McDOWELL RACKNER GIBSON PC
419 SW 11th Ave, Suite 400 | Portland, OR 97205

JENNIFER MILLER
Direct (503) 595-3927
jennifer@mrg-law.com

August 4, 2021

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, Oregon 97308-108

Re: Docket No. LC 74 – Idaho Power Company's 2019 Integrated Resource Plan ("IRP")

Attention Filing Center:

Attached for filing in the above-captioned docket is Idaho Power Company's Valmy Unit 2 Exit Analysis.

Please contact this office with any questions.

Thank you,

Jennifer Miller
Legal Assistant

Attachment

Valmy Unit 2 Exit Analysis

August 2021

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Glossary of Acronyms

B2H—Boardman to Hemingway
ELCC—Effective Load Carrying Capability
kV—Kilovolt
kW—Kilowatt
IRP—Integrated Resource Plan
ITC—Investment Tax Credit
LOLE—Loss of Load Expectation
LTCE—Long-Term Capacity Expansion
MW—Megawatt
MWh—Megawatt-hour
O&M—Operations and Maintenance Expense
OPUC—Public Utility Commission of Oregon
RFP—Request for Proposals
WECC—Western Electricity Coordinating Council

1. Summary

Idaho Power filed its Second Amended 2019 Integrated Resource Plan (IRP) with the Public Utility Commission of Oregon (OPUC or Commission) on October 2, 2020. In the action plan of the Second Amended 2019 IRP, Idaho Power identified the need to conduct focused economic and system reliability analysis regarding the timing of exit from Valmy Unit 2. Therefore, in compliance with Order No. 21-184, which acknowledged the Company's Second Amended 2019 IRP, Idaho Power submits this report detailing the results of the system reliability and economic analyses performed for Valmy Unit 2.

In developing the modeling runs for the Second Amended 2019 IRP, cost analyses specific to Idaho Power suggested that exiting Valmy Unit 2 in 2022, rather than the existing date of 2025, would provide approximately $3 million on a total system basis in Net Present Value savings due to avoided capital investment and net operations and maintenance (O&M) reductions. However, as the Company noted in its Second Amended 2019 IRP, potential savings based on a long-term analysis should not be the sole consideration. Rather, near-term economic and reliability impacts of an earlier exit must also be evaluated using data points such as forward market hub price forecasts, planned unit outages, and recent market conditions, among other items. Therefore, the Company performed the analysis presented in this report with the objective of identifying any tradeoffs between an earlier exit date and the ability to provide reliable, affordable power. As discussed in detail in this report, the results of this analysis support an exit from operations of Valmy Unit 2 in 2025.

2. The North Valmy Power Plant

The North Valmy Power Plant (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. Recently, Valmy has primarily operated as a summer resource and only operates during the winter months if driven by the market.

[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.

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, 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. 19-341 deemed the Framework Agreement with NV Energy as prudent and commercially reasonable.

Valmy End-of-Life Assumptions

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 Stipulation approved by the Commission with Order No. 17-235 in Docket No. UE 316, agreed that a 2025 closure expectation of Valmy reflects prudent planning but that the Company would continue to conduct ongoing analyses to evaluate the economics of an earlier retirement for one or both units.

In Advice No. 18-02, the Commission approved Idaho Power's request to update the revenue requirement on Valmy investments to reflect the Company's accelerated exit from coal-fired operations of Valmy Unit 1 by year-end 2019. On December 31, 2019, the Company's

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[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.

participation in coal-fired operations at Unit 1 concluded. The remaining capacity available to Idaho Power from Valmy Unit 2 is 134 MW.

3. The Second Amended 2019 Integrated Resource Plan

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. 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. The LTCE modeling capability of AURORA produced portfolios optimized for the 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.

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 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 due to the avoided capital investment and net O&M reductions compared to a year-end 2025 exit. However, as presented in the Second Amended 2019 IRP, Idaho Power no longer believes that it is economic or reliable to exit Valmy Unit 2 in 2022 as discussed in more detail below.

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 this report, 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.

