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IDAHO PUBLIC
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Before the

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO MODIFY ITS NET METERING SERVICE AND TO INCREASE THE GENERATION CAPACITY LIMIT	**Case No. IPC-E-12-27**

DIRECT TESTIMONY OF RICK GILLIAM

ON BEHALF OF

THE CITY OF BOISE

May 10, 2013

Direct Testimony of Rick Gilliam

The City of Boise

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Introduction and Overview

Q. Please state your name and business address.

A. My name is Rick Gilliam. My business address is 1120 Pearl Street, Suite 200, in Boulder, Colorado.

Q. On whose behalf are you submitting this pre-filed direct testimony?

A. This testimony is submitted on behalf of the City of Boise (the "City").

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

A. I serve as Director of Research and Analysis for the Vote Solar Initiative ("Vote Solar"), and oversee policy initiatives, development and implementation. Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence, and fight climate change by making solar a mainstream energy resource across the United States. Since 2002, Vote Solar has engaged in state, local and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. We have eighty (80) members in Idaho. Because our interests in this proceeding are in alignment with the City of Boise's interests, I was asked by the City to participate in this proceeding on its behalf.

Q. Please describe your educational background.

A. I have a Masters Degree in Environmental Policy and Management from the University of Denver, Denver, Colorado. I also have a Bachelor of Science Degree in Electrical Engineering from Rensselaer Polytechnic Institute in Troy, New York.

Q. Please describe your experience in utility regulatory matters.

A. Prior to joining Vote Solar in January of 2012, my regulatory experience included five (5) years in the Government Affairs group at Sun Edison, one of the world's largest solar developers, as a manager, director and eventually vice president; twelve (12) years in the Public Service Company of Colorado rate division as Director of Revenue Requirements; and twelve (12) years with Western Resource Advocates (WRA – formerly known as the Land and Water Fund of the Rockies) as Senior Policy Advisor. Prior to that, I spent six (6) years with the Federal Energy Regulatory Commission as a technical witness (engineer). All told, I have in excess of thirty (30) years of experience in utility regulatory matters. A summary of my background is attached as Appendix A.

Q. Have you previously testified before the Idaho Public Utilities Commission ("PUC" or "Commission")?

A. No, I have not.

Q. Before what other utility regulatory commissions have you testified?

A. I have testified in proceedings before the Arizona Corporation Commission, Public Utilities Commission of Colorado, Nevada Public Utilities Commission, the New Mexico Public Regulation Commission, the Utah Public Service Commission, the Wyoming Public Service Commission, and the Federal Energy Regulatory Commission.

Q. How did this proceeding come about?

A. According to Matthew T. Larkin, witness for Idaho Power Company ("IPCo" or the "Company"), the Company initiated this proceeding in response to the Commission's Final Order No. 29094, issued in 2002. *See* Direct Testimony of Matthew T. Larkin at p. 3, ll. 8-33. In Order No. 29094, the Commission stated:

> We accept for now the Company's proposed cap to Schedule 84, i.e., the 2.9 MW cumulative nameplate capacity limit. We apprise Idaho Power, however, that when the cap is reached, the Company is to immediately notify the Commission in writing that the Company is in the position of having to refuse further applications. At

> that point, this Commission will look at the cap again and determine whether it continues to be reasonable or if there is a better measure of what's appropriate or if there is a need for a cap at all.

Order No. 29094 at p. 7.

In response to this Order, the Company is proposing to double the current cap on all net-metered generation capacity for all of its customer classes, not just residential and small general service customers, from 2.9 MW to 5.8 MW, and proposing to make numerous other changes that impact net-metered customers.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the Direct Testimony and exhibits of IPCo witness, Matthew T. Larkin, regarding the Company's proposals to change certain practices, impose new untested policies, and initiate special treatments for a very small subset of residential and small general service ("SGS") customers. The changes outlined by IPCo create barriers to, and thwart deployment of, net-metered renewable generation, especially solar, and has significant impacts on the economic viability of these new resources. Further, I will discuss the ramifications of the IPCo proposals on economic development for the City.

Q. Please summarize your testimony.

A. The issues raised by IPCo underscore the success of the solar industry. One of the most interesting things about this proceeding is that it results from utility concerns related to what is occurring naturally in the market, namely customers are installing solar generation to supplement or replace their grid-supplied electricity without any incentives[1] from the state or utility. The actions and changes proposed by IPCo in this case are

[1] Idaho does provide a capped state income tax deduction for solar energy devices spread over four years.

individually and collectively designed to make customer-sited generation more difficult to install or more expensive to utilize, or both.

These actions by IPCo are in conflict with the policy and action recommendations of the recently adopted 2012 Idaho Energy Plan.[2] The following policies address resources:

> 1. The State of Idaho should enable robust development of a broad range of cost-effective energy efficiency and power generation resources within environmentally sound parameters.
>
> 2. Align legislative policies, regulatory policies, and state agency activity to consistently reinforce and support state objectives regarding energy efficiency, energy production, and delivery.
>
> 3. When acquiring resources, Idaho and Idaho utilities should give priority to cost-effective and prudent: (1) conservation, energy efficiency, and demand response; and (2) renewable resources, recognizing that these alone will not fulfill Idaho's growing energy requirements and that these resources play a role in addition to conventional resources in providing for Idaho's energy needs.
>
> 4. Encourage the development of customer-owned and community-owned renewable energy and combined heat and power facilities that meet the Energy Plan objectives of the State of Idaho.

Additionally, Action item E-11 encourages fair treatment of the resources at issue in this proceeding:

> It is Idaho policy to encourage investment in customer-owned generation; therefore the Idaho PUC, utilities, municipalities, and cooperatives are encouraged to ensure non-discriminatory policies for interconnection and net metering.

[2] This plan was approved by the Energy, Environment and Technology Interim Committee on January 10, 2012, and was formally adopted by the Idaho Legislature on March 6, 2012. The report is available at http://www.puc.state.id.us/hot/2012_idaho_energy_plan_final_2.pdf.

The proposed changes I will address include (1) the new capacity cap on net-metered generation; (2) the creation of new customer classes (Schedules 6 and 8); (3) the changes in rate structure under the new rate schedules; (4) the changes to the interconnection requirements in Schedule 72; and (5) the treatment of annual net excess generation credits.

