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IDAHO PUBLIC
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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 BY 2023 TO SECURE ADEQUATE AND RELIABLE SERVICE TO ITS CUSTOMERS	**CASE NO. IPC-E-22-13** **COMMENTS OF THE COMMISSION STAFF**

Staff of the Idaho Public Utilities Commission ("Staff"), by and through its attorney of record, Riley Newton, Deputy Attorney General, submits the following comments.

BACKGROUND

Idaho Power Company ("Company"), through this filing is requesting a Certificate of Public Convenience and Necessity ("CPCN") from the Commission to acquire 120 mega-watts ("MW") of dispatchable energy storage necessary to meet the capacity deficiency in 2023. The Company plans to make a future filing to address cost recovery associated with the energy storage resource.

Prior to the filing of the 2021 Integrated Resource Plan ("IRP") in May 2021, the Company's identified capacity deficiency date was the summer of 2028.[1] The 2021 IRP identified a capacity deficiency of 101 MW by the summer of 2023.

STAFF ANALYSIS

After a detailed review and analysis, Staff recommends the Commission: 1) grant the request for a CPCN specific to the Company's decision to acquire 120 MW of dispatchable capacity to be operational by July 1, 2023, based on the immediate need for capacity resources and to ensure system reliability; and 2) 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).

In addition, Staff concludes the following:

1. The Company has demonstrated an immediate need for incremental capacity given risks to reliability with resource deficits starting to occur during the summer of 2021 based on the Load and Resource Balance in the Company's 2021 IRP;
2. The 120 MW Battery Energy Storage System[2] ("BESS") will resolve the current capacity deficit starting in 2023 if both projects are completed by their contracted completion date;
3. The resource the Company selected through the June 2021 Request for Proposals ("RFP") is not likely to be least-cost due to the limited pool of available resources bid into the RFP;
4. The Company did not comply with the Commission's requirements for resource acquisition which likely contributed to resources not being least-cost; however, given the compressed timeline, Staff believes following all of the requirements would not have been prudent;
5. Based on the expected 20-year depreciable life, the Commission should establish a 5% depreciation rate for the BESS when placed into service; and

[1] Second Amended 2019 Integrated Resource Plan - Load and Resource Balance (Application - page 5)
[2] The 120 MW BESS represents a 40 MW (4 hour) BESS at Black Mesa, and a second 80 MW (4 hour) BESS proposed to be located at the Hemmingway Substation.

6. The Company should use all available Investment Tax Credits ("ITCs") for the resource.

Need for Incremental Capacity

Staff performed a decisional prudence review of the Company's Application to acquire 120 MW of dispatchable capacity to be operational by July 1, 2023 and recommends that the CPCN be granted. Staff's recommendation is based strictly on an immediate need for incremental capacity necessary to ensure reliability of the Company's system.

Staff extensively reviewed the Company's 2021 IRP (Case No. IPC-E-21-43) and the Company's Capacity Deficiency Case (Case No. IPC-E-21-09) both which identified capacity deficits of 329 MW in July and 173 MW in August of 2021, 146 MW in July of 2022, and 101 MW in July of 2023. Although the deficits that occurred in 2021 and 2022 did not result in customer load being unserved, the Company has and will be operating with reserves insufficient to meet reliability requirements until the 120 MW BESS resources become operational.

Selected Resources meet Capacity Needs

Staff believes the 120 MW BESS resources will satisfy the Company's need for capacity through 2023. Staff reviewed the Company's requirements for resources specified in the Company's RFP and compared them to the operational characteristics and guarantees contained in the two energy storage contracts for the BESS resources. If the contracts are executed, Staff believes that delivery of energy from these resources will satisfy the capacity needs for the Company's system through 2023 and will continue to provide capacity over the life of these assets. However, the contracts do not provide for battery augmentation, which is an option the supplier can provide to ensure battery degradation is mitigated and the full capacity of the BESS is maintained over the life of the resource. The Company's 2021 IRP indicates incremental capacity needs for 2024 and beyond, which the Company indicated will be satisfied through additional resource acquisitions.

