BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR A DETERMINATION ACKNOWLEDGING ITS NORTH VALMY POWER PLANT UNIT 2 EXIT DATE.	)	CASE NO. IPC-E-21-12

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JARED L. ELLSWORTH

Q. Please state your name, business address, and present position with Idaho Power Company ("Idaho Power" or "Company").

A. My name is Jared L. Ellsworth and my business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power as the Transmission, Distribution & Resource Planning Director for the Planning, Engineering & Construction Department.

Q. Please describe your educational background.

A. I graduated in 2004 and 2010 from the University of Idaho in Moscow, Idaho, receiving a Bachelor of Science Degree and Master of Engineering Degree in Electrical Engineering, respectively. I am a licensed professional engineer in the State of Idaho.

Q. Please describe your work experience with Idaho Power.

A. In 2004, I was hired as a Distribution Planning engineer in the Company's Delivery Planning department. In 2007, I moved into the System Planning department, where my principal responsibilities included planning for bulk high-voltage transmission and substation projects, generation interconnection projects, and North American Electric Reliability Corporation's ("NERC") reliability compliance standards. I transitioned into the Transmission Policy & Development group with a similar role, and in 2013, I spent a year cross-training with the Company's Load Serving Operations group. In 2014, I was promoted to Engineering Leader of the Transmission Policy & Development department and assumed leadership of the System Planning group in 2018. In early 2020, I was promoted into my current role as the Transmission, Distribution and Resource Planning Director. I am currently responsible for the planning of the Company's wires and resources to continue to provide customers with cost-effective and reliable electrical service.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to present the near-term economic and reliability impact analyses performed following Idaho Power's Second Amended 2019 Integrated Resource Plan ("IRP") that support an exit from operations of Valmy Unit 2 in 2025 based on currently known information.

Q. What specific action is the Company requesting of the Idaho Public Utilities Commission ("Commission") in this case?

A. As directed by the Commission in Order No. 34349, Idaho Power is requesting the Commission acknowledge its appropriate exit date from Valmy Unit 2 as December 31, 2025, based on information known today. The Company respectfully requests a Commission order no later than September 29, 2021, to allow adequate time for notification to plant operator NV Energy should the Commission determine an earlier exit date of Valmy Unit 2 is appropriate.

I. BACKGROUND

Q. Please describe the Valmy plant.

A. Valmy is a coal-fired power plant that consists of two units and is located near Battle Mountain, Nevada. Unit 1 went into service in 1981 and Unit 2 followed in 1985. Idaho Power owns 50 percent, or 284 megawatts[1] ("MW") (generator nameplate rating), of Valmy. NV Energy is the co-owner of the plant with the remaining 50 percent ownership and operates the Valmy facility. NV Energy and Idaho Power (collectively, the "Parties") work jointly to make decisions regarding Valmy. The plant is connected via a single 345 kilovolt ("kV") transmission line to the Idaho Power control area at the Midpoint substation. Idaho Power owns the northbound capacity and NV Energy owns the southbound capacity of this line.

Q. How have the Parties been operating Valmy?

A. Recently, Valmy has primarily operated as a summer resource and only operates during the winter months

[1] For planning purposes, Idaho Power uses the net dependable capability of 262 MW. It should also be noted that the remaining capacity available to Idaho Power is 134 MW due to the Company's exit of coal-fired operations at Unit 1 at year-end 2019.

if driven by the market. For example, in 2019 when the Mid-Columbia market hub ("Mid-C") prices were high, Valmy was economically dispatched during the winter months to meet load while the excess generation provided customers benefits through off-system sales.

Q. What are the current agreements under which NV Energy and Idaho Power own and operate Valmy?

A. The ownership and operation of Valmy is dictated by three agreements: the Agreement for the Ownership of the North Valmy Power Plant Project ("Ownership Agreement"), the Agreement for the Operation of the North Valmy Power Plant Project ("Operation Agreement"), both of which are dated December 12, 1978, and the North Valmy Station Operating Procedures Criteria, dated as of February 11, 1993, between Idaho Power Company and Sierra Pacific Power Company, as amended by Amendment No. 1 to the Operating Procedure Criteria for Valmy Coal Diversion Procedures and Usage, dated as of January 1, 2012 (collectively, the "Existing North Valmy Agreements"). Additionally, as presented in Case No. IPC-E-19-08, the Parties entered into the North Valmy Project Framework Agreement between NV Energy and Idaho Power dated as of February 22, 2019 ("Framework Agreement"), memorializing the terms and conditions under which either partner may elect exit of participation of Valmy by means of a 15 month notice. Commission Order No. 34349 deemed the Framework Agreement with NV Energy as prudent and commercially reasonable.

Q. What are the current end-of-life assumptions used by the Parties for each Valmy unit?

A. In its 2018 Update to the Life Span Analysis Process of Valmy Units 1 and 2, NV Energy recommended retirement dates of both units at year-end 2025.[2] However, on December 21, 2018, in Docket No. 18-06003, the Public Utilities Commission of Nevada ("Nevada PUC") issued an order adopting NV Energy's 2019-2038 Triennial Integrated Resource Plan, 2019-2021 Action Plan, and 2019-2021 Energy Supply Plan, all of which included an early retirement of Unit 1 on December 31, 2021, under NV Energy's stated conditions[3]. The end-of-life date for Unit 2 remained at year-end 2025.[4] Idaho Power, in the Settlement Stipulation approved by the Commission with Order No. 33771 in Case No. IPC-E-16-24, agreed to use prudent and commercially

---

[2] *Application of Sierra Pacific Power Company d/b/a NV Energy and Nevada Power Company d/b/a NV Energy for approval of its 2017-2036 Triennial Integrated Resource Plan and 2017-2019 Energy Supply Plan, 2016 Annual Demand Side Management Update Report as it relates to the Action Plan of its 2016-2035 Integrated Resource Plan, and the second amendment to its 2016-2035 Integrated Resource Plan and 2016-2018 Action Plan to include the acquisition of the South Point Energy Center, Docket No. 16-07001. Updated Life Span Analysis Process in compliance with Order dated February 16, 2017, filed on February 16, 2018.*

[3] *Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2019-2038 Triennial Integrated Resource Plan and 2019-2021 Energy Supply Plan, Docket No. 18-06003 (December 21, 2018).*

[4] *Nevada PUC Order dated December 21, 2018, Document ID 34967.*

reasonable efforts to end its participation in the operation of Unit 1 by December 31, 2019, and Unit 2 by December 31, 2025.