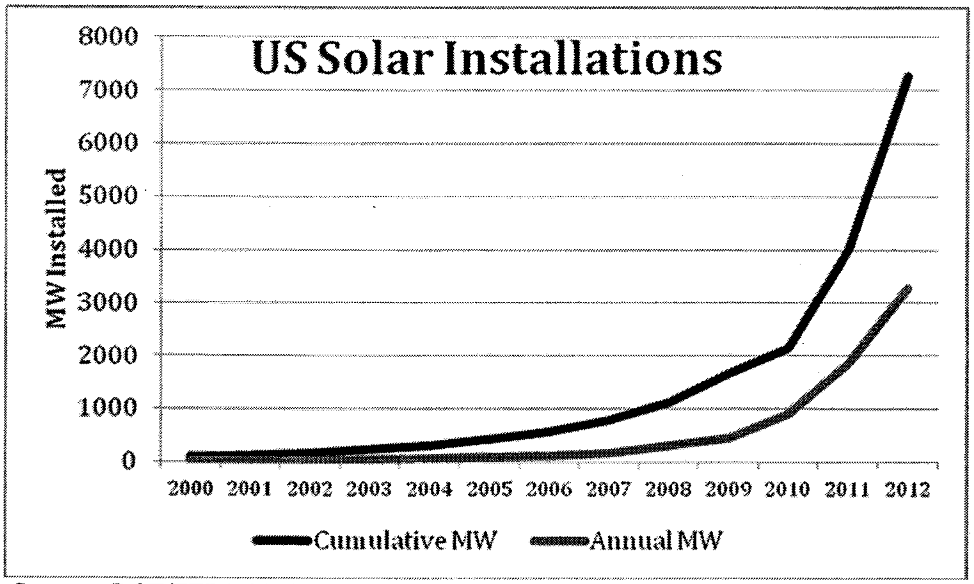
In each case, I generally find that IPCo has not provided sufficient evidence to justify the changes it proposes, has not taken other factors into account, and is attempting to impose significant changes on a small group of customers outside the context of a formal rate proceeding in which all rate-related issues can be addressed comprehensively by interested parties.

Additionally, I will address certain economic development effects of IPCo's filing.

Background

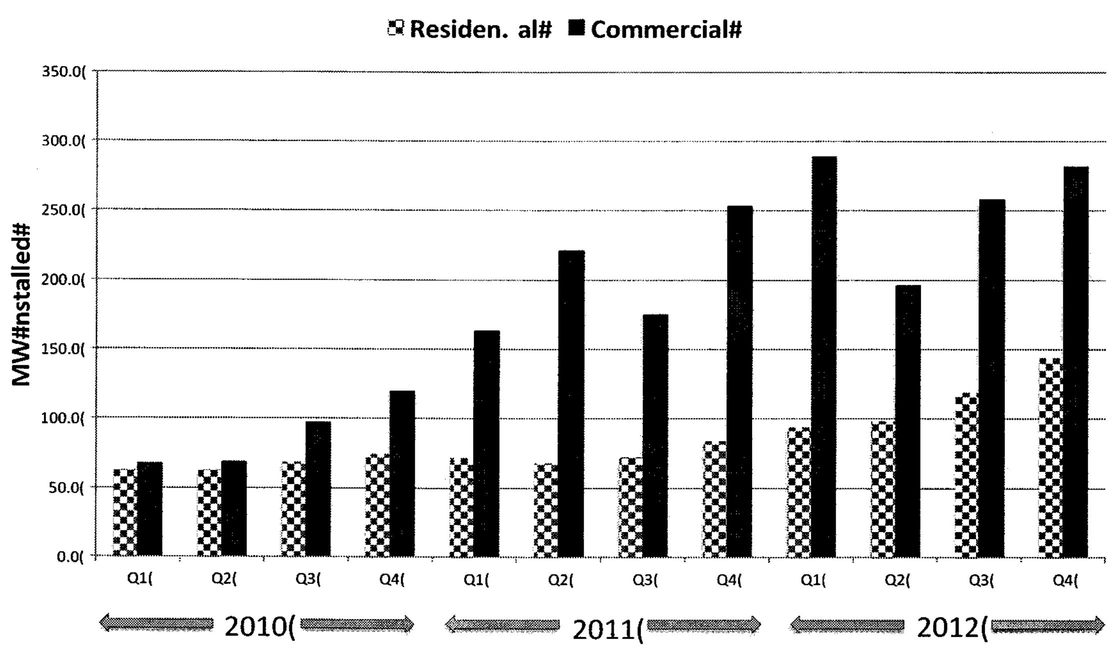
Q. The concerns raised by IPCo primarily deal with solar generation. Please discuss the growth in solar generation capacity nationally.

A. Across the country, solar generation capacity has been growing at a rapid rate — exceeding 75% per year for the last five (5) years.



Sources: DOE/EERE 2010 Renewable Energy Data Book and SEIA/GTM Research Solar Market Insight Reports.

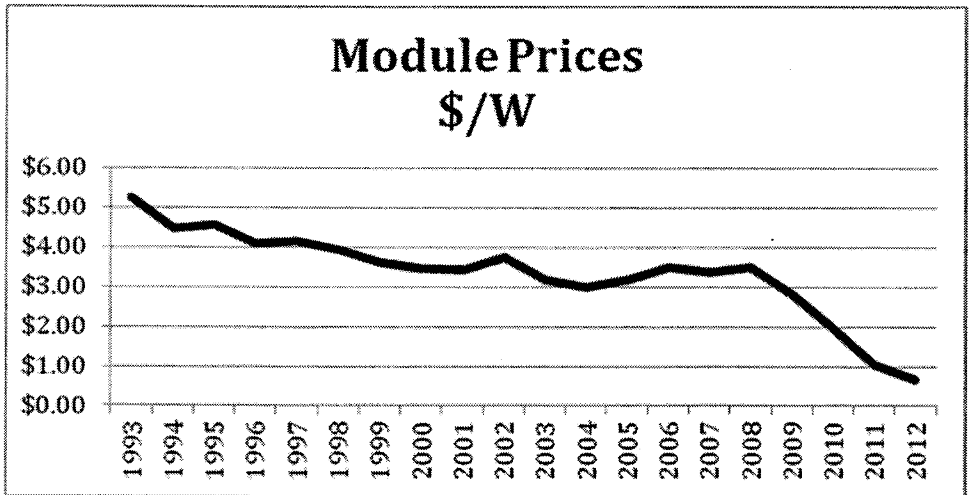
The growth has occurred across the spectrum of market segments — utility scale, commercial on-site, and residential on-site. As the latter two (2) categories are of particular interest in this proceeding, the following chart[3] shows the deployment by major retail market segment over the last few years across the United States.



[3] Source: SEIA/GTM Research, U.S. Solar Market Insight.

Q. To what do you attribute such dramatic growth of solar?

A. The growth is due in large part to increased global demand and the corresponding growth in manufacturing, increased scale economies and efficiencies, and driving hardware prices down. For example, the cost of solar modules has declined precipitously on a $\$/W_{DC}$ basis over the past twenty (20) years.



Sources: US Energy Information Administration through 2010, 2011-12 from GTM Research.

Bloomberg[4] reports an 80% decline since 2008 and a 99.2% decline in solar module costs since 1971.

Q. Why hasn't Idaho's solar market grown as dramatically?

A. As a result of these declining prices, the Idaho market is starting to grow, albeit getting off to a late start. While solar remains the most popular energy resource in virtually every poll, historically it has been more expensive than the alternatives, including grid-supplied electricity. Customer-sited solar penetration levels are largely tied to the purchaser's cost, net of any incentives provided. Most of the states that have higher penetration levels have used various types of financial incentives to promote the adoption of solar on homes and businesses.

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4 http://gigaom.com/2013/04/26/video-the-trends-behind-the-year-of-clean-energy-turbulence/

The incentives help to reduce the initial cost of solar (or the per kWh cost) so that the net cost of a solar kWh is "close enough" to that of grid-supplied electricity for the home or business owner that he or she can rationalize a reasonable payback period. These policies have "kick-started" the markets, and in many places, attracted significant development in value chain manufacturing, administrative offices and installation companies.

