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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION TO ESTABLISH NEW SCHEDULES FOR RESIDENTIAL AND SMALL GENERAL SERVICE CUSTOMERS WITH ON-SITE GENERATION.	CASE NO. IPC-E-17-13

The Sierra Club

Direct Testimony of R. Thomas Beach

December 22, 2017

Executive Summary

Idaho Power has asked the Commission to take important initial steps toward changing the compensation for customers who install renewable distributed generation (DG) under net energy metering (NEM). This includes placing residential and small commercial customers who install renewable DG into customer classes distinct from standard customers. The Sierra Club is concerned that Idaho Power seeks approval of this ratemaking step without actually establishing that there is a significant economic problem with net metering that needs to be addressed at this time.

If the Commission wishes to review the economics of NEM in Idaho, the Commission should only grant Idaho Power's request to establish a stakeholder process to assess the benefits and costs of all types of distributed energy resources (DERs), including those that involve net metering. All DERs should be evaluated using the same best practices that the electric industry has used for many years to assess the cost-effectiveness of long-term energy efficiency and demand response resources. If this evaluation determines that the benefits of net metered DERs exceed the costs, then the Commission does not need to change the rates applicable to those DERs. If the Commission concludes the opposite, it can proceed to a rate case to consider adjusting the rates (or other compensation) applicable to DERs to restore an equitable balance of benefits and costs. Ratemaking changes that affect the balance of benefits and burdens associated with DERs – such as the creation of separate customer classes – should be evaluated in a rate case, and only after the Commission has completed the benefit / cost assessment.

This testimony also discusses certain key attributes of net metered customers that Idaho Power's testimony does not characterize correctly. DG customers do not make "bi-directional use" of the grid for both importing and exporting power. When a solar customer exports power to the utility, it is the utility that uses the grid to deliver those exports to neighboring customers (and the utility is fully compensated by the neighbors for that service). Exported power represents a service – generation – that the solar customer provides <u>to the utility</u>, not the other way around. Thus, a DG customer actually uses the distribution system less than a regular non-DG customer of comparable size, and provides the utility with significant benefits by reducing peak loads on the distribution system. The utility also does not incur costs to "store" DG output, nor does it incur significant costs to "standby" to serve the DG customer's loads that are greater than its comparable costs to be ready to serve standard customers.

The Commission should establish a clear policy that existing NEM customers will be allowed to remain under the rules and rate structure that applied when they originally applied to interconnect with the utility for a 20-year period that represents the reasonable economic life of the DG system. Such a grandfathering policy has been adopted by most states that have changed the rates, terms, and conditions applicable to net metered customers. In the one state that did not follow this policy (Nevada), there was significant customer backlash and political turmoil until existing NEM customers were grandfathered for 20 years.

In sum, the key points of this testimony are the following:

1. Customers who install renewable DG have a legal right under PURPA to install generation to serve their own loads behind the meter.
2. Rates for all customers, including those who install DERs, should be based on the utility's cost to deliver power to the customer.
3. The exports that DG customers deliver to the grid are a generation service which they provide to the utility, not a service which they receive from the utility.
4. DG customers should not be charged costs associated with the delivery of their exported power to neighboring customers, because this delivery is a service which the utility provides to the neighbors.
5. The key public policy issue with net metering is whether the bill credits for exported power at the retail rate are the equitable credit for those exports.
6. DER customers should be grandfathered on the NEM rules and the rate design that applied when they made the investment, for a 20-year period that represents the useful life of that investment.
7. Rate design should evolve to send more accurate price signals to all types of DERs – for example, through a greater use of time-sensitive rates – rather than trying to design a different rate structure for each type of DER.
8. If the long-term benefits of DERs exceed the costs, other ratepayers will be disadvantaged if DERs are moved into their own class.

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I. INTRODUCTION

Q: Please state your name, address, and business affiliation.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Please describe your experience and qualifications.

A: I have over 30 years of experience in utility analysis, resource planning, and rate design. I began my career at the California Public Utilities Commission, working from 1981-1984 on the initial implementation in California of the Public Utilities Regulatory Policies Act (PURPA) of 1978. I then served for five years as an advisor to three CPUC commissioners.

Since entering private practice as a consultant in 1989, I have served as an expert witness in a wide range of utility proceedings before many state utility commissions. This includes sponsoring testimony on PURPA-related issues in state regulatory proceedings in Idaho, California, Montana, Nevada, North Carolina, Oregon, Utah, and Vermont. With respect to benefit-cost issues concerning renewable distributed generation ("DG"), I have sponsored testimony or studies on net energy metering ("NEM") or solar economics in Idaho, Arkansas, Arizona, California, Colorado, Georgia, Minnesota, New Hampshire, New Mexico, North Carolina, South Carolina, Texas, and Virginia. I also co-authored a chapter on Distributed Generation Policy in America's Power Plan, a report on emerging energy issues, which was released in 2013 and is designed to provide policymakers with tools to address key questions concerning distributed generation (DG) and other distributed energy resources (DERs).

Prior to this professional experience, I earned degrees in English and Physics from Dartmouth College and a Masters in Mechanical Engineering from the University of California, Berkeley.

Q: On whose behalf are you testifying in this proceeding?

A: I am appearing on behalf of the Sierra Club (Sierra).

