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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR AUTHORITY TO IMPLEMENT CHANGES TO THE COMPENSATION STRUCTURE APPLICABLE TO CUSTOMER ON-SITE GENERATION UNDER SCHEDULES 6, 8, AND 84 AND TO ESTABLISH AN EXPORT CREDIT RATE METHODOLOGY	)	CASE NO. IPC-E-23-14

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 scope of your testimony in this case?

A. I will first describe the Company's proposed methodology for establishing an Export Credit Rate ("ECR") for on-site customer generation exports. Next, I will describe the Company's proposed methods for valuation of the ECR, including values for the avoided cost of energy, capacity (generation, transmission, and distribution), line losses, and integration costs. Finally, I will describe the Company's proposed technical requirements to support a modified project eligibility cap.

Q. Have you prepared any exhibits?

A. Yes. My testimony includes Exhibit Nos. 1-5. Exhibit No. 1 is the summary pages of the workpaper supporting the proposed ECR to be effective January 1, 2024, to May 31, 2024. Exhibit No. 2 is an Excel copy of the workpaper with summary schedules and supporting data included. Exhibit No. 3 is a copy of the Company's T&D deferral calculation and Exhibit No. 4 is a copy of the Company's most recent line loss study completed in March 2023. Exhibit No. 5 is a copy of the Company’s most recent Variable Energy Resource Integration study.

I. **EXPORT CREDIT RATE VALUATION**

Q. Is there value associated with on-site customer generation exports?

A. Yes. As demonstrated in the Commission-acknowledged October 2022 Value of Distributed Energy Resources Study (“VODER Study”)[1], there are several variables to consider when assessing the value of on-site generation exports:

- Avoided energy costs
- Avoided generation costs
- Avoided or deferred transmission and distribution costs
- Avoided line losses
- Avoided environmental costs
- Integration costs

Q. Did the Commission approve a method for valuing on-site generation exports?

A. No. The Commission found that the VODER Study was completed in accordance with the Commission directives and provided a basis for the Company to make recommendations in an implementation case.[2] The Commission directed the Company to request any changes to its net metering service offering in a

[1] See Attachment 1.

[2] *In the Matter of Idaho Power Company’s Application to Complete the Study Review Phase of the Comprehensive Study of Costs and Benefit of On-Site Customer Generation & For Authority to Implement Changes to Schedules 6, 8, and 84,* Case No. IPC-E-22-22, Order No. 35631 at 29 (Dec. 19, 2022).

separate implementation case by proposing specific methods or systems in support of changes to its customer generation service offering.

Q. Has the Company developed its proposal and methods for how the ECR should be valued? If so, please describe generally how the Company developed its recommendation.

A. Yes. As articulated in Ms. Aschenbrenner's testimony, the Company identified four primary objectives as it developed its overall proposal. Specific to the development of the ECR, the Company sought to identify and apply methods that result in a fair and accurate valuation of customers' exported energy while balancing customer understandability. The Company also prioritized relying on recent data and implementing a repeatable method for updating the ECR that will ensure timely recognition of changing conditions on Idaho Power's system and the broader power markets. Generally, the Company relied on avoided cost principles as a foundation for its proposal in this case.

In the following portion of my testimony, I will describe the methods the Company is proposing for each component of the ECR. Mr. Anderson's testimony will describe the Company's proposed annual update cycle for the ECR as well as the source that will be relied on for each of the respective components of the ECR.

Q. Please describe the term "avoided cost."

A. The term “avoided cost” is a commonly used term which can be defined as the incremental cost that is not incurred when additional output is not produced. More simply stated, in the specific context of on-site customer generation exports, when Idaho Power generates or purchases a kilowatt-hour (“kWh”) of energy to serve customer need, there is an associated cost. When, through customer action, the utility does not have to serve that kWh, the avoidance of the cost associated with generation or procurement of that energy is an “avoided cost.” These costs are specific to costs “avoided” by the utility system. As described in the VODER Study, there can be an avoided cost of energy or capacity, as well as the related line losses, associated with on-site customer generation exports.

Q. Please explain the significance of the Company’s proposed measurement interval as it relates to developing the ECR.

A. The measurement interval selected for net billing is an important input to many of the components of calculating the ECR under the Company’s proposed methods because it determines the volume and timing of exported energy. As more fully explained in Ms. Aschenbrenner’s testimony, the Company is proposing to implement a real-time measurement interval. Consistent with that recommendation, the Company has developed the ECR valuation methodology relying on exports measured on a real-time basis. It is important to note, the measurement interval selected to measure customer-generator exports should be the same measurement interval used for the inputs in the ECR calculation. A misalignment of the measurement intervals between the ECR calculation and measurement of exports would result in over- or under-valuing the ECR.

ECR Summary

Q. What structure is the Company proposing for the ECR?

A. The Company is proposing a seasonal and time-variant ECR to compensate for energy and other elements associated with avoided capacity, line losses, and integration costs as I will describe in more detail. Exhibit Nos. 1 and 2 provide the workpaper summary and associated calculations for the Company's proposed methods.

Figure 1 shows a summary of the ECR components for the methods proposed by the Company in this docket with an on-peak and off-peak ECR.

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Figure 1
Proposed Export Credit Rate

	Season	ECR
Export Profile		
Volume (kWh per kW)	Annual	1,465
Capacity Contribution (%)	Annual	8.76%
Export Credit Rate by Component (cents/kWh)		
Energy	On-Peak	8.59 ¢
Including integration and losses	Off-Peak	4.91 ¢
	*Annual**	*5.16 ¢*
Generation Capacity	On-Peak	11.59 ¢
	Off-Peak	0.00 ¢
	*Annual**	*0.79 ¢*
Transmission & Distribution Capacity	On-Peak	0.25 ¢
	Off-Peak	0.00 ¢
	*Annual**	*0.02 ¢*
Total	**On-Peak**	**20.42 ¢**
	Off-Peak	**4.91 ¢**
	*Annual**	*5.96 ¢*

**Annual values provided for informational purposes only and reflect seasonal weighting for 12 months ending December 2022.*

Note: On-Peak defined as June 15 - September 15, Monday - Saturday (exluding holidays), 3pm - 11pm. All other hours defined as Off-Peak.

If the Company's proposal is approved as filed, the ECR shown in Figure 1 will be in effect from January 1, 2024, through May 31, 2024. As more fully explained in Mr. Anderson's testimony, the Company anticipates submitting a filing in April of 2024 as part of a proposed annual update process (based on most recently available information), to be in effect from June 1, 2024, through May 31, 2025.

Q. How are the proposed on- and off-peak periods identified?

A. The proposed on-peak hours are 3pm to 11 pm, June 15 through September 15, Monday through Saturday, excluding holidays. As described in more detail in the avoided generation capacity cost section of my testimony, these hours are those currently identified as the hours of the Company’s greatest system need for energy and capacity.[3]

Q. Did the Company consider differentiating seasonal on- and off-peak time periods to compensate for energy and capacity components of an ECR separately?

A. Yes. The VODER Study evaluated differentiating the basis for defining seasonal on- and off-peak time periods for energy separate from those hours of need for capacity and found energy prices generally align with the Company’s hours of capacity need.[4] Additionally, the Company believes different on- and off-peak periods for energy and capacity would add additional complexity without commensurate benefit. As an example, if different on- and off-peak times were used for energy and capacity you could double the number of time periods – potentially without a meaningful difference in the ECR for certain time periods. For these reasons, the Company is proposing a singular on- and off-peak ECR for both energy and capacity components.

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[3] *In the Matter of Idaho Power Company’s Application for Approval to Modify Its Demand Response Programs*, Case No. IPC-E-21-32, Application, Table 3.
[4] Case No. IPC-E-22-22, October 2022 VODER Study, Appendix 4.8.

Q. As illustrated in Figure 1, the Company is proposing a single on- and off-peak ECR applicable to all customer-generators. Did the Company consider calculating the ECR by customer class?

A. Yes. However, as the Company explored the feasibility of this type of an approach, several potential issues were identified. For example, and as I will discuss when describing the generation capacity component of the ECR, the Company determined that quantifying class specific capacity will result in over- or under- valuing capacity at a system level. Additionally, the Company is generally concerned that class specific ECRs will lead to customer confusion. While each respective class's export quantities and shape would be relied upon in the development of the differing rate by class, that nuance may not be apparent to customers, leading to confusion, frustration, and potentially customer complaints from one class of customers not understanding why their solar export is worth less than another class's export.

Avoided Energy Costs

Q. How is the Company proposing to value the avoided cost of energy?

A. The Company recommends using a twelve-months ending December 31 weighted average Energy Imbalance Market ("EIM") Load Aggregation Point ("ELAP") price for the avoided energy component of the ECR. These prices would be weighted relative to customer-generator exports over the twelve-month period.

Q. Did the Company consider other prices in its proposed method for valuing the avoided energy component of the ECR?

A. Yes. As discussed in the VODER Study,[5] the Company also considered the Intercontinental Exchange Mid-Columbia ("ICE Mid-C") and the Idaho Power Integrated Resource Plan ("IRP") forecast prices. Both methods were evaluated in the VODER Study but ultimately the Company believes the ELAP prices most closely meet the Company's objectives of a value that fairly and accurately reflects the value of on-site generation exports on Idaho Power's system and the broader power markets, while also balancing customer understandability and a need for transparent pricing.

Q. Did the Company consider using ELAP actual hourly pricing rather than relying on a historical weighted average price?

A. Yes. ELAP actual hourly pricing would be the most accurate approach to valuing the avoided energy component for an ECR. Under this method, the customer is compensated for all exports at that hour's ELAP price which means that all customers, irrespective of customer class, would be compensated for the value of their energy at the time of day and year it is

[5] See Attachment 1, pp 40-41.

exported. This approach mitigates the risk of over- or under-compensating customers for their exports as there is no lag to pass those market prices on to the customer generators.

However, dynamic pricing of this nature could be challenging for some customers to understand due to ever-changing prices and potential volatility from one hour to the next. Because actual ELAP prices are far more dynamic than a fixed price - in fact they will likely vary hour-to-hour, relying on this type of an input would assume customers are able and willing to access real-time EIM data to respond to the price signal sent in a given hour. While the Company could bill on these dynamic market prices, making data available to customers when reviewing their bills online would require significant information technology system development and customization. In the alternative, the Company considered developing a report that could be generated on a monthly basis that would reconcile the number of exports with the market price in each hour. However, the Company does not view this as a viable approach as it would require each customer to receive a 720 to 744 row reconciliation report each month just to understand how the value of their exports was determined.

Finally, this type of an approach does not provide transparency for customers as there is no tariffed rate associated with the exports, which could lead to customer frustration or confusion. I am also not aware of any utilities in the country that have adopted such an elaborate structure for compensating exports from customer-generators.

Q. Please describe why the Commission should approve using the ELAP historical weighted average as the value of avoided energy.

A. The use of a twelve-month weighted average to develop the avoided energy value component of an ECR would allow for ECR value(s) to be published in Idaho Power's tariff and on its website for public transparency and customer understanding. This approach also provides for a repeatable method for updating the ECR to achieve timely recognition of changing conditions on Idaho Power's system and the broader power markets. The Company proposes to update the ECR annually, which will mitigate the lag that would otherwise occur by updating less frequently, or if the method relied on the average price of energy over multiple years. Ultimately, the Company believes those benefits outweigh the accuracy and timing of the more dynamic actual market price approach.

Q. How does the Company propose the twelve-month historical ELAP weighted average price be calculated?

A. The Company is proposing to calculate an on-peak and off-peak value weighted with customer exports. The on-peak period would align with the greatest system need.[6] Currently the on-peak time period for the ECR would be June 15 to September

[6] Case No. IPC-E-21-32, Application, Table 3.

15, 3-11 pm, Monday through Saturday, excluding holidays. All other hours would be considered off-peak. Starting with the 2023 IRP and each successive IRP, the Company will evaluate and update the hours of greatest system need that will inform the annual update to the ECR.

Avoided Generation Capacity Costs

Q. How is the Company proposing to value the avoided generation cost?

A. Three components collectively determine the avoided cost of a generation resource: (1) contribution to capacity, (2) the cost of an appropriate proxy, or alternative resource, and (3) the energy generated during a given period.

Q. What method is the Company proposing to determine the contribution to capacity?

A. The Company proposes to use the same method that is utilized in the Company's IRP process. At this time, that method is the Effective Load Carrying Capability ("ELCC") method – the ELCC method would calculate the capacity contribution for all on-site customer generation exports.

Q. Please describe the ELCC method and how it determines the contribution of a resource to meet the Company's capacity needs.

A. The ELCC method looks at the equivalent capacity of a given resource that can be added to or removed from the system and maintain the same level of reliability. This method is more fully described on page 58 of the October 2022 VODER Study and was also relied on as the method to value capacity of all supply-side resources in the Company’s 2021 IRP.

Q. What other methods were considered in the evaluation of capacity contribution?

A. Three methods were considered for the quantification of capacity contribution: the ELCC method, the National Renewable Energy Laboratory (“NREL”) 8,760 hour-based method and a variant of the Peak Capacity Allocation Factor (“PCAF”) method. These methods are more fully described on pages 58 to 60 of the October 2022 VODER Study. ELCC is the most robust and accurate method to determine capacity contribution of variable resources and it is widely utilized in the electric industry as the preferred method to determine capacity contribution.

Whereas the ELCC method calculates risk for all hours, the NREL 8,760 hour-based method utilizes only the top hours of a load duration curve as a proxy to determine the highest risk hours. The PCAF method is based on a capacity factor during high load hours and fails to account for any shift in high-risk hours. Said plainly, both the NREL and the PCAF methods oversimplify capacity contribution by assuming Idaho Power’s resource needs align with the total system load. While that may have been the case through most of the last century, the development of non-dispatchable resources on the Company’s system has necessitated a change in how capacity needs are identified and met.

Q. Why is a proxy, or alternative, resource utilized in determining the avoided cost of a generation resource?

A. A proxy resource is utilized to determine the equivalent capacity of the IRP-identified lowest-cost resource that the on-site generation is avoiding.

Q. What resource does the Company propose be utilized as a proxy resource?

A. The Company proposes to rely on the levelized fixed cost associated with the least-cost dispatchable resource from the Company’s most recently acknowledged IRP. In the 2021 IRP, that was a simple-cycle combustion turbine (“SCCT”).[7]

Q. Currently, what is the Company’s periods of greatest capacity need?

A. Currently, the highest Loss of Load Probability (“LOLP”) hours are from 3 to 11 pm, June 15 through September 15, Monday through Saturday, excluding holidays.

Q. How are the highest LOLP hours calculated?

A. LOLP can be calculated by determining the probability that the available generation at any given hour is able to meet the net load during that same hour. The highest-risk hours are those which have the highest LOLP values.

[7] 2021 IRP, Appendix C at 38.

Q. How do the highest LOLP hours pertain to the ELCC calculation?

A. In general terms, the ELCC calculation is driven by the quantity of generation produced during the highest-risk hours.

Q. How is the Company proposing to compensate customers for avoided generation capacity?

A. The Company proposes to distribute the calculated avoided generation capacity value across on-site generation exports during the Company's identified period of capacity need.

Q. Why does the Company believe it is reasonable to provide a time-variant credit for capacity?

A. The procurement of capacity resources is driven by the identified hours of highest risk - the period that capacity can be avoided. By aligning the period of capacity avoidance with that of the ECR, a price signal is created that could incentivize customers to invest in or optimize systems to maximize output during the period of capacity avoidance. Examples of a potential incentivized price signal with a time-variant credit for capacity include systems with optimized direction of panels or installation of energy storage devices.

Q. Does the proposed methodology satisfy the Commission's aim of having an avoided generation capacity value that accurately considers actual avoided costs?[8]

[8] IPC-E-22-22, Order No. 35631 at 29.

A. Yes. The proposed methodology aligns with the Company's IRP process for determining greatest capacity needs. Future IRPs will identify the hours of greatest capacity need, which will be used to determine the capacity avoided by customers with on-site generation.

Q. Did the Company consider incorporating its next capacity deficiency date when valuing exports?

A. Yes, however the Company identified several issues that it believes would be challenging to overcome. First, relying on a capacity deficiency period would necessitate the Company tracking and applying a different ECR depending on the vintage of systems. Second, this type of an approach would not be easily understood by customers, as it would result in differing ECRs (one that excludes capacity) for a number of years, and then inclusion at a future point in time. Ultimately, it is the Company’s position that the capacity deficiency date should be considered in most avoided cost applications; however, valuing exports from customer generators inherently presents a set of challenges that are not present with large, utility-scale projects.

It is also important to note that at this point in time, the Company is capacity deficient, so compensating customer generators for an avoided cost of capacity is reasonable. The Company is open to incorporating the capacity deficiency period if this can be done in a manner that is fair for all customers, can be consistently applied, and does not result in unnecessary customer confusion.

Q. Did the Company consider calculating the avoided generation capacity component of the ECR by customer class?

A. Yes. However, the Company identified a few issues related to determining the ELCC by class rather than considering all on-site generators as a single resource. First, a class-specific ELCC determination creates a timing issue based on the order in which the class ELCCs are calculated – resulting in a higher value to whichever class adds capacity to the system "first." Additionally, due to the relatively small size of certain customer classes, in terms of megawatts, the margin of error in the ELCC calculation increased significantly, resulting in an inaccurate valuation of capacity avoided and potential over-payment for capacity. For these reasons, in combination with my earlier comments about customer understandability, the Company is not proposing to calculate the avoided generation capacity component of the ECR by customer class.

Deferred Transmission & Distribution Capacity Costs

Q. What is Idaho Power proposing for the value associated with avoided, or deferred, transmission and distribution ("T&D") costs?

A. The October 2022 VODER Study presented a method that incorporates data specific to Idaho Power's electrical system to determine what transmission and distribution projects could be avoided or deferred and the associated value. This method has been recognized as a best practice by energy industry expert Kurt Strunk, managing director of NERA Economic Consulting.[9] As described in Mr. Anderson's testimony, the Company would plan to update these calculations it its 2024 annual update – after the next IRP has been filed.

Q. Did the Company consider other methods?

A. Yes. The VODER Study considered other T&D deferral approximation methods that, when applied in the absence of project-level data, may provide a reasonable proxy for T&D deferral value.[10] These "top-down" approximation methods often rely on general utility information and ignore or make assumptions about whether T&D investments could be deferred. When project-level data is available, as it is for the Company's proposed method, it is the preferred analysis method. It provides the most applicable and accurate calculation of the T&D deferral value because it considers how and when T&D investments are made.

Q. Please explain how the Company's proposed method calculates the value of deferred transmission and distribution capacity from customer-generator exports.

A. To determine the potential value of on-site generation in deferring or delaying the need for Idaho Power to

[9] IPC-E-22-22, Idaho Power Reply Comments, Attachment 1 – Affidavit of Kurt G. Strunk.
[10] Case No. IPC-E-22-22, October 2022 VODER Study, pp. 71-72.

build T&D resources, the analysis identifies local peak hours for each T&D resource. Local peak hours are specific to the amount and types of loads connected to individual resources. The analysis incorporates 15 years of historical project data and five years of forecasted project data on Idaho Power's T&D system. This data identifies the historical trends and projected T&D projects and the capacity need for each project. Exhibit No. 3 includes the T&D deferral calculations.

Q. How is the Company proposing to compensate customers for avoided T&D?

A. The Company proposes to compensate on-site customer generation exports for the value of deferred T&D during the same hours as described for the avoided generation capacity component of the ECR.

Q. Did the Company consider using different hours for T&D deferral value?

A. Yes. The avoided cost of T&D could be spread over all exports in a given year; however, the Company believes it is most reasonable to align with the hours of system need. While not all T&D projects are deferrable by on-site customer generation, a vast majority of the deferrable projects are projects that would have otherwise been installed to serve system need during those highest risk hours.

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Avoided Line Losses

Q. What is the Company proposing as it relates to avoided line losses in the ECR?

A. The Company is proposing to include an adjustment to the avoided energy value of the ECR to account for the benefit of avoided line losses. The Company proposes to use its line loss study completed in March 2023; Table 1 provides a summary of the avoidable transmission and distribution line losses. Exhibit No. 4 of my testimony is a copy of the Company's 2023 line loss study.

Table 1
Energy Loss Coefficient Table from 2023 Line Loss Study

VODER		
System Level	Energy Loss Coefficient	Peak Loss Coefficient
Transmission	1.026	1.034
Distribution Station	1.029	1.037
Distribution Primary	1.044	1.050
Distribution Secondary	1.044	1.050

Q. What does an avoided line loss percentage value represent?

A. These values represent the reduction in losses that the Company avoids from a reduction in serving load due to exports from customers with on-site generation.

Q. How were the avoided line loss values calculated?

A. The losses for transmission lines were obtained by applying Ohm's law to the conductors, that is, the current measured at one end of the line squared times the resistance of the line. The losses in the distribution system were obtained by determining the hourly energy leaving a station in comparison with the energy consumed by all customers served by that station during the same hour; the difference between those two energy values equates to the losses in the distribution system. The transformer losses were obtained by adding the transformer core losses and the transformer winding losses together.

Transmission line losses, distribution primary line losses and transformer winding losses are the only line losses that can be avoided by customers with on-site generation; the sum of these three loss components equate to the hourly isolated avoidable losses.

Q. How are the avoided line losses valued in the ECR?

A. The avoided line losses are applied to both energy and capacity. The energy prices are multiplied by the loss percentage to determine the corresponding impact of the energy price due to losses. This calculation is depicted in Figure 4.21 on page 78 of the October 2022 VODER Study. For capacity, the Company proposes a slightly different method for valuing the line losses. For the capacity line losses, hourly customer-generator exports are scaled up to be inclusive of avoided losses and then utilized in the generation capacity value calculation.

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Environmental & Other Benefits

Q. Is Idaho Power proposing to include any value associated with externalities such as local job creation, avoided health costs, or other environmental benefits?

A. No. These externalities are just that – external to the utility's system and have not been included in the Company's proposal for implementation. Similarly, environmental benefits based on non-quantifiable or speculative values are not appropriate to include in the ECR. In Order No. 35631, the Commission stated the following:

> Generic conclusions and recommendations from third-party studies that do not fully reflect the environmental conditions and legislative requirements in Idaho or the particulars of the Company's system, should not be considered by the Company in its implementation recommendations. Likewise, environmental benefits or costs that cannot be quantified or shown to affect customers' rates, should not be considered in valuing an ECR.[11]

In accordance with the Commission findings in Case No. IPC-E-22-22, and as more fully described in the VODER Study,[12] the Company has not proposed to include a value in the ECR at this time. However, if environmental and/or legislative requirements change, the Company anticipates initiating a docket that would seek to modify the ECR methodology to include any

[11] Order No. 35631 at 29.
[12] Attachment 1, pp. 78-81.

benefits or costs that can be quantified and affect customers' rates.

Integration Costs

Q. Does Idaho Power incur costs to receive excess energy from on-site generation?

A. Yes. All Variable Energy Resources ("VERs") such as solar and wind cause incremental costs associated with accommodating variable resources on the system. Examples include dispatchable unit cycling from increased unit stops and starts, increased load following ramping, and imperfect unit commitment and dispatch.

Q. Is the Company proposing to include costs in the ECR to account for integration costs?

A. Yes.

Q. How does the Company propose to account for integration costs?

A. Idaho Power periodically conducts integration studies based on the number of variable resources on its system. The most recent integration study was completed in 2020 and reflected the then-current level of intermittent generation on the system. The 2020 VER Integration Study relied on a 2023 base year and determined the costs to integrate additional variable resources including customer generation under a variety of assumed conditions on the Company's system and the broader power markets. Exhibit No. 5 includes a copy of the 2020 VER

Integration Study. The October 2022 VODER Study[13] also summarizes the 2020 VER Integration study results.

The Company has proposed to use the 2020 VER Integration Study Case Number 1 integration cost. The 2020 VER Integration Study identifies an applicable solar integration rate in Case Number 1 of $2.93 per megawatt-hour ("MWh"), or $0.00293 per kWh.

Q. Please explain why the 2020 VER Integration Study Case Number 1 is most appropriately applied?

A. Case Number 1 is directly comparable to the base case (Case Number 7). While a Bridger unit is retired in Case Number 1, it is also retired in the comparative Case Number 7. Therefore, all of the integration costs can be attributed to the difference of 251 MW of solar between cases. The identified $2.93 per MWh is therefore a *solar* integration cost and is appropriate in the purposes of the ECR.

Q. Did the Company consider developing a new VER Integration Study in support of its request in this case?

A. Yes, however VER Integration Studies are complex and the 2020 study is still considered to be current. While the last VER study was performed by an externally contracted company, the key Idaho Power personnel who are involved with the development of the study are also key contributors to the IRP. Similar to the IRP, the Company also solicits feedback for a VER

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[13] See Attachment 1, page 83, Table 4.10.

study through a stakeholder process called a Technical Review Committee. Therefore, the opportune time to complete a VER Integration Study for both stakeholder engagement, and to ensure adequate Company representation, is during those years between IRPs. Idaho Power expects to complete its next VER Integration Study, if necessary, following the completion of the 2025 IRP.

Q. Will the addition of battery storage impact solar integration costs?

A. Potentially. This will be determined in the next VER Integration Study. Generally new VERs will continue to increase integration costs, and battery storage can potentially act to counter those cost increases. The Company plans to gather operational data on recent and planned near-term solar additions, as well as determine the operational characteristics associated with battery storage the Company is able to leverage, prior to beginning the next VER Integration Study.

II. PROJECT ELIGIBILITY CAP

Q. Please explain the Company's proposal for the project eligibility cap for on-site generation systems.

A. As described in Mr. Anderson's testimony, the Company is not proposing to modify the 25 kW project eligibility cap for Schedules 6 and 8. The Company is, however, proposing that the project eligibility cap for Schedule 84 be set at the greater of 100 kW or 100 percent of demand at the service point for commercial, industrial, and irrigation customers.

