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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION TO COMPLETE THE STUDY REVIEW PHASE OF THE COMPREHENSIVE STUDY OF COSTS AND BENEFITS OF ON-SITE GENERATION & FOR AUTHORITY TO IMPLEMENT CHANGES TO SCHEDULES 6, 8, AND 24	**CASE NO. IPC-E-22-22** **IDAHO CONSERVATION LEAGUE** **INITIAL COMMENT**

Introduction

The Idaho Conservation League ("ICL") submits to the Idaho Public Utilities Commission ("Commission") the following initial comments regarding Idaho Power Company's ("IPC" or "Company") Value of Distributed Energy Resources Study ("VODER study" or "study"). ICL supports the development of distributed solar generation and other distributed energy resources ("DER") as key components of a reliable, cost effective, and carbon neutral energy portfolio. ICL appreciates the Company's clarity and detailed explanations in the VODER study and respects its continued commitment to industry, customer, and community involvement. Its engagement is welcome, and critical to resolve complex policy and technical issues in the public interest. Nonetheless, ICL is concerned that the VODER study undervalues distributed generation to a degree that will inhibit development and contribute to an adverse economic and regulatory environment in future policy decisions.

ICL co-commissioned Crossborder Energy[1] to review IPC's VODER study. The resulting critique ("Crossborder review" or "critique", included with comment as "ATTACHMENT A") assesses IPC's VODER study using data from IPC's integrated resource plan ("IRP"), discovery productions, and publicly available data. The Crossborder review concludes that IPC's choice of assumptions and methodologies undervalue distributed resources and corresponding export credit rate ("ECR"). Additionally, the critique identifies benefits and costs that are quantifiable and measurable, and avoided costs that effect rates that IPC was required to study[2] but were either omitted, diminished, or defined outside its scope of review. On both the listed price components and other identifiable costs and benefits, the VODER study substantially undervalues distributed energy resources.

Just as Order No. 35284 directed IPC to assess five components of the value of solar resources[3], the Crossborder review applied the same data sets or reasonable, necessary alternatives to industry recognized methods and assumptions for each component. The resulting ECR recommendations are more favorable to DERs and consistent with industry standards and regional prices. Crossborder demonstrates that differing analytic choices by reasonable, competent industry professionals produce widely varying figures, and that IPC's choices in the VODER study consistently devalued its distributed energy ECR.

This comment focuses on the VODER study's ECR estimates and other identifiable costs and benefits. Methodological critiques and alternative ECR estimates presented by the

[1] Crossborder Energy is an energy consulting firm. Thomas Beach is its principal and prepared the commissioned review (CV included with comment as "ATTACHMENT B").
[2] Order No. 35284 at 27 Case No. IPC-E-21-21.
[3] *Id.* at 14.

Crossborder review are introduced for each of the five components of the ECR: a) avoided energy costs; b) avoided generation capacity; c) transmission and distribution ("T&D") deferral; d) line losses; and e) integration costs. Fuel hedging benefits and avoided costs of carbon emissions are introduced as quantifiable components of the value of DERs that affect rates. Other environmental and external costs identified in the Crossborder review are separately discussed.

ICL's initial comment and the attached Crossborder review highlight the importance of selecting an appropriate set of assumptions and methodologies in assessing energy value. Accordingly, ICL asserts that the VODER study underestimates the value of solar generation by relying on dated data, unfavorable assumptions, and methodologies that selectively disfavor distributed energy resources.

Discussion

1. Idaho Power Company's VODER study consistently applies assumptions and methodologies that minimize the estimated Export Credit Rate.

ICL disputes the VODER study's estimated ECR. While IPC's analysis generally complies with the Commission's direction to study individual components of ECR, it consistently does so with assumptions and methodologies that minimize the estimated value of solar generation. ICL does not claim the Company's analysis is facially wrong. However, we are concerned that the study repeatedly exercises discretion in its calculations that favor the Company's programmatic and business aims at the expense of distributed generation development.

ICL previously raised concerns about the objectivity and incentives of an internal study when establishing the project framework.[4] Others parties also requested third-party study preparation or review.[5] While the Commission balanced the needs for a cost-effective and system-specific study, the study order recognizes the "argument that third-party evaluators have a different perspective and the results may be believed to be more credible by some customers."[6] Along with the study and its conclusions, the Commission directed the Company to provide sufficient data "so others have insight as to how the results were derived."[7] ICL commissioned Crossborder Energy to provide such insights into the VODER study's ECR. Discrepancies between IPC's analysis and the Crossborder critique represent good faith disagreement between qualified professionals. We offer the following comments on the five required components of ECR to illustrate the importance of methodological objectivity and to afford parties the benefit of expert review.

a. Disruption to fossil fuel markets makes the study's inputs and estimates of avoided costs outdated and insufficient to meaningfully inform the Commission.