The Sierra Club is a national, non-profit environmental and conservation organization dedicated to the protection of public health and the environment. Sierra Club is participating in this case on behalf of itself and nearly 3,500 Sierra Club members who live and purchase utility services in Idaho. Sierra Club's Idaho members have a direct and substantial interest in this proceeding as a result of its potential impact on additional solar deployment in Idaho and on the environmental, health, and economic benefits that would result from the continued growth of this renewable generation resource for the Idaho electric system.

Q: Have you previously testified or appeared as a witness before the Idaho Public Utility Commission?

A: Yes, I have. I testified on behalf of the Idaho Conservation League (ICL) in Case No. IPC-E-12-27 concerning proposed changes to Idaho Power's net metering service. I also testified on behalf of Sierra and ICL in Case No. IPC-E-15-01 concerning changes to the terms of PURPA contracts in Idaho.

Q: Do you have any exhibits?

A: No.

I. IDAHO POWER'S REQUEST

Q: Please summarize Idaho Power's request in this application.

A: ldaho Power has asked the Commission to authorize the following:

- closure of Schedule 84 to new service for Residential and Small General Service (R&SGS) customers with on-site generation,
- establishment of two new customer classes applicable to R&SGS customers with on-site generation that request to interconnect to ldaho Power's system on or after January 1, 2018, with no pricing changes at this time,
- amendment of the Company's applicable tariff schedules to require the installation and operation of smart inverters for all new customer-owned generator interconnections within 60 days following IEEE's adoption of an industry standard definition of smart inverters, and
- commencement of a generic docket at the conclusion of this case to establish a compensation structure for customer-owned DERs that reflects both the benefits and costs that DER interconnection brings to the electric system.[1]

Q: Why does Idaho Power believe that these steps should be taken at this time?

A: The utility asserts that net metering is a "non-cost based policy" and therefore not an equitable way to compensate net-metered customers for the renewable generation that they provide to the Idaho Power system.[2] Idaho Power alleges that there is an undue "cost shift" from the installation of renewable DG by small customers in its service territory.[3] Idaho Power wants to place net metered customers into separate customer classes in order to "position the company to study this segment of customers, providing the data necessary to understand how this customer segment utilizes the company's system."[4] The utility also indicates that this step would inform prospective net metering customers that their rates may change in the future.[5]

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[1] Idaho Power Application, at pp. 15-16, summarizing pp. 5-14.
[2] *Ibid.*, at p. 4.
[3] Idaho Power testimony (Tatum), at pp. 5-6.
[4] *Ibid.*, at p. 19.
[5] *Ibid.*, at p. 18.

II. EVALUATING THE BENEFITS AND COSTS OF NET METERING

A. Is There a Problem Today with Net Metered Renewable Resources in Idaho?

Q: What is your principal concern with Idaho Power's request in this application?

A: My primary concern is that the utility is asking the Commission to take important initial steps toward changing the compensation for customers who install renewable DG under net metering, without actually establishing that there is an economic issue with net metering that needs to be addressed at this time. Before beginning surgery on a patient, a responsible doctor first should determine whether the patient is actually ill.

Further, the proposal to create separate customer classes for customers who install renewable DG – with the strong presumption that future rates will be different for NEM vs. regular customers – suggests that Idaho Power regards net metering as exclusively a ratemaking issue, and may seek to evaluate NEM using only a cost-of-service analysis similar to the approach that the utility uses to set rates. Indeed, the annual net metering reports that Idaho Power submit to the Commission use such an analysis to calculate an alleged "cost shift" from NEM customers.

Q: Is net metering solely or even principally a ratemaking issue?

A: No. Net metering is principally a long-term resource planning and compensation issue. Net metering is the means used in Idaho and over 40 other states to compensate customers who install renewable DG, using their private capital on their private premises, and who then export excess generation to the grid.[6] DG facilities that qualify for NEM are long-lived renewable generation resources. The solar panels that a small customer installs on the roof of their home are warrantied to produce power for 20-25 years, and

[6] Today, 47 states offer some type of net metering. See http://programs.dsireusa.org/system/program/maps. This includes Arizona, California, Nevada, New Hampshire, and Hawaii, states which have large numbers of existing DG customers on traditional net metering, but which recently have adopted revised compensation rules for new DG customers that make changes in the compensation for excess generation exported to the grid.

will do so reliably for long beyond the test year for the next rate case. They are a demand-side resource that will reduce a customer's long-term consumption from the grid, just as an energy efficiency measure (such as a more efficient appliance) will result in a long-term reduction in a customer's energy usage for the measure's life. In addition, the solar panels will produce excess generation that the utility can use to serve other nearby loads. The output of renewable DG, when brought to scale, can provide a major new source of clean electricity for the electric system.[7] This is power that, due to its location, is already delivered to load. Thus, renewable DG can displace the need not only for additional central station generation but also for upgrades to the transmission and distribution (T&D) wires that would be needed to deliver that avoided central station generation to loads.

Q: Are the issues concerning net metering solely related to customers who install solar panels?

A; No. Idaho Power's application focuses on solar DG, although the utility does refer to distributed energy resources (DERs) more broadly.[8] Although solar DG is the predominant net metered resource today, DER technologies also include:[9]

- Wind
- Small hydro
- Biomass
- Fuel cells
- Combined heat and power (CHP)
- Storage, both battery and thermal
- Electric vehicles (EVs)
- Energy efficiency (EE)
- Demand response (DR)

[7] For example, in the last decade, California has added about 15 GW of new solar capacity. 10 GW of this capacity is from wholesale, utility-scale projects; 5 GW is from net-metered, behind-the-meter solar facilities on customers' premises. On several of the Hawaiian islands, solar DG penetration is approaching 20% of customers with solar DG systems, representing more capacity than the utility-scale solar plants in Hawaii.

