RECEIVED
2021 DEC -9 PM 2:52
IDAHO PUBLIC
UTILITIES COMMISSION

C. Tom Arkoosh, ISB No. 2253
ARKOOSH LAW OFFICES
913 W. River Street, Suite 450
P.O. Box 2900
Boise, ID 83701
Telephone: (208) 343-5105
Facsimile: (208) 343-5456
Email: tom.arkoosh@arkoosh.com
Admin copy: erin.cecil@arkoosh.com

Attorneys for IdaHydro

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR APPROVAL OF THE CAPACITY DEFICIENCY TO BE UTILIZED FOR AVOIDED COST CALCULATIONS	Case No. IPC-E-21-09 **DECLARATION OF C. TOM ARKOOSH**

C. TOM ARKOOSH, upon penalty of perjury, states:

1. I am counsel for Intervenor IdaHydro in the above-entitled action, and I make this declaration of my own personal knowledge.

2. That attached hereto as Exhibit A is a true and correct copy of the *Application* filed in Idaho Public Utilities Commission Case No. IPC-E-21-41, without attachments.

3. As provided by Idaho Code §9-1406, I certify and declare under penalty of perjury pursuant to the law of the State of Idaho that the foregoing is true and correct to the best of my knowledge and belief.

DATED this 9th of December 2021.

ARKOOSH LAW OFFICES

C. Tom Arkoosh
Attorney for IdaHydro

CERTIFICATE OF MAILING

I HEREBY CERTIFY that on the 9th of December 2021, I served a true and correct copy of the foregoing document(s) upon the following person(s), in the manner indicated:

Commission Secretary Idaho Public Utilities Commission 11331 W. Chinden Blvd., Building 8, Suite 201-A P.O. Box 83720 Boise, ID 83720-0074	______ ______ ______ ______ __X__	U.S. Mail, Postage Prepaid Overnight Courier Hand Delivered Via Facsimile E-mail: secretary@puc.idaho.gov
Matt Hunter Idaho Public Utilities Commission 11331 W. Chinden Blvd., Building 8, Suite 201-A P.O. Box 83720 Boise, ID 83720-0074	______ ______ ______ ______ __X__	U.S. Mail, Postage Prepaid Overnight Courier Hand Delivered Via Facsimile E-mail: matt.hunter@puc.idaho.gov
Donovan E. Walker Regulatory Dockets Idaho Power Company 1221 West Idaho Street (83702) P.O. Box 70 Boise, ID 83707	______ ______ ______ ______ __X__	U.S. Mail, Postage Prepaid Overnight Courier Hand Delivered Via Facsimile E-mail: dwalker@idahopower.com dockets@idahopower.com
Michael Darrington Energy Contracts Idaho Power Company 1221 West Idaho Street (83702) P.O. Box 70 Boise, ID 83707	______ ______ ______ ______ __X__	U.S. Mail, Postage Prepaid Overnight Courier Hand Delivered Via Facsimile E-mail: mdarrington@idahopower.com energycontracts@idahopower.com
Peter J. Richardson Richardson Adams, PLLC 515 N. 27th St. P.O. Box 7218 Boise, ID 83702	______ ______ ______ ______ __X__	U.S. Mail, Postage Prepaid Overnight Courier Hand Delivered Via Facsimile E-mail: peter@richardsonadams.com

Dr. Don Reading 6070 Hill Road Boise, ID 83703	_______	U.S. Mail, Postage Prepaid
	_______	Overnight Courier
	_______	Hand Delivered
	_______	Via Facsimile
	__X___	E-mail: dreading@mindspring.com

____
C. Tom Arkoosh

EXHIBIT A

RECEIVED
2021 DEC -3 PM 4:36
IDAHO PUBLIC
UTILITIES COMMISSION

DONOVAN WALKER
Lead Counsel
dwalker@idahopower.com

December 3, 2021

VIA ELECTRONIC FILING

Jan Noriyuki, Secretary
Idaho Public Utilities Commission
11331 W. Chinden Blvd., Bldg 8,
Suite 201-A (83714)
PO Box 83720
Boise, Idaho 83720-0074

Re: Case No. IPC-E-21-41
In The Matter Of Idaho Power Company's Application For Authority to Proceed with Resource Procurements to Meet Identified Capacity Deficiencies in 2023, 2024, and 2025 to Ensure Adequate, Reliable, and Fair-Priced Service to its Customers

Dear Ms. Noriyuki:

Enclosed for electronic filing, please find Idaho Power Company's Application for Authority to Proceed with Resource Procurements in the above matter. Please feel free to contact me directly with any questions you might have about this filing.

Very truly yours,

Donovan E. Walker

Donovan E. Walker

DEW:cld
Enclosures

DONOVAN E. WALKER (ISB No. 5921)
Idaho Power Company
1221 West Idaho Street (83702)
P.O. Box 70
Boise, Idaho 83707
Telephone: (208) 388-5317
Facsimile: (208) 388-6936
dwalker@idahopower.com

Attorney for Idaho Power Company

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR AUTHORITY TO PROCEED WITH RESOURCE PROCUREMENTS TO MEET IDENTIFIED CAPACITY DEFICIENCIES IN 2023, 2024, AND 2025 TO ENSURE ADEQUATE, RELIABLE, AND FAIR-PRICED SERVICE TO ITS CUSTOMERS.	)	CASE NO. IPC-E-21-41 APPLICATION FOR AUTHORITY TO PROCEED WITH RESOURCE PROCUREMENTS

Idaho Power Company ("Idaho Power" or "Company"), in accordance with *Idaho Code* §§ 61-501, 61-502, 61-503, 61-508, 61-526; as well as RP 52, and 112, hereby respectfully makes application to the Idaho Public Utilities Commission ("Commission" or "IPUC") for an order authorizing the Company to move forward with the procurement of capacity resources needed to provide adequate, reliable, and fair-priced service to customers. Idaho Power requests that the Commission issue an order: (1) eliminating the IPUC requirement to comply with the Public Utility Commission of Oregon ("OPUC") resource procurement rules in favor of a competitive, but expedited process; (2) authorizing Idaho Power to move forward expeditiously with resource procurements to meet identified generation resource needs in 2023, 2024, and 2025; and (3) affirming support and the continuation of the state of Idaho's system of public utility regulation under which the interests of customers are best served by a vertically integrated electric utility maintaining ownership of the necessary generation, transmission and distribution utility functions, with limited exceptions.

I. INTRODUCTION AND SUMMARY - A DYNAMIC ENERGY LANDSCAPE

Idaho Power has not added a supply-side, dispatchable resource since the Langley Gulch combined-cycle, natural gas combustion turbine, which was granted a Certificate of Public Convenience and Necessity ("CPCN" or "Certificate") in 2009.[1] Idaho Power's most recent Integrated Resource Plan ("IRP"), the Second Amended 2019 IRP, acknowledged by the Commission on March 16, 2021[2], does not show a first capacity deficit until the summer of 2028. However, during the preparation of the 2021 IRP that Idaho Power anticipates filing before the end of this year, an updated Load and Resource ("L&R") balance analysis in May 2021 identified a first capacity deficit of 78 megawatts ("MW") in June of 2023, growing each year through 2026, when the Boardman to Hemingway ("B2H") 500 kilovolt transmission line is expected to be operational. This rapid change in deficit position was caused by several dynamic and evolving factors including: third-party transmission constraints and changes to the assumptions in the L&R balance regarding available transmission capacity following the retirement of coal plants; the unavailability of import transmission capacity on the market; planning margin adjustments associated with incorporating Loss of Load Expectation ("LOLE") and Effective Load Carrying Capability ("ELCC") planning methodologies; increasing population and associated emergent demands on the Company's system; and the

---

[1] Case No. IPC-E-09-03, Order No. 30892
[2] Case No. IPC-E-19-19, Order No. 34959.

diminishing demand response ("DR") resource effectiveness and low solar generation effectiveness during critical demand hours. These factors and the dynamic energy landscape in which the Company is operating are discussed further in this Application.