Resources Selected are not Least-Cost

Staff does not believe that the 40 and 80 MW BESS resources are least cost. As such, Staff recommends that the investment cost of these two resources be subject to "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) when the Company seeks recovery to ensure customers are not penalized for unreasonable costs. Staff believes that the resources are not least cost for the following reasons:

1. The Company did not identify the need for incremental resources within lead times necessary for potential bidders to supply resources, severely restricting the pool of potential bidders resulting in an uncompetitive bid pool.
2. The Company further restricted the pool of potential bidders in its RFP by:
    a. Only allowing Build-Transfer Agreements ("BTA") for energy storage projects and not allowing acquisition through power purchase agreements ("PPA") or other forms of ownership agreements. Application at 9.
    b. Restricting bidders to wind, solar, and/or battery energy storage instead of expanding the pool to allow for a greater number and broader range of potential resources.
3. 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. Hackett Direct at 18.

Insufficient Lead Time

The Company was not able to issue the 2021 RFP with sufficient lead time for potential bidders of resources to complete projects by the July 2023 capacity deficiency date because of issues with the Company's 2019 IRP. The Company proposed an August 2028 first capacity deficiency date in its initial application in its capacity deficiency case, Case No. IPC-E-21-09, that was filed in April 2021 after Commission acknowledgement of the 2019 IRP.[3] However, the Company filed a Motion and Amended Application in that case proposing a 2023 first capacity deficiency date, five years earlier than proposed in its initial application.[4] Because of the insufficient lead time, Staff believes there were too few bidders for a competitive bid pool which resulted in increased cost to customers.

[3] *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, Application at 3 (Apr. 9, 2021).
[4] *Id.*, Motion and Amended Application at 4-5 (Feb. 4, 2022).

In its comments on the 2021 IRP in Case No. IPC-E-21-43, Staff discusses the deficiencies in the 2019 IRP that the 2021 IRP resolved. However, the improvements the Company made while developing the 2021 IRP came too late to allow for reasonable lead times for developers to construct projects. In fact, the 2023 first capacity deficit date is based on when the Company can reasonably acquire resources, not on when the first deficit date occurs. *See* Response to Staff Production Request No. 32 in Case No. IPC-E-21-09.

RFP Restriction of Eligible Projects

The Company further restricted its bid pool only allowing BTA for energy storage projects and by restricting the type of resources to wind, solar, and energy storage, even though the 2021 RFP was advertised as an "All-Source RFP."[5] In its Application, the Company claimed that it needed to own the storage resources because: (1) it could not obtain the control needed necessary for energizing and dispatch; and (2) acquiring the resources through a PPA would increase its imputed debt and harm its credit rating. Application at 9.

Staff does not believe it is necessary for the Company to own a BESS to have sufficient control. Below are examples of BESS projects that other utilities acquired through PPAs and have been able to negotiate terms necessary for the dispatch needs of their systems:

- Capacity 88 MW / 352 MWh - Southern Power, a leading U.S. wholesale energy provider and subsidiary of Southern Company, has been awarded a 20-year power purchase agreement by Southern California Edison to add a battery-based energy storage resource at Southern Power's Garland Solar Facility in Kern County, California.[6]
- Capacity 72 MW / 288 MWh - Southern Power, a leading U.S. wholesale energy provider and subsidiary of Southern Company, has been awarded a 20-year power

[5] *See* "2021 All Source Request for Proposals for Peak Capacity Resources - Pre-Bid Presentation." Although the title suggested the 2021 RFP was an "All-Source" RFP, the resources were restricted to Wind, Solar, Energy Storage, Wind plus Energy Storage, and Solar plus Energy Storage.

[6] Energy Storage News, March 30, 2022, "Southern Power Turns 640 MWH Solar – Co-located BESS Projects Online in California." https://www.energy-storage.news/southern-power-retrofitting-640mwh-of-battery-storage-at-two-california-solar-power-stations/

purchase agreement by Southern California Edison to add a battery-based energy storage resource at Southern Power's Tranquility Solar Facility in Fresno, California.[7]

- The California Public Utilities Commission has approved 497 MWs of energy storage procured by the utility company Southern California Edison to go online starting in August 2023 through June 2024. The California Public Utility Commission has approved five PPAs for BESS projects that total 497MW of nameplate power and 1,988 MWh of energy, each being four-hour duration systems.[8]

In addition, Avista Utilities has been successfully managing the Lancaster Combined Cycle Combustion Turbine Plant as a dispatchable resource through a PPA for years by negotiating contract terms that allow it sufficient control.

The Company also asserts that an increase in PPAs would steadily increase the costs of debt, because most rating agencies consider long-term PPAs as debt. *See* Application Page 9 and Company Response to Production Request No. 3. Rating agencies do consider PPAs as commitments of future revenues and therefore can act as long-term debt; however, the increase in debt costs is not linear. The Moody's Cross-Sector: Market Data Highlights on Chart 1 shows more of a cliff for interest rate increases as the credit rating decreases.