[8] Idaho Power testimony (Tatum), at pp. 6, 8 and 14.

[9] CHP facilities are not eligible for net metering in Idaho, and the treatment of storage is unclear.

Further, DER technologies can be combined in many different ways. The benefits and costs of a solar installation with on-site battery storage will be significantly different than a solar-only installation. DER generation technologies can be combined with new EV loads and with EE and DR measures and programs, all of which will alter the size and time profile of the load that a customer places on the utility system. DERs such as electric vehicles (EVs) will increase the customer's load as well as shift the customer's load profile.

Q: Idaho Power has asked the Commission to open a generic docket to establish a compensation structure for customer-owned DERs that reflects both the benefits and costs of DERs. Should this be the first step that the Commission takes, before making ratemaking choices such as the creation of separate customer classes?

A: Yes; however, the docket should be specific to Idaho Power, for reasons that I discuss below. The Commission should establish a framework and methodology for assessing the benefits and costs of all types of DERs on the Idaho Power system, including those that involve net metering. All DERs should be evaluated using the same industry best practices that are commonly used to assess the cost-effectiveness of any type of resource, either demand-side DERs or utility-scale, supply-side resources. There are two possible outcomes to this assessment:

1. If this evaluation determines that **the benefits exceed the costs** for various types of net metered DERs, then the Commission does not need to change the rates applicable to customers who install those DERs. With this outcome, it will benefit all ratepayers if DER customers continue to be served from the same customer class as other, non-DER customers.
2. If there is evidence of that **the costs exceed the benefits** for a type of DER, such that there is an undue cost shift, the Commission then can then proceed to consider adjusting the rates (or other compensation) applicable to that DER to restore a more equitable balance of benefits and costs.

Thus, ratemaking changes that affect the balance of benefits and burdens associated with NEM – such as the creation of separate customer classes – should occur only after the Commission has completed the benefit/cost assessment.

Q: Why should this docket be specific to Idaho Power, rather than a generic proceeding?

A: There are several reasons. First, each utility in Idaho has its own set of resources, and each has a distinct cost structure and rates. As a result, the benefits and costs of DERs will be unique to each utility. Second, generic dockets with multiple utilities are more complicated to process, more difficult to schedule, and more burdensome for intervening parties who have to focus on multiple utilities at the same time. Establishing a docket specific to Idaho Power would streamline the process of developing a benefit / cost methodology and avoid unnecessary complication and delay. Finally, once the benefit / cost methodology is selected, the appropriate venue for applying the methodology and determining the rate design and compensation for DERs will be in a rate case, which of course will be specific to each utility.

B. Best Practices for Evaluating the Benefits and Costs of DERs

Q: Are there best practices for designing benefit-cost analyses of behind-the-meter DERs that should inform how the Commission undertakes this analysis?

A: Yes, there are. If the Commission grants Idaho Power's request to initiate a docket to establish a compensation structure for customer-owned DERs that reflects both the benefits and costs of DERs, the Commission should specify the use of the best practice benefit/cost methodology that the U.S. utility industry uses to perform such assessments for demand-side resources.

In this regard, the first and perhaps most important observation is that the issues raised by the growth of demand-side DG and other DERs are not new. Solar DG is also not the first type of DER that has raised issues of impacts on the utilities, on non-participating ratepayers, and on society as a whole. The same issues arose when utilities and state regulators began to manage demand growth through EE and DR programs. To provide a framework to analyze these issues in a comprehensive fashion, the utility industry in the

U.S. developed a set of standard cost-effectiveness tests for demand-side programs.[10] These tests examine the cost-effectiveness of demand-side programs from a variety of perspectives, including from the viewpoints of the program participant, other ratepayers, the utility, and society as a whole.

A central goal of this standard practice is to apply to DERs the same cost-effectiveness standards that a commission will use to assess the long-term merits of a new supply-side addition that the utility has asked to add to its rate base. This framework for evaluating demand-side resources is widely accepted, and state regulators have years of experience overseeing this type of cost-effectiveness analysis, with each state customizing how each test is applied and the weight which policymakers place on the various test results. States are now adapting this suite of cost-effectiveness tests to analyses of DERs more broadly, as state legislatures and commissions recognize that evaluating the costs and benefits of all demand-side resources – EE, DR, DG, and other types of DERs – using the same cost-effectiveness framework will help to ensure that all of these resource options are evaluated in a fair and consistent manner.

Each of the principal demand-side cost-effectiveness tests uses a set of costs and benefits appropriate to the perspective under consideration. These are summarized in **Table 1** below. "+" denotes a benefit; "-" a cost.

[10] See the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* (October 2001), available at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF.

