Independent Review of the Idaho Power Company's *Value of Distributed Energy Resources* Study

R. Thomas Beach
Patrick G. McGuire

September 20, 2021

Table of Contents

Independent Review of the Idaho Power Company's *Value of Distributed Energy Resources* Study

Idaho Power Company (IPC or Idaho Power) completed a *Value of Distributed Energy Resources* Study (VODER Study or Study) in June 2022. This study responded to a series of orders from the Idaho Public Utilities Commission (Idaho PUC), including Order No. 35284 in Case No. IPC-E-21-21 which approved a framework for the study. The VODER Study presents an analysis of the benefits and costs of on-site customer generation – principally rooftop solar systems that customers install on their own premises – within Idaho Power's service area. The study comments on several alternatives for valuing the power exported to the IPC grid from such facilities, and quantifies five of the components of the value of solar distributed energy resources (DERs):

- Avoided energy costs
- Avoided generation capacity
- T&D deferral
- Avoided line losses
- Integration costs

Crossborder Energy has reviewed the VODER Study, and presents this summary critique of the study. For the reasons set forth below, we conclude that Idaho Power's choice of assumptions and calculation methods significantly undervalue the five components that the utility quantified. We present our own calculations of an ECR rate with these five elements, in Table 3 below. In addition, the VODER Study fails to quantify important benefits of distributed solar that the Commission directed the utility to analyze in Order No. 35284 -- benefits that are known and measurable, will impact rates, and will benefit Idaho ratepayers and citizens. These include the benefits of a long-term physical hedge against volatile natural gas prices and of avoiding the rate impacts of reducing carbon emissions.

Notwithstanding our differences, Crossborder appreciates Idaho Power's clear and detailed explanation of the analysis that it conducted for the VODER Study, and for making available a substantial amount of the data and workpapers for the study. The clarity of the study is helpful in identifying and highlighting the important policy and technical issues associated with the work.

A. Benefits of Solar Quantified in the Idaho Power VODER Study

We first summarize our critique of the five components of the value of solar that IPC quantified in the VODER Study.

1. Avoided Energy Costs

The Commission's Order recognizes that the calculation of avoided energy costs must produce results that are up to date.[1] The VODER Study proposes 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 use historical electric market prices from 2019-2021. All of these metrics are now outdated and inaccurate. None of them reflect the significant increases over the past year in the market prices for electricity and natural gas – price increases that have become particularly acute since the war in Ukraine began at the end of February 2022. The price of natural gas in 2022 to date (through August) at the U.S. benchmark Henry Hub market has more than doubled (+130%) compared to the three-year average price in 2019-2021, and recently has reached $8 to $9 per MMBtu.

We have updated IPC's avoided energy costs to reflect today's new reality of much higher fossil fuel costs. We calculate that IPC's solar-weighted avoided energy costs using the most recent year of Energy Imbalance Market (EIM) prices (August 1, 2021 to July 31, 2022) are **$47.30 per MWh**, 68% above the $28.24 per MWh EIM price that IPC cites using the three-year 2019-2021 average.[2] Today's natural gas forward market indicates that prices will remain at very high levels for the remainder of 2022 and into 2023 before declining to the $5 per MMBtu range, still well above 2019-2021 levels.

Avoided energy costs should reflect more timely and accurate data than the IRP forecast or the three-year rolling averages used by IPC. For example, they could be based on EIM prices from the prior 12 months, adjusted based on natural gas forward market prices for the next year.

With respect to the three possible sources for avoided energy costs discussed in the VODER Study, we recommend the use of the western EIM prices. The EIM locational marginal prices (LMPs) are the prices most specific to the IPC system. Mid-Columbia (Mid-C) market prices could be used, but raise complicated issues about whether distributed solar exports are "firm"[3] and how to adjust Mid-C prices to the IPC system that is located at a significant distance from the Mid-C market. The IRP price forecast has a significant issue with accuracy and

---

1 See Order, at p. 16: "The Commission recognizes the calculations and documentation for the value of exported energy should use current energy price assumptions…."

2 See VODER Study, at p. 41 and Figure 4.2.

3 The issue of the "firmness" of distributed solar is a matter of the time scale – on an individual day, the amount of solar generation from an individual distributed solar system can be variable depending on the weather. But the solar output becomes much more predictable as both the time scale and the number of distributed systems increases. On an annual basis for an entire solar fleet, the amount of solar generation can be accurately predicted with a relatively small uncertainty – much less than the uncertainty in hydro generation, for example.

timeliness, as shown by how inaccurate the IPC *2021 IRP* forecast has proven to be.

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 significant issues with how IPC has valued both of these components.

Capacity contribution. IPC maintains that the capacity contribution of distributed solar is just 7.6% of the solar nameplate capacity, based on what the utility claims to be an effective load carrying capacity (ELCC) analysis of solar exports in 2020 and 2021.[4] This low ELCC is surprising, given that the *2021 IRP* shows that the ELCC of IPC's existing solar resources are over 60%, and the new Jackpot solar project that IPC is adding in late 2022 or 2023 has an ELCC of 34%.[5] Yes, utility-scale solar facilities that use tracking arrays will have somewhat higher ELCCs than fixed rooftop arrays, and the ELCC of solar generally will decline as more solar is added to a utility's resource mix, but the difference between a 34% ELCC for new utility-scale solar and 7.6% for new rooftop solar is excessive. IPC's proposed 7.6% ELCC is similar to the marginal "last-in" solar ELCC of 7.8% for new resources on the CAISO grid in California,[6] which has very high solar penetration – over 25,000 MW of solar (both rooftop and utility-scale) on a grid with a peak demand of 45,000 MW. Idaho is not California – in contrast, Idaho Power has only 380 MW of solar (both rooftop and utility-scale) on a grid with a peak demand of 3,800 MW.[7]

IPC's ELCC analysis calculates the 7.62% ELCC capacity contribution by looking at the capacity value of distributed solar exports as a percentage of the <u>total</u> distributed solar capacity on the IPC system in 2020 and 2021. This approach makes the mistake of ignoring that only about one-half of the distributed solar capacity is used to produce exports; the other half serves the customers' loads behind the meter. The amount of real-time exports in 2020-2021, as a percentage of total output, indicates that about 52% of the solar capacity is used for exports. Thus, IPC's capacity contributions need to be increased by a factor of 1 divided by 0.52. Correcting this error increases the capacity contribution to 14.7% using the ELCC method, and to 19.8% under the NREL approach.

We are also concerned with the volatility of the results under the capacity contribution methods used by IPC. For example, the IPC ELCC method produced a capacity contribution of 4.3% in 2020, but 10.9% in 2021, i.e. 153% higher in 2021 than 2020. Instead of using ELCCs, we prefer the use of the peak capacity allocation factor (PCAF) method. This is a widely-used

---

4 See VODER Study, at p. 51 and Figure 4.7.

5 See 2021 IRP, Appendix C, p. 99.

6 Energy & Environmental Economics (E3) and Astrape Consulting, *Incremental ELCC Study for Mid-Term Reliability Procurement*, updated version submitted to the California Public Utilities Commission on October 22, 2021, at Table ES1.

7 See *2021 IRP*, pp. 44-47.

approach to determining the capacity contribution of solar that is much more stable and transparent than ELCCs. The PCAF method calculates the capacity contribution of solar exports across all hours that have loads within 10% of the system peak hour. This method weights the solar output in these high-load hours by how close the system load in that hour is to the annual peak hour load. The hour with the annual peak load is weighted the most. We have derived hourly PCAFs for IPC using system load data from 2016-2020. Using this PCAF method, the capacity contribution of real-time solar exports is 28.6% in 2020 and 25.3% in 2021, for an average of 27.0%. We recommend use of the PCAF method as simpler and more stable than the ELCC approach.

Marginal or avoided cost of generation capacity. The VODER Study assumes, without explanation, that a gas-fired combustion turbine (CT) is IPC's marginal source of generation capacity.[8] However, 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. The pure capacity resource that is included in IPC's preferred resource plan is battery storage. Thus, 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* and with IPC's commitment to move to 100% clean resources by 2045. **Table 1** shows our recommended avoided generation capacity costs for distributed solar, using the battery storage costs included in the *2021 IRP* and the 27% capacity contribution discussed above. Our recommendation for IPC's avoided generation capacity cost is **$35.00 per MWh**.