4. Valmy Unit 2 Exit Analysis

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 analyses performed only apply to the years between 2022 through 2025 because, under the Framework Agreement with NV Energy, the Company agreed to cease coal-fired operations of Unit 2 by December 31, 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. 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.

Reliability Evaluation

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

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. 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.

Idaho Power adjusted the load and resource balance used in the Second Amended 2019 IRP as part of the Valmy Unit 2 reliability and economic impact analyses because development of the 2021 IRP was occurring simultaneously. It 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. First, the Company identified changes to its market purchase assumptions. 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. 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.

Market Purchase Assumptions

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. Figure 4.1 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.

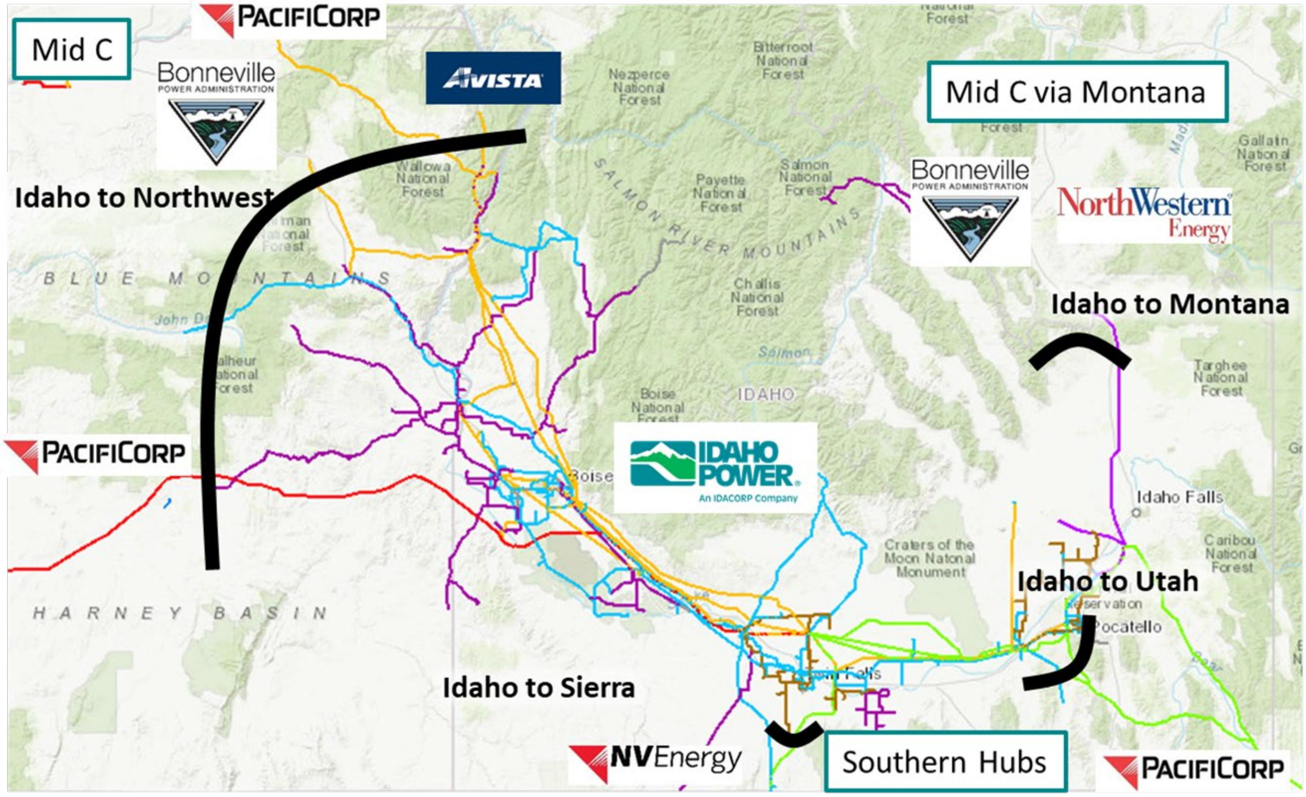

Figure 4.1 Idaho Power's Transmission System

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 the Mid-Columbia trading hub ("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 B2H project would greatly increase this transmission capacity. 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.