Recently, however, with the dramatic reduction in costs noted above, we are beginning to see solar prices approaching the cost of grid-supplied electricity without incentives in some states. As one would expect, this is happening in states with higher electricity costs initially. Interestingly, although Idahoans enjoy the lowest electricity prices in the nation in the residential and commercial sectors, solar has been establishing itself as a viable alternative resource for Idahoans. This can be seen in the chart on page 11 of IPCo witness Larkin's Direct Testimony.

While starting at a much lower level, growth in solar capacity on the IPCo system has been increasing at a good pace. Thus, Idaho is seeing the start of a healthy solar industry, albeit potentially fragile, given proposed size limitations, burdensome requirements and uncertainty regarding consistent solar policy.

Q. Is the solar resource in Idaho sufficient to support a growing solar market?

A. Yes. The National Renewable Energy Laboratory reports[5] Idaho is ranked eleventh (11th) in the country for its solar resource, placing it above states like Texas, North Carolina, New Jersey and others that have deployed far more solar generation.

[5] Denholm & Margolis, The Regional Per Capita Solar Electric Footprint for the United States, National Renewable Energy Laboratory Technical Report NREL/TP-670-42463, December 2007.

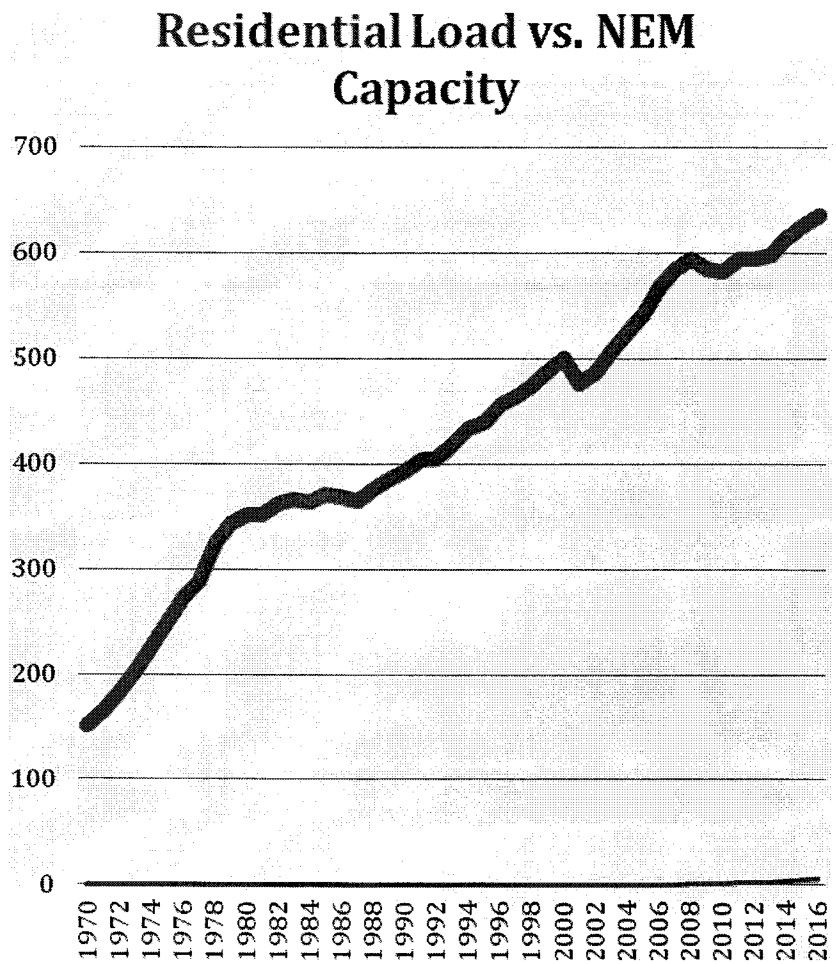
<u>The Overall Capacity Cap on Net-Metered Generation</u>

Q. Would you say the Company has high solar penetration on its system?

A. No. According to IPCo, it had 2.246 MW of net-metered system generation capacity from all of its customer classes installed on its grid at the time of its filing, representing approximately 1/14th of one percent of the Company's peak load. As a state, Idaho falls in the bottom quartile of solar deployment. The amount of 2012 energy generation offset by IPCo's systems was approximately 1/50th of one percent. At the current cap of 2.9 MW, those proportions rise to 1/11th of one percent of IPCo's peak load and about 1/40th of one percent of the Company's sales.

If IPCo's proposed cap of 5.8 MW is reached in three (3) years, the corresponding shares will be a little less than 1/6th of one percent of peak load and 1/20th of one percent of generation. In other words, the existing solar and the amounts related to the current and IPCo's proposed capacity limits on the IPCo system are all almost too small to be measured. The following chart[6] illustrates this point.

[6] Sources: Idaho Power Company 2011 IRP, and response to discovery. Note last three years estimated to grow at 1 MW per year.


Residential Load vs. NEM Capacity
700
600
500
400
300
200
100
0
1970
1972
1974
1976
1978
1980
1982
1984
1986
1988
1990
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2012
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1

Q. How does IPCo support the need for a cap?

A. While acknowledging that the current penetration is relatively small, IPCo bases its proposed new limit on the following:

> If current growth trends continue or increase, it is important to maintain a capacity limit to allow the Company and other stakeholders to evaluate this service as it expands. This provides the Company with the ability to identify any future modifications that may be necessary to accommodate more widespread expansion of its net-metering service.

Larkin Direct at p. 13, ll. 9-15.

Q. Do you believe there is a need for a system-wide cap on customer-sited solar generation?

A. No. While I can understand from the utility's perspective that the recent growth in net-metered solar generation capacity may be surprising, it is critical to keep the penetration of this resource in perspective.

Q. Can you provide some perspective on the reduced sales and load for IPCo?

A. Yes. IPCo's 2011 Integrated Resource Plan projected growth of 1.4% per year, or about an additional 650 GWh over the next three (3) years. If solar generation continues growing at the highest level it has over the last few years (~1MW/year), IPCo's proposed 5.8 MW cap would be reached in three (3) years and produce about 8 GWh. Thus, that 650 GWh of projected sales <u>growth</u> would be about 642 GWh, or about 98.8% of the originally projected growth.

Q. Has IPCo performed any analyses of the future growth of net-metered solar?

A. No it hasn't.[7]

Q. Has IPCo performed any economic analyses of solar generation that takes into account costs that are avoided by customer-sited generation?

A. No, the Company has made no attempt to quantify the value of generation provided by net-metered systems.[8]

Q. Does IPCo experience a fixed cost-related loss from customer-sited net-metered solar generation?

A. No. The Company has in place a Fixed Cost Adjustment (FCA) mechanism that is "designed to ensure the company recovers its fixed costs of serving customers regardless of the amount of energy conservation".[9]

Q. Has IPCo raised any operational concerns about customer-sited solar generation?

A. IPCo has presented no evidence of operational concerns in its testimony in this proceeding. In addition, at the public workshop on April 25, 2013, IPCo noted that at present penetration levels, they have no operational concerns.

Q. Are there policies and procedures already in place that address operation issues?

A. Yes. Interconnection standards are in place across the country that address technical, engineering and reliability issues of customer-sited generation. In this proceeding, IPCo is proposing to extensively revamp its interconnection requirements contained in Schedule 72, not only making the requirements more onerous, but more costly as well. These issues will be addressed in more detail below.