Table 1: *Crossborder Recommendation for IPC's Avoided Generation Capacity Costs*

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	Distributed solar capacity contribution	27.0%	PCAF method
e	Solar avoided generation capacity cost	$60 / kW-year	*d x e*
f	Solar output kWh per kW	1,710 kWh / kW	PVWATTS output for Boise
g	Solar avoided generation capacity cost	**$35.00 / MWh**	*e / f*

3. T&D Deferral

The VODER Study reports very low avoided costs for transmission and distribution (T&D) capacity deferrals on IPC's grid. Our first concern with IPC's approach is that it 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.[9] This results in very small reductions to the peak loads on the IPC T&D system, and just a few short project deferrals.

---

8 VODER Study, at p. 51, Table 4.5.

9 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.

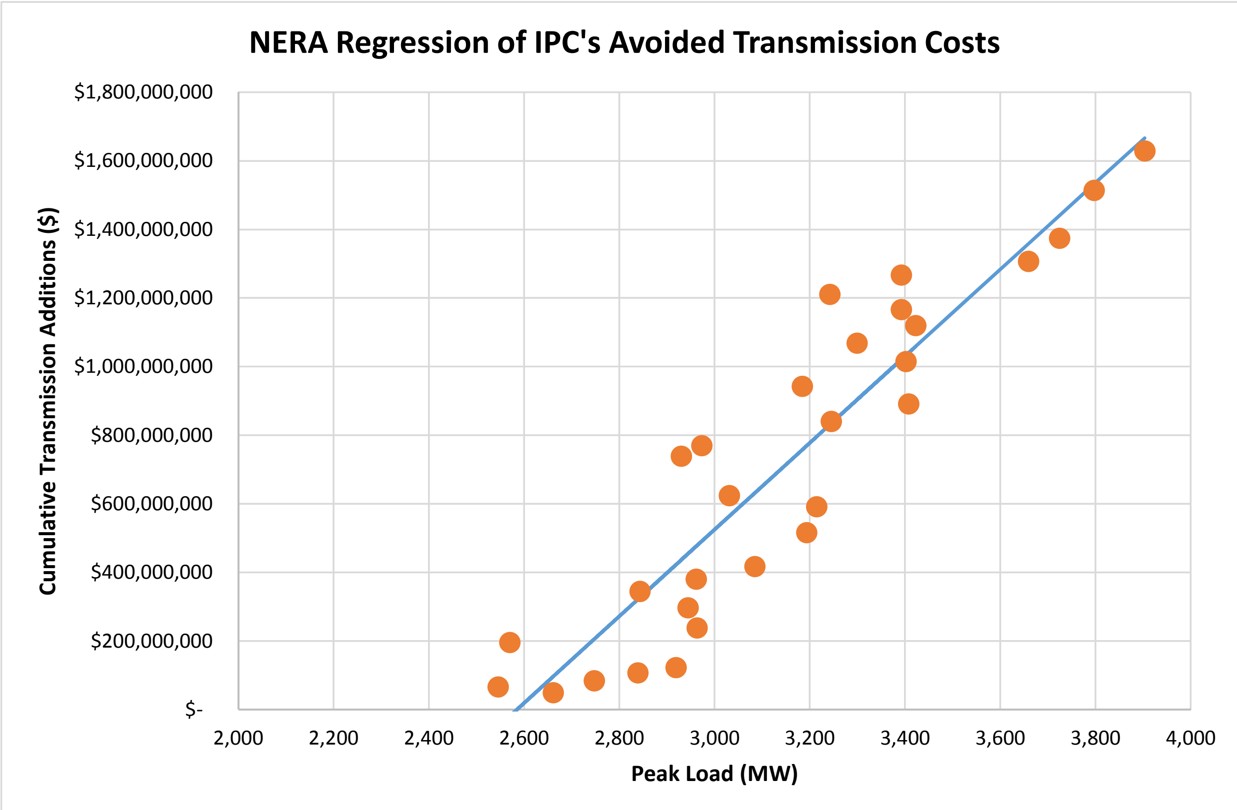
The problem with the utility's approach can be seen by considering a single 7 kW residential solar system. The utility's analysis would conclude that such a system, by itself, will never avoid any T&D costs, even though it will lower loads on the grid. IPC's analysis shows that even the existing 65 MW of distributed solar will produce few savings when that capacity is assumed to be spread thinly across the entire IPC system. But this is a *Value of Distributed Energy Resources* study, and 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 – by being a much larger amount of capacity, by concentrating load reductions in certain locations, and by moving the utility to a much lower long-term demand trajectory. If considered collectively and over their economic lifetimes, DERs will produce a far larger T&D deferral value per kW of demand reduction than if each type of DER is analyzed in isolation for just a few years into the future. In short, the long-run avoided costs of T&D capacity should be calculated for <u>any</u> long-run kW reduction in IPC's peak loads, regardless of which type of DER produces that saved kW.

To capture the long-run marginal or avoided costs of T&D capacity from a kW reduction in demand from any type of DER, we use a "top down" approach that U.S. utilities have long used to calculate marginal T&D capacity costs for ratemaking. This is the National Economic Research Associates (NERA) regression method, which calculates marginal T&D capacity costs by analyzing long-term data on how the utility's investments in transmission or distribution change with changes in peak demand. This "top-down" calculation captures the fact that peak loads impact T&D additions in many ways. Most directly, T&D infrastructure must be expanded as load grows, to serve peak demands. Load growth can also be an indirect factor in other types of T&D expansions and upgrades. For example, an upgrade may be required for reliability reasons to address contingencies that arise under high-load conditions, or to access new generation resources needed to serve growing peak demands. Even replacement projects are demand-related in that they are necessary to keep the grid's capacity from declining. Although peak demand may not be the primary driver of all of these projects, it has a significant overall influence on the need to invest in T&D infrastructure.

The NERA regression model determines avoided T or D costs by fitting incremental T or D investment costs to peak load growth. The slope of the resulting regression line provides an estimate of the marginal cost of T or D investments associated with changes in peak demand. The NERA methodology typically uses as many years as possible of historical expenditures on T&D investments and historical data on peak transmission system loads, as reported in FERC Form 1, and, if available, the forecast of future expenditures and expected load growth.

We have used a NERA regression based on IPC's FERC Form 1 data on its historical transmission expenditures as a function of its peak load growth over a 30-year period from 1996 to 2025. **Figure 2** shows the regression fit of cumulative transmission capital additions as a function of incremental demand growth on the IPC system.

Figure 2: *Regression of Cumulative IPC Transmission Additions vs. Peak Demand*



The regression slope resulting from this analysis is $1,315 per kW. We add 6.2% to this amount to account for the overhead costs of IPC's general plant, convert the total to an annualized marginal transmission cost using a real economic carrying charge (RECC) of 7.1%,[10] and include $9.09 per kW-year for transmission O&M costs.[11] The resulting avoided cost for transmission capacity is $107.50 per kW-year. A similar NERA regression for IPC's distribution investments produces an avoided cost for distribution capacity of $160.30 per kW-year.

The final step is to consider the capacity contributions of distributed solar to avoiding investments in marginal T&D capacity. Distributed solar can avoid T&D investments by reducing peak loads on the IPC grid. For transmission, we used a PCAF analysis of IPC's hourly system loads over the 2016-2020 period (from FERC Form 714) to determine the capacity contribution of solar PV to reducing peak transmission system loads.[12] The result of this PCAF analysis is a capacity contribution of 29.4% of the solar nameplate. For distribution, we performed a PCAF analysis on IPC distribution substation loads in 2020, resulting in a 33.4% capacity contribution. **Table 2** shows our final calculation of IPC's T&D deferral costs, which

10 Based on IPC's currently-authorized capital structure and cost of capital.

11 Our estimates of general plant and transmission O&M costs are from IPC's FERC Form 1 data.

12 We would prefer to use a PCAF analysis of IPC's distribution substation loads to determine the capacity contribution of solar to avoiding distribution costs, but IPC has yet to respond to our request for that detailed substation load data.

total **$49.80 per MWh**.