Idaho Power has options to purchase energy from southern markets as well. 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. 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 to access the Southern Hubs. The Company does not anticipate any firm transmission capacity south of Idaho in the near-term, however, there is 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 tested this possibility with a market request for proposals (RFP), which will be discussed later in this report.

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 reliability and the security of the bulk power system. Ultimately this also impacted Idaho Power's transmission system.

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 Figure 4.2.

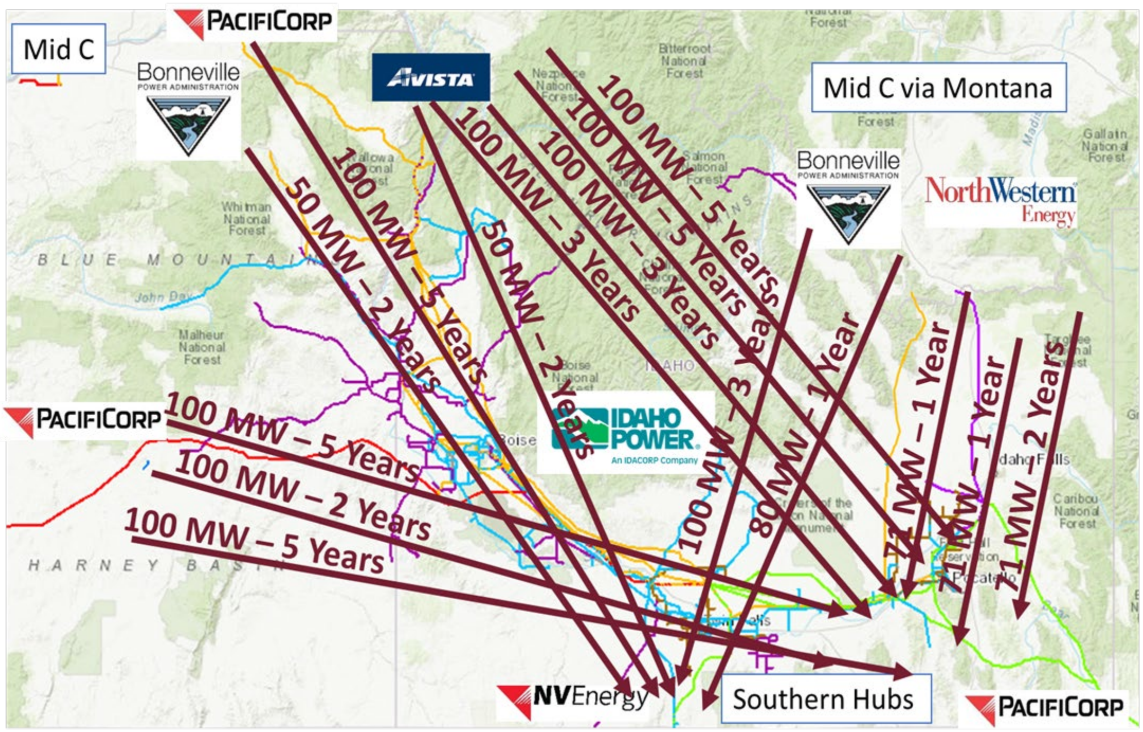

Figure 4.2 Transmission Service Requests

Although it requires more wheels, it is likely the third-party marketing firms saw the opportunity at Mid-C as summer forward prices between Mid-C and the south varied significantly. Table 4.1 presents a comparison between the two hubs, Mid-C and Palo Verde, of the heavy load hour forward prices, in costs per megawatt-hour (MWh), as of March 2021:

Table 4.1 Forward Market Prices, March 2021[5]

	Mid-C	Palo Verde
July, 2021	$57.60	$215.25
August, 2021	$82.25	$198.90
July, 2022	$48.15	$134.20
August, 2022	$62.70	$134.05

[5] Intercontinental Exchange (ICE), March 17, 2021.

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.