Under Idaho law, Idaho Power has an obligation to provide adequate, efficient, just, and reasonable service on a nondiscriminatory basis to all those that request it within its certificated service area.[3] In order to meet its obligations to reliably serve customer load, and given the extremely short turn-around to construct a resource to meet a summer 2023 deficit, particularly in the midst of supply chain disruption,[4] ongoing COVID-19 impacts, and constraints in the industry and in ancillary industries, the Company is currently conducting a competitive solicitation through a Request for Proposals ("RFP") seeking to acquire up to 80 MW of company-owned resources to meet the 2023 capacity deficit - seeking projects to be online by June of 2023. The RFP contemplated wind, solar, energy storage, some combination of the forementioned resources, or other options to meet critical demand hours. Idaho Power is also, in parallel, investigating different configurations of Company owned and constructed battery storage systems, possible modifications to existing DR programs[5], and pursuing other short-term market solutions in attempts to meet the forecasted capacity deficits. However, this will not be enough to meet the rapidly evolving and dynamic forecasted capacity deficits.

In 2010, the Commission initiated a case[6] seeking to establish competitive bidding guidelines for the RFP process used to acquire supply-side resources by Idaho Power.

---

[3] *Idaho Code* §§ 61-302, 61-315, 61-507.

[4] Idaho Power has seen the general supply chain disruption in its own supply chain which has increased timelines across the board. The Notice of Force Majeure received by Idaho Power from Jackpot Holdings is based upon and also evidences the wide-spread nature and uncertainty in the current environment regarding third parties' ability to deal with such issues even when needed to meet their firm contractual commitments. See generally, *How the Supply Chain Broke, and Why It Won't Be Fixed Anytime Soon*, Peter S. Goodman, New York Times, Oct. 31, 2021. Supply Chain Shortages: Your Questions Answered - The New York Times (nytimes.com)

[5] IPC-E-21-32

[6] Case No. IPC-E-10-03.

In 2013, the Commission closed this case without establishing Idaho-specific resource procurement guidelines, but rather directed Idaho Power to follow the RFP guidelines applicable in its Oregon service area. The Oregon RFP guidelines to which the Commission referred were later codified into the administrative rules of the OPUC. OAR 860-089-0010 *et. seq.* ("OPUC Resource Procurement Rules"). The OPUC Resource Procurement Rules impose competitive bidding requirements upon an electric utility for the "acquisition of a resource or a contract for more than an aggregate of 80 megawatts and five years in length," among other requirements. OAR 860-089-0100(1)(a). There are certain exceptions to the applicability of the OPUC Resource Procurement Rules, including the exception used for executing the Jackpot Solar power purchase contract:[7] "There is a time-limited opportunity to acquire a resource of unique value to the electric company's customers." OAR 860-089-0100(3)(b). The OPUC Resource Procurement Rules also contain an exception to their applicability based upon the OPUC acknowledging an alternative acquisition method in the utility's IRP. OAR 860-089-0100(3)(c). What the OPUC Resource Procurement Rules do not contain, however, is an exception or exemption from the lengthy procurement process for when a utility identifies a critical and time-sensitive need to obtain capacity resource to reliably serve load.

While the 80 MW RFP could be addressed through a procurement process that was not subject to the OPUC Resource Procurement Rules due to the size-based exception, additional capacity deficits recently identified for 2023, 2024, and 2025 will require incremental generating capacity that exceeds the 80 MW applicability threshold for the OPUC Resource Procurement Rules. Applying the OPUC Resource Procurement

[7] IPC-E-19-14

Rules to the procurement processes needed to meet the currently identified capacity deficits in 2023, 2024, and 2025 would be extremely detrimental to the Company and its customers from both a timing and a methodology standpoint.

The proposed acquisitions, as described in this Application, are necessary and required in a dynamic energy landscape in order to continue to provide reliable and adequate electric service to Idaho Power's customers starting in the summer of 2023 and into the future. To timely meet its resource needs and continue to provide reliable service, the Company requests that it be relieved of the IPUC's requirement to follow the OPUC Resource Procurement Rules and that it be authorized to move forward with capacity resource procurements under RFP guidelines outlined below to meet the identified deficits in 2023, 2024, and 2025. As required by Idaho law, the Company would subsequently bring Certificate of Public Convenience and Necessity filings to the Commission for any supply-side resources identified through the procurement processes, with the Commission's attendant review of the resource need and expected costs for the procurement. Ultimately, a review of the prudence of costs incurred would occur in a general rate case or other revenue requirement proceeding prior to authorization of cost recovery through customer rates.

II. SEVERAL FACTORS HAVE RESULTED IN AN URGENT CAPACITY RESOURCE NEED

As noted above, Idaho Power has been generally resource-sufficient since the addition of the Langley Gulch natural gas-fired power plant almost a decade ago but has rapidly moved from an expected resource-sufficient position, through 2028, to a near-term capacity deficiency starting in 2023, since the acknowledgement of the 2019 IRP in March of this year. Idaho Power's most current L&R balance analysis as of November 2021 identifies capacity deficits beginning in 2023 and growing each year until 2026, when the B2H 500 kilovolt transmission line is expected to be operational. In addition to load growth, several factors have contributed to the notable change in the L&R balance, including significant current third-party transmission constraints limiting wholesale market import purchases at peak, the ability of DR programs to meet peak load, planning margins and methodology modernization, and environmental regulatory uncertainty and economics for fossil fuel-fired power plants and the related timing of ceasing operations at those resources.

In May 2021, the Company identified the 2023 deficit as approximately 78 MW at the time Idaho Power issued the currently pending RFP to acquire up to 80 MW of dispatchable capacity resource. The following Table 1 details the projected capacity deficits for the years 2023 through 2025, updated to include the most current data from the preparation of the 2021 IRP.[8] As shown below in Table 1, the Company's projected capacity deficits have grown to 101 MW in 2023, 186 MW in 2024, and 311 MW in 2025.

Table 1: Peak-Hour Load and Resource Balance	2023	2024	2025
	23-Jul	24-Jul	25-Jul
Surplus / Deficit (MW)	-101	-186	-311

Changes in L&R Since the 2019 IRP: Idaho Power filed its Second Amended 2019 IRP on October 2, 2020. The goal of the IRP is to ensure: (1) Idaho Power's system has sufficient resources to reliably serve customer demand and flexible capacity needs over a 20-year planning period; (2) the selected resource portfolio balances cost, risk,

[8] As of November 30, 2021, the developer of the Jackpot Solar project indicated that a delay is likely. If Jackpot Solar is not in-service by summer 2023 then Idaho Power will need approximately 40 MW of additional summer peak capacity to meet projected customer demands.

and environmental concerns; (3) balanced treatment is given to both supply-side resources and demand-side measures; and (4) the public is involved in the planning process in a meaningful way. Historically, the Company developed portfolios to eliminate resource deficiencies identified in a 20-year L&R balance. The L&R balance from the Second Amended 2019 did not show a capacity deficiency occurring until the summer of 2028. However, the Company's L&R balance analysis has since been updated a number of times as circumstances and conditions have changed significantly in the interim, with each iteration showing capacity deficits as early as 2023.