Table 2: *Crossborder Recommendation for IPC's T&D Deferral Costs*

line	Parameter	Transmission	Distribution	Notes
a	Avoided Capacity Cost	107.50 / kW-year	160.30 / kW-year	*NERA regressions*
b	Solar Capacity Contribution	29.4%	33.4%	*PCAF analysis*
c	Solar Output	1,710 kWh / kW	1,710 kWh / kW	*PVWATTs – Boise*
d	Solar Avoided T&D Costs	**$18.50 / MWh**	**$31.30 / MWh**	*a x b / c*

4. Avoided Line Losses

The avoided energy and generation capacity costs discussed above are at the generation level, and need to be increased to reflect the marginal line losses on both the transmission and distribution systems that are avoided by customer-sited solar. Solar reduces losses due to its location behind the customer's meter at the point of end use. As discussed in the last section, the impact of customer-sited solar, including the impact of the power exported to the local distribution system, 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.

It is important to recognize the physical fact that resistive line losses are a function of the square of loads;[13] as a result, marginal resistive losses are roughly double average losses. This means that the marginal impact on losses of reducing a kW of load on the T&D system is significantly greater than the average losses at that moment. In addition, the marginal losses associated with behind-the-meter solar resources are higher than system average losses because much of the solar output occurs in the afternoon hours when loads and losses are higher.[14]

The VODER Study understates IPC's avoided line losses substantially, for several reasons. First, IPC relies on a line loss study that is a decade old.[15] Loads have increased modestly on the IPC system since 2012, and are expected to grow even more rapidly over the next 20 years.[16] Further, the utility proposes to use system average losses, not marginal losses. This is surprising, as IPC itself recommended that the VODER Study distinguish marginal

13 Per the formula that the power P dissipated in a circuit equals the square of the current I times the circuit's resistance R: $P = RI^2$. R is essentially constant, while I varies with the load placed on the circuit. The marginal losses are obtained by taking the derivative of this formula with respect to I, which yields the relationship that marginal losses are double average losses.

14 The line loss impacts of DERs are explained in detail in the Regulatory Assistance Project's paper, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements* (August 2011). See http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

15 *VODER* Study, at pp. 58-61.

16 See *2021 IRP*, at Figure 8-1.

losses,[17] and the utility recognizes that losses increase with system loads.[18]

IPC's system average resistive losses from 2012, as shown in Table 4.9 of the Study, are about 5.8%. In the absence of an up-to-date study of marginal line losses, it is reasonable to double IPC's system average resistive line losses from 2012, to 11.6%, to capture the higher marginal losses avoided by new DER resources. The resulting loss factors are still conservatively low, in that they may not reflect the higher marginal losses experienced during the peak demand hours in summer afternoons when solar output is high. We have calculated the total avoided line losses by applying an 11.6% loss factor to both the avoided energy and generation capacity costs discussed above. Avoided losses total **$9.50 per MWh**.

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. The VODER Study includes a solar integration cost of $2.93 per MWh taken from the base result case of a 2020 wind and solar integration cost study that the E3 consultants performed for IPC (E3 Study). The base case in the E3 Study included only existing resources, and the study was completed before the *2021 IRP*. The study did include a variety of scenarios with different mixes of future resources. The scenario whose resource mix most closely resembles the subsequent *2021 IRP*'s preferred plan is Case 9 – the High Solar with 200 MW Storage case.[19] This scenario shows much lower integration costs of $0.64 per MWh.[20] Battery storage provides a significant, flexible, and fast-responding source of ancillary services, reducing integration costs significantly. 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.

---

17 See Order, at p. 20.

18 *VODER* Study, at p. 58: "Line losses are proportionate to the amount of energy flow. In other words, the higher the energy flow, the higher the line losses."

19 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.

20 E3 Study, at Table ES1.

6. Summary

Table 3 summarizes our recommended adjustments to IPC's proposed ECR.

Table 3: *ECR Recommendations ($ per MWh)*

Component	IPC VODER Study	Crossborder
Avoided Energy	28.24	47.30
Avoided Generation Capacity	10.60	35.00
T&D Deferral	0.26	49.80
Avoided Line Losses	1.64	9.50
Integration Costs	(2.93)	(0.64)
Total	37.81	140.96

7. Policy Implications of Crossborder's Analysis

- Our recommended flat ECR exceeds IPC's current volumetric rates for residential and small commercial customers.[21] Today, net metering customers are compensated at the retail volumetric rate for their exports. Our results indicate that net metering at the retail rate remains cost-effective today on Idaho Power's system, and there is no cost shift to other customers from the current net metering tariffs.

- If the Commission were to move to a net billing construct, compensation to solar customers should be increased as indicated by our recommended ECR rate.

- Other states with far higher penetrations of distributed solar, such as Arizona, California, and Hawaii, have moved to the use of time-of-use (TOU) rates for net metering customers as a first step prior to or at the same time as adopting net billing. TOU rates price electricity more accurately across the seasons and the hours of the day, and thus can help to avoid the development of any adverse cost shift as solar penetration increases.

- The use of TOU rates for net metering customers is also important given that DER technology is not standing still, and IPC should expect solar systems paired with on-site storage to become the industry standard in the coming years. This trend is driven in significant part by customers' desire for an assured backup supply of clean energy to improve their energy resiliency in the face of climate disruptions and more frequent grid outages. IPC's analytic framework in the VODER Study is limited because it is based entirely on export profiles from the existing fleet of solar-only customers. The profiles of the coming solar-plus-storage installations will be substantially different – and more valuable to the IPC system – than those that IPC has modeled in the VODER Study.

21 This includes the rates for the upper usage tiers of IPC's residential and small commercial rates.

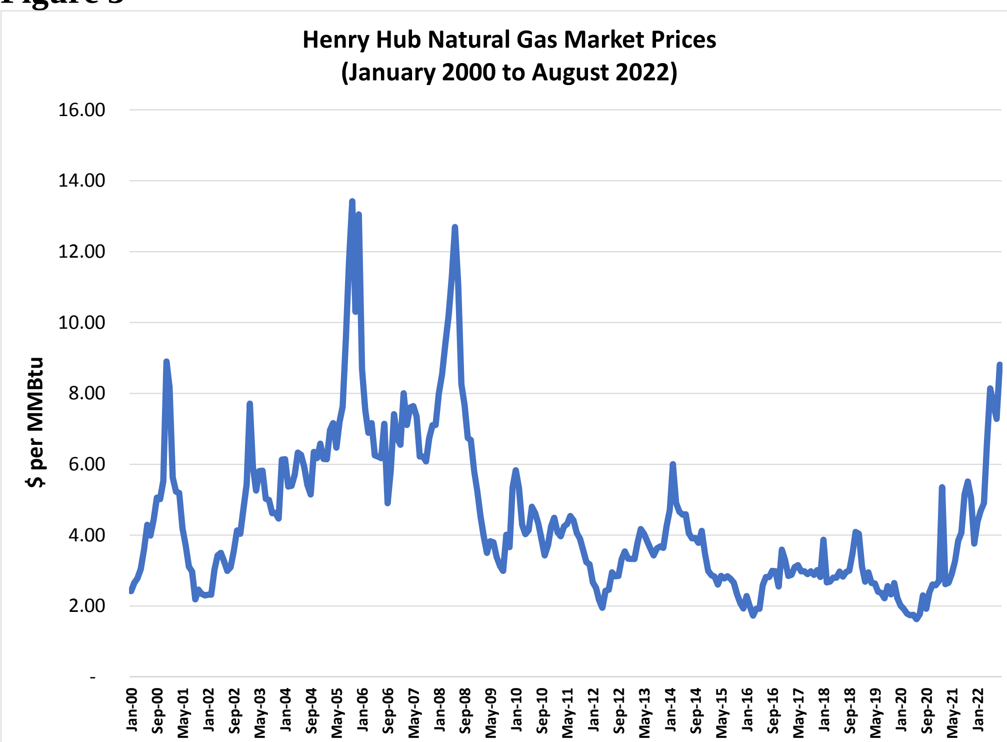
B. Benefits of Distributed Solar Not Discussed or Quantified in the VODER Study

Our review of the Commission's Order and the VODER Study indicates that there are several benefits of DERs that the Order directed the utility to analyze, but that the VODER Study failed to address. We quantify these benefits below. As we explain, these benefits are known, measurable, and have a direct impact on IPC's rates and ratepayers.