Table 1: *Demand-side Cost/Benefit Tests*

Perspective (Test)	DG Customer (Participant)	Other Ratepayers (RIM)	Total Resource Cost to Utility or Society (TRC or Societal)
Capital and O&M Costs of the DG Resource	—		—
Customer Bill Savings or Utility Lost Revenues	+	—	
Benefits (Avoided Costs) -- Energy -- Hedging/market mitigation -- Generating Capacity -- T&D Capacity -- Line losses -- Reliability/Resiliency/Risk -- Environmental / RPS		+	+
Federal Tax Benefits	+		+
Program Administration, Interconnection & Integration Costs		—	—

The key goal for regulators is to implement demand-side programs that produce balanced, reasonable results when the programs are tested from each of these perspectives. A program will need to pass the Participant Test (PCT) if it is to attract customers by offering them an economic benefit for their participation – thus, their bill savings and tax benefits should be comparable to the cost of participating. The program also should be a net benefit as a resource to the utility system or society more broadly – thus, the Total Resource Cost (TRC) and Societal Tests compare the costs of the program to its benefits, which are principally the costs which the utility can avoid from the reduction in demand for electricity.[11] The Ratepayer Impact Measure (RIM) test gauges the impact on other, non-participating ratepayers: if the utility's lost revenues and program costs are greater than its avoided cost benefits, then rates may rise for non-

[11] The Societal Test is a version of the TRC Test which adds the broader benefits of DERs to all citizens as a social whole, and includes benefits that may not be reflected in utility rates.

participating ratepayers in order to recover those costs. This can present an issue of equity among ratepayers. The RIM test sometimes is called the "no regrets" test because, if a program passes the RIM test, then all parties are likely to benefit from the program. However, it is a test that measures equity among ratepayers, not whether the program provides an overall net benefit as a resource (which is measured by the TRC and Societal tests).

Q: Does Idaho use these a set of these tests for evaluating established DERs such as EE and DR programs?

A: Yes. Under the terms of the Memorandum of Understanding for Prudency Determination of DSM Programs, Idaho Power uses three primary cost-effectiveness tests: the TRC, which "reflects the total benefits and costs to all customers (participants and non-participants) in the utility service territory," the utility cost test (UCT), which "calculates the costs and benefits of the program from the perspective of ... the utility implementing the program;" and the PCT, which "assesses the costs and benefits from the perspective of the customer installing the measure."[12] The RIM test "examines the potential impact the energy efficiency program has on rates overall" including impacts to customers who do not participate in the demand-side management (DSM) or net metering programs.[13] Because this is the strictest of the tests, Idaho Power is "not required to use the non-participant ("no losers") RIM test."[14]

Q: Why would you apply a method developed for evaluating DSM programs to evaluate NEM costs and benefits, when a NEM customer can go beyond reducing their own consumption and deliver excess energy to Idaho Power's system?

A: In practice a NEM customer is most similar to an energy efficient customer and is fundamentally different than an independent power producer who seeks to sell all of their output to a utility in a wholesale transaction. NEM systems typically are limited to

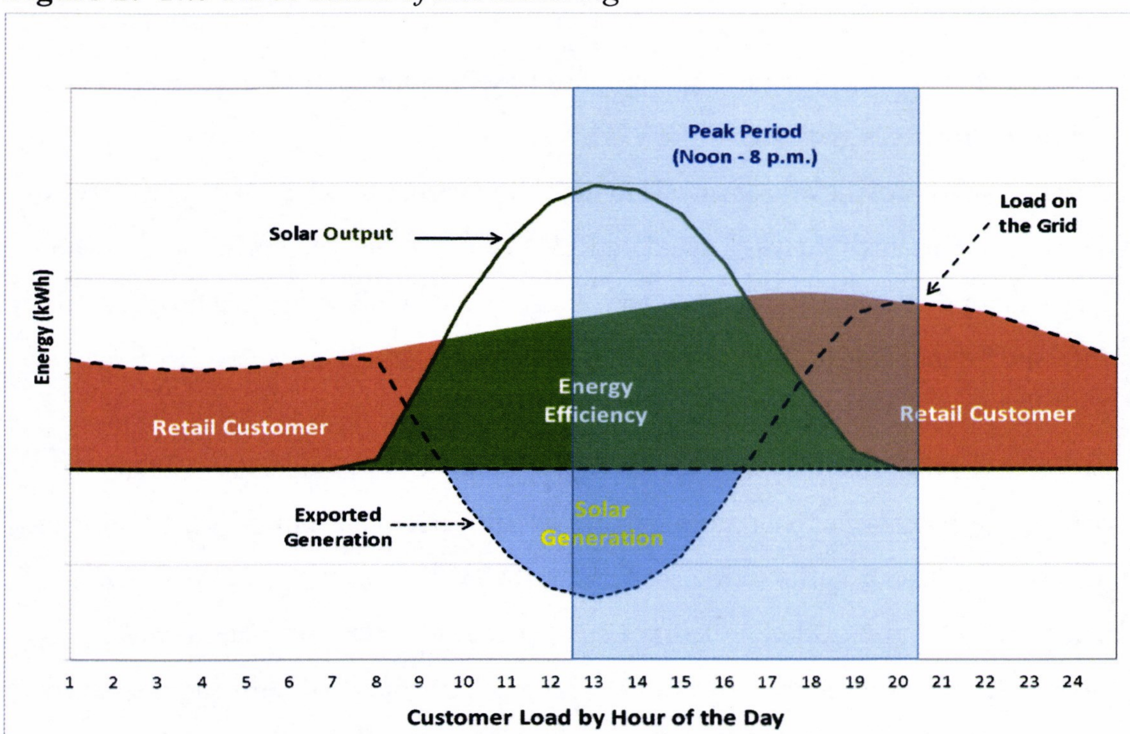
[12] *Order No 32331* at 9 – 10, IPC-E-11-05.