Following development of the Second Amended 2019 IRP, the Company conducted focused system reliability and economic analyses to assess the appropriate timing of a Valmy Unit 2 exit between 2022 and 2025. The result of the reliability and economic evaluations demonstrated that coal-fired operations of Valmy Unit 2 through the end of 2025 is the most reliable and economic path forward.

The analysis that led to this conclusion started with adjustment of the L&R balance analysis used in the Second Amended 2019 IRP as part of the Valmy Unit 2 reliability and economic impact analyses completed in May 2021. Development of the 2021 IRP was occurring simultaneously, and the Company updated the L&R balance to include modifications to existing resource availability, as is standard when developing the L&R balance as part of the IRP process. First, the Company identified changes to its market purchase assumptions due to third party transmission constraints. Additionally, the existing resource availability was revised to include updated thermal capacity and reduced DR capacity determined through the refinement of the planning margin calculation. The net change between the Second Amended 2019 IRP and the updated L&R balance is a reduction of over 500 MW in available capacity each July during the 2022 through 2025 time period. As a result of these changes to the L&R balance in May

2021, the Company anticipated a capacity deficit of approximately 78 MW in 2023, assuming Valmy Unit 2 operations continue through 2025.

As can be seen on Table 1, the final L&R balance used for the 2021 IRP indicates the 2023 capacity deficit of 78 MW, as calculated in May 2021, has grown to 101 MW. While all the same factors that influenced the changes in the May 2021 L&R balance still exist, the latest L&R balance includes a revised load forecast with greater load growth projections.

Transmission Market Shifts and Constraints: In the Second Amended 2019 IRP, the Company assumed Valmy Unit 2 could be replaced with capacity purchases from the south. However, market conditions have changed dramatically because of ripple effects stemming from the August 2020 energy emergency event in California. During this event, the West experienced a heat wave, increasing the demand for energy and causing several balancing authorities across the Western Interconnection to declare energy emergencies. Generation was not able to meet demand in California and transmission capacity was strained, limiting the ability to import energy. As a result, the California Independent System Operator was required to shed firm load to maintain the reliability and security of the bulk power system. Ultimately, this also impacted Idaho Power's ability to use third party transmission to import energy and meet load deficits.

Understanding the importance of transmission availability during times of high electricity demand, third-party marketing firms began reserving unprecedented amounts of firm transmission capacity just outside the Company's border, significantly limiting Idaho Power's access to market hubs. Soon after the event, Idaho Power's own transmission service queue was flooded with multi-year requests totaling 1,293 MW, as of April 2021, looking to move energy from the Mid-C hub across Idaho Power's transmission system to the south.

While the Company is able to reserve its own transmission for usage by the Company's customers, the transmission service requests just outside of Idaho Power's borders have added constraints to an already constrained market limiting the Company's access to capacity at Mid-C. Idaho Power tested the market availability with an RFP issued April 26, 2021, which ultimately validated the existence of these transmission system constraints. The RFP requested a market purchase with delivery at Idaho Power's border; however, no bids were received at any price-point, further emphasizing the difficulty of importing energy under a constrained transmission system.

As a result of these recent and significant market changes, for the years 2023 through 2025, Idaho Power has reduced the transmission availability within the L&R balance from approximately 900 MW in the 2019 IRP to approximately 700 MW in the 2021 IRP during the peak load month of July.

Planning Margin Adjustments: The Company's planning margin is intended to provide a sufficient reliability margin to prevent the need to curtail customer demand more than one time in 20 years. The planning margin is intended to cover (1) Idaho Power's contingency reserve obligation, (2) severe weather events, consisting of both extreme heat and extreme cold, (3) poor water conditions, and (4) planned and unplanned resource and transmission outages. In the Second Amended 2019 IRP, Idaho Power established a 15 percent planning margin, which was calculated as 15 percent of the Company's average (50th percentile) peak demand forecast for each month. For example, if Idaho Power had a peak-hour-load of 3,500 MW, the Company would add the planning margin and target 4,025 MW of resource capacity (3,500 multiplied by 1.15).

Following the development of the Second Amended 2019 IRP, the Company looked to refine its planning margin in accordance with best practices to ensure consideration of issues specific to Idaho Power's system. The 15 percent planning margin utilized in the Second Amended 2019 IRP is essentially a rule of thumb. Individual utilities can experience different frequencies of demand extremes, varying forced outage rates among resources, and resource size compared to load size, all of which should be considered when determining the planning margin. Rather than continue to utilize a planning margin based on a rule of thumb, the Company modernized its approach and is using probabilistic methods in the 2021 IRP to determine system needs to ensure reliability for all hours of the day on the Company's system, which is the "LOLE method."

The LOLE approach allows for a comparison of load to generation on an hourly basis over a specified period. Given feedback from the IRP Advisory Council, and the increased frequency of extreme events, the Company aligned with the Northwest Power and Conservation Council standard of no more than one loss of load event per 20 years, or an LOLE of 0.05 days per year. The Company believes the LOLE method's hourly approach fully considers the reliability value of renewable resources over time compared to the previous method.

In addition to taking a more granular hourly approach, the LOLE method evaluates the capability of existing resources to meet peak demand through the determination of the ELCC. Use of the ELCC resulted in a change to the peak-serving capability of Idaho Power's existing resources, most notably the peak capacity contribution of DR. When analyzing the Company's system on an hour-by-hour basis, the results indicate the ability of DR programs to meet peak load under the changing dynamics of Idaho Power's system is significantly lower than previously assumed. This is primarily the result of increased solar resources on the Company's system pushing net peak load hours outside the current DR program window. Therefore, the Company has filed a request for modifications to its DR programs that, while making the programs more effective at meeting system needs, may result in lower DR participation.

Current Load Forecast Increases: While the change in peak load expectations for 2023 through 2025 between the Second Amended 2019 IRP and the May 2021 L&R analysis was relatively immaterial, based on updates the Company currently expects 2023 through 2025 peak load to be greater than anticipated in those prior analyses. Migration into the Company's service area exceeded prior forecasts, both during and after the recession, as customer additions into the service area were approximately 30% higher than prior expectations. In addition, there have been several industrial customers, both existing and new, that have made a sufficient and significant binding investment and/or interest indicating a commitment of locating or expanding operations in the Company's service area. These drivers predict that the Company's peak capacity by 2023 will grow faster than forecasted expectations used in both the second amended 2019 IRP and the May 2021 L&R analysis.

Current L&R Balance Analysis: Since the Valmy study was completed in June 2021, the Company has continued to update the L&R balance analysis for the 2021 IRP using the most currently available resource and load inputs. On the resource side, Idaho Power has applied the adjusted transmission assumptions, as well as the LOLE and ELCC methods described above. On the load side, Idaho Power has also included higher load growth expectations. The resulting capacity deficiency of approximately 101 MW in 2023, 186 MW in 2024, and 311 MW in 2025 as presented in Table 1, clearly demonstrates the need for the new capacity resource to meet those capacity deficits prior to the addition of the Boardman to Hemingway transmission line in 2026.