1. Fuel Hedging

The Order finds, at page 22, that "[i]t is reasonable to evaluate fuel price risks. It is the Commission's expectation that the ECR be updated regularly to mitigate risks." Renewable generation, including distributed solar, permanently reduces a utility's use of natural gas, and thus decreases the exposure of ratepayers to the volatility in natural gas prices. That volatility has been exemplified by the sharp increases in natural gas prices over the past year. Similar spikes have occurred regularly over the last several decades, as shown in the plot of the benchmark Henry Hub gas prices since January 2000, in **Figure 3** below.[22]

Figure 3



Renewable generation also hedges against market dislocations or generation scarcity such as was experienced throughout the West during the California energy crisis of 2000-2001 or as has occurred periodically during drought conditions in the U.S. that reduce hydroelectric output and curtail generation due to the lack of water for cooling.[23]

---

22 Source for Figure 3: Energy Information Administration data.

23 For example, in 2014, the rapidly increasing output of solar projects in California made up for

We note that this benefit will be reduced to the extent that the ECR is linked directly to electric market prices that are driven by natural gas prices. In that case, the ECR payments recovered from ratepayers will be impacted by volatile fossil fuel prices. However, the 50% of distributed solar output that is not exported will reduce permanently the utility's use of natural gas, providing a long-term physical hedge. It is critical to note that this benefit will accrue for the 25- or 30-year life of the distributed solar system, and thus is far more valuable than the limited 18-month benefit provided by IPC's existing fuel hedging activities.

To calculate this benefit, we follow the methodology used in the *Maine Distributed Solar Valuation Study (Maine Study)*, a 2015 study commissioned by the Maine Public Utilities Commission and authored by Clean Power Research.[24] This approach calculates the financial cost of fixing the cost of natural gas for 25 years, thus eliminating all fuel price risk. It recognizes that one could contract for future natural gas supplies today, and then set aside in risk-free investments the money needed to buy that gas in the future. This would eliminate the uncertainty in future gas costs. The additional cost of this approach, compared to purchasing gas on an "as you go" basis (and using the money saved for alternative investments), is the benefit that distributed solar provides for IPC ratepayers by reducing the uncertainty and volatility in IPC's costs for natural gas.

We have performed this calculation for IPC, using an up-to-date natural gas forecast that combines near-term forward market prices with, in the out years, the Energy Information Administration's *2022 Annual Energy Outlook* forecast for Henry Hub prices. We also have used U.S. Treasuries (at current yields) as the risk-free investments and a marginal heat rate of 7,500 Btu per kWh. The result is a value of $23.40 per MWh as the 25-year levelized benefit of reducing fuel price uncertainty. We then reduce this value by 50% given that the ECR for the portion of solar output that is exported may be linked to near-term electric and gas market prices, and thus may not provide a hedging benefit. The resulting fuel hedge benefit is **$11.70 per MWh**.

2. Avoided Costs of Carbon Emissions

With respect to the evaluation of the quantifiable environmental benefits of DERs, the Order states, at page 27, that "[t]he Commission finds it reasonable that the Study include an evaluation of all benefits and costs that are quantifiable, measurable, and avoided costs that affect rates."

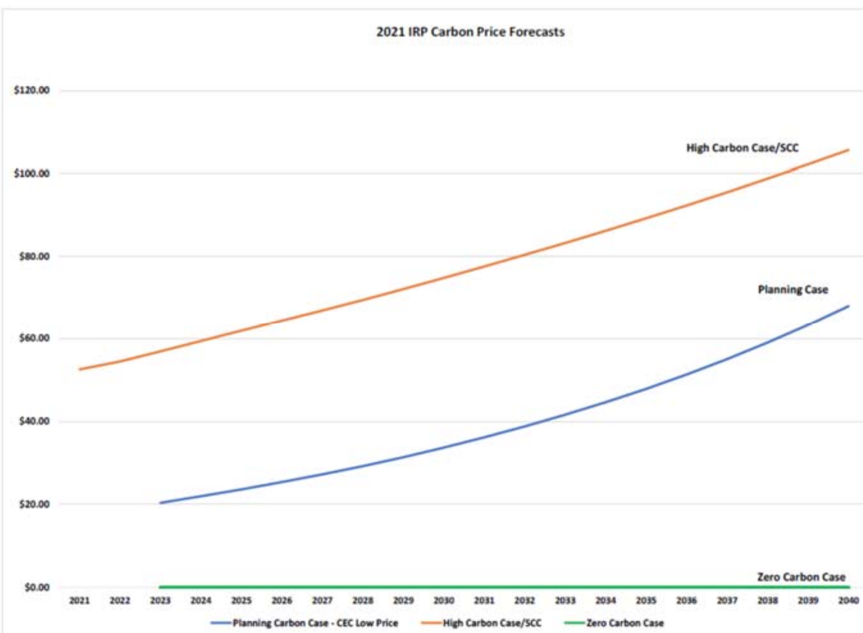
83% of the reduction in hydroelectric output due to the multi-year drought in that state. Based on Energy Information Administration data for 2014, as reported in Stephen Lacey, *As California Loses Hydro Resources to Drought, Large-Scale Solar Fills in the Gap: New solar generation made up for four-fifths of California's lost hydro production in 2014* (Greentech Media, March 31, 2015). Available at http://www.greentechmedia.com/articles/read/solar-becomes-the-second-biggest-renewable-energy-provider-in-california.

[24] See Maine Public Utilities Commission, *Maine Distributed Solar Valuation Study* (March 1, 2015). Available at https://www.maine.gov/tools/whatsnew/attach.php?id=639056&an=1.

Like other renewables, distributed solar will avoid carbon emissions from traditional fossil-fueled power plants, and help to mitigate the impacts of climate change. Idaho Power has committed to eliminating its carbon emissions by 2045,[25] and recognizes that carbon emissions must be reduced in order to mitigate the adverse impacts of climate change.[26] The 2021 IRP also makes clear that the impacts of climate change in Idaho are likely to impose significant risks, with associated cost impacts, on the utility and its Idaho ratepayers for both mitigation and adaptation.[27] IPC also has assumed carbon emission costs in its IRP planning, which results in actionable resource plans that have significant cost consequences for Idaho ratepayers.[28] We conclude that avoided carbon emission costs are quantifiable and measurable avoided costs that will affect IPC's rates

Figure 4 shows the range of carbon emission costs (in $ per short ton) from the *2021 IRP*.[29] As noted above, IPC's assumed carbon costs in the Planning Case are taken from forecasts of carbon cap & trade costs in California. The figure includes, as the high case, the U.S. Environmental Protection Agency's (EPA) social cost of carbon (SCC), which is a measure of carbon costs based on the societal damages from unmitigated climate change. The SCC can be used to value the societal benefits from reduced carbon emissions.

Figure 4: *Carbon Cost Forecasts from 2021 IRP*



25 *2021 IRP*, at p. 27.

26 *Id.*: "Limiting the impact of climate change requires reducing GHG emissions, primarily CO2."

27 *Id.*, at pp. 27-34.

28 *Id.*, at p. 34: "Similarly, federal climate legislation has not been passed by Congress. However, the company believes that climate- and emissions-related policies will emerge in future years. To account for this expected future, the company models multiple scenarios with varying prices on carbon."

29 *Id.*, at Figure 9.3.

Our analysis of avoided carbon costs uses the Environmental Protection Agency's ("EPA") "AVoided Emissions and geneRation Tool" (AVERT) to calculate the avoided carbon emissions due to distributed solar installations in Idaho. AVERT calculates hourly avoided emissions based on a given hourly profile for energy efficiency savings or renewable energy production. Our model uses a PV profile for 1 MW of distributed solar sited in Boise, and the Northwest AVERT regional data file, to calculate the avoided carbon emissions in Idaho. The avoided carbon emissions are 1.53 lbs per kWh of solar output.

