BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR ITS FIRST ANNUAL UPDATE TO THE EXPORT CREDIT RATE FOR NON-LEGACY ON-SITE GENERATION CUSTOMERS FROM JUNE 1, 2025 THROUGH MAY 31, 2026, IN COMPLIANCE WITH ORDER NO. 36048.	)	CASE NO. IPC-E-25-15

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

JARED L. ELLSWORTH

Q. Please state your name and business address.

A. My name is Jared L. Ellsworth My business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company (“Idaho Power” or “Company”) as the Transmission, Distribution and Resource Planning Director for the Planning, Engineering and 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 reliability compliance standards. I transitioned into the Transmission

Policy and 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 and Development department and assumed leadership of the System Planning group in 2018. In early 2020, I was promoted into my current role as the Transmission, Distribution, and Resource Planning Director. I am currently responsible for the planning of the Company’s wires and resources to continue to provide customers with cost-effective and reliable electrical service.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the results of the Company’s annual update to its Export Credit Rate (“ECR”) per the Idaho Public Utilities Commission (“Commission”) Order No. 36048, issued in Case No. IPC-E-23-14. In that case, the Commission directed Idaho Power to update all proposed components of the ECR except the season and hours of highest risk in an annual filing beginning April 1, 2025.[1]

Q. What is the Company requesting regarding the ECR in this case?

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[1] Case No. IPC-E-23-14, Order No. 36048 at 7 (December 29, 2023).

A. The Company is requesting the Commission approve its proposed ECR which will apply on a per kilowatt-hour (“kWh”) of excess energy exported to Idaho Power’s system by non-legacy customers with on-site generation. Specifically, Idaho Power is requesting the Commission approve the following rates to be effective between June 1, 2025, and May 31, 2026: 14.0598¢ for summer on-peak, 1.7682¢ for summer-off peak, and 0.9540¢ for all hours during the non-summer season.

Q. How is your testimony organized?

A. My testimony will first give an overview of the components of the ECR, and the Commission approved methodology in which they are updated. I will then discuss the proposed ECR to be effective between June 1, 2025, and May 31, 2026, and the main drivers behind the change in the updated ECR.

Q. Have you prepared any exhibits?

A. Yes, my testimony includes the following exhibits:

- Exhibit No. 1 provides a summary of the proposed ECR to be effective between June 1, 2025, and May 31, 2026.
- Exhibit No. 2 contains the Excel ECR workpaper with summary schedules and supporting data included.

- Exhibit No. 3 contains the 2023 line loss study relied on for the ECR update.
- Exhibit No. 4 contains the most recently filed Variable Energy Resource ("VER") Integration study relied on for the ECR update.
- Exhibit No. 5 contains the transmission and distribution ("T&D") deferral calculation.

I. ECR COMPONENTS

Q. What are the components of the ECR?

A. As approved by the Commission in Order No. 36048, the following are the components of the ECR:

- Avoided Energy Costs
- Avoided Line Losses
- Integration Costs
- Avoided Generation Capacity
- Avoided or Deferred T&D Capacity Costs

Q. Did the Commission approve a method for calculating the ECR?

A. Yes. In Order No. 36048, the Commission approved a seasonal and time-variant ECR with avoided cost-based value considerations.[2] The Commission further approved the specific methods in which each component of the ECR is to be calculated. In the following portion of my testimony,

[2] *Id.*, at 6.

I will describe the approved methods for each component of the ECR.

Q. Are there any components of the ECR which the Commission did not order to be updated annually?

A. Yes. In Order No. 36048, the Commission found that the season and on- and off-peak hours shall only be updated in a separate docket or in a General Rate Case ("GRC") filing as appropriate.[3] This was based on the recommendation from Commission Staff that updates to the summer season be part of future GRC filings and updates to on-peak hours should be filed in a separate docket.[4]

Q. Please describe the seasonal and time-based structure of the ECR.

A. The Commission-approved summer season is June 1 through September 30. During the summer season, the on-peak hours are 3 p.m. to 11 p.m. Monday through Saturday, excluding holidays, and the off-peak hours during the summer season are between 11 p.m. and 3 p.m. Monday through Saturday, and all hours on Sundays and holidays. The non-summer season is October 1 through May 31, and during non-summer all hours are considered off-peak.[5]

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[3] *Id.*
[4] *Id.*, Staff Comments at 5 (October 12, 2023).
[5] *Id.,* Order No. 36048 at 6 (December 29, 2023).

Avoided Energy Costs

Q. Please explain the Commission-approved methodology for valuing avoided energy.

A. The avoided energy costs are determined using twelve months (January 1 through December 31) of Energy Imbalance Market ("EIM") Load Aggregation Point ("ELAP") market prices, weighted for historical customer-generator exports ("ELAP Weighted Average").

Q. Did the Commission instruct the Company to distribute the avoided energy costs in alignment with the summer and non-summer seasons?

A. Yes.

Avoided Line Losses

Q. Please explain the Commission-approved methodology for valuing avoided line losses.

A. Avoided line losses are to be valued using the most recently completed line loss study. The Commission directed the Company to apply the annual energy line losses to the avoided energy value. Further, the peak loss coefficient is applied to the avoided capacity calculation.

Integration Costs

Q. What methodology did the Commission approve to account for integration costs?

A. In Order No. 36048, the Commission approved the use of the then most recently completed VER Study, which was the 2020 VER Study. However, in the order, the Commission also directed Idaho Power to complete an updated integration study as soon as possible and to file for Commission approval and inclusion for future ECR updates. Integration costs are accounted for as an offset to the avoided energy component.

Avoided Generation Capacity

Q. Please explain the Commission-approved method for valuing avoided generation capacity.

A. Three primary inputs are used to determine the avoided generation capacity value: (1) contribution to capacity (adjusted by the on-peak line loss coefficient), (2) the cost of an alternative resource, and (3) the energy exported during the on-peak hours.

Q. Please explain the method for determining the contribution to capacity.

A. The Commission approved the Effective Load Carrying Capacity ("ELCC") method to calculate the capacity contribution for all on-site customer generation exports that occur over the course of a year. ELCC values are individually calculated by year, and these results are averaged to produce a five-year trailing average. The five-year average ELCC is then multiplied by the maximum export value from the most-recently available year's data; the resulting capacity contribution is then multiplied by the on-peak line loss coefficient. This value represents the total capacity contribution utilized in the calculation of the avoided generation capacity value.

Q. What resource is used as the alternative resource?

A. The Company was ordered to use the levelized capacity cost for the least-cost dispatchable resource from its most recently filed Integrated Resource Plan ("IRP").

Q. What hours is the avoided generation capacity value applied to?

A. The avoided generation capacity value is applied to the on-peak hours of the summer season.

Q. Please summarize how the avoided generation capacity component of the ECR is calculated.

A. The below equation shows how the avoided generation capacity component of the ECR is calculated.

$$ECR\ of\ Avoided\ Capacity_{Year} = \frac{ELCC_{Average} \cdot Losses\ \cdot Max\ Output_{Year} \cdot Avoided\ Cost_{IRP}}{Export\ Energy\ in\ All\ Risk\ Hours_{Year}}$$

Avoided or Deferred T&D Capacity Costs

Q. Please explain the Commission-approved methodology for valuing avoided or deferred T&D capacity.

A. The Commission approved a method where T&D capacity is valued using a project-by-project deferral analysis, assessing every T&D capacity project over a 20-year time frame. To determine the 20-year time frame the

Company will reference the most recently filed IRP.

