciation, and ITC

Staff analyzed the Company's need for capacity, the resources it selected to meet its capacity needs, the Company's compliance with the Commission's direction to follow OPUC's resource procurement rules, the depreciation rates for the BESS projects, and the applicability of the Income Tax Credit ("ITC") to the Company's BESS projects.

Staff confirmed that the "Company has and will be operating with reserves insufficient to meet reliability requirements until the 120 MW BESS resources become operational." Staff Comments at 3.

Staff believed the 120 MW BESS resources would satisfy the Company's capacity need through 2023 and contribute to meeting the need beyond. However, Staff noted that the contracts the Company has with Powin for the BESS projects did not include provisions for battery augmentation, which can ensure "the full capacity of the BESS is maintained over the life of the resource." *Id.*

Staff encouraged "the Company to fully consider the . . . procurement requirements when it issues RFPs in the future" so that it can ensure it selects the least-cost resources. *Id.* at 8.

Staff recommended the Commission "issue an accounting order to change the Battery Storage account (Account 363) depreciation rates from 6.66% (15-year life) to 5% (20-year life)[,] and approve a 5% depreciation rate for the BESS projects when they are placed in service." *Id.* at 9.

[3] To qualify for an exception to the Oregon procurement rules, the applicant utility files a request for an exception; there is no order or other acknowledgement from the Oregon Commission granting or denying the exception, however. *See* Company's response to ICIP's Request for Production No. 12 and Oregon Administrative Rules 860-089-100(4).

Staff believed that either one or both of the BESS projects may qualify for the ITC if they were charged from renewable resources. Thus, Staff recommended "the Commission order the Company to reflect for ratemaking purposes all available ITCs for these plant assets." *Id.*

b. Selected Resources are not Least Cost

Staff believed there was insufficient lead time for the 2021 RFP and that the RFP was too restrictive. Additionally, Staff's own analysis indicated that the BESS contracts were not the least-cost. In sum, Staff did not believe that the Company selected the least-cost resources.

i. Insufficient lead time and Selection of Resources Outside the RFP

Staff contended the Company failed to allow sufficient lead time for the RFP due to issues with the 2019 IRP. Staff further contended that improvements the Company made while developing the 2021 IRP came too late to allow enough bidders to participate and make a sufficiently competitive bid pool.

Staff also argued that the fact that the two BESS projects were not bid through the RFP process constituted additional evidence that the bid pool was insufficient. Staff contended the insufficient bid pool results in increased costs being passed on to customers.

ii. Restrictive RFP

Staff also believed the RFP unduly restricted the bid pool by "only allowing BTA for energy storage projects and by restricting the type of resources to wind, solar, and energy storage," or a combination of these resources. *Id.* at 5. Staff stated the Company's justification for its claim that it needed to own the resources is that: (1) it would lack the necessary control for "energizing and dispatch" and (2) its imputed debt and credit rating would suffer if it obtained the resources through a PPA. *Id.* at 5.

Staff did not believe it was necessary for the Company to own the BESS projects. In response to the Company's claim that it needed to own the resources to maintain sufficient control, Staff highlighted examples of BESS projects other utilities acquired through PPAs that allow the utility to maintain adequate control. In response to the Company's assertion that an increase in PPAs correlated with an increased cost of debt and a poorer credit rating, Staff responded that, while it may be true that the cost of debt would increase, such increase would be minimal and, even if it resulted in a downgrade to the Company's credit rating, this downgrade would only increase the interest rate by 0.14%. Staff further noted that any impact on interest rates would only affect new debt issuances and "if the Company were to issue all debt that has been currently approved by the Commission, a 13% increase in interest rates would have an approximate 0.021% increase in the Company's overall rate of return." *Id.* at 7.