Based on the carbon planning costs in Figure 4 and the modeled avoided carbon emissions of 1.53 lbs per kWh, and assuming a 7.12% discount rate and 0.5% annual solar output degradation, we have calculated 25-year levelized avoided costs for carbon emissions. This calculation results in avoided carbon emission costs of **$30.30 per MWh** of solar output.

Table 4 summarizes these additional rate-related benefits, combined with the five ECR components from Table 3.

Table 4: *Total Recommended Rate-related Value of Solar DERs ($ per MWh)*

Component	Recommended Value
Five Components from Table 3	141.00
Fuel Hedging Benefit	11.70
Avoided Carbon Emission Costs	30.30
Total	**183.00**

C. Societal Benefits of Distributed Solar Generation

Renewable distributed generation (DG) has benefits to society that do not directly impact utility rates, but impact IPC ratepayers as citizens of Idaho. These benefits are well-known, and, in many cases, are measurable and quantifiable. The Order did not direct IPC to study these benefits, and such benefits may not be appropriate for inclusion in the ECR. However, the Order recognizes that, even if the Commission is not able to monetize these 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 metering or 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.[30]

[30] Order, at p. 12.

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. Distributed generation uses already-built sites, preserving land for other uses or as natural habitat. Distributed generation makes the power system more reliable and resilient, and stimulates the local economy. Many of these benefits can be quantified, as discussed below. We use a lower, societal discount rate of 5% (3% real) in calculating these benefits, rather than the 7.12% IPC discount rate used for the direct benefits.

1. Carbon Social Cost and Methane Leakage

The **social cost of carbon** (SCC) is "a measure of the seriousness of climate change."[31] It is a way of quantifying the value of actions to reduce greenhouse gas emissions, by estimating the potential damages if carbon emissions are not reduced. The carbon costs which we have included in the direct benefits of solar DG above are limited to the anticipated costs to plan for and procure enough new, clean generation to meet IPC's goal of 100% clean energy by 2045. These planning and procurement costs are assumed to be lower than the true costs that carbon pollution imposes on society, which are the damages estimated by the SCC. As a result, the additional costs in the SCC, above the planning costs of mitigating carbon emissions, represent the societal benefits of avoided carbon emissions.

An early source for estimates of the social cost of carbon was the federal government's Interagency Working Group on the Social Cost of Carbon.[32] These values were vetted by numerous government agencies, research institutes, and other stakeholders, and are presented in Figure 9.3 of the *2021 IRP*. The cost values were derived by combining results from the three most prominent integrated assessment models, each run under five different reference scenarios.[33] However, the Interagency working group forecast is more than 10 years old, and is in the process of being updated. A recent academic estimate of the SCC for the U.S. is the median estimate of $417 per metric tonne from a review of the range of SCC values published in October 2018 in *Nature Climate Change*.[34] This more recent SCC is far higher than the Interagency SCC values. IPC's *2021 IRP* uses an SCC forecast that starts at $52 per ton, as shown in Figure 9.3. This appears to be an effort to escalate the older Interagency SCC values to today. We have used the IPC SCC values recognizing that they are likely to be a conservatively low value.

---

31 Anthoff, D. and Toll, R.S.J. 2013. The uncertainty about the social cost of carbon: a decomposition analysis using FUND. *Climactic Change* 117: 515-530.

32 Interagency Working Group on Social Cost of Greenhouse Gases, *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (May 2013, Revised August 2016). Available at: https://www.epa.gov/sites/default/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.

33 *Id.* The three models are the Dynamic Integrated Climate-Economy (DICE) model, the Climate Framework for Uncertainty, Negotiation and Distribution (FUND) model, and the Policy Analysis of the Greenhouse Effect (PAGE) model.

34 See Ricke et al., "Country-level social cost of carbon," *Nature Climate Change* (October 2018). Available at: https://www.nature.com/articles/s41558-018-0282-y.epdf.

We calculate the societal benefits of reducing carbon emissions in the years 2023 – 2047 as (1) the SCC values used in the *2021 IRP* less (2) the planning case for carbon emission costs used in our direct benefits, discussed above. The 25-year levelized difference is **$30.40 per MWh**.

Reduced methane leakage. In addition, we also determine the total greenhouse gas emissions that will result from methane leakage in the natural gas infrastructure that serves marginal gas-fired power plants. We attach to this report as **Attachment 1** a white paper summarizing recent studies on the additional greenhouse gas emissions associated with methane leaked in providing the fuel to gas-fired power plants. This issue has received significant attention as a result of the major methane leak in 2015 from the Aliso Canyon gas storage field in southern California and new technologies for the remote sensing of methane leakage. The bottom line is that the CO_2 emission factors of gas-fired power plants should be increased by more than 60% to account for these directly-related methane emissions from the production and pipeline infrastructure that serves gas-fired electric generation. This additional societal benefit amounts to **$11.60 per MWh**.

2. Health Benefits of Reducing Criteria Air Pollutants

Reductions in criteria pollutant emissions improve human health. Exposure to particulate matter (PM) causes asthma and other respiratory illnesses, cancer, and premature death.[35] Nitrous oxides (NO_X) react with volatile organic compounds in the atmosphere to form ozone, which causes similar health problems.[36]

We use AVERT to calculate the avoided emissions of SO_2, NO_x, and fine particulate matter ($PM_{2.5}$), assuming 1 MW of distributed solar development. The avoided emissions of these criteria pollutants are shown in **Table 5**.

Table 5: *Avoided Emissions of Criteria Pollutants*

Pollutant	Avoided Emissions lbs/MWh
SO_2	0.71
NOx	1.11
$PM_{2.5}$	0.079

The value of these avoided emissions is calculated as follows:

1. Determine the amount of avoided emissions using AVERT as described above.

[35] EPA, *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014), p. 4-17 ("CPP Technical Analysis"). Available at https://www.epa.gov/sites/default/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

[36] *Ibid.*

2. Calculate the social cost of the avoided emissions and subtract the compliance cost or emissions market value of those emissions.

For quantifying the health benefits, we recommend using the health co-benefits from reductions in criteria pollutants that EPA developed in conjunction with the Clean Power Plan. These benefit estimates were developed in 2014 as part of the technical analysis for the proposed rule.

SO_2. The total social cost of SO_2 emissions is taken from the EPA's *Regulatory Impact Analysis for the Final Clean Power Plan (CPP Impact Analysis)*.[37] The EPA calculated social cost values for 2020, 2025, and 2030. This analysis uses the values given for these three years assuming a 3% discount rate. Values for intermediate years are interpolated between the five-year values. The market value of SO_2 is taken from the EPA's 2016 SO_2 allowance auctions. However, the final clearing price of the latest spot auction was just $0.06 per ton.[38] This is low enough compared to the social cost that it is negligible for our calculations. The societal benefit of avoided SO_2 emissions is **$7.40 per MWh**.

NOx. Heath damages from exposure to nitrous oxides come from the compound's role in creating secondary pollutants: nitrous oxides react with volatile organic compounds to form ozone, and are also precursors to the formation of particulate matter.[39] The social cost of NOx is taken from the EPA's CPP Impact Analysis.[40] We use a 2017 NO_x market price of $750 per ton for compliance with the Cross State Pollution Rule as the compliance cost for NOx.[41] The benefit of avoiding NOx emissions is **$2.70 per MWh**.

Fine Particulates ($PM_{2.5}$). We use the emissions factor and damage costs for $PM_{2.5}$, because $PM_{2.5}$ are the small particulates with the most adverse impacts on health. The EPA health co-benefit figures distinguish between types of PM, and calculate two separate benefit-per-ton estimates for PM: for PM emitted as elemental and organic carbon, and for PM emitted as crustal particulate matter.[42] The EPA estimates that approximately 70% of primary $PM_{2.5}$ emitted in Wyoming and Nevada (where the coal plants serving IPC are located) is crustal material, with the bulk of the remainder being elemental or organic carbon.[43] The emissions factor of 0.0077 lbs per MMBtu for total primary $PM_{2.5}$ does not differentiate among particle types.[44] As a result, we weigh the mid-point of each of the two benefit-per-ton estimates

37 *Regulatory Impact Analysis for the Final Clean Power Plan*. Found at: https://www.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule-ria.pdf.