The VODER study estimates avoided energy costs with dated price assumptions made irrelevant by disruption to energy markets caused by the Russian invasion of Ukraine. The Commission directed IPC to base avoided cost calculations and on best available information, including current energy price assumptions, the most recent IPR inputs, and market price index assumptions.[8] While the VODER study applies these inputs, modeling used in the 2021 IPR process and indexes based on past market performance do not account for considerable increases

[4] ICL Reply Comments at 4, IPC-E-21-21. Again, ICL does not impute the competency or professionalism of IPC. The Company continues to exemplify transparency, cooperation, and communication amongst interested parties.
[5] Order No. 35284 at 10-11. ICEA and Kluckhohn requested a third-party study. ISON requested third-party review. Staff noted environmental and other benefits were reviewable by third-party.
[6] *Id.* at 11.
[7] *Id.*
[8] *Id.* at 16-17.

in energy prices and volatility in the spring and summer of 2022. Without accounting for this lasting shift in energy markets, the VODER study fails to present an accurate or meaningful estimate of avoided energy costs.

Crossborder Energy recalculated avoided energy costs using data and energy price forecasts that reflect post Ukrainian invasion energy markets.[9] The review was completed in late August of 2022 and uses Energy Imbalance Market ("EIM") prices for the full year ending July 31, 2022 to better represent current market conditions. With updated data and forecasts, Crossborder estimates the avoided energy costs of distributed generation at $47.30 per MWh, well above IPC's estimates based on the 2021 IRP forecast, ICE Mid-C, or ELAP prices.[10] The VODER study relies on older data sets for its IRP market forecast that do not account for recent disruptions and a three-year rolling averages of historic ELAP and ICE Mid-C prices estimate avoided costs.[11] While longer period averages are useful to mitigate short-term variability, they sacrifice sensitivity to lasting paradigm shifts as occurred this year. IPC must update its methodologies and data inputs with sensitivity to shifting energy markets to meaningfully inform the Commission and the public of avoided energy costs.

b. The study's avoided cost of generation capacity analysis assumes marginal capacity will be filled by gas facilities that are not planed and inconsistent with the 2021 IRP.

Estimates of avoided costs of generation capacity in the study rely on unsupported and unplanned substitution of DERs with thermal generation and needlessly complex methodology that produces volatile results. The VODER study introduces gas-fired turbines as the modeled replacement resource for DERs.[12] This is done without explanation, analysis, or context. Gas-

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[9] Crossborder review at 2.
[10] VODER Study at 41.
[11] *Id.* at 36-38.
[12] *Id.* at 50, Table 4.4.

fired turbine generation is not planned for[13], inconsistent with the 2021 IRP, and contrary to the Company's commitment to carbon neutrality by 2045. Instead, the Company's 2021 IRP identifies battery storage as its preferred dispatchable marginal resource. An appropriate study should incorporate either planned, or most likely suitable alternatives to DERs that provide equivalent capacity to DERs.

Additionally, the Crossborder review disputes the usefulness of IPC's preferred methodology for calculating avoided generation capacity. The effective load carrying capacity ("ELCC") figure used in the VODER study is substantially lower than the ELCC of existing solar resources and recent projects. The study's ELCC also does not reflect solar development in Idaho, and is more consistently a higher solar penetration, higher peak energy system. Finally, the VODER study's annual ELCC figures show significant year-to-year variability in capacity contribution attributable to the method's complexity and volatility. Crossborder Energy offers the much simpler peak capacity allocation factor ("PCAF") calculation as an alternative method to cure these defects.[14] Crossborder's capacity contribution figure is 27.0% to the VODER study's 7.6%.[15] The PCAF method is recommended as simpler, more stable, and more transparent than the ELCC approach.