Q. Did Idaho Power's cessation of coal-fired operations in Unit 1 occur?

A. Yes. On December 31, 2019, the Company's participation in coal-fired operations at Unit 1 concluded. The remaining capacity available to Idaho Power from Valmy Unit 2 is 134 MW.

Q. Does Commission Order No. 34349[5] address the Company's proposed cessation of Unit 2 operations by December 31, 2025?

A. Yes. During review of Idaho Power's Application in Case No. IPC-E-19-08, Commission Staff indicated that they reviewed the Company's Unit 2 closure analysis but did not have adequate information from Idaho Power at the time to determine whether the Company had completed a thorough review of a unit withdrawal date of December 31, 2025. Therefore, Order No. 34349 directed the Company to use best efforts to file within 21 days of the service date of the order: (1) an analysis validating the December 31, 2025, economic retirement date of Unit 2, or

---

[5] *In the Matter of the Application of Idaho Power Company for Authority to Increase Its Rates for Electric Service to Recover Costs Associated with the North Valmy Plant*, Case No. IPC-E-19-08 (May 31, 2019).

(2) an analysis supporting a different economic retirement date of Unit 2.

Q. Did Idaho Power comply with the Commission's directive in Order No. 34349?

A. Yes. On June 27, 2019, the Company filed a request for acknowledgement that it had sufficiently validated the economic retirement date of Valmy Unit 2 as year-end 2025 in Case No. IPC-E-19-18. However, during processing of the case, the Company determined that further review of Idaho Power's 2019 IRP modeling was necessary. Because the 2019 IRP modeling was also used to develop the Valmy Unit 2 closure analysis, the case schedule was suspended while the review was performed. The review of the 2019 IRP modeling ultimately resulted in the filing with the Commission of Idaho Power's Second Amended 2019 IRP.

Q. Did the model updates performed for the Second Amended 2019 IRP impact the Valmy Unit 2 closure analysis?

A. Yes. After performing a revised analysis based on adjustments stemming from the IRP review, certain modeling runs indicated the potential for additional savings from a Valmy Unit 2 exit date as early as year-end 2022. However, the potential savings included a key assumption that firm market purchases from the south of Idaho Power's service area would be available to replace Valmy Unit 2 capacity. This key assumption warranted further examination with regard to economics and reliability. As such, Idaho Power withdrew its Application in Case No. IPC-E-19-18 to perform the additional evaluation of both the economic and reliability impacts of an early Valmy Unit 2 closure. As initially directed by Commission Order No. 34349, the Company is presenting the results of the additional evaluation in this case.

II. <u>THE SECOND AMENDED 2019 IRP</u>

Q. What is the goal of the IRP?

A. As described in the Second Amended 2019 IRP, Idaho Power believes 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, 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.

Q. How are the portfolios developed through the IRP process?

A. Historically, the Company developed portfolios to eliminate resource deficiencies identified in a 20-year load and resource balance. Under this process, Idaho Power developed portfolios which were demonstrated to eliminate the identified resource deficiencies. However, beginning with the Second Amended 2019 IRP, the Company began using AURORA's long-term capacity expansion ("LTCE") modeling capability to develop portfolios.[6]

Q. Please describe the LTCE modeling capability of AURORA.

A. In the Second Amended 2019 IRP, the LTCE modeling capability of AURORA produced portfolios optimized for the Western Electricity Coordinating Council ("WECC") under various future conditions, such as varying natural gas prices and carbon costs. The WECC-optimized portfolios included the addition of supply and demand-side resources for Idaho Power's system while simultaneously evaluating the economics of exiting from current generation units.

Q. What was the outcome of the modeling performed to identify the Preferred Portfolio in the Second Amended 2019 IRP?

A. As part of this robust method of assessing future resource options over a two-decade time frame, the Preferred Portfolio was derived from a combination of two AURORA LTCE-produced portfolios that were manually optimized for Idaho Power under Planning Gas and Planning Carbon conditions with the selection of the Boardman to Hemingway ("B2H") transmission line. Although the AURORA modeling consistently showed an economic exit of Valmy Unit

---

[6] Case No. IPC-E-19-19.

2 in 2025 in WECC-optimized runs, the refinement of these analyses specific to Idaho Power's service area suggested the potential for additional savings from earlier exit dates.

Q. What were the potential savings associated with a 2022 Valmy Unit 2 exit as identified in the Second Amended 2019 IRP?

A. The long-term analysis performed as part of the Second Amended 2019 IRP suggested net present value savings of approximately $3 million associated with a Valmy Unit 2 exit in 2022 due to the avoided capital investment and net operations and maintenance ("O&M") reductions compared to a year-end 2025 exit.

Q. In the event of a Valmy Unit 2 exit prior to 2025, what are the notification requirements under the Framework Agreement?

A. Under the terms of the Framework Agreement, to exit operations of Unit 2, Idaho Power is required to provide NV Energy notice 15 months in advance of the Company's date to cease participation in coal-fired operations. Therefore, for a year-end 2022 exit date, Idaho Power would be required to provide NV Energy notice by September 30, 2021.

Q. Based on the results of the Second Amended 2019 IRP, was it the recommendation of the Company to proceed with providing NV Energy notice of cessation of participation in coal-fired operations of Valmy Unit 2 based on the long-term analysis results?

A. No. As presented in the Second Amended 2019 IRP, Idaho Power does not believe that the potential savings based on a long-term analysis should be the sole consideration in the decision to exit Valmy Unit 2. Once the exit notice is given, it cannot be withdrawn.