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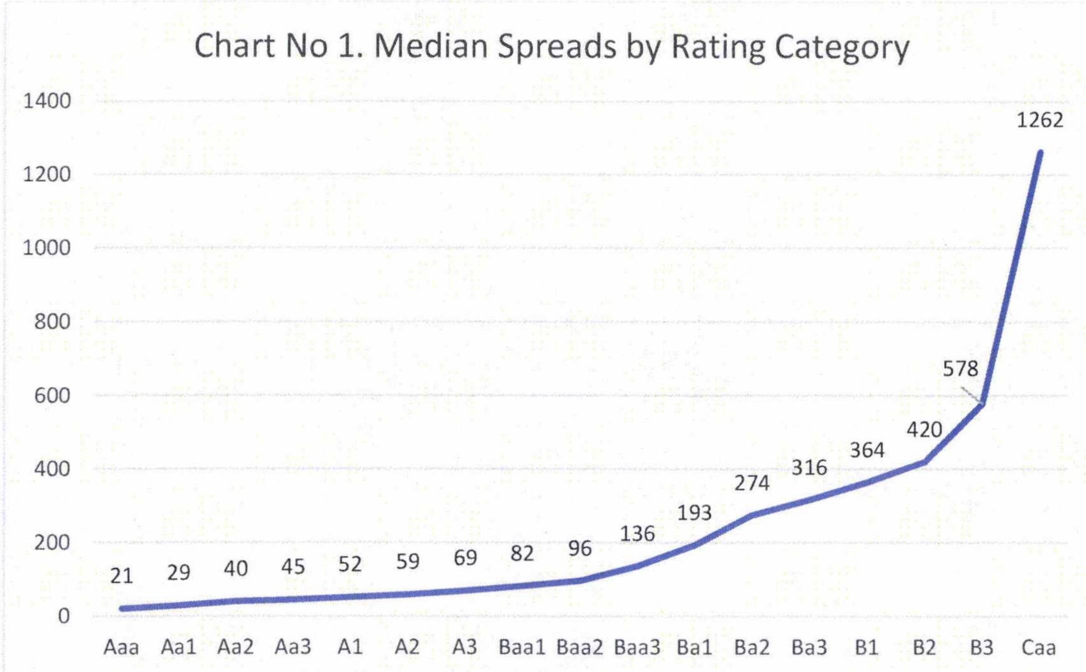
[7] *Id.*

[8] Energy Storage News, May 24, 2022, "California Regulator CPUC approves utility SCE's fast-tracked 500 MW BESS projects Online in California." https://www.energy-storage.news/california-regulator-cpuc-approves-utility-sces-fast-tracked-500mw-bess-projects/



When the Application was filed, the Company had an A3 credit rating. On July 6, 2022, Moody's downgraded the Company's credit rating to Baa1, and upgraded the Company's outlook from negative to stable. Chart No. 1 shows the spread increase from A3 to Baa1 to be 13 basis points or a 0.13% increase in debt costs. Even if the Company should get another downgrade, which based on the stable outlook Moody's is not expecting, the interest rate increase would be another 0.14%.

It is important to note that the impact on the interest rate would only effect new debt issuances. The Company's previously issued debt would stay at the current interest rates. Using a 50%/50% debt to equity ratio, and if the Company were to issue all debt that has been currently approved by the Commission, a 0.13% increase in interest rates would have an approximate 0.021% increase in the Company's overall rate of return.

Projects Selected Outside of the RFP

As evidence that the bid pool was insufficient, the two BESS projects were not bids that were submitted through the 2021 RFP. Both of these projects were solicited and negotiated directly by the Company outside of the RFP.

BESS Cost Benchmarks and Cost Recovery Soft Cap

As further evidence that the resulting contracts are not least-cost, Staff benchmarked the completed cost of the 120 MW BESS at $150,684,988 using comparable 4-hour BESS installations which is 11.7 % or $17.6 million lower than the Company's estimated cost. Hackett Direct at 21. Staff's benchmark 4-hour BESS pricing is based on published costs for Utility-Scale Battery Storage using the National Renewable Energy Laboratory ("NREL") Annual Technology Baseline,[9] updated in June of 2022 using the Moderate Technology Innovation Scenario. Given the lower NREL cost compared to the Company's negotiated contract and other Company estimated completion costs,[10] the total amount of recovery should be adjusted so that Customers are not penalized for the additional cost.