The Crossborder review substitutes IPC's assumed marginal resource of thermal generation with battery storage and applies the PCAF method for capacity contribution to arrive at a cost of avoided generation of $35.00 per MWh.[16] Again, different methodologies and

[13] The conversion of Bridger Units 1 & 2 from coal to gas replaces existing capacity and does not add to marginal dispatchability.
[14] Crossborder review at 4
[15] *Id.*; VODER Study at 51.
[16] Crossborder review at 4. Calculation presented in Table 1.

assumptions account for the discrepancy between values in the critique and those offered by IPC in the VODER study.

c. **The study minimizes transmissions and distribution deferral by using a bottom up method where a system wide approach is more reliable.**

The VODER study finds very low avoided T&D costs by assuming an average distributed generation system across all instances, thereby failing to capture the greatest avoided need for additional T&D resources. The VODER study spreads distributed generation evenly across its whole system. This flattens peak system loads avoided by DERs across wide service areas, obscuring needed T&D investments for the most stressed areas of the system.[17] Additionally, the study fails to consider other distributed energy technologies beyond generation that reduce long-term system demand.[18]

Regression models can account for marginal T&D costs and the value of infrastructure avoided by reducing peak loads. The NERA regression model used by Crossborder fits incremental T&D investments to historic peak load growth, allowing projection of future costs and those avoided by peak load reduction.[19] Regression analysis benefits from reliance on historic system data; real increases in peak load are matched to real increases in T&D costs. Using peak load contributions estimated with the previously discussed PCAF analysis, the Crossborder review calculates IPC's T&D costs deferred by DER development at $49.00 per MWh.[20]

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[17] Crossborder review at 5.
[18] *Id.*
[19] *Id.*
[20] *Id.*

d. Avoided line loss estimates fail to account for top marginal increases in load and rely on a decade old study that does not anticipate projected growth.

The VODER study does not apply a marginal analysis appropriate to DER development in estimating avoided line losses. Resistance and line loss are exponential functions of load, making marginal analysis at peak demand critical to accurate modeling. Again, IPC applies system-wide average losses where behind the meter demand reduction by DERs reduce loads on localized connections.[21] Moreover, IPC average system loads come from a decade-old lineloss study that fails to account for rapid projected growth across the Company's system.[22] Resistive losses are likely much higher, and behind-the-meter marginal demand reduction can more accurately model avoided line losses.[23] Crossborder conservatively estimates the value of avoided line losses at $9.50 per MWh.

e. The VODER study's estimate of integration costs does not account the resource mix or battery storage planned for by the Company.

IPC's integration costs for DERs again relies on a dated study that does not reflect current Company planning. Integration costs for distributed solar resources in the VODER study come from a 2020 study completed before the most recent 2021 IRP.[24] The IRP,[25] and current Company requests before the Commission,[26] plan for significant growth and installment of dispatchable battery resources. Dispatchable battery storage reduces system variability and balancing needs, lowering integration costs of variable resources such as distributed solar. The

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[21] VODER Study at 59.
[22] *Id.*
[23] Crossborder review at 8.
[24] VODER Study at 63.
[25] 2021 IRP at 4, Table 1.1
[26] Case No. IPC-E-22-13. Application for Public Convenience, at 6.

Company's plans mostly reflect a use case in its integration study that assesses DER integration costs of $0.64 per MWh.[27] The Crossborder review agrees with this result.

2. The Commission directed IPC to analyze avoided fuel price risks that meaningfully contribute to the value of distributed energy resources.

While the five components of the ECR account for much of the value solar exports, fuel hedging benefits directly impact rates and should be fully considered as a component value of DERs. The Commission directed IPC to study avoided risks of fuel price volatility with the "expectation that the ECR be updated regularly to mitigate risks."[28] The VODER study fails to fully assess fuel hedging benefits. The only mention of fuel hedging in the VODER study comes in two discussions of pricing methodology.[29] IPC notes with no elaboration that ELAP and ICE Mid-C market prices capture some fuel hedging value. The discussion here is cursory, does not explain interactions between fuel pricing and DERs, and is inadequate to address the Commission's direction or parties' comments to the study framework. The VODER study is incomplete without substantive discussion of fuel hedging benefits from DER development.

Distributed solar resources have measurable fuel hedging value. This value is realized when renewable resources offset generation by price-volatile resources, primarily gas and coal, but also annually variable resources such as hydro generation. Benefits also accrue during market disruptions or times of grid-wide low generation. While an ECR tied to the price of alternative fuels captures some of this value, it is important to note that that energy generated by DERs used behind the meter also reduces reliance on variable price resources.

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[27] Crossborder review at 8.
[28] Order No. 35284 at 22.
[29] VODER study at 38, 39.

The Crossborder review calculates benefits from fuel hedging. The methodology used estimates the cost of fixing fuel prices at 25 years, a time span that matches the expected life of distributed solar systems.[30] This timespan more closely models the benefits of typical DERs than the 18-month forecast and contract period used by IPC to secure fuel prices. Accounting for the fraction of benefits already incorporated into an ECR tied to fuel prices, Crossborder offers a fuel hedging value of $7.70 per MWh.