While these estimates reflect Idaho Power's best available information at the time of this filing, the Company wishes to make the Commission aware of a recent development that could ultimately increase the forecast capacity deficit beginning in 2023. Idaho Power had previously contracted with Jackpot Solar, LLC ("Jackpot Solar") for 120

MW of solar generation to become commercially operational by December 2022. The energy contract with Jackpot Solar was reviewed and approved by the Commission by Order No. 34515 issued in December 2019.[9] On November 9, 2021, Jackpot Solar informed Idaho Power that that global supply chain disruptions have raised concerns regarding Jackpot Solar's ability to achieve commercial opperation by the dates identified in the approved agreement. Specifically, Jackpot Solar alleges that current global supply chain disruptions brought on by the COVID 19 pandemic represents a force majeure event as defined in the energy sales agreement, as its solar modual supplier will not meet the supply provisions of the modual supply agreement. Idaho Power is currently in discussions with Jackpot Solar, and it is unknown to the Company when, or if, the associated 120 MW of solar generation will begin commercial operations. If the Jackpot Solar project is delayed beyond summer 2023, or not built, Idaho Power will need approximately 40 MW of incremental peak capacity to meet projected customer demands.

III. THE OREGON RESOURCE PROCUREMENT RULES ARE UNABLE TO TIMELY ADDRESS DYNAMIC CIRCUMSTANCES

On February 9, 2010, the Commission initiated Case No. IPC-E-10-03 to establish competitive bidding guidelines for the RFP process used when supply-side resources are acquired by Idaho Power. On February 12, 2013, the Commission issued Order No. 32745 closing the case without establishing Idaho-specific resource procurement guidelines, but rather directed Idaho Power to comply with RFP guidelines applicable in its Oregon service area. According to Order No. 32745, the Company is required to adhere the Oregon Competitive Bidding Guidelines should it commence an RFP process for a new supply-side resource prior to the development of Idaho-specific RFP guidelines. The referred to Oregon RFP Guidelines were later codified into the administrative rules

[9] Case No. IPC-E-19-14.

of the OPUC. OAR 860-089-0010 *et. seq.*. The OPUC Resource Procurement Rules impose Competitive Bidding Requirements upon an electric utility for the "acquisition of a resource or a contract for more than an aggregate of 80 megawatts and five years in length," among other requirements. OAR 860-089-0100(1)(a). There are certain exceptions to the applicability of the OPUC Resource Procurement Rules, including the one used for the Jackpot Solar contract: "There is a time-limited opportunity to acquire a resource of unique value to the electric company's customers." OAR 860-089-0100(3)(b). The OPUC Resource Procurement Rules also contain an exception to their applicability based upon the OPUC acknowledging an alternative acquisition method in the utility's IRP. OAR 860-089-0100(3)(c).

Idaho Power asks that the Commission relieve Idaho Power of the IPUC's requirement to follow the OPUC Resource Procurement Rules in the state of Idaho. A procurement process that complies with all requirements set forth by the OPUC Resource Procurement Rules would not timely address the Company's near-term resource needs and would be unnecessarily costly. By Idaho Power's estimates based upon the required timelines from the OPUC Resource Procurement Rules, it could take a minimum of more than 18 months from the initial stages of selection of the required independent evaluator until the final step of the process where the OPUC approves the short list of bidders. *See*, Attachment 1 hereto, incorporated herein by this reference. In fact, PacifiCorp's 2017 wind resource RFP took nearly a year from PacifiCorp's first filing to the OPUC's decision on the short list of bidders. *See In the Matter of PacifiCorp, dba PacifiCorp Power,2017R Request for Proposals*, OPUC Docket No. UM 1845, Order No. 18-178 (May 23, 2018). And even though it took nearly a year just to identify the short list of bidders, the RFP process was considered "expedited" and the OPUC referred to it as "fast-moving." *Id.* at 8, 10.

PacifiCorp's 2020 all-source RFP has taken even longer. PacifiCorp initiated the RFP with an OPUC filing in February 2020 and now—over 20 months later—the OPUC has yet to rule on the short list of bidders. *See In the Matter of PacifiCorp d/b/a Pacific Power Application for Approval of 2020 All-Source Request for Proposals*, OPUC Docket No. UM 2059. This timeframe does not take into account the time to actually engineer and construct the generation resources, which can take up to another two years to complete.

PacifiCorp also recently submitted its initial OPUC filing for its 2022 all source RFP. *See In the Matter of PacifiCorp d/b/a Pacific Power Application for Approval of 2022 All-Source Request for Proposals*, OPUC Docket No. UM 2159. PacifiCorp's initially proposed schedule called for submission of its final shortlist by May 2022, eight months after the initial filing. OPUC Staff referred to the proposed schedule as "aggressive" and claimed that the schedule did not comply with the OPUC's rules. *See In the Matter of PacifiCorp d/b/a Pacific Power Application for Approval of 2022 All-Source Request for Proposals*, OPUC Docket No. UM 2159, Order No. 21-351, App'x A at 5 (Oct. 25, 2021). In response, PacifiCorp modified the schedule to include 80 more days on the front end before the RFP may be approved by the OPUC and over 200 more days for bidders to prepare their bids. Under the now extended schedule, PacifiCorp will not even issue the RFP until April 1, 2022—seven months after the initial filing—and the RFP process will not conclude until May 2023—more than 19 months after PacifiCorp's initial OPUC filing.

Portland General Electric Company (PGE) also recently initiated the OPUC RFP process with a filing in April 2021. *In the Matter of Portland General Electric Company Application for Approval of Independent Evaluator for 2021 All Source RFP*, OPUC Docket No. UM 2166. Under the approved schedule, PGE anticipates issuing the RFP in December 2021—more than seven months after initiating the OPUC process—and PGE anticipates submitting its final shortlist in June 2022—more than a year after initiating the OPUC process. *In the Matter of Portland General Electric Company Application for Approval of Independent Evaluator for 2021 All Source RFP*, OPUC Docket No. UM 2166, Schedule for Post IE Selection (August 3, 2021).

An RFP process that takes over 12-18 months, in addition to the time to go from an approved RFP shortlist through negotiations, engineering, and construction, is clearly not practical in the current dynamic, rapidly changing environment, as evidenced by the changes in the transmission market conditions, customer growth, and corresponding resource needs between the 2019 and 2021 IRPs. The resource needs of the Company and its customers emerge with such urgency, such as the present capacity deficits identified in 2023, 2024, and 2025, that the Oregon Resource Procurement Rules and process is not viable if the Company is to reliably serve customers. Concurrent with this Application, Idaho Power will file a request with the OPUC to waive the applicability of the OPUC Resource Procurement Rules to Idaho Power in its Oregon jurisdiction for the required resource acquisitions discussed herein for 2023, 2024, and 2025.