Q. What considerations did Idaho Power suggest evaluating in addition to the long-term analysis?

A. A key component of the Second Amended 2019 IRP that allowed for the exit of Valmy Unit 2 at year-end 2022 was the availability of firm market purchases from the south of Idaho Power's service area over the transmission path currently utilized by Idaho Power's share of the Valmy plant output. While the Company considered the availability of wholesale energy for import across the Idaho to Nevada path as less certain, it had been considered as a potential to source seldom-needed capacity during peak-loading periods. As discussed later in my testimony, Idaho Power subsequently evaluated this assumption in light of recent changes in regional transmission availability.
Additionally, as part of the Valmy Unit 2 exit discussion included in the Second Amended 2019 IRP, the Company indicated economic and reliability impacts of an earlier

Unit 2 exit must be evaluated using data points such as forward market hub price forecasts, planned unit outages, and recent market conditions. The objective of these analyses is to identify any tradeoffs between an earlier exit date and the ability to provide reliable, affordable power.

III. VALMY UNIT 2 EXIT ANALYSIS

Q. Has Idaho Power completed the analysis of the reliability and economic impacts associated with an exit of Valmy Unit 2 prior to year-end 2025?

A. Yes. 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 intent of these analyses is to ensure customer reliability, while considering more current operating budgets and up-to-date economics, to inform a decision that will minimize costs for customers while also maintaining system reliability.

Q. Did the Company evaluate exit dates beyond 2025?

A. No. Under the Framework Agreement with NV Energy, and the Settlement Stipulation approved by the Commission with Order No. 33771, the Company agreed to cease coal-fired operations of Unit 2 by December 31, 2025.

Therefore the analyses performed in this case only apply to the years between 2022 and 2025.

Q. Please summarize the Company's approach to the reliability and economic impact analyses.

A. Idaho Power began the analysis with an evaluation of system reliability, as the Company must first ensure dependable capacity resources exist to meet expected load. Next, Idaho Power analyzed the economics of various portfolios with resources that could replace the Company's existing 134 MW at Valmy Unit 2. The result of the reliability and economic evaluations is the most reliable and economic path toward an exit from coal-fired operations of Valmy Unit 2.

IV. RELIABILITY EVALUATION

Q. Why is a reliability analysis necessary?

A. Reliability is the foundation for any resource plan; the Company must ensure it has sufficient resources to meet customer demand. It is critical when comparing future resource portfolios that each plan achieve a base reliability threshold. To analyze the reliability impacts associated with an early exit from coal-fired operations at Valmy Unit 2, Idaho Power (1) refined the load and resource balance to determine any resource deficiencies, (2) enhanced the approach to computing the planning margin, and

(3) identified multiple options to replace the 134 MW of firm capacity in the absence of Valmy Unit 2.

Load and Resource Balance

Q. Please explain the "load and resource balance".

A. The load and resource balance is the Company's operational plan that identifies resource deficiencies during the 20-year IRP planning horizon. It incorporates the expected availability of Idaho Power's existing resources, comparing the total output to the Company's forecasted load, and computes the resulting surplus or deficit by month. This will identify the Company's first resource need date, or the point at which Idaho Power's reliability requirements may not be met. The availability of existing resources, including Public Utility Regulatory Policies Act ("PURPA") projects, power purchase agreements, hydro, coal, gas, demand response, and market purchases, is determined using a number of factors such as expected stream flows, plant run times, forced outages, and transmission availability, among other considerations.

Q. What is the purpose of the load and resource balance?

A. The load and resource balance ensures Idaho Power has sufficient resources to meet projected customer demand plus a margin to account for extreme conditions and resource outages. It is critical when comparing future resource portfolios that each plan achieve at least a base reliability threshold.

Q. Did Idaho Power make any adjustments to the load and resource balance used in the Second Amended 2019 IRP as part of the Valmy analysis presented in this case?

A. Yes. Because development of the 2021 IRP is occurring simultaneously to the Valmy Unit 2 reliability and economic impact analyses, the load and resource balance was updated to include modifications to existing resource availability, as is standard when developing the load and resource balance as part of the IRP process.

Q. Please describe the modifications to the existing resource availability.

A. First, the Company identified changes to its market purchase assumptions, which I will discuss later in this section. Additionally, the existing resource availability was revised to include updated thermal capacity and reduced demand response capacity determined through the refinement of the planning margin calculation, which I will explain later in my testimony. The net change between the Second Amended 2019 IRP and the updated load and resource balance is a reduction of approximately 480 MW - 500 MW in available capacity each July during the 2022 through 2025 time period.

Q. What market purchases assumptions have been used to develop the load and resource balance?

A. To explain the market purchase assumptions, it is necessary to first describe the regional transmission market in general. Transmission lines connect Idaho Power to wholesale energy markets and help economically and reliably mitigate variability of intermittent resources through the transfer of electricity between utilities, not only to serve load, but also to share operating reserves.

Q. Please describe the Company's transmission system.

A. Exhibit No. 1 presents Idaho Power's transmission system, with the thick black lines representing the boundaries. The Company owns the transmission assets within the boundaries and thus can reserve transmission within this area to serve load. However, once outside the boundaries, Idaho Power must reserve transmission from third-party entities which is subject to availability.

Historically, the Company experiences its peak load at different times of the year than most Pacific Northwest utilities. As a result, Idaho Power can purchase energy from Mid-C during its peak and sell excess energy to the Pacific Northwest utilities during their peak. Although energy is plentiful at the Mid-C market, imports from Mid-C are frequently limited by transmission availability. The proposed Boardman to Hemingway ("B2H") project would greatly increase this transmission capacity.

Q. What transmission paths are available to Idaho Power to bring energy in from Mid-C?

A. The Company typically imports energy from Mid-C during the summer months from the west on the Idaho to Northwest transmission path. A portion of this transmission capacity is reserved by BPA to serve their southern Idaho customers. Energy can be brought in from Mid-C via Montana on the Idaho to Montana path as well, which consists of two lines to the Northeast of the Company's system.

Q. Does Idaho Power have options to purchase energy from the southern markets?

A. Yes. South of Idaho are the Mead, Palo Verde, and Four Corners market hubs, collectively referred to as the Southern Hubs. However, the Company infrequently purchases energy from the Southern Hubs as the southern utilities are also summer peaking, increasing demand in the region thus creating unfavorable pricing. In addition, a purchase from the Southern Hubs will often require multiple transmission wheels that can be difficult to obtain due to transmission availability constraints. The Idaho to Sierra path, the path that energy from the Valmy 345 kV line connects to, and the Idaho to Utah path, which has more line interconnections, also run to the south of Idaho Power's transmission system.