3. Eliminated carbon emissions affect rates and should be considered in the value of distributed generation.

Carbon emissions and their effect on climate warming have definitive impact on economic activities and energy rates and must be considered in the value of all energy resources. The Commission ordered the VODER study to "include an evaluation of all benefits and costs that are quantifiable, measurable, and avoided costs that affect rates."[31] Elsewhere, the Commission notes that its legislative mandate is to conduct economic analysis to determine rates, and that it would exceed its authority to monetize many environmental attributes.[32] ICL takes notice of the Commission's mandate and its limitations. Still, the commission observes, "there are many environmental considerations that are quantifiable and will be included in an ultimate determination of fair, just and reasonable terms."[33] Carbon emissions and the economic impacts of climate change are such considerations.

The economic costs of carbon emissions are manifest and knowable. The Company recognizes this, and its commitment to carbon neutrality by 2045 is a critical step towards

[30] Crossborder review at 11, *see* Maine Public Utilities Commission, *Maine Distributed Solar Valuation Study* (March 1, 2015).
[31] Order No. 35284 at 27.
[32] *Id.* at 12.
[33] *Id.*

environmental and economic security.[34] Still, pricing carbon emissions is difficult and contentious. Crossborder offers a valuation using the Environmental Protection Agency's AVERT[35] tool for avoided emissions and the 2021 IPR's planning case to arrive at an avoided cost of carbon of $19.20 MWh. Under any reasonable methodology the cost of avoided carbon is non-zero. The commission directed IPC to analyze all measurable considerations that effect rates. If this direction is to be meaningful, the cost of carbon must be included. ICL urges the Company to revise the VODER study, and offer an assessment of avoided costs of carbon emissions.

4. The VODER Study's assessment of avoided environmental costs is deficient because costs are known, measurable, and effect rates.

Multiple known and measurable environmental and societal benefits that are reasonably considered in the public interest determination of fair, just and reasonable rates are not considered in the VODER study. Specifically, the social cost of carbon emissions, health benefits of reduced air pollution, land use costs, local economic benefits, reliability and resiliency, and customer choice are all quantifiable, yet not offered or analyzed. ICL urges the Commission to include these quantifiable factors in its public interest analysis of what constitutes a fair, just and reasonable rate.

a. Social cost of carbon

The social cost of carbon is the measure of the seriousness of climate change.[36] It is quantified by subtracting the planning and procurement costs of new, clean power generation

[34] 2021 IRP at 27.

[35] ENVIRONMENTAL PROTECTION AGENCY, *Avoided Emissions and Generation Tool*. Available at https://www.epa.gov/avert.

[36] Crossborder review at 14, *referencing* 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.

from the costs of carbon pollution imposed on society.[37] IPC's 2021 IRP applies a commonly used, yet outdated, calculation for valuing the social cost of carbon,[38] resulting in a $52/ton value.[39] A more recent estimate finds the social cost of carbon to be $417/ton, far higher than the outdated estimate.[40] Even still, Crossborder used IPC's values and calculated a 25-year levelized difference for the societal benefit of reducing carbon emissions of $30.40 per MWh.[41] The VODER study should include the social cost of carbon in its cost and benefit analysis.

b. Human health criteria

At a base level, increased renewable energy leads to fewer carbon emissions which leads to improved human health. Unfortunately, much of IPC's territory falls into one of several state and federally designated Priority Areas where air quality is of particular concern.[42] However, a quantifiable health benefit of the increased DERs at issue here is reduced carbon emissions. The AVERT model discussed above is instructive in quantifying this health benefit. Crossborder used the AVERT tool to analyze the avoided emissions of SO_2, NO_x and PM 2.5, primary air pollutants contributing to human health problems.[43] Its analysis finds a societal benefit of avoided SO_2 emissions at $7.40 per MWh, avoided NO_x emissions at $2.70 per MWh, and avoided PM 2.5 emissions at $2.60 per MWh, all on a 25-year levelized basis. These quantifiable benefits are integral and should be factored into the VODER rate analysis.

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[37] *Id.*

[38] Crossborder review at 14, *citing* the Interagency Working Group on Social Cost of Carbon, *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (May 2013, revised July 2015) https://www.epa.gov/sites/default/files/2016-12/documents/sc_co2_tsd_august_2016.pdf. Last checked on September 21, 2022.

[39] *Id.* at 14.

[40] *Id. citing* 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. Last checked September 21, 2022.