Idaho Power is also concerned that the OPUC Resource Procurement Rules do not align with the state of Idaho's system of public utility regulation. In fact, Idaho Power objected to the adoption of the Competitive Bidding Guidelines, the precursor to the OPUC Resource Procurement Rules. Under the state of Idaho's chosen system of public utility regulation, customers benefit in the long-term when the utility is responsible for the obligation to reliably serve customers within its certificated service area, subject to IPUC oversight over, among other things, capacity resource acquisition. Additionally, Idaho Power believes the OPUC Resource Procurement Rules are very inflexible, unrealistic as to timing, and introduce a bias against the acquisition of utility-owned resources into generation resource procurements, favoring the standalone per-MWh price of a fixed term contract (typically well short of the useful life of the asset) over reliability, long-term customer impacts, and the financial viability of the utility. The OPUC Resource Procurement Rules are designed to favor least cost PPA resources that are not the optimal resources operationally or for a utility such as Idaho Power that already holds a proportionately large amount of PPAs. By contrast, a procurement process for resources that takes into account not only price, but also reliability, system operation, long-term operation and maintenance of facilities, financial viability of the utility, economic dispatch, environmental policies, real-time needs and load growth, and other attributes, is one that benefits customers, developers, and the utility.

IV. IDAHO POWER'S RFP PROCESS, AND THE MANDATORY CPCN, CREATE AN IDEAL PROCESS AND PROTECTIONS

Idaho Power seeks authority to proceed with supply-side resource procurements designed to meet the identified capacity deficits in 2023, 2024, and 2025 - prior to the time that the B2H transmission line is expected to be operational - in much the same manner that all prior supply-side resources have been procured and approved by the IPUC for Idaho Power. For all of those resource acquisitions, the Company will conduct an RFP to obtain competitive pricing and identify the best resource to ensure adequate, reliable, and fair-priced service to its customers, and will then bring that resource to the IPUC for its independent evaluation and determination as to whether acquisition of that resource is consistent with the Public Convenience and Necessity under applicable standards. *Idaho Code* § 61-526.[10]

As previously stated, Idaho Power has initiated an RFP for a dispatchable capacity resource up to 80 MW in order to meet the initially identified 78 MW capacity deficit in

[10] Notably, the state of Oregon does not have a corresponding requirement for the issuance of a CPCN for supply-side or generation resources like Idaho.

2023.[11] In the Spring of 2021, recognizing the urgency of the capacity deficit, the Company assembled an interdisciplinary team to develop and process an RFP for 2023 peak capacity resources ("RFP evaluation team"). The Company also retained a consultant, Black & Veatch Management Consulting, LLC, to assist the RFP evaluation team with development of the RFP and to provide guidance and evaluation support of the Company's RFP process. The RFP evaluation team developed detailed criteria and a methodology for evaluating both price and qualitative attributes of a proposed resource. On June 30, 2021, the RFP evaluation team issued a formal request for competitive proposals for up to 80 MW of electric generating capacity. The RFP document is attached hereto as Attachment 2 and incorporated herein by this reference. The RFP document sets forth the process and procedure utilized to solicit and evaluate the proposals as to meeting the Company's and its customers' present needs.

A public Notice of Intent was released on May 20, 2021, to industry developers and media outlets and was posted to Idaho Power's website noticing Idaho Power's intent to release the RFP. Interested developers responded with an Intent to Bid by June 11, 2021. The "2021 All Source Request for Proposals for Peak Capacity Resources" was solicited directly to 38 Developers. The RFP solicitation identified the purpose, key product specifications, proposal format, qualitative and quantitative evaluation criteria, template draft form term sheet ("Build Transfer Agreement" or "BTA"), technical specifications, and additional requirements necessary to submit a qualifying proposal. The RFP solicitation also focused on the importance of having a project in-service by June 2023. Thirteen proposals were submitted by third-party developers on August 11, 2021. The RFP evaluation process assesses both price and non-price attributes. Price

[11] The Oregon Procurement Rules do not apply to resources below 80 MW.

attributes were weighted at 60 percent of the total valuation and non-price attributes were given a 40 percent weighting.

Once a winning bidder is selected and contractual documents are executed, the Company, as it has done in the past, will bring the proposed generation acquisition to the Commission for is review in a CPCN proceeding to establish both the need and expected cost of the procurement. The required CPCN process as well as the subsequent rate making proceedings will provide considerable oversight of the procurement process, and ensure low cost, reliable resource acquisitions for customers - as it has done for the Company's more than 100-year history.

V. UTILITY OWNERSHIP OF SUPPLY-SIDE CAPACITY RESOURES IS BENEFICIAL TO CUSTOMERS, THE UTILITY, AND IDAHO'S REGULATED UTIILITY MODEL

Idaho's Regulatory Mandate and Model: Idaho Power has an obligation to provide adequate, efficient, just, and reasonable service on a nondiscriminatory basis to all those that request it within its certificated service area. *Idaho Code* §§ 61-302, 61-315, 61-507. As part of the regulatory compact, Idaho Power must serve all customers in the service aera, in exchange for its exclusive right to provide retail electric service within the service area. The compact provides Idaho Power the opportunity to earn a reasonable return by investing capital into the resources and systems necessary to perform its service obligation. At the same time, the Commission has oversight of the provision of that service and must assure that the rates Idaho Power charges its customers and that the rules and regulations by which it provides service are just, reasonable, nondiscriminatory, and non-preferential. *Idaho Code* §§ 61-501, 61-502, 61-503, 61-507, 61-508.

The Company must at times acquire additional resources to meet the identified capacity deficits on its system, regardless of when those deficits occur and with whatever urgency they arise, in order to comply with its continuing obligation to serve customers. While the IRP provides insight into resource procurement, it is a biennial process, and circumstances change in the interim that can make resource procurement for reliable load-service more urgent, as is the present case. Additionally, those resource acquisitions must take into account the benefits of utility ownership and operation of resources, and not be premised solely on short-term/least-cost, which can have catastrophic outcomes for electric service and the public. The Commission has oversight of those procurements, to ensure the company is prudently investing its capital. With only limited exception, these resources should be Company-owned, as Idaho Power must satisfy its obligation to provide its customers with reliable service and at the same time maintain its financial health to remain a viable, going-concern, regulated entity in the state of Idaho’s chosen and mandated system of regulated public utility service.

The Commission has the express authority to order a utility to build new structures, or to upgrade and/or improve existing plant and structures, in order to secure adequate service or facilities. Idaho’s applicable statute states:

> Whenever the commission, after a hearing had upon its own motion or upon complaint, shall find that additions, extensions, repairs or improvements to or changes in the existing plant, scales, equipment, apparatus, facilities or other physical property of any public utility . . . ought reasonably to be made, or that a new structure or structures should be erected, to promote the security or convenience of its employees or the public, or in any other way to secure adequate service or facilities, the commission shall make and serve an order directing such additions, extensions, repairs, improvements, or changes be made or such structure or structures be erected in the manner and within the time specified in said order.

Idaho Code § 61-508.

A Certificate of Public Convenience and Necessity represents the exercise by the Commission of foundational authority and principles that are necessary in Idaho’s system of permitting regulated, vertically integrated public utilities to exist and to provide necessary services to the public. Certificates have been utilized in various ways from the time that Idaho's statutory system of public utility regulation was enacted by the Legislature in 1913, *Idaho Code* § 61-101, *et seq*., to the present time. After over 100 years of legislative enactments, Commission orders, and Idaho Supreme Court reviews, the Certificate remains the embodiment of 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. *See Idaho Power & Light Co. v. Bloomquist et al.*, 26 Idaho 222, 141 P.1083 (1914); *Idaho Op. Atty. Gen. No. 87-2*, 1987 WL 247587 (Idaho A.G.).