Q. Is there firm transmission availability south of Idaho for the Company to access the Southern Hubs?

A. Currently there is no firm transmission capacity available across NV Energy's transmission system, and, other than an existing 50 MW Idaho Power reservation across the PacifiCorp East system, there is limited availability through Utah.

Q. Does Idaho Power anticipate any firm transmission capacity availability south of Idaho in the near-term?

A. No. There is, however, a chance that a power marketer may control some of this transmission capacity south of Idaho and wish to sell energy to the Company. Idaho Power's intention is to test this possibility with a market request for proposals ("RFP"), which I will discuss later in my testimony.

Q. In the Second Amended 2019 IRP, the Company assumed Valmy Unit 2 could be replaced with capacity purchases from the south. What has changed?

A. Market conditions have changed dramatically in the south because of ripple effects stemming from the energy emergency event in California in August 2020 ("August 2020 event").

Q. What happened during the California energy emergency event?

A. During August 2020, 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 reliability and the security of the bulk power system.

Q. How did this impact Idaho Power's transmission system?

A. Understanding the importance of transmission availability during times of high electricity demand, third-party marketing firms began reserving 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, enabling these third-party marketing firms to move energy from Mid-C across Idaho Power's transmission system to the south. These transmission service requests have been overlaid on the Company's transmission system map to illustrate the flood of requests in Exhibit No. 2.

Q. Why would the third-party marketing firms request transmission service on paths from Mid-C to the south when energy from the Southern Hubs would likely require fewer wheels?

A. A comparison of the summer market forward prices between the two hubs demonstrates why it is likely the marketing firms saw the opportunity at Mid-C. The following table presents a comparison of the heavy load hour forward prices, in costs per megawatt-hour ("MWh"), between Mid-C and Palo Verde as of March 2021:

Table 1. Forward Market Prices, March 2021

	Mid-C	**Palo Verde**
July, 2021	[redacted]	[redacted]
August, 2021	[redacted]	[redacted]
July, 2022	[redacted]	[redacted]
August, 2022	[redacted]	[redacted]

With a wheeling cost of approximately $3.42 per MWh to use Idaho Power's transmission system, marketing firms are able to economically deliver energy from Mid-C and sell to summer peaking utilities in the south even with multiple wheeling charges.

Q. Does this also impact Idaho Power's ability to access the Mid-C market?

A. Yes. The transmission service requests have added to an already constrained market limiting the Company's access to Mid-C. However, as I will discuss later in my testimony, Idaho Power is testing the market availability with the RFP issued April 26, 2021, to further assess these transmission system constraints. Because a key assumption used to develop the load and resource balance for the Second Amended 2019 IRP was that Idaho Power's exit from coal-fired operations at Valmy would free up transmission capacity for imports to Idaho from the south, it is essential that the Company update the transmission availability assumptions used in the development of the load and resource balance to reflect these recent changes.

Q. What was the net reduction in transmission capacity availability incorporated into the updated load and resource balance for the analysis review period?

A. For the years 2022 through 2025, Idaho Power reduced the transmission availability within the load and resource balance by approximately 140 MW to 277 MW during the peak load month of July.

Planning Margin

Q. What is Idaho Power's planning margin?

A. 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 10 years, the industry standard. The planning margin is intended to cover (1) Idaho Power's contingency reserve obligation, (2) severe weather events, both extreme heat and extreme cold, (3) poor water conditions, and (4) planned and unplanned resource and transmission outages.

Q. How did the Company compute the planning margin in the Second Amended 2019 IRP?

A. In the Second Amended 2019 IRP, Idaho Power established a 15 percent planning margin. Planning margin was calculated as 15 percent of the Company's average (50^{th} 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).

Q. Is Idaho Power considering any enhancements to the planning margin utilized in the Second Amended 2019 IRP to meet reliability requirements as part of the Valmy Unit 2 reliability analyses?

A. Yes. Following the development of the Second Amended 2019 IRP, the Company looked to refine its planning margin 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 planning margin. Rather than continue to utilize this "rule of thumb" planning margin, the Company used probabilistic methods in the Valmy Unit 2 exit analysis to determine system needs to ensure reliability for all hours of the day on the Company's system, referred to as the Loss of Load Expectation ("LOLE") method.

Q. What is the LOLE approach for determining the planning margin to meet reliability requirements?

A. The LOLE approach allows for a comparison of load to generation on an hourly basis over a specified period. The industry standard to planning is no more than one loss of load event per 10 years, or an LOLE of 0.1 days per year[7].

Q. Why does Idaho Power believe the hourly approach of the LOLE calculation for determining planning margin improves upon the previous method from the Second Amended 2019 IRP?

---

[7] The Southwest Power Pool, PJM Interconnection, and the Midcontinent Independent System Operator are among those that use this probabilistic approach.

A. The Company believes the LOLE method's hourly approach fully considers the reliability value of renewable resources over time compared to the previous method. Table 2 below utilizes the forecasted peak day in 2023 to illustrate the importance of an hourly approach in determining planning margin requirements.

Table 2. Planning Margin Example[8]

		A	B	C	D
		2023 Peak Day at 5 PM	**2023 Peak Day at 9 PM**	**2023 Peak Day at 10 PM**	**2023 Peak Day at 11 PM**
1	**Demand**	(3,672)	(3,357)	(3,272)	(3,100)
2	**Resources (w/o Solar & Wind)**	2,774	2,763	2,766	2,754
3	**Demand Response**	340	40	0	0
4	**Solar**	243	0	0	0
5	**Wind**	69	111	133	95
6	**Market Need**	**(246)**	**(443)**	**(373)**	**(251)**

Row 1 reflects the system demand. Column A presents the calculation of the deficit when only considering the daily resource availability. Demand response and solar are helping meet the peak demand hour with the aid of some wind resources, reducing the deficit and resulting market need to 246 MW.

[8] Forecasted demand and resource values are representative and subject to change.