38 EPA 2016 SO2 Allowance Auction. Found at: https://www.epa.gov/airmarkets/2016-so2-allowance-auction.

39 CPP Technical Analysis, p. 4-14.

40 *CPP Impact Analysis*, at Table 4-7.

41 See the EPA Cross State Air Pollution Rule. Found at: https://www.epa.gov/csapr. NOx emission allowance prices can be found at http://www.evomarkets.com/content/news/reports_23_report_file.pdf.

42 CPP Technical Analysis, p. 4-26, Table 4-7.

43 *Ibid*., p. 4A-8, Figure 4A-5.

44 AP 42, Table 1.4-2, Footnote (c).

according to EPA's assumptions. The health benefits of reducing $PM_{2.5}$ emissions are **$2.60 per MWh** on a 25-year levelized basis.

3. Water

Thermal generation consumes water, principally for cooling. Reducing water use in the electric sector through the use of renewable generation lowers the vulnerability of the electricity supply to the availability of water, and reduces the possibility that new water supplies will have to be developed to meet growing demand. However, water consumption by efficient gas-fired generation is relatively low, and the cost of incremental water supplies varies widely depending on the local abundance of water resources. As a result, the value of avoided water use is relatively modest. We have used **$1.20 per MWh** for the value of avoided water use, based on several sources.[45]

4. Local Economic Benefits

The development of solar DG will benefit the economy of the community in which it is installed. Although solar DG has higher costs per kW than utility-scale solar generation, a portion of the higher costs – principally for installation labor, permitting, permit fees, and customer acquisition (marketing) – are spent in the local economy, and thus provide a local economic benefit in close proximity to where the DG is located. These local costs are an appreciable portion of the "soft" costs of DG. Central station power plants have significantly lower soft costs, per kW installed, and often are not located in the local area where the power is consumed.

There have been a number of studies of the soft costs of solar DG, as the industry has focused on reducing these costs, which are significantly higher in the U.S. than in other major international markets for solar PV. The following **Table 6** presents data on the soft costs for residential PV systems that are likely to be spent in the local area where the DG customer resides, from detailed surveys of solar installers that were conducted by two national labs (LBNL and NREL) in 2013.

[45] This figure is based on the American Wind Energy Association's estimate that, in 2016, operating wind projects produced 226 million MWh and avoided the consumption of 87 billion gallons of water, with a cost of new water resources of about $1,000 per acre-foot. This is similar to the mid-point of cost estimates for the cost of water savings at gas-fired power plants by implementing dry cooling technologies. See Maulbetsch, J.S.; DiFilippo, M.N. *Cost and Value of Water Use at Combined-Cycle Power Plants*. CEC-500-2006-034. Sacramento: California Energy Commission, PIER Energy-Related Environmental Research, 2006, available at http://www.energy.ca.gov/2006publications/CEC-500-2006-034/.

Table 6: *Residential Local Soft Costs*

Local Costs	LBNL – J. Seel *et al.*[46]		NREL – B. Friedman *et al.*[47]	
	$/watt	**%**	**$/watt**	**%**
Total System Cost	6.19	100%	5.22	100%
Local Soft Costs				
Customer acquisition	0.58	9%	0.48	9%
Installation labor	0.59	10%	0.55	11%
Permitting & interconnection	0.15	2%	0.10	2%
Permit fees	0.09	1%	0.09	2%
Total local soft costs	**1.41**	**22%**	**1.22**	**23%**

Based on these studies, we assume that 22% of residential solar PV costs are spent in the local economy where the systems are located. These economic benefits occur in the year when the solar capacity is initially built, which for the purpose of this study is 2023. We have converted these benefits into a $ per kWh benefit over the expected DG lifetime that has the same net present value in 2023 dollars. We also use more current DG capital costs than the system costs used in the LBNL and NREL studies. The result is a societal benefit of **$30.20 per MWh** of DG output for residential systems.

5. Land Use

Distributed generation makes use of the built environment in the load center – typically roofs and parking lots – without disturbing the existing use for the property. In contrast, central station fossil or renewable plants require large single parcels of land, and tend to be more remotely located where the land has agricultural or habitat uses. Unless the site is already being used for power generation, the land must be removed from its prior use when it becomes a solar farm or a fossil power plant. Although fossil natural gas plants have small footprints per MWh produced, one must also consider that upstream natural gas wells, processing plants, and pipelines have substantial land use impacts in the basins where gas is produced. Central-station solar photovoltaic plants with fixed arrays or single-axis tracking typically require 7.5 to 9.0 acres per MW-AC, or 3.3 to 4.4 acres per GWh per year. The lost value of the land can vary over a wide range, depending on the alternative use to which it could be put. As an example of the magnitude of land use impacts, we calculate that, based on the 2022 U.S. Department of Agricultural rental value for irrigated croplands in Idaho ($262 per acre),[48] and the alternative of a utility-scale solar plant (4 acres per GWh), the land use value avoided by DG is about **$1.10 per MWh**. This value will be lower if the land has an alternative use of lower value than

---

[46] J. Seel, G. Barbose, and R. Wiser, *Why Are Residential PV Prices So Much Lower in Germany than in the U.S.: A Scoping Analysis* (Lawrenece Berkeley National Lab, February 2013), at pp. 26 and 37.

[47] B. Friedman et al., *Benchmarking Non-Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey – Second Edition* (National Renewable Energy Lab, October 13, 2013), at Table 2.

[48] See USDA, National Agricultural Statistics Service, Survey of 2017 Cash Rents, available at https://quickstats.nass.usda.gov/results/58B27A06-F574-315B-A854-9BF568F17652#7878272B-A9F3-3BC2-960D-5F03B7DF4826.

irrigated land for farming.

6. Reliability and Resiliency

Renewable distributed generation resources are installed as thousands of small, widely distributed systems and thus are highly unlikely to experience unexpected, forced outages at the same time. Furthermore, the impact of any individual outage at a DG unit will be far less consequential than an outage at a major central station power plant. In addition, the DG customer, not the ratepayers, will pay for the repairs.

Most electric system interruptions do not result from high demand on the system, but from weather-related transmission and distribution system outages. In these more frequent events, renewable DG paired with on-site storage can provide customers with an assured back-up supply of electricity for critical applications should the grid suffer an outage of any kind. This benefit of enhanced reliability and resiliency has broad societal benefits as a result of the increased ability to maintain government, institutional, and economic functions related to safety and human welfare during grid outages. These benefits could be considered to be ratepayer benefits given that customers need to prepare and pay for their energy needs both with and without the availability of grid power.

Both DG and storage are essential in order to provide the reliability enhancements that are needed to eliminate or substantially reduce weather-related interruptions in electric service. The DG unit ensures that the storage is full or can be re-filled promptly in the absence of grid power, and the storage provides the alternative source of power when the grid goes down. DG also can supply some or all of the on-site generation necessary to develop a micro-grid that can operate independently of the broader electric system. Solar DG is a foundational element necessary to realize this benefit – in much the same way that smart meters are necessary infrastructure to realize the benefits of time-of-use rates, dynamic pricing, and demand response programs that will be developed in the future – and thus the reliability and resiliency benefits of wider solar DG deployment should be recognized as a broad societal benefit.

7. Customer Choice

There are important public policy reasons to ensure that the customers who invest in DG are treated equitably in assessments of the merits of net metering and renewable DG, so that consumers continue to have the freedom to exercise a competitive choice, to become more engaged and self-reliant in providing for their energy needs, and to encourage others to invest private capital in Idaho’s energy infrastructure.

There are many dimensions to the customer choice benefits of DG technologies:

- **New Capital.** Customer-owned or customer-sited generation brings new sources of capital for clean energy infrastructure. Given the magnitude and urgency of the task of moving to clean sources of energy, expanding the pool of capital devoted to this task is essential.

- **New Competition.** Rooftop solar provides a competitive alternative to the utility's delivered retail power. This competition can spur the utility to cut costs, to innovate in its product offerings, and to offer more accurate, cost- and time-based rates. With the widespread availability of rooftop solar, energy efficient appliances, and load management technologies, plus – in the near future – customer-sited storage, this competition will only intensify. In the now-foreseeable future, the combination of solar, storage, and load management technologies may offer an on-site electric supply whose quality and reliability is comparable to utility service.