In the broadest sense, a Certificate allows a company that meets the definition of a "public utility" pursuant to *Idaho Code* § 61-129 to exclusively provide its service to the public in a specified geographic region, its service area. It is a codified part of the "regulatory compact" whereby the utility takes on the exclusive obligation/right to serve all those requesting service within its service area and, correspondingly, submits itself to the rate and service quality regulation of the Commission. In a more literal sense, a Certificate from the Commission is required for the construction or extension of a line, plant, or system by any street railroad, gas, electrical, telephone, or water corporation. *Idaho Code* § 61-526. § 61-526 also provides that "if public convenience and necessity does not require or will require such construction or extension [of a line, plant, or system] the commission . . . may, after hearing, make such order and prescribe such terms and conditions for the locating or type of line, plant or system affected as to it may seem just and reasonable . . . ." A CPCN is required for the utility to construct a new generation resource or plant but is not required to increase the capacity of existing generating facilities. *Id*. The required CPCN provides a broad mechanism for considerable regulatory oversight into the procurement process for a generation or supply-side resource - one that is fundamental to our system of regulation and has historically in Idaho been exercised for the benefit of both the utility customers and the utility.

Idaho's system of regulation is based upon the core concept that state regulation of a single service provider in the public interest is better than, and preferrable to, an environment of competition and competitive service providers. *See Idaho Power & Light Co. v. Bloomquist et al.*, 26 Idaho 222, 141 P.1083 (1914) ("*Bloomquist*"). The positive virtues of this system of regulation have been repeatedly confirmed. Idaho's public utility laws were enacted in 1913. A seminal case, *Bloomquist,* in 1914 considered the constitutionality of the state's public utility laws and held that they were consistent with both the state and federal constitutions. *Bloomquist*, 26 Idaho 222, 141 P. at 1097. In its decision upholding the enactment of the public utility laws in the state of Idaho as constitutional, the Idaho Supreme Court stated,

> There is nothing in the Constitution that prohibits the Legislature from enacting laws prohibiting competition between public utility corporations, and the Legislature of this state no doubt concluded that a business like that of transmitting electricity through the streets of the city and furnishing light and power to the people must be transacted by a regulated monopoly, and that free competition between as many companies or as many persons as might desire to put up wires in the streets is impracticable and not for the best interests of the people.

Bloomquist, 26 Idaho 222, 141 P. at 1088. The Court analyzes and discusses the regulation of a single service provider, as a monopoly, by a state commission as a lawful, valid, and preferred substitution for the control of public utilities by competition. The Court in its discussion refers to several quotes citing the benefits of a regulated monopoly environment over a competitive environment, stating "In our opinion, the government, which properly assumes to prescribe reasonable rates and compel adequate service by public utilities, should also protect such utilities and the public from unwise and useless competition, and the wasteful investment of capital in the unnecessary duplication of plants." *Bloomquist*, 26 Idaho 222, 141 P. at 1089 (quoting Forty-First Report of the Georgia Railroad Commission). The Court stated,

> The regulating of rates and compelling proper service is for the purpose of obtaining rates and service as nearly equitable as possible to both the consumer and the utility corporation, and competition can have no other effect than to destroy the very groundwork of regulation, and therefore competition may be regulated by a commission under laws enacted by the Legislature.

Bloomquist, 26 Idaho 22, 141 P. at 1089. In addressing Idaho's public utility laws in particular the Court stated,

> Under the act in question, the commission is given power to fix the rate absolutely, and neither of the competing companies can charge more or less than the rate fixed. Under those conditions competition can amount to nothing, and the only reason for having two corporations covering the same field is to secure satisfactory service. But, under our utilities act, the commission is the arbitrator in regard to all matter of service. If the utility corporation is not giving satisfactory service, the commission has absolute power to compel it to do so. If its facilities are such that the cost of operation is unnecessarily high, the commission can enforce the installation of proper machinery and facilities and a correspondingly proper charge for the commodity furnished. The commission may force the public utility to keep abreast of the times in the employment of proper machinery and appliances in their plants and in the economic conduct of its business. If wasteful methods are indulged in, the public utility must bear the loss, and not the consumer. Thus the reason for competition is entirely taken away.

Bloomquist, 26 Idaho 222, 141 P. at 1089.

The state of Idaho and Idaho Power's customers are better served by the traditional, rate-based, vertically integrated single service provider model, as discussed and held lawful in *Bloomquist,* than the various incarnations of competition and eroded monopolies subjected to undue competition by modern forces. By design, Idaho's chosen system of regulation is set up to protect the utility service provider from competition in its certificated service area, whilst subject to Commission oversight, and not to promote competitive forces against the utility such that the utility eventually erodes and ceases to be viable. Instead, Idaho's long-standing, successful, and lawful system of utility regulation relies upon and needs financially healthy utilities that are able to rate base investment that is used and useful in the public service and have an opportunity to earn a return on that investment at a regulated rate.

The modern tools used in attempts to force deregulation onto state jurisdictions that have chosen to retain the traditional vertically integrated, state regulated service providers, such as the Public Utility Regulatory Policies Act of 1978 ("PURPA") and its unbounded mandatory purchase Power Purchase Agreements ("PPAs"), the Federal Energy Regulatory Commission's ("FERC") promotion of Regional Transmission Organizations ("RTO") and Independent System Operator ("ISO") operational environments, anticompetitive tax credit policy for renewable energy procurement, and competitive procurement rules and regulations specifically designed to "remove the utility's competitive advantage" (or in other words to give competitive advantage to non-utility, third-party generation or PPAs with incentives mis-aligned with customer benefit). While some aspects of these policies can, and have, resulted in positive outcomes for utilities and the customers they serve, certain policy aspects, if not properly implemented, have the potential to create an environment that erodes the financial health and viability of the regulated utility, and the ability of a utility to reliably serve customers, and in turn can erode the state's ability to protect customers through its regulation of the public utility.

These tools of deregulation, promoting a proliferation of third-party, PPA generation resources creates an environment where the public utility is no longer protected from competition in its certificated service area, but must still be subjected to the economic regulation of the state and face disadvantages in the marketplace. In essence, the model gravitates toward defaulting the utility and its customers into less useful, more expensive, and operationally difficult PPA arrangements that undermine the regulatory environment while allowing non-utility, third party generators - who have no obligation to customers and mis-aligned incentives - to walk away with profits and to consider their own bottom line, as opposed to reliable service to electric utility customers.

Non-utility generation or plant such as PPA or similar arrangements may have a viable and lawful place amongst a public utility's diverse portfolio of resources as a seemingly low-cost dump of energy onto the system. However, PPAs are of very limited value to meet capacity deficits when the generation generally cannot be controlled, dispatched, curtailed, available, or economically managed for the benefit of customers and the company in the same manner as utility-owned generation. PPAs may have an initial appearance of being a lower-cost generation resource alternative, but this can be false in the context of full utility operations. If one looks beyond just the price per MW in the written contract and looks at how useful the PPAs generation is to the system and the entirety of the financial costs to customers in the long run, their appeal diminishes rapidly in many contexts. As the amount of PPA generation resources in a public utility's portfolio increases, a number of issues arise: integration of the power becomes more difficult and costly; the utility loses maintenance and control over the facility and its 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; curtailment of the facility is non-existent, expensive, or fraught with potential legal challenges; and cyber and physical security oversight of the facility is diminished. Further, it starts to undermine the regulated service provider model, and acts in effect as a tool for deregulation.