iii. BESS Cost Benchmarks and Cost Recovery Soft Cap

Staff "benchmarked the completed cost of the 120 MW BESS at $150,684,988 using comparable 4-hour BESS installations . . . ." *Id.* at 8. Staff noted that this amount was "11.7% or $17.6 million lower than the Company's estimated cost." *Id.* Staff's benchmark was "based on published costs for Utility-Scale Battery Storage using the National Renewable Energy Laboratory ("NREL") Annual Technology Baseline . . . ." *Id.* Staff compared its NREL benchmarks to the cost of the Company's projects in an analysis provided in a confidential attachment to its comments. Staff believed that, based on the NREL benchmarks, the Commission should set "'soft caps' of $50,228,329 for the 40 MW storage project and $100,456,659 for the 80 MW storage project (without the cost of interconnection or transmission upgrades)." *Id.* Staff believed that these "soft caps" should be the maximum the Company is "allowed to recover, *unless it can provide compelling evidence otherwise*." *Id.* (emphasis added.).

In sum, Staff recommended the Commission grant the Company's request for a CPCN, issue an accounting order to change the Battery Storage account (Account 363) depreciation rates from 6.66% (15-year life) to 5% (20-year life), and order the Company to reflect all available ITCs for these plants. Staff further recommended the Commission set "soft caps" limiting the Company's recovery, excluding the cost of interconnection or transmission upgrades, to $50,228,329 for the 40 MW BESS and $100,456,659 for the 80 MW BESS, unless the Company presented evidence in a subsequent recovery case indicating why these amounts were too low.

II. ICL

ICL commented that the Company's criterion in the RFP that all resource must be Company-owned was unreasonable. ICL contended that this undue restriction was "rooted in profit-seeking motives[,]" and resulted in depriving ratepayers and stakeholders from knowing whether the selected resources were truly the "'least-cost, least risk procurement . . . .'" ICL Comments at 2.

ICL questioned the Company's justifications for the claim that it had to include a BTA in the RFP to avoid the inherent risks from PPAs. ICL pointed to other examples of utilities successfully using PPAs to acquire resources. ICL also noted the Company's statement that issues related to executing a PPA for a BESS "could conceivably be addressed through an agreement with a third-party provider . . . ." *Id.* (citing the Company's Application at 10.).

ICL noted the Company's primary justification for its inability to negotiate PPAs was the "exigency created by the capacity deficit . . . ." *Id.* at 3. However, ICL questioned why the Company did not act sooner to address this deficit. ICL was concerned that granting the Company's request would set a precedent that enabled the Company to evade a fair procurement process in future actions.

ICL further contended that the Company unreasonably ignored customer-owned generation as a potential resource to meet the 2023 capacity deficit. ICL requested the Commission require the Company to analyze the potential of new customer generations and include more "robust analyses of the potential of customer generation to fulfill future capacity needs." *Id.* at 5.

III. Company Reply

The Company agreed with Staff's recommendations that the Commission grant the Company a CPCN and Staff's proposal that the Commission issue an accounting order to update the depreciation rates for battery storage. The Company also stated that any tax benefits it receives from the BESS projects, "will be reflected in revenue requirement determinations in a future ratemaking proceeding." Company Reply Comments at 21.

In opposition to Staff's and ICL's positions, the Company argued that it completed a robust competitive resource procurement process, and that third-party owned assets have an imputed debt cost to the Company and, ultimately, its customers. The Company also asserted that Staff's analysis supporting a soft cap was flawed.

a. <u>Robust Competitive Procurement Process</u>

The Company explained that the "rapid change" in the 2023 capacity deficiency was due to a multitude of "dynamic and evolving factors." *Id*. at 5. The Company stated, contrary to Staff's assertion that the Company failed to identify a capacity deficiency due to issues with the 2019 IRP, that it did not identify a capacity deficiency until the spring of 2021 through preparation of the North Valmy Power Plan Unit 2 exit analysis . . . ." *Id.* In analyzing the Valmy exit, the Company determined that it would lack access to southern energy markets—access to this market was a key assumption of the 2019 IRP. In addition, the Company claimed that changes in its planning margin methodology led to updates in the load and resource balance analysis which revealed, for the first time in May 2021, the 2023 capacity deficit.