Columns B, C and D present measurements on the same peak day, but in three different hours. As can be seen, by 9 PM, most of the demand response is no longer available as many of the Company's existing programs have ended and solar has dropped to zero because the sun has set. Although wind generation has increased, the deficit has increased to 443 MW. While not the peak demand hour, in this example 9 PM is the "net peak" hour for the system, i.e. the peak demand net of variable resources and demand response. By 11 PM, when the decrease in load experienced during late evening hours has been reflected, coupled with the increased wind generation, the deficit reduces to 251 MW. The hour-by-hour look better reflects the variability of renewable resources on the system and will better inform Idaho Power of its resource needs.

Q. Aside from taking a more granular hourly approach, are there other components of the LOLE method that impacted the Company's determination of resource needs?

A. Yes. The LOLE method also evaluates the capability of existing resources to meet peak demand through the determination of Effective Load Carrying Capability ("ELCC").

Q. Did the use of the ELCC result in any changes to the peak-serving capability of Idaho Power's existing resources?

A. Yes. When analyzing Idaho Power's system on an hour-by-hour basis, the results indicate the ability of demand response 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 demand response program window.

Q. Does the Company plan on using the LOLE approach when determining reliability requirements for the 2021 IRP?

A. Yes, the LOLE approach will be used for meeting reliability requirements over the 20-year planning horizon in development of the 2021 IRP. For purposes of the reliability analysis associated with a Valmy Unit 2 exit date, Idaho Power performed the LOLE analysis for the years 2023 and 2025.

Q. What capacity deficits were identified as a result of the LOLE study performed for the years 2023 and 2025?

A. Utilizing the new ELCC values and the updated transmission assumptions, the load and resource balance shows a deficit of 381 MW in July 2023 and a deficit of 490 MW in July 2025. It should be noted that these deficits reflect resource actions from the Second Amended 2019 IRP: the exit of Valmy Unit 2 and one unit at the Jim Bridger Power Plant ("Bridger") at year-end 2022, and the addition of Jackpot Solar in 2023.

Q. You previously stated Idaho Power's current share of Valmy Unit 2 is 134 MW. Based on the results of the LOLE analysis, is Idaho Power able to exit Valmy Unit 2 at the end of 2022 while meeting its reliability threshold?

A. No. Given the capacity deficits of 381 MW and 490 MW in 2023 and 2025, respectively, with assumed unit exits at Valmy and Bridger, it is not feasible to exit coal-fired operations at Valmy Unit 2 at year-end 2022 without procuring additional firm capacity, which I will discuss in the following section.

<u>Options for Meeting Reliability Needs</u>

Q. How did the Company evaluate options for meeting reliability needs given the fact that Idaho Power's share of capacity at Valmy Unit 2 is 134 MW, and previously identified capacity deficits are 381 MW in 2023 and 490 MW in 2025?

A. The intent of this case is to determine the appropriate exit date for Valmy Unit 2 and its associated 134 MW of firm capacity. Therefore, when evaluating options for meeting reliability needs, the Company considered effective replacements for the 134 MW of firm capacity at Valmy Unit 2. The 2021 IRP currently in development will be utilized to address the broader capacity needs.

Q. Please describe in general the Company's approach for evaluating options for meeting reliability needs.

A. The results of the LOLE analysis indicate that exiting from Valmy Unit 2 at year-end 2022 results in a capacity deficit. Therefore, an initial option is to delay the exit from this unit given the identified need for firm capacity for 2023 through 2025 and retain the existing 134 MW to meet expected capacity needs. The Company then evaluated other options to provide the 134 MW in firm capacity in place of retaining Valmy Unit 2 operations through 2025.

Q. What other options did Idaho Power evaluate for meeting reliability requirements other than delaying the exit of Valmy Unit 2?

A. There are a number of other potential options for meeting the reliability hurdle in addition to the delay in the exit of coal-fired operations of Valmy Unit 2, including firm market imports through transmission interconnections, new internal resources, an expanded demand response program, or delaying the 2022 exit from the

Bridger unit to 2025. The economic analysis of each of these options is presented later in my testimony.

Q. You stated earlier that forward market prices in the Southern Hubs were significantly higher than Mid-C. Why are you indicating the possibility a market import will ensure the Company meets the reliability requirements when it appears to be very costly?

A. As I discussed earlier, forward market prices of heavy load hours at Palo Verde are forecast to be nearly four-times the price of Mid-C in 2021. However, the pricing forecasted at Palo Verde settles after a few years. When examining heavy load hour forward market prices at Palo Verde, by 2023 the prices drop near $[redacted]/MWh, and below $[redacted]/MWh in 2024 and 2025. Given this price trend, and the ability to purchase targeted quantities of energy through a market purchase, it is possible that the Southern market hubs could allow for a more cost-effective approach than delaying the exit of Valmy Unit 2.

Q. How will Idaho Power determine whether transmission availability exists to import from the market to maintain reliability and at a price that is economical?

A. The Company issued an RFP on April 26, 2021, with responses due May 4, 2021, for the delivery to Idaho of firm capacity and energy during the summer months through 2025.

Q. How will the Company incorporate the results of the RFP into this proceeding?

A. Given the timing constraints associated with the September 30, 2021, deadline for notice to NV Energy, Idaho Power is filing this case concurrently with the processing of the RFP. This will allow the Commission and interested stakeholders to begin reviewing the Company's case without delaying the filing date. Upon conclusion of the RFP, the Company will evaluate the various proposals received and supplement its filing in this case in June 2021 to inform stakeholders of proposals received.

V. ECONOMIC ANALYSIS OF RESOURCE OPTIONS

Q. What was the nature of the economic analysis performed for this case?

A. Any number of resources can be added to a resource portfolio, and, provided the resource portfolio meets or exceeds the reliability threshold, the costs of the various portfolios can be compared. Idaho Power evaluated the costs of portfolios under the various scenarios for replacing generation from an early exit of Valmy Unit 2 and identified the portfolio that is least-cost and least-risk to the Company and its customers.