[13] National Action Plan for Energy Efficiency, *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers* at 3-6 (November 2008).

[14] *Order No 28894* at 7, IPC-E-01-13. A RIM score above one indicates rates are likely to decrease due to the net metering program, as has been the case with Idaho Power's net metering program.

having an annual output that is no greater than the customer's on-site load. The utility continues to provide delivered power to serve a significant portion of the customer's load. The Commission has stated that the "primary thrust of net metering," like other demand-side programs, "is to provide customers the opportunity to offset their own load and energy requirements."[15] A significant portion, often over 50%, of the output of a net metered DG system serves the customer's on-site load without ever touching the grid,[16] as illustrated in **Figure 1.** In this respect, the DG customer looks to the utility like an energy efficiency (EE) or demand-side management (DSM) resource. Because of the required focus on serving on-site load, NEM should be evaluated in a manner that is consistent with how other demand-side resources are assessed.

Figure 1: *The Three States of Net Metering*



[15] *Order No. 28951* at 11.

[16] The exact percentage used on-site will depend on the size of the solar DG system compared to the customer's load, and on the customer's load profile through the day. For the typical residential customer (such as shown in Figure 1), 50% or more of the DG output is used on-site, with the rest exported to the grid.

Traditional DSM programs pay customers an incentive to reduce on-site loads. For NEM customers, the "incentive" is crediting, at the energy portion of the retail rate, the portion of the NEM customer's output that is exported to the grid, instead of paying a wholesale power price. This incentive is conceptually no different than a rebate, which is paid to a customer when the customer buys an energy-efficient air conditioner or agrees to manage his irrigation pumping loads. Those DSM programs are analyzed to ensure that the costs and benefits are balanced such that society as a whole benefits and other ratepayers are not unduly burdened. Similarly, any analysis of the benefits and costs of Idaho Power's NEM program going forward should focus on whether NEM provides fair value as a long-term resource, by assessing whether the cost of NEM credits at the retail energy rate are offset by the benefits to other ratepayers from the reduced demand and the new source of power that the NEM customer brings to the grid.

Q: Have you used this approach to calculate the benefits and costs of net metered solar DG on Idaho Power's system?

A: Yes, in part, and I provided this analysis to the Commission in my testimony in Case No. IPC-E-12-27. This analysis was a standard RIM test measuring the impacts of NEM on non-participating ratepayers. As noted above, my recommendation is that any evaluation of NEM should include all of the relevant tests and perspectives, not just a RIM analysis. My analysis compared the retail rate credits paid to solar net metered customers (the primary costs of net metering) to the costs which Idaho Power avoided by not having to procure and deliver alternative power supplies to net metered customers (the benefits of net metering). These benefits were based primarily on avoided cost data from the Company's 2011 and 2013 IRPs. **Table 2** summarizes the costs and benefits that I calculated. My analysis concluded that, for Idaho Power's non-participating ratepayers, the benefits of net metering significantly exceeded the costs, by a factor of 1.6 to 1.9. In other words, my analysis showed that crediting NEM generation at the retail rate for either the Residential or Small Commercial class actually undervalued this new generation source. Notably, my analysis included only generation and transmission benefits, without considering avoided distribution costs (other than avoided line losses) or other benefits that can be quantified (such as lower market prices or the reduction in fuel price volatility).

Table 2: *Summary of Idaho Power NEM Costs and Benefits*

	20-year Levelized $ per MWh
Costs	
Lost Utility Revenues	**$81**
Integration Costs	**$4**
Total Costs	**$85**
Benefits	
Energy	
2011 IRP	$ 92
2013 IRP (estimated)	$ 64
Capacity – both IRPs	$ 40
Transmission – both IRPs	$ 32
Total Benefits - 2011 IRP	**$ 164**
Total Benefits - 2013 IRP	**$ 136**
Benefit / Cost Ratio	
2011 IRP	**1.9**
2013 IRP	**1.6**

Q: Have you updated this analysis based on Idaho Power's 2017 IRP?

A: I have not done a final analysis, in recognition that the scope of this case does not include the quantification of NEM's benefits and costs. My initial analysis of an updated RIM Test indicates that, although the energy and capacity benefits of solar DG are lower today than they were in 2013, these reductions are more than offset when one quantifies the distribution and other benefits of solar DG that I did not quantify in my 2013 testimony. In addition, the Commission should be aware that there is a much broader array of DER technologies on the market or on the horizon today than in 2017.

Q: Please summarize the key attributes of the methodology that the Commission should specify to assess the benefits and costs of net metered DG resources.

A: There are three key attributes:

1. **Analyze the benefits and costs from the multiple perspectives of the key stakeholders.** As discussed above, it is important that the Commission assess the benefits and costs of net metering from the perspectives of each of the major stakeholders – the utility system as a whole, participating NEM customers, and other ratepayers – so that the regulator can balance all of these important interests. Examining all of these perspectives is critical if public policy is to support customer choice and equitable competition between DG providers and the monopoly utility.

2. **Consider a comprehensive list of benefits and costs.** The location, diversity, and technologies of DG resources will require the analysis of a broader set of benefits and costs than, for example, traditional QF facilities installed under PURPA. Renewable DG projects produce power in many small (less than 1 MW) installations that are widely distributed across the utility system. The power is produced and consumed on the distribution system;[17] indeed, each net-metered DG project is generally associated with a load at least as large as the DG project's output,[18] which will limit the amount of power than is exported to the grid. An important attribute of DG exports is their ability to serve loads without the use of the transmission system. Accordingly, an analysis of DG benefits should consider the avoided costs for line losses and for transmission and distribution capacity. Renewable DG also will avoid the costs associated with environmental compliance at marginal fossil-fueled power plants. On the cost side, the analysis should consider whether solar or wind DG will result in new costs to integrate these variable resources.