During the early 1990's, many states, including Idaho, considered the enactment of legislation to deregulate the electric utility industry. Deregulation was considered and rejected in Idaho primarily based upon the success of the vertically integrated, state-regulated service provider system of regulation, the corresponding regulatory compact, and the state commission-based system of regulation that has resulted in Idaho electric customers consistently enjoying some of the lowest cost and most reliable electric service in the nation. This is bolstered by the additional security and customer protection afforded by the regulator maintaining oversight of the utility, as opposed to the unregulated, third-party who is not concerned with, nor answers to, customers or the regulator and is only concerned with profits.

In fact, many jurisdictions that went down the road of enacting deregulation legislation, particularly in the east, employed initial price caps to protect customers from inflated electric rates as part of the package. However, as time would tell, once those initial price caps expired those jurisdictions experienced very large price increases to customers, in many cases far exceeding those in regulated jurisdictions and with no recourse to the regulators. More recently, it was reported that since 2004 deregulated Texas electricity residential customers paid $28 billion more for their power than they would have paid at the rates charged to the customers of the state's traditional utilities.[12] From 2004 through 2019 that the annual rate for electricity from Texas's traditional utilities was 8 percent ***lower***, on average, than the nationwide average rate, while at the same time the rates of de-regulated retail providers averaged 13 percent ***higher*** than the nationwide rate.[13]

[12] *Texas Electric Bills Were $28 Billion Higher Under Deregulation*, Tim McGinty and Scott Patterson, Wall Street Journal, Feb. 24, 2021.
[13] *Id*.

The Texas Model is a Cautionary Tale: Recent system reliability events in Texas offer a cautionary tale regarding the risks associated with a restructured electric generation sector.[14] In 1996, the Electric Reliability Council of Texas ("ERCOT") was established as the Independent System Operator ("ISO") in the state of Texas (approximately 10% of Texas is not served by ERCOT), as provided for in Senate Bill 373. Subsequently in 2002, vertically integrated electric utilities were required to restructure by separating their generation, transmission, and distribution functions into separate entities. One of the goals of this restructuring was to create competition in the wholesale electric energy market. While restructuring has certainly accomplished that goal, it has also changed the financial and regulatory model that drives investment in generation resources in the state. Under the vertically integrated utility model that existed in Texas prior to 2002, investor -owned utilities had a financial incentive to invest in and maintain generation resources to meet their obligation to provide safe and reliable service to customers. In exchange for that obligation to serve, investor-owned utilities were provided an opportunity to earn a reasonable financial return for shareowners. Ultimately, the state regulator, the Public Utility Commission of Texas ("PUCT"), determined the prudence of those investments. Under a restructured market, independent generation operators do not have the same regulatory oversight or financial incentives, which may have led to underinvestment in the Texas generation fleet, and thereby compromising system reliability.

In February 2021, much of the ERCOT system was being impacted by extreme cold weather associated with Winter Storm Uri, which resulted in prolonged power

[14] Source information for this section: *The Timeline and Events of the February 2021 Texas Electric Grid Blackouts A report by a committee of faculty and staff at The University of Texas at Austin July 2021*, attached hereto as Attachment 3, and incorporated herein by this reference.

outages during the week of February 14. More than 4.5 million homes and business lost power during this event, and at least 210 people died as a direct result of those outages. The outages occurred despite ERCOT's best efforts in the days prior to deploy operating reserves, load shedding, and other conservation measures.

By February 15, 2021, ERCOT experienced generation outages of over 50,000 MW, or approximately 40 percent of total ERCOT nameplate generating capacity. Of those outages, approximately 30,000 MW, representing 167 generating units, experienced weather-related outages. These weather-related issues included, but were not limited to, wind turbine icing, frozen water intakes, and freezing of other general equipment.

The financial fallout from this event was also severe. The financial pain caused by these events impacted all categories of market participants, including wholesale energy suppliers, retail energy suppliers, and retail customers. Wholesale energy prices reached $9,000/MWh. Extremely high prices led to unpaid power payments within ERCOT of nearly $3 billion by May 2021. Retail providers experienced negative financial impacts in the billions of dollars, with several bankruptcies occurring in the aftermath.

It is important to note, all of the operational and financial chaos brought on by this extreme weather event occurred with relatively little transparency or oversight by the PUCT, even though Texas law requires the PUCT to analyze and report on the preparedness of generating units to operate during extreme weather events. The last such report was filed with the legislature in 2012. The reduced regulatory oversight and changed business model that exists in Texas is a clear reminder of the risks that exist in deregulated electric markets. Deregulated power generators serving ERCOT did not have the incentive to invest in systems to address extreme weather events, as presumably they were single-mindedly focused on maximizing profits instead of providing reliable service to customers in Texas. These tragic events demonstrate the that “invisible hand” of the free market doesn’t work well in extreme situations because the economic signals don’t last long enough to incent the investments that are necessary to ensure reliability during those events.

Third Party-Owned Assets Have an Imputed Debt Cost to the Utility and Ultimately to Customers: A PPA brings added costs beyond the direct contract costs for the purchased energy in the form of imputed debt adjustments made by credit rating agencies. When Idaho Power enters into a PPA for third-party supply of energy, credit ratings agencies like Standard and Poor’s (S&P), Fitch, and Moody’s view such agreements as creating fixed debt-like obligations given the lengthy stream of payment obligations by the utility. In light of this view, credit agencies make what are called “imputed debt adjustments” to Idaho Power’s credit metrics to reflect the credit exposure that exists with PPAs. Ultimately, these imputed debt adjustments amount to real costs that are passed on to Idaho Power’s customers through the rate-making process over time, but not visible in the PPA.[15]

Imputed debt adjustment calculations can vary depending upon the level of perceived credit exposure associated with a PPA, typically as apportioned between Idaho Power and its customers based on the certainty of rate recovery provided for by applicable law or regulatory assurances. The adjustment process begins with a calculation of the net present value (“NPV”) of the outstanding contract payments over the remaining life of a PPA. The NPV value is then adjusted for the level of perceived credit exposure associated with a PPA. Depending on the perceived credit exposure of a PPA, the credit

---

[15] Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements Primary Credit Analyst: David Bodek, Secondary Credit Analysts: Richard W Cortright, Jr. and Solomon B Samson, May 7, 2007, attached hereto as Attachment 4 and incorporated herein by this reference.

rating agency may apply risk factors that typically range from 0 to 50 percent – but can be as high as 100 percent.[16]

Ultimately, the result of the imputed debt applied by the rating agencies will be downgrades in credit ratings unless there is some type of mitigation to offset the imputed debt, such as additional equity. For example, in June 2021 Moody's put Idaho Power on negative watch, which is the first step towards a down grade in Moody's credit ratings for the company. There are many factors that impact credit ratings, and the imputed debt is one of those factors.

In comparing the cost of a PPA to utility ownership it is important to consider these imputed debt adjustments and their resulting cost. To illustrate the financial impact of the imputed debt adjustment, the Company has prepared the following illustrative example using the following financial input assumptions:

- Current authorized return on equity = 10%
- Incremental Cost of debt = 4%
- Incremental composite tax rate 25.74%

Any PPA will cause rating agencies to impute debt on Idaho Power's balance sheet based on the estimated present value of the PPA resource payments discounted at the incremental cost of debt and adjusted by a risk factor. In order to maintain an assumed 50/50 capitalization structure, the imputed debt will require an equal amount of equity to be issued to maintain the current debt equity ratio.