Q. Please describe each of the portfolios analyzed.

A. Idaho Power analyzed four portfolios, each with the addition of a different resource in 2023 to replace the exit from Valmy Unit 2 at year-end 2022, and compared the cost of each to the portfolio cost of exiting Valmy Unit 2 at year-end 2025: (1) a Valmy Unit 2 exit in 2022 with the addition of solar plus battery storage in 2023 ("Solar Plus Battery Portfolio"), (2) a Valmy Unit 2 exit in 2022 with the addition of only battery storage in 2023 ("Battery Portfolio"), (3) a Valmy Unit 2 exit in 2022 with an expansion of Idaho Power's existing demand response programs in 2023 ("Demand Response Portfolio"), and (4) a Valmy Unit 2 exit in 2022 with a delayed Bridger unit exit from 2022 to 2025 ("Bridger Portfolio").

Q. Why did Idaho Power not consider a portfolio that includes a new thermal resource such as natural gas?

A. The Valmy Unit 2 exit analysis is focusing on the near-term with a resource on-line date of 2023. The Company assumes it is not feasible to permit and install a natural gas resource prior to the summer of 2023. Instead, Idaho Power focused on those resources that could be located within its transmission system area, constructed, and online by 2023.

Portfolio Cost Development

Q. How were the portfolio costs determined?

A. Idaho Power used AURORA, the Company's electric modeling forecasting and analysis software, to quantify the total portfolio costs of each of the portfolios for the 2022 through 2025 time period.

Q. Is Idaho Power utilizing the LTCE functionality in AURORA to inform the analysis in this case?

A. No. As mentioned previously, the LTCE functionality of AURORA is utilized in the Company's long-term 20-year planning analysis to construct the least-cost, least-risk portfolio. Because the Company's analysis in this case is limited to the time period 2023 to 2025, and because the suite of viable options is limited as discussed previously, the Company is utilizing AURORA solely to determine the relative cost performance of the identified portfolios.

Q. What cost inputs did Idaho Power use for this analysis?

A. The Company used the most up-to-date cost information possible for the economic analysis. Although work to update inputs for the 2021 IRP has begun, this work is still in progress. Therefore, Idaho Power updated AURORA with those inputs it typically updates when preparing a base net power supply expense update, including variable coal costs, natural gas prices, and the load forecast. The breadth of this update is appropriate given the limited use of AURORA in this case.

Q. Did the Company update the relevant Valmy fixed costs associated with the various portfolios?

A. Yes. For the base portfolio, the Valmy Unit 2 exit of 2025, the fixed costs defined by the Framework Agreement that are Idaho Power's responsibility should the Company continue participation in coal-fired operations in Unit 2 through 2025 are not included in the AURORA modeling, therefore they must be added to the variable costs from AURORA to determine the total base portfolio cost.

Q. How were the fixed costs associated with the Solar Plus Battery Portfolio determined?

A. The Solar Plus Battery Portfolio costs are based on the dollar per MW cost of a solar array and an associated dollar per MW cost of a battery storage project, including the 26 percent Investment Tax Credit ("ITC")[9]. The fixed costs reflect information gathered from industry data, peer utilities, and regional developers. The fixed cost inputs for the Solar Plus Battery Portfolio include costs for a 134 MW solar/134 MW battery project to

[9] Currently, the ITC is scheduled to begin phasing out over the next two years. However, President Biden's infrastructure proposal would extend the phasedown for an additional 10 years, if approved.

sufficiently replace the peak capacity of Valmy Unit 2 during the 2023 through 2025 time period.

Q. Please explain the fixed costs associated with the Battery Portfolio.

A. The Battery Portfolio fixed costs are based on the cost of a 134 MW battery-storage project. Idaho Power used the battery fixed cost component determined for the Solar Plus Battery Portfolio in the modeling of the Battery Portfolio, however no ITC savings were modeled. ITC's only occur with a combined solar and battery project. The results of the information gathered and Idaho Power's determination of the fixed cost input can be found in Exhibit No. 3. Similar to the Solar Plus Battery Portfolio, one 134 MW battery storage project is modeled in AURORA for the equivalent replacement of Valmy Unit 2 capacity.

Q. How did the Company compute the fixed costs associated with the Demand Response Portfolio?

A. The Demand Response Portfolio fixed costs are based on the expansion of Idaho Power's existing demand response programs. The Company estimated the incremental program costs associated with an additional 50 MW of demand response, including estimated increases in labor, incentive expenses, and device costs for the three programs and grew those linearly up to the 134 MW of Valmy Unit 2 capacity.

Q. Why was the initial estimate of the Demand Response Portfolio fixed costs based on a program expansion of only 50 MW?

A. The initial estimate was based on 50 MW because Idaho Power believes an expansion of the three existing demand response programs above 50 MW may not be feasible at this time based on current participation and cost-effectiveness levels. Further, as was mentioned earlier in my testimony, the ability for demand response under current program parameters to meet peak load capacity need is diminishing over time making it increasingly challenging to maintain existing demand response capacity. That said, in order to provide a conservative estimate of the cost of a hypothetical program expansion equivalent to the generation capacity of Valmy Unit 2, the Company extrapolated the 50 MW expansion cost estimate to 134 MW. The Company will be evaluating the potential for further demand response expansion and associated cost in its 2021 IRP.

Q. Why did the Company evaluate expanding the demand response programs in this study rather than modifying existing programs to increase their ELCC?

A. The Company is currently studying potential modifications to the existing demand response programs. The extent of the proposed modifications, and resulting impact to customer participation, are uncertain at this point, but will likely impact the load and resource balance. The purpose of analyzing an expanded demand response option in this case is to provide a comparison of the cost effectiveness between operating Valmy Unit 2 through 2025 and the expansion of demand response, in general.

Q. Did the fixed costs for the Bridger Portfolio incorporate existing plant values?

A. Yes. The fixed costs assumed for the Bridger Portfolio include the plant values associated with one Bridger unit that would still need to be recovered once the unit is retired.

Q. What are the total portfolio costs for each of the four portfolios modeled as compared to the base portfolio that included operations of Valmy Unit 2 through 2025?

A. Table 3 presents the results of the economic analysis, detailing the total portfolio costs of each scenario modeled as compared to the base portfolio.