Q. What hours is the deferred T&D capacity value applied to?

A. The T&D capacity value is applied to the on-peak hours of the summer season.

II. PROPOSED ECR

Q. How frequently is the ECR to be updated?

A. Per Commission Order No. 36048, the Company is to update the ECR annually beginning in 2025. As I previously outlined, the Company will review all value components of the ECR annually.

Q. What are the ECR values the Company proposes to implement for June 1, 2025, through May 31, 2026, and how do those compare to the existing ECR values?

A. Figure 1 displays a summary of the proposed ECR values in the “Proposed” column and the currently in-effect ECR values in the “Current” column. The proposed ECR per kWh of exported energy is 14.0598¢ for summer on-peak, 1.7682¢ for summer off-peak, and 0.9540¢ for all hours during the non-summer season. Exhibit No. 1 contains a summary of the proposed ECR values, and Exhibit No. 2 contains all inputs and calculations for the proposed ECR.

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Figure 1: Current and Proposed ECR values

ECR SUMMARY	Season	Current	Proposed
Export Profile			
Volume (kWh per kW)	Annual	1,465	1,362
Capacity Contribution (%)	Annual	10.12%	10.07%
Export Credit Rate by Component (cents/kWh)			
Energy	Summer	5.6533 ¢	1.7682 ¢
Including integration and losses	Non-Summer	4.8365 ¢	0.9540 ¢
	*Annual**	*5.1566 ¢*	*1.2852 ¢*
Generation Capacity	On-Peak	11.1679 ¢	11.9017 ¢
	Off-Peak	0.0000 ¢	0.0000 ¢
	*Annual**	1.0616 ¢	*1.1360 ¢*
Transmission & Distribution Capacity	On-Peak	0.1755 ¢	0.3899 ¢
	Off-Peak	0.0000 ¢	0.0000 ¢
	*Annual**	*0.0167 ¢*	*0.0372 ¢*
Total	**Summer On-Peak**	**16.9966 ¢**	**14.0598 ¢**
	Summer Off-Peak	**5.6533 ¢**	**1.7682 ¢**
	Non-Summer	**4.8365 ¢**	**0.9540 ¢**
	*Annual**	*6.2348 ¢*	*2.4585 ¢*

**Annual values provided for informational purposes only and reflect seasonal weighting for 12 months ending December 31.*

Note: Summer season is defined as June 1 - September 30. On-Peak hours is defined as 3pm - 11pm, Monday - Saturday, excluding holidays. All other Summer hours defined as Off-Peak. Non-Summer season defined as October 1 - May 31.

Energy

Q. Please describe how the Company quantified the proposed energy component of the proposed ECR values.

A. The Company first used the 2024 hourly ELAP market prices, weighted for historical customer-generator exports to determine the avoided energy component, and then included adjustments for avoided line losses and integration costs. The Company distributed the values in alignment with the summer and non-summer season, as more fully described above.

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Q. What are the resulting updated energy components?

A. The energy-related component (which includes avoided energy valued at the weighted average ELAP prices, line losses, and integration), per kWh of exported energy, are 1.7682¢ for the summer season and 0.9540¢ for the non-summer season. Figure 2 below summarizes the proposed energy component of the ECR.

Figure 2: Proposed ECR Energy Component

Energy Component	Summer	Non-Summer	Units
ELAP - Weighted Average	$23.61	$15.81	$/MWh
Plus: Line Loss Gross-up	$1.04	$0.70	$
Less: Integration Costs	$(6.97)	$(6.97)	$/MWh
Energy Value	**$17.68**	**$9.54**	**$/MWh**

Q. How did updating the ECR with the 2024 ELAP prices impact the energy component of the ECR?

A. The updated energy component decreased primarily due to lower 2024 ELAP prices during export hours as compared to 2022 ELAP prices (those relied upon for the ECR rates currently in effect). Figure 3 below displays average monthly ELAP prices from 2021 through 2024.

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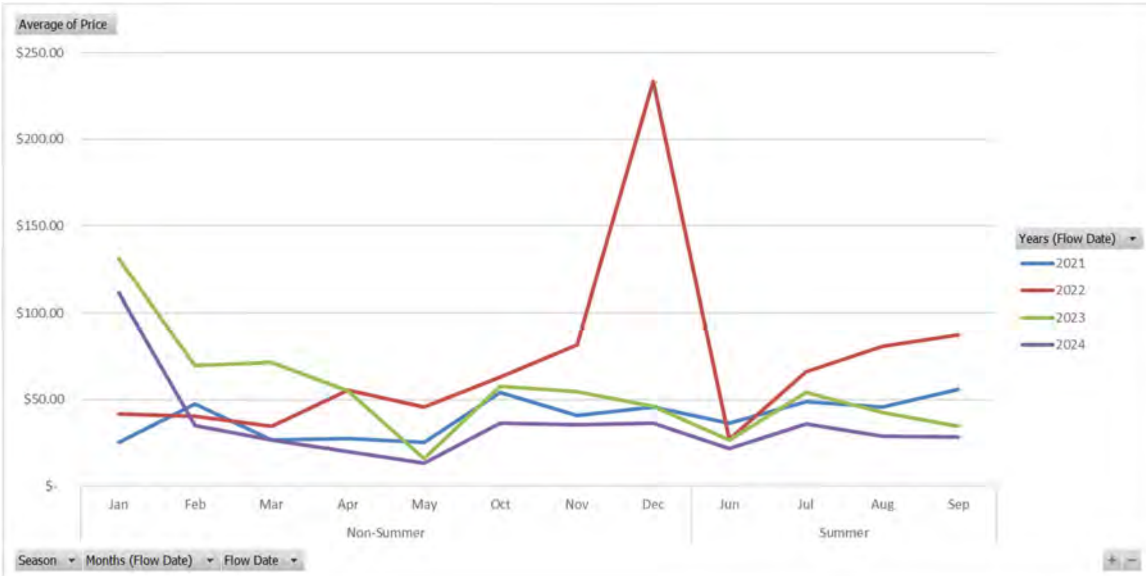
Figure 3: 2021-2024 ELAP Prices



As can be seen in Figure 3, 2022 ELAP prices experienced a higher degree of volatility during 2022 that persisted through the first few months of 2023.

Figure 4 shows the monthly ELAP Weighted Average for the current ECR (which relies on 2022 EIM prices) and the proposed ECR (which relies on 2024 EIM prices).

Figure 4: Monthly ELAP Weighted Average Prices.