3. **Analyze the benefits and costs in a long-term, lifecycle time frame.** The benefits and costs of DG should be calculated over a time frame that corresponds to the useful life of a DG system, which, for solar DG, is 20 to 30 years. This treats solar DG on the same basis as other utility resources, both demand- and supply-side. When a utility assesses the merits of adding a new power plant, or a new EE program, the company will look at the costs to build and operate the plant or the program over its useful life, compared to the costs avoided by not operating or building other resource options. The same time frame should be used to assess the benefits and costs of DG.

C. Experience in Other States: Nevada, California, and Utah

Q: Can you provide examples of other state commissions which have developed analyses of NEM using the approach that you recommend?

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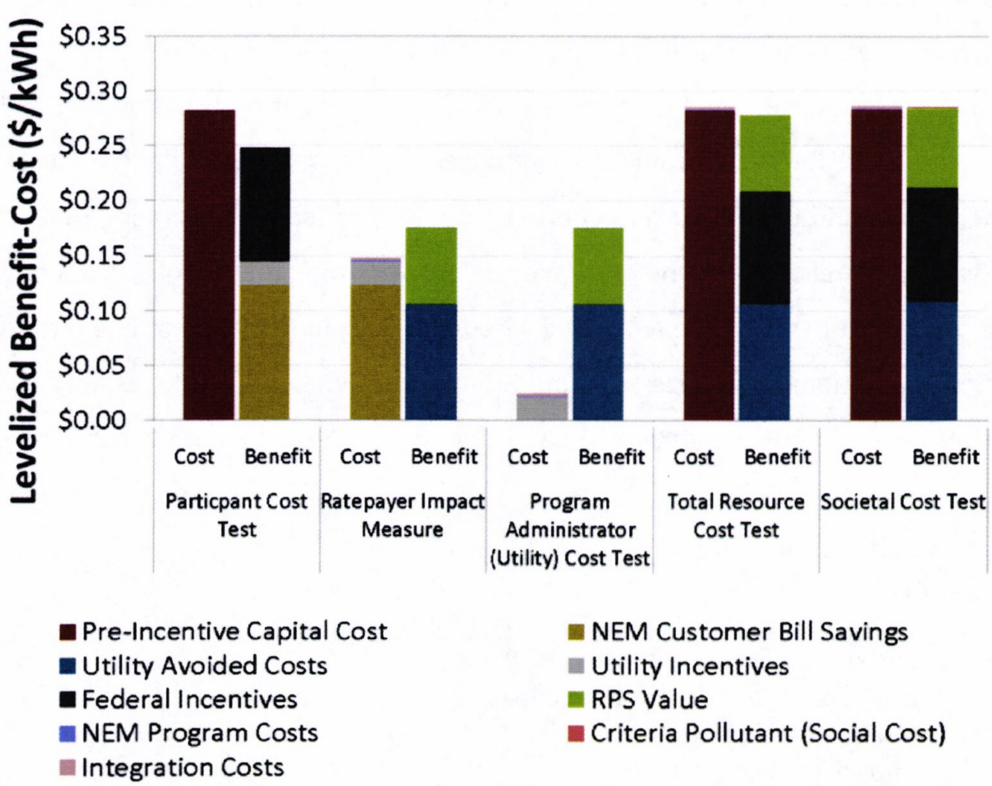
[17] It is possible that, at high penetrations, DG output to a distribution circuit could exceed the minimum load on the circuit, as has occurred at some locations in Hawaii. Such penetrations from NEM customers, the focus of this docket, are not expected to be reached in Idaho for many years.

[18] Idaho Power's current Schedule 84 defines net metering as a service "for Customers to install Generation Facilities to interconnect to the Company's system to offset <u>all or a portion of their electrical usage</u>." Schedule 84 limits the size of NEM facilities for R&SGS customers to no more than 25 kW and for customers other than R&SGS to no more than 100 kW.

A: Yes. The Public Utilities Commission of Nevada ("PUCN") adopted this multi-perspective approach in the net metering study which it released on July 1, 2014. The consulting firm Energy and Environmental Economics (E3) performed the analytic work for this study, and I served on a Stakeholder Committee that the PUCN convened to provide input on the study methodology and analysis. **Figure 2** below shows the costs and benefits of net-metering for solar PV systems in Nevada going forward, in the years 2014-2016, from each of the key stakeholders' perspectives.

Figure 2: *Public Utilities Commission of Nevada NEM Benefit-Cost Results*



Notably, the Nevada study showed that NEM was cost-effective for non-participating ratepayers (i.e., the benefits in the RIM test exceeded the costs), while the costs were somewhat higher than the benefits for participants (i.e., for solar customers). As with any such set of cost-effectiveness tests, it is not reasonable or practical to expect each of these tests to achieve a precise 1.0 benefit/cost ratio. Instead, the goal should be to achieve a reasonable, equitable balance of benefits and costs for all concerned – solar customers, other ratepayers, and the utility system as a whole. In my judgment, the Nevada study demonstrated that, in 2014, NEM at the full retail rate, without any further rate design modifications, achieved that desired "rough justice" balance of interests in Nevada.