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[7] *See* Response to Idaho Conservation League's Request for Production No. 6.b.
[8] *See* Response to ICL Discovery Request No. 15.

Q. Is IPCo precluded from requesting changes from this Commission related to its perceived impacts of solar at any time?

A. No, it is not.

Q. Have other states imposed caps?

A. Yes. Roughly half of states with net-metering have system-wide capacity caps, according to the Database for State Incentives for Renewable Energy. The vast majority of the states with caps set the limit based upon a percentage of retail peak demand.

Q. What is the average percentage limit?

A. The average for states that have established caps is approximately 3.5% of peak retail demand. This would equal 114 MW in the case of IPCo, based upon the 2012 peak load of 3245 MW (2012 FERC Form 1).

Q. Have there been any economic or operational problems created by solar penetration in the states with no caps?

A. Not to my knowledge.

Q. What do you recommend the Commission do with respect to the overall system-wide cap issue?

A. I recommend the current cap be lifted and no cap be imposed. IPCo has presented neither economic justification nor operational necessity for a cap. There is currently a miniscule amount of net-metered solar generation in Idaho, and it is growing at a slow enough rate that any significant impacts can be anticipated and addressed by this Commission as the need arises, if at all.

Imposition of New Rate Classes

Q. What rate class changes is IPCo proposing?

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[9] http://www.puc.idaho.gov/internet/press/040212_IPCFCAfinal.htm

A. IPCo is proposing to implement two new customer classes — Schedule 6 and Schedule 8 for residential and SGS net-metering customers currently on Schedules 1 and 7, respectively. Additionally, IPCo is proposing modifications to Schedule 84 and significant changes to its Schedule 72 interconnection procedures.

Q. What is IPCo's rationale for creating a new class of customers?

A. IPCo appears to believe that a potential inequity exists between customers that have net-metered generation and those that don't within the same rate class. Its objective is to limit the "potential inequity between net metering and standard service for Residential and SGS customers."[10]

Q. What is the amount of the "potential inequity?"

A. In response to Discovery Request No. 9 from Commission Staff, IPCo calculated the difference in bills for customers affected by the filing to be approximately $65,000.00. Based upon IPCo's rationale and proposals, this is the amount that the remaining 440,000+ non-net-metered customers within Schedules 1 and 7 would have to contribute to keep the Company whole through the FCA.

It should be noted that IPCo's estimates are purely based upon the reduction in revenue it perceives is representative of the cost of net-metered solar generation. IPCo has not performed any calculation of the benefits that distributed solar generation provides to the grid and to other customers.

Q. Are there any other *potential inequities* in electric utility rates?

A. Yes. The process of determining revenue requirements, classifying and allocating costs, and designing rates is full of assumptions, estimates, modeled data, statistical methods, and adjustments made in a legitimate effort to spread cost responsibility to customer classes based on causation, and achieve a reasonably consistent relationship between costs and revenue so that the utility can have an opportunity to recover its costs and earn its authorized return on equity between rate cases. For example, IPCo's cost allocation manual notes that for customers without interval meter data, coincident demands are estimated using coincidence factors determined through a load research sample. Moreover, even accepting all the approximations in the process, the rate for a class is designed for that mythical customer that represents the weighted mean of the group.

This is further complicated because customers and customer classes tend not to be static, but change usage and demand patterns over time. Thus, as soon as new rates are placed into effect, imbalances will begin to occur, with some customers paying more and some less than their up-to-the-minute theoretically appropriate cost of service, were one to be performed at that point in time.

This is not intended to be an indictment of the regulatory system — there are very good reasons why the process has evolved in this way. However, as we start to make selective changes that move away from current structures and practices, we should carefully examine the basis for doing so and the potential for unintended consequences. Any assumption that the revenue recovered from an individual customer in a given rate class is an accurate reflection of the actual cost of providing electric service to that customer would be a stretch at best.

Some examples of areas where there are potential inequities include the following:

[10] *See* Direct Testimony of IPCo witness Larkin, page 20, ll. 9-12.

- The return on equity generated by each customer class (e.g. residential commercial and industrial classes) and approved by the Commission in the last rate class differs, meaning that certain rate classes are paying higher or lower than average shares of IPCo earnings requirements;
- Low income programs are often subsidized by other ratepayers;
- Certain geographic areas are more costly to serve than others. An example is densely populated urban areas, where there is a relatively large number of customers per mile of distribution line, versus low-density rural areas. The latter is clearly more expensive to serve (as the rural electric cooperatives will tell you), yet there is no differentiation in rates or rate structures;
- The distance a customer may be from a distribution substation affects the amount of equipment (and investment) required of the utility to serve that customer. Again, there is no differentiation among customers related to this factor;
- Residential (and SGS) rates are designed to recover costs on the basis of energy consumed. Customers who consume more energy than average in these rate classes contribute more fixed cost recovery to the utility than those who use less than average;
- Line extension policies: While generally intended to have no impact on existing customers, the differential between the actual

cost of attaching new customers and the customer contribution can be more or less than zero;

- Utilities invest new capital to build power plants and transmission lines to serve growth on its system, resulting in an increase in rate levels. Those customers whose load has not grown at all share in the burden of these additional investments.

Q. Are you suggesting that each of these "inequities" be culled out and new rate classes, designs or structures be implemented?

A. Not at all. I raise these issues to debunk the notion that rates are precise, and that singling out changes in sales due to a very small amount of customer-sited generation is arbitrary and unfair. Indeed, reductions in sales for any reason, whether related to a new more efficient refrigerator or a shrinking household, have the same effect. Moreover, increases in sales due to growing households, new "must have" appliances, electric vehicles and so forth add to the earnings of the utility.[11]

Q. Has IPCo defined the specific requirements for eligibility for these new rate classes?

A. While not laid out in testimony, the proposed new rate schedules include applicability language that reads as follows:

> Customer owns and/or operates a Generation Facility fueled by solar, wind, biomass, geothermal, or hydropower, or represents fuel cell technology, with a total nameplate capacity rating of 25 kilowatts (kW) or less.

[11] The changes described are, of course, subject to the effects of the FCA in the case of IPCo.

Presumably, this means that any residential or SGS customer that installs a net-metered system would be subject to the applicable new tariff. Additionally, net-metered systems that exceed 25kW would be subject to Schedule 84, provided they are smaller than 100 kW.

Q. In your experience, is it standard practice to cap individual system sizes at such low levels?

A. No. In the territories of utilities that have low system size caps, the solar markets are virtually non-existent.

Q. Is there a need for individual system size caps?

A. No. There is really no need for an individual system size cap for net-metered solar generation because the economic viability of such facilities drops dramatically if the system generates more energy than the host can consume.

Q. Is there a practical limit for these two customer classes?

A. Yes. It is rare for a home to be so large as to consume the full amount of energy generated by a 25kW solar system. In Idaho, such a system would generate nearly 34,000 kWh per year – about three (3) times the average usage. Similarly, the SGS class has a monthly consumption limit of 2,000 kWh, after which it would get bumped into a new rate class. These practical considerations make the 25kW limit virtually meaningless.