In response to the positions of ICL and Staff that the RFP was unduly limited by the criterion that any proposal had to include a BTA, the Company asserted that "both parties fail to acknowledge that the only economic project that was able to meet the required commercial operation date of June 2023, and selected through the RFP process, was in fact a 20-year PPA associated with a 40 MW solar PV facility." *Id.* at 7. The Company then stated that, "[w]hile the initial proposal also envisioned a BTA associated with a 40 MW battery storage, during negotiations the developer indicated that they were no longer interested in pursuing the BTA and instead negotiated an agreement to coordinate with the Company" for the Company to procure a Company-owned battery storage system to be co-located with the developer's 40 MW solar PV project. *Id.* The Company claimed that the "indicative pricing" based on its "parallel investigations" into BESS systems "was comparative to the lowest-cost proposals for similar battery storage projects submitted through the RFP process." *Id.*

In response to Staff's concern that the RFP was inadequate because it did not identify any viable projects, the Company responded that no viable projects resulted from the RFP because no bidding entity could commit to achieving the required "commercial operation date of July 1, 2023." *Id.* at 8.

The Company insisted that it followed the OPUC procurement rules as required by Order No. 32745. The Company explained that OPUC "RFP guidelines may ultimately be aligned with the public interest under circumstances that allow Idaho Power the needed time required in order to follow the guidelines." *Id.* at 9. The Company stated that when there is more time, the range of potential resources available to satisfy a capacity deficiency may broaden, and that its current and anticipated RFPs should indicate "resources that have the ability to be in-service within a less compressed timeline, as recommended by Staff." *Id.*

b. <u>Third-Party Owned Assets</u>

The Company mentioned that Staff agreed that "third-party owned assets such as PPAs" entail "imputed debt adjustments made by credit rating agencies . . . ." *Id.* However, the Company contended that Staff did not "correctly consider the impact imputed debt can have on the Company's cost of capital for both debt and equity." *Id.* at 10.

The Company stated that to obtain debt and equity to finance capital projects, lenders consider the strength of the Company's "overall financial profile, including the strength of its balance sheet." *Id.* The Company explained that credit agencies "evaluate contractual obligations related to long-term PPAs as they consider future debt obligations of issuers during their ongoing monitoring of credit quality." *Id.* The Company further explained that imputing debt "is a credit rating agency's way of transferring the project risk from the developer to the utility because the contractual obligation of the utility is essentially providing cash flow and credit support to the developer." *Id.* As the Company clarified, "[c]redit agencies account for this transferred risk as a fixed debt obligation of the utility and impute this risk to the utility's balance sheet," which ultimately results into a higher cost of capital borne by customers. *Id*. 10-11.

The Company expressed that credit rating agencies, in their most recent evaluations, discussed pressures on the Company's "financial risk profile related to the significant level of contractual obligations" and their concerns related to future resource need "and the potential of additional PPAs versus higher capital spending . . . ." *Id.* at 11. The Company stated that its credit was recently downgraded by Moody's, and that future increase in contractual obligations would lead to diminished credit ratings, "ultimately impacting customer rates." *Id.* at 12.

The Company stated that, "deteriorating credit ratings . . . impact long-term debt costs . . . [as well as] . . . short-term credit markets, including existing and future credit facilities and the ability of Idaho Power to access the commercial paper market." *Id.* at 14. This results in higher short-term debt costs that, as the Company claims, "negatively impact customers in the form of higher Allowance for Funds Used During Construction . . . rates." *Id.*

The Company claimed that Staff's calculations did not consider debt financing for additional PPAs. The Company pointed out that a "similar pattern of PPAs" when "compounded with $4 billion of existing contractual obligations" could negatively "impact the overall cost of capital and customer rates . . . ." *Id.*

The Company stated that Staff "did not address the cost of equity impacts associated with imputed debt obligations." *Id.* The Company stated that "as the actual or perceived credit quality of a company deteriorates, the corresponding cost of equity increases due to that perception, impacting the Company's weighted average cost of capital." *Id*. at 14-15. The Company explained that when it incurs more debt obligations from PPAs, the debt-to-equity ratio becomes imbalanced which can lead to higher costs to customers when the Company issues equity (stock) to rebalance.

