Review of the Idaho Power Company's Proposed Changes to Net Energy Metering

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A. Introduction

Idaho Power Company (IPC or Idaho Power) has proposed significant changes to its net energy metering (NEM) program, in an application filed May 1, 2023 (Case No. IPC-E-23-14). This application follows a comprehensive *Value of Distributed Energy Resources* Study (VODER Study or Study) which IPC filed in June 2022 (Case No. IPC-E-22-22) and which the Idaho Public Utilities Commission (IPUC) acknowledged in Order 35631 (Order), released December 19, 2022. Crossborder Energy prepared an extensive critique of the VODER Study that was submitted in IPC-E-22-22. This review assesses the impact of IPC's proposed changes on a typical residential solar customer in IPC's service territory, and suggests a number of changes to IPC's proposal that we believe are merited and consistent with the Order..

B. Principal Changes to NEM Proposed by the Utility

IPC has proposed the following significant changes to net metering:

- Instantaneous netting of imports and exports
- Revised export compensation – replace export compensation at the volumetric retail rate with an Export Compensation Rate (ECR) that supposedly better reflects the value of exports.
- ECR has a TOU structure:
  - Summer on-peak ECR: 20.4 c/kWh, 3p – 11p, Monday-Saturday, June 15 – Sept 15
  - Off-peak ECR: 4.9 c/kWh in all other hours.
- Key ECR components:
  - Avoided energy costs based on Energy Imbalance Market (EIM) prices in the prior calendar year
  - Avoided generation capacity costs using an Effective Load Carrying Capacity (ELCC) contribution for solar and the costs of a new combustion turbine (CT)
  - T&D deferral costs based on IPC's T&D planning
  - Avoided line losses using a new study of system average line losses
  - Integration costs using certain Integrated Resource Plan (IRP) scenarios
  - Annual update to ECR values, effective every June 1
- Maximum allowable size for non-residential systems set at a customer's peak demand
- Changes to the process to transfer excess energy credits to other accounts

These changes would apply to all "non-legacy" distributed solar systems on the IPC system, with an effective date of January 1, 2024.

C. Impact of the IPC Proposal on a Non-Legacy Solar Customer's Bill Savings

We have analyzed the impacts of IPC's proposed new ECR rate on the bill savings available to non-legacy residential solar customers, using the same bill savings model that we employed to analyze the ECR rate options presented in the VODER Study.

Our model includes a range of residential customer annual loads (5,000 to 15,000 kWh per year) as well as a range of solar system sizes that produce 50%, 75%, or 100% of the customer's annual load. To compute customer bills before and after solar, we used an NREL hourly residential load profile for Idaho and an hourly solar profile for Boise from the NREL PVWATTS tool. We find that our bill calculations – before solar, after solar, and the resulting bill savings – are consistent with the numbers that IPC presents in Mr. Anderson's Exhibit No. 6 when the same assumptions are used.

Table 1 shows IPC's proposed time-of-use (TOU) ECR rates. The utility's proposed ECR rates in the second column are based on calendar year (CY) 2022 real-time electricity market prices, which were elevated by high natural gas prices in the wake of the war in Ukraine. For comparison, the third column shows what the proposed ECR rates would be using a four-year average (2019-2022) of electric market prices. We believe that this four-year average is a more realistic estimate of future ECR rates than using 2022's high market prices. Finally, the fourth column shows IPC's current residential volumetric rates (both Increasing Block [Schedule 1] and TOU [Schedule 5]), which are the basis for export rates today under net metering.

Table 1: *Proposed ECR Rates vs. Volumetric Retail Rates ($/MWh)*

ECR or Size of System	ECR Real Time / CY 2022 ELAP	ECR RT / 2019-2022 ELAP	Volumetric Residential Retail Rate
Flat / Increasing Block	60	39	88
Summer On Peak	204	167	129
Summer Off Peak	49	31	95
Winter	49	31	74
Weighted Average of TOU ECR			
50%	63		
65%	64		
80%	65		
95%	65		
Improvement vs. Flat ECR			
50%	6%		
65%	7%		
80%	8%		
95%	9%		

IPC proposes that, for the ECR, the summer season should run from June 15 to September 15, with on-peak hours from 3 p.m. to 11 p.m. from Monday to Saturday each week, except holidays. The bottom sections of Table 1 show the weighted average export rates for IPC's TOU ECR rates, with instantaneous (real-time) netting for a customer with usage of 10,000 kWh per year, for the range of solar system sizes (50% / 65% / 80% / 95% of annual usage). The proposed TOU ECR rates produce average export rates that are 6% to 9% better than a flat ECR rate. This is because there would be appreciable solar exports in the summer on-peak period, at the higher on-peak ECR rate.