Q. In your opinion, could the Company safely interconnect systems larger than that the proposed demand-based cap?

A. Yes. However, not without system upgrades – some of which could be significant. While the on-site generation customer would be responsible for the initial cost of that equipment, the ongoing cost, including maintenance, replacement, property taxes, and other ancillary costs will become the responsibility of the Company. These costs are collectively paid for by all customers. The Company does not routinely install facilities in excess of customer demand in any other instance and it would be inappropriate to do so here. Ultimately, the benefit of tying a system size to customer demand is to ensure Idaho Power does not have oversized distribution equipment on its system necessary to serve those customers.

Q. Mr. Anderson’s testimony states that the existing project eligibility cap for Schedule 6 and 8 is larger than their average demand. Does this result in a similar magnitude of concern to the Company?

A. No. Most transformers on Idaho Power’s system to serve residential and small general customers are 25 kW or larger, so it is not as common for residential customers to have to complete system upgrades when installing on-site generation. This is not to say it does not happen, as often there may be multiple customers on a shared transformer, but the occurrence is less common.

Interconnection Process Overview

Q. What does the Company generally require of customers installing generation for exporting systems?

A. The customer is required to complete the application process as outlined in Schedule 68, Interconnections to Customer Distributed Energy Resources (“Schedule 68”). This process includes requirements for how upgrades to the Company’s system may be treated and what types of equipment is required on the customer’s side of the meter.

Q. Please describe the Company’s process to determine whether and to what extent upgrades or modifications may be required on the Company’s side of the point of delivery.

A. Because exporting systems are operating in parallel - meaning they are connected to and receiving voltage from Idaho Power’s system - it is critical to implement requirements that will provide for the safety of Company employees and members of the public, as well as integrity of the system through system protection equipment, as necessary. The Company performs a Feasibility Review to evaluate the feeder capacity, phase compatibility, and transformer size. If any of these fail the Feasibility Review, the customer is required to fund upgrades before interconnecting their generation facilities.

Q. What type of equipment or requirements are imposed on the customer and/or equipment installed on the Company's side of the point of delivery?

A. Safety is critical with any interconnection to the Company's system. As outlined in Section 1: General Interconnection Requirements of Schedule 68, Idaho Power requires inverters meet Institute of Electrical and Electronics Engineers ("IEEE") standards; there must be an operable disconnect switch present, proper signage, and the disconnect switch must be readily accessible by the Company at all times.

Q. How does the Company validate these customer requirements have been met?

A. The Company has developed an initial on-site inspection, that is updated from time to time, to verify that the customer equipment installed matches the information provided on the system verification form and that the interconnection generally complies with the IEEE standards.

Additional Interconnection Requirements for Larger Systems

Q. Will the Company need to modify any of its existing interconnection requirements for exporting customers if the Commission approves the Company's proposal to increase the project eligibility cap for Schedule 84?

A. Yes. There are additional requirements necessary to interconnect exporting systems larger than 100 kW safely and reliably. Table 2 provides a summary of the additional interconnection requirements the Company proposes to include in Schedule 68.

Table 2
Exporting System Interconnection Requirements 100 kW and Greater

Total Nameplate Capacity	Inverter Settings Documentation	Install Plant Controller	Interconnection Agreement
100kW - 500 kW	✓	✗	✗
500kW - 3 MW	✓	✓	✗
3 MW+	✓	✓	✓

As illustrated in Table 2, the Company proposes to revise Schedule 68 to require the following: (1) inverter-based generation 100 kW and greater will provide documentation validating inverter settings; (2) for systems 500 kW and greater, a power plant controller (or in the alternative, a properly configured inverter) will be installed on the customer’s side of the point of delivery; (3) for systems 3 MW and greater, the existing uniform interconnection agreement and requirements applicable to non-exporting systems larger than 3 MW will apply.

Q. Please explain why the Company will require the customer using inverter-based generation to provide documentation validating their inverter settings.

A. The larger inverter-based generation systems have a greater potential to negatively impact the Company’s system if not properly configured because of their relative size to the local area load. In order to ensure safe and reliable operation of the Company’s equipment and the service to our customers, it is essential to verify that the larger inverter-based generation systems are properly configured. An improperly configured generation system could lead to power quality issues or damage to equipment for other customers and on the Company’s system. For these reasons, inverter-based generation systems larger than 100 kW will need to provide documentation of their inverter settings.

Q. What is the rationale for the interconnection requirement of a plant controller for systems 500 kW and greater?

A. Pursuant to IEEE 1547-2018, Section 4.2 Reference points of applicability, customer-generators operating Distributed Energy Resources (“DERs”) in aggregate of 500 kilovolt-ampere (“kVA”) or greater, are responsible for installing equipment required to monitor voltage, current, and frequency on the customer’s side of the point of delivery. This equipment measures data to calculate and to communicate required operating settings to individual inverters and other devices to control the generation facility output. In order to meet the IEEE standard, the interconnection requirements dictate customer generation facilities 500 kVA and larger be designed with a power plant controller. If all power flows through a single inverter, the inverter may be operated such that it is equivalent to a power plant controller.

Q. Please describe the interconnection requirement for exporting systems 3 MW and greater.

A. Idaho Power proposes to require that exporting systems 3 MW and greater include the same study and communication requirements that are currently applicable to non-exporting systems larger than 3 MW under Schedule 68. These requirements align with the interconnection requirements for similar sized generator interconnections.

III. CONCLUSION

Q. Does the Company’s proposal for methods to value the ECR and modify the Schedule 84 project eligibility cap meet the Company’s primary objectives in this case?

A. Yes. I believe the methods described in my testimony to value the ECR result in a fair and accurate valuation of customers’ exported energy and provide for a repeatable method for updating the ECR that will ensure timely recognition of changing conditions on Idaho Power’s system and the broader power markets. I also believe that the Company’s proposed method reasonably balances accuracy with customer understandability. Additionally, the proposed modification to the Schedule 84 project eligibility cap concurrent with approved changes to the compensation structure provides additional flexibly and opportunities for customers to install on-site generation.

//

Q. Does this conclude your testimony?

A. Yes.

//

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 Transmission, Distribution & Resource Planning Director in the Planning, Engineering & Construction Department.

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibit Nos. 1-5 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 1st day of May 2023, at Boise, Idaho.

Signed: ______________________

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-14

IDAHO POWER COMPANY

ELLSWORTH, DI
TESTIMONY

EXHIBIT NO. 1

	Season	ECR
Export Profile		
Volume (kWh per kW)	Annual	1,465
Capacity Contribution (%)	Annual	8.76%
Export Credit Rate by Component (cents/kWh)		
Energy	On-Peak	8.59 ¢
Including integration and losses	Off-Peak	4.91 ¢
	*Annual**	*5.16 ¢*
Generation Capacity	On-Peak	11.59 ¢
	Off-Peak	0.00 ¢
	*Annual**	*0.79 ¢*
Transmission & Distribution Capacity	On-Peak	0.25 ¢
	Off-Peak	0.00 ¢
	*Annual**	*0.02 ¢*
Total	**On-Peak**	**20.42 ¢**
	Off-Peak	**4.91 ¢**
	*Annual**	*5.96 ¢*

**Annual values provided for informational purposes only and reflect seasonal weighting for 12 months ending December 2022.*

Note: On-Peak defined as June 15 - September 15, Monday - Saturday (exluding holidays), 3pm - 11pm. All other hours defined as Off-Peak.

Avoided Energy — ECR Annual Update

Avoided Energy Calculation	On-Peak Update	Off-Peak Update	Units	Description
ELAP - Weighted Average	$ 84.60	$ 49.84	$/MWh	
Plus: Line Loss Gross-up	$ 4.23	$ 2.19	$	Exhibit No. 3 - Analysis of System Losses (March 2023)
Less: Integration Costs	$ (2.93)	$ (2.93)	$/MWh	Exhibit No. 4 - Idaho Power 2020 VER Integration Study
Avoided Energy Value	**$ 85.90**	**$ 49.10**	**$/MWh**	
Annual Energy Value	*$ 51.60*	*$ 51.60*		

Monthly Seasonal Energy Calculation

On/Off-Peak	Month	Value	Energy	$/MWh
Off-Peak	1	$ 102,879	3,144	$ 32.72
Off-Peak	2	$ 167,545	6,362	$ 26.33
Off-Peak	3	$ 233,461	8,973	$ 26.02
Off-Peak	4	$ 436,204	9,977	$ 43.72
Off-Peak	5	$ 445,602	11,077	$ 40.23
Off-Peak	6	$ 263,414	9,105	$ 28.93
On-Peak	6	$ 57,053	1,624	$ 35.14
Off-Peak	7	$ 385,929	6,750	$ 57.17
On-Peak	7	$ 188,394	2,100	$ 89.72
Off-Peak	8	$ 402,482	6,195	$ 64.97
On-Peak	8	$ 165,264	1,767	$ 93.52
Off-Peak	9	$ 474,169	7,779	$ 60.96
On-Peak	9	$ 118,488	764	$ 155.00
Off-Peak	10	$ 516,061	9,157	$ 56.36
Off-Peak	11	$ 332,075	4,809	$ 69.06
Off-Peak	12	$ 517,249	2,494	$ 207.40
Annual		$ 4,806,268	92,076	$ 52.20
On-Peak		$ 529,199	6,255	$ 84.60
Off-Peak		$ 4,277,069	85,821	$ 49.84

Avoided Generation Capacity — ECR Annual Update

Avoided Generation Capacity Calculation	Update	Units	Description
Effective Load Carrying Capability	8.760%	%	3-year rolling average ELCC (CY2020-2022)
(x) Nameplate Capacity	62.86	MW	
Total Capacity Contribution	**5.51**	MW	
(x) Levelized Fixed Cost of Avoided Resource	$ 131.60	$/kW-year	2021 Integrated Resource Plan - Appendix C, page 38
(x) kW to MW conversion	1,000	kW	
(/) On-Peak Exports	6,255	MWh	CY2022 real-time customer generation exports
On-Peak Avoided Generation Capacity Value	**$ 115.86**	**$/MWh**	
Annual Generation Capacity Value	*$ 7.87*	*$/MWh*	

Customer Generation Exports - ELCC & Maximum Output | Current Reliability & Capacity Assessment Tool (Historical Data)

Year - 2020		
ELCC (MW)	2	
Maximum Output (MW)	27	
ELCC (%)	**7.50%**	
Year - 2021		
ELCC (MW)	5	
Maximum Output (MW)	40	
ELCC (%)	**12.42%**	
Year - 2022		
ELCC (MW)	4	
Maximum Output (MW)	63	
ELCC (%)	**6.36%**	
3-Year Average	**8.76%**	3-year rolling average ELCC (CY2020-2022)

Avoided Transmission & Distribution Capacity — ECR Annual Update

Avoided T&D Capacity Calculation	Update	Units	Description
Distribution Capacity Savings	$ 307,263	$	Exhibit No. 2 - Transmission and Distribution Avoided Capacity
Plus: Transmission Capacity Savings	-	$	Exhibit No. 2 - Transmission and Distribution Avoided Capacity
Total T&D Capacity Savings	**$ 307,263**	$	
(/) Project Years	20	years	Exhibit No. 2 - Transmission and Distribution Avoided Capacity
Annual T&D Capacity Savings	**$ 15,363**	$/year	
(/) On-Peak Exports	6,255		CY2022 real-time customer generation exports
On-Peak T&D Capacity Value	**$ 2.46**	**$/MWh**	
Annual Generation Capacity Value	*$ 0.17*	*$/MWh*	

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-14

IDAHO POWER COMPANY

ELLSWORTH, DI
TESTIMONY

EXHIBIT NO. 2

SEE ATTACHED SPREADSHEET

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-14

IDAHO POWER COMPANY

ELLSWORTH, DI
TESTIMONY

EXHIBIT NO. 3

SEE ATTACHED SPREADSHEET

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-14

IDAHO POWER COMPANY

ELLSWORTH, DI
TESTIMONY

EXHIBIT NO. 4

ANALYSIS OF SYSTEM LOSSES

In

Idaho Power Company

Prepared by:

Jackson Daly

Andrés Valdepeña Delgado

System Planning Department

March 2023

Contents

Executive Summary

This study presents the peak and energy loss coefficients for the Idaho Power delivery system. The analysis was conducted using 2022 data. The delivery system was broken down into four different system levels, including:

- **Transmission:** Includes voltage levels between 46 kV and 500 kV
- **Distribution Stations:** Includes distribution station transformers
- **Distribution Primary:** Includes distribution lines and facilities between 12.47 kV and 34.5 kV
- **Distribution Secondary:** Includes distribution service lines and distribution line transformers

The losses documented in this study represent the physical losses that occurred on the Idaho Power delivery system facilities. Application of the calculated loss coefficients is limited to loads served from Idaho Power Company facilities. The peak loss coefficients were calculated based on data from the system peak hour in 2022, which occurred on July 14th, 2022, at 7:00 PM.

The study incorporated various methods to calculate the losses at different voltage levels. For the 161 kV and above transmission system, current readings and resistance from the lines were used to determine the losses. For the 138 kV transmission system, the losses were determined by calculating the total inputs into the 138 kV system and subtracting the outputs, leaving the difference as the losses in the 138 kV system. For the sub-transmission system, electric current or power and resistance readings were used to determine losses. The total transformer losses were determined by adding the winding and core losses. The distribution system losses were determined as the difference between the input to the distribution system and the output, where the output of the distribution system is the end-use customer usage obtained from the Advance Metering Infrastructure ("AMI") and the industrial and commercial usage, MV90 database.

The individual system loss coefficients are determined as the system level inputs, divided by the system level outputs. The loss coefficients used at each delivery point in the system are calculated as the product of the individual level loss coefficients. The resulting coefficients for the 2022 study are summarized in **Table 1**.

System Level	Energy Loss Coefficient	Peak Loss Coefficient
Transmission	1.029	1.037
Distribution Station	1.036	1.042
Distribution Primary	1.051	1.056
Distribution Secondary	1.076	1.076

Table 1: Delivery Point Loss Coefficients

Introduction

Loss coefficients are the ratio of the system input required to provide a given output at a particular system level. Individual loss coefficient for each system level relates the input and the output by (1):

$$Loss\ Coefficient = \frac{Level\ Input}{Level\ Output} = 1 + \frac{Level\ Losses}{Level\ Output}$$

The system loss coefficient is obtained by multiplying all the upstream system level coefficients together.

System Level Description

The Idaho Power delivery system was split into four categories: transmission, distribution stations, distribution primary, and distribution secondary. The system inputs and outputs for each level are described below.

Transmission System

The transmission level includes losses for all facilities and lines from 46 kV up through 500 kV. Losses from the Generation Step-Up ("GSU") transformers and transmission tie-bank transformers are included in the transmission level. Customer owned facilities at the transmission level are not included.

Transmission level **inputs** consist of the following:

+ Idaho Power Generation
+ Power Purchases/Exchanges
+ Customer Owned Generation Connecting to Transmission Lines
+ Wheeling Transactions

Transmission level **outputs** consist of the following:

- High Voltage Sales
- Power Exchanges*
- Wheeling Transactions
- Output to Distribution Stations

The exchanges outputs are adjusted to remove the scheduled losses for the Idaho Power share of losses in the jointly owned Bridger-Idaho and Valmy-Midpoint transmission systems. FERC From 1 includes the Bridger and Valmy scheduled losses as exchanged out. The calculated losses in this study include the Idaho Power share of losses on the Bridger and Valmy systems as transmission level losses.

Distribution System

The distribution system consists of all equipment operating at 35 kV and below. This accounts for all substation transformers, distribution lines, and distribution transformers. The distribution system can be split into 3 different levels: stations, primary and secondary. These different levels are chosen to account for the losses most accurately at the different points of delivery.

Stations Level

Stations level consists only of the substations servicing the distribution system (transformers with a low voltage side of 7 – 35 kV).

Station level **inputs** consist of the following:

+ Transmission System Outputs

Station level **outputs** consist of the following:

- Direct Sales
- Wheeling Transactions

Although this level has no additional inputs, it is chosen as there are several customers who are served directly from the substation.

Primary Level

The primary level consists of all the primary distribution power lines. Primary lines being lines operated between 7 - 35 kV.

Primary level **inputs** consist of the following:

+ Distribution Stations Outputs
+ PURPA/Customer Generation

Primary level **outputs** consist of the following:

- Customer Sales
- Wheeling Transactions

The primary distribution level contains a large amount of generation under the Public Utility Regulatory Policies Act ("PURPA") and customers with on-site generation and customers who connect directly to the distribution primary level.

Secondary Level

The secondary level consists of all equipment operating at a service voltage. This includes distribution transformers and distribution lines operating at a service voltage.

Secondary level **inputs** consist of the following:

+ Primary Level Outputs
+ Net Metering/Customer Generation

Secondary level **outputs** consist of the following:

- Customer Sales
- Idaho Power Internal use
- Street Lighting/ Unbilled
- Wheeling Transactions

Customer with on-site generation are inputs to the secondary level and come from both rooftop solar and small hydro generation.

Energy Loss Coefficient Calculations

Table 8 shows the total system flow diagram for the 2022 energy losses. The table outlines each system level's input and output as well as the total energy losses (MWh) and loss coefficient. The transmission level output (MWh) to the distribution station level is calculated by subtracting the remaining output and calculated losses from the transmission level inputs

Transmission Level Energy Losses

For the 500 – 161 kV, 69 kV, and 46 kV voltage levels, the transmission losses were calculated using Ohm's Law where current readings were available (2).

$$P_{Loss} = I^2 \cdot R$$

Where I is the current flowing in a particular transmission line in Amperes and R is the resistance of the transmission line in Ohms.

For the lines where current readings were unavailable, the apparent power (*S)* in MVA and voltage (*V*) readings were used to calculate the current using the equation below (3).

$$I = \frac{V}{S}$$

Due to the complexity of the 138-kV system, the losses were calculated by obtaining all the energy into the 138-kV system and subtracting all the energy leaving the 138-kV system.

The summary of losses for the different voltage levels in the transmission system are shown in **Table 2:**

	Voltage Level							
Loss Type	**500kV**	**345kV**	**230kV**	**161kV**	**138kV**	**(Stations) 138kV**	**69kV**	**46kV**
Lines	23,400	214,741	224,711	3,210	128,558	-	48,061	23,037
Core	7,148	9,909	39,915	990	9,088	36,450	9,210	5,827
Winding	6,005	3,504	18,393	6,222	4,931	35,175	7,065	3,961
Total Losses	**36,553**	**228,154**	**283,019**	**10,422**	**142,577**	**71,625**	**64,336**	**32,825**

Table 2: Type of Losses (MWh) by Voltage Level

The losses in the transmission transformers, generator step-up transformers and tie-banks, were calculated by adding the two components of the losses in a transformer, the winding losses, and the core losses.

The winding losses, also called copper losses, were calculated using (4):

$$Losses\ (MWh) = \sum_{n=1}^{N} (Hourly\ Usage)^2 \cdot \frac{R_{pu}}{100}$$

Where R_{pu} is the total per-unit resistance on a 100 MVA base and $Hourly\ Usage$ is the average hourly usage on the transformer in MWh.

The core losses were obtained using records from the Idaho Power Apparatus department "no-load losses" records. It was assumed that the transformers were energized the entire year. The total core losses for each transformer were calculated using (5):

$$Core\ Losses\ (MWh) = NLL \cdot \frac{8760}{1000}$$

Where NLL are the no-load losses in kWh for each transformer, and 8760 is the hours in the year 2022.

The total losses for the transmission level were found by adding the losses for the transmission lines and the losses for the transmission transformers. The total losses for the transmission system are shown below, broken down by voltage level and component type **Table 3**.

Transmission Losses By Voltage	
500kV	36,553
345kV	228,154
230kV	283,019
161kV	10,422
138kV	142,577
69kV	48,061
46kV	23,037
Total	**771,823**

Transmission Losses By Component	
Lines	665,718
Core	67,050
Winding	39,055
Total	**771,823**

Table 3: Transmission Losses (MWh) Breakdown

Distribution Substation Level Energy Losses

The distribution station losses were found by calculating the losses in the substation distribution transformers for the calendar year 2022. Distribution transformers are classified, in this study, as any transformer with a secondary voltage of 35-kV, 25-kV, or 12.5kV. The losses in other station apparatus equipment and bus are assumed to be negligible.

The losses in the station transformer were calculated using the same method used to calculate the losses in the transmission transformers using (3) and (4). For the few transformers that had no metering data available in Idaho Power's PI data custodian, the MV90 data was used. The total losses in the distribution stations are broken down by both voltage level and component type are shown in **Table 4**.

Stations Losses By Voltage	
500kV	-
345kV	-
230kV	-
161kV	-
138kV	71,625
69kV	16,275
46kV	9,788
Total	**97,688**

Stations Losses By Component	
Lines	-
Core	51,487
Winding	46,201
Total	**97,688**

Table 4: Station Losses (MWh) Breakdown

Distribution Level Energy Losses

The losses in the distribution level were determined by comparing the input to the system (feeder meter data) to the output (customer billing data). Losses were inputs (feeder meter data) minus outputs (customer billing data).

Distribution Line Transformer Losses

The distribution system losses can be separated into primary distribution and secondary distribution losses. The distribution losses can be split between line and transformer losses. The split was done by taking the average losses of the 138-k, 69-kV, and 46-kV systems as a proxy and determining what proportion of those losses were line losses and which were transformer losses. These proportions were then applied to the adjusted distribution losses to determine the distribution line losses and distribution transformer losses. The results of this calculation can be seen in **Table 5** below.

Line vs Transformer losses	
Line Losses	316,822
Transformer losses	178,213
Total Distribution Losses	**495,035**

2022 System Losses	
Avg Line Loss	64%
Avg Transformer Loss	36%

Table 5: Line vs Transformer Losses (MWh)

Primary-Secondary Distribution Losses Split

The split between the distribution primary and secondary lines losses was determined using the wire milage for the distribution primary and secondary systems. The line mileage was obtained from the form TAX650; the total distribution wire milage was found by adding up the total wire milage for the 12.5-kV, 25-kV, and 34.5-kV systems. From the TAX671 form, the primary line milage can be found broken down by number of phases; the mile milage was converted to wire mileage by multiplying it by the number of phases. The result is the total primary wire mileage which we can subtract from the total distribution wire mileage to find the secondary wire mileage.

Using the final wire mileage, it was determined that the primary lines make up 68% of the total wire mileage and the secondary lines make up the other 32%. These percentages can then be applied to the total distribution line losses to determine the primary and secondary specific line losses. These calculations can be seen in **Table 6** below.

Primary vs Secondary Losses	
Primary Line Losses	215,080
Secondary Line Losses	101,743
Total Line Losses	**316,822**
Primary Losses	215,080
Secondary Losses	279,955
Total Distribution Losses	**495,035**

Distribution Wire Mileage	
12.5kV	50,974.12
25kV	1,377.87
34.5kV	16,797.35
Total Line Mileage	**69,149.34**
Primary Line Mileage	
1 – Phase	13,250.97
2 – Phase	928.81
3 – Phase	10,611.49
Primary Wire Mileage	**46,943.06**
Secondary Wire Mileage	**22,206.28**
Total Wire Mileage	**69,149.34**

Table 6: Distribution Losses (MWh) Breakdown

The primary distribution losses consist only of the primary line losses, the total losses for the primary level is 214,985 MWh. The secondary distribution losses can be found by adding the distribution transformer losses from **Table 5** and the secondary line losses calculated above in **Table 6**, resulting in 279,955 MWh of losses for the secondary distribution level.

Losses Comparison with FERC Form 1

The losses obtained in the distribution system were added to the losses calculated from the levels above and compared to the FERC Forum 1 losses. Idaho Power collects hourly data via SCADA for all generation above 3 MW, for generation under the 3 MW limit there is no SCADA data being collected creating a mismatch on the total losses calculated via FERC Form 1 and the losses calculated in this study. To adjust for the generation without SCADA, the losses were adjusted in the distribution system to match the total losses reported in FERC Form 1. This calculation can be seen in **Table 7** below.

Calculated Distribution Losses	
Distribution Input	15,619,939
Distribution Output	15,120,270
Distribution Losses	**499,669**
Missing Losses	(4,634)
Corrected Losses	**495,035**

FERC Forum 1 Comparison	
FERC Total Energy	18,376,323
FERC Forum 1 Losses	1,238,735
Bridger/Valmy Losses	125,811
Total FERC Losses	1,364,546
Calculated Losses	1,369,180
Adjusted Losses	(4,634)

Table 7: Calculated Losses (MWh) Correction

Loss Coefficients Tables

Tables 8 and 9 contain the MWh losses in each of the level as well as the inputs and output to each level. **Table 8** shows the energy coefficients over the entire calendar year 2022 whereas **Table 9** shows the peak coefficients during the peak day in 2022.

2022 Energy Loss Coefficients Table - Wheeling Included (Values in MWh)						
Transmission Inputs		**Loss Coefficients**		**Losses**	**Transmission Outputs**	
Power Supply	11,325,243	Transmission	1.029	771,823	Retail Sales	151,444
Utility purchases	4,394,440				High Volt	1,318,132
PURPA/Cust Gen	1,950,434				Wheeling	9,114,526
Exchange IN	27,768				Exchange OUT	0
Wheeling IN	9,325,825					
Total	**27,023,710**	**Delivery Point Coefficient**	**1.029**	**771,823**	**Total**	**10,584,102**
Stations Inputs		Distribution Stations	1.006	97,688	**Stations Outputs**	
From Transmission	15,667,785				Direct Sales	946,593
					Wheeling	91,552
Total	**15,667,785**	**Delivery Point Coefficient**	**1.036**	**869,511**	**Total**	**1,038,145**
Primary Inputs		Distribution Primary	1.014	215,080	**Primary Outputs**	
From Stations	14,531,952				Sales	3,067,827
PURPA/Cust Gen	805,834				Wheeling	656
Total	**15,337,786**	**Delivery Point Coefficient**	**1.051**	**1,084,591**	**Total**	**3,068,483**
Secondary Inputs		Distribution Secondary	1.024	279,955	**Secondary Outputs**	
From Primary	12,054,223				Sales	11,704,706
NET Metering	92,076				Wheeling	117,676
					Street lighting	43,961
Total	**12,146,929**	**Total**	**1.076**	**1,364,546**	**Total**	**11,866,343**

Table 8: 2022 Energy Loss (MWh) Coefficients Table

Peak Loss Coefficients

An identical method to the annual losses coefficients was used in calculating the peak hour loss coefficients. For the calculated losses, the same equations were used but only for the data from July 14th at 7:00 PM. The inputs to the system were determined with the use of historical PI data from the same hour, along with MV90 hourly data. Some aspects were determined to be 0 or small enough to not influence the end results and were excluded to simplify the calculation. The results of this peak hour analysis are shown in **Table 9** below.