- **High-tech Synergies.** Rooftop solar appeals to those who embrace the latest in technology. Solar has been described as the "gateway drug" to a host of other energy-saving and clean energy technologies. Studies have shown that solar customers adopt more energy efficiency measures than other utility customers, which is logical given that it makes the most economic sense to add solar only after making other lower-cost energy efficiency improvements to your premises.[49] Further, with net metering, customers retain the same incentives to save energy that they had before installing solar. These synergies will only grow as the need to make deep cuts in carbon pollution drives the increasing electrification of other sectors of the economy, such as buildings and transportation.

- **Customer Engagement.** Customers who have gone through the process to make the long-term investment to install solar learn much about their energy use, about utility rate structures, and about producing their own energy. Given their long-term investment, they will remain engaged going forward. There is a long-term benefit to the utility and to society from a more informed and engaged customer base, but only if these customers remain connected to the grid. As we saw in Nevada in 2015-2016, when the Nevada commission unexpectedly slashed the compensation for existing net-metered solar customers, this positive customer engagement can turn to customer "enragement" if the utility and regulators do not accord the same respect and equitable treatment to customers' long-term investments in clean energy infrastructure that is provided to the utility's investments and contracts. Emerging storage technologies may allow customers in the future to "cut the cord" with their electric utility in the same way that consumers have moved away from the use of older infrastructure for landline telephones and cable TV. Given the important long-term benefits that renewable DG can provide to the grid if customer-generators remain connected and engaged,

---

[49] See the *2009 Impact Evaluation Final Report on the California Solar Initiative*, prepared by Itron and KEMA and submitted in June 2010 to Southern California Edison and the Energy Division of the California Public Utilities Commission. See pages ES-22 to ES-32 and Chapter 10. Also available at the following link: http://www.cpuc.ca.gov/workarea/downloadasset.aspx?id=7677. Also see Center for Sustainable Energy, *Energy Efficiency Motivations and Actions of California Solar Homeowners* (August 2014), at p. 6, finding that more than 87% of solar customers responding to a survey had installed or upgraded one or more energy efficiency technologies in their homes. Available at https://energycenter.org/sites/default/files/docs/nav/policy/research-and-reports/Energy%20Efficiency%20Motivations%20and%20Actions%20of%20California%20Solar%20Homeowners.pdf.

it is critical for regulators and utilities to avoid alienating their most engaged customers.

- **Self-reliance.** The idea of becoming independent and self-reliant in the production of an essential commodity such as electricity, on your own property using your own capital, has deep appeal to Americans, with roots in the Jeffersonian ideal of the citizen (solar) farmer.

These benefits of customer choice are difficult to express in dollar terms; however, all are important reasons for ensuring that Idaho's energy policies encourage new clean energy infrastructure, including a robust market for rooftop solar and other DERs.

8. Summary of Societal Benefits

We have quantified many of the societal benefits discussed above, and they have significant value. **Table 7** below summarizes the societal benefits of solar DG. **The societal benefits total 8.7 cents per kWh.** Given their magnitude, these benefits should not be ignored by policymakers, as ignoring them implicitly values them at zero.

Table 7: *Societal Benefits of Distributed Solar in Idaho*

Benefit	Value ($ per MWh)	Method Used
Carbon: avoid societal damages from climate change	30.40	Use the difference between IPC's *2021 IRP* SCC estimate and the assumed planning carbon costs.
Carbon: reduce methane leaks from natural gas infrastructure	11.60	Assumes 2% leakage, per 2015 National Academy of Sciences report
Reduce SO_2 emissions	7.40	EPA AVERT model for avoided SO2 emissions. EPA estimates of health benefits.
Reduce NO_x emissions	2.70	EPA AVERT model for avoided NOx emissions. EPA estimates of health benefits.
Reduce $PM_{2.5}$ emissions	2.60	EPA Clean Power Plan technical appendices and EPA AP 42 for emissions factors.
Avoid consumptive water use	1.20	Several estimates of avoided water use from renewable generation.
Local economic benefit	30.20	22% of residential system cost is incremental expenses in the local economy.
Land use	1.10, but varies	Highly variable based on alternative uses of land at which large power plants are sited.
Reliability	Significant and positive	Significant reliability and resiliency benefits from the pairing of solar DG and on-site storage.
Customer choice	Significant and positive	New capital for clean energy infrastructure, new competition, greater customer engagement
Total	**87.20**	Use in the Societal Test

Methane Leaks from Natural Gas Infrastructure Serving Gas-fired Power Plants

Andrew B. Peterson
R. Thomas Beach
Crossborder Energy
February 19, 2016

1. Summary

Natural gas has been commonly depicted as a “bridge” fuel between coal and renewable energy for the generation of electricity. Natural gas is considered more environmentally friendly because burning natural gas produces less CO_2 than coal on a per unit of energy basis. Most analyses of the greenhouse gas (GHG) emissions associated with burning natural gas to produce electricity use an emission factor of 117 lbs of CO_2 per MMBtu of natural gas burned. However, this number does not include methane leaked to the atmosphere during the production, processing, and transmission of natural gas from the wellhead to the power plant. Methane is both the primary constituent of natural gas and a potent greenhouse gas (GHG), so quantifying the methane leakage is important in assessing the impact of natural gas systems on global warming.

Methane is emitted to the atmosphere from natural gas systems in both normal operating conditions and in low frequency, high emitting incidents. The Environmental Protection Agency’s (EPA) “Inventory of U.S. Greenhouse Gas Emissions and Sinks” attempts to calculate methane emissions from natural gas systems using a “Bottom Up” accounting method, which essentially adds up methane emissions from production, processing, transmission, storage, and distribution. This method sets a reasonable baseline for methane emissions during normal operating conditions, but does not account for low frequency high emitting situations.

Low frequency high emitting situations happen when some part of the production, processing, or transmission systems fail, leaking large amounts of methane into the atmosphere. The recent Aliso Canyon leak from a major Southern California Gas storage field in Parker Ranch, California is probably the best-known example of a low frequency high emitting event. The Aliso Canyon leak has emitted 2.4 MMT CO2-eq., or roughly 1.5% of total yearly methane emissions from all U.S. natural gas Infrastructure, in a single event. Several studies have shown that low frequency high emitting events like Aliso Canyon contribute significantly to methane emissions from natural gas systems.

The following analysis and discussion lays out an argument for increasing the carbon emission factor for burning natural gas in power plants to include the carbon equivalent of the methane emitted in the production, processing, transmission, and storage of natural gas,

leaving out the losses in local distribution that are downstream from power plants on the gas system. A conservative starting point for the leakage from wellhead to power plant is that 2% of natural gas produced is lost to leakage in the form of methane. This estimate is based the IPCC Fifth Assessment Report, the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks," adjusted based on several studies quantifying how the EPA's method underestimates actual emissions.

Using the conservative estimates of 2% of total production emitted, and a global warming potential (GWP) of 25 (the low end of methane's GWP) increases the CO_2 emitted by burning methane to 175.5 lbs of CO_2-eq. per MMBtu of natural gas burned (a factor of 1.5). Using a GWP of 34 (high end) yields 196.6 lbs of CO_2 per MMBtu of natural gas burned (a factor of 1.68).

2. Measuring Natural Gas Leakage (Methods)

Determining methane leaks from natural gas systems is relatively new field of study. Until 2011 methane leaks were calculated almost exclusively using a Bottom Up accounting method based on data published in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks". Several issues with this method, including outdated Emission Factors and low frequency high emitting events, have led researchers to use "Top Down" aerial measurements of methane leakage.

Bottom Up. Bottom Up (BU) methods attempt to identify all sources of methane emissions in a typical production chain and assign an Emission Factor (EF) to each source. The total emissions are determined by adding up all of the EFs through the life cycle of natural gas. BU measurements are useful because they avoid measuring methane from biogenic sources (landfills, swamps, etc), anthropogenic sources in geographic proximity to natural gas systems (coal plants, oil wells, etc), and only require an engineering inventory of equipment and activity. However, BU measurements often rely on decades-old EFs. The EFs used in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks" are based on a report published in 1996, which in turn is based on data collected in 1992. The EPA has developed a series of correction factors based on technological improvements and new regulations.