We have calculated the change in a solar customer's bills savings if the IPC proposal is adopted, compared to the current NEM policy of pricing exports at the full volumetric retail rate.

These calculations use the four-year average (2019-2022) of electric market prices as the basis for the ECR. These bill savings comparisons are shown in **Tables 2 and 3**. The tables show clearly that the utility's proposal will result in a significant reduction in the ability of its customers to save money by installing solar.

Table 2 is for south-facing systems; Table 3 is for west-facing systems. IPC's proposed structure would favor west-facing systems, because they will have more output in the summer on-peak period after 3 p.m. when the value of exported power is high. In addition, IPC's residential TOU rate (Schedule 5) is more favorable than IPC's increasing block (IB) rate (Schedule 1), because solar can offset some of a customer's load in the 1 p.m. to 9 p.m. summer weekday on-peak period when the TOU rate is high. Most of a solar customer's imports from the grid will happen in the lower-priced off-peak hours.

Table 2

South-facing: Percent Change in Annual Bill Savings compared to Current NEM…						
Rate: Export Import	% Solar	**Annual Usage**				
		5,000	7,500	10,000	12,500	15,000
Flat ECR IB Rate	50%	-22%	-22%	-22%	-22%	-21%
	65%	-27%	-27%	-27%	-27%	-27%
	80%	-31%	-31%	-31%	-31%	-30%
	95%	-34%	-34%	-34%	-33%	-33%
TOU ECR IB Rate	50%	-20%	-20%	-20%	-20%	-19%
	65%	-24%	-24%	-24%	-24%	-24%
	80%	-27%	-27%	-27%	-27%	-27%
	95%	-29%	-29%	-29%	-29%	-29%
TOU ECR TOU Rate	50%	-8%	-8%	-8%	-8%	-8%
	65%	-15%	-15%	-15%	-15%	-15%
	80%	-20%	-20%	-20%	-20%	-20%
	95%	-24%	-24%	-23%	-23%	-23%

Table 3

West-facing: Percent Change in Annual Bill Savings compared to Current NEM…						
Rate: Export Import	% Solar	**Annual Usage**				
		5,000	7,500	10,000	12,500	15,000
Flat ECR IB Rate	50%	-22%	-22%	-21%	-21%	-21%
	65%	-27%	-27%	-27%	-26%	-26%
	80%	-31%	-31%	-31%	-30%	-30%
	95%	-34%	-34%	-34%	-33%	-33%
TOU ECR IB Rate	50%	-14%	-14%	-14%	-14%	-14%
	65%	-17%	-17%	-17%	-17%	-17%
	80%	-19%	-19%	-19%	-19%	-19%
	95%	-21%	-21%	-21%	-20%	-20%
TOU ECR TOU Rate	50%	-2%	-2%	-3%	-3%	-3%
	65%	-9%	-9%	-9%	-8%	-9%
	80%	-12%	-12%	-12%	-12%	-12%
	95%	-15%	-15%	-15%	-15%	-15%

Note that one way to mitigate some of the loss in bill savings from the IPC proposal would be to use the Schedule 5 TOU rate plus the TOU ECR rate. With these choices, when compared to current NEM, bill savings decrease by -8% to -24% for south-facing systems and by -2% to -15% for west-facing systems. West-facing systems perform better even though they produce less power than south-facing over the course of a year.