2022 Peak Loss Coefficients Table - Wheeling Included (Values in MWh)						
Transmission Inputs		**Loss Coefficients**		**Losses**	**Transmission Outputs**	
Power Supply	1,869	Transmission	1.037	181	Retail Sales	19
Utility purchases	1,500				High Volt	0
PURPA/Cust Gen	853				Wheeling	752
Wheeling IN	804					
Total	**5,026**	**Delivery Point Coefficient**	**1.037**	**181**	**Total**	**771**
Stations Inputs		Distribution Stations	1.005	20	**Stations Outputs**	
From Transmission	4,074				Direct Sales	108
					Wheeling	15
Total	**4,074**	**Delivery Point Coefficient**	**1.042**	**201**	**Total**	**123**
Primary Inputs		Distribution Primary	1.013	55	**Primary Outputs**	
From Stations	3,931				Sales	404
PURPA/Cust Gen	365				Wheeling	0
Total	**4,296**	**Delivery Point Coefficient**	**1.056**	**256**	**Total**	**404**
Secondary Inputs		Distribution Secondary	1.019	72	**Secondary Outputs**	
From Primary	3,837				Sales	3,765
Total	**3,837**	**Total**	**1.076**	**328**	**Total**	**3,765**

Table 9: 2022 Peak Loss (MWh) Coefficients Table

Avoidable Losses by On-Site Customer Generation

Customers with on-site generation could avoid some of the losses previously discussed in this report. However, there are losses, such as transformer core losses, that are not a function of load and will not be able to be avoided by customers with on-site generation

To determine the avoidable losses from customers with on-site generation, the losses due to transformer core-losses and distribution secondary were removed from the calculation and new coefficients were calculated. The avoidable losses were separated into two different periods, an on-peak period that covers June 15th to September 15th from 3:00pm to 11:00pm excluding Sundays and holidays and an off-peak period that cover the rest of the hours in the year.

Previously, the loss coefficients were determined for the entire year and for the peak hour. In order to determine the coefficients for the on-peak season, the hourly data from 138-kV system was used as proxy to modify the peak and energy calculations. The 138-kV system was chosen due to having all hourly data available and being a better representation on the Company loading at any given time.

The peak losses were modified to capture the load variability (and losses) that occurred from June 15th to September 15th. **Table 10** shows the adjustments to the peak coefficients to determine the on-peak avoidable losses.

2022 On-Peak Loss Coefficients Table - Adjusted VODER (Values in MWh)						
Transmission Inputs		**Loss Coefficients**		**Losses**	**Transmission Outputs**	
Power Supply	1,869	Transmission	1.034	164	Retail Sales	19
Utility purchases	1,500				High Volt	0
PURPA/Cust Gen	853				Wheeling	752
Exchange IN	0				Exchange	0
Wheeling IN	804					
Total	**5,026**	**Delivery Point Coefficient**	**1.034**	**164**	**Total**	**771**
Stations Inputs		Distribution Stations	1.003	14	**Stations Outputs**	
From Transmission	4,091				Direct Sales	108
					Wheeling	15
Total	**4,091**	**Delivery Point Coefficient**	**1.037**	**178**	**Total**	**123**
Primary Inputs		Distribution Primary	1.012	52	**Primary Outputs**	
From Stations	3,954				Sales	404
PURPA/Cust Gen	365				Wheeling	0
Total	**4,319**	**Delivery Point Coefficient**	**1.050**	**230**	**Total**	**404**
Secondary Inputs		Distribution Secondary	1.000		**Secondary Outputs**	
From Primary	3,863				Sales	3,863
Total	**3,863**	**Total**	**1.050**	**230**	Total	**3,863**

Table 10: Adjusted VODER Energy Losses (MWh) Coefficients Table

Similarly, the off-peak coefficients were modified to remove the on-peak data and obtained an off-peak coefficient. **Table 11** shows the modifications to the off-peak coefficients.

2022 Off-Peak Loss Coefficients Table - Adjusted VODER (Values in MWh)							
Transmission Inputs		**Loss Coefficients**		**Losses**	**Transmission Outputs**	
Power Supply	11,325,243	Transmission	1.026	697,937	Retail Sales	150,532
Utility purchases	4,394,440				High Volt	1,318,132
PURPA/Cust Gen	1,945,752				Wheeling	9,114,526
Exchange IN	53,368				Exchange	25,600
Wheeling IN	9,325,825					
Total	**27,044,628**	**Delivery Point Coefficient**	**1.026**	**697,937**	**Total**	**10,608,790**
Stations Inputs		Distribution Stations	1.003	45,753	**Stations Outputs**	
From Transmission	15,737,901				Direct Sales	946,593
					Wheeling	91,552
Total	**15,737,901**	**Delivery Point Coefficient**	**1.029**	**743,690**	**Total**	**1,038,145**
Primary Inputs		Distribution Primary	1.014	212,900	**Primary Outputs**	
From Stations	14,654,003				Sales	3,042,892
PURPA/Cust Gen	805,968				Wheeling	656
Total	**15,459,971**	**Delivery Point Coefficient**	**1.044**	**956,589**	**Total**	**3,043,548**
Secondary Inputs		Distribution Secondary	1.000		**Secondary Outputs**	
From Primary	12,203,524				Sales	12,203,524
Total	**12,203,524**	**Total**	**1.044**	**956,589**	Total	**12,203,524**

Table 11: Adjusted VODER Peak Losses (MWh) Coefficients Table

The avoidable losses coefficients are shown in **Table 12** below.

VODER		
System Level	**Off-Peak Loss Coefficient**	**On- Peak Loss Coefficient**
Transmission	1.026	1.034
Distribution Station	1.029	1.037
Distribution Primary	1.044	1.050
Distribution Secondary	1.044	1.050

Table 12: Adjusted VODER Delivery Point Loss Coefficients

Appendix A: 2012 Energy Losses Data Sources

Transmission Inputs	Value (MWh)	Data Source	Notes
Power Supply Generation	11,325,243	FERC Form 1 p 401a line 9	
Utility Purchases	4,394,440	FERC Form 1 p 326.8 - 327.12 col g (Subset of Utility Purchases FERC Form 1 p 401a line 10)	OATT Power purchases from utilities/entities not directly connected to IPC system
PURPA/Cust Gen	1,950,434	FERC Form 1 pp 326-327.7 col g (Subset of Utility Purchases FERC Form 1 p 401a line 10)	Power purchased from non-IPC owned generation connected to IPC transmission system
Exchange In	27,768	FERC Form 1 p 401a line 12	Details on FORM 1 p 326.12-327.13 See "FF1 326-327.xlsx"
Wheeling In	9,325,825	FERC Form 1 p 401a line 16	File: "Wheeling Form 1 Detail.xlsx"
Transmission Outputs			
High Voltage Sales	1,318,132	FERC Form 1 p 401a line 24	Details on Form 1 p 311
Exchange Out	25,600	FERC Form 1 p 401a line 12	Details on FORM 1 p 326.12-327.13 See "FF1 326-327.xlsx"
Wheeling Out	9,114,526	FERC Form 1 p 401a line 17	File: "Wheeling Form 1 Detail.xlsx"
Retail Transmission Sales	151,444	FERC Forum 1 – p 304	FERC Forum 1 – p 304 Rate 9T, 19T, and Unbilled Rev. Large
Distribution Station Outputs			
Direct Station Sales	946,593	FERC Forum 1 – p 304	FERC Forum 1 – p 304 Special Contracts
Wheeling Out	91,552	Operation Data	File: "Wheeling Form 1 Detail.xlsx"
Distribution Primary Inputs			
PURPA	805,834	PURPA gen connected to IPC Primary distribution system from FERC Form 1 p 326-327.7 col g	Subset of Utility Purchases FERC Form 1 p 401a line 10 Total from p 401a line 10 is split by system level on spreadsheet: "FF1 326-327.xlsx"

Distribution Primary Outputs			
Direct Primary Sales	3,067,827	FERC Forum 1 – p 304	FERC Forum 1 – p 304 Rate 09P, 19P, 08, and Unbilled Rev. Small
Wheeling Out	656	Operations Data	File: "Wheeling Form 1 Detail.xlsx"
Distribution Secondary Inputs			
Net Met/Ore Solar	92,076	Operations Data	"IPC_Exports_by_Class.xlsx"
Distribution Secondary Outputs			
Distribution Sales	11,704,706	FERC Forum 1 – p 304	FERC Forum 1 – p 304 07, 09S, 19S, 24S, Total Billed Residential Sales – Rate 15., and Unbilled Rev.
Street Lighting	43,961	FERC Forum 1 – p 304	FERC Forum 1 – p 304 Rate 15, 40, and TOTAL Billed Public Street and Highway Lighting
Wheeling Out	117,676	Operations Data	File: "Wheeling Form 1 Detail.xlsx"

Appendix B: 2012 Peak Losses Data Sources

Transmission Inputs	Value (MW)	Data Source	Notes
Power Supply Generation	1,869	Pi	
Utility Purchases	1,500	Pi	see file "Peak_day_data.xlsx"
PURPA/Cust Gen	853	Pi	
Wheeling In	804	Operations data on peak hour	File: "Wheeling Forum 1 Detail.xlsx"
Transmission Outputs			
Retail Sales	19	Transmission customer sales from MV90 data: filename "MV90 2022 8760.xlsx"	
Wheeling Out	752	Pi	File: "Wheeling Forum 1 Detail.xlsx"
Distribution Station Outputs			
Direct Station Sales	108	Sales from MV90 data: filename "MV90 2022 8760.xlsx"	
Wheeling Out	15	Pi	File: "Wheeling Forum 1 Detail.xlsx"
Distribution Primary Inputs			
PURPA	365	Pi	
Distribution Primary Outputs			
Direct Primary Sales	404	Sales from MV90 data: filename "MV90 2022 8760.xlsx"	
Distribution Secondary Outputs			
Wheeling Out	36.9	Pi	File: "Wheeling Forum 1 Detail.xlsx"

Appendix D: Reconciliation with FERC Form 1

The data used in the development of the energy loss coefficients in this report is consistent with that reported in the 2022 FERC Form 1, page 401a. Values used in Figure 1 are reconciled with values in 2022 FERC Form 1 below.

System Losses

Item	Figure 1 MWh	2012 FERC Form 1 MWh	Comment
Total System Losses	1,364,546	1,238,725	Form 1, pg 401a, line 27
Adjustment for Bridger Loss Transactions		124,135	Bridger Loss transactions counted as system outputs in Form 1 (part of total in Form 1, pg 401a, line 13)
Adjustment for Valmy Loss Transactions		1,676	Valmy Loss transactions counted as system outputs in Form 1 (part of total in Form 1, pg 401a, line 13)
Adjusted Total	1,364,546	1,364,180	

The ratio of Adjusted FERC Form 1 losses to Figure 1 losses is 99.66%. Reasons for the small discrepancy may include non-uniformity between the calculation method used to determine transmission losses on the Bridger and Valmy subsystems in this study versus the calculation method used to determine the actual loss transactions and estimation methods used where small amounts of data were missing in the tabulation of individual level losses.

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-23-14

IDAHO POWER COMPANY

ELLSWORTH, DI
TESTIMONY

EXHIBIT NO. 5

Variable Energy Resource (VER) Integration Analysis

Idaho Power Company

December, 2020

Energy+Environmental Economics

Variable Energy Resource (VER) Integration Analysis

Idaho Power Company

December 2020

Energy and Environmental Economics, Inc.
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Executive Summary

Energy and Environmental Economics, Inc. (E3) was retained by Idaho Power to investigate the integration cost of variable energy resources in Idaho Power's service territory. These costs are incurred due to increased dispatchable unit cycling (from increased unit stops and starts; increased load following ramping) and imperfect unit commitment and dispatch (resulting in higher average thermal unit heat rates and/or lower net market earnings); and, in cases in which economic VER curtailment is allowed, increased curtailment costs. E3's analysis calculates both average and incremental integration costs on a $/MWh basis, using the proposed unit additions and retirements to Idaho Power's 2023 system as a base case.

The study examines eleven cases of potential future VER builds in Idaho Power territory. These cases are illustrated below in Table ES1. These include high wind and high solar builds; cases in which low, average and high annual hydro energy budgets are simulated; cases in which there is solar plus investment tax credit (ITC)-enabled storage; cases in which solar can be economically curtailed; and a case in which a planned unit retirement at the Bridger coal plant is not in effect in 2023. As can be seen in Table ES1, the overall incremental integration costs were found to range from $0.64/MWh-$4.65/MWh. Generally, these costs are lower than those in the 2018 Idaho Power VER Integration Analysis, although it is notable that the method of deriving integration costs was substantially different in the last study.[1]

Table ES1: Case Description and Results Summary

Case	Description	First Bridger Unit	Proposed Existing 2023 Solar Capacity (MW)	Proposed Existing 2023 Wind Capacity (MW)	Hydro Year	Amount of New VER Added to Existing 2023 Builds: New 2023 Solar Build (MW)	Amount of New VER Added to Existing 2023 Builds: New 2023 Wind Build (MW)	Can New Solar be Curtailed?	New Solar-Coupled 4-hr Li-Ion Battery Build (MW)	Total Integration Cost
1	Base 2023 Case	Retired	561	728	Normal	0	0	No	0	$ 2.93
2	Base Case + First Bridger Unit Online	Online	561	728	Normal	0	0	No	0	$ 3.61
3	High Solar	Retired	561	728	Normal	794	0	No	0	$ 3.86
4	High Solar, Low Hydro	Retired	561	728	Low	794	0	No	0	$ 4.55
5	High Wind	Retired	561	728	Normal	0	669	No	0	$ 0.77
6	High Solar, High Wind	Retired	561	728	Normal	794	669	No	0	$ 2.46
7	Existing Solar Base Case	Retired	310	728	Normal	0	0	No	0	n/a
8	High Solar, High Hydro	Retired	561	728	High	794	0	No	0	$ 4.65
9	High Solar + 200 MW Storage	Retired	561	728	Normal	794	0	No	200	$ 0.64
10	High Solar + 400 MW Storage	Retired	561	728	Normal	794	0	No	400	$ 0.93
11	Curtailable Solar	Retired	561	728	Normal	794	0	Yes	0	$ 3.13

E3 believes that the integration costs in this study are lower than previous studies primarily due to four factors: 1) Reduced need for modeled ancillary services, 2) The fact that the remaining 2023 coal fleet is modeled as must-run (i.e. its commitment decisions are not affected by VER penetration), 3) Access to the Energy Imbalance Market (EIM) makes it easier to use market transactions to

[1] https://docs.idahopower.com/pdfs/AboutUs/PlanningForFuture/wind/VariableEnergyResourceIntegrationAnalysis.pdf

integrate VERs (the EIM was not included in the previous study) and 4) Allowing additional system flexibility, in some cases (e.g. from batteries).

The integration costs calculated in this current effort specifically do not consider fuel savings or capacity contributions from, nor do they consider the capital costs of new VERs. Therefore, this VER integration cost study serves as a valid basis for calculating integration costs but may not include all economic and operational factors required to integrate VERs on the Idaho Power system.

Table of Contents

1 Introduction

1.1 Motivation and Background

In 2019, Idaho Power committed to using 100 percent clean energy by 2045. While more than 50 percent of Idaho Power's annual load was served by clean resources in 2018 (primarily from hydroelectricity, with some additional wind and solar resources), Idaho Power may potentially add significant amounts of variable energy resources (VERs), such as wind and solar power, to achieve this 2045 goal.

Energy and Environmental Economics (E3) was retained by Idaho Power to perform a study of the cost of integrating new VERs into Idaho Power's system. Idaho Power has periodically performed these studies and analyses to inform regulatory proceedings, and to determine integration charges included in Public Utility Regulatory Policies Act (PURPA) contracts. Idaho Power hired E3 to update integration costs. E3 conducted this analysis by designing a suite of scenarios that are relevant to the 2023 timeframe.

The following report details the modeling methodology, data collection and assumptions, and results from E3's 2020 investigation of VER integration costs for Idaho Power.

2 Methodology

2.1 Calculating VER Integration Costs

E3 used five metrics to estimate the total cost of VER integration to Idaho Power's system. These were:

- Start/Stop Costs: The costs resulting from changes in unit start and stop counts due to differing patterns of net load fluctuations caused by higher VER penetration
- Ramping Costs: The costs resulting from changes in unit ramping due to differing patterns of net load fluctuations caused by higher VER penetration
- Imperfect Unit Commitment and Dispatch Costs (Fuel Costs): The costs resulting from holding a greater amount of committed dispatchable resources operating at part load and lower efficiency. These resources operate at part load to provide reserves necessary to manage increased VER-induced forecast error and subhourly net load variability
- Imperfect Unit Commitment and Dispatch Costs (Net Import Costs): The costs resulting from suboptimal market transactions due to holding more headroom and footroom on generators to account for increased VER-induced forecast error and subhourly net load variability
- Curtailment Costs: In all cases, VERs are assumed to be contracted on a take-or-pay basis (i.e. all VER energy is paid for whether it is consumed or not). However, in the case in which solar can be economically curtailed, Idaho Power would incur a cost from no longer generating a renewable

energy credit (REC). This REC cost is factored into the integration cost for that case.

The total VER integration cost for each case is calculated by summing each of these costs.

To calculate these costs, E3 performed three model runs for each of the eleven analyzed cases. In the first model run, E3 ran a 2023 "base case" model that served as the reference point for each of the subsequent investigated cases. The base case included potential unit additions and retirements, the relevant hydro budget, as well as projected load growth from 2019 through 2023. Next, E3 ran an intermediate "perfect foresight" case in which any new VER additions beyond the 2023 base case have perfect foresight (i.e. no new forecast error reserves are held vs. the base case), and the new VER profiles are "smoothed" on a subhourly timescale (i.e. no new regulation reserves are held vs. the base case). This perfect foresight case is designed specifically to look at the effect of forecast error and subhourly variability from VERs on integration costs, not factoring in savings from extra energy provided by new VER additions. Finally, E3 ran a case with higher VER-induced regulation reserves and higher net load forecast error reserves. The formulae for calculating integration costs from these three cases are provided below. In the formulae, "Case j" refers to an individual case for which E3 calculated the VER integration costs. The "base case" is the 2023 base case common to all but two of the evaluated cases. The remaining two cases are the 2023 base case and the base case with Bridger Unit 1 cases. These use the existing solar case instead of the 2023 base case due to the need for an incremental VER build to assess the integration costs in the equations provided below. The resulting Total Integration Costs pursuant to this study are calculated in units of

$/MWh. The graphical depiction of this three-part process is also shown below in Figure 1.

$$\boldsymbol{Incremental\ Start\ Costs\ for\ Case\ j}$$
$$= \Sigma_{All\ Units}\ Start\ Cost_{Unit\ i} * (Annual\ Start\ Count_{Unit\ i,Case\ j} - \ Annual\ Start\ Count_{Unit\ i,Base\ Case})$$

$$\boldsymbol{Incremental\ Ramping\ Costs\ for\ Case\ j}$$
$$= \Sigma_{All\ Units}\ Ramping\ Cost_{Unit\ i} * (Cumulative\ RT5\ MW\ Ramping_{Unit\ i,Case\ j} - Cumulative\ RT5\ MW\ Ramping_{Unit\ i,Base\ Case})$$

$$\boldsymbol{Incremental\ Imperfect\ Unit\ Commitment}\ \&\ \boldsymbol{Dispatch\ Cost\ for\ Case\ j}$$
$$= \Sigma_{All\ Units}\ Fuel\ Cost_{Unit\ i} * (Fuel\ Use_{Unit\ i,\text{"Perfect Foresight"}\ Case\ j}) + (Net\ Import\ Cost_{Case\ j} - Net\ Import\ Cost_{\text{"}Perfect\ Foresight\text{"}\ Case\ j})$$

Note: the page prints the Fuel Use terms as $(Fuel\ Use_{Unit\ i,Case\ j} - Fuel\ Use_{Unit\ i,\text{"Perfect Foresight"}\ Case\ j})$:

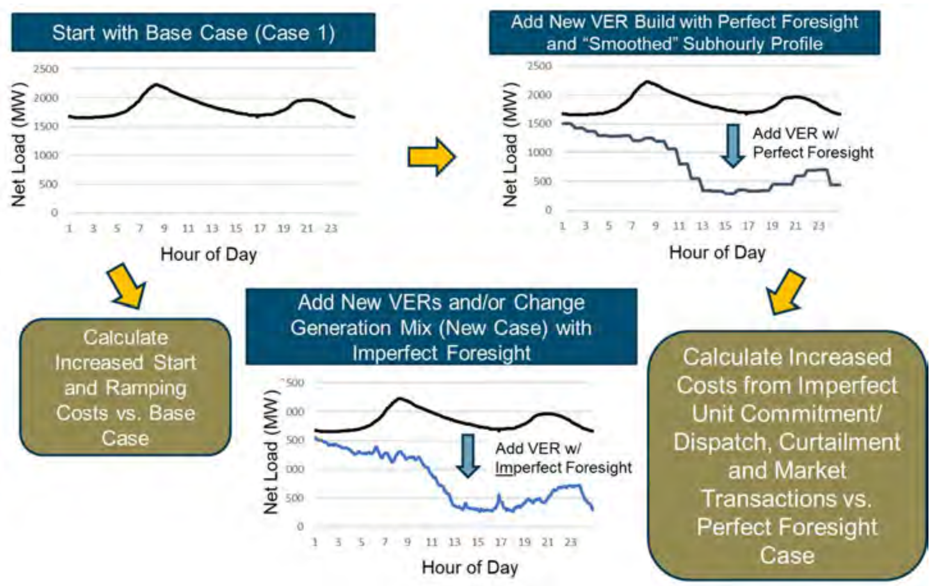
$$= \Sigma_{All\ Units}\ Fuel\ Cost_{Unit\ i} * (Fuel\ Use_{Unit\ i,Case\ j} - Fuel\ Use_{Unit\ i,\text{"Perfect Foresight"}\ Case\ j}) + (Net\ Import\ Cost_{Case\ j} - Net\ Import\ Cost_{\text{"}Perfect\ Foresight\text{"}\ Case\ j})$$

$$\boldsymbol{Incremental\ Curtailment\ Costs\ for\ Case\ j}$$
$$= \Sigma_{All\ Units}\ Curtailment\ Cost_{Unit\ i} * (Cumulative\ RT5\ MW\ Curtailment_{Unit\ i,Case\ j} - Cumulative\ RT5\ MW\ Curtailment_{Unit\ i,\text{"}Perfect\ Foresight\text{"}\ Case\ j})$$

$$\boldsymbol{Total\ Integration\ Cost_{Inc.,Case\ j}} = (Inc.Start\ Cost_{,Case\ j} + Inc.Ramping\ Cost_{,Case\ j} + Incremetnal\ Imperfect\ Unit\ Commitment\ and\ Dispatch\ Cost_{,Case\ j} + \ Inc.Curt.Cost_{,Case\ j})$$

$$\frac{\begin{gathered}\boldsymbol{Tot.\,Integration\,Cost_{Inc.,Case\,j}} = \\ (Inc.\,Start\,Cost_{,Case\,j} + Inc.\,Ramping\,Cost_{,Case\,j} + \\ Inc.\,Imperfect\,Unit\,Comm.\,and\,Disp.\,Cost_{,Case\,j}\end{gathered}}{VER\,Energy\,Potential_{,Case\,j} - VER\,Energy\,Potential_{,Base\,Case}}$$

Figure 1: VER Integration Cost Calculation Methodology



This methodology for deriving VER integration costs does not calculate various costs and benefits from the VER additions. Additionally, this method does not calculate fuel cost savings due to VER deployment, nor the capacity value of new VERs in offsetting the need for firm generation unit additions. This method also does not calculate capital or PPA costs associated with contracting new VERs. Therefore, the future use of these VER integration costs must be done with knowledge and awareness of what costs and benefits they omit.

2.2 Production Cost Modeling

E3 used Energy Exemplar's PLEXOS 7.2 Software[2] to calculate the total production costs associated with each evaluated case. The model uses load, VER, generator, fuel cost and external market data provided by Idaho Power and other data sources to calculate annual production costs for Idaho Power under varying scenarios, which are then used to calculate VER integration costs. This is shown schematically below in Figure 2.

In order to perform this modeling, E3 used a four-stage PLEXOS model. For each day, the model sequentially solves the day-ahead (DA), hour-ahead (HA), 15-minute (RT15) and 5-minute (RT5) markets. In each stage, the model is solved completely (i.e. all units and transmission committed and dispatched). Then, any unit commitment or other model decisions with a lead time longer than the next phase's lead time to the real time are passed down to the next stage. In this manner, the model approximates the actual unit commitment and dispatch constraints associated with the longer commitment times of thermal and transmission markets. This captures the effects of greater average forecast error and higher average reserves in model stages that are farther from the real time on the ability of Idaho Power to efficiently commit long start units. This daily sequential model execution process is depicted in Figure 3.