Q. Do other states have system size limits?

A. Yes. Many states have a one (1) or two (2) MW limit for individual net-metered system sizes, but even this is arbitrary. This is too large for many customers and too restrictive for others. The most practical limits for individual system sizes are those found in Arizona and Colorado, in which the system size limit is tied to the size of the customer.

Q. What happens to a larger IPCo customer who would like to utilize the solar resource and net-metering?

A. As noted above, anything larger than 25kW would place the customer in Schedule 84, effectively denying the customer the ability to reduce its own load by investing in on-site generation.

Q. Has IPCo provided evidentiary support for the need to segregate all present and future net-metered customers into separate rate classes?

A. No. It has not.

Q. Has IPCo clearly defined the attributes and characteristics of customers that would be required to take service under these new rate schedules?

A. No. There is a great deal of diversity within rate classes today, and IPCo has not clearly described the breadth of attributes in its testimony that would delineate the subgroup of customers that need to be segregated. The applicability section of Schedules 6 and 8 appear to be the only place where such characteristics can be found at all, raising a number of questions. Are all net-metered customers required to take service under one of these two (2) schedules, or is there a minimum threshold system size that would trigger applicability? Are customers taking service from rate schedules other than 1 and 7 precluded from net-metering service under Schedules 6 and 8? Should the schedule only apply to those who export energy since non-exported generation simply reduces consumption like other demand side technologies and behaviors? Or should it apply to any customer who can "unduly reduce"[12] their consumption for <u>any</u> reason?

Without clear and fully vetted definitions of eligibility criteria, the law of unintended consequences is likely to come into play. Rates are price signals, and customers will respond to these signals. For example, residential customers with high load factors might install a token or undersized solar system in order to take advantage of the much lower energy charge proposed by IPCo in its proposed Schedule 6. Indeed, this new rate could cause a migration that results in a great deal of revenue shifting to lower load factor customers.

Q. Do you have other concerns with a separate rate schedule solely for net-metered customers?

A. Yes. IPCo has not provided a cost of service nor demonstrated revenue neutrality for these proposed new classes of customers or the classes from which they were derived, calling into question whether it is able to make these changes outside the context of a formal rate proceeding.

Q. You noted that IPCo is modifying Schedule 84. Do you have any comments on its proposals?

A. Yes. As I understand the proposed new paradigms, all net-metered systems that are not eligible under IPCo's proposed Schedules 6 or 8 would fall under Schedule 84, provided they do not exceed 100 kW. However, the changes to the existing schedule are so extensive and intertwined with other Schedules and policies, it is difficult to segregate the proposed Schedule 84 elements sufficiently to develop an alternative

[12] Direct Testimony of IPCo witness Larkin, page 21, l. 10. This undefined term is seemingly an effort to segregate those customers that can reduce consumption beyond some threshold from those that can reduce consumption, but not past the unspecified threshold.

proposal. I will, however, point out a number of problem areas and then make a recommendation:

- The 100 kW limit is overly restrictive and will not allow larger customers to take full advantage of the benefits of investing in solar generation on their premises;
- IPCo may require curtailment of customer's own generation at any time;
- IPCo may require curtailment of a Schedule 84 customer's consumption (paragraph 6), but it is very unclear how this would occur, given the reductions that may be ongoing resulting from the customer's own generation.

Q. What are your recommendations regarding the rate class proposals of IPCo?

A. We urge the Commission to reject IPCo's proposals for its proposed Schedules 6, 8 and 84. We recommend that the Commission increase the system size limit to 120% of consumption (or 2 MW), and allow any customer in any class to install net-metered solar generation up to that limit.

Proposed Rate Structure Changes for Net-Metered Customers

Q. Please describe the proposed rate structure changes for net-metered customers.

A. IPCo is proposing to increase the monthly flat customer charge from $5.00 per month in both Schedules 1 and 7 to $20.92 and $22.49 per month under proposed Schedules 6 and 8 respectively, representing a 320% increase for Residential customers and a 350% increase for SGS customers. Second, IPCo is initiating a new type of charge for these two new customer classes — a demand charge of $1.48 and $1.37 per maximum 15' kW load during the month. Neither the proposed increased customer charge nor the proposed demand charge is employed by IPCo for any other residential or SGS customer.

Q. What is IPCo's rationale for the increase in the monthly flat customer charge?

A. IPCo is proposing to increase the customer charges for residential and SGS service "to reflect collection of 100% of customer-related revenue requirement."[13]

Q. Do you believe that IPCo's customer-related revenue requirement results in a charge exceeding $20.00 per month?

A. No. In fact, IPCo's April 25, 2013 presentation during the public workshop at the Commission showed the amount of the customer-related revenue requirement currently *not* being collected in the current $5.00 per month residential service charge, but rather through the energy charge is $0.0017 per kWh. Multiplying this charge by the average monthly residential consumption of 1050 kWh in IPCo's service territory yields $1.785. Thus, IPCo's own data suggests recovery of 100% of the customer-related revenue requirement in the customer charge is accomplished with a fee of $6.785 per month.

It should be noted that subsequent to the April 25, 2013 workshop, IPCo made a slight change to its presentation to indicate that the fixed distribution related costs were somehow being spread to both the demand charge and the customer service charge. While this may be how IPCo developed such a high customer charge, there remains no evidentiary support for the development of the charge nor the cost basis or rationale for the type and amount of distribution costs included in the service charge. IPCo repeatedly said in the April 25th public workshop that its rates are cost-based, but has not provided the cost basis.

Q. Please describe the new demand charge proposed to be required of customers under Schedules 6 and 8.

A. IPCo proposes to impose a demand charge on net-metered customers. In testimony, IPCo witness Larkin refers to it as a Basic Load Capacity charge or "BLC." He notes that it is designed to collect "the demand-related revenue requirement of the distribution system."[14]

Q. Do you support the use of demand charges on small customers to recover distribution related costs as proposed by IPCo in this proceeding?

A. No, I do not. In my view, there are too many unknowns at this point in time. This type of change is better addressed in a comprehensive rate proceeding where issues of functionalization, classification and cost causation can be fully reviewed.

Q. What costs are proposed to be recovered through the demand charge?

A. This is unclear. IPCo's filing tells us these are distribution-related costs, but does not tell us how much of the costs of the distribution system the Company is proposing to collect through this charge. The pre-filed testimony seems to indicate 100%, but the presentation by IPCo at the public workshop on April 25th suggested otherwise.

Q. Has IPCo provided an analysis of the costs and cost incurrence rationale to support its new charge(s)?

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[13] *See* Direct Testimony of IPCo witness Larkin, page 19, line 9.
[14] *See* Direct Testimony of IPCo witness Larkin, page 19, ll. 12-14.

A. No. In addition to not knowing which costs (by FERC account or otherwise) are being proposed for recovery by these new charges, no analyses have been provided to support the assignment of these costs to new collection parameters.

Q. Did IPCo study the benefits of distributed generation to help guide the rate redesign?

A. No, not to my knowledge.

Q. What would an examination of the benefits show?

A. A number of studies have been performed around the country which compare the benefits provided by distributed solar generation behind the meter with the costs incurred by the host utility. In virtually all cases, the benefits have exceeded the costs.