D. Recommended Modifications to the Idaho Power Proposal

The Order acknowledging the VODER Study is not prescriptive on exactly how IPC's ECR rate should be calculated. For example, the Order mentions the chapters of the VODER Study that it found to "fully comply with the Commission's previous directives and provide a basis for the Company to make recommendations in its subsequent implementation case" [p. 29]. These chapters do not include the chapter on the calculation of the ECR itself. Here are what we view as the key findings in the Order that encourage stakeholders to propose changes and improvements in IPC's proposed ECR rates (emphasis added):

- "We want to make clear that our decision in this case is whether to acknowledge that the Study complied with our previous directives. Our decision is not a determination that a specific method or value within the Study is superior to another." [p. 28]
- "We find the general discussion, data, and methods explicated in the ECR section of the October VODER Study comply with our previous directives and provide a basis to support the Company's recommended changes to its on-site generation tariffs. However, we note the importance of an avoided generation capacity value that accurately considers capacity costs actually avoided. We believe that additional discussion between Staff, Intervenors, and the Company on the topic of avoided line losses, during the implementation case, may be fruitful and potentially resolve any remaining issues or confusion surrounding the Company's calculation of avoided line losses." [p. 29, emphasis added]
- "In the implementation case, Intervenors, Staff, and the public will have the opportunity to provide comments and arguments for or against the Company's proposed methods and implementation recommendations." [p. 28]

1. Avoided Energy Costs

The VODER Study proposed three possible metrics for avoided energy costs – one is the forecast of electric market prices from the modeling performed in 2021 for the IPC *2021 Integrated Resource Plan* (*2021 IRP*). The other two used historical electric market prices from 2019-2021, either the Mid-Columbia wholesale price or the price for the Idaho electric load aggregation point (ELAP) in the western EIM.

We think IPC made the correct choice to use the EIM ELAP price for the ECR. EIM prices are the market prices most specific to the IPC system and are based on transparent market prices administered by a sophisticated Regional Transmission Operator (the CAISO).[1]

[1] Mid-Columbia (Mid-C) market prices raise complicated issues about whether distributed solar

That said, there are several issues of concern with IPC's proposal to use a solar export-weighted ELAP price from the prior calendar year as the avoided energy component of the ECR:

- This price will fluctuate from year-to-year and can be volatile. As shown in Table 1 and the following table, 2022 ELAP prices were much higher than in 2019-2021 due to higher natural gas prices resulting from the war in Ukraine and the December 2022 spike in western U.S. gas prices. 2023 prices will be lower than 2022 due to increased hydro availability and falling gas prices.

TOU Period	**IPC ELAP Prices** *($/MWh)*			
	2019	**2020**	**2021**	**2022**
On-peak	29.5	32.9	68.5	84.6
Off-peak	23.8	18.5	32.7	49.8

  This uncertainty and volatility in market prices can make it difficult to convince customers to invest in solar. There are several possible ways to provide avoided energy prices that reduce this volatility or that are fixed and known for longer than one year. For example, Idaho Power's original proposal in its VODER Study was to use an average of recent historical market prices, over the prior three years. The use of a longer historical sample dampens the year-to-year volatility in these prices. As another example, to provide a fixed price for 5 or 10 years going forward, the prior year's ELAP price could be extended to cover the next 5 or 10 years using escalation factors for subsequent years based on natural gas futures prices from the Henry Hub forward market or a recognized long-term gas forecast such as the U.S. EIA *Annual Energy Outlook* (*AEO*). Here is a five-year sequence of escalation factors and the resulting avoided cost prices using the 2023 EIA *AEO* forecast for the Henry Hub market. The factors are less than 1.0 in the years after 2022 because gas prices are expected to fall.

		2022	**2023**	**2024**	**2025**	**2026**	**2027**
Henry Hub (EIA *AEO*)		6.52	5.48	4.34	3.80	3.41	3.24
Escalation Factor		1.00	0.84	0.67	0.58	0.52	0.50
ELAP Price	On-peak	**84.6**	71.1	56.3	49.3	44.2	42.0
	Off-peak	**49.8**	41.9	33.2	29.0	26.1	24.8

- The weighting of the hourly ELAP prices by solar exports assumes that all solar customers have that same "average" profile for their exports. But customers can impact their export profile in a number of ways – (1) face the panels west, (2) reduce their on-peak loads in order to export more, and (3) most significant, install storage, which allows tremendous flexibility in when solar is used and when it is exported to the grid. The use of exports from solar-only projects to weight hourly ELAP prices is particularly unfair to solar-paired-storage projects, which provide much more valuable generation that can be shaped to when it is needed most.

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exports are "firm" and how to adjust Mid-C prices to the IPC system located at a significant distance from the Mid-C market. The IRP price forecast has significant issues with accuracy and timeliness.

A straightforward way to accommodate all types of projects and all output profiles is to pay an export price differentiated by hour that is the average of all ELAP prices in that hour of the day for the relevant TOU period, over the historical period used to set the ECR energy component. **Table 4** shows those hourly prices based on the historical data for 2019-2022.