The Company stated that Staff's citation to other utilities' ability to successfully manage PPAs for dispatchable resources, ignored the fact that "potential dispatch rights can ultimately adversely impact credit ratings, and thus the cost of debt and equity." *Id.* at 15. Having dispatch rights, the Company claimed, "would likely . . . result in a lease liability on its balance sheet . . . treated as the equivalent of long-term debt in credit quality metrics, while not bringing the adjoining benefits of collateral assets that can be securitized by the utility." *Id.* at 15-16.

In sum, the Company asserted that it must assess the "effect of imputed debt from long-term contractual obligations in its analysis of RFP responses from third parties" to correctly evaluate projects on a comparable basis and the "net financial impact of the project on the Company and its customers." *Id.*

c. <u>Staff's Soft Cap</u>

Last, the Company averred that Staff's imposition of the soft cap on the BESS projects was based on an imprecise analysis. The Company noted that Staff's analysis was based on a NREL study. However, the Company asserted that the NREL study was intended for "long-term planning purposes and ignores current market realities which impact the costs of lithium-ion battery systems," and resulted in a "flawed analysis." *Id.* at 16-17. In support of its argument, the Company pointed out that "the downward pricing trend anticipated by NREL" for lithium-ion battery systems, "reversed into an upward trend starting in late-2021 and continued into 2022." *Id.* at 17.

The Company pointed out that the 2020 NREL study Staff cited used data which anticipated a 27 percent decline in costs of lithium-ion battery systems from 2020-2023, when just the opposite has occurred due to increased demand, inflation, and other issues. *Id.* at 17-18.

In sum, the Company concluded that Staff used outdated data to benchmark the BESS costs which did not accurately consider "current market conditions" and "industry trends." *Id.* at 19.

FINDINGS AND DECISION

The Commission has jurisdiction in this case under its express statutory authority to investigate rates, charges, rules, regulations, practices, and contracts of public utilities and to determine whether they are just, reasonable, preferential discriminatory, or in any way in violation of any provision of law and may fix the same by order. *Idaho Code* §§ 61-502 and 61-503. By law, public utilities shall "furnish, provide and maintain such service, instrumentalities, equipment and facilities as shall promote the health, safety, comfort and convenience of its patrons, employees and the public, and as shall be in all respects adequate, efficient, just and reasonable." *Idaho Code* § 61-302. The Commission has authority to order a utility to build new structures or upgrade and improve existing plant and structures to secure adequate services or facilities. *Idaho Code* § 61-508.

Before constructing "a line, plant, or system," a public utility providing electrical service must obtain a CPCN from the Commission (establishing that the "public convenience and necessity" requires it). However, a CPCN is not required to extend lines, plant or system in an area already served by the utility. *Idaho Code* § 61-526. Under *Idaho Code* § 61-526, "if the public convenience and necessity does not require or will require" the construction or extension of lines, plant or system, the Commission "may, after hearing, make such order and prescribe such terms and conditions for the locating or type of the line, plant or system affected" as the Commission finds just and reasonable. *Idaho Code* § 61-526.

We find that the evidence and the record in this case demonstrates that the public convenience and necessity requires the Company to acquire 120 MW of dispatchable energy storage. A review of the Company's most recently acknowledged IRP (Case No. IPC-E-21-43) and capacity deficiency case (Case No. IPC-E-21-09 which established a new summer 2023 capacity deficit date) demonstrates the Company's needs to acquire additional, dispatchable resources to meet customer demand and to ensure system reliability beginning in the summer of 2023. This is not in dispute. We find that the proposed 120 MWs of dispatchable energy storage, consisting of a 40 MW BESS and an 80 MW BESS, will position the Company to meet increasing customer demand and ensure system reliability beginning in the summer of 2023.

We further find it fair, just, and reasonable to order the Company to change the Battery Storage account (Account 363) depreciation rates from 6.66% (15-year life) to 5% (20-year life). We note that this is consistent with the treatment of BESS projects in other jurisdictions. We also approve a 5% depreciation rate for the BESS projects when they are placed in service. This rate can be reviewed and updated as necessary. In addition, we find it reasonable that the Company reflect all available ITC for the BESS projects.