Based upon a presentation given by the Idaho Conservation League at the public workshop on April 25th, there will be a benefit and cost study submitted into evidence in this proceeding specific to IPCo. I would also point out that IPCo commented at the workshop that solar generation "lines up quite well" with its load patterns — not surprising, as solar generation provides electricity during the day when loads and costs tend to be higher.

Q. What are the main components of rooftop solar's value?

A. When examining the value components of solar, it's important to look at the marginal, not average, costs that are avoided or deferred. Utility rates are based upon accumulated plant investments — some newer and some much older — as well as market prices based on supplementary generation assets. The energy-related rates from this blend are typically illustrated in hourly avoided cost statistics.

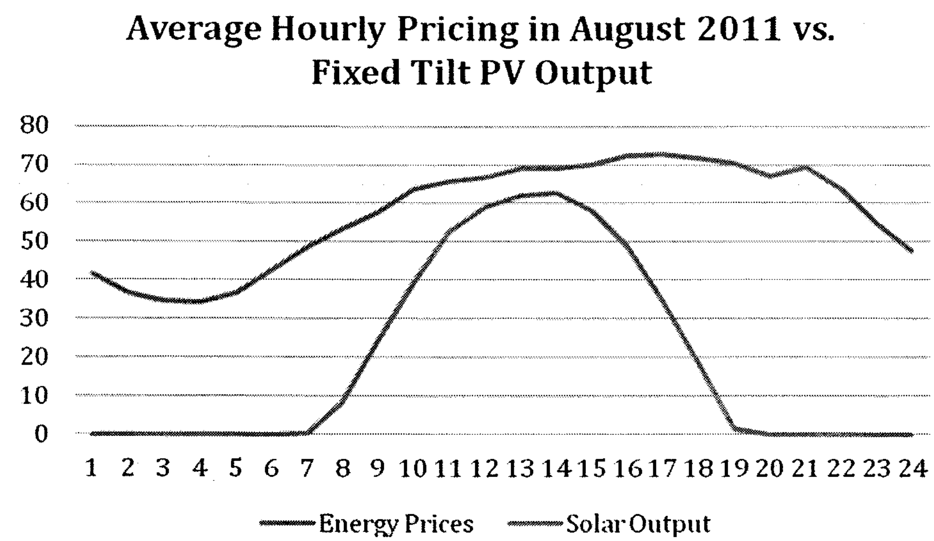
On a levelized basis, construction of new incremental generation is more expensive than the typical avoided cost rate, regardless of the plant technology. It is similar to comparing the average price of a new car thirty (30) years ago to one today. As load growth increases and generation assets reach the end of their useful life and are retired, new sources of electricity are needed. Utilities generally plan their system and design rates around the summer peak load periods, at the time solar tends to be producing close to its highest generation levels.

The chart[15] below illustrates the relationship between electricity prices in August 2011 compared to solar output. According to IPCo's 2011 IRP, the price for electricity during those times range from $40-65/MWh in 2011, with a price projection of $130-190/MWh in 2030. Accordingly, avoided energy cost is the first major component to solar's value. The second is capacity value, or the amount of new generation solar can help avoid or defer.

As penetration levels increase, the more likely the existence of solar on the grid will be able reduce the size or the need altogether for new peaking power plants. This same concept can also be applied to new costly transmission lines.

Finally, there are components that are more complicated to quantify, such as the environmental attributes of solar, economic opportunities, and features of having a more diversified and less centralized generation portfolio.

[15] Sources: Hourly cost data provided in Response to ICL Discovery Request No. 1; solar data from NREL PVWatts model.



Q. What are the implications of factoring in these benefits to IPCo's rate design proposal?

A. If the benefits here in Idaho are at all similar to those determined in other jurisdictions, it means that IPCo's current retail rates are likely a fair approximation of the value of distributed generation, and potentially under-compensating solar system owners. More specifically, it means that any perceived cost shift from solar adopters to non-solar customers is more than compensated by the benefits of adding new incremental energy sources with the attributes derived from solar energy.

Q. Please describe the end result of IPCo's proposed rate structure changes.

A. The end result is a compounding series of deleterious effects on the customers of IPCo. It has been remarkable that individuals in the Company's service territory have, of their own volition and without financial encouragement from the utility, invested in clean solar-generating resources on their homes and businesses. These customers should be applauded for their leadership. Instead, IPCo is attempting to undercut the already marginal economics upon which electricity consumers took such action, by shifting cost recovery out of the variable charge and into largely unavoidable monthly service fees and demand charges that have not been justified by any cost or revenue analyses. If IPCo's proposals are approved, current net-metering customers will be paying substantially more than they had planned.

In addition, the likelihood of new customers installing solar and other renewable energy technologies on their homes and businesses is greatly diminished. The perceived payback period for such systems would be dramatically longer under the proposed tariff changes, and perhaps more importantly, the uncertainty of rate stability in Idaho would lead solar businesses, especially installers, to look elsewhere.

Q. What else concerns you about the proposed rate changes?

A. As mentioned, the rate changes are sweeping and violate several principles of proper rate-making. The changes, if adopted, would significantly alter the economics for system owners. This greatly undermines confidence in the market, which in turn hinders the ability to not only attract investment but also future adopters.

Q. **Can you elaborate on the consequences of lost confidence?**

A. Investors seek a stable regulatory environment so they can plan and invest in confidence — the higher the uncertainty, the greater the risk to financiers and entrepreneurs. This risk increases the cost of borrowing, if investors do not pull out altogether. Adoption of the proposed rate changes on future customers would likely rattle confidence in the market and deter investment in Idaho, particularly from companies in the distributed-generation market sector. However, applying the proposed changes to both future customers and existing net-metering customers would decimate confidence in

Idaho's market and likely set back distributed generation adoption and investment for years to come.

Q. **What can this Commission do to avoid such a scenario?**

A. In the event that any rate changes are adopted in this proceeding, which I do not believe are justified based upon IPCo's filed case, they should be gradual and applied only to new customers. Existing customers should be somehow shielded from the impacts of the price, rate design and structural changes. This will send a signal to investors and prospective technology adopters that the rug will not be pulled out from them, rendering them underwater or at significant loss.

Q. What are your recommendations regarding the proposed changes in rate structure?

A. We recommend rejection of IPCo's proposed rate structure changes in this proceeding. If IPCo believes such dramatic changes are warranted, it should resubmit these proposals in a comprehensive rate proceeding, allowing for all elements of the revenue requirement and cost of service to be scrutinized. Further, we encourage the Commission to issue a policy statement that reassures prospective investors that any rate redesign in the future will follow the principle of gradualism.

<u>Proposed Changes to Schedule 72: Interconnection</u>

Q. You noted above that IPCo is making significant changes to its Schedule 72 interconnection requirements. Do you have any comments on its proposals?

A. Yes. As is the case with Schedule 84, the changes to Schedule 72 are extensive, restrictive, and at times, internally inconsistent. For example, IPCo indicates on page 12 in paragraph 2 that the FERC-approved Large Generator Interconnection

Procedures and Small Generator Interconnection Procedures (SGIP) posted on the Company's website will apply to the Generator Interconnection Process unless modified by the provisions of Schedule 72.