		Current ECR			ECR Update		
Season	**Month**	**Value**	**Energy**	**$/MWh**	**Value**	**Energy**	**$/MWh**
NS	1	$ 102,879	3,144	$ 32.72	$ 245,051	3,913	$ 62.63
NS	2	$ 167,545	6,362	$ 26.33	$ 136,706	7,016	$ 19.49
NS	3	$ 233,461	8,973	$ 26.02	$ 141,922	12,802	$ 11.09
NS	4	$ 436,204	9,977	$ 43.72	$ 31,692	18,703	$ 1.69
NS	5	$ 445,602	11,077	$ 40.23	$ (12,752)	20,240	$ (0.63)
S	6	$ 320,466	10,728	$ 29.87	$ 270,382	17,346	$ 15.59
S	7	$ 574,323	8,850	$ 64.90	$ 416,881	13,686	$ 30.46
S	8	$ 567,746	7,962	$ 71.30	$ 361,978	14,319	$ 25.28
S	9	$ 592,657	8,543	$ 69.37	$ 351,963	13,988	$ 25.16
NS	10	$ 516,061	9,157	$ 56.36	$ 434,150	12,701	$ 34.18
NS	11	$ 332,075	4,809	$ 69.06	$ 241,687	6,853	$ 35.27
NS	12	$ 517,249	2,494	$ 207.40	$ 150,126	4,311	$ 34.82
Annual		$4,806,268	92,076	$ 52.20	$2,769,787	145,879	$ 18.99
S		$2,055,192	36,084	$ 56.96	$1,401,205	59,339	$ 23.61
NS		$2,751,076	55,993	$ 49.13	$1,368,582	86,539	$ 15.81

Q. Generally, what causes year-over-year fluctuations in the ELAP prices?

A. There are many factors that can lead to fluctuations in ELAP prices. Overall, the ELAP prices are a function of supply and demand and lower ELAP prices mean there was either high energy supply, or low demand, or both. Notably, in the spring months there are more negative prices due to more hydropower output during spring run-off conditions, and more solar on the market combined with a lower demand for electricity. This creates oversupply conditions, which can lead to negative prices. Additional factors that affect prices include the cost of coal and gas and extreme weather events.

Q. Are the 2024 ELAP prices relied upon for the Company's proposal final?

A. The January 2024 through November 2024 ELAP prices are final. While unlikely to occur, the December 2024 ELAP prices remain subject to change, based on the outcome of the California Independent System Operator's ("CAISO") dispute resolution process.

Q. When will the December 2024 ELAP prices be considered final?

A. The primary factor driving the completeness of the ELAP prices is the dispute resolution process for the EIM, which is defined by CAISO. The Initial Statement T+9B is received nine business days after the relevant trading day and has a dispute deadline of 31 business days from the relevant trading day (in this case, December 31, 2024). Note, the data submitted with this filing has already passed that initial dispute deadline.

However, to ensure completeness, the Company relies on the Recalculation Statement T+70B, which is not fully reconciled and received until 70 business days after the relevant trading day. As such, the Company has submitted ELAP prices through November 2024 based on the Recalculation Statement T+70B, and while it is unlikely December values will change when the December Recalculation Statement T+70B is received, should the December values change, Idaho Power will immediately notify Staff and will submit a supplemental filing with the updated values. Given the infrequency of these occurrences, it is expected there would either be no impact to the ECR or a very slight change.

Q. What study did the Company rely on to quantify the avoided line losses?

A. The Company relied on its most recent line loss study, which remains the 2023 line loss study (this study was also relied on to determine the current ECR values). Specifically, in determining the proposed line loss values applied to the energy component, the Company applied a loss coefficient of 1.044. Exhibit No. 3 contains the 2023 line loss study.

Q. What were the resulting values?

A. The proposed avoided per kWh line losses are 0.104¢ and 0.070¢ in the summer and non-summer seasons, respectively, which compares to 0.251¢ and 0.216¢ for the same period in the current ECR.

Q. What drove the decrease in the line loss values?

A. Because the specific line loss coefficients have not changed – and the avoided line-losses are simply a function of the ELAP Weighted Average and the coefficients – the driver of the decrease in the line losses was the result of a lower ELAP Weighted Average in 2024.

Q. What study did the Company rely on as a basis for its proposed integration costs?

A. The Company relied on its 2024 VER Study, which was completed in December 2024 and is attached as Exhibit No. 4 to my testimony.

Q. Which value from the 2024 VER Study is the Company proposing be used in its ECR update?

A. The integration cost most appropriate to use in the ECR update is from the 0-100 megawatt solar portfolio, which translates to a reduction in the energy component of 0.697¢ per kWh. This compares to integration costs of 0.293¢ per kWh that are included in the current ECR.

Q. Please describe the drivers of the change in the integration costs.

A. Between the 2020 VER Study and the 2024 VER Study, the cost to integrate solar resources with Idaho Power’s system has increased, primarily attributed to an increase in solar on Idaho Power’s system. As the amount of solar on the system increases, the need and use of integrating resources increases proportionally. It is the increased need to provide more integration capability with the increased solar resources that has increased the cost of integration.

Avoided Generation Capacity

Q. Please describe how the Company quantified the generation capacity component of the proposed ECR.

A. The Company first updated its five-year trailing average ELCC to include 2023 and 2024. The ELCC values for years 2020 through 2024 were then averaged to produce an ELCC of 10.07 percent. To calculate the capacity contribution the Company multiplied the updated average ELCC by the maximum export value from 2024 (the latest year of available data) and the on-peak line loss coefficient. As stated in the avoided line loss section above, the line losses have not been updated since the current ECR was filed, therefore the Company is using the same on-peak line loss coefficient of 1.053.

The cost of an alternate resource was also not updated as the Company has not filed a new IRP since it filed its current ECR values. The most recently filed IRP is the 2023 IRP and the least cost dispatchable resource is a simple cycle combustion turbine at a cost of $145.94/kW-year. The energy generated during on-peak hours was updated using 2024 customer exports.

The equation below shows how these components are utilized to calculate the ECR of avoided generation capacity.

$$ECR\ of\ Avoided\ Capacity_{2024} = \frac{(10.07\%) \cdot (1.053)\ \cdot (107{,}127\ kW) \cdot \left(\frac{\$145.94}{kW \cdot year}\right)}{\left(\frac{13{,}924{,}296\ kWh}{year}\right)} = \left(\frac{11.9017¢}{kWh}\right)$$

Q. How is the result accounted for in the ECR values?

A. The generation capacity value of 11.9017¢ per kWh is only applied to the summer on-peak hours.

Q. Please describe the drivers of the change in the generation capacity value.

A. As noted above, only the ELCC, the maximum export value, and the energy generated during on-peak hours changed. The maximum export value and the energy generated during on-peak hours both increased because of more customer generators on the Company’s system in 2024 versus 2022, the year used in the current ECR. The updated average ELCC value is 10.07 percent as compared to 10.12 percent from the current ECR.

Q. Is the Company proposing any changes to the ELCC values for 2020, 2021, or 2022 as part of this year’s filing?

A. Yes. In preparation of this year’s filing, the Company identified it had inadvertently double counted customer generator exports in the system load calculation when it previously determined the adjustment to recalculate 2020, 2021, and 2022 ELCC values. If the prior year ELCC values are not adjusted, there will be discrepancy between how 2023 and 2024 ELCC values were developed as related to those prior years.

Q. Please explain the significance of the needed ELCC modification you identified.

A. When presenting ELCCs for 2020, 2021, and 2022 in Case No. IPC-E-23-14, the Company calculated the ELCC of customer generator exports the same way it calculates the ELCC of all other resource types. That is, a base run was calculated that excluded the specified resource and a second run where the specified resource was added to the system. The addition of the specified resource *lowers* the net load. Of note, the Company's system load is derived by considering all the generation in-front-of-the-meter and the interchange flows.