Table 4: *2019-2022 IPC ELAP Prices, by hour*

Hour Ending	2019-2022 IPC ELAP Prices *($/MWh)*	
	On-peak	Off-peak
1		39.7
2		36.5
3		35.4
4		34.1
5		34.5
6		36.6
7		40.7
8		43.4
9		41.0
10		36.4
11		34.2
12		33.6
13		33.8
14		34.2
15		35.5
16	50.7	37.8
17	59.3	43.9
18	62.9	50.7
19	69.1	56.2
20	78.1	61.1
21	80.3	61.7
22	59.7	54.6
23	46.5	46.6
24		43.5

We note that California recently moved to an even more granular hourly schedule of export prices in its new net billing tariff (NBT), mainly in recognition that solar-plus-storage projects require that level of detail.[2] The California NBT changed export compensation for solar customers in California to use hourly avoided costs, exactly as IPC is proposing with its ECR.

2. Avoided Generation Capacity

Avoided generation capacity costs have two components: first, the contribution of distributed solar to reducing the utility's need for generation capacity and, second, the marginal or avoided cost of generation capacity for the utility. We have identified issues with how IPC has valued both of these components.

Capacity contribution. IPC maintains that the capacity contribution of distributed solar is 8.76% of the solar nameplate capacity, based on an effective load carrying capacity (ELCC) analysis of solar exports over the three years 2020-2022.[3] We challenged IPC's use of low and shifting ELCCs for distributed solar in our critique of the VODER Study, and recommended the use of a peak capacity allocation factor (PCAF) method that is more stable, transparent, and easier to perform and verify. However, we recognize that ELCCs are widely used for these analyses. In addition, IPC is now using a three-year average of the ELCCs for exported power over 2020-2022, in an effort to mitigate the year-to-year volatility in this parameter. This is an improvement over the ELCCs used in the VODER Study.

However, IPC should use a different, much higher ELCC for solar-plus-storage installations. These make a far greater capacity contribution because much of the solar output can be stored, and then the stored energy can be discharged during the on-peak hours.

Marginal or avoided cost of generation capacity. The utility continues to claim, without any significant explanation, that a gas-fired combustion turbine (CT) is its marginal source of generation capacity. However, as we noted in our critique of the VODER Study, the preferred resource plan in the *2021 IRP* includes no CT capacity, and the only gas-fired capacity added is the conversion of an existing coal unit to burn gas. IPC's testimony tries to skirt this issue by describing the CT as a "proxy" capacity resource.[4] However, the capacity resource that actually <u>is</u> included in IPC's preferred resource plan is battery storage. There is no need for a "proxy."

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2 See CPUC Decision No. 22-12-056, at pp. 100-106 and 138-147: "the retail export compensation rate is set at averaged monthly [avoided cost] values for each hour, differentiated between weekday and weekend/holiday" [p. 141]. Available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043682.PDF.

3 See IPC, Ellsworth, at pp. 14-16.

4 *Id.*, at p. 16. All IPC provides is a statement that is not really an explanation:

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.

We note that the Order on the VODER Study, at page 29, observed that "we note the importance of an avoided generation capacity value that accurately considers capacity costs actually avoided" (emphasis added). A gas-fired CT is not a future resource selected in the *2021 IRP*, and thus cannot be "actually avoided." As a result, the use of the costs of new battery storage as the marginal or avoided cost of generation capacity is more consistent with the *2021 IRP*. Finally, IPC has made a corporate commitment to move to 100% clean resources by 2045; this would seem to rule out gas-fired CTs as a possible new resource. **Table 5** shows our recommended avoided generation capacity costs for distributed solar, using the battery storage costs included in the *2021 IRP* and the 8.76% capacity contribution just discussed. Our recommendation for IPC's avoided generation capacity cost for solar projects is **$0.195 per kWh** for the summer on-peak period.