Q: Did the Nevada Commission subsequently move away from the use of a long-term benefit-cost approach to analyze NEM in that state?

A: Yes, it did. In 2015, in response to new legislation, the PUCN reviewed a study from NV Energy that was limited to the short-term cost of service for residential and small commercial customers who install solar DG. The PUCN issued a decision in December 2015 which accepted the results of that study, and, based on that evidence, found that there was a significant cost shift from non-participating ratepayers to solar DG customers. As a result, the PUCN ended NEM in Nevada, increased the fixed monthly customer charge for DG customers, and reduced the export rate credited to DG systems from the full retail rate (about 11 cents per kWh for residential customers) to an energy-only wholesale rate of 2.6 cents per kWh. The PUCN took this action even though its order found that there are the following 11 components to the value of DG (based on an adopted stipulation on NEM issues from South Carolina), and that it was only able to quantify the first two components of DG value in the adopted 2.6 cents per kWh export rate:

1. Avoided energy costs
2. Line losses
3. Avoided capacity
4. Ancillary services
5. Transmission and distribution capacity
6. Avoided criteria pollutants
7. Avoided CO_2 emission costs
8. Fuel hedging
9. Utility integration and interconnection costs
10. Utility administration costs
11. Environmental costs

Q: What was the result of the PUCN decision?

A: The reduction in the export rate and the increased fixed charge reduced the bill savings available to NEM customers in Nevada by 40% or more. DG was no longer economic for new systems, and existing customers who expected modest savings from their solar investments faced substantial added costs for electric service. Even though the PUCN subsequently decided to phase-in the new DG rates over a 12-year period, the elimination of NEM and, in particular, the reduction in the export rate, decimated the rooftop solar market in Nevada, resulting in more than 1,000 documented layoffs at solar companies. The controversy was particularly heated because the PUCN applied the new rates to existing solar customers as well as to prospective ones. The changes sparked significant public outcry, a ballot initiative, and lawsuits from unhappy customers whose investments in renewable DG had been severely and unexpectedly rendered uneconomic.

In 2016, the PUCN reversed course, asked E3 to re-evaluate the benefits and costs of solar DG, and subsequently adopted a limited reopening of full retail net metering in northern Nevada.[19] In the order re-instating net metering, the new chair of the PUCN wrote:

> The landscape on these issues continues to grow. Abraham Lincoln once said that 'Bad promises are better broken than kept.' The PUCN's prior decisions on NEM, in several respects, may be best viewed as a promise better left unkept. The PUCN is free to apply a new approach.[20]

The PUCN also reversed course on the treatment of existing NEM customers, adopting a grandfathering policy that will allow them to net meter at full retail rates for a 20-year period.[21]

Pursuant to 2017 legislation (AB 405), the compensation for the exports from new solar DG customers in Nevada has been set at a small (5%) discount to the retail rate, with the discount increasing in steps for every 80 MW of DG that is installed. The compensation structure for exports is guaranteed for 20 years for new DG customers. The legislation also includes consumer protection provisions and a Solar Bill of Rights specifying that every Nevada customer has the right to generate and store solar energy and providing that

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[19] See https://www.greentechmedia.com/articles/read/nevada-regulators-retore-retail-rate-net-metering-in-sierra-pacific-territo.

[20] See PUCN Order in Dockets Nos. 16-06006 *et al.* issued December 20, 2016, at p. 39. Available at http://pucweb1.state.nv.us/PDF/AXImages/Agendas/25-16/6801.pdf.

[21] See https://www.greentechmedia.com/articles/read/nevada-regulators-restore-net-metering-for-existing-solar-customers#gs.aExnCD4.

each solar customer will be in the same class and have the same rate options as non-solar customers.[22]

Q: Did the California Public Utilities Commission recently review the benefits and costs of net metered DG?

A: Yes. In 2015, the investor-owned utilities in California were approaching that state's 5% cap on NEM systems. The California Commission asked parties to analyze their proposals for a NEM successor tariff using a common "Public Tool" spreadsheet program similar to the Nevada NEM benefit-cost model. Like the Nevada model, the California Public Tool analysed a proposed tariff from multiple perspectives, using all of the SPM's cost-effectiveness tests and looking at the long-term, life-cycle costs and benefits. The CPUC received detailed analyses of NEM benefits and costs using the Public Tool from a variety of parties. In January 2016, the California commission decided to extend NEM in California until a further review in 2019, with certain changes such as requiring NEM customers to be on time-of-use ("TOU") rates, removing certain public benefit charges from export rates, and requiring NEM customers to pay interconnection costs.[23] The CPUC's order does not rely on the Public Tool analyses, because important information related to both costs (rate design changes) and benefits (locational benefits on the distribution grid and societal benefits) remain under development in other CPUC proceedings. However, the CPUC made clear that it intends to continue to refine and to use this SPM-based, long-term benefit-cost approach in its future evaluations of NEM and DG.

Q: The Utah commission recently approved a settlement with a process for reviewing the benefits and costs of NEM in that state.[24] Please comment on the Utah stipulation.

[22] The PUCN implemented the provisions of AB 405 on September 1, 2017 in its *Order Granting in Part and Denying in Part Joint Application by NV Energy on Assembly Bill 405* in PUCN Docket No. 17-07026.

[23] See CPUC Decision No. 16-01-044 (January 28, 2016), in Docket R. 14-07-002.