[2] https://energyexemplar.com/solutions/plexos/

Figure 2: Using PLEXOS to Calculate VER Integration Costs

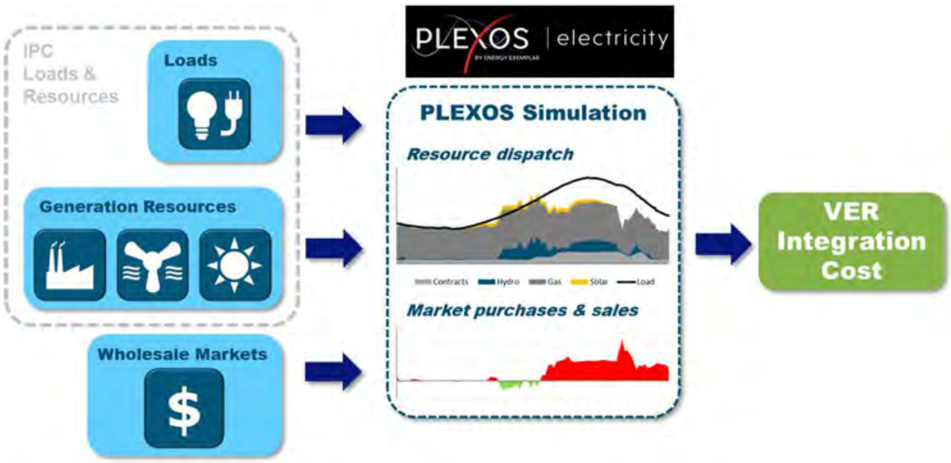
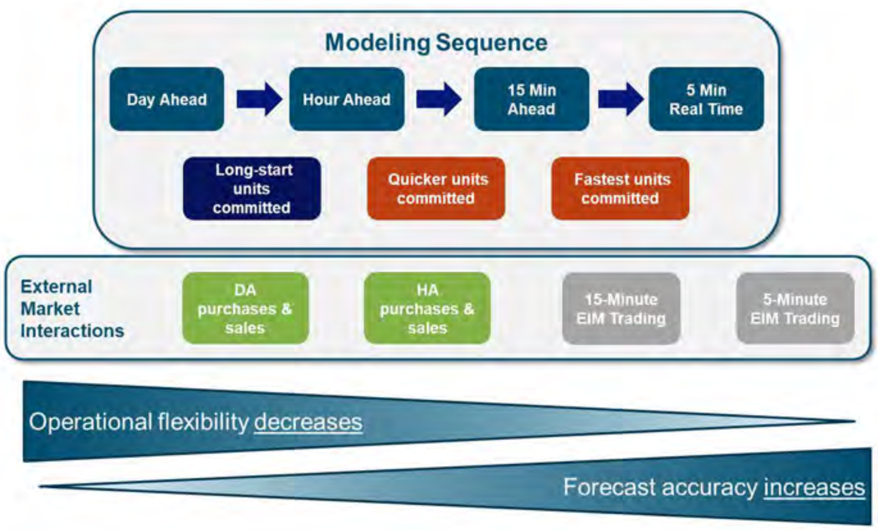


Figure 3: PLEXOS Multistage Modeling



The change in start/stop cost, and the imperfect unit commitment costs are calculated endogenously in PLEXOS. However, E3 used data from the 2013 National Renewable Energy Laboratory's (NREL) *Western Wind and Solar*

Integration Study: Phase 2[3] to estimate $/MW ramping costs for Idaho Power's thermal units. The annual total ramping costs were calculated as a post-processing step by calculating the total annual MW of ramping in the RT5 stage for each thermal unit, and multiplying that by the per MW ramping cost from NREL. The $/MW values that E3 used are shown in Table 2 below.

Table 2: Ramping Costs Used in Study (Sourced from NREL[4])

Value	Coal	Gas GT	Gas CCGT
Median Ramping Cost ($/MW)	$3	$2	$1

2.3 Reserve Modeling

E3 used its RESERVE tool[5] to model 2019 and 2023 levels of hourly reserves that Idaho Power needs to hold in each PLEXOS interval. This is done to account for the fact that Idaho Power needs to hold reserves to manage net load forecast error and subhourly net load variations in its daily operations.

Idaho Power's participation in the California Independent System Operator's (CAISO's) Energy Imbalance Market (EIM) means that Idaho Power holds reserves of CAISO's Flexible Ramping Product[6] (FRP). It must do this so that it can trade in the RT15 and RT5 EIM markets. Additionally, Idaho Power holds amounts of regulation reserves and contingency reserves dictated by the North American

[3] https://www.nrel.gov/docs/fy13osti/55588.pdf
[4] https://www.nrel.gov/docs/fy13osti/55588.pdf
[5] https://www.ethree.com/tools/reserve-model/
[6] http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedClosedStakeholderInitiatives/FlexibleRampingProduct.aspx

Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC).

While the derivation of contingency reserves is standardized (calculated as 3 percent of load and 3 percent of generation total, with at least half held as for spinning reserves and the rest as non-spinning reserves), Idaho Power's future CAISO FRP and regulation reserve needs are unknown. This is because future VER additions and load growth will increase the level of net load forecast uncertainty on Idaho Power's system relative to current conditions. Therefore, E3 used its RESERVE tool along with Idaho Power's 2019 forecast and actual load and VER data to simulate reserves that approximate the CAISO FRP and regulation needs. E3 also used RESERVE to calculate CAISO FRP and regulation reserves in 2019 to enable a consistent baseline for model comparisons.

These contingency, CAISO FRP and regulation reserves were input to the PLEXOS model such that the reserves are held in all time intervals. Further information on the derivation of the 2023 load and VER profiles for each analyzed case are provided in subsequent sections of this report.

3 Data Collection, Processing and Methods

3.1 PLEXOS Modeling

3.1.1 LOAD PROFILES, VER PROFILES AND DISPATCHABLE GENERATION FLEET

E3 collected forecast and actual gross load, wind and solar profiles for 2019 from Idaho Power for the DA, HA, RT15 and RT5 phases. The VER data was on a plant-level basis and covered most of Idaho Power's existing PURPA and Idaho Power-owned facilities, with only a few small wind and solar plants omitted from the data collection process due to their small effect on net load forecast error. Idaho Power also provided the total 2019 wind and solar nameplate build in Idaho Power territory so that E3 could use a correct baseline VER build in its analysis.

Idaho Power's 2019 average load was 1,980 aMW. To estimate 2023 loads, E3 used load growth projections from Idaho Power to uniformly increase 2019 loads by approximately 5 percent total to 2,081 aMW. The method for deriving new 2023 VER profiles is detailed below, but the 2019 historical VER profiles were used in all cases to derive the 2023 VER profiles.

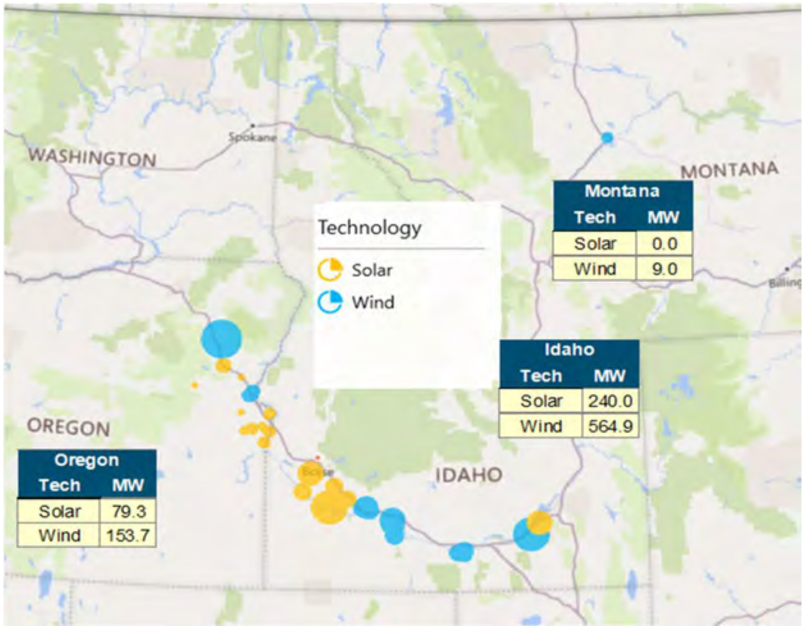
In all cases, E3 modeled existing and proposed solar, solar + storage and wind plants as qualifying facilities (QF) operating under PURPA. This means that, under all circumstances except for one case, these resources are treated as must take facilities.

E3 chose to use 2019 load and VER data to derive 2023 load and VER profiles in order to capture the spatial and temporal correlations between load, wind and solar production and forecast error, as well as the typical hourly and seasonal distributions of load, and VER production. Most of Idaho Power's existing solar capacity is modern, single-axis tracking utility solar, meaning that future installations were likely to have similar annual capacity factors as existing arrays. Idaho Power's solar and wind is mostly distributed across the Snake River Plain and Eastern Oregon, as shown below in Figure 4, because this is where the majority of existing Idaho Power transmission and load is, and it is also the best solar resource in Idaho Power's service territory. Idaho Power stated that they are likely to continue to add new VER resources within the Snake River Plain. Therefore, E3's use of 2019 VER profiles to represent future profiles is reasonable.

Idaho Power proposed that, for the 2023 base case, it was reasonable to assume that 251 MW of new solar was online in their service territory (131 MW of unspecified PURPA contracts and 120 MW from the planned Jackpot Solar facility). Idaho Power also proposed that the 2023 wind capacity remain the same as that from 2019.

Idaho Power provided detailed information on each of its thermal (coal, natural gas combustion turbine, natural gas combined cycle and diesel) plants, as well as its hydroelectric fleet. Unit outages, heat rates, fuel prices and other relevant data were collected. Coal plants are modeled as must-run units with seasonal outages for Idaho Power's North Valmy Generating Station. Combined Cycle plants (Langley Gulch) are committed in the hour-ahead timeframe and the gas combustion turbine fleet has subhourly commitment intervals.

Figure 4: Existing Idaho Power VER Units for which E3 was Provided 2019 DA, HA, RT15 and RT5 Profiles



Given the large share of hydroelectricity on Idaho Power's system, E3 focused on ensuring proper representation of the hydro fleet's capacity, ramping capability, daily energy budgets, hourly maximum and minimum power ratings and other such data. Additionally, E3 considered three hydro years, comprising representative "low," "average," and "high," hydro years. These profiles were determined by Idaho Power by choosing from historical data. The average daily energy profiles for these low, average and high hydro years are shown in Figure 5.

Planned future coal unit retirements through 2023 were modeled per Idaho Power input. The overall planned change in fleet composition from 2019 to 2023, as well as the total unit capacities by generation type are provided in Table 3.

Idaho Power's projected base case load and resource balance is shown below in Figure 6.

Table 3: 2019 and 2023 Base Case Unit Capacities by Generator and Resource Type

Unit Name	Unit Type	2019 Capacity (MW)	2023 Capacity (MW)	Change in Capacity
Boardman	Coal	60	0	-60
Bridger	Coal	706	532	-174
Valmy	Coal	261	130	-130
Bennett Mountain	Gas CT	173	173	0
Danskin 1	Gas CT	180	180	0
Danskin 2	Gas CT	45	45	0
Danskin 3	Gas CT	45	45	0
Langley Gulch	Gas CCGT	319	319	0
Idaho Wind	Wind	728	728	0
Idaho Solar	Solar	310	561	+251
Hells Canyon Complex	Hydro	843	843	0
Run-of-River	Hydro	539	539	0

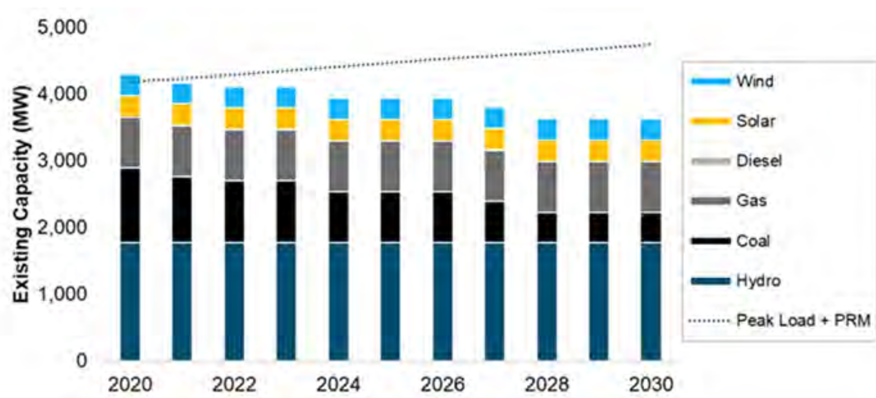
Figure 5: Daily High, Average and Low Hydro Energy Budget Profiles for Idaho Power

3.1.2 EXTERNAL MARKET REPRESENTATION

Idaho Power was modeled as being able to trade with external electricity markets at the Palo Verde and Mid C hubs. In the DA and HA stages of the model, Idaho

Power can make bilateral trades with its neighbors, while incurring a hurdle rate to do so.

Figure 6: Base Case Load and Resource Balance in Idaho Power through 2030



E3 determined historical 2019 bilateral energy prices, hurdle rates, and transfer limits through discussions with Idaho Power. In the RT15 and RT5 stages, Idaho Power can trade with its neighbors in a manner consistent with Idaho Power's participation in the CAISO EIM, i.e. there are no hurdle rates, but there are transfer limits. In the RT15 and RT5, Idaho Power trades electricity at the RTPD (RT15) and RTD (RT5) 2019 EIM prices for the DGAP_IPCO_APND node, which is an aggregated node that averages Idaho Power prices. E3 benchmarked the 2019 DGACP_IPCO_APND node prices versus 2019 nodal prices for the Elkhorn, High Mesa and Rockland plants and found that the aggregated node provided a satisfactory representation of these various wind plants.

In Q1 of 2019, there was a natural gas pipeline outage in the Alberta Electricity System Operator (AESO) service territory, which inflated market prices in the Pacific Northwest. Accordingly, E3 replaced the Q1 2019 market prices with Q1

2020 market prices for the DA, HA, RT15 and RT5 phases. Additionally, given the 2023 timeframe of the model, E3 used its AURORA Market Price forecasts to create a month-hourly average basis differential between 2023 and 2019. This was added to the historical market prices in order to reflect the effect of anticipated growth of VERs and storage across the Western Interconnection from 2019 through 2023, among other changes.

E3 benchmarked the historical interaction of the Elkhorn, High Mesa and Rockland wind plants with the EIM. E3 found its representation of Idaho Power's interactions with the EIM to be reasonable.

Finally, E3 combined Idaho Power's multiple hydroelectric projects into two units for modeling simplicity. One unit consisted of aggregated run-of-river (RoR) plants, whose output is largely inflexible and in flat hourly blocks, and the other consisted of the combined Hells Canyon Complex (HCC) units (consisting of the Oxbow, Brownlee and Hell's Canyon dams), whose output can be varied within certain time windows. This division of Idaho Power's hydroelectric assets into two aggregated units was done to reflect the variation in flexibility, water storage and dispatchability across Idaho Power's hydro fleet.

Planned future coal unit retirements through 2023 were modeled per Idaho Power input. The overall planned change in fleet composition from 2019 to 2023, as well as the total unit capacities by generation type are provided in Table 3. Idaho Power's projected base case load and resource balance is shown in Figure 6.

3.2 RESERVE Modeling

3.2.1 DERIVATION OF 2023 VER PROFILES

As new VER resources are added, the average forecast error and subhourly variability of the aggregated fleet will decline on a per MW of installed resources basis. This is due to well-known diversity effects (i.e. as solar and wind plants are installed at different locations, the average forecast error and subhourly variation across all units will tend to decline on a per MW basis). Additionally, based on experience in other jurisdictions, E3 assumed that there will be improvements to VER forecast error in the future.

In order to capture these effects while using the 2019 VER data, E3 assessed the reduction in forecast error and subhourly variability that Idaho Power has observed to date. A similar approach was taken in Idaho Power's 2018 Variable Energy Resource Analysis. E3 performed this through the following steps

+ Randomly order the forecast and actual profiles for existing wind and solar that Idaho Power provided to E3
+ Sequentially add solar profiles or wind profiles, each time calculating the average forecast error and regulation reserves of the aggregated solar or wind profiles using RESERVE
+ Fit a polynomial trend to the average reserves versus the total MW of online VERs for the solar and wind profiles

- From prior work in the CAISO Extended Day Ahead Market project[7], E3 assumed a 2 percent per annum improvement in VER forecasting (average mean average percentage error reduction)
- For each future VER build, linearly scale up the 2019 VER forecast and actual profiles by the ratios of future VER build total online MW to 2019 online MW
- Reduce the forecast error equally in all intervals using the polynomial trend fit to forecast error data and using the estimated 2 percent per annum improvement in forecast error from 2019 to 2023
- Reduce the subhourly interval-to-interval variation by the amount derived from the polynomial trend fit to the regulation error data
- Run RESERVE for this new set of profiles; and
- Input these new set of profiles to PLEXOS

Using this process, the average standalone (i.e. not net-load-based) HA forecast error reserves and regulation reserves for wind and solar would decline as shown below in Table 4. These data show the reduction in average forecast error and regulation needs across all hours of the year, *relative* to a case with no diversity benefits or forecast error improvements and the same VER unit additions.

As can be seen in Table 4, E3 projects that regulation reserves will drop more on a percentage basis than CAISO FRP reserves needs will in the high solar and high wind cases. This is consistent with the larger percentage increase in solar build than wind build in the high solar versus high wind cases, respectively.

[7] https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market

Table 4: Average Projected Improvement in Forecast Error and Regulation Reserves from Diversity and Forecasting Improvements

Case	Average CAISO FRP Reserve Improvement	Average Regulation Reserve Improvement
Base 2023 Case Solar (251 MW new solar added to 2019 build)	11.7 %	14.2 %
Base 2023 Wind Case (0 MW new wind added to 2019 build)	7.8 %	0.0 %
2023 Hi Solar Case (794 MW new solar added to 2019 build)	17.2 %	31.6 %
2023 Hi Wind Case (669 MW new wind added to 2019 build)	13.2 %	19.1 %

3.2.2 DERIVING RESERVES COMPONENTS

The CAISO FRP's reserves for each interval consist of an uncertainty component, plus a net load change from the previous interval, minus a credit component based on the lesser of either the EIM-wide average footprint diversity or the Balancing Authority's (BA) trading position-derived credit. E3 used the information provided by Idaho Power on forecast and actual load, wind and solar to derive uncertainty requirements for the CAISO FRP. Given E3's simplified representation of Idaho Power's external market transactions, E3 assumed that the credit component of the reserve created a 40 percent reduction versus the uncertainty component alone. This 40 percent value is an approximate value, and was calculated using average historically-observed EIM footprint diversity in

2019.[8] This derivation, and its differences from the 2018 Idaho Variable Energy Resource Integration Study is further discussed in Section 5.3.2.

3.3 Case Matrix

E3 and Idaho Power worked together to derive a total of eleven 2023 cases to examine, in addition to a 2019 base case, which are described below. Table 5 details the specifics of each case.

+ Case 1 is the 2023 base case for Cases 3-6 and Cases 8-11, which has proposed unit additions and retirements and also includes the known 2019 through 2023 load growth
+ Case 2 explores the effect of not retiring one of the Bridger coal plant's units, but is otherwise identical to Case 1
+ Case 3 builds on Case 1 by exploring the effect of adding enough new solar (794 MW of new solar) such that 10 percent of the 2023 Idaho Power average gross load is provided by this new solar build
+ Case 4 extends the Case 3 analysis to a low, rather than average hydro year
+ Case 5 builds on Case 1 and explores the integration costs of a high wind build. Case 5 assumes a new wind build that can supply 10 percent of the annual 2023 Idaho Power gross load (669 MW of new wind)
+ Case 6 builds on Case 3 and Case 5, including both high solar and high wind builds (794 MW of new solar and 669 MW of new wind)

[8] https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx

- Case 7 is identical to Case 1, except that none of proposed solar additions come online from 2019 to 2023, resulting in 251 MW fewer of solar than Case 1 and lower reserves needs
- Cases 8 extends the Case 3 analysis to a high, rather than average hydro year
- Case 9 extends the Case 3 analysis to have 200 MW of 4-hour, Federal Investment Tax Credit (ITC)-enabled Li-Ion battery storage
- Case 10 extends the Case 3 analysis to have 400 MW of 4-hour, ITC-enabled Li-Ion battery storage
- Case 11 extends the Case 3 analysis to allow economic curtailment of the 794 MW of new solar resource, while the 561 MW of existing and proposed solar remain must-take resources

Table 5: Case Matrix for 2023 Cases

Case	Description	First Bridger Unit	Proposed Existing 2023 Solar Capacity (MW)	Proposed Existing 2023 Wind Capacity (MW)	Hydro Year	Amount of New VER Added to Existing 2023 Builds New 2023 Solar Build (MW)	New 2023 Wind Build (MW)	Can New Solar be Curtailed?	New Solar-Coupled 4-hr Li-Ion Battery Build (MW)
1	Base 2023 Case	Retired	561	728	Normal	0	0	No	0
2	Base Case + First Bridger Unit Online	Online	561	728	Normal	0	0	No	0
3	High Solar	Retired	561	728	Normal	794	0	No	0
4	High Solar, Low Hydro	Retired	561	728	Low	794	0	No	0
5	High Wind	Retired	561	728	Normal	0	669	No	0
6	High Solar, High Wind	Retired	561	728	Normal	794	669	No	0
7	Existing Solar Base Case	Retired	310	728	Normal	0	0	No	0
8	High Solar, High Hydro	Retired	561	728	High	794	0	No	0
9	High Solar + 200 MW Storage	Retired	561	728	Normal	794	0	No	200
10	High Solar + 400 MW Storage	Retired	561	728	Normal	794	0	No	400
11	Curtailable Solar	Retired	561	728	Normal	794	0	Yes	0

4 Results

The following section provides detailed results from this work. A discussion of the implications of these detailed results on VER integration in Idaho Power's system is provided in Section 5.

4.1 RESERVE Outputs

4.1.1 ANNUAL AVERAGE RESULTS

The average annual reserves for each of the cases is shown below in Table 6. It should be noted that actual reserves vary on an hourly or subhourly basis in all stages. However, E3 provided these average annual reserves as a general indicator of how reserves needs change from case to case. These same data are displayed below for the hour-ahead forecast's CAISO FRP, regulation and contingency reserves on a percentage of average monthly load basis for each unique combination of solar and wind in Table 7, Table 8, Table 9, Table 10 and Table 11. As observed in Table 6, wind reserves have more forecast error (CAISO FRP reserves), whereas solar reserves have more subhourly variability. This trend, observed here, is also expressed elsewhere in the literature.