Because customer generator exports originate from behind-the-meter, the reported system load already accounts for the impact of customer generator exports. The Company identified that a more appropriate way to calculate the ECR ELCC is to *add* the exports to the system load. This changes the base run to include the impact of the customer generator exports through the system load, meaning the second run should now add the customer generator exports back to the net load. This change is necessary to ensure that the impact of customer generator exports to the Company's system load are not double counted.

Q. Please summarize the Company's proposed 5-year average ELCC?

A. Table 1 below shows the ELCC values previously relied upon when the current ECR was approved in Case No. IPC-E-23-14 (column "IPC-E-23-14"). The Company is proposing to use an average ELCC of 10.07 percent, which updates the 2020 through 2022 ELCC values consistent with what I explained above and averages those with the ELCC values for 2023 and 2024; these values averaged together results in the proposed 5-year average ELCC relied upon in this year's annual update.

Table 1: ELCC Values

Year	IPC-E-23-14	Proposed Updated
2020	7.50%	7.50%
2021	14.90%	17.39%
2022	7.95%	9.55%
2023	-	12.17%
2024	-	3.73%
Average	**10.12%**	**10.07%**

Note, correcting for the subtraction of exports did not impact the 2020 ELCC, likely due to the relatively low penetration of on-site generation. However, both 2021 and 2022 values are impacted and accordingly, the Company believes it is appropriate to update those values for inclusion in this year’s update.

Avoided or Deferred T&D Capacity Costs

Q. Please describe how the Company quantified the T&D capacity component of the proposed ECR.

A. Using the Commission-approved methodology to determine the value of on-site generation in deferring the need for the Company to build additional T&D resources, the Company identified local peak hours for each T&D resource. Local peak hours are specific to the amount of types of loads connected to individual resources. The analysis incorporated the 20 years of project data from the 2023 IRP, 2007 to 2026, to identify the historical trends and projected T&D projects and the capacity need for each project.

Q. What are the updated avoided or deferred T&D capacity costs?

A. The updated avoided or deferred T&D capacity costs, per kWh of exported energy for summer on-peak is 0.3899¢.

Q. Please describe the drivers of the change in the avoided or deferred T&D capacity costs.

A. The primary driver of the increase in the avoided or deferred T&D capacity costs was related to an increase in solar penetration from 0.61 percent to 2.12 percent and an increase in customer generator exports. Using 20 years of project data from the 2023 IRP, the number of deferrable T&D projects increased from nine to 42, which increased the dollar value of deferral savings. The updated T&D deferral value calculations can be found in Exhibit No. 5 and the updated T&D capacity costs calculations can be found in Exhibit Nos. 1, 2, and 5.

III. <u>CONCLUSION</u>

Q. Please summarize the Company’s request in this filing.

A. Idaho Power requests the Commission approve its annual ECR update to be effective June 1, 2025, through May 31, 2026. The ECR update follows the methodology approved by the Commission in Order No. 36048. The updated ECR per kWh exported is 14.0598¢ for summer on-peak, 1.7682¢ for summer off-peak, and 0.9540¢ for non-summer.

Q. Does this conclude your testimony?

A. Yes, it does.

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DECLARATION OF JARED L. ELLSWORTH

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

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

2. On behalf of Idaho Power, I present this pre-filed direct testimony and Exhibits 1-5 in this matter.

3. To the best of my knowledge, my pre-filed direct testimony is 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 April 2025, at Boise, Idaho.

Signed: Jared Ellsworth
Jared L. Ellsworth

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-15

IDAHO POWER COMPANY

ELLSWORTH, DI TESTIMONY

EXHIBIT NO. 1

ECR SUMMARY		ECR Annual Update

	Season	ECR
Export Profile		
Volume (kWh per kW)	Annual	1,362
Capacity Contribution (%)	Annual	10.07%
Export Credit Rate by Component (cents/kWh)		
Energy	Summer	1.7682 ¢
Including integration and losses	Non-Summer	0.9540 ¢
	*Annual**	*1.2852 ¢*
Generation Capacity	On-Peak	11.9017 ¢
	Off-Peak	0.0000 ¢
	*Annual**	*1.1360 ¢*
Transmission & Distribution Capacity	On-Peak	0.3899 ¢
	Off-Peak	0.0000 ¢
	*Annual**	*0.0372 ¢*
Total	**Summer On-Peak**	**14.0598 ¢**
	Summer Off-Peak	**1.7682 ¢**
	Non-Summer	**0.9540 ¢**
	*Annual**	*2.4585 ¢*

**Annual values provided for informational purposes only and reflect seasonal weighting for 12 months ending December 2024.*

Note: Summer season is defined as June 1 - September 30. On-Peak hours is defined as 3pm - 11pm, Monday - Saturday, excluding holidays. All other Summer hours defined as Off-Peak. Non-Summer season defined as October 1 - May 31.

Avoided Energy — ECR Annual Update

Avoided Energy Calculation	Summer Update	Non-Summer Update	Units	Description
ELAP - Weighted Average	$ 23.61	$ 15.81	$/MWh	
Plus: Line Loss Gross-up	$ 1.04	$ 0.70	$	Exhibit No. 3 - Analysis of System Losses (March 2023)
Less: Integration Costs	$ (6.97)	$ (6.97)	$/MWh	Exhibit No. 4 - Idaho Power 2024 VER Integration Study
Avoided Energy Value	**$ 17.68**	**$ 9.54**	**$/MWh**	
Annual Energy Value	*$ 12.85*	*$ 12.85*		

Monthly Seasonal Energy Calculation

Season	Month	Value	Energy	$/MWh
NS	1	$ 245,051	3,913	$ 62.63
NS	2	$ 136,706	7,016	$ 19.49
NS	3	$ 141,922	12,802	$ 11.09
NS	4	$ 31,692	18,703	$ 1.69
NS	5	$ (12,752)	20,240	$ (0.63)
S	6	$ 270,382	17,346	$ 15.59
S	7	$ 416,881	13,686	$ 30.46
S	8	$ 361,978	14,319	$ 25.28
S	9	$ 351,963	13,988	$ 25.16
NS	10	$ 434,150	12,701	$ 34.18
NS	11	$ 241,687	6,853	$ 35.27
NS	12	$ 150,126	4,311	$ 34.82
Annual		$ 2,769,787	145,879	$ 18.99
S		$ 1,401,205	59,339	$ 23.61
NS		$ 1,368,582	86,539	$ 15.81

Avoided Generation Capacity | ECR Annual Update

Avoided Generation Capacity Calculation	Update	Units	Description
Effective Load Carrying Capability	10.07%	%	5-year rolling average ELCC (CY2020-2024)
(x) Nameplate Capacity	107.13	MW	
Total Capacity Contribution	**10.78**	MW	
(x) Levelized Fixed Cost of Avoided Resource	$ 145.94	$/kW-year	2023 Integrated Resource Plan - Appendix C, page 18
(x) kW to MW conversion	1,000	kW	
(/) On-Peak Exports	13,924	MWh	CY2024 real-time customer generation exports
On-Peak Avoided Generation Value	$ 113.03		
(x) Capacity Peak Loss Coefficient	1.053		
On-Peak Avoided Generation Capacity Value	**$ 119.02**	**$/MWh**	
Annual Generation Capacity Value	*$ 11.36*	*$/MWh*	