BU studies have been shown to underestimate methane emissions from natural gas systems.[1]–[5] While outdated EFs can cause both under and overestimation of emissions, low frequency high emission events are responsible for consistent underestimation of emissions by BU calculations.[1], [5]–[7] A recent study in the Barnett Shale region of Texas found that 2% of facilities were responsible for 50% of the emissions and 10% were responsible for 90% of the emissions.[5] BU measurements do not accurately take into account these low frequency high emitters. First, most BU measurements either sample only a few facilities or rely on facility and equipment inventories rather than local measurements. Secondly, most BU data is self-reported. Finally, several studies have found that the low frequency high emitters were both spatially and temporally dynamic, with the high emission rates resulting from equipment breakdowns and failures, and not from design flaws in a few facilities.

Top Down. Top Down (TD) methane measurements have used aerial flyovers to measure the atmospheric methane content, then use mass balance and atmospheric transport models to determine methane emissions from a geographical region. A signature compound such as ethane is used to distinguish fossil methane from biogenic methane. Unlike BU measurements, TD measurements account for low frequency high emitter situations. TD studies consistently measure higher levels of methane emissions than do BU studies. Only recently have measurements TB and BU studies converged, and this convergence was only after additional low frequency high emission situations were characterized in BU studies.[5]

3. Methane Leak Calculations

The EPA divides methane emissions from natural gas systems into four categories: Field Production, Processing, Transmission and Storage, and Distribution. This analysis focuses on only the first three categories, leaving out local distribution networks. Detailed descriptions of these categories can be found in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks."

US Natural Gas Production 2005 - 2013

Expressed as BCF Natural Gas

Source	2005	2009	2010	2011	2012	2013
Withdrawals from Gas Wells	16,247	14,414	13,247	12,291	12,504	10,760
from Shale Shale Wells	0	3,958	5,817	8,501	10,533	11,933
Total Withdrawals from Natural Gas Systems	16,247	18,373	19,065	20,792	23,037	22,692

Emissions from US Natural Gas Systems 2005 - 2013

Expressed as % of Total Production

Stage	2005	2009	2010	2011	2012	2013
Field Production	0.91	0.66	0.58	0.48	0.42	0.41
Processing	0.20	0.20	0.18	0.20	0.19	0.20
Transmission and Storage	0.59	0.56	0.53	0.51	0.44	0.47
Total	1.70	1.43	1.30	1.19	1.05	1.07

Using the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks," methane emissions from natural gas infrastructure from the wellhead to a gas-fired power plant (excluding local distribution) are currently estimated to be 1.1% of production.[8] Given that EPA uses a BU method for calculating emissions, it is reasonable to assume that 1.1% is an underestimation. A 2015 study that combined seven different datasets from both TD and BU and included the most aerial measurements to date concluded that methane emissions were 1.9

(1.5 – 2.4) times the number reported in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks."[5] If the EPA's estimate is multiplied by 1.9 the result is 2.09%.

The IPCC Fifth Annual Report agrees, stating that: "Central emission estimates of recent analyses are 2% - 3% (+/– 1%) of the gas produced, where the emissions from conventional and unconventional gas are comparable." [9]

4. Global Warming Potential of Natural Gas

Global warming potentials (GWP) provide a method of comparing different GHGs. A GWP is: "a relative measure of how much heat a greenhouse gas traps in the atmosphere. It compares the amount of heat trapped by a certain mass of the gas in question to the amount of heat trapped by a similar mass of carbon dioxide." The Intergovernmental Panel on Climate Change (IPCC) regularly publishes updated GWPs based on the most current scientific knowledge. The most current value for methane (based on the 2013 IPCC AR5) is 34 for the 100-year GWP of methane.[9] The previous value (based on the 2007 IPCC AR4) is 25. Because methane's heat-trapping impacts are greatest in the first years after it enters the atmosphere, methane's 20-year GWP is about 85.[10]

5. Conclusion

This report recommends the use of a 2% emissions rate for methane leakage from natural gas systems when calculating the GHG emissions associated with natural gas-fired electric generation. Current analyses use 117 lbs of CO2 per MMBtu as the emissions factor from burning natural gas, which essentially assumes zero leakage. Adopting a 2% emission rate would increase this number to 190 lbs of CO2 per MMBtu of natural gas burned, assuming a 20-year GWP of 85.

6. Citations

[1] D. R. Caulton, P. B. Shepson, R. L. Santoro, J. P. Sparks, R. W. Howarth, A. R. Ingraffea, M. O. L. Cambaliza, C. Sweeney, A. Karion, K. J. Davis, B. H. Stirm, S. a Montzka, and B. R. Miller, "Toward a better understanding and quantification of methane emissions from shale gas development.," *Proc. Natl. Acad. Sci. U. S. A.*, vol. 111, no. 17, pp. 6237–42, 2014.

[2] R. A. Alvarez, S. W. Pacala, J. J. Winebrake, W. L. Chameides, and S. P. Hamburg, "Greater focus needed on methane leakage from natural gas infrastructure.," *Proc. Natl. Acad. Sci. U. S. A.*, vol. 109, no. 17, pp. 6435–40, 2012.

[3] J. Wilcox, a M. Gopstein, D. Arent, S. Wofsy, N. J. Brown, R. Bradley, and G. D. Stucky, "Methane Leaks from North American Natural Gas Systems," *Science (80-.).*, vol. 343, no. 6172, pp. 733–735, 2014.

[4] D. R. Lyon, D. Zavala-Araiza, R. A. Alvarez, R. Harriss, V. Palacios, X. Lan, R. Talbot, T. Lavoie, P. Shepson, T. I. Yacovitch, S. C. Herndon, A. J. Marchese, D. Zimmerle, A. L. Robinson, and S. P. Hamburg, "Constructing a Spatially Resolved Methane Emission Inventory for the Barnett Shale Region," *Environ. Sci. Technol.*, vol. 49, no. 13, pp. 8147–8157, 2015.

[5] D. Zavala-Araiza, D. R. Lyon, R. A. Alvarez, K. J. Davis, R. Harriss, S. C. Herndon, A. Karion, E. A. Kort, B. K. Lamb, X. Lan, A. J. Marchese, S. W. Pacala, A. L. Robinson, P. B. Shepson, C. Sweeney, R. Talbot, A. Townsend-Small, T. I. Yacovitch, D. J. Zimmerle, and S. P. Hamburg,

"Reconciling divergent estimates of oil and gas methane emissions," *Proc. Natl. Acad. Sci.*, vol. 112, no. 51, pp. 15597–15602, 2015.

[6] A. L. Mitchell, D. S. Tkacik, J. R. Roscioli, S. C. Herndon, T. I. Yacovitch, D. M. Martinez, T. L. Vaughn, L. L. Williams, M. R. Sullivan, C. Floerchinger, M. Omara, R. Subramanian, D. Zimmerle, A. J. Marchese, and A. L. Robinson, "Measurements of Methane Emissions from Natural Gas Gathering Facilities and Processing Plants: Measurement Results," *Environ. Sci. Technol.*, vol. 49, no. 5, pp. 3219–3227, Mar. 2015.

[7] R. Subramanian, L. L. Williams, T. L. Vaughn, D. Zimmerle, J. R. Roscioli, S. C. Herndon, T. I. Yacovitch, C. Floerchinger, D. S. Tkacik, A. L. Mitchell, M. R. Sullivan, T. R. Dallmann, and A. L. Robinson, "Methane Emissions from Natural Gas Compressor Stations in the Transmission and Storage Sector: Measurements and Comparisons with the EPA Greenhouse Gas Reporting Program Protocol," *Environ. Sci. Technol.*, vol. 49, no. 5, pp. 3252–3261, Mar. 2015.

[8] EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2013," *US Environ. Prot. Agency*, pp. ES1–ES26, 2014.

[9] IPCC, "IPCC Fifth Assessment Report (AR5)," *IPCC*, 2013.

[10] EPA, "Understanding Global Warming Potentials," *EPA Website*, 2016. [Online]. Available: http://www3.epa.gov/climatechange/ghgemissions/gwps.html.