[41] *Id.* at 15.

[42] *See* Priority Areas at https://www.deq.idaho.gov/air-quality/improving-air-quality/priority-areas/. Last checked September 21, 2022.

[43] Crossborder review at 16 *citing* Regulatory Impact Analysis for the Final Clean Power Plan. Available at https://www3.epa.gov/ttn/ecas/docs/ria/utilities_ria_final-clean-power-plan-existing-units_2015-08.pdf. Last checked on September 21, 2022.

c. Local economic benefits

Numerous studies have found local economic benefits when solar DERs are installed in communities. This is because DERs involve costs spent locally on installation and maintenance labor, permitting and affiliated permitting fees, and marketing to customers.[44] Idaho's National Renewable Energy Laboratory and the Lawrence Berkeley National Laboratory found that up to 22% of the money spent by customers and installers in establishing DERs is spent in the local communities in which the DERs are built.[45] The VODER study should analyze and value this local economic benefit.

d. Reliability and resiliency

Societal benefits flow from the reliability and resiliency built into renewable distributed energy systems. Since they are comprised of hundreds, or thousands, of small, widely distributed systems, they are unlikely to experience widespread weather induced or other transmission outages at the same time, making them a reliable source of power for customers while also alleviating pressure on IPC to meet widespread customer need during outages. This quantifiable benefit is not valued in the VODER study.

e. Customer choice

Personal autonomy and self-reliance are quintessential Idaho values, and they are relevant here in the form of customer choice. Distributed energy projects allow customers to actively invest in and participate in their energy choices, bringing monetary value to their residential and commercial properties as well as allowing partial self-reliance. Additionally, IPC needs

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[44] Crossborder review at 17-18.
[45] *Id.*.

increased usage of DG systems to meet its 100% Clean Energy by 2045 commitment. See further discussion of this point in Crossborder's review.[46]

In sum, human health, personal autonomy, local economies, transmission reliability and resiliency, and the social cost of carbon are all quantifiable and should be included in the Commission's ultimate determination of what constitutes fair, just and reasonable terms for the Company's on-site generation program.

Conclusion

ICL offers these comments as a starting point to discuss the importance of methodologic objectivity and analytic perspective. The attached Crossborder review illustrates the impact of professional judgment and discretion. Although ICL contests the Company's findings in the VODER study, comments are offered in hopes of arriving at a maximally beneficial result. Parties represent a variety of particular and public interests; each considers an appropriate value of distributed energy resources critical to economic and energy development in the State. ICL requests the Commission, the Company, and parties take these comments and the attached study into advisement.

DATED: September 21, 2022

/s/ Marie Callaway Kellner

Marie Callaway Kellner
Attorney for Idaho Conservation League

[46] Crossborder review at 19-21.

CERTIFICATE OF SERVICE

I hereby certify that on this 21st day of September, 2022, I delivered true and correct copies of the foregoing INITIAL COMMENT and attachments to the following persons via the method of service noted:

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Crossborder Energy

Comprehensive Consulting for the North American Energy Industry

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

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September 20, 2021

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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 total 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

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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.