Table 5: *Crossborder Revised IPC Avoided Generation Capacity Costs – **Solar-only***

line	Component	Value	Sources / Notes
a	Battery storage cost of capacity	$192 / kW-year	*2021 IRP*, Appendix C, p. 47
b	Reserve margin	15.5%	*2021 IRP*
c	Avoided cost of generation capacity	$222 / kW-year	*a x (1 + b)*
d	Solar capacity contribution - exports	**8.76%**	3-yr ELCC
e	Solar avoided generation capacity cost	$19.43 / kW-year	*d x e*
f	Solar On-peak kWh per kW	99.5 kWh / kW	IPC Export Profile
g	Solar avoided generation capacity cost Summer on-peak only	**$0.195 / kWh**	*e / f*

States such as Hawaii and California that have moved to a net billing structure similar to IPC's proposal have seen dramatic increases in the pairing of storage with distributed solar, to enable customers to manage time-varying import and export rates. Customers are also adding storage to provide assured backup power during increasingly-frequent grid outages. A major weakness of the Idaho Power proposal is its failure to recognize this important technological evolution in customer-sited renewable generation.

The capacity value of solar paired with storage is much higher, because the stored solar energy can be dispatched exactly when it is most needed, in response to the price signals in TOU rates. For customers who install solar-plus-storage, it is reasonable to require such customers to be on a retail TOU rate, and to have an TOU structure for the export rate, so that they receive strong price signals concerning when to dispatch the storage. IPC's 2021 IRP includes an ELCC value of 97.0% for solar-plus-storage resources. We believe it is reasonable to spread this capacity value equally across all of the summer on-peak hours used for the ECR, recognizing that IPC may not yet have significant data on the output of solar-plus-storage systems. **Table 6** shows the resulting avoided generation capacity cost for these resources – **$0.325 per kWh** for the summer on-peak period.

Table 6: *Crossborder Avoided Generation Capacity Costs – **Solar + Storage***

line	Component	Value	Sources / Notes
a	Battery storage cost of capacity	$192 / kW-year	*2021 IRP*, Appendix C, p. 47
b	Reserve margin	15.5%	*2021 IRP*
c	Avoided cost of generation capacity	$222 / kW-year	*a x (1 + b)*
d	Solar + storage capacity contribution	97.0%	*2021 IRP*, Appendix C, p.99
e	Solar avoided generation capacity cost	$215.11 / kW-year	*d x e*
f	Summer on-peak hours per year	631	Summer on-peak definition
g	Solar avoided generation capacity cost Summer on-peak only	**$0.325 / kWh**	*e / f*

3. T&D Deferral

The IPC proposal for an ECR includes the same very small avoided cost for transmission and distribution (T&D) capacity deferrals that IPC included in the VODER Study. We have the same concerns with the IPC approach that we discussed in our critique of the VODER Study:

- IPC's approach is a "bottom up" method which assumes that the relatively small amount of solar exports in 2021 is, unrealistically, spread evenly across IPC's entire system, is not assumed to grow in future years, and will only defer T&D capacity in the near future.[5]

- IPC should be determining its marginal T&D capacity costs – i.e. how its T&D investments change with any reduction in the demands that it serves. Distributed solar is only one source of demand reductions, and is only one type of Distributed Energy Resource (DER). DERs include a broad range of demand-side resources, including energy efficiency, demand response, and on-site storage as well as behind-the-meter (BTM) solar. Collectively, these resources can have a much larger impact to reduce IPC's need for T&D upgrades over time than IPC calculates by only looking at the impact of distributed solar. In sum, the avoided costs of T&D capacity should be calculated for <u>any</u> long-run kW reduction in IPC's peak loads, regardless of the source of that saved kW.

Our critique of the VODER Study used a "top down" approach to calculating the long-run marginal or avoided costs of T&D capacity, a method that a number of U.S. utilities have long used to calculate marginal T&D capacity costs for ratemaking. IPC submitted a detailed rebuttal to our use of this approach. In response, we would make a few technical changes to our calculations, but we firmly believe that our approach is valid, and is necessary to remedy the major problems with IPC's approach, which clearly understates avoided T&D costs. A revised calculation of avoided T&D capacity costs for IPC is beyond the scope for this review, and would require obtaining certain data from IPC in discovery.

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[5] This even "peanut-buttering" of distributed solar capacity across the entire system is almost certainly unrealistic, as we expect that most of the existing distributed solar capacity on the IPC system is clustered in a few urban and suburban locations in the Treasure Valley.

It is particularly questionable that IPC claims that it has zero avoided transmission capacity costs. Idaho Power has been deferring its major Boardman-to-Hemingway 500 kV transmission project for years, as its peak demand has not grown as quickly as expected when the project was first proposed. This major amount of avoided / deferred transmission costs is the result of many factors that have reduced IPC's loads – and distributed solar is one of the contributing factors, albeit a small one.