These transmission service requests have added to an already constrained market limiting the Company's access to Mid-C. Idaho Power tested the market availability with an RFP issued April 26, 2021, to further assess these transmission system constraints. The RFP requested a market purchase with delivery at Idaho Power's border, however no bids were received, further emphasizing the difficulty importing energy under a constrained transmission system.

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. Therefore, 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

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. 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 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.

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[6]. 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 4.2 below utilizes the forecasted peak day in 2023 to illustrate the importance of an hourly approach in determining planning margin requirements.

Table 4.2 Planning Margin Example[7]

		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.

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.

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 Effective Load Carrying

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

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

Capability (ELCC). Use of the ELCC resulted in a change to the peak-serving capability of Idaho Power's existing resources. When analyzing the Company'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. As a result, 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. Utilizing the resource 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. 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 will be discussed further in the following section.

Options for Meeting Reliability Needs

Because the intent of this analysis is to determine the appropriate exit date for Valmy Unit 2 and its associated 134 MW of firm capacity, when evaluating options for meeting reliability needs, the Company considered effective replacements for the 134 MW of firm capacity at Valmy Unit 2 only. The 2021 IRP currently in development will be utilized to address the broader capacity deficits of 381 MW in 2023 and 490 MW in 2025.

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. There are a number of other potential options for meeting the reliability hurdle, 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.

As presented 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, by 2023 the prices drop near \$100/MWh, and below \$100/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. As discussed earlier, to test the market availability, Idaho Power issued an RFP April 26, 2021, for the delivery to Idaho of firm capacity and energy during the summer months through 2025. No bids were received. Therefore, a market import is not an option for meeting the reliability hurdle associated with an early Valmy Unit 2 exit at this time. The economic analysis of each of the remaining options are presented herein.

Economic Analysis of Resource Options

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. Four portfolios were analyzed, 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:

- a Valmy Unit 2 exit in 2022 with the addition of solar plus battery storage in 2023 (Solar Plus Battery Portfolio),
- a Valmy Unit 2 exit in 2022 with the addition of only battery storage in 2023 (Battery Portfolio),
- a Valmy Unit 2 exit in 2022 with an expansion of Idaho Power's existing demand response programs in 2023 (Demand Response Portfolio), and
- a Valmy Unit 2 exit in 2022 with a delayed Bridger unit exit from 2022 to 2025 (Bridger Portfolio).

Because 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 the summer of 2023.

Portfolio Cost Development

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. However, because 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 and the Company's analysis is limited to the time period 2023 to 2025, Idaho Power is utilizing AURORA solely to determine the relative cost performance of the identified portfolios. 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.

Base Portfolio

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.

Solar Plus Battery Portfolio

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

Battery Portfolio

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 Table 5.1. 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.

Table 5.1 Battery Storage Fixed Cost Determination

	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-month)	Variable O&M ($/MWh)
2019 IRP	1,973	0.78	2.47
NREL ATB 2020	1,118 – 1,463	2.33 – 3.05	0.00
2021 IRP[9]	1,150	2.49	0.00
Average Developer Cost 2021	1,100	N/A	N/A
Regional Benchmark	1,000 – 1,828	2.30 – 4.12	0.00

[8] 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.

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

Demand Response Portfolio

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. Idaho Power based the initial estimate on 50 MW because the Company 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 mentioned earlier, the ability for demand response under current program parameters to meet net-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. 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.

Bridger Portfolio

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.

Economic Analysis Results

Table 5.2 presents the results of the economic analysis, detailing the total portfolio costs of each scenario modeled as compared to the base portfolio.

Table 5.2 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, indicating that the modeled scenarios are not more economically beneficial to meet Idaho Power's reliability needs through 2025 than retaining Valmy Unit 2.

5. CONCLUSION

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.

Idaho Power 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. 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 should the results indicate an exit at year-end 2023 or 2024 is least-cost and continues to meet reliability requirements.

[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.

As the Company committed to 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. The current results of the resource alternative analyses support an exit from operations of Valmy Unit 2 in 2025. Therefore, based on information known at this time, the appropriate exit date from Valmy Unit 2 is December 31, 2025.