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

Year - 2020		
ELCC (MW)	2	
Maximum Output (MW)	26.67	
ELCC (%)	**7.50%**	
Year - 2021		
ELCC (MW)	7	
Maximum Output (MW)	40.26	
ELCC (%)	**17.39%**	
Year - 2022		
ELCC (MW)	6	
Maximum Output (MW)	62.86	
ELCC (%)	**9.55%**	
Year - 2023		
ELCC (MW)	11	
Maximum Output (MW)	90.40	
ELCC (%)	**12.17%**	
Year - 2024		
ELCC (MW)	4	
Maximum Output (MW)	107.13	
ELCC (%)	**3.73%**	
5-Year Average	**10.07%**	5-year rolling average ELCC (CY2020-2024)

Avoided Transmission & Distribution Capacity			ECR Annual Update
Avoided T&D Capacity Calculation	**Update**	**Units**	**Description**
Distribution Capacity Savings	$ 1,085,776	$	Exhibit No. 5 - Transmission and Distribution Avoided Capacity
Plus: Transmission Capacity Savings	-	$	Exhibit No. 5 - Transmission and Distribution Avoided Capacity
Total T&D Capacity Savings	**$ 1,085,776**	$	
(/) Project Years	20	years	Exhibit No. 5 - Transmission and Distribution Avoided Capacity
Annual T&D Capacity Savings	**$ 54,289**	$/year	
(/) On-Peak Exports	13,924		CY2024 real-time customer generation exports
On-Peak T&D Capacity Value	**$ 3.90**	**$/MWh**	
Annual Generation Capacity Value	*$ 0.37*	*$/MWh*	

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-15

IDAHO POWER COMPANY

ELLSWORTH, DI
TESTIMONY

EXHIBIT NO. 2

SEE ATTACHED SPREADSHEET

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-25-15

IDAHO POWER COMPANY

ELLSWORTH, DI TESTIMONY

EXHIBIT NO. 3

ANALYSIS OF SYSTEM LOSSES

In

Idaho Power Company

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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-25-15

IDAHO POWER COMPANY

ELLSWORTH, DI TESTIMONY

EXHIBIT NO. 4

2024 VER Integration Cost Study

December 2024

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Acknowledgements

Idaho Power would like to thank the members of the Technical Review Committee whose expertise was invaluable towards the development of this VER Integration Study.

Name	Organization
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Brian Johnson, Ph.D., P.E.	University of Idaho
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Kim Herb, Ryan Bain, Ryan Kern	Public Utility Commission of Oregon (OPUC)

Glossary

EUA—Expected Unserved Ancillaries

EUE—Expected Unserved Energy

IPUC—Idaho Public Utilities Commission

IRP—Integrated Resource Plan

IRPAC—IRP Advisory Council

k—indicates a multiple of 1,000

LOLE—Loss of Load Expectation

LTCE—Long-Term Capacity Expansion

MW—Megawatt

MWh—Megawatt-hour

NPV—Net Present Value

O&M—Operations and Maintenance

OPUC—Public Utility Commission of Oregon

RCAT—Reliability and Capacity Assessment Tool

SCCT—Simple-Cycle Combustion-Turbine

TRC—Technical Review Committee

VER—Variable Energy Resource

VODER—Value Of Distributed Energy Resources

Executive Summary

Idaho Power Company's (Idaho Power or company) 2024 Variable Energy Resource Integration Cost Study (2024 VER Integration Study) contains the company's updated integration costs and lays out the methodology by which they were produced. See the Methodology section for more details.

The company assembled and leveraged the expertise of a Technical Review Committee (TRC) to provide feedback throughout the study process. See the Acknowledgements section for a list of the members and organizations represented on the TRC.

The methodology proposed and implemented in this report leverages the preferred portfolio and the regulation reserve requirements utilized in the most recently acknowledged Integrated Resource Plan (IRP), namely the 2023 IRP. Going forward, leveraging the results of the IRP will simplify and streamline the VER study process and allow for more frequent updates to the company's integration costs.

Idaho Power's updated integration costs are in the last column of the following table:

Portfolio	Portfolio Cost with Ancillaries NPV ($ x 1,000)	Portfolio Cost without Ancillaries NPV ($ x 1,000)	Cost Differential Relative to Preferred Portfolio Difference ($ x 1,000)	Incremental Energy (MWh)	Integration Cost $/MWh
Preferred Portfolio	$9,678,287	$9,406,427	N/A	N/A	
100MW Solar	$9,677,224	$9,369,718	$35,646	5,116,037	6.97
200MW Solar	$9,696,854	$9,330,309	$94,685	10,232,074	9.25
100MW Wind	$9,589,833	$9,314,133	$3,840	6,005,227	0.64
200MW Wind	$9,505,452	$9,220,324	$13,268	12,010,455	1.10

Regulatory History

Idaho Power has historically used VER integration studies as the basis for developing the company's integration charges, specifically Schedule 87 – Intermittent Generation Integration Charges (Schedule 87) in Idaho. In Oregon, integration charges are addressed within Schedule 85 – Cogeneration and Small Power Production Standard Contract Rates, which Idaho Power files with the Public Utility Commission of Oregon (OPUC).

Prior Study

The company's last VER integration study was published in 2020 (2020 VER Integration Study). This study was referenced in the IPUC's Order No. 36048 regarding the compensation structure applicable to customers with on-site generation. In that order, the IPUC directed Idaho Power to use the 2020 VER Study to update Schedule 87.

Given that the data used to develop the 2020 VER Study is now at least six years old, Idaho Power petitioned the IPUC in Docket No. IPC-E-24-08 to allow the company to develop an updated VER Study and use it as the basis for updating integration charges. On June 10, 2024, the IPUC issued Order No. 36219 granting Idaho Power permission to develop a new VER study and use it as the basis for updating Schedule 87. The order also required Idaho Power to file both the study and updated integration charges with the IPUC no later than December 31, 2024.

On-Site Generation and the Export Credit Rate

The Company additionally uses the results from the VER integration study as one of the components of the Export Credit Rate ("ECR") for on-site generation customers. The ECR is the rate paid to retail customers with on-site generation taking service under net billing. Customer on-site generation, most typically from solar generation, is a VER, meaning it does not provide firm or dispatchable energy to the company's system; therefore, there are costs associated with accommodating the uncertainty associated with these resources. Idaho Power incurs integration costs due to reduced flexible resource optimization, caused by VER uncertainty, when planning operations ahead of real time. The ECR reflects the total costs and benefits of customer on-site generation on the Company's system, including VER integration costs which will come from the most recent VER Integration Cost Study.

While the VER integration study determined the cost of accommodating additional utility scale solar, the Company found that a utility scale profile is a reasonable proxy for the shape of on-site solar generation. As such, the Company assesses that the integration costs identified in this report are an appropriate input to the ECR without modification.

Future Cadence of Updates

Beginning with this study, Idaho Power intends to more frequently update both its VER studies and the associated integration costs. Historically, Idaho Power has filed VER integration studies as one-off studies, each of which had a distinct and largely incomparable methodology and scope.