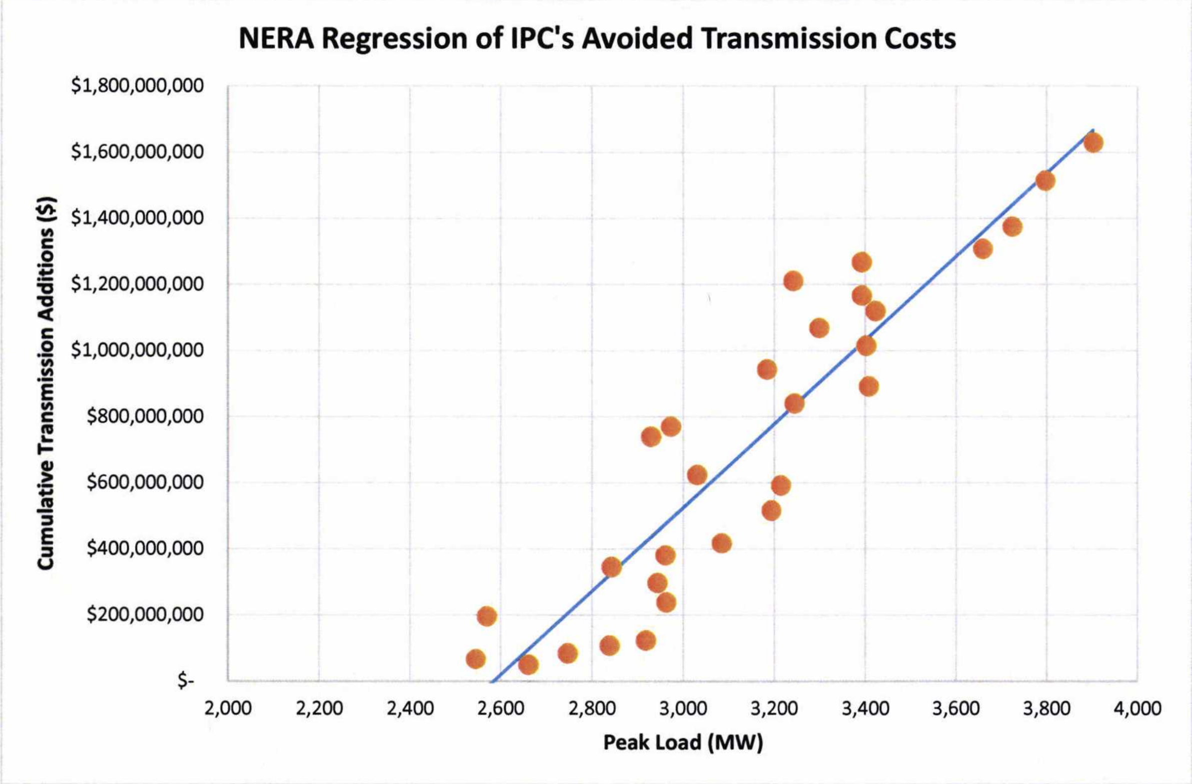
The problem with the utility's approach can be seen by considering a single 7 kW residential solar system. The utility's analysis would conclude that such a system, by itself, will never avoid any T&D costs, even though it will lower loads on the grid. IPC's analysis shows that even the existing 65 MW 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

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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.

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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.

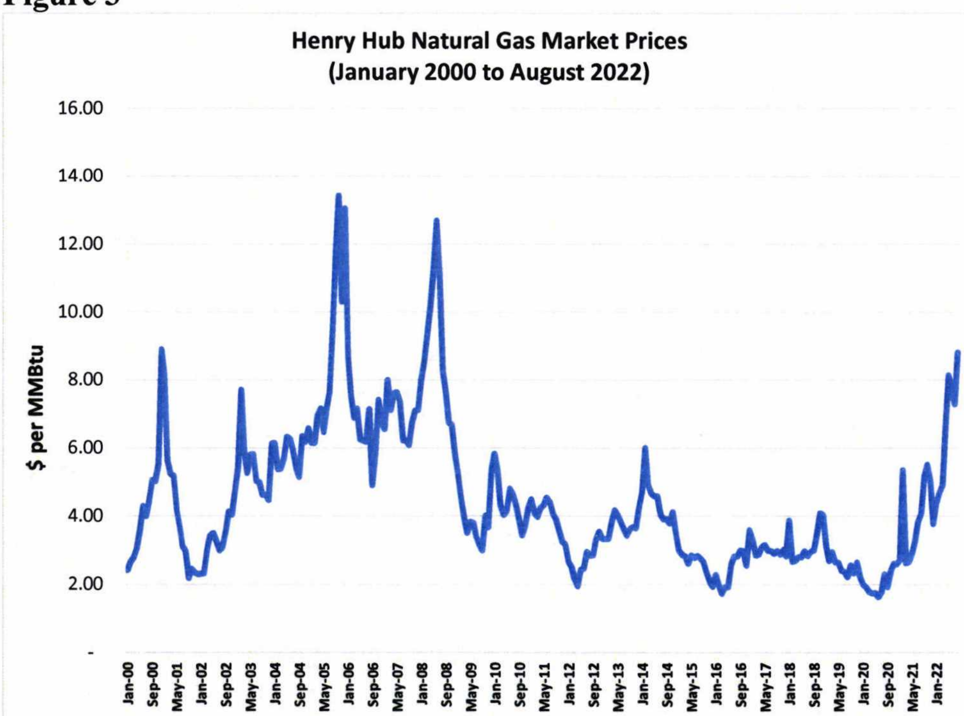
B. Benefits of Distributed Solar Not Discussed or Quantified in the VODER Study

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."