Table 6: Average 2023 Case Reserves Needs

Case	Total MW Wind (MW)	Total MW Solar (MW)	Avg. RT15 FRP Up (MW)	Avg. RT15 FRP Down (MW)	Avg. Reg. Up (MW)	Avg. Reg. Down (MW)	Avg. Conting. Res. (MW)	Avg. Total Res. Up (Percent of Avg. Load)	Avg. Total Reserves Down (Percent of Avg. Load)
1. 2023 Base Case	728	561	100	97	40	41	104	13 %	7 %
2. Jim Bridger Online	728	561	100	97	40	41	104	13 %	7 %
3. Hi Solar	728	1,354	147	142	71	72	104	17 %	11 %
4. Hi Solar, Low Hydro	728	1,354	147	142	71	72	104	17 %	11 %
5. Hi Wind	1,396	561	152	147	50	52	104	16 %	10 %
6. Hi Solar, Hi Wind	1,396	1,354	193	186	79	81	104	19 %	13 %
7. Existing Solar Case	728	561	87	86	32	33	104	11%	6%
8. Hi Solar, Hi Hydro	728	1,354	147	142	71	72	104	17 %	11 %
9. Hi Solar, 200 MW Battery	728	1,354	147	142	71	72	104	17 %	11 %
10. Hi Solar, 400 MW Battery	728	1,354	147	142	71	72	104	17 %	11 %
11. Curtail. Solar	728	1,354	147	142	71	72	104	17 %	11 %

Table 7: 2023 Monthly Average, Load Normalized CAISO FRP, Regulation and Contingency Reserves, Base 2023 Cases (Case 1 and Case 2)

Month	Hour Ahead FRP + Reg. + Contingency Headroom, Total (% of Load)	Hour Ahead FRP + Reg. Headroom, Solar (% of Load)	Hour Ahead FRP + Reg. Headroom, Wind (% of Load)	Hour Ahead FRP + Reg. + Contin. Headroom, Load (% of Load)	Hour Ahead FRP + Reg. Footroom, Total (% of Load)	Hour Ahead FRP + Reg. Footroom, Solar (% of Load)	Hour Ahead FRP + Reg. Footroom, Wind (% of Load)	Hour Ahead FRP + Reg. Footroom, Load (% of Load)
1	12.1%	0.9%	3.0%	8.2%	5.8%	1.0%	3.0%	1.7%
2	11.8%	0.9%	2.7%	8.3%	6.4%	1.1%	3.6%	1.6%
3	14.3%	2.9%	3.1%	8.3%	7.8%	2.9%	3.2%	1.7%
4	14.7%	2.9%	3.6%	8.2%	9.6%	3.2%	4.6%	1.7%
5	13.8%	2.8%	2.8%	8.2%	8.7%	3.3%	3.8%	1.6%
6	13.5%	2.5%	2.9%	8.1%	5.5%	1.7%	2.3%	1.6%
7	11.6%	1.9%	1.5%	8.2%	4.5%	1.3%	1.7%	1.4%
8	11.7%	2.0%	1.5%	8.2%	4.9%	1.5%	1.9%	1.5%
9	13.4%	2.1%	2.8%	8.5%	6.6%	2.0%	2.8%	1.8%
10	13.4%	2.2%	2.9%	8.3%	8.3%	2.3%	4.4%	1.6%
11	13.1%	2.2%	2.5%	8.4%	7.6%	1.8%	4.0%	1.8%
12	11.4%	0.9%	2.4%	8.1%	7.3%	1.0%	4.6%	1.6%
Avg.	12.9%	2.0%	2.6%	8.3%	6.9%	1.9%	3.3%	1.6%

Table 8: 2023 Monthly Average, Load Normalized CAISO FRP, Regulation and Contingency Reserves, Existing Solar 2023 Case (Case 7)

Month	Hour Ahead FRP + Reg. + Contingency Headroom, Total (% of Load)	Hour Ahead FRP + Reg. Headroom, Solar (% of Load)	Hour Ahead FRP + Reg. Headroom, Wind (% of Load)	Hour Ahead FRP + Reg. + Contin. Headroom, Load (% of Load)	Hour Ahead FRP + Reg. Footroom, Total (% of Load)	Hour Ahead FRP + Reg. Footroom, Solar (% of Load)	Hour Ahead FRP + Reg. Footroom, Wind (% of Load)	Hour Ahead FRP + Reg. Footroom, Load (% of Load)
1	11.6%	0.5%	2.9%	8.2%	5.1%	0.5%	2.8%	1.7%
2	11.2%	0.5%	2.5%	8.3%	5.8%	0.6%	3.5%	1.6%
3	12.8%	1.5%	3.0%	8.2%	6.2%	1.5%	3.0%	1.7%
4	13.3%	1.6%	3.5%	8.2%	8.0%	1.8%	4.6%	1.6%
5	12.4%	1.6%	2.7%	8.2%	7.4%	2.0%	3.8%	1.6%
6	12.1%	1.4%	2.6%	8.1%	4.8%	1.0%	2.2%	1.6%
7	10.6%	1.0%	1.4%	8.2%	3.9%	0.8%	1.7%	1.4%
8	10.7%	1.0%	1.5%	8.2%	4.1%	0.8%	1.8%	1.5%
9	12.3%	1.1%	2.7%	8.5%	5.5%	1.0%	2.7%	1.8%
10	12.2%	1.2%	2.8%	8.3%	7.2%	1.3%	4.3%	1.6%
11	12.1%	1.2%	2.5%	8.4%	6.7%	1.1%	3.8%	1.8%
12	10.9%	0.5%	2.3%	8.1%	6.3%	0.6%	4.1%	1.6%
Avg.	11.86%	1.1%	2.5%	8.2%	5.9%	1.1%	3.2%	1.6%

Table 9: 2023 Monthly Average, Load Normalized Regulation Reserves, High Solar Cases (Cases 3, 4, 8-11)

Month	Hour Ahead FRP + Reg. + Contingency Headroom, Total (% of Load)	Hour Ahead FRP + Reg. Headroom, Solar (% of Load)	Hour Ahead FRP + Reg. Headroom, Wind (% of Load)	Hour Ahead FRP + Reg. + Contin. Headroom, Load (% of Load)	Hour Ahead FRP + Reg. Footroom, Total (% of Load)	Hour Ahead FRP + Reg. Footroom, Solar (% of Load)	Hour Ahead FRP + Reg. Footroom, Wind (% of Load)	Hour Ahead FRP + Reg. Footroom, Load (% of Load)
1	14.0%	2.5%	3.3%	8.2%	7.9%	2.8%	3.4%	1.8%
2	14.0%	2.4%	3.3%	8.3%	8.7%	3.1%	4.0%	1.7%
3	19.5%	7.7%	3.5%	8.3%	13.7%	8.2%	3.7%	1.8%
4	20.5%	8.2%	4.1%	8.3%	15.6%	8.8%	5.1%	1.7%
5	19.0%	7.6%	3.0%	8.3%	14.0%	8.3%	4.0%	1.7%
6	17.9%	6.4%	3.4%	8.2%	8.6%	4.5%	2.4%	1.6%
7	15.2%	5.3%	1.7%	8.2%	7.2%	3.8%	1.9%	1.5%
8	15.2%	5.2%	1.7%	8.3%	7.6%	4.0%	2.0%	1.5%
9	17.3%	5.7%	3.1%	8.5%	10.8%	5.8%	3.2%	1.9%
10	17.8%	6.2%	3.2%	8.3%	12.6%	6.2%	4.8%	1.7%
11	16.6%	5.4%	2.7%	8.5%	11.5%	4.8%	4.8%	1.8%
12	13.1%	2.4%	2.6%	8.1%	10.1%	2.7%	5.8%	1.7%
Avg.	16.7%	5.4%	3.0%	8.3%	10.7%	5.2%	3.7%	1.7%

Table 10: 2023 Monthly Average, Load Normalized Regulation Reserves, High Wind Case (Case 3)

Month	Hour Ahead FRP + Reg. + Contingency Headroom, Total (% of Load)	Hour Ahead FRP + Reg. Headroom, Solar (% of Load)	Hour Ahead FRP + Reg. Headroom, Wind (% of Load)	Hour Ahead FRP + Reg. + Contin. Headroom, Load (% of Load)	Hour Ahead FRP + Reg. Footroom, Total (% of Load)	Hour Ahead FRP + Reg. Footroom, Solar (% of Load)	Hour Ahead FRP + Reg. Footroom, Wind (% of Load)	Hour Ahead FRP + Reg. Footroom, Load (% of Load)
1	15.5%	1.1%	6.2%	8.2%	8.4%	1.0%	5.7%	1.8%
2	14.7%	0.9%	5.5%	8.3%	9.6%	1.1%	6.8%	1.7%
3	17.9%	3.0%	6.7%	8.3%	10.4%	2.9%	5.9%	1.7%
4	18.8%	3.1%	7.4%	8.2%	13.9%	3.4%	8.9%	1.7%
5	17.3%	3.2%	5.9%	8.2%	12.5%	3.6%	7.2%	1.6%
6	16.2%	2.8%	5.3%	8.1%	8.1%	2.0%	4.5%	1.6%
7	13.6%	2.2%	3.2%	8.2%	6.4%	1.5%	3.5%	1.4%
8	13.7%	2.2%	3.3%	8.2%	6.9%	1.7%	3.7%	1.5%
9	16.7%	2.4%	5.8%	8.5%	9.2%	2.0%	5.3%	1.8%
10	16.7%	2.3%	6.1%	8.3%	12.3%	2.4%	8.3%	1.6%
11	16.3%	2.5%	5.4%	8.4%	10.9%	2.0%	7.1%	1.8%
12	14.3%	0.9%	5.3%	8.1%	10.5%	1.0%	7.8%	1.6%
Avg.	16.0%	2.2%	5.5%	8.2%	9.9%	2.1%	6.2%	1.6%

Table 11: 2023 Monthly Average, Load Normalized Regulation Reserves, High Solar and High Wind Case (Case 6)

Month	Hour Ahead FRP + Reg. + Contingency Headroom, Total (% of Load)	Hour Ahead FRP + Reg. Headroom, Solar (% of Load)	Hour Ahead FRP + Reg. Headroom, Wind (% of Load)	Hour Ahead FRP + Reg. + Contin. Headroom, Load (% of Load)	Hour Ahead FRP + Reg. Footroom, Total (% of Load)	Hour Ahead FRP + Reg. Footroom, Solar (% of Load)	Hour Ahead FRP + Reg. Footroom, Wind (% of Load)	Hour Ahead FRP + Reg. Footroom, Load (% of Load)
1	17.1%	2.4%	6.4%	8.2%	10.5%	2.6%	6.1%	1.8%
2	16.7%	2.3%	6.1%	8.3%	11.7%	2.9%	7.1%	1.7%
3	22.9%	7.5%	7.0%	8.3%	15.6%	7.5%	6.4%	1.7%
4	23.7%	7.7%	7.7%	8.3%	19.1%	8.2%	9.2%	1.7%
5	21.9%	7.6%	6.1%	8.2%	17.1%	8.1%	7.3%	1.7%
6	20.7%	6.4%	6.2%	8.2%	10.8%	4.4%	4.7%	1.6%
7	16.9%	5.3%	3.4%	8.2%	8.7%	3.7%	3.6%	1.5%
8	17.0%	5.3%	3.5%	8.2%	9.4%	4.1%	3.8%	1.5%
9	20.0%	5.6%	5.9%	8.5%	12.9%	5.3%	5.7%	1.8%
10	20.5%	5.8%	6.3%	8.3%	16.0%	5.7%	8.6%	1.6%
11	19.4%	5.6%	5.4%	8.5%	14.5%	4.5%	8.1%	1.8%
12	15.9%	2.3%	5.5%	8.1%	13.8%	2.5%	9.6%	1.7%
Avg.	19.4%	5.3%	5.8%	8.3%	13.3%	5.0%	6.7%	1.7%

4.1.2 DETAILED RESERVE RESULTS

While additions of new solar and wind both cause a similar increase in *average* reserves needs, the hours in which they increase reserves are very different. The following discussion illustrates these differences.

As observed in Table 6, wind reserves have more forecast error (CAISO FRP reserves), whereas solar reserves have more subhourly variability. This trend, observed here, is also expressed elsewhere in the literature.[9]

Conversely, the incremental FRP needs from adding solar shown in Figure 11 indicate that CAISO FRP reserves increase primarily during solar hours. FRP reserves do increase at night because caps on the level of uncertainty imposed

[9] https://www.nrel.gov/docs/fy13osti/55588.pdf

by the CAISO FRP derivation[10] (see further discussion in Section 5.3.2) also increase. Similarly, solar regulation needs increase only during solar hours.

Because reserves can only be provided with dispatchable resources in the PLEXOS model, it is important to compare the need for reserves with the availability of dispatchable resources. Figure 13 and Figure 14 show month-hourly average residual net load, calculated as load minus wind, solar, and RoR hydro for the High Solar and High Wind cases. This residual net load is the average load that must be met by dispatchable resources and imports. If the need for reserves is greater than the residual net load, then the model must export power to the market to be able to serve Idaho Power's reserves needs while not violating minimum generation setpoints for online units. As discussed below, this can result in exports to the market at a loss.

As can be seen from Figure 13, in the High Solar case, in March, April, May and October, the residual net load is very low during the midday hours in which there is high demand on reserves. Alternatively, as can be seen in the high wind case for Figure 10, the residual net load is significantly higher during those midday hours, and as shown earlier, average reserves needs are not especially high midday.

[10] See **https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market percent20Operations** for a discussion of these caps; E3 derives its own caps from P98 and P2 values of the seasonal forecast error.

Figure 7: Average Month-Hourly CAISO FRR Headroom Needs for Base 2023 Case

Average Modeled CAISO FRR Headroom (MW)																										
		Hour of Day																								Month Average
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
Month	1	54	72	54	103	82	83	99	84	73	95	98	95	103	103	103	103	103	103	100	103	54	69	75	93	88
	2	71	52	35	63	75	57	43	50	67	95	103	103	103	103	103	103	103	103	80	84	103	103	103	103	84
	3	68	81	80	92	65	80	84	80	102	110	127	127	71	124	127	127	127	127	127	73	64	78	75	71	95
	4	56	47	58	74	80	97	83	67	84	127	127	127	105	105	127	127	127	127	127	113	67	90	93	67	96
	5	67	90	84	63	68	71	67	86	112	127	127	127	89	127	127	127	127	127	127	121	104	71	72	78	99
	6	71	78	130	151	151	151	151	151	151	151	151	151	151	151	151	128	101	151	151	151	116	99	101	80	132
	7	57	63	53	50	41	44	59	67	151	142	151	128	115	151	144	122	147	151	151	151	120	103	87	53	104
	8	25	50	63	59	61	57	54	53	113	151	142	151	151	117	134	144	151	151	151	151	98	85	103	61	103
	9	71	72	76	66	80	72	92	108	129	129	129	129	129	129	129	129	129	129	129	122	122	83	69	68	105
	10	76	69	73	56	53	63	53	54	61	113	129	129	129	129	125	129	129	129	74	50	89	74	54	78	88
	11	56	54	65	58	57	75	80	78	93	122	118	129	118	109	129	129	129	95	110	87	70	59	59	56	89
	12	71	55	65	63	66	80	70	67	51	78	91	103	103	103	94	71	71	66	47	50	61	68	87	87	74
Hour Average		62	65	70	75	73	77	78	79	99	120	124	125	114	121	124	120	120	122	115	105	89	82	81	74	

Figure 8: Average Month-Hourly Regulation Reserves Headroom Needs for 2023 Base Case

Average Regulation Headroom - RMS Combined Load + Wind + Solar (MW)																										
		Hour of Day																								Month Average
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
Month	1	24	24	24	24	24	25	25	27	27	32	39	40	41	48	47	53	51	41	26	26	25	24	24	24	32
	2	25	25	25	25	25	25	26	28	27	33	39	41	41	48	46	55	51	42	27	26	26	25	25	25	33
	3	21	21	21	22	23	23	23	33	49	53	50	74	74	85	99	109	99	90	67	34	22	22	21	21	48
	4	21	21	20	21	22	23	23	34	48	49	46	58	65	71	82	85	91	83	66	35	24	24	22	22	44
	5	20	21	21	21	21	22	22	38	43	42	42	53	58	62	67	77	86	74	63	34	24	23	22	21	41
	6	25	24	23	23	23	23	28	45	60	60	40	37	41	44	44	62	68	71	59	54	35	34	29	27	41
	7	29	27	25	24	24	25	29	57	74	73	49	42	45	45	44	68	76	81	59	52	35	37	38	34	46
	8	26	24	24	23	23	24	27	56	72	61	48	44	46	47	49	61	66	77	83	53	35	36	33	29	45
	9	23	23	23	22	23	23	24	24	35	54	51	47	49	53	61	78	77	57	36	26	27	26	25	24	38
	10	22	21	21	21	23	23	24	24	35	58	51	56	51	61	69	84	83	57	36	23	23	24	23	22	39
	11	23	22	22	22	22	22	23	23	34	57	54	57	62	68	78	87	82	57	36	23	22	22	23	23	40
	12	23	23	23	23	23	23	24	24	25	30	37	40	40	50	50	57	53	43	25	24	24	24	23	23	31
Hour Average		23	23	23	23	23	23	25	34	44	50	46	49	51	57	62	73	74	64	49	34	27	27	26	24	

Figure 9: High Wind Minus Base Case CAISO FRR Headroom

Difference, Hi Wind to Base Case, Average CAISO FRR Headroom (MW)

	Hour of Day																								
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Month Average
1	44	81	47	63	82	74	67	74	82	69	68	70	51	63	63	63	63	63	53	59	51	53	56	73	64
2	67	43	28	51	85	65	38	40	40	35	42	63	63	63	18	40	63	63	74	79	63	63	63	63	55
3	77	84	79	96	77	92	79	67	55	44	61	6	37	27	61	35	61	61	61	90	70	87	91	81	66
4	61	52	61	77	82	75	80	45	38	61	61	48	66	49	61	61	61	61	61	75	80	87	87	72	65
5	71	96	90	85	53	66	68	61	18	59	50	48	50	55	61	61	61	61	61	66	84	77	65	77	64
6	65	80	78	57	57	57	57	57	57	57	57	57	57	57	57	68	83	57	57	57	84	97	101	82	66
7	47	91	55	67	47	31	41	41	57	35	48	66	64	57	63	59	57	57	57	43	71	64	47	44	54
8	20	53	61	64	56	61	39	33	6	43	58	57	52	80	36	44	38	19	57	57	66	59	76	56	50
9	86	66	81	71	84	59	73	82	61	61	52	57	61	61	61	61	61	61	29	66	40	80	69	71	65
10	82	70	82	54	46	33	46	36	34	9	61	61	61	61	65	61	56	61	47	48	82	68	42	79	56
11	55	53	61	52	41	32	25	71	94	68	72	61	72	81	61	61	51	39	69	63	61	57	45	49	58
12	76	63	77	74	71	76	82	75	44	28	27	38	63	45	35	30	51	46	34	44	55	74	79	79	57
Hour Average	62	69	67	67	65	60	58	57	49	47	55	53	58	58	53	54	59	54	55	62	67	72	68	69	60

Figure 10: High Wind Minus Base Case Regulation Headroom

Difference, Hi Wind to Base Case, Average Regulation Headroom (MW)

	Hour of Day																								
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Month Average
1	16	17	17	16	16	17	17	16	15	14	11	11	11	9	10	9	9	11	15	15	15	16	16	16	14
2	17	17	17	17	17	17	17	16	16	14	13	12	12	11	11	10	10	12	16	16	16	16	16	17	15
3	13	13	13	13	13	13	13	10	8	7	7	5	5	4	4	3	4	4	5	9	12	12	12	13	9
4	16	17	17	16	15	15	14	11	8	8	8	7	7	7	6	6	6	6	7	11	15	15	16	17	11
5	14	13	13	14	13	13	11	8	7	7	7	6	6	6	6	6	5	6	7	11	14	14	14	13	10
6	15	14	14	14	14	13	11	8	6	7	8	8	8	8	8	8	7	7	8	9	13	13	14	14	10
7	14	14	15	14	14	13	12	7	6	6	6	7	7	7	8	6	6	7	8	9	13	13	12	13	10
8	13	13	13	13	13	12	11	6	5	6	7	6	6	6	6	6	6	5	5	8	12	11	12	13	9
9	15	15	15	14	14	14	13	13	10	7	7	8	7	8	7	6	5	7	10	13	14	14	14	15	11
10	15	15	15	14	14	14	15	14	11	8	8	8	9	7	6	5	5	8	12	15	15	15	15	15	12
11	13	12	13	13	13	12	13	12	9	6	6	6	5	5	4	4	4	6	10	13	13	13	13	13	10
12	15	14	14	14	14	14	13	13	12	11	9	8	8	7	7	6	7	8	12	13	13	14	14	15	11
Hour Average	15	15	15	14	14	14	13	11	9	8	8	8	7	7	7	6	6	7	10	12	14	14	14	14	11

Figure 11: High Solar Minus Base Case CAISO FRR Headroom

Difference, Hi Solar to Base Case, Average CAISO FRR Headroom (MW)

	Hour of Day																								Month Average
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1	0	0	0	3	0	0	0	0	-1	19	47	61	60	60	60	60	60	58	2	6	0	0	0	0	21
2	0	0	0	0	0	0	0	1	7	40	60	60	60	60	60	60	60	60	7	0	42	21	60	44	29
3	0	0	0	0	0	0	0	12	28	75	114	114	63	103	114	114	114	114	104	23	0	0	0	0	45
4	0	0	0	0	0	1	10	36	52	114	114	114	124	116	114	114	114	114	114	56	4	0	0	0	55
5	0	0	0	0	0	2	24	41	129	114	114	114	119	114	114	114	114	114	114	88	12	0	0	0	60
6	0	0	0	9	45	99	89	116	124	124	124	124	124	124	124	147	67	124	124	124	43	1	0	0	77
7	0	0	0	0	0	11	31	72	124	133	124	113	106	124	116	136	126	124	124	124	27	1	0	0	67
8	0	0	0	0	0	2	9	70	135	124	132	124	101	69	72	104	124	124	124	104	4	0	0	0	59
9	0	0	0	0	0	0	3	20	85	111	111	111	111	111	111	111	111	111	111	23	0	0	0	0	52
10	0	0	0	0	0	0	4	19	40	127	111	111	111	109	95	111	111	111	30	0	0	0	0	0	45
11	0	0	0	0	0	0	0	7	15	28	58	82	81	71	111	111	111	37	0	0	0	0	0	0	30
12	0	0	0	0	0	0	0	0	3	33	62	60	60	60	68	49	35	6	0	0	0	0	0	0	18
Hour Average	0	0	0	1	4	10	14	33	62	87	98	99	93	93	97	103	96	91	71	46	11	2	5	4	47

Figure 12: High Solar Minus Base Case Regulation Headroom

Difference, Hi Solar to Base Case, Average Regulation Headroom (MW)

	Hour of Day																								Month Average
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	
1	0	0	0	0	0	0	0	0	0	19	37	39	42	55	53	65	60	41	0	0	0	0	0	0	17
2	0	0	0	0	0	0	0	0	0	20	35	40	41	53	49	60	59	42	0	0	0	0	0	0	17
3	0	0	0	0	0	0	0	27	58	64	60	97	97	106	131	144	134	122	87	33	0	0	0	0	48
4	0	0	0	0	0	0	0	30	56	57	54	71	82	91	108	112	121	106	85	32	0	0	0	0	42
5	0	0	0	0	0	0	1	38	48	46	46	63	72	77	85	99	107	91	78	28	0	0	0	0	37
6	0	0	0	0	0	0	12	45	71	63	26	16	27	32	33	55	66	73	70	51	3	0	0	0	27
7	0	0	0	0	0	0	5	62	92	74	30	21	32	36	37	77	93	100	85	52	3	0	0	0	33
8	0	0	0	0	0	0	5	65	87	66	34	19	34	38	44	60	77	88	105	52	3	0	0	0	32
9	0	0	0	0	0	0	0	1	31	59	56	46	56	59	70	99	99	67	30	0	0	0	0	0	28
10	0	0	0	0	0	0	0	0	30	68	60	65	61	73	86	117	110	71	35	0	0	0	0	0	32
11	0	0	0	0	0	0	0	0	30	72	65	71	80	89	105	118	111	71	35	0	0	0	0	0	35
12	0	0	0	0	0	0	0	0	0	19	36	42	42	59	60	71	64	45	0	0	0	0	0	0	18
Hour Average	0	0	0	0	0	0	2	22	42	52	45	49	55	64	72	90	92	76	51	21	1	0	0	0	31

Figure 13: Residual Net Load, High Solar Case 3

Average Net Load, Minus RoR Hydro Budget (MW)

Month	Hour of Day: 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Month Average
1	1255	1228	1225	1229	1273	1364	1525	1654	1679	1475	1228	1007	920	873	943	1020	1194	1475	1661	1624	1596	1519	1402	1301	1320
2	1303	1282	1283	1298	1337	1422	1598	1711	1663	1474	1272	1094	973	908	983	1060	1198	1438	1664	1694	1632	1573	1464	1356	1362
3	1157	1149	1159	1192	1267	1412	1559	1549	1259	927	699	558	425	394	445	536	676	838	1117	1422	1405	1329	1232	1174	1037
4	867	843	839	871	956	1131	1192	981	702	453	327	150	105	136	182	264	410	432	673	1107	1221	1078	969	919	700
5	1127	1096	1087	1104	1178	1307	1286	1010	733	554	467	398	375	381	431	533	653	635	773	1238	1502	1405	1238	1175	903
6	1507	1444	1408	1389	1421	1498	1329	1043	824	767	734	714	738	772	853	996	1126	1124	1161	1591	1980	1959	1751	1626	1240
7	1876	1786	1718	1682	1689	1748	1664	1434	1239	1150	1179	1190	1269	1356	1494	1656	1802	1753	1794	2209	2492	2416	2173	2011	1699
8	1779	1697	1642	1615	1648	1738	1744	1477	1180	1065	1098	1128	1265	1363	1496	1627	1718	1735	1940	2372	2503	2287	2068	1898	1670
9	1291	1238	1211	1214	1267	1389	1490	1331	1040	816	755	706	684	753	832	956	1084	1238	1539	1826	1739	1580	1438	1333	1198
10	1098	1080	1090	1123	1212	1373	1510	1487	1167	837	590	467	379	424	444	574	703	1055	1417	1437	1374	1276	1183	1134	1018
11	1278	1266	1264	1282	1330	1430	1585	1700	1577	1237	952	755	722	764	827	871	1099	1497	1613	1588	1560	1489	1385	1304	1266
12	1348	1327	1297	1306	1341	1431	1580	1694	1740	1618	1447	1258	1162	1125	1234	1325	1501	1729	1782	1730	1700	1628	1519	1411	1468
Hour Average	1585	1547	1529	1536	1587	1698	1765	1682	1492	1289	1155	1045	1011	1031	1108	1212	1358	1506	1688	1914	1987	1890	1746	1648	1240

Figure 14: Residual Net Load, High Wind Case 5

Average Net Load, Minus RoR Hydro Budget (MW)

Month	Hour of Day: 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Month Average
1	971	940	937	935	978	1065	1229	1359	1386	1292	1192	1055	984	938	956	983	1082	1256	1386	1350	1317	1234	1115	1014	1123
2	1025	1003	1008	1027	1065	1143	1326	1441	1422	1335	1234	1124	1038	979	983	1006	1084	1222	1382	1411	1351	1296	1192	1082	1174
3	972	968	979	1014	1088	1232	1375	1399	1273	1102	966	872	775	725	721	744	807	898	1041	1223	1212	1141	1047	992	1024
4	627	597	591	626	711	890	983	923	812	684	613	520	472	464	469	492	547	559	658	896	964	825	723	677	680
5	968	937	932	952	1033	1169	1239	1164	1051	974	932	893	861	847	843	868	918	907	958	1187	1329	1235	1070	1016	1012
6	1302	1242	1213	1194	1228	1314	1342	1295	1238	1250	1272	1277	1290	1305	1347	1416	1473	1468	1467	1632	1781	1727	1536	1417	1376
7	1698	1607	1540	1510	1520	1583	1627	1617	1589	1622	1706	1770	1854	1927	2022	2111	2161	2127	2127	2253	2315	2217	1983	1824	1846
8	1587	1511	1460	1437	1477	1576	1629	1601	1548	1556	1636	1709	1829	1925	2013	2092	2117	2102	2156	2289	2306	2102	1891	1704	1802
9	1107	1052	1026	1032	1092	1216	1323	1295	1204	1120	1117	1115	1108	1138	1174	1248	1314	1382	1517	1651	1550	1392	1256	1152	1233
10	895	872	884	914	998	1152	1284	1293	1160	1004	852	746	687	681	680	738	818	1005	1214	1223	1167	1070	981	934	969
11	1101	1097	1096	1113	1159	1259	1412	1529	1499	1365	1215	1078	1033	1025	1036	1042	1154	1366	1431	1403	1374	1297	1189	1112	1224
12	1101	1091	1050	1061	1099	1189	1345	1459	1508	1450	1374	1263	1188	1154	1180	1221	1322	1486	1531	1480	1449	1379	1272	1167	1284
Hour Average	1113	1076	1060	1068	1120	1232	1343	1365	1308	1230	1176	1118	1093	1092	1119	1163	1233	1315	1405	1500	1509	1410	1271	1174	1229

4.2 2019 PLEXOS to Historical Case Benchmarking

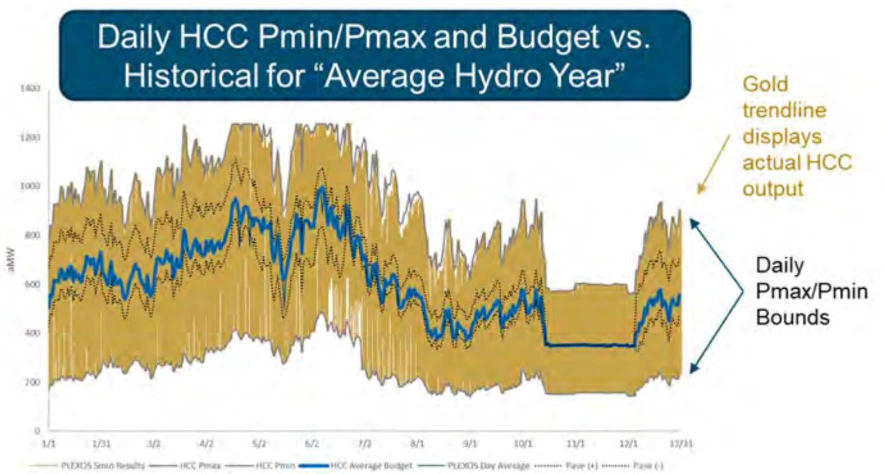
E3 and Idaho Power performed rigorous benchmarking to ensure that the PLEXOS model was able to reasonably replicate actual 2019 historical behavior. E3 and Idaho Power verified that the following were in line with historical 2019 behavior:

- Hydro and thermal unit flexibility (ramping rate) and dispatch (distribution of ramps);
- Total generation by unit and technology class;
- Market transaction behavior and external market prices;
- Average Idaho Power nodal energy prices;
- Unit capacities;
- Unit outages;
- Number of unit starts; and
- Average unit marginal operational cost

Particular attention was paid to the HCC to ensure its operation was reasonable. This was critical because of the large amount of Idaho Power's energy from hydroelectricity in a typical year, as well as the crucial role that this unit has in providing flexibility. Figure 15 below shows a sample of the verification of the model wherein actual dispatch of the PLEXOS HCC is shown to be within the daily maximum and minimum power output ranges, and the dispatch of the HCC adheres to the input daily hydro budget.