Assume the Company signs a PPA that would result in imputed debt of $100 million on the Company's balance sheet based on the estimated payments and the incremental debt rate and risk factor. In order to maintain a 50/50 debt/equity ratio, the company must

[16] *Id.*

issue $100 million of equity. The company would use the $100 million proceeds of the equity issuance for ongoing capital projects.

As a result, Idaho Power customers would now pay the monthly/annual cost of the PPA plus the cost of the equity issuance due to the PPA ($100 million*10%) = $10 million plus a gross up for tax ($10 million* (1/(1-0.2574))) = $13.466 million.

As mentioned earlier, the Company would use the funds from the equity issuance to cover the cost for the on-going capital projects needed to reliably serve Idaho Power customers. However, had the Company financed those same capital projects with a blend of 50% debt and 50% equity, the cost to customers would be $100 million * (4%*50%+10%*50%) = $7 million plus a gross up for tax ($7 million *(1/(1-0.2574))) = $9.426 million.

Therefore, in this example, customers would be paying an additional $4.04 million ($13.4662M - $9.426M) per year beyond the PPA price due to the imputed debt adjustment. Consequently, because of imputed debt, when evaluating the relative cost of a PPA, regulatory bodies should consider the less-visible added annual customer cost of $40.4 for every $1,000 of imputed debt related to the PPA.

PPAs May Bring Other Hidden Harms to Customers: Most PPAs are much shorter in duration than the physical and economic life of the underlying asset and generally start with a low and attractive cost in the first year but increase every year thereafter. At the end of the PPA Idaho Power must procure a new resource to cover the expiring PPA or renew the PPA at the then current market prices, which may be much higher. The owner of the PPA has the physical asset that hedges the likely increases in market prices and then passes along to customers the higher market-based costs. When Idaho Power owns an asset, customers benefit from locking in the fixed costs over the full life of the underlying asset, and as market prices go up, customers pay less on a nonlevelized basis than they did the first year the resources was in service due to depreciation. Customers also benefit by the assurance that Idaho Power will diligently maintain the asset, potentially extending the use on behalf of customers beyond the expected physical life.

Idaho Power recently performed an analysis using information from our current RFP for an 80 MW resource which compared the lowest PPA cost for solar from the bidders including the renewing of the PPA to match the life of the asset of 35 years as well as adding the impact of imputed debt compared to an ownership option, the company could save customers over $175 million over the 35-year life of the asset and over $30 million customer savings on a net present value basis. See Attachment 5 hereto, incorporated herein by this reference.

Risk of the PPA Failing to Produce or the Resource Not Being Built: Another cost to customers is when a contracted PPA does not actually show up due to circumstances that the Company cannot control, as appears to be the case with Jackpot Solar and its PPA for 120 MW of solar scheduled to be online by December 2022 prior to the currently identified capacity deficits. When the Company relies on a PPA and includes it in its IRPs for a number of years, the cost to replace such a resource without the advantage of the time that the developer had to build-out the resource, can be much more costly and it can create significant operational risks and constraints.

Idaho Power's Request Benefits the Utility and Customers: Once again, we are at a crossroads where the regulatory compact is being challenged , only this time it is not in the form of proposed legislation - it is in the form of non-utility ownership of generation assets, promoted by mechanisms such as PURPA, disproportionate tax incentives and practices, and state-mandated resource procurement rules designed to advantage non-utility generation that act to erode the financial viability of vertically integrated utilities. Ultimately this impacts customers through higher long-term costs and the potential erosion of system reliability. As the Company rapidly transitions from being resource sufficient to the identified capacity deficits in 2023, 2024, and 2025, Idaho Power asks the Commission to recognize and uphold the long-standing and successful regulatory policy of this state as originally set forth in *Bloomquist*, acknowledging the required protection of both the utility and customers from the destructive forces of this emerging form of deregulation , and setting forth regulatory policy acknowledging the customer benefits of utility ownership of supply-side capacity resources under the regulated utility business model.

VI. COMMUNICATIONS AND SERVICE OF PLEADINGS

Communications and service of pleadings with reference to this Application should be sent to the following:

Donovan E. Walker
Lead Counsel
Idaho Power Company
1221 West Idaho Street (83702)
P.O. Box 70
Boise, Idaho 83707
dwalker@idahopower.com
dockets@idahopower.com

Tim Tatum
Vice President, Regulatory Affairs
Idaho Power Company
1221 West Idaho Street (83702)
P.O. Box 70
Boise, Idaho 83707
ttatum@idahopower.com

VII. CONCLUSION

Idaho Power has been in a resource sufficient position for almost a decade since the addition of the Langley Gulch combined-cycle, natural gas-fired power plant, in 2012. Over the course of approximately two months - from the March 2021 acknowledgement of the 2019 IRP to the revised Load and Resource Balance in May of 2021 - Idaho Power rapidly identified near term capacity deficiencies starting in summer 2023 and growing through 2024 and 2025 until the B2H 500 kilovolt transmission line is expected to be operational in 2026. These rapidly emerging capacity deficits are driven by an increasing population and associated emergent demands in the Company's service area; third-party transmission constraints; changes to the assumptions in the L&R balance regarding available transmission capacity following the retirement of coal plants; the unavailability of import transmission capacity on the market; planning margin adjustments associated with incorporating LOLE and ELCC planning methodologies; and the potential diminishing demand response resource and solar effectiveness during peak and critical times.

Idaho Power must meet its obligation to reliably serve customers and must meet those capacity deficits to prevent wide-spread outages in its service area. The Company must do this in a rapidly changing and dynamic environment, with an already short turn-around time to meet deficits in 2023 exacerbated by an environment of global supply chain disruption and issues preventing the timely construction of new resources as well as previously contracted PPA generation from coming online in a timely manner.

Idaho has a long, successful history of state commission regulation of public utility service providers, focused on the public interest and Commission oversight. The Commission's regulation, particularly through the required CPCN and rate-making processes, provides sufficient protection and has benefit for both customers and the Company, and has served Idaho customers and Idaho Power very well for over 100 years. For the reasons cited above in this Application, Idaho Power asks the Commission for authority to move forward expeditiously with the procurement of capacity resources needed to provide adequate, reliable, and fair-priced service to customers to meet the identified capacity deficits in 2023, 2024, and 2025.

VIII. REQUEST FOR RELIEF

Idaho Power respectfully requests that the Commission issue an order authorizing the Company to move forward with the procurement of dispatchable resources needed to secure adequate, reliable, and fair-priced service to customers. More specifically, Idaho Power requests that the Commission issue an order: (1) eliminating the IPUC requirement to comply with OPUC Resource Procurement Rules; (2) authorizing Idaho Power to move forward expeditiously with resource procurements to meet identified generation resource needs in 2023, 2024, and 2025; and (3) affirming support and the continuation of the state of Idaho's system of public utility regulation under which the interests of customers are best served by a vertically integrated electric utility maintaining ownership of the necessary generation, transmission and distribution utility functions, with limited exceptions.

Idaho Power requests that the Commission issue Notice of this Application, set an intervention deadline, and convene a prehearing conference in this matter at its earliest convenience to establish a proper procedure to expedite the orderly conduct and disposition of this proceeding. RP 211.

DATED at Boise, Idaho this 3rd day of December 2021.

Donovan E. Walker

DONOVAN E. WALKER
Attorney for Idaho Power Company