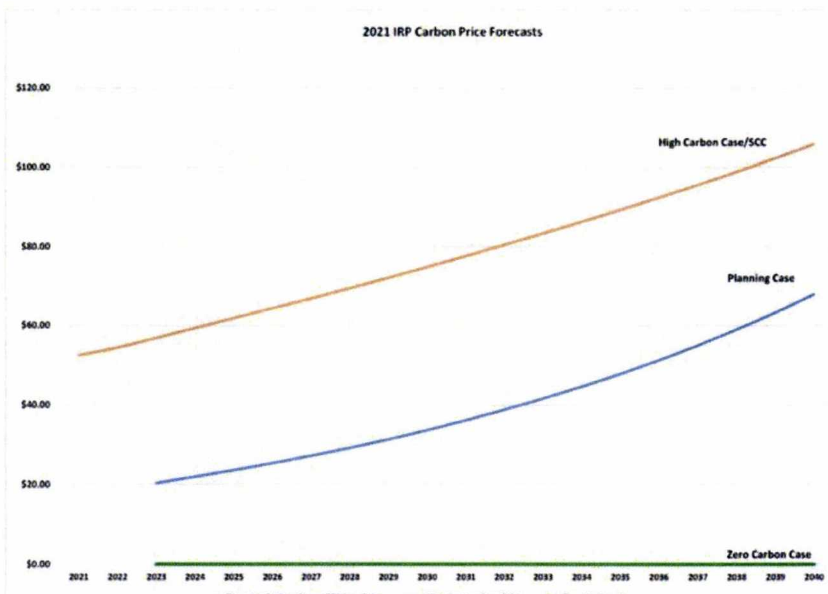
83% of the reduction in hydroelectric output due to the multi-year drought in that state. Based on Energy Information Administration data for 2014, as reported in Stephen Lacey, *As California Loses Hydro Resources to Drought, Large-Scale Solar Fills in the Gap: New solar generation made up for four-fifths 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

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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.

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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,

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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

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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.

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Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

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1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

    - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

    - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

    - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

    - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

    - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar thermal power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar thermal power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

    - *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

    - *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

    - *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

    - *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

    - *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

    - *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

    - *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

    - *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

    - *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

    - *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

    - *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

63. a. Phase II Direct Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

    - *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

67. Prepared Rebuttal Testimony on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

    - *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

78. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

79. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
    b. Prepared Direct Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
    c. Prepared Rebuttal Testimony on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
    d. Prepared Rebuttal Testimony on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

    - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)

    - *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

83. a. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
    b. Prepared Rebuttal Testimony on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

    - *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony on behalf of the **Joint Solar Parties** (R. 14-07-002 — September 30, 2015)

    - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

85. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 15-04-012—July 5, 2016)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

86. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 16-09-003 — April 28, 2017)

- *Selection of Time-of-Use periods, and rate design issues for solar customers.*

87. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 17-06-030 — March 23, 2018)

- *Selection of Time-of-Use periods, and rate design issues for solar customers.*

88. Prepared Direct and Rebuttal Testimony on behalf of **Calpine Corporation** (A. 17-11-009 – July 20 and August 20, 2018)

- *Gas transportation rates for electric generators, gas storage and balancing issues*

89. Prepared Direct Testimony on behalf of **Gas Transmission Northwest LLC** and the **City of Palo Alto** (A. 17-11-009 – July 20, 2018)

- *Rate design for intrastate backbone gas transportation rates*

90. Prepared Direct Testimony on behalf of **EVgo** (A. 18-11-003 – April 5, 2019)

- *Electric rate design for commercial electric vehicle charging*

91. Prepared Direct and Rebuttal Testimony on behalf of **Vote Solar** and the **Solar Energy Industries Association** (R. 14-10-003 — October 7 and 21, 2019)

- *Avoided cost issues for distributed energy resources*

92. Prepared Direct and Rebuttal Testimony on behalf of **EVgo** (A. 19-07-006 – January 13 and February 20, 2020)

- *Electric rate design for commercial electric vehicle charging*

93. Prepared Direct Testimony on behalf of the **Solar Energy Industries Association** (A. 19-03-002 — March 17, 2020)

- *Electric rate design issues for solar and storage customers*

EXPERT WITNESS TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION

1. Prepared Direct, Rebuttal, and Supplemental Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. E-00000J-14-0023, February 27, April 7, and June 22, 2016).

    - *Development of a benefit-cost methodology for distributed, net metered solar resources in Arizona.*

2. Prepared Surrebuttal and Responsive Testimony on behalf of the **Energy Freedom Coalition of America** (Docket No. E-01933A-15-0239 – March 10 and September 15, 2016).

    - *Critique of a utility-owned solar program; comments on a fixed rate credit to replace net energy metering.*

3. Direct Testimony on behalf of the **Solar Energy Industries Association** (Docket No. E-01345A-16-0036, February 3, 2017).