Additionally, after initial results were analyzed, the Idaho Power team thought that EIM transactions were unrealistically high in the PLEXOS model, given that the model operates a price taker for market transactions. In reality, if Idaho Power made particularly large sales or purchases in the EIM, prices would be affected. Therefore, E3 and Idaho Power worked together to limit total net sales and purchases in the EIM to +/- 300 MW in price taker mode. In instances in which the model traded between +/- 300 MW up to the line limits in the real time, the model paid a hurdle rate of $150/MW, which was implemented to approximate “price setting” behavior. Overall, there were few hours in which the model accessed this additional EIM flexibility.

Figure 15: PLEXOS HCC Dispatch vs. Historical Power and Hydro Budget Bounds



4.3 2023 Case Result Summary

The Incremental specific integration costs for each of the cases is provided below in Table 12. These results are discussed in greater detail below in Chapter 5.

Table 12: Summary of Incremental VER Integration Costs

Case	Inc. Start Costs ($Million/ yr)	Inc. Ramping Costs ($ Million/ yr)	Total Inc. Imperf. Unit Commit. & Dispatch Costs ($Mill./yr)	Total Curtail. Costs ($Million/ yr)	Total Inc. Integrat. Costs ($Million/ yr)	Total Product. Cost ($Million/ yr)	Total Inc. VER Gen. (GWh /yr)	Total Inc. Specific Integrat. Costs ($/MWh)
1. 2023 Base Case	-$0.15	$0.22	$1.62	$0.00	1.69	$181	577	$2.93
2. Jim Bridger Online	-$0.17	$0.37	$1.88	$0.00	$2.08	$180	577	$3.61
3. Hi Solar	$0.80	$0.45	$5.78	$0.00	$7.04	$146	1,824	$3.86
4. Hi Solar, Low Hydro	$0.60	$0.53	$7.16	$0.00	$8.29	$172	1,824	$4.55
5. Hi Wind	$0.35	-$0.07	$1.12	$0.00	$1.41	$143	1,823	$0.77
6. Hi Solar + Hi Wind	$1.63	$0.33	$7.01	$0.00	$8.96	$109	3,647	$2.46
7. Existing Solar Base	n/a	n/a	n/a	n/a	n/a	$193	0	n/a
8. Hi Solar, Hi Hydro	$2.41	$0.19	$5.87	$0.00	$8.47	$75	1,823	$4.65
9. Hi Solar, 200 MW Battery	$0.58	$0.02	$0.56	$0.00	$1.16	$144	1,823	$0.64
10. Hi Solar, 400 MW Battery	$0.58	-$0.34	$1.46	$0.00	$1.69	$142	1,823	$0.93
11. Hi Curtail. Solar	$0.72	$0.39	$4.31	$0.29	$5.71	$147	1,823	$3.13

4.4 System Dispatch Results

In the following subsections, detailed day plots and other modeling results will be used to illustrate how the Idaho Power system responds to adding different capacities and kinds of VERs, and increasing or decreasing system flexibility. To facilitate this, this study will examine the following case groupings:

- Existing Solar (Case 7), Base Case (Case 1) and Jim Bridger First Unit Online (Case 2)
- High Solar (Case 3), High Wind (Case 5) and High Solar + Wind (Case 6)
- High Solar with Low (Case 4), Average (Case 3) and High (Case 8) Hydro Budgets
- High Solar with (Cases 9 and 10) and without (Case 3) battery storage
- Hi Solar with (Case 11) and without the ability to economically curtail solar (Case 3)

4.4.1 EXISTING SOLAR, 2023 BASE CASE AND JIM BRIDGER FIRST UNIT ONLINE CASES

This case comparison illustrates the effect of adding successively more VERs, as well as increasing the aggregate system thermal minimum power level (Pmin). The salient differences between cases are outlined as follows

- Total online solar
  - Existing Solar (Case 7): 310 MW
  - 2023 Base Case (Case 1): 561 MW
  - Jim Bridger Online Case (Case 2): 561 MW
- Jim Bridger Coal Plant Pmin/Pmax

- Existing Solar (Case 7): 89 MW / 533 MW
- 2023 Base Case (Case 1): 89 MW / 533 MW
- Jim Bridger Online Case (Case 2): 118 MW / 707 MW

In the modeled year of 2023, there will be periods during the daytime in the spring and fall in which external electricity prices are low or negatively priced. This is due to the growing penetration of solar across the WECC footprint and the low net loads during these periods. Figure 16 illustrates the Idaho Power system operation operating during a day (April 23, 2023) that exhibits these conditions.

Beginning with the “Existing Solar Case,” which models the Idaho Power system with the 2019 levels of wind and solar, the model will choose to purchase power from the market rather than generate its own power during these periods. This is shown by the purchase of electricity 4 am through 8 pm MST in Figure 16.

In the 2023 base case, 561 MW of solar is assumed to be online, which increases Idaho Power’s total VER Pmin during midday periods. This decreases Idaho Power’s ability to purchase negatively priced electricity from the market. This is shown in Figure 16, wherein purchases are now only made in the morning and evening periods.

Per discussions with Idaho Power, the Jim Bridger coal plant is modeled as a must-run unit. As such, in the first Jim Bridger unit online case, the aggregate thermal Pmin increases during all hours by 29 MW. Having both more solar and Jim Bridger’s first unit online further increases Idaho Power’s aggregate Pmin. In Figure 16, this results the model no longer purchasing negatively priced electricity in the afternoon.

Though not depicted here, during periods of high net load (e.g. during summer peaking events), the addition of extra solar and the ability to dispatch more power from Jim Bridger can prove beneficial in reducing system costs by displacing expensive market purchases and/or natural gas combustion turbine (CT) and/or combined cycle (CCGT) generation. Per Table 13, as more solar is added, and if a Jim Bridger unit is not retired, total incremental specific VER integration costs rise but total production costs fall.

Figure 16: Existing Solar vs. 2023 Base Case vs. First Bridger Unit Online Daily Dispatch Plots

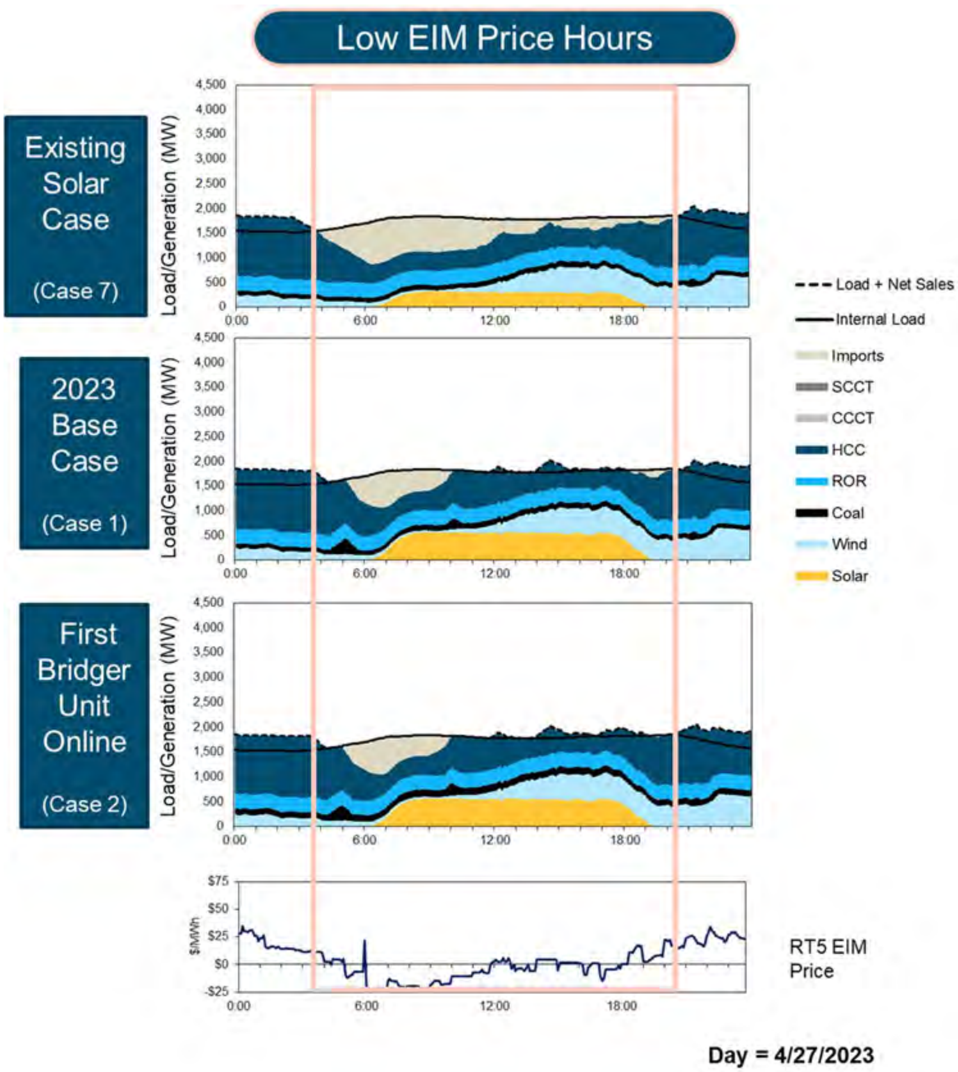


Table 13: Summary of Results for Existing Solar, Base Case Solar and Jim Bridger Cases

Case	Inc. Start Costs ($Million/ yr)	Inc. Ramping Costs ($ Million/ yr)	Total Inc. Imperf. Unit Commit. & Dispatch Costs ($Million / yr)	Total Curtail. Costs ($Million /yr)	Total Inc. Integrat. Costs ($Million / yr)	Total Product. Cost ($Million / yr)	Total Inc. VER Gen. (GWh /yr)	Total Inc. Specific Integrat. Costs ($/MWh)
1. 2023 Base Case	-$0.15	$0.22	$1.62	$0.00	1.69	$181	577	$2.93
2. Jim Bridger Online	-$0.17	$0.37	$1.88	$0.00	$2.08	$180	577	$3.61
7. Existing Solar Base	n/a	n/a	n/a	n/a	n/a	$193	0	n/a

4.4.2 HIGH SOLAR, HIGH WIND, AND HIGH SOLAR + WIND CASES

This set of cases illustrates the difference in the ease of integrating equivalent amounts of new VER *energy* from solar and wind. Additionally, the effects of combining these solar and wind additions is shown.

The salient differences in VER capacities between these cases are as follows:

- Total Online Solar
  - High Solar Case (Case 3): 1,355 MW
  - High Wind Case (Case 5): 561 MW
  - High Solar + High Wind Case (Case 6): 1,355 MW
- Total Online Wind

- High Solar Case (Case 3): 728 MW
- High Wind Case (Case 5): 1,397 MW
- High Solar + High Wind Case (Case 6): 1,397 MW

This case builds on the phenomena observed in Section 4.4.1, wherein adding more VERs reduces the model's ability to optimally perform market transactions during low net load, springtime conditions. Figure 17 below depicts the high wind, high solar, and high solar + high wind cases on the same low net load spring day (April 27, 2023).

Starting with the high wind case, one observes that during periods of low net load, the system is fairly balanced in terms of imports and exports, only exporting to the low to negatively priced EIM market in the afternoon when wind generation begins to climb. Additionally, the system is able to provide the required reserves for carrying wind with only the coal and HCC units. This is due to the relatively low level of reserves required to integrate wind, as shown in Figure 9 and Figure 10.

In the high solar case, the increased midday reserves needs shown in Figure 11 and Figure 12 coincide with high solar production. The increase in reserves needs causes the model to start a CCGT unit, as the reserve can no longer just be provided with hydro and coal. Bringing the CCGT unit online when there is high solar production causes the model to make significant exports to the EIM market during low and negatively priced hours. This, along with the start costs of the CCGT, increases the costs of integrating solar relative to the costs of integrating wind.

Finally, adding both high solar and high wind further exacerbates the issues that arise during the high solar case. Due to the increase in production of wind during the afternoon, the model must make further exports to a low and negatively priced market. Additionally, the model turns on a CT instead of a CCGT to provide the additional reserves required due to wind and solar.

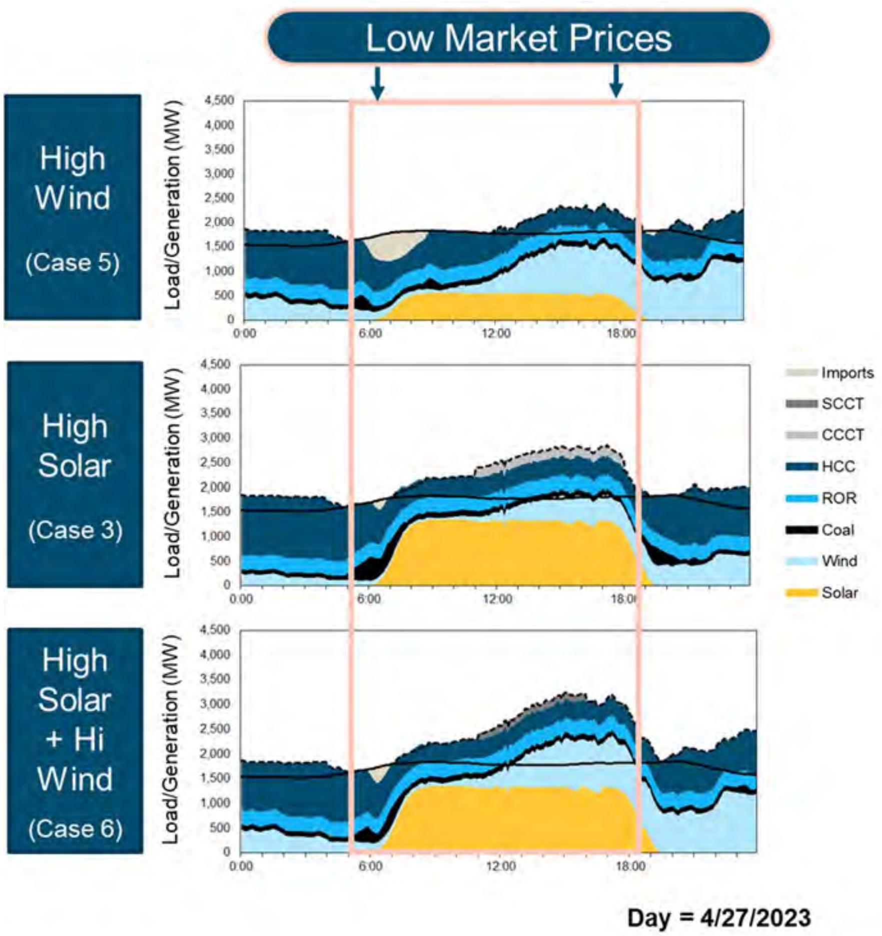
Figure 17 presents daily operations from the imperfect foresight cases. However, as described in Section 2.1, the difference in total market transactions and generator costs for each case are calculated using the difference between each case's perfect and imperfect foresight cases. Though not shown here, on the day shown in Figure 17, the model chooses to not start CCGTs or CTs in the respective high solar and high wind + high solar cases in the perfect foresight cases. This is due to the lower reserve need of the perfect foresight case.

Table 14: Summary of Results for High Solar, High Wind and High Solar + High Wind Cases

Case	Inc. Start Costs ($Million/ yr)	Inc. Ramping Costs ($ Million/ yr)	Total Inc. Imperf. Unit Commit. & Dispatch Costs ($Million/ yr)	Total Curtail. Costs ($Million/ yr)	Total Inc. Integrat. Costs ($Million/ yr)	Total Product. Cost ($Million/ yr)	Total Inc. VER Gen. (GWh /yr)	Total Inc. Specific Integrat. Costs ($/MWh)
3. Hi Solar	$0.80	$0.45	$5.78	$0.00	$7.04	$146	1,824	$3.86
5. Hi Wind	$0.35	-$0.07	$1.12	$0.00	$1.41	$143	1,823	$0.77
6. Hi Solar + Hi Wind	$1.63	$0.33	$7.01	$0.00	$8.96	$109	3,647	$2.46

As shown in Table 14, total incremental VER integration costs are highest in the high solar + high wind case, followed by the high solar case and the high wind case. However, the total specific incremental VER integration cost is lower for the high wind + high solar than the high solar case because, while the total integration cost rises with more VERs, there is also more total incremental VER generation in the high wind + high solar case versus the high solar case.

Figure 17: High Wind vs. High Solar vs. High Solar + Hi Wind



4.4.3 HIGH SOLAR WITH LOW, AVERAGE AND HIGH HYDRO BUDGETS

This set of cases compares the effects of varying hydro budgets under high solar conditions. On a typical year, Idaho Power derives the majority of their power from their hydro fleet, but the total annual energy derived from hydro varies considerably year-to-year. The simulated conditions considered in this set of cases is depicted below in Figure 18.

Figure 18: Hydro Conditions in Low, Average and High Hydro Cases

	Run of River (RoR)		Hell's Canyon Complex (HCC)	
Case	Capacity Factor %	Annual Generation GWh	Capacity Factor %	Annual Generation GWh
Low	41%	1,936	57%	4,172
Average	48%	2,276	70%	5,160
High	90%	4,249	92%	6,822

In the model, RoR hydro is treated as an inflexible, must take resource, whereas HCC is dispatchable. The high hydro budget case capacity factor shown in Figure 18 indicates that both HCC and RoR hydro must operate near their Pmax throughout the year in order to not violate daily hydro energy budgets, which greatly reduces hydro system flexibility. As shown in Figure 15, hydro conditions are generally highest in the spring due to runoff from snow melt. Figure 19 below compares a spring day (April 20, 2023) in which the combination of low electricity market prices, hydro availability and VERs interact with one another.

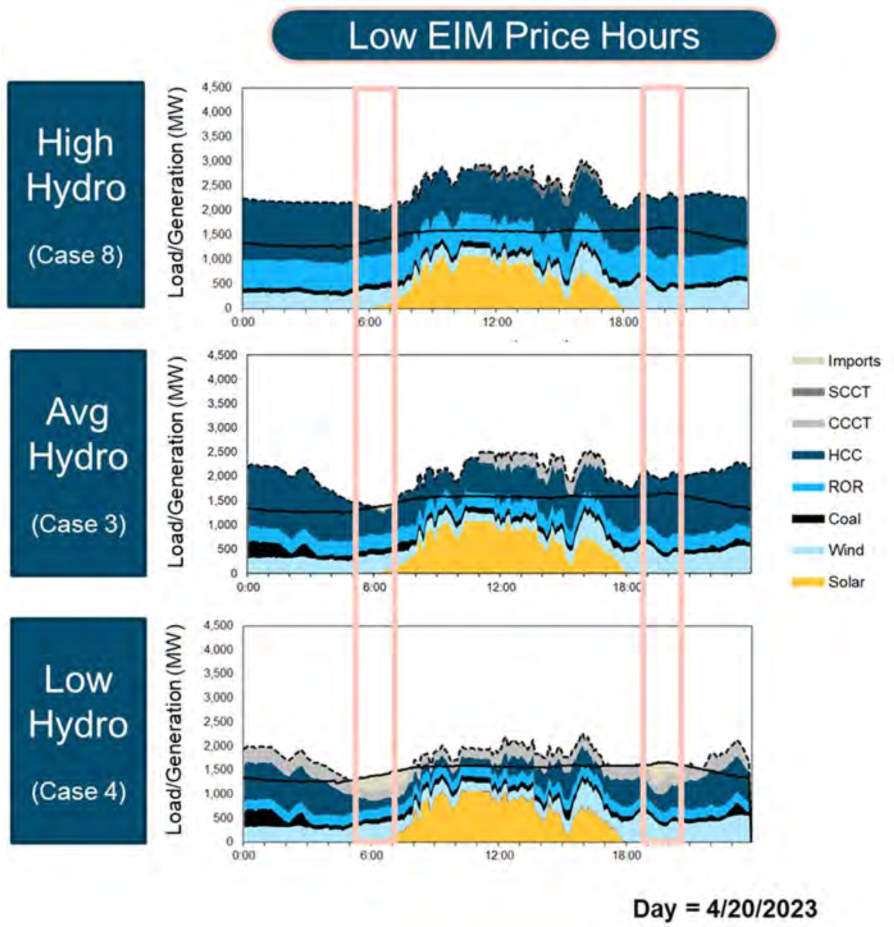
Starting with the high hydro case, the model must sell HCC and RoR output to the market all day, due to the high hydro budget. This includes sales during periods of negative external market prices. Additionally, the model must start a CT to provide solar reserves during midday. Conversely, during average hydro conditions, this need to sell to the market at a loss is reduced, and the model shifts HCC production to avoid selling hydro at a loss during the morning. The model switches from using a CT to a CCGT to provide solar reserves. Finally, during low hydro conditions, Idaho Power's system can buy from the market during negatively priced hours, but the model must run the CCGT more due to lower hydro budgets.

Table 15: Summary of Results for High Solar with Low, Average and High Hydro Budgets Cases

Case	Inc. Start Costs ($Million/ yr)	Inc. Ramp Costs ($ Million/ yr)	Total Inc. Imperf. Unit Commit. & Dispatch Costs ($Million / yr)	Total Curtail. Costs ($Million /yr)	Total Inc. Integrat. Costs ($Million / yr)	Total Product. Cost ($Million / yr)	Total Inc. VER Gen. (GWh /yr)	Total Inc. Specific Integrat. Costs ($/MWh)
3. Hi Solar	$0.80	$0.45	$5.78	$0.00	$7.04	$146	1,824	$3.86
4. Hi Solar, Low Hydro	$0.60	$0.53	$7.16	$0.00	$8.29	$172	1,824	$4.55
8. Hi Solar, Hi Hydro	$2.41	$0.19	$5.87	$0.00	$8.47	$75	1,823	$4.65

As shown in Table 15, total incremental specific VER integration costs are higher in both the low and high hydro year cases. Moving from low to high hydro conditions, market purchases and thermal generation decreases. This causes production costs to decrease.

Figure 19: Low, Average and High Hydro Case Comparison



4.4.4 HIGH SOLAR WITH AND WITHOUT STORAGE

This set of cases compares the cost of integrating solar with and without battery storage. Because Idaho Power is a vertically integrated utility, there is no ancillary services market for these PURPA facilities. Therefore, batteries do not provide reserves to the Idaho Power system in these cases. Additionally, the model treats solar + storage systems having ITC-eligible battery storage. Per ITC regulations, this requires storage to charge solely using solar power production. At the time of this study's completion, compensation rate methodologies had not been finalized for PURPA solar + battery storage facilities pursuing contracts with Idaho Power. Thus, the model used a simplified approach of allowing the battery to only discharge between 4 pm and 10 pm daily. However, the model allowed the battery dispatch to minimize total Idaho Power production costs when during the permitted charging and discharging periods. Finally, as shown in Table 6, the reserves needs are modeled as identical in each of these cases.

In all of these cases, the model uses a high solar build (1,355 MW of total solar), but only the 794 MW of the solar (i.e. the incremental solar built vs. the 2023 Base Case) is coupled with an ITC-eligible battery. The differences in these cases are as follows:

- Total Battery Capacity
  - High Solar Case: 0 MW
  - High Solar + 200 MW Battery Case: 200 MW, 4-hour (800 MWh) Li-Ion Battery
  - High Solar + 400 MW Battery Case: 400 MW, 4-hour (1,600 MWh) Li-Ion Battery

As can be seen in Figure 20 and Figure 21, on a typical medium-load spring day (5/10/2023), the battery is used to move solar energy from morning and evening solar production hours to increase net sales to the market and reduce Idaho Power coal generation.