Another option would be to use the avoided on-peak T&D capacity costs for energy efficiency that IPC shows in its *2021 IRP*, Appendix C, page 38. This would acknowledge that the same avoided T&D costs should be used for all demand-side resources, because all types of demand-side resources produce lower loads on the IPC grid. **Table 7** shows that this would result in an on-peak T&D deferral avoided cost of **$0.0645 per kWh**.

Table 7: *EE-based T&D Deferral Avoided Cost*

line	**Component**	**Value**	**Sources / Notes**
a	2023 EE avoided T&D costs	$6.42 / kW-year	*2021 IRP*, Appendix C, p. 38
b	Solar On-peak kWh per kW	99.5 kWh / kW	IPC Export Profile
c	Solar avoided T&D capacity cost Summer on-peak only	**$0.0645 / kWh**	*a / b*

We use this value from Table 7 in the summary of our recommendations presented below.

4. Avoided Line Losses

Solar reduces T&D line losses due to its location behind the customer's meter at the point of end use. When a customer's solar array exports power to the local distribution system, the impact is to reduce loads on the upstream portions of the utility's T&D system. With lower loads, less power is lost in T&D circuits and other equipment.

The Order, at page 29, directed that "additional discussion between Staff, Intervenors, and the Company on the topic of avoided line losses, during the implementation case, may be fruitful and potentially resolve any remaining issues or confusion surrounding the Company's calculation of avoided line losses." The primary issue is that IPC's proposed ECR uses a new study of <u>average</u> line losses on its system, when the impact of distributed resources is to avoid <u>marginal</u> line losses. <u>The utility is making a fundamental error here.</u> All of the other components of the ECR – the locational marginal price for energy (ELAP), the use of the marginal resource for generation capacity, and the calculation of marginal or avoided T&D costs – use marginal values that reflect the <u>change</u> in utility costs when a customer provides its own generation. Avoided line losses also should reflect marginal values.

What is the relationship between marginal and average line losses on an electric circuit? Consider a conductor (e.g. a wire) carrying an electric current between two terminals. Ohm's Law states that the current through the conductor is proportional to the voltage drop ($V = V_A - V_B$)

across the conductor:

$$V = I \times R,$$

where V = voltage (volts), I = current (amperes), and R = resistance (ohms) of the conductor. The line losses (watts) due to heating in the circuit is equal to the voltage times the current:

$$\text{Total Line Loss} = P = I \times V = I \times (I \times R) = I^2 \times R$$

This indicates the total line loss in the conductor is proportional to the square of the total current. The voltage drop across the conductor provides an indication of the <u>average</u> line loss per unit of current, i.e. the total line loss divided by the total current:

$$\text{Average Line Loss} = P / I = I \times R$$

The <u>marginal</u> line loss for a small change in current (for example, if the voltage is increased slightly) is equal to the derivative of the total line loss with respect to current:

$$\text{Marginal Loss} = \partial P/\partial I = 2 \times I \times R$$

This shows that the marginal line losses are double the level of average line losses that occur due to resistance in the circuit. This result is widely cited in the literature on the treatment of line losses in utility systems.[6] In practice, if a portion (e.g. 25%) of the overall losses on a utility system are "no-load" losses associated with energizing the system, then the marginal losses equal 1.5 times average losses (i.e. 2 x 75%), where average losses include both resistive and no-load losses.[7] Here is a graphic comparison of average and marginal line losses prepared by the Regulatory Assistance Project, for a hypothetical utility with an average annual resistive loss of 7% on its system, and 25% no-load losses. Note that marginal line losses are as high as 20% in the system peak hour.[8]