4. Direct and Surrebuttal Testimony on behalf of **The Alliance for Solar Choice and the Energy Freedom Coalition of America** (Docket Nos. E-01933A-15-0239 (TEP), E-01933A-15-0322 (TEP), and E-04204A-15-0142 (UNSE) – May 17 and September 29, 2017).

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits on behalf of the **Colorado Solar Energy Industries Association** and the **Solar Alliance**, (Docket No. 09AL-299E – October 2, 2009). https://www.dora.state.co.us/pls/efi/DDMS_Public.Display_Document?p_section=PUC&p_source=EFI_PRIVATE&p_doc_id=3470190&p_doc_key=0CD8F7FCDB673F1043928849D9D8CAB1&p_handle_not_found=Y

    - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits on behalf of the **Vote Solar Initiative** and the **Interstate Renewable Energy Council**, (Docket No. 11A-418E – September 21, 2011).

    - *Development of a community solar program for Xcel Energy.*

3. Answer Testimony and Exhibits, plus Opening Testimony on Settlement, on behalf of the **Solar Energy Industries Association**, (Docket No. 16AL-0048E [Phase II] – June 6 and September 2, 2016).

    - *Rate design issues related to residential customers and solar distributed generation in a Public Service of Colorado general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

1. Direct Testimony on behalf of **Georgia Interfaith Power & Light and Southface Energy Institute, Inc.** (Docket No. 40161 – May 3, 2016).

   - *Development of a cost-effectiveness methodology for solar resources in Georgia.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

   - *Costs and benefits of net energy metering in Idaho.*

2. a. Direct Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

2. a. Direct Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — December 22, 2017)
   b. Rebuttal Testimony on behalf of the **Sierra Club** (Case No. IPC-E-17-13 — January 26, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

1. Direct and Rebuttal Testimony on behalf of **Northeast Clean Energy Council, Inc.** (Docket D.P.U. 15-155, March 18 and April 28, 2016)

   - *Residential rate design and access fee proposals related to distributed generation in a National Grid general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

1. Prepared Direct Testimony on behalf of **Vote Solar** (Case No. U-18419—January 12, 2018)

2. Prepared Rebuttal Testimony on behalf of the **Environmental Law and Policy Center, the Ecology Center, the Solar energy Industries Association, Vote Solar, and the Union of Concerned Scientists** (Case No. U-18419 — February 2, 2018)

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony on Behalf of **Geronimo Energy, LLC**. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

   - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

1. Pre-filed Direct and Supplemental Testimony on Behalf of **Vote Solar and the Montana Environmental Information Center** (Docket No. D2016.5.39, October 14 and November 9, 2016).

   - *Avoided cost pricing issues for solar QFs in Montana.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

   - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

   - *QF pricing issues in Nevada.*

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

   - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

4. a. Prepared Direct Testimony on behalf of **The Alliance for Solar Choice (TASC),** (Docket Nos. 15-07041 and 15-07042 –October 27, 2015).
   b. Prepared Direct Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 1, 2016).

c. Prepared Rebuttal Testimony on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 5, 2016).

- *Net energy metering and rate design issues in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

1. Prepared Direct and Rebuttal Testimony on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. DE 16-576, October 24 and December 21, 2016).

   - *Net energy metering and rate design issues in New Hampshire.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)
   http://164.64.85.108/infodocs/2011/3/PRS20156810DOC.PDF

   - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

April 25, 2014: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=89f3b50f-17cb-4218-87bd-c743e1238bc1
May 30, 2014: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=19e0b58d-a7f6-4d0d-9f4a-08260e561443
June 20, 2104: http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=bd549755-d1b8-4c9b-b4a1-fc6e0bd2f9a2

2. Direct Testimony on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018; Docket E-100 Sub 158; June 21, 2019)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

3. Direct Testimony on Behalf of the **Oregon Solar Energy Industries Association** (UM 1910,01911, and 1912 — March 16, 2018).

   - *Resource value of solar resources in Oregon*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014)
   https://dms.psc.sc.gov/attachments/matter/B7BACF7A-155D-141F-236BC437749BEF85

   - *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF TEXAS

1. Direct Testimony on behalf of the **Solar Energy Industries Association** (SEIA) (Docket No. 44941 – December 11, 2015)

   - *Rate design issues concerning net metering and renewable distributed generation in an El Paso Electric general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

   - *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

Direct Testimony and Exhibits on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011) http://www.scc.virginia.gov/docketsearch/DOCS/2gx%2501!.PDF

- *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.