Figure 20: High Solar vs. High Solar + 200 MW Battery, Medium Load Spring Day

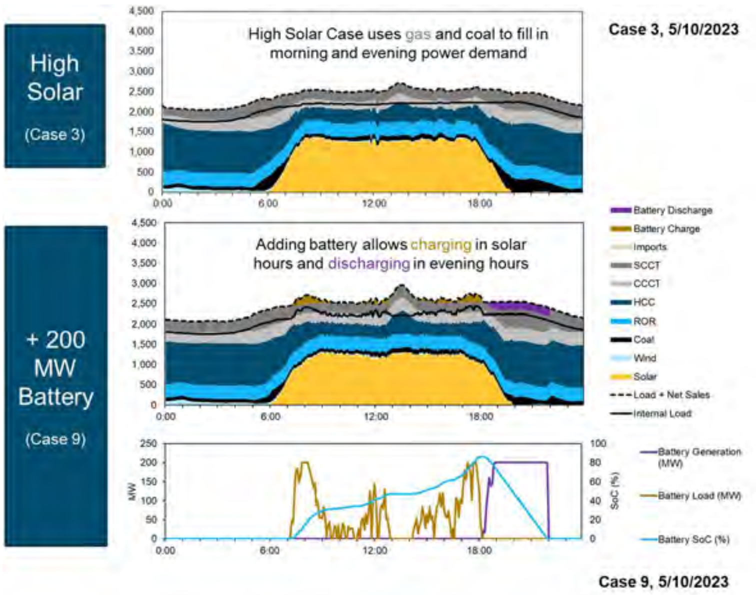
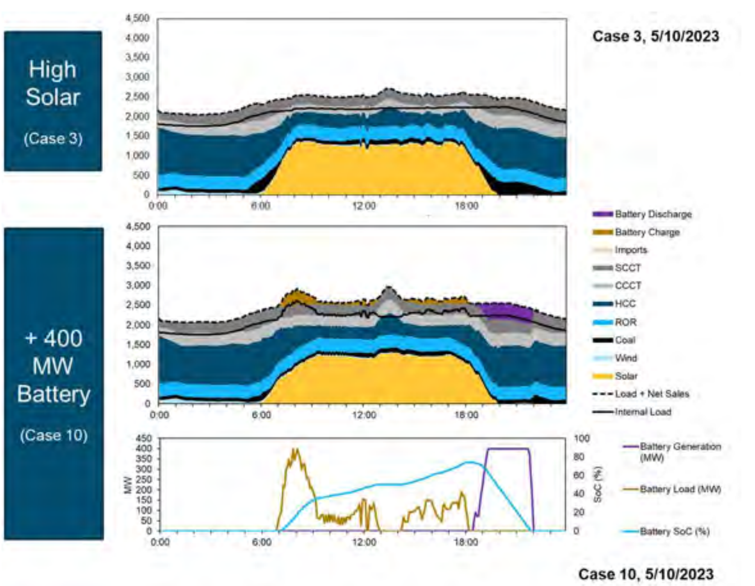


Figure 21: High Solar vs. High Solar + 400 MW Battery, Medium Load Spring Day



The average month-hourly dispatch of charging and discharging for the ITC-eligible storage is depicted in Figure 22. As can be seen in each of these figures, having greater battery capacity does not fundamentally alter when charging and discharging occur on a given day, or across the year.

Figure 22: Month-Hourly Average Battery Charge and Discharge Power for 200 MW and 400 MW ITC-Eligible Batteries

200 MW

	Battery Charge (MW)																							
	Hour																							
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0	0	0	0	0	0	0	0	1	36	77	55	71	67	65	62	61	12	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	4	29	42	76	103	113	105	74	37	6	0	0	0	0	0	0
3	0	0	0	0	0	0	0	16	47	108	109	91	84	84	74	56	7	10	3	0	0	0	0	0
4	0	0	0	0	0	0	9	27	69	88	65	60	51	91	93	98	29	55	1	0	0	0	0	0
5	0	0	0	0	0	0	9	58	78	37	41	61	47	22	34	84	81	74	7	0	0	0	0	0
6	0	0	0	0	0	1	35	79	85	66	49	44	67	67	46	87	35	30	9	1	0	0	0	0
7	0	0	0	0	0	0	35	139	153	123	98	34	50	63	45	48	19	8	3	0	0	0	0	0
8	0	0	0	0	0	0	11	64	135	111	28	14	19	55	38	90	99	138	1	0	0	0	0	0
9	0	0	0	0	0	0	0	17	37	26	15	7	8	20	44	136	133	116	16	0	0	0	0	0
10	0	0	0	0	0	0	0	0	34	68	61	50	38	32	35	86	124	53	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	20	81	79	36	27	38	58	86	69	1	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	1	6	25	15	25	29	32	33	8	0	0	0	0	0	0	0

	Battery Discharge (MW)																							
	Hour																							
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19	82	112	74	48	133	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19	65	100	104	96	159	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	63	64	94	71	171	173	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	37	26	140	148	156	171	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	115	184	144	131	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	29	30	69	166	188	164	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19	70	138	177	194	156	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	4	158	194	197	183	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	9	89	72	170	182	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	16	65	102	174	178	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10	103	83	73	68	121	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	24	21	15	50	42	0	0

400 MW

	Battery Charge (MW)																							
	Hour																							
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	0	0	0	0	0	0	0	0	2	54	126	103	115	94	104	117	95	17	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	5	45	66	128	161	187	159	110	42	7	0	0	0	0	0	0
3	0	0	0	0	0	0	0	20	72	175	165	136	177	181	172	105	10	14	2	0	0	0	0	0
4	0	0	0	0	0	0	12	62	155	172	112	96	75	133	159	151	42	61	2	0	0	0	0	0
5	0	0	0	0	0	0	14	113	152	74	80	107	88	44	50	88	112	123	37	0	0	0	0	0
6	0	0	0	0	0	1	47	102	119	100	106	106	110	133	130	192	71	34	13	0	0	0	0	0
7	0	0	0	0	0	0	61	238	270	218	219	101	132	141	101	92	28	4	2	0	0	0	0	0
8	0	0	0	0	0	0	16	88	235	188	65	24	48	93	75	176	198	238	5	0	0	0	0	0
9	0	0	0	0	0	0	0	33	61	35	18	11	13	48	64	254	258	199	22	0	0	0	0	0
10	0	0	0	0	0	0	0	0	44	113	90	93	65	74	86	160	235	73	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	31	143	115	60	32	32	72	139	99	2	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	1	6	39	17	31	35	37	40	9	0	0	0	0	0	0	0

Table 16 shows the summary of results for these cases. The total production costs are lowest for the 400 MW battery, increasing in the 200 MW battery case and further increasing in the no battery cas+es. However, the total specific integration costs are lowest for the 200 MW battery size. Both storage cases exhibit dramatically lower VER integration costs than the high solar without storage case. This is discussed in greater detail in Section 5 of this report.

Table 16: Summary of Results for High Solar with and without Storage

Case	Inc. Start Costs ($Million/ yr)	Inc. Ramping Costs ($ Million/ yr)	Total Inc. Imperf. Unit Commit. & Dispatch Costs ($Million/ yr)	Total Curtail. Costs ($Million/ yr)	Total Inc. Integrat. Costs ($Million/ yr)	Total Product. Cost ($Million/ yr)	Total Inc. VER Gen. (GWh /yr)	Total Inc. Specific Integrat. Costs ($/MWh)
3. Hi Solar	$0.80	$0.45	$5.78	$0.00	$7.04	$146	1,824	$3.86
9. Hi Solar, 200 MW Battery	$0.58	$0.02	$0.56	$0.00	$1.16	$144	1,823	$0.64
10. Hi Solar, 400 MW Battery	$0.58	-$0.34	$1.46	$0.00	$1.69	$142	1,823	$0.93

4.4.5 HIGH MUST TAKE SOLAR AND CURTAILABLE SOLAR CASES

Idaho Power is not able to perform economic solar curtailment of PURPA facilities. The high must take solar and high curtailable solar cases were therefore implemented to show how being able to economically curtail PURPA solar would change the cost of integrating VERs.

In the high solar case, the model can only perform reliability-based curtailment, i.e. the model will curtail VERs only when the alternative is to have unserved energy or face some other infeasibility. In the curtailable case, the model may economically curtail power for the incremental 794 MW of solar installed vs. the 2023 base case. This allows the model to curtail power to reduce Idaho Power's total production costs. There would be no difference in short-run marginal energy costs from economically curtailing PURPA solar, however Idaho Power may have to pay for the lost renewable energy credit (REC) due to curtailing solar. Therefore, the model assumes a $20/MWh curtailment penalty, which is a typical REC price in WECC. Similarly to the solar with storage cases, the VER reserves needs are modeled as identical between the must take and curtailable cases.

Figure 23 and Figure 24 respectively show the difference between the must take and curtailable cases on a low net load spring day (4/21/2023) and a high net load summer day (7/21/2023). In Figure 23, the model chooses to curtail power both when the external market price is below the curtailment penalty (i.e. below -$20/MWh), as well as during the middle of the day. The model chooses to curtail power midday because, while the market price is not below -$20/MWh, the model performs reliability curtailment of solar in the must take case as well. In other words, this low net load day requires VER curtailment of some sort. Total annual curtailment in the curtailable solar case is 3.8% of potential generation for the 794 MW of new solar. This curtailment is largely confined to spring hours, when the net load is very low.

Alternatively, Figure 24 shows that the model does not curtail solar when solar helps reduce total production costs. This is because solar increases net sales to a high-priced market.

Figure 23: High Must Take Solar and High Curtailable Solar, Low Load Day

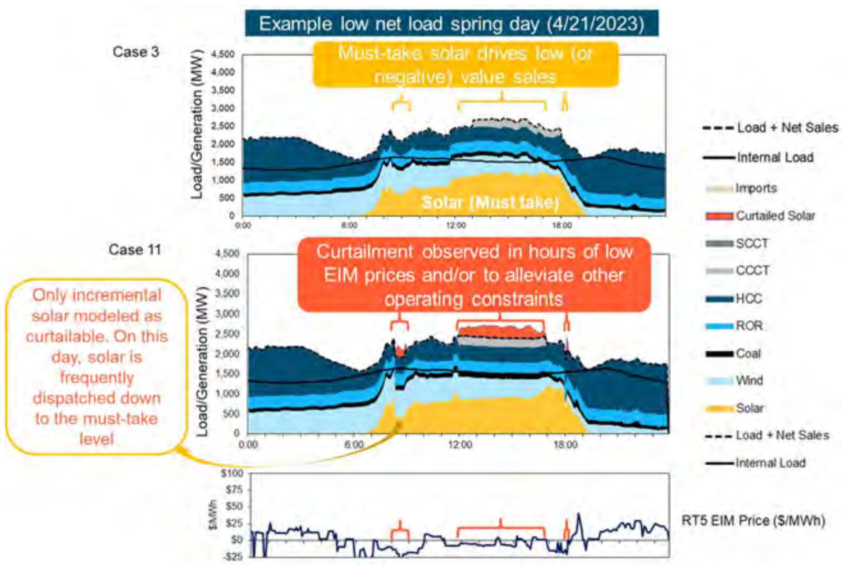


Figure 24: High Must Take Solar vs. High Curtailable Solar, High Load Day

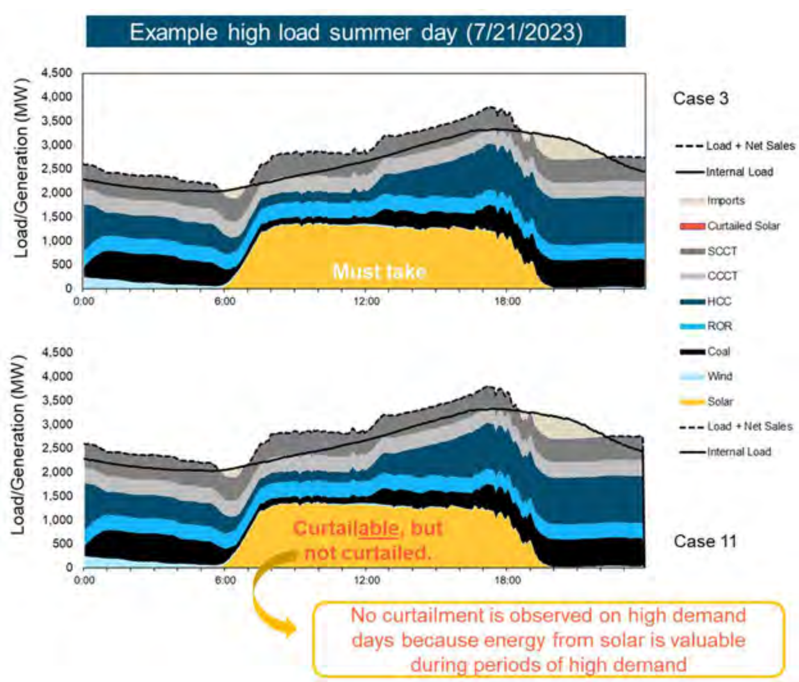


Table 17 shows that while the total incremental specific integration cost is lower in the curtailable solar case than the must take solar case, the total production costs are essentially identical between the two cases.

Table 17: Summary of Results for High Must Take and Curtailable Solar

Case	Inc. Start Costs ($Million/ yr)	Inc. Ramping Costs ($ Million/ yr)	Total Inc. Imperf. Unit Commit. & Dispatch Costs ($Million/ yr)	Total Curtail. Costs ($Million/ yr)	Total Inc. Integrat. Costs ($Million/ yr)	Total Product. Cost ($Million/ yr)	Total Inc. VER Gen. (GWh /yr)	Total Inc. Specific Integrat. Costs ($/MWh)
3. Hi Solar	$0.80	$0.45	$5.78	$0.00	$7.04	$146	1,824	$3.86
11. Hi Curtail. Solar	$0.72	$0.39	$4.31	$0.29	$5.71	$147	1,823	$3.13

5 Discussion

5.1 Discussion of Current Study Results

E3's results provide several high-level insights about integrating VERs:

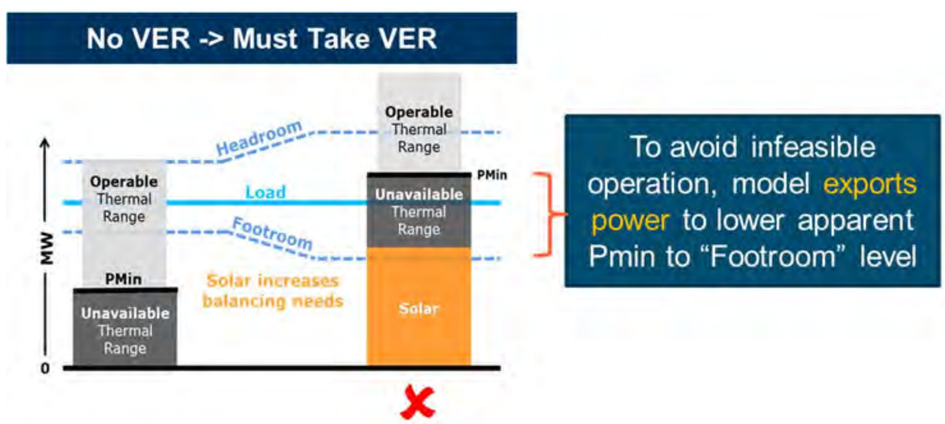
+ Integration costs are driven by the need for procuring system flexibility on dispatchable generators during periods of low net load
+ Integrating solar is more expensive that integrating new wind resources
+ VER integration costs can be lowered by adding flexibility to the Idaho Power system, such as battery storage, allowing economic curtailment and reducing the must-run thermal Pmin of the system
+ VER integration costs increase during abnormal hydro conditions (low or high annual budgets)
+ The integration costs found in this 2020 Idaho Power VER integration study are lower than the 2018 Idaho Power Variable Energy Resource Analysis

These results are discussed in more detail below.

5.1.1 EFFECTS OF BINDING PMIN CONSTRAINTS ON VER INTEGRATION COSTS

As discussed in Section 3.2, as more VERs are added to Idaho Power's system, the aggregate reserve and flexibility needs tend to increase. Only HCC, coal, CTs and CCGTs are modeled as eligible to provide reserves. Because all these generators have a non-zero Pmin, the aggregate thermal Pmin grows when more generators are brought online to provide reserves. Idaho Power has a large penetration of PURPA VERs, which are treated as must take units by Idaho Power. When these must take resources produce large amounts of power, the net load on Idaho Power's system can fall to very low values. In order to maintain supply-demand equilibria on Idaho Power's system, Idaho Power must export power to the market when the aggregate system Pmin, plus the required system footroom, is greater than the system net load. This is depicted schematically below in Figure 25.

Figure 25: Effects of Additional Solar on Unit Commitment and Market Transactions



During these "binding Pmin" events, exporting power to the market does not by itself cause VER integration costs to rise. However, due to the growing penetration of solar across the EIM footprint, 2023 EIM market prices are projected to be, on average, below typical marginal thermal unit generation costs during daytime hours in the spring and fall, as shown in Figure 26. These periods of low EIM prices are also when Idaho Power's solar generators will be producing enough power to significantly lower Idaho Power's net load to binding Pmin levels. Therefore, under high solar builds, Idaho Power is often exporting power at a financial loss to a low- or negative-priced EIM market. At other times, Idaho Power may have to shift its hydro production to non-optimal hours (e.g. away from times when hydro could earn the greatest amount of export revenues) in order to provide sufficient flexibility on HCC while adhering to the HCC daily energy budget.

Figure 26: Month-Hourly Average 2023 EIM Market Prices

Month-Hour Average 2023 RT15 Price ($/MWh)

Month \ Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	25	25	25	24	24	24	23	21	23	21	20	21	19	19	18	20	19	24	28	22	20	26	26	25
2	22	21	21	22	21	22	14	18	15	10	9	10	10	9	8	10	12	13	9	12	16	22	22	22
3	27	27	26	26	25	23	13	18	18	17	18	18	17	18	18	19	18	16	21	22	26	25	27	28
4	26	24	23	22	20	21	15	18	12	10	12	13	13	13	13	13	14	15	25	37	38	29	27	26
5	33	32	31	30	33	36	31	25	25	27	25	24	23	27	27	25	22	27	46	57	53	44	38	34
6	35	35	34	34	35	31	26	21	20	20	20	21	21	23	28	31	41	48	81	100	73	50	39	35
7	35	34	32	31	28	26	21	20	20	22	22	24	24	25	27	28	30	40	55	60	50	41	36	34
8	28	25	25	24	23	22	20	19	17	18	21	23	24	25	25	23	22	21	40	40	35	30	29	27
9	22	22	21	20	20	21	20	19	19	19	20	21	20	20	18	16	10	24	39	57	24	24	23	22
10	20	19	19	19	20	21	15	24	16	13	13	15	16	17	17	16	8	12	21	20	19	21	21	20
11	29	28	27	28	28	29	29	33	28	26	23	25	24	25	25	25	29	38	35	27	26	31	30	31
12	28	27	26	26	26	28	25	26	26	24	23	25	25	24	24	23	21	25	20	19	28	29	29	29

Month-Hour Average 2023 RT5 Price ($/MWh)

Month \ Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	25	24	24	24	23	23	22	19	30	19	18	18	16	11	16	18	17	20	21	18	18	25	26	25
2	21	20	20	21	21	21	10	13	22	5	6	7	7	7	6	7	7	9	12	8	14	39	22	22
3	28	26	26	26	25	26	9	14	22	16	17	19	17	18	15	18	15	21	18	17	21	26	27	28
4	32	29	28	26	22	14	-8	7	2	5	12	13	22	15	13	13	12	50	34	32	22	25	38	31
5	69	53	46	42	47	45	32	29	37	38	37	33	36	41	39	36	33	50	111	99	73	61	62	52
6	56	52	51	50	49	43	28	23	22	24	24	25	26	27	45	34	42	69	108	114	81	66	56	54
7	47	44	43	42	35	29	21	19	20	20	21	24	23	26	26	26	29	51	85	87	65	51	44	45
8	33	30	30	29	26	22	17	19	16	17	20	24	21	20	19	13	9	9	37	35	33	30	31	31
9	23	22	21	20	19	15	19	14	16	17	18	18	19	16	11	0	-12	-2	5	1	25	22	42	23
10	17	18	17	17	16	13	-5	13	9	4	5	7	10	11	11	7	-9	4	-3	-2	4	15	19	18
11	28	29	27	28	26	23	15	17	35	13	16	19	21	22	22	19	9	14	10	8	12	23	24	29
12	26	26	26	25	24	23	9	9	17	14	15	18	19	24	20	18	7	-9	-9	2	16	18	22	28

As shown in Section 3.2, in contrast to the High Solar case, in the High Wind case, the reserves profile is more uniform across time. Additionally, the period of highest reserves needs do not necessarily coincide with low net loads resulting from high Idaho Power wind production because Idaho Power wind production tends to be highest during wintertime evenings. This results in fewer binding Pmin intervals in the High Wind case that force suboptimal market transactions.

Not retiring a Bridger unit and high hydro conditions increases the cost of integrating new solar. In these cases, having higher levels of must run coal or must take hydro has the effect of decreasing the solar production level at which these binding Pmin events take place.

As shown in

Table 12, the VER integration costs are typically dominated by the costs of imperfect unit commitment and dispatch costs. Therefore, the reader can largely focus on periods in which these binding Pmin events occur when seeking to understand what drives integration costs for the different cases.

5.1.2 HIGH SOLAR WITH STORAGE CASES

A paradoxical finding of this analysis is that the total specific integration cost of solar is *lower* for the High Solar + 200 MW Battery case than the High Solar + 400 MW Battery case.

The reason for this is due to the way in which this study calculates VER integration costs. As discussed in Section 2.1, the VER integration costs are calculated as the sum of the ramping and start costs, plus the total imperfect unit commitment and dispatch costs. The total imperfect unit commitment and dispatch cost is calculated for each case as the difference of production costs for the imperfect foresight and perfect foresight cases. The only difference between these cases is how much VER forecast error, subhourly VER variability and reserves are carried for the incremental VER build. Due to its greater capacity, the larger 400 MW battery allows for a greater production cost savings than the 200 MW battery when moving from the imperfect foresight to the perfect foresight case. This larger savings is added into the integration cost. Therefore, the apparent integration cost is higher for the 400 MW battery than the 200 MW battery. However, there are limitations to how this study was able to model a PURPA solar + ITC-enabled solar fleet in PLEXOS. These limitations are discussed below.

The PLEXOS model used to calculate Idaho Power's VER integration costs has multiple stages that reflect different levels of uncertainty the DA, HA, RT15, and RT5 time intervals. Storage dispatch can change between the stages due to different grid conditions and solar forecasts. If storage provides more flexibility ahead of real time, it can leave real-time dispatch with lower levels of flexibility, or vice versa. The difference between storage dispatch in perfect and imperfect foresight cases, propagated through multiple modeling time horizons, results in the potential for small, unexpected swings in VER integration costs. Considerations with respect to storage scheduling include:

+ Storage scheduling between different commitment timeframes will evolve as more storage is deployed. Currently, there is not a standard practice for battery storage scheduling
+ The scheduling of PURPA-contracted storage over multiple timeframes is especially uncertain given the lack of experience with this type of resource

+ The scheduling of PURPA-contracted storage in a perfect foresight counterfactual will never be known with any precision because grids are not operated with perfect foresight.

The impact of storage sizing on unit commitment may be non-linear – a bigger battery may cause a large Idaho Power unit to alter its commitment schedule whereas a small battery would not be able to cause as big of an impact.

Additionally, the interaction between storage dispatch and Idaho Power market revenues can create significant swings in the VER integration cost. The extent to which Idaho Power has control over PURPA-contracted battery operations can impact market revenues, especially during periods of extreme EIM prices.

The considerations above imply that there is uncertainty around future PURPA-contracted storage dispatch and VER integration costs. E3 has included many of the relevant dynamics in the PLEXOS model, and believes that the two integration cost calculations for storage are within reasonable bounds of error given what is known currently about PURPA-contracted storage. However, E3 believes it is appropriate to use the results from these two cases to derive an *average* solar + storage VER integration cost, rather than assign discrete values to different storage capacities.

5.2 Comparison to Data in Literature and 2018 Idaho Power VER Study

In its *Western Wind and Solar Integration Study: Phase 2*[11], NREL calculated integration costs for up to 33 percent penetration of wind and solar in the Western Interconnection. The summary integration costs by scenario from the NREL study, the 2018 Idaho Power VER integration study and this study are shown below in Table 18, in 2020 dollars. Generally, it can be seen that the values from this study vary considerably more than the values from the NREL study. The NREL study integrated wind and solar across the Western Interconnection versus a small individual balancing area, and did not use the same reserves derivation process as this study. Modeling the entire Western Interconnection meant that NREL did not assess the effects of suboptimal market trades on integration costs at the interconnection footprint level. Additionally, the greater resource diversity across the entire Western Interconnection likely reduces specific VER integration costs. However, the general takeaway from this modeling is that VER integration costs in the 2018 and 2020 Idaho Power VER integration studies are generally higher than those from prior NREL work.

[11] https://www.nrel.gov/docs/fy13osti/55588.pdf

Table 18: Comparison of 2020 Idaho Power VER Study Results to Other VER Integration Cost Results

Case	Total percent of Annual Load Supplied by VERs (Total VER Generation/Gross Load)	Specific Integration Cost, Low Bound (2020$/MWh VER)
NREL High Wind	33 %	$0.25-0.75
NREL High Solar	33 %	$0.22-0.56
NREL Mixed Resources	33 %	$0.16-0.43
2020 Idaho Power VER Study High Solar Cases (no storage or curtailment allowed)	28 %	$3.86-4.65
2020 Idaho Power VER Study High Wind Case	28 %	$0.77
2020 Idaho Power VER Study High Wind and Solar Case	38 %	$2.46
2018 Idaho Power VER Study 1,000 MW of Wind Case	14 %	$6.17

5.3 Methodological Differences between 2020 and 2018 Idaho Power Company Variable Energy Resource Analysis

5.3.1 OVERVIEW

The incremental integration costs shown in this study are lower than those from the 2018 Idaho Variable Energy Resource Analysis. While it was not in scope for E3 to perform a detailed analysis of the 2018 study and how its methodology differed from that of this analysis, several things stand out as important differences between the two studies.