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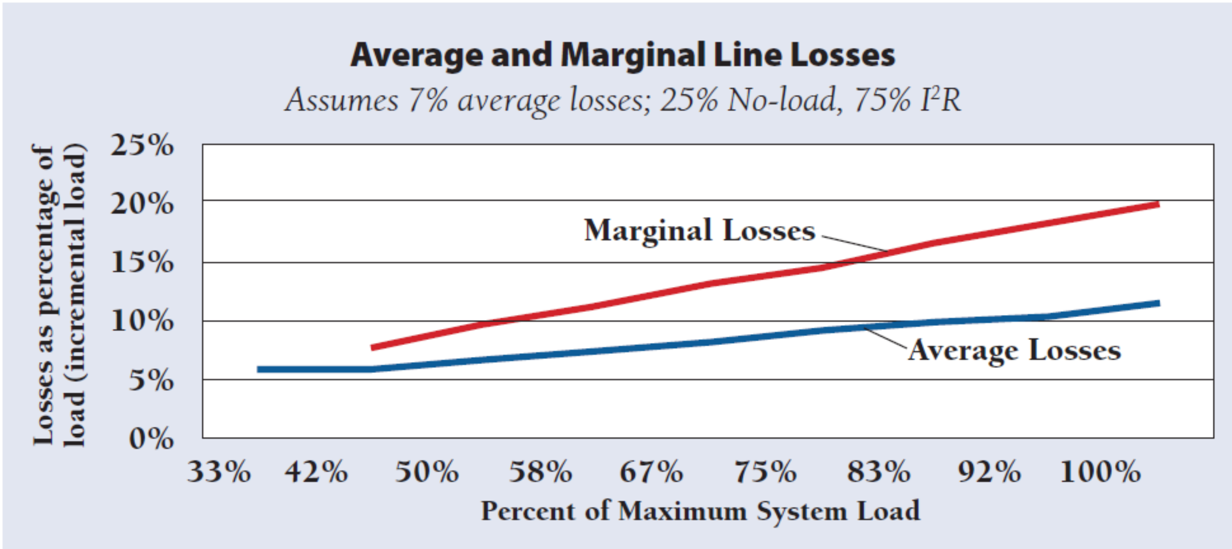
[6] See Lazar and Baldwin, Regulatory Assistance Project, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements* (August 2011), at page 5: "Mathematically, the formula I^2R reduces the marginal resistive loses to a calculation. At any point on the load duration curve, marginal resistive loses are two-times the average resistive losses at that same point on the load duration curve." See https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

Also, Brent Eldridge, Richard P. O'Neill, and Anya Castillo, *Marginal Loss Calculations for the DCOPF, FERC Technical Report on Loss Estimation* (January 24, 2017), at p. 3: "Since losses are approximately quadratic, marginal losses are about twice the average losses."

[7] See Lazar/Baldwin, at p. 5.

[8] *Id.*, at p. 4 (Figure 3).



In addition, the marginal losses associated with behind-the-meter solar resources are higher than system average losses across all loading levels because much of the solar output occurs in the afternoon hours when loads and losses are higher.[9]

IPC's filing includes a new 2022 study of system average line losses, including the average line losses avoidable by DERs, which have the "no load" transformer losses removed. We double these average resistive line losses to convert them to marginal line losses. IPC's marginal line losses for the on-peak period are 10.0% of avoided energy costs; for the off-peak period they are 8.8%.[10]

5. Integration Costs

Integration costs are the costs of the additional ancillary services needed to accommodate the increased variability that wind and solar output add to the utility system. IPC continues to use the solar integration cost of $2.93 per MWh from its VODER Study, which was taken from a 2020 wind and solar integration cost study that the E3 consultants performed for IPC (E3 Study).[11] The E3 Study included a variety of scenarios with different mixes of future resources. IPC bases its integration value on the difference in integration costs between two scenarios in the E3 Study that are the same except for varying amounts of solar.

Integration costs depend on the resources on the system that can provide ancillary services. Battery storage provides a significant, flexible, and fast-responding source of ancillary services, reducing integration costs significantly. IPC is planning to add battery storage, which

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9 *Id*: "incremental losses during the critical peak period are much larger than the average losses over the year."

10 See IPC, Ellsworth, Exhibit 4 (Line Loss Study), at Table 12. We doubled the Distribution Primary/Secondary line loss coefficients in this table.

11 See IPC, Ellsworth, Exhibit 5 (E3 Variable Energy Resource Integration Study).

will reduce its integration costs. The two scenarios in the E3 Study that IPC compares to derive its integration costs have no battery resources. The scenario in the E3 Study whose resource mix most closely resembles the subsequent *2021 IRP*'s preferred plan is Case 9 – the High Solar with 200 MW Storage case.[12] This scenario shows much lower integration costs of $0.64 per MWh.[13] Given that IPC is now planning to add significant storage resources, this lower integration cost of **$0.64 per MWh** should be used instead of the $2.93 per MWh used in the VODER Study and the IPC application.