In the past, VER integration studies have been a holistic process in which the reserve requirements were defined and calculated and then fed directly into a modeling effort to calculate the cost of integrating additional VERs. Although the company's prior VER studies aligned with modeling used in IRPs, the standalone nature of each new VER study made it difficult to compare integration studies or integration costs over time. Additionally, this bespoke approach to VER studies did not allow Idaho Power to fully leverage already vetted models to generate VER integration charges—in part due to misalignment between study timing and the availability of data, as well as their ultimate use case.

Now, there are robust datasets with which to model the cost of integrating wind and solar resources and, due to the significant overlap of the IRP process, Idaho Power intends to update VER integration costs after IRP acknowledgment when factors warrant an update. Such an approach would end the one-off nature of VER integration studies and would, instead, yield a simplified and easily replicable process that leverages the highly scrutinized and vetted IRP. To be clear, Idaho Power is not indicating that the process would need to occur after each IRP. Rather, the company's objective, beginning with this VER study, is to build a standard protocol for updating integration costs as needed following completion of the IRP process.

Study Integration and Process Flow

Looking ahead, Idaho Power intends to connect, rather than have disjointed processes for, the IRP and VER integration studies. Going forward, both processes could be included in the IRP. In order to merge these processes as much as possible and to minimize duplicative work, the determination of regulating reserve requirements will need to be separated from the generation of VER integration costs. Idaho Power intends for reserve requirements to be determined as part of the process of updating IRP inputs, thus creating a standardizing update process. The standard IRP modeling process would then follow, with the determination of the Preferred Portfolio and its vetting culminating in regulatory consideration of the IRP. Upon IRP acknowledgment, the VER Integration Cost study can commence in a structured and mechanical manner using the same model as the IRP. Study cases would be determined and the VER integration costs would be calculated with the results filed in an update to the current charges. An overview diagram of the proposed process is outlined in the figure below, with the timing and order of actions moving from left to right:

Methodology

As part of this study, Idaho Power has updated its methodology for calculating VER integration charges as used in Schedule 87. The goal of the changes are as follows:

- leverage existing models to the extent possible,
- create an evergreen process that is simple to update and is largely automatic and, based on the above,
- develop a method that is transparent and easy to review.

In the today's rapidly changing electric utility industry, it will be difficult to create a truly evergreen process, but Idaho Power believes that the methods detailed below provide a solid foundation from which this process can evolve as necessary.

Model Basis

Where possible, this integration study has used the 2023 IRP model. That model has been well vetted through the entire IRP process and serves as the basis for many analyses that Idaho Power has undertaken since the acknowledgment of the 2023 IRP. That model has been vetted first in the public IRP Advisory Council (IRPAC) meetings, where important inputs and assumptions are made available to stakeholders for comment and feedback. From there, the analysis was scrutinized via validation and verification tests, with draft results presented to the IRPAC for further feedback. The results culminated in the IRP report, which received extensive regulatory review by key stakeholders, including staff members of the IPUC and OPUC. Finally, to conclude the cycle, the 2023 IRP was acknowledged by Idaho Power's state regulators.[1]

Ancillary Service Requirements and Reserves

To be consistent with the 2023 IRP analysis, Idaho Power is leveraging Energy Exemplar's AURORA software, the same tool that has been used for numerous prior plans. Idaho Power has a long history using the AURORA electric market model as its primary tool for modeling resource operations and determining operating costs among many other uses. AURORA is an economic model that optimizes the dispatch of generation and transmission resources to match demand. The operation of existing and future resources is based on forecasts of important

[1] Idaho PUC Case No. IPC-E-23-23, Order No. 36233 and Oregon PUC Docket No. LC 84, Order No. 24-285

drivers including: demand, fuel prices, hydroelectric conditions, and operational resource characteristics.

One of AURORA's notable strengths is its ability to quantify the cost of VER integration by modeling the regulating reserves required to reliably deliver power to an electric system with non-dispatchable generation. AURORA does this through the use of ancillary services in the form of "up regulation" and "down regulation" products. In order for a resource to provide an up regulating reserve it needs to be able to respond by increasing its output to match a decrease in generation of the VER resource. Effectively, the resource needs to be online and in a state to respond. For most resources, this means that, instead of outputting a megawatt-hour (MWh), they are instead held back such that additional capacity could be deployed, hence earning the title of a reserve.

When AURORA dispatches resources, it optimizes to reduce the cost to serve load while adhering to the ancillary or regulation requirements. In doing so, it also calculates the cost of providing those regulating reserves. For this study, the regulating reserve requirements are the same as those used in the 2023 IRP model.[2]

Incremental Resource Study Cases

The first step in determining the cost of integrating the next incremental wind or solar resource (applicable to both distributed and utility-scale installations) is selecting appropriate study or use cases. These cases were created considering a handful of pertinent factors detailed below.

Integration Block Size: There are tradeoffs when selecting the size of the incremental resource used to study the cost of VER integration. If the size is too small, it may be difficult to reasonably guess which block of integration charges a project would be subject to without going through the full process of understanding where a project is in the queue. If the size is too large, then a subsidy could potentially be created between early and late entrants in a block. Thus, it is important to strike a balance of reasonably size blocks.

For this integration study, Idaho Power, with help from the TRC, selected a 100-megawatt (MW) block size for the study. This size aligned with the 2023 IRP proxy wind or solar resource sizing. It also strikes a reasonable balance to avoid to the extent possible the negative effects of having blocks that are too large or too small. If historical trends continue with the average size of a wind or solar Public Utility Regulatory Policies Act of 1978 qualifying facility (QF) at roughly 20 MW,[3] the 100 MW block approach would allow five projects to integrate before moving to

[2] 2023 IRP Report: Table 9.1 page 123.
[3] 2023 IRP Appendix C: Technical Appendix, pg 28-29. Average Solar QF size 18 MW and Wind QF size of 20 MW.

the next block, thereby ensuring near-term certainty of the integration charge for a new QF project.

VER Groups: With the 100 MW block size determined, Idaho Power then focused on determining the appropriate combination and total amount of the different VERs to study. Similar to incremental block sizing, there are tradeoffs with the number and variety of cases to analyze. With too few cases, the integration charge that a project is subject to may not reasonably represent the system as it exists at the time of integration. With too many cases, significant effort can be wasted studying cases that have low probability of occurring.

In consultation with the TRC after describing the prior parameters, it was agreed that four incremental resource cases would be studied: 100 MW of solar, 200 MW of solar, 100 MW of wind, and 200 MW of wind. Although these cases are limited compared to the prior VER studies, they represent more than the expected increase in new QF VER development to occur between this update and the next expected update following acknowledgment of the 2025 IRP. The 2023 IRP showed that if recent trends in the development of either wind or solar QFs continue, even the 100 MW blocks are not expected to be exceeded in the next few years,[4] which is well past the next expected update to the integration charges. This is true with the inclusion of distributed solar installations as well.

Consideration of the Inclusion of Incremental Resource Capital Costs

During meetings with the TRC, the question was raised whether capital and fixed operations and maintenance (O&M) costs should be included in the update to integration charges. The TRC was concerned that, because the IRP's preferred portfolio is optimized around a particular set of resources, the inclusion of additional VER resources might not be able to meet the ancillary service requirements they necessitate. Although Idaho Power agrees with the TRC that this is a possibility and may include this charge in the future, the Company, through a literature review, found little information on how to assess unmet ancillary needs and no information on how to correct an unmet ancillary need should one be found. Given the current lack of generally accepted modeling practice regarding this concept, Idaho Power does not believe it appropriate to include in this study but finds it valuable to detail a proposed methodology so that the company can receive feedback for possible inclusion in future studies.