5.3.2 RESERVES

The 2018 study calculates reserves in a very different manner than in the 2020 study. The resulting average reserves levels are higher in the 2018 study than those investigated in the 2020 study. The 2020 study includes CAISO FRP reserves, regulation reserves and contingency reserves. The 2018 study included regulation reserves and contingency reserves, but the regulation reserves were calculated differently.

In the 2020 study, to derive the CAISO FRP reserves, E3 used a method that approximates the method used to derive the CAISO FRP within reasonable bounds.[12] The CAISO FRP has RT15 and RT5 stages. For the RT15 stage, E3 calculated the uncertainty component of the FRP using the difference between 2019 HA forecast net load and RT5 actual net load. Similarly to CAISO's derivation methodology, E3 then binned this net load forecast error by month-hour and used a 95 percent confidence interval (as does CAISO) to determine headroom and footroom components of the uncertainty reserves. After capping these net load-based reserves using P98 and P2 values for footroom and headroom, respectively, E3 assumes a 40 percent diversity credit to reduce the uncertainty component by the same percentage in all hours, based on historical levels of EIM footprint diversity. This 40 percent value approximates the caps and "credit" system that the CAISO FRP uses.[13] Finally, E3 calculates the RT5 CAISO FRP using

[12] See, e.g. http://www.caiso.com/InitiativeDocuments/DMMResourceSufficiencyEvaluationPresentation-EnergyImbalanceMarketofferRulesTechnicalWorkshop.pdf for a description of CAISO FRR components.

[13] See, e.g. http://www.caiso.com/InitiativeDocuments/DMMResourceSufficiencyEvaluationPresentation-EnergyImbalanceMarketofferRulesTechnicalWorkshop.pdf for a description of CAISO FRR components.

historical data derived from the ratio of 2019 CAISO RT5 FRP uncertainty reserves to the 2019 CAISO RT15 FRP uncertainty reserves.[14]

E3 calculates regulation reserves for the individual load, wind and solar profiles using a persistence forecast of the 5-minute data. Solar data are then binned by season, hour and percent output, whereas load and wind are binned by percent of maximum observed load and output, respectively. A 95 percent confidence interval is then used to derive headroom and footroom needs for these reserves, and they are then combined using a root mean square, assuming that the load, wind and solar regulation components have no covariance on this short timescale. Finally, spinning contingency reserves are calculated at 3 percent of load. This results in the average reserves shown below in Table 19.

Table 19: Reserves Summary for Different 2020 Idaho Power VER Integration Cost Cases

Case	Total MW Online Wind (MW)	Total MW Online Solar (MW)	Avg. RT15 FRP Up (MW)	Avg. RT15 FRP Down (MW)	Avg. Reg. Up (MW)	Avg. Reg. Down (MW)	Avg. Conting. Res. (MW)	Avg. Total Res. Up (Percent of Avg. Load)	Avg. Total Reserves Down (Percent of Avg. Load)
1. 2023 Base Case	728	561	100	97	40	41	104	13 %	7 %
2. Jim Bridger Online	728	561	100	97	40	41	104	13 %	7 %
3. Hi Solar	728	1,354	147	142	71	72	104	17 %	11 %

[14] http://oasis.caiso.com/mrioasis/logon.do

4. Hi Solar, Low Hydro	728	1,354	147	142	71	72	104	17 %	11 %
5. Hi Wind	1,396	561	152	147	50	52	104	16 %	10 %
6. Hi Solar, Hi Wind	1,396	1,354	193	186	79	81	104	19 %	13 %
7. Existing Solar Base Case	728	561	87	86	32	33	104	11%	6%
8. Hi Solar, Hi Hydro	728	1,354	147	142	71	72	104	17 %	11 %
9. Hi Solar, 200 MW Battery	728	1,354	147	142	71	72	104	17 %	11 %
10. Hi Solar, 400 MW Battery	728	1,354	147	142	71	72	104	17 %	11 %
11. Hi Curtail. Solar	728	1,354	147	142	71	72	104	17 %	11 %

In the 2018 study, Idaho Power calculated the regulation reserves using 2HA forecasted wind and load, and 1-minute actual wind and load data. These data were then binned by percentage of wind output or maximum load. It is not clear from the study if confidence intervals are subsequently applied to this data, but the resulting reserves, as a percentage of normalized load, are shown below as Table 20 and Table 21. Spinning reserves are calculated as 3 % of the hourly load, which is identical to the method E3 used.

Table 20: 2018 Idaho Power VER Integration Study Wind Reserves

	Winter		Spring		Summer		Fall	
Wind Quartile of Forec. Output	Reg Up % of Avg Wind Forec.	Reg Down % of Avg (Namplate – Forec.)	Reg Up % of Avg Wind Forec.	Reg Down % of Avg (Namplate – Forec.)	Reg Up % of Avg Wind Forec.	Reg Down % of Avg (Namplate – Forec.)	Reg Up % of Avg Wind Forec.	Reg Down % of Avg (Namplate – Forec.)
1.	100%	28 %	100%	62 %	100 %	48 %	100 %	66 %
2.	86 %	51 %	94 %	79 %	93 %	75 %	80 %	65 %
3.	55 %	65 %	71 %	81 %	68 %	85 %	76 %	75 %
4.	49 %	34 %	43 %	69 %	59 %	82 %	39 %	43 %

As shown in Table 20 and Table 21, the 2018 study had much higher reserves than the 2020 study, particularly for VERs. This likely results in higher costs for integrating VERs in the 2018 study, due to the high reserves levels causing more binding Pmin constraints for a given VER penetration level.

Table 21: 2018 Idaho Power VER Integration Study Load Reserves

	Winter		Spring		Summer		Fall	
Load Quartile of Forecast Maximum	Reg Up % of Avg Load	Reg Down % of Avg Load	Reg Up % of Avg Load	Reg Down % of Avg Load	Reg Up % of Avg Load	Reg Down % of Avg Load	Reg Up % of Avg Load	Reg Down % of Avg Load
1.	4.9 %	9.1 %	8.1 %	10.5 %	7.9 %	11.5 %	8.0 %	10.6 %
2.	9.3 %	6.8 %	6.8 %	11.3 %	8.1 %	6.0 %	7.5 %	8.9 %
3.	9.5 %	5.8 %	9.9 %	6.7 %	9.7 %	9.8 %	9.9 %	8.5 %
4.	7.9 %	6.9 %	8.3 %	7.0 %	6.2 %	13.3 %	7.3 %	7.1 %

E3 believes that its 2020 reserve derivation methodology is closer to standard practice than the method used in the 2018 study. There was negligible observed unserved energy in E3's models. Similar normalized levels of reserves (MW per

MW of installed VERs) and confidence intervals of historical forecast error have been used elsewhere.[15] [16] [17]

In both the 2018 study and the 2020 study, there were a significant number of hours in which the AURORA and PLEXOS models were unable to hold sufficient reserves to meet the requirements outlined above. In the PLEXOS model, the reserve violation penalties were set up such that regulation reserves were typically not met whereas CAISO FRP reserves and contingency reserves were nearly always met.

5.3.3 TREATMENT OF EXTERNAL MARKETS

The 2020 study is modeled with an EIM market, whereas the 2018 study is not. Because Idaho Power joined the EIM in Q2 2018, this omission was reasonable in the 2018 study. In the 2020 study, the presence of the EIM market allows the model to balance forecast error from the DA and HA intervals to the real time. The 2018 model had less flexibility in its ability to trade, which likely reduces the ability of Idaho Power's system to buy and sell from the market to enable procuring reserves relative to a scenario with the EIM.

5.3.4 MULTISTAGE VS. SINGLE STAGE MODEL

The 2020 study used a multistage PLEXOS model, which contains information about typical net load forecast error and subhourly net load variability, whereas

[15] Z. Zhou, T. Levin, G. Conzelmann, "Survey of U.S. Ancillary Services Markets." https://publications.anl.gov/anlpubs/2016/01/124217.pdf

[16]http://www.ercot.com/content/wcm/key_documents_lists/137978/9_2019_Methodology_for_Determining_Minimum_Ancillary_Service_Requirements.pdf

[17] http://www.caiso.com/Documents/Addendum-DraftFinalTechnicalAppendix-FlexibleRampingProduct.pdf

the 2018 study used a single hourly stage AURORA model that did not reflect forecast error. In executing its multistage PLEXOS model, E3 did not observe significant levels of unserved energy. Therefore E3 believes its reserves derivation method provides reasonable reserve levels.

6 Conclusions

6.1 Integration Costs

Overall, it was found that integration costs for new VERs on Idaho Power's system vary from \$0.64/MWh up to \$4.65/MWh. Generally, solar integration costs are significantly higher than those for new wind. Adding more must-run resources, such as hydro operating at very high capacity factors, or keeping must run thermal units online, increases VER integration costs. Increasing system flexibility, such as by pairing solar with dispatchable storage, or by allowing solar to be economically curtailed, reduces VER integration costs.

Additionally, the VER integration costs found herein are significantly lower than those from the 2018 Idaho Power VER integration study. This is due to multiple factors, but likely the single greatest cause is the reduction in growth in reserves per unit of online wind and solar capacity in the 2020 study versus the 2018 study.

Finally, the results from this study are contingent upon VERs being must take; coal units being committed as baseload, must run units; maintaining strategies for deploying Idaho Power's HCC hydroelectric resources; storage paired with solar not being able to provide reserves; and other assumptions about current practices that may change in the future.

7 Appendix 1: Process Document

7.1 Introduction

This Appendix is provided as a guide to further understand how E3 developed its PLEXOS model for this study.

The production cost simulation software, PLEXOS, was used to calculate VER integration costs in this study. This was done by using PLEXOS to generate the outputs necessary to derive the VER integration costs: start/stop costs, ramping cost, imperfect unit commitment and dispatch fuel costs, imperfect unit commitment and dispatch net import costs and curtailment costs.

To yield results, PLEXOS requires various inputs into E3's four stage model. The inputs to the PLEXOS model were developed by E3, Idaho Power, and in some instances in collaboration between Idaho Power and E3. These include:

+ **Load Profiles:** The 2019 profiles were developed by Idaho Power and E3 and consist of 4 comma separated value (CSV) files to represent load forecasts at the DA, HA, and RT15 stages with the RT5 profile seen as the actual load profile, and these were scaled to 2023 load profiles by E3.
+ **Renewable Profiles:** Solar and wind profiles were developed by E3 using Idaho Power's data and consist of 4 CSV files to represent generation forecasts at the DA, HA, and RT15 stages with the RT5 profile seen as the actual output.

- **Hydro Profiles:** Daily hydro budgets were created by E3 using Idaho Power's historical hydro data, and Pmax/Pmin levels were derived using Idaho Power input. These are fed into the model using separate CSVs for daily HCC maximum power, daily HCC minimum power, daily HCC energy budget and daily RoR power outputs
- **Generator Characteristics:** Generator characteristics were provided by Idaho Power as E3's part of the data collection process and include properties such as maximum and minimum capacity, ramp rates, start-up costs, VO&M, as well as any must-run flags or particular generating patterns. These are input for each generator using the PLEXOS UI.
- **Reserve Policies and Profiles:** Reserve profiles for the "perfect foresight" and "imperfect foresight" cases were developed using E3's RESERVE tool, along with the renewable and load profiles provided by E3. Each case has its own set of reserve profiles, which are in the form of CSVs read in for the flexible ramping requirement and the regulation needs. Contingency reserves are enforced within the PLEXOS UI.
- **Topology and Transmission:** The transmission and zonal topology of the model was created by E3 with input from Idaho Power towards transmission capacity to the Mid C and PV market nodes. These limits and the topology were input to the PLEXOS UI.
- **Markets:** Market transaction limits were provided by Idaho Power for the two markets nodes, Mid C and PV, represented within this model. Forward Q2-Q4 2019 and Q1 2020 market prices were provided to E3 by Idaho Power, and E3 downloaded historical Q2-Q4 2019 and Q1 2020 EIM market prices. These prices are then modified using E3's in-house AURORA price forecasts to adjust them to 2023 expected market prices. These adjusted prices are fed into the model using CSVs for each market and model stage.

+ **Fuel Prices**: Fuel prices were provided to E3 for each of the generators, and are enforced within the PLEXOS UI.

When running a case within PLEXOS, it is important to ensure that the appropriate renewable profiles are added as data files in the model. These are found in the 'Wind Profiles' and 'Solar Profiles' subfolders within the 'Data' directory and 'Data Files' folder illustrated in Figure 27. In addition, if need be, updated reserve profiles must also be added to the PLEXOS model. These data files are named to correspond with the relevant case they will be used for and can be found under the 'Reserves Idaho Power' subfolder in the 'Data' directory and within the 'Data Files' folder. Daily hydro budget profiles can be added or adjusted within the 'Hydro Budgets' subfolder within the 'Data Files' folder.

Figure 27: PLEXOS Data Directory

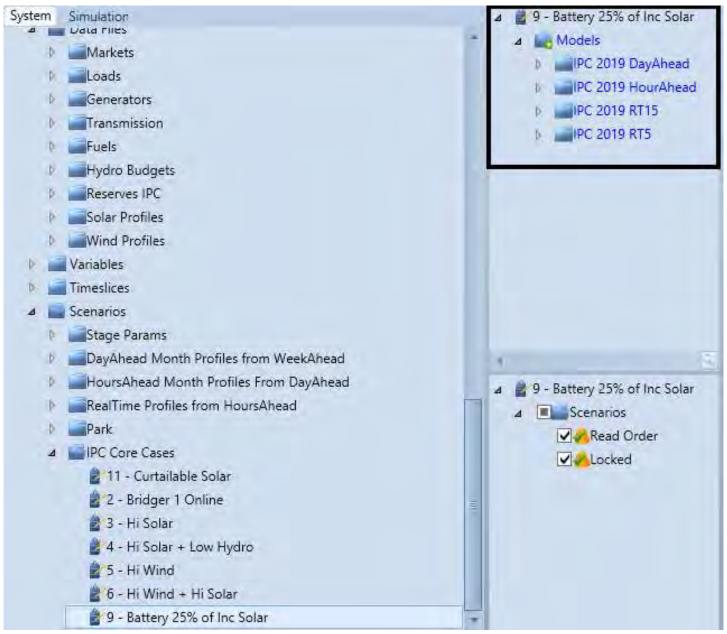
Creating a new case or editing an existing case's properties can be done within the PLEXOS UI's 'Scenarios' folder seen in Figure 28 under 'Idaho Power Core

Cases'. Each Scenario represents an individual case. The properties that are tagged with this case 'Scenario' will only be used if this case is being run.

Figure 28: PLEXOS Scenario Directory

A specific case is only run if the 'Scenario' associated with it is included in the 'Membership' of each monthly stage model (DA, HA, RT15, RT5) and can be identified as shown in Figure 29. Only one 'Idaho Power Core Cases' 'Scenario' can be linked to the models at any one time. If multiple case 'Scenarios' are included in the model 'Memberships', errors may occur while attempting to execute the full model or may yield incorrect results.

Figure 29: PLEXOS Membership view



To derive VER integration costs, the overall PLEXOS model is run twice for each case, once using the perfect foresight profiles for the relevant VER resources and reserves, and then once using the imperfect foresight reserve and VER profiles.

The individual cases are expressed as individual PLEXOS models with custom modifications and, in some instances, CSV files. The primary differences between the cases are described below.

+ Case 1 is the 2023 base case for Cases 3-6 and Cases 8-11, which has all known unit additions and retirements and also includes the known 2019 through 2023 load growth. The Solar and Wind objects are scaled to the appropriate size for Case 1

- Case 2 explores the effect of not retiring one of the Bridger coal plant's units, but is otherwise identical to Case 1. The Bridger coal plant Pmin and Pmax are increased to reflect this change
- Case 3 builds on Case 1 by exploring the effect of adding enough new solar (794 MW of new solar) such that 10 percent of the 2023 Idaho Power average gross load is provided by this new solar build. This is done using the existing aggregated solar plant from Case 1
- Case 4 extends the Case 3 analysis to a low, rather than average hydro year. The hydro budgets and daily Pmin/Pmax levels are updated using the CSVs fed into the model
- Case 5 builds on Case 1 and explores the integration costs of a high wind build. Case 5 assumes a new wind build that can supply 10 percent of the annual 2023 Idaho Power gross load (669 MW of new wind). This is performed using the existing wind object from Case 1
- Case 6 builds on Case 3 and Case 5, including both high solar and high wind builds (794 MW of new solar and 669 MW of new wind). This is done using the existing solar and wind objects from Case 1
- Case 7 is identical to Case 1, except that none of proposed solar additions come online from 2019 to 2023, resulting in 251 MW fewer of solar than Case 1 and lower reserves needs. This is done using the existing solar object from Case 1
- Cases 8 extends the Case 3 analysis to a high, rather than average hydro year, and as in Case 4, this is accomplished by feeding in different CSVs to adjust the energy budgets and Pmax/Pmin levels
- Case 9 builds on Case 3 by adding a 200 MW 4-hour Battery object with a roundtrip efficiency of 85% and can only charge from the additional 794 MW of new solar

- Case 10 adds a 400 MW 4-hour Battery object with an 85% roundtrip efficiency and is only able to charge from the additional 794 MW of new solar
- Case 11 splits the solar object in Case 3 into two distinct generator objects: an 'Idaho Solar' and 'Idaho Solar Curtailable'. The 'Idaho Solar' resource is modeled as must-take, while the 'Idaho Solar Curtailable' object is allowed economically curtail

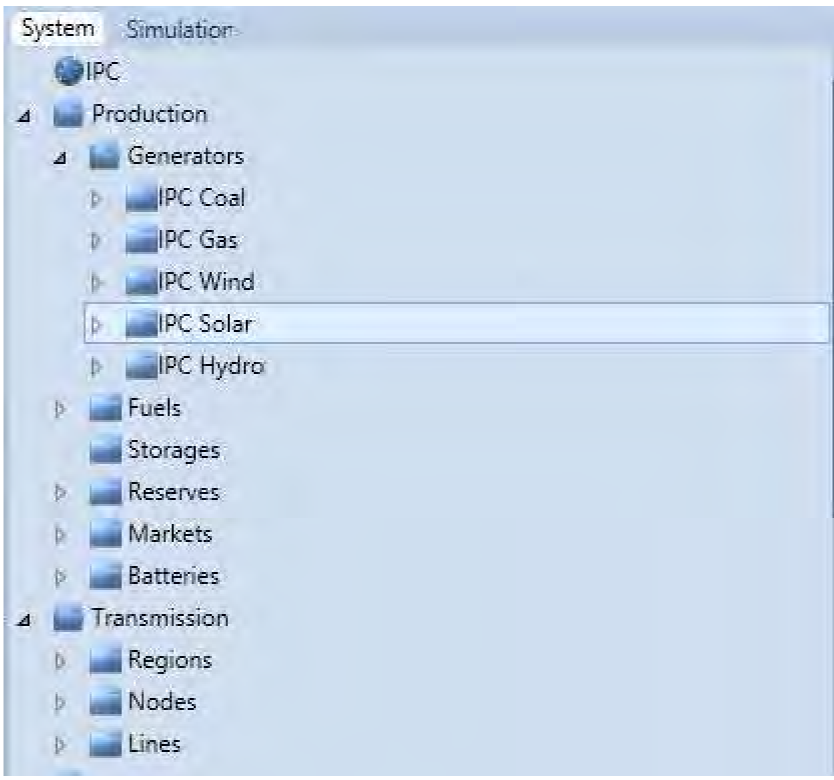
7.2 Results Processing

The results viewer enables us to display annual PLEXOS ST data in a more user-friendly format and consists of several different tabs. Below, we explain how to navigate and manipulate each tab in the order of their use when processing results:

- **Cover:** this tab provides a high-level overview of the workbook and is not of any practical use in processing results
- **Params:** The Params tab is used as a library that the embedded excel macro will read and use to pull outputs from individual properties in the PLEXOS solutions zip files. The 'ParentClassName' column corresponds to the tabs within the PLEXOS UI either 'System' or 'Simulation' as seen in Figure 29. The 'ParentName' is the system name within PLEXOS which is given as 'IPC' in this model. 'ChildClassName' is the subfolder name within any of the 'Production', 'Transmission', 'Generic', 'Data' folders. For example, 'Generators' or 'Lines'. The 'PropertyName' column is the name of the property to be output to the results viewer. 'ChildName' is the name of the object that the output property belongs to. If the generation of a generator called 'GEN1' needed to be brought into the

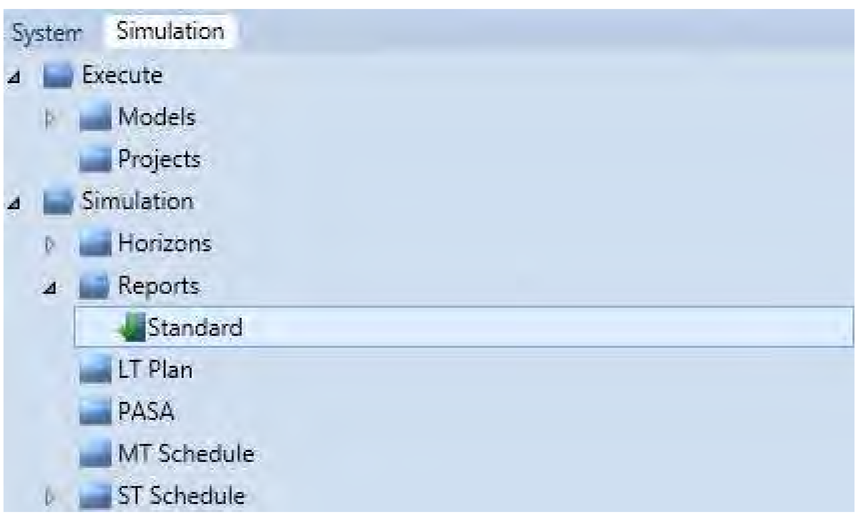
results viewer then the 'PropertyName' would be 'Generation' and the 'ChildName' would be 'GEN1'.

Figure 30: PLEXOS UI



If pulling in individual object properties, the 'AggregrationEnum_type' column by default should be input as 'AggregationEnum_None' and the 'agg_category' column should be left blank; however if it is more beneficial to load properties from all objects within a subfolder of the 'ChildClassName' folders such as 'IPC Solar' as seen in Figure 30, then it is possible to do this by leaving the 'ChildName' column blank, changing the 'AggregrationEnum_type' column entry to 'AggregationEnum_Category', and changing the ‘agg_category’ entry to ‘IPC Solar’. Finally, the ‘Units’ column should contain the units of the property that is being selected. One should ensure that the properties that are being listed in the Params tab in the results viewer are being output by the PLEXOS model. It is possible to verify and, if need be, add the property to be output as part of the PLEXOS solution zip file through the PLEXOS UI. As seen in Figure 31, by clicking on the ‘Simulation’ tab in the PLEXOS UI and double clicking on the object within the ‘Reports’ subfolder, the ‘Field List’ tab will show the entire list of possible outputs from the model.

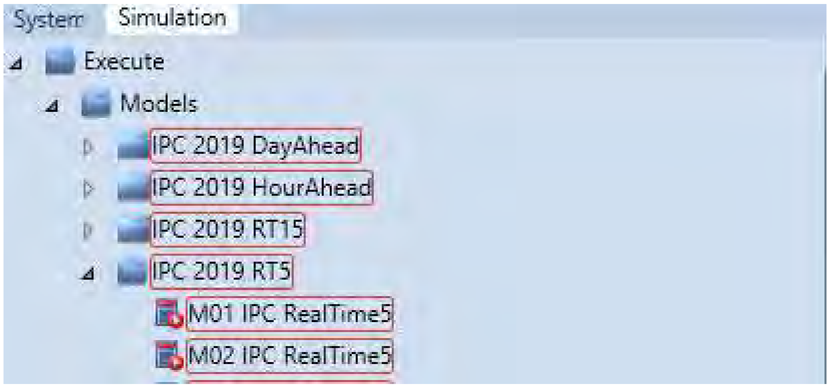
Figure 31: PLEXOS Reports



Ensure that the desired outputs have the ‘Period’, or ‘Flat File’ boxes checked. PLEXOS Help documentation is extremely thorough in providing additional detail in understanding the full amount of available output properties. This must be done before running the models to ensure that the selected outputs are created in the PLEXOS solution zip files.

Control: Once the desired outputs are set in the ‘Params’ tab, the results viewer can be run. The ‘Control’ tab contains a few cells that must be filled out before running the Macro. The 'Start Solution Month' and 'End Solution Month' allows the flexibility to run the results viewer for one month or a set of months if need be, though use caution as the results viewer capacity factor calculations are set up to calculate over the whole year so may yield incorrect results if not run over the whole year. In addition, ensure that the 'Stage Name' and 'Model Name Constant' inputs are aligned with the model names as seen in Figure 32, where the 'Stage Name' is 'RealTime5' and the 'Model Name Constant' is 'IPC'. The rest of the values within the 'Control' tab should not be touched. Ensure calculations within the workbook are set to manual and then click the 'Do all the PLEXOS things NOW!' button to start the results viewer.

Figure 32 PLEXOS Model Naming Convention



- **TimeSeries Data:** Once the results viewer is finished compiling the PLEXOS outputs these will all appear in the 'TimeSeries Data' tab.
- **Plot:** The 'Plot' tab provides dispatch plots, price plots, and market transaction plots of a user-selected date. The day chosen can be toggled between any days represented within the output data. The 'Plot' tab also

provides an annual look at capacity factor, cost, generation, number of starts by generator and provides annual cost and generation figures associated with market transactions to provide an overall production cost for the system over the year.

- **Month-Hour Summary:** This tab converts the 5-minute data within the 'TimeSeries Data' tab to hourly average values which is then used to create heat maps.
- **Month-Hour:** This tab is used as a data visualizing tool to display output data as month-hour average heat maps. The data being shown in the heat map can be toggled by the user via the dropdown menu.
- **SummaryAll:** The 'SummaryAll' tab offers a quick average value of each of the properties listed in the 'Params' tab.
- **Hydro Budget:** This tab provides information on Hells Canyon Complex hydro budgets.
- **Conversion:** This tab provides conversion figures within the workbook.