One of the most important elements of the FERC SGIP is to provide a path (known as "fast-track") for small systems to interconnect without going through the same onerous and costly procedures to which large systems are subject. The FERC SGIP has a series of screens to determine fast-track eligibility, primarily to avoid unnecessary studies by the host utility. Schedule 72, however, has no screening process and subjects all interconnecting systems, no matter how small, to a feasibility analysis, generally costing thousands of dollars.

IPCo plans to perform a Net Metering Feasibility Review on every net-metered system, regardless of size, to determine the capability of the Company's electrical system to incorporate the proposed Net Metering System and determine if any upgrades are necessary. There is no limit to how much time IPCo can take to perform this analysis. Larger systems are subject to more costly and onerous requirements.

Another example of a concern with proposed Schedule 72 is the requirement for a visible "separation of conductors" (a switch does not satisfy this requirement) under disconnection equipment for systems under 100kW (Schedules 6, 8, and 84), whereas for larger systems, a switch is satisfactory. Many jurisdictions do not require *any* separate disconnection equipment, as all inverters today automatically disconnect the generation system from the grid during disturbances. IPCo goes on to list a variety of reasons why a system may be disconnected (e.g., planned or unplanned grid outages) and requires that the system owner pay for the cost of disconnection — presumably the utility service representative walking to the home or business to manually disconnect the system.

Further, there are few time limits placed on IPCo for performing analyses that may be necessary — an oversight ripe for abuse.

Q Are there other policy changes proposed by IPCo that seem arbitrary and/or discriminatory?

A. Yes. The $100.00 application fee for new net-metering customers or customers looking to modify their system appears high. IPCo states that it "feels this charge is commensurate to the services provided...." However, "it has not prepared a study that specifically delineates each of these costs." Among the services are administration, customer service, distribution research, and field visit and inspection. As listed in Schedule 66 (Miscellaneous Charges), IPCo has a service establishment charge of $20.00 and a field visit charge of $20.00 to $40.00. It is hard to conceive that the extra services provided to a net-metered customer represent a 60% to 40% premium over comparable utility charges.

Q. To clarify, even a small modification to the system triggers a $100.00 application fee?

A. Correct. A new net-metering customer pays the $100.00 fee, and then most modifications and all system expansions thereafter trigger a new $100.00 application fee. For example, a customer simply updating a single inverter or adding a panel or two would have to pay an additional $100.00. This would bring the customer's total to $200.00 in fees paid. According to IPCo's pricing, these small system changes require the same level of services as a new net-metering customer interconnecting to the grid.

Again, it is hard to comprehend how upgrading an inverter would trigger all the services IPCo requires for a new net-metering customer and at the same inflated price.

Q. Is there a nationwide standard for interconnection procedures?

A. No. However, many states have modeled their statewide interconnection standards after those included in FERC Order 2006. In addition, the Interstate Renewable Energy Council has developed a set of best practices in both interconnection and net-metering policies that are derived from vibrant solar markets across the country. In these standards, there is great detail on the roles and responsibilities of both the host utility and the interconnecting customer, and the need for maintaining a high degree of reliability and safety.

There is also a set of screening criteria that determines the necessity for a utility to perform feasibility and other studies associated with a new connecting facility. The relevant screen that addresses system size in those standards typically allows for solar capacity penetration by distribution line circuit up to 15% of the peak load on the line before any additional study is required.

It should also be noted that these standards are currently under review in FERC Docket No RM13-2-000, Small Generator Interconnection Agreements and Procedures. The Notice of Proposed Rulemaking suggests an expansion of the 15% standard, indicating that such penetration levels have created no operational problems.

Q. What are your recommendations regarding Schedule 72?

A. Because of the burdensome and costly requirements imposed by the changes to Rule 72, I recommend that the Commission reject IPCo's proposed changes and that a new docket be opened to review interconnection agreements and procedures in Idaho and across the country, with the goal of implementing new statewide interconnection rules based upon the best practices it finds will work in Idaho.

<u>**Proposed Treatment of Annual Net Excess Energy Credits**</u>

Q. What is IPCo proposing in this regard?

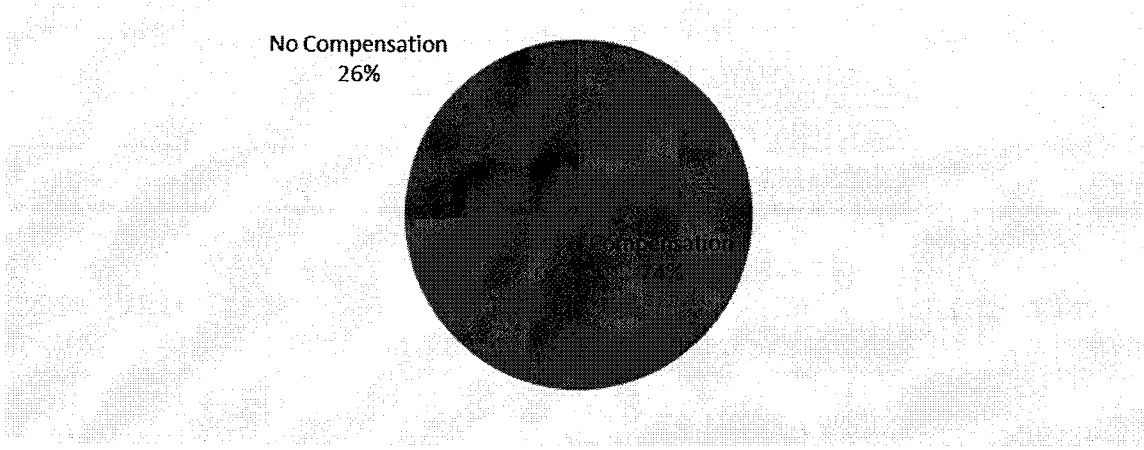
A. IPCo is proposing that any excess generation credits for a net-metering customer be carried forward as an energy or kWh credit from month to month, rather than providing a financial payment as a billing credit. Second, it proposes that any excess credits that may exist at the end of the year simply "expire."

Q. Is this standard practice in the industry?

A. Most net-metering policies carry forward a kWh credit from month to month, but provide for payment at avoided energy cost rates for any net excess remaining at the end of a twelve-month period or allow for continuous rollover of the credits. According to the Database for State Incentives for Renewable Energy, about one quarter (1/4) of net-metering states let net excess credits expire at the end of a twelve-month period.

Clearly, as IPCo witness Larkin explains on page 28 of his Direct Testimony, there is a benefit to other customers, as energy generated or purchased throughout the year has been reduced. Yet the net-metering customer who has generated the excess energy and created the benefit receives no financial remuneration under the IPCo proposal. In contrast, IPCo currently does compensate net-metered system owners for all excess generation.

State Treatment of Excess Credits



Q. Are there other considerations?

A. Yes. The seasonal interplay between solar generation and load patterns tends to result in the lowest level of excess generation credits at the end of the first quarter of the year. By this time, excess generation from the fall has been used up during the winter months, but solar generation has not begun to pick up again. This is logical, as the Spring equinox is the point where the sun and earth begin getting closer, and the northern hemisphere angles towards the sun. Thus, moving the annual true-up date to March 31 will minimize the amount of excess credits.