We approve the Company's acquisition of 120 MWs of dispatchable energy storage resources but find that implementing a soft cap of up to $50,228,329 and $100,456,659, for the 40 MW BESS and 80 MW BESS, respectively, is reasonable and supported by the evidence presented in this case. We acknowledge the Company restricted its pool for projects to meet its summer 2023 capacity deficiency by requiring every developer placing a bid to agree to a BTA and by only soliciting projects limited to energy storage, solar PV plus storage, wind plus storage, or a combination thereof.

The Company did not procure either BESS under its RFP.[4] The RFP process is designed to facilitate a robust, competitive bid pool from which the resource(s) best suited to meet the Company's need(s) can be selected and ensures customers are paying for the least-cost resource to meet the new capacity demand. The Company claimed that it restricted its bid pool because of time constraints and because of the economic impact third-party owned assets ultimately have on customer rates. However, the Company acknowledged that "a competitive procurement process akin to that detailed in the Oregon RFP guidelines may ultimately be aligned with the public interest under circumstances that allow . . . [the Company] . . . the needed time required in order to follow the guidelines." Company Reply Comments at 9. The Company also acknowledged that it could address issues of "dispatchability, curtailment, maintenance, security, mandatory payment, and operational terms, conditions, and limitations . . . through an agreement with a third-party provider," but that, "especially in the limited time available," it was not convinced "that such contract terms were actually achievable." Application at 10. In addition, the Company acknowledges that, mostly due to time constraints, it did not "develop a formal benchmark resource in the RFP." Application at 10. The Company appears to claim that, had it adequate time, it would have been able to solicit a greater number of bids through the RFP process and potentially consider a third-party owned BESS under a PPA with terms that would alleviate many of the Company's concerns related to a lack of control of the resource.[5]

We expect the Company to closely monitor its projected capacity needs going forward and to act proactively to ensure a robust RFP process can be completed. The Company is responsible for planning and managing its load and resource portfolio. This responsibility extends to planning for contingencies. The Company's customers should not bear the financial consequences incurred when Idaho Power fails to adequately plan for its capacity deficiency and in turn acts reactively, forcing it to add resources that the Commission is unsure are actually the least-cost resource because a robust RFP was not undertaken. We expect that in the future the Company will better

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[4]The Company claimed that the "successful bidder of the 80 MW resource RFT was Black Mesa Energy, LLC" even though the "developer of the successful bid" (Black Mesa Energy, LLC) was not interested in the BTA proposals which the RFP requested for battery storage facilities. Application at 7. Additionally, Staff noted that the "two BESS projects selected by the Company were not included as bids through the RFP and were procured directly by the Company outside of the RFP." Staff Comments at 4.

[5] The Company noted that while issues related to "dispatchability, curtailment, maintenance, security, mandatory payment, and operational terms, conditions, and limitations could conceivably be addressed through an agreement with a third-party provider . . . the Company was not convinced that such contract terms were actually achievable, especially in the limited time available for the resource procurement . . . ." Application at 10.

assess the capacity needs of its system and plan far enough ahead to ensure a robust, competitive bidding process.

ORDER

IT IS HEREBY ORDERED that the Company's request for a CPCN to acquire 120 MWs of dispatchable energy storage necessary to meet the first identified summer 2023 capacity deficiency is granted.

IT IS FURTHER ORDERED that the Company change the Battery Storage account (Account 363) depreciation rate to 5% and reflect all available ITC for the BESS projects.

IT IS FURTHER ORDERED that the Company, unless it presents additional evidence in a subsequent recovery case, be limited to recover $50,228,329 for its 40 MW BESS project and $100,456,659 for its 80 MW BESS project.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order regarding any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 27th day of December 2022.

ERIC ANDERSON, PRESIDENT

JOHN CHATBURN, COMMISSIONER

JOHN R. HAMMOND JR., COMMISSIONER

ATTEST:

Jan Noriyuki
Commission Secretary

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