6. Summary

Table 8 summarizes our recommended adjustments to IPC's proposed ECR, so that the new ECR more reasonably and equitably represents the value of customer-sited solar resources in Idaho. We show the four-year average of historical ELAP market prices for the avoided energy cost component, which is why our avoided energy component is lower than IPC's. In order to accommodate both solar-only and solar-plus-storage projects, we recommend the use of average ELAP market prices from the prior four years, in each hour of the day, as shown in Table 4. We do not show an avoided energy cost (or a total ECR) for solar-plus-storage, as that will depend on how the storage is operated.

Please note that "S + S" in Table 8 means solar paired with storage. It is important to have distinct ECR values for solar paired with storage, at least for the avoided generation capacity component, due to the much higher value of these systems to the grid. As discussed above, the value shown in Table 7 for avoided T&D costs is one option; another option is to develop more rigorous values for distinct avoided transmission and distribution costs – this second option would require further data from the utility.

Table 8: *ECR Recommendations ($ per MWh)*

ECR Component	Resource	IPC ECR Proposal		Crossborder Revisions	
		On-peak	Off-peak	On-peak	Off-peak
Avoided Energy	Solar	84.6	49.8	64.2	40.3
Avoided Generation Capacity	Solar	115.9	--	195.0	--
	S+S	115.9	--	325.0	--
T&D Deferral	Solar and S+S	2.5	--	64.5	--
Avoided Line Losses	Solar and S+S	4.2	2.2	10.6	6.1
Integration Costs	Solar and S+S	(2.9)	(2.9)	(0.6)	(0.6)
Total ECR	Solar	204.2	49.1	333.7	45.8
Annual Average ECR	Solar	59.6		65.4	

12 The *2021 IRP* preferred plan adds 420 MW of solar, 700 MW of wind, and 225 MW of storage from 2023-2025. See Table 1.1.

13 E3 Study, at Table ES1.

Given our analysis of bill savings under the IPC proposal, in Section C above, our recommended increases to the ECR are important to mitigate the significant erosion in compensation for new solar and solar-plus-storage customers that would result from Idaho Power's proposed ECR, particularly in future years as electric market prices decline from the peak in 2022. We note that the Order specifically mentions (1) the choice of the avoided generation capacity resource and (2) avoided line losses, as issues that need to be reviewed in this application. There are good reasons to make changes to the proposed ECR in both of these areas. Finally, the IPC proposal should be revised to recognize that, in the near future, many customer-sited solar installations will include storage. The ECR rates that the Commission adopts needs to include the much higher avoided costs for exports from these hybrid solar / storage units.

E. Economic and Environmental Benefits

Renewable distributed generation (DG) has benefits to society that do not directly impact utility rates, but that impact IPC ratepayers as citizens of Idaho. These benefits are well-known, and, in many cases, are measurable and quantifiable. This includes benefits to the Idaho economy and to the state's environmental health. Order 35284 did not direct IPC to study these benefits in the VODER Study, and the Order 35631 on that study makes clear that the ECRs for distributed generation will only include avoided costs that directly reduce ratepayer costs. However, Order 35284 recognized that, even if the Commission is not inclined or allowed to monetize these societal benefits for inclusion in the ECR, they can be part of the overall public interest determination that the Commission will make of a just and reasonable net billing program for IPC:

> … This Commission was granted authority by the Idaho legislature to conduct economic analyses to determine rates that are fair, just and reasonable. We have not been granted the legislative or executive authority to monetize many of the environmental attributes addressed by Parties and customers. That said, there are environmental considerations that are quantifiable and will be included in an ultimate determination of fair, just and reasonable terms for the Company's on-site generation program.[14]

Distributed generation makes the power system more reliable and resilient, and stimulates the local economy by encouraging significant private investment in the state's energy infrastructure. When renewable generation takes the place of conventional fossil fuel generation, all members of society benefit from reductions in air pollutants that harm human health and exacerbate climate change. Demands on existing water supplies are reduced, avoiding the potential need to acquire new sources of supply and making more water available for other uses. Distributed generation uses already-built sites, preserving land for other productive endeavors or

[14] Order 35284, at p. 12.

as natural habitat. Many of these benefits can be quantified, as we discussed in Section C of our VODER critique.