Q. What are your recommendations?

A. I recommend accepting IPCo's proposal to carry forward energy credits for net excess generation from month to month in lieu of financial payments. Further, I recommend moving the annual true-up date to March 31 of each year, and payments be made for any net excess generation at that time at an avoided cost rate. Finally, I recommend that, at the customer's discretion, the option of continuous rollover of excess generation credits be made available.

Economic Development Considerations

Q. In addition to the benefits identified by other parties in this proceeding, are there other considerations?

A. Yes. According to the Solar Foundation, there are 300 solar-related jobs in the state of Idaho as of 2012. This places Idaho 35th in the nation or 20th on a per-capita basis. For a state ranked 11th in terms of solar resources, we believe it can do much better.

Q. Why should Idaho and this Commission take solar jobs and related economic activity into account?

A. The solar industry has a number of positive attributes. For example, installation services represent about half of the jobs in the value chain from manufacture to utilization. These jobs cannot be outsourced. Moreover, solar generation uses an indigenous resource and means fewer kWhs generated by fuels extracted in other states or energy purchased from other utilities out of state. According to the 2012 Idaho Energy Plan ("Plan"), 52% of Idaho's 2009 electric energy supply was imported from out of state. Importantly, the Plan notes at page 21:

> Enhancing energy conservation and efficiency measures and continuing to support the further development of cost-effective in-state renewable energy resources in order to reduce Idaho's dependence on imported coal-fired power are important aspects of Idaho policy.

Promoting solar generation as a resource in Idaho can provide new jobs and investment. Further, as the Plan quote above notes, it helps retain dollars in the state by keeping electricity generation local. Most importantly, there is no fuel risk and no water consumption with solar PV technology. Finally, rooftop solar can assist in diversifying and enhancing the reliability of IPCo's system in general.

Q. Does Idaho have any other economic activity related to renewable energy?

A. Yes. Idaho National Laboratory has a major research program on energy systems and technologies. One of the core divisions in that program is biofuels and renewable energy.

Q. What is your recommendation?

A. I recommend that the Commission take into account the local and statewide economic benefits that result from reducing barriers to solar deployment. IPCo's filing in numerous ways serves to increase barriers.

Recommendations

Q. Please summarize your recommendations in this testimony.

A. First, I recommend that the current cap be removed and no overall system-wide cap be imposed, as the Company has not presented economic justification or operational necessity. The very low level of net-metered solar generation in Idaho is growing slowly enough for future impacts to be addressed in a timely manner.

Second, I recommend rejection of IPCo's proposed Schedules 6 and 8, as well as the changes to Schedule 84. I further recommend that the Commission increase the individual net-metered system size limit to 120% of consumption (or 2 MW), applicable to any customer in any class.

Third, I recommend rejection of IPCo's proposed rate structure changes in this proceeding. There has been no analysis of the cost basis for such dramatic changes. Major rate changes such as these proposals should be addressed in a comprehensive rate proceeding, where all elements of the revenue requirement and cost of service can be scrutinized. In addition, we urge the Commission to issue a policy statement that any rate redesign in the future will follow the principles of gradualism.

Fourth, I recommend that the Commission reject IPCo's proposed changes to Rule 72. The changes result in requirements that are burdensome and costly, and which fail to acknowledge the FERC SGIP screening process for expedited interconnection. Because interconnection requirements can be complicated, I recommend a new rulemaking docket be opened to establish new statewide interconnection rules based on the best practices of other states.

Fifth, I recommend accepting IPCo's proposal to carry forward energy credits for net excess generation from month to month in lieu of financial payments. Further, I recommend moving the annual true-up date to March 31 of each year, and payments be made for any net excess generation at that time at an avoided cost rate. I also recommend that, at the customer's discretion, the option of continuous rollover of excess generation credits be made available.

Sixth and lastly, I recommend that the Commission take into account the local and statewide economic benefits that result from reducing barriers to solar deployment, and encouraging self-sufficiency, job creation and the resultant economic development.

Q. Do you have any final thoughts for the Commission?

A. Yes. In this proceeding, virtually all of IPCo's proposals are designed to make net-metered customer-sited solar generation more costly or more administratively difficult. The formal submittal by IPCo in late 2012 unfortunately put all interested parties into an immediate adversarial position, polarizing the discussion in this proceeding. There are high resource costs associated with proceedings such as this one. While the Company always has the prerogative to file formally for changes to its rates and tariffs, I urge the Company to meet with interested stakeholders to inform its thinking prior to making such filings.

In addition, the Commission could take the lead from a policy standpoint and initiate informal workshops leading to rulemaking proceedings for interconnection (as noted above) and for net metering. Similarly, it could hold informal workshops or open an investigatory docket looking into new and creative rate structures to address the changes to the utility industry.

Q. Does this conclude your direct testimony?

A. Yes, it does.

<u>APPENDIX A</u>: Qualifications

Rick Gilliam

January 2012 to Present: Director of Research and Analysis, the Vote Solar Initiative, San Francisco, CA. Manage the technical and policy research for Vote Solar, and engage in state, regional and national campaigns related to key solar market policies.

January 2007 to January 2012: Vice President, Government Affairs, SunEdison, LLC, Beltsville, MD. Directed and managed policy development and implementation for the Americas at the regulatory and legislative levels. (Promoted from Managing Director June '09 and from Director Sept. '07.)

December 1994 to January 2007: Senior Energy Policy Advisor, Western Resource Advocates (formerly the Land and Water Fund of the Rockies), Boulder, CO. Developed innovative clean energy and air quality public policies within the economic and cultural framework unique to this region. Led environmental advocate in development of Arizona Environmental Portfolio Standard, Nevada Renewable Portfolio Standard implementation rules, Colorado Renewable Energy Standard legislative proposals, and the 2003 Utah Renewable Energy Standard legislative proposal. Principal author of Colorado's Amendment 37 and lead advocate for related PUC rule development.

January 1983 to December 1994: Director of Revenue Requirements, Public Service Company of Colorado, Denver, CO. Primary responsibility for development of formal rate-related filings for this investor-owned utility for electric, gas and thermal energy service in two states and the FERC. Developed and responded to a variety of proposed mechanisms to encourage the use of energy efficiency technologies, including innovative rate design approaches.

December 1976 to December 1982: Technical Witness (Engineer), Federal Energy Regulatory Commission, Washington, D.C. Testified as expert witness on behalf of the FERC in wholesale rate filings on technical, accounting and economic issues related to rate design, pricing and other issues.

A. Education

Masters, Environmental Policy and Management, University of Denver, Denver, CO

Bachelor of Science, Electrical Engineering, Rensselaer Polytechnic Institute, Troy, NY

B. Related Publications

Gilliam and Baker, "Green Power to the People," *Solar Today*, July/August 2006.

Dalton & Gilliam, "Walking on Sunshine: Energy Independence on the Rez," *Orion Afield*, Summer 2002.

Gilliam, Rick, "Revisiting the Winning of the West," *Bulletin of Science, Technology & Society*, April 2002.

Blank, Gilliam, and Wellinghoff, "Breaking Up Is Not So Hard To Do: A Disaggregation Proposal," *The Electricity Journal*, May 1996.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY That on this **10th** day of May, 2013, I caused a true and correct copy of the foregoing to be served upon the following in the manner indicated:

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PIONEER POWER, LLC

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John R. Hammond, Jr.