In the TRC meetings, the Company proposed an outline for a possible method to calculate these additional costs. At a high level, the method first involves determining a metric with which to evaluate unmet ancillary needs and from there to determine a cutoff point at which a corrective action would be necessary. Once the threshold is set, the IRP model would be run to determine if there were violations of the threshold and then also to determine the corrective generation resource to bring any unmet ancillary needs under the threshold. With the

[4] Cogeneration and Small Power Production Forecast, 2023 IRP Advisory Council Meeting Oct. 13, 2022.

corrective generation resources added to the model, the additional capital and fixed O&M costs could be captured, as well as any cost-offsetting activities those resources could provide.

Metric and Threshold Evaluation

As previously noted, when doing a literature review on the subject, Idaho Power was not able to find an accepted industry best practice method with which to evaluate unmet ancillary needs. Thus, for this first proposal, other analogous metrics were evaluated from typical reliability analysis because of their overlap with ability to serve load. First evaluated was the use of a Loss-of-Load-Expectation (LOLE) type analysis. This method was investigated because the company already used it for evaluating portfolio reliability as part of the 2023 IRP and there are readily accepted LOLE thresholds used in the industry. In its investigations, it was quickly determined that generating a similar metric for expected unmet ancillaries would not be practical. The current Reliability and Capacity Assessment Tool (RCAT) has been designed to evaluate LOLE and not assess ancillary regulating reserves. Thus, further metrics were explored that could be implemented for this study. The use of Expected Unserved Energy (EUE) was deemed analogous and possible to implement with the outputs of the 2023 IRP model. The EUE metric is a measure of the amount of energy that a particular system is expected to not be able to supply due to a lack of generating capacity in a given year. The EUE metric could also be applied within the time constraints of this study to analyze unmet ancillaries because it is simple to check what the expected unmet ancillaries are in a given year and then determine if they cross the threshold value. As part of its algorithms, the Aurora based 2023 IRP model already calculates if, when, and to what extent there would be an expected unserved ancillary. With the ability to determine expected unserved ancillaries, the question becomes where to set the threshold for when corrective action would be required.

Although many regions within the United States are still in the exploratory phase of analyzing the use of EUE as a primary reliability metric, Australia is currently using it with a maximum value of 0.002 percent of annual energy expected to be unserved and others are beginning to coalesce around this same value. Again, because this method has not yet been widely evaluated or adopted, in some contexts the 0.002 percent threshold may be referred to as a 20 parts per million threshold. In other words, for a utility expected to deliver 1,000,000 MWh in a year, they would set their threshold at 20 MWh of EUE in that year, which is 0.002 percent of 1,000,000 MWh.

With the 0.002 percent threshold set, the next issue is to determine the basis by which to calculate the expected unserved ancillaries– specifically whether the 0.002 percent threshold should be applied strictly to the expected ancillaries in a given year or applied to some other value. In this case, Idaho Power believes that using the same expected delivered energy basis may be appropriate. The reason for this basis is that within AURORA, as in actual operations, a reserve MWh and an energy MWh are intermingled items. In order for a resource to provide a MWh of up regulation reserve, it must be held back from producing a MWh of energy, hence reserve. Because these values are so intertwined, Idaho Power proposes that the threshold for expected unserved ancillaries be set at 0.002 percent of annual delivered energy.

Corrective Measure

With the metric and threshold set, the final component to analyzing the inclusion of incremental capital costs necessary for the integration of VERs is the determination of a corrective measure. The determination of the corrective measure requires considerable analysis, including identifying the cost-optimal resource type and quantity of that resource to provide the ancillary reserves necessary for the integration of VERs.

For simplicity and alignment with the 2023 IRP, 50 MW blocks of 4-hour battery storage were used as the corrective measure for this study. The primary candidate resources from the 2023 IRP that can provide the necessary reserves are peaking gas and 4-hour storage. For this study, 4-hour storage was chosen because its operational characteristics and cost make it the least-cost ancillary-providing resource.

In the case of the peaking gas plant in the form of a Simple-Cycle Combustion-Turbine (SCCT), once the unit is online, it can provide ancillaries but will be limited by both its ramp rate and the difference between its minimum and maximum capacity. This effectively limits the 170 MW SCCTs modeled in the 2023 IRP to 85 MW or 50 percent of their nameplate of reserve providing capacity. In comparison, 4-hour storage resources can go from a state of charging to a state of discharging in very short periods. If a storage resource is charging from a solar facility and the output of that solar facility drops rapidly due to cloud cover, the storage resource can, in that moment, switch to a discharging state. This swing from charging to discharging is a swing of twice the nameplate of the storage resource. Thus, for the 50 MW 4-hour storage modeled in the 2023 IRP, it could provide 100 MW of reserve capability. Using the levelized capacity costs in the 2023 IRP[5] of $12/kW-month and $17/kW-month for an SCCT and 4-hour storage resource respectively and adjusting to account for the ancillaries each resource could provide, the values change to $24/kW-month and $8.5/kW-month per kW of ancillaries provided, respectively, for an SCCT and 4-hour storage resource. This analysis shows that the 4-hour storage resource is the least cost per kW of ancillary providing resources in the 2023 IRP.

With the least-cost ancillary-providing resource selected, the next issue is determining the amount of that resource needed to bring the amount of expected unserved ancillaries below the previously determined threshold. After consulting with the TRC, Idaho Power chose to use the following algorithm:

1. Determine if the expected unserved ancillaries in any given year exceeds the 0.002 percent threshold.
    a. If a year exceeds the threshold, add a number of blocks equal to the expected unserved ancillaries minus the total delivered energy times the threshold, all divided by the ancillary-providing capability of the correcting resource block

[5] Idaho Power 2023 IRP - Appendix C: Technical Appendix page 25.

rounded up. Should this value exceed the block additions in a prior year, the incremental blocks are added.

b. If a year is determined to be below the 0.002 percent threshold, then no corrective action is necessary and any blocks identified in a prior year are allowed to remain.

2. Now, there exists the possibility that because of the state of charge or other operational constraints, the blocks may be insufficient to provide the necessary ancillaries. To account for this possibility, the new resources are added to the portfolio and it is rerun through AURORA to determine if the additional resources provide the necessary ancillaries to reduce the EUA below the threshold. If they do, the process ends; but if they do not, then the process repeats until sufficient ancillary-providing resources are added to the model.

The pseudocode for this process is provided below:

- While output max(EUA_t) > 0.002% * $Energy_t$
  - If $EUA_t \leq 0.002\% * Energy_t$
    - $Blocks_t = \max(0, Blocks_{t-1})$
  - If $EUA_t > 0.002\% * Energy_t$
    - Add 50 MW blocks of 4-hr Storage resources equal to:
    - $Blocks_t = \max\left(\left\lceil \frac{EUA_t - Energy_t * EUAThreshold}{AncillaryMaxOfCorrection} \right\rceil, Blocks_{t-1}\right)$
- Loop

Where:

EUA_t is the expected unserved ancillaries in a year t

$Blocks_t$ is the number of blocks of resources in year t

$Energy_t$ is the total expected delivered energy in year t

And ⌈x⌉ represents the ceiling function or round up.