///

///

///

///

///

///

Table 3. Economic Analysis Results

Modeled Scenarios – Adjustments from the Second Amended 2019 IRP Preferred Portfolio	**Results as Compared to 2025 Valmy Unit 2 Exit**
2025 Valmy 2 Exit	$-
2022 Valmy 2 Exit – Capacity Replaced with Solar + Battery (2023)	$28.09 million
2022 Valmy 2 Exit – Capacity Replaced with Battery (2023)	$30.78 million
2022 Valmy 2 Exit – Capacity Replaced with Expanded Demand Response[10] (2023)	$23.70 million
2022 Valmy 2 Exit – Capacity Replaced with Delayed Bridger Exit (2022 → 2025)	$15.89 million

As can be seen, the results are portfolio costs in the range of approximately $15.89-$30.78 million more than the base portfolio.

Q. What conclusions can be drawn from these results?

A. These results indicate that the modeled scenarios are not more economically beneficial to meet Idaho Power's reliability needs through 2025 than retaining Valmy Unit 2.

VI. RECOMMENDATION

Q. Please summarize the results of the reliability and economic impact analyses performed by the Company.

[10] Assumes 134 MW of demand response program expansion at existing cost-effectiveness levels. Idaho Power is uncertain if this amount of program expansion at assumed cost effectiveness levels is achievable. Further, the ability for demand response under current program parameters to meet peak load capacity need is diminishing over time making it increasingly challenging to maintain existing demand response capacity.

A. The Company conducted focused, near-term system reliability and economic analyses on the timing of a Valmy Unit 2 exit between 2022 and 2025. The goal of the analyses was to use current operating budgets and up-to-date economics to inform a Valmy exit decision that will minimize costs for customers and maintain system reliability. After refining the load and resource balance and performing an LOLE analysis, it is clear that Idaho Power is unable to meet reliability requirements if participation in coal-fired operations of Valmy Unit 2 ceases in 2022 without procuring an alternate source of peak capacity. The Company identified four alternatives to delaying a Unit 2 exit of Valmy until 2025 and performed an economic analysis on the resulting portfolio costs. The results indicate that operating Valmy Unit 2 through 2025 costs approximately $15.89 million less on a net present value basis than the least-cost feasible alternative.

Q. Is it the Company's recommendation that participation of coal-fired operations in Valmy Unit 2 continue during the 2023 through 2025 time period?

A. Yes. However, once results of the RFP are received, and portfolio costs associated with any feasible market purchases are determined, the Company will supplement its filing in this case.

Q. Will Idaho Power continue to evaluate a Valmy Unit 2 exit prior to 2025?

A. Yes. The Company will continue to evaluate an early exit of Unit 2 as part of the 2021 IRP. The timing of the 2021 IRP appropriately aligns with Idaho Power's notification requirement to NV Energy beyond the September 2021 deadline should the results indicate an exit at year-end 2023 or 2024 is least-cost and continues to meet reliability requirements.

VII. <u>CONCLUSION</u>

Q. Please summarize your testimony.

A. As the Company committed in the Second Amended 2019 IRP, Idaho Power performed near-term economic and reliability impact analyses to determine the appropriate exit date from Valmy Unit 2. Pending the results of the market RFP, the current results of the resource alternative analyses support an exit from operations of Valmy Unit 2 in 2025. Therefore, the Company requests Commission acknowledgement that, based on information known at this time, the appropriate exit date from Valmy Unit 2 is December 31, 2025. A Commission order issued no later than September 29, 2021, will allow Idaho Power adequate time to notify NV Energy should the Commission direct Idaho Power to pursue an earlier exit date of Valmy Unit 2.

Q. Does this complete your testimony?

DECLARATION OF JARED L. ELLSWORTH

I, Jared L. Ellsworth, declare under penalty of perjury under the laws of the state of Idaho:

1. My name is Jared L. Ellsworth. I am employed by Idaho Power Company as the Transmission, Distribution & Resource Planning Director for the Planning, Engineering & Construction Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 1-3 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony and exhibits are true and accurate.

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence before the Idaho Public Utilities Commission and is subject to penalty for perjury.

SIGNED this 30th day of April 2021, at Boise, Idaho.

Signed:

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

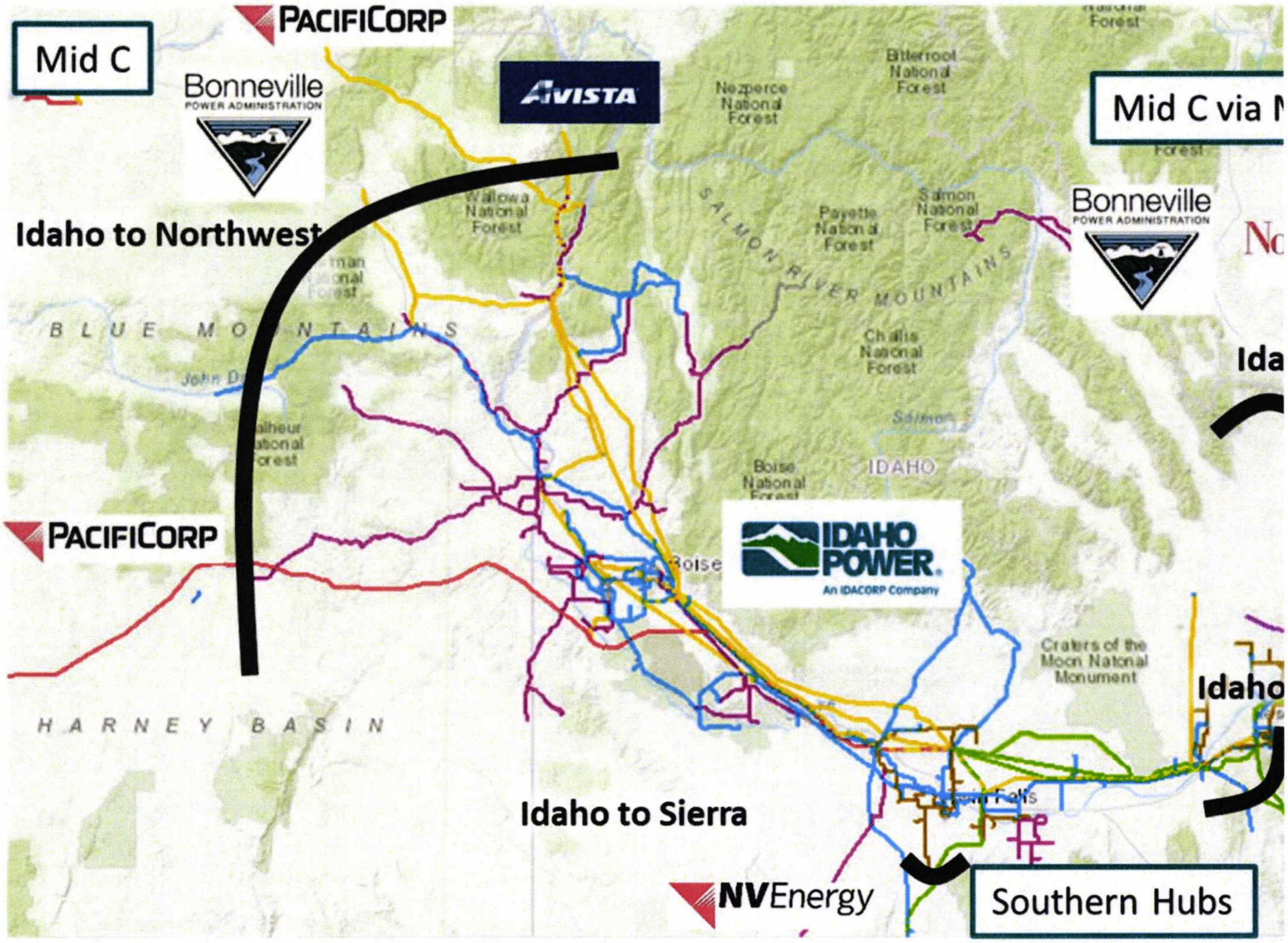
CASE NO. IPC-E-21-12

IDAHO POWER COMPANY

ELLSWORTH, DI
TESTIMONY

EXHIBIT NO. 1

IDAHO POWER'S TRANSMISSION SYSTEM



BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

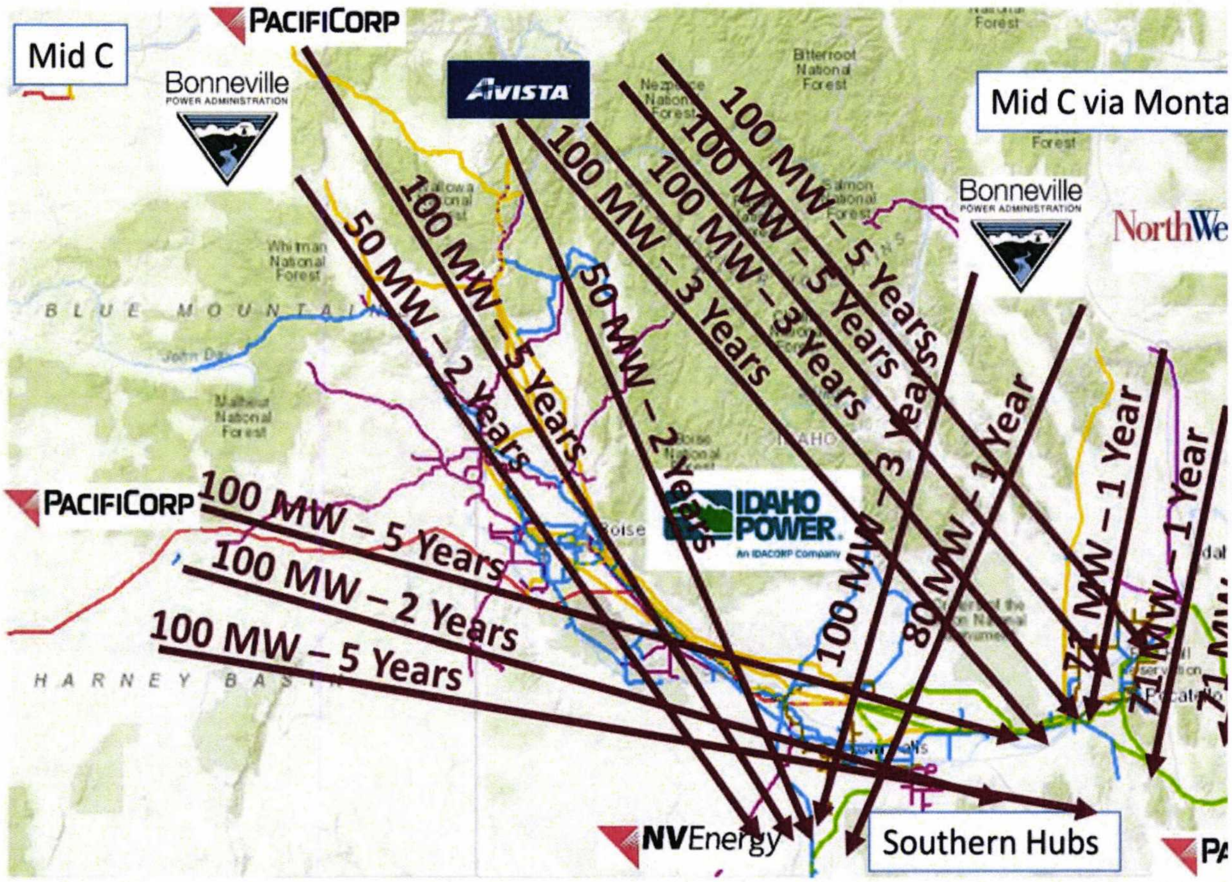
CASE NO. IPC-E-21-12

IDAHO POWER COMPANY

ELLSWORTH, DI
TESTIMONY

EXHIBIT NO. 2

TRANSMISSION SERVICE REQUESTS



BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-21-12

IDAHO POWER COMPANY

ELLSWORTH, DI
TESTIMONY

EXHIBIT NO. 3

BATTERY STORAGE FIXED COST DETERMINATI

Source	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-month)	Va
2019 IRP	1,973	0.78	
NREL ATB 2020	1,118 - 1,463	2.33 - 3.05	
2021 IRP[1]	1,150	2.49	
Avg Developer Cost 2021	1,100	N/A	
Regional Benchmark	1,000 - 1,828	2.30 - 4.12	

[1] Preliminary cost. Subject to change during development of the 2021 IRP.