Based on these benchmarks, Staff recommends the Commission 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). The purpose of the soft cap is to provide a maximum amount of recovery that the Company should be allowed to recover, unless it can provide compelling evidence otherwise. Staff provided an analysis comparing the NREL benchmarks to the cost of the Company's projects in Confidential Attachment 1 to develop the amounts for the soft caps. This analysis ensures that Staff's comparisons were done on an equivalent basis.

<u>Commission Procurement Requirements</u>

The Company did not comply with the Commission's procurement requirements under Commission Order No. 32745. Staff believes following all requirements within the guidelines would not have been prudent given the compressed timeline for this resource need. However, the procurement requirements can protect customers by ensuring selected resources are least-cost, Had the Company followed the requirements it could have avoided issues that Staff has discussed in these comments. Thus, Staff encourages the Company to fully consider the Commission's procurement requirements when it issues RFPs in the future.

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[9] https://atb.nrel.gov/electricity/2022/utility-scale_battery_storage

[10] Costs were developed using Company confidential responses from Production Responses No. 18, 23, and 24.

Depreciation Rates

Staff recommends 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). In Case No. IPC-E-21-18, Account 363 depreciation rate was set at 6.66%. At that time, the Company did not have any battery storage assets in that account; therefore, no analysis was done on the appropriate depreciation life. Installers and other companies that build BESS have supported a 20-year life for these types of assets. Staff recommends that the Commission approve a 5% depreciation rate for the BESS when it is placed in service. This rate will be reviewed in the Company's next depreciation case and updated as needed with data from the battery storage assets the Company has in place at that time.

Income Tax Credit

There are ITCs available for generation plants with renewable attributes. The battery that is "envisioned" to be co-located with the solar generation facility will therefore be eligible for ITCs because the Company can reasonably assure that the energy stored in this BESS will be using the power from the solar facility. Application at 6. However, the BESS that is expected to be "potentially installed" next to the Hemingway Substation, *Id.* at 6, does not have the same assurances that the energy stored will be from renewable resources and therefore may not qualify for ITCs. Staff recommends that the Commission order the Company to reflect for ratemaking purposes all available ITCs for these plant assets.

RECOMMENDATIONS

Staff recommends the Commission:

1. Grant the request for a CPCN specific to the Company's decision to acquire 120 MW of dispatchable capacity to be operational by July 1, 2023, based on the immediate need for capacity resources and to ensure system reliability.
2. Establish "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) when the Company seeks recovery for the projects.
3. 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).

4. Order the Company to reflect all available ITCs for these plants.

Respectfully submitted this 30th day of August 2022.

Riley Newton,
Deputy Attorney General

Technical Staff: Rick Keller
Jolene Bossard
Kevin Keyt
Joe Terry

i:umisc/comments/ipce22.13rnrkjtjb ksk comments

SUMMARY SHEET
120 MW BESS COST COMPARISON TO NREL
2022 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies

DESCRIPTION	UNITS	NREL	IDAHO POWER	DIFFERENCE	NOTES
40 MW Battery Energy Storage (4-hour) Black Mesa	$	50,228,329	[redacted]		
80 MW Battery Energy Storage (4-hour) Hemmingway	$	100,456,659	[redacted]		
TOTAL COMBINED 120 MW Battery Energy Storage System	$	150,684,988	[redacted]	17,612,728	Idaho Power Total 120 MW BESS System Cost is Higher by this Amount
Percentage Difference				11.7%	Idaho Power Total 120 MW BESS System Cost is Higher by this Percentage

Redacted Attachment 1
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NREL Cost Projections for Utility-Scale Battery Storage: 2021 Update
2022 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies

DESCRIPTION	UNITS	VALUE		NOTES
https://atb.nrel.gov/electricity/2022/data				2022 v1 Annual Technology Baseline Workbook Original 6-14-2022.xlsx
40 MW Battery Energy Storage (4-hour) Black Mesa				
System Detail				Total System Cost ($/kW) = Battery Energy Cost ($/kWh) * Storage Duration (hr) + Battery Power Cost ($/kW)
System Size	MW	40		
Storage Duration	Hours	4		
2023 Year Data				
Moderate Technology Innovation Scenario				
Battery Energy Capital Cost ($/kWh)	$/kWh	254.84		
Battery Power Capital Cost ($/kW)	$/kW	236.37		
Moderate				
CAPEX (2023 Installed Capital Cost)	$/kW	1,255.71		Value is consistent with Figure ES-3 for year 2023 Moderate (Page xi)
NREL Cost Breakout				
Developer Cost + Profit	$	144.73	11.5%	
Sales Tax	$	49.34	3.9%	
EPC Ovehead	$	49.34	3.9%	
Installation Labor & Equipment	$	92.92	7.4%	
Electrical BOS	$	172.69	13.8%	
Structural BOS	$	78.94	6.3%	
Battery Central Converter	$	49.34	3.9%	
Lithium-ion Battery	$	618.40	49.2%	
SUM CHECK	$	1,255.71	100.0%	
NREL ATB 2023 Total System Cost (40 MW 4-hour BESS)	$	50,228,329		[redacted]
Production Request Response No. 23				
Idaho Power				
Project Management, Engineering, Design, Construction Management, Permitting, and General Administration	$	[redacted]		
Civil Construction, Site Work, Underground Conduit and Grounding, Fencing, Concrete Foundations	$	[redacted]		
Electrical Construction	$	[redacted]		
BESS Installation	$			
Testing and Commissioning	$			
BESS Assignment and Assumption	$			
Contract Price (Exhibit E)	$			
SUM	$	[redacted]		Value does not consider AFUDC
COST DIFFERENCE (40 MW 4-hour BESS)				
NREL ATB 2023 Total System Cost	$	50,228,329		
Idaho Power Estimated Total System Cost	$	[redacted]		
DIFFERENCE ABOVE NREL COST				
Cost Difference	$	[redacted]		Idaho Power Total System Cost is Higher by this Amount
Percentage Difference				Idaho Power Total System Cost is Higher by this Percentage

Redacted Attachment 1
Case No. PAC-E-22-13
Staff Comments
08/30/22 Page 2 of 3

DESCRIPTION	UNITS	VALUE		NOTES
NREL Cost Projections for Utility-Scale Battery Storage: 2021 Update				
2022 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies				
https://atb.nrel.gov/electricity/2022/data				2022 v1 Annual Technology Baseline Workbook Original 6-14-2022.xlsx
80 MW Battery Energy Storage (4-hour) Hemmingway				
System Detail				Total System Cost ($/kW) = Battery Energy Cost ($/kWh) * Storage Duration (hr) + Battery Power Cost ($/kW)
System Size	MW	80		
Storage Duration	Hours	4		
2023 Year Data				
Moderate Technology Innovation Scenario				
Battery Energy Capital Cost ($/kWh)	$/kWh	254.84		
Battery Power Capital Cost ($/kW)	$/kW	236.37		
Moderate				
CAPEX (2023 Installed Capital Cost)	$/kW	1,255.71		Value is consistent with Figure ES-3 for year 2023 Moderate (Page xi)
NREL Cost Breakout				
Developer Cost + Profit	$	144.73	11.5%	
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Electrical BOS	$	172.69	13.8%	
Structural BOS	$	78.94	6.3%	
Battery Central Converter	$	49.34	3.9%	
Lithium-ion Battery	$	618.40	49.2%	
SUM CHECK	$	1,255.71	100.0%	
NREL ATB 2023 Total System Cost (80 MW 4-hour BESS)	$	100,456,659		
Production Request Response No. 24				
Idaho Power				
Project Management, Engineering, Design, Construction Management, Permitting, and General Administration	$	[redacted]		
Civil Construction, Site Work, Underground Conduit and Grounding, Fencing, Concrete Foundations	$	[redacted]		
Electrical Construction	$	[redacted]		
BESS Installation	$			
Testing and Commissioning	$			
BESS Assignment and Assumption	$			
Idaho Power Interconnection Facilities	$	[redacted]		
Contract Price (Exhibit E)	$			
SUM	$	[redacted]		Value does not consider AFUDC
COST DIFFERENCE (80 MW 4-hour BESS)				
NREL ATB 2023 Total System Cost	$	100,456,659		
Idaho Power Estimated Total System Cost	$	[redacted]		
DIFFERENCE ABOVE NREL COST				
Cost Difference	$	[redacted]		Idaho Power Total System Cost is Higher by this Amount
Percentage Difference				Idaho Power Total System Cost is Higher by this Percentage

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 30TH DAY OF AUGUST 2022, SERVED THE FOREGOING **COMMENTS OF THE COMMISSION STAFF WITH REDACTED ATTACHMENT,** IN CASE NO. IPC-E-22-13, BY E-MAILING A COPY THEREOF, TO THE FOLLOWING:

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