Determination of the Integration Cost

The primary tool used to develop updated integration costs is the same AURORA model used to develop and analyze the portfolios of the 2023 IRP. The process used to quantify those costs was multi-step but largely procedural.

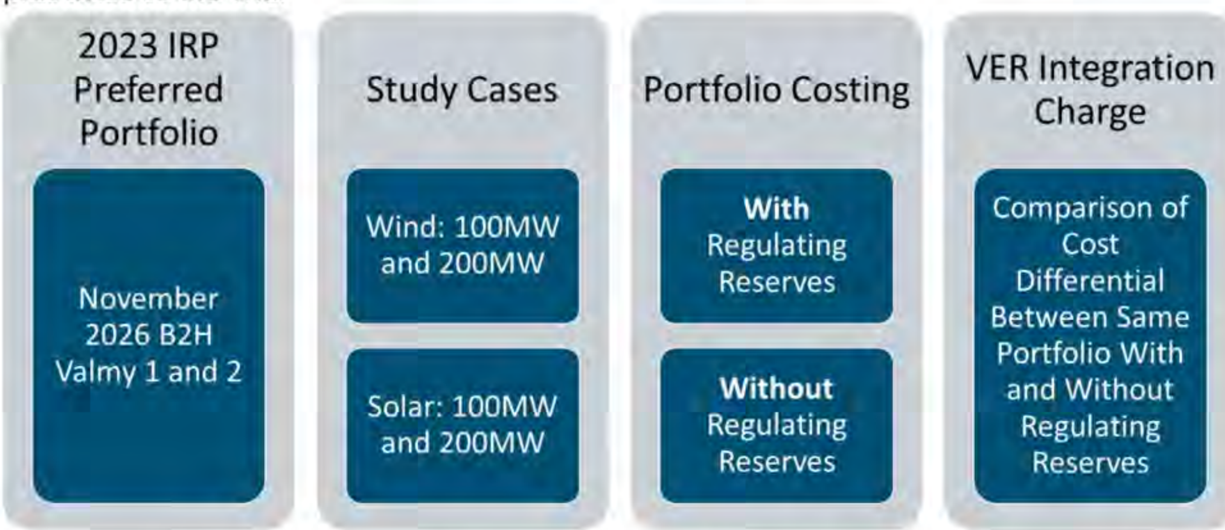
1. Start with the 2023 IRP's revised preferred portfolio, titled "November 2026 B2H Valmy 1 & 2".[6] In the course of regulatory review of the 2023 IRP, a revised preferred portfolio became relevant to reflect an update to the timing associated with the Boardman to Hemingway Transmission Line (B2H).

2. Create the incremental resource builds. Reflecting the incremental resource study cases previously discussed, the VERs were added to the preferred portfolio starting in year 2025 as must-take resources reflecting the must-take obligation of QF projects.

3. Analyze the various portfolios using AURORA, consistent with the methods deployed in the 2023 IRP. For each of these portfolios, perform additional analysis in AURORA with the ancillary services calculations turned off.

4. The integration cost is then calculated using the relative change between the base case with and without the ancillary services calculations compared to the same cases with the incremental resource study cases.

The process of producing integration charges is outlined in the figure below as it was presented to the TRC:



There are compelling reasons to use this method to calculate the VER integration charge. First, the selected method leverages the AURORA-based 2023 IRP. The model inputs have already been extensively vetted through the IRP process and the Aurora software is among the best production cost modeling software used in North America.

Second, AURORA is able to model the holistic change in operations required to reliably integrate renewables and, thus, is well suited to calculate the cost of integration.

[6] Idaho Power 2023 IRP - Appendix C: Technical Appendix, page 45.

By considering how additional must-take VERs change the Idaho Power's whole dispatch stack, the entire cost and value stream of the additional resources can be considered in aggregate.

Results

Using the methods and procedures described above, the following net present value (NPV) portfolio costs are produced, along with associated integration costs, for each portfolio:

Portfolio	Portfolio Cost with Ancillaries NPV ($ x 1,000)	Portfolio Cost without Ancillaries NPV ($ x 1,000)	Cost Differential Relative to Preferred Portfolio Difference ($ x 1,000)	Incremental Energy (MWh)	Integration Cost $/MWh
Preferred Portfolio	$9,678,287	$9,406,427	N/A	N/A	
100MW Solar	$9,677,224	$9,369,718	$35,646	5,116,037	6.97
200MW Solar	$9,696,854	$9,330,309	$94,685	10,232,074	9.25
100MW Wind	$9,589,833	$9,314,133	$3,840	6,005,227	0.64
200MW Wind	$9,505,452	$9,220,324	$13,268	12,010,455	1.10

In the above table, the Portfolio column identifies the study cases, as well as the baseline reference case, which is the "November 2026 B2H Valmy 1 & 2" portfolio from the 2023 IRP. As the name implies, the 100MW Solar case includes 100 MW of incremental must-take solar to the preferred portfolio. By extension, the other portfolio case names specify the resource type and incremental must-take resource added.

The "Portfolio Cost with Ancillaries" column shows the total portfolio cost using the same financial assumptions[7] and calculation methods used in the 2023 IRP. The "With Ancillaries" in the title refers to the fact that the model had to account for the regulating reserves necessary to integrate the VERs in the Preferred Portfolio, as well as the incremental VERs in the study cases where applicable. The next column, "Portfolio Cost without Ancillaries," uses the same financial assumptions and calculation methods except that the AURORA dispatch model was allowed to integrate the VERs in the various portfolios without regard for the need to hold regulating reserves.

The difference between the "With Ancillaries" and the "Without Ancillaries" cases is the model estimated cost for holding regulating reserves for the VERs in each case. Thus, for the Preferred Portfolio, the cost of the regulating reserves is the difference between $9,678,287k and $9,406,427k or $271,860k.

[7] Idaho Power 2023 IRP - Appendix C: Technical Appendix, page 20.

The "Cost Differential Relative to Preferred Portfolio Difference" column calculates each study case's regulating reserve cost and then subtracts the preferred portfolio difference. Working through this for the 100MW Solar case the calculation is ($9,677,224k – $9,369,718k) – ($9,678,287k – $9,406,427k) = $35,646k. This method isolates the additional regulating reserve costs caused by the incremental VER resource in each study case.

The column "Incremental Energy" is the amount of energy associated with the incremental VER resource over the planning horizon. Finally, the column "Integration Cost" divides the regulating reserve cost due to the incremental resources and the energy expected from those resources and converts it to a $/MWh. In the 100MW Solar case, $35,646,000/5,116,037MWh = $6.97/MWh. The other integration costs follow this same calculation specific to each portfolio. Additionally, the results presented do not include costs related to additional capital for portfolios that would need to include additional integrating resources to accommodate the must-take VERs.

These integration costs will be reflected in Idaho Power's updated tariffs that directly or indirectly address integration charges.

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CASE NO. IPC-E-25-15

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EXHIBIT NO. 5

SEE ATTACHED SPREADSHEET