[24] See the Settlement filed August 28, 2017 in Public Service Commission of Utah Docket No. No. 14-035-114.

A: In Utah, Rocky Mountain Power (RMP) and a range of parties, including solar advocates, reached a settlement under which RMP withdrew a proposal to increase fixed charges and to implement a demand charge for residential customers who install DG. The utility had justified this proposal with a cost-of-service analysis. The settlement provides for a transition period during which there will be a defined export rate comparable to current retail rates for new NEM customers. For delivered power during the transition period, new NEM customers will continue to take service under their standard, otherwise-applicable rate, and will remain in their present rate class.[25] The future rates applicable to these new DG customers will be adjudicated in future general rate cases.[26] Export rates after the transition period will be determined in a future proceeding in which parties can submit testimony on reasonably quantifiable costs and benefits or other considerations.[27] The settlement includes a grandfathering period for existing NEM customers through December 31, 2035, with existing NEM customers allowed to remain in their current rate class and subject to the rates adopted for that entire class.[28]

D. The DG Customer as "Prosumer"

Q: The framework you have proposed and illustrated draws on benefit/cost analyses used for other types of demand-side programs. But isn't there a crucial difference between DG and other demand-side resources: DG is generation that at times can supply power to the grid, whereas EE and DR only reduce the demand for power?

A: This difference exists, is important, and should be considered. DG located behind the meter will both reduce the demand for power from the utility, and, at times, will supply power to the utility. On-site storage units can supply stored energy to the grid at a different time than when the power was produced. When a DG system or storage unit produces more power than the on-site load requires, the excess is exported to the grid, and the DG owner is no longer a consumer, but becomes a supplier (i.e. a generator).

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[25] *Ibid.*, at Section 25.
[26] *Ibid.*, at Section 27.
[27] *Ibid.*, at Section 30.
[28] *Ibid.*, at Sections 12 and 13.

Some have applied a new label – "prosumers" – to DER customers in recognition of this dual role.

Q: Does the fact that DG customers also export power mean that they make "bi-directional" use of the grid, i.e. they use the grid more than a standard, non-DG customer, as the Company's Mr. Angell argues?[29]

A: No. Mr. Angell claims that "[a] net zero customer utilizes all aspects of Idaho Power's grid during the hours they are consuming energy (including the generation, transmission, and distribution systems) and utilizes the distribution system during the hours they are exporting energy to the grid." This view confuses who is providing a service to whom when the DG customer exports power.

The fundamental flaw in Mr. Angell's argument is the assumption that, when a solar customer exports power to the grid, it is the solar customer who is taking service from the utility. Clearly, the opposite is true: when a solar customer exports power to the utility, it is the solar customer that is providing a service – generation – to the utility. Once the exported power passes the DG customer's meter, the <u>utility</u> takes title to the exported power. It is the <u>utility</u> that delivers the exported DG power to the DG customer's neighbors. It is the <u>utility</u> that is compensated by the neighbors for the service that the utility provides in delivering the DG exports to them.[30] Thus, it is the utility and the neighboring customer that use the distribution system to deliver the DG exports. The DG customer is in no way responsible for the delivery of their exported power, has no control over who receives their exports, and receives no compensation for the delivery of the exports. DG exports are a service – generation – that the DG customer provides to the utility at the DG customer's meter, and it is a service that ends at that meter when the

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[29] Idaho Power testimony (Angell), at pp. 10-14.

[30] Indeed, the utility charges and receives its full delivery rate from the neighbors when the neighbors' meters roll forward and consume the DG exports, even though the utility needs to use only a small portion of its distribution system to make this delivery. It is the utility's use of DG exports to serve other nearby customers that makes available upstream capacity that the utility then can use to serve other customers and satisfy growing loads elsewhere without upgrades. The utility's use of DG exports thus allows it to avoid both generation and delivery costs.

utility accepts the DG exports into its distribution system. This is no different than the generation service that any other third-party generator, of any size, provides to the utility. Accordingly, since the DG customer does not receive service from the utility system when DG exports are delivered, <u>the DG customer actually uses the distribution system less than a regular non-DG customer of comparable size</u>. It would be wrong to allocate costs to DG customers associated with their exports and thus to charge them for the distribution costs associated with delivering their exports. By doing so, the utility would double-recover its costs to deliver the DG exports:

1. once from the neighboring customers to whom the utility actually delivers the exports, and

2. again from the DG customer whose rate is wrongly and artificially increased by the export-related delivery costs that the utility assigns to the DG class.

Q: In a recent proceeding concerning the rates for DG customers in Arizona, several of the utility witnesses analogized net metering to a customer borrowing his neighbor's car, then driving it both forward and backwards, such that the odometer reading has not changed when the car is returned even though many miles of wear & tear had been put on the car.[31] Why is this analogy flawed?

A: This analogy fails to recognize that it is the DG customer that is providing a service when it exports power. The correct analogy is that, when the DG customer imports power and runs the meter forward, it is receiving a service from the utility which is analogous to you borrowing your neighbor's car. When the DG customer exports power and runs the meter backward, it is providing a service to the utility – with the correct analogy being your neighbor borrowing your car. If your neighbor drives your car the same number of miles that you drove his car, then both sides received equal value and no compensation needs to be paid. The error that the utility witnesses made is to assume incorrectly that when a DG customer exports power to the utility, the DG customer is somehow receiving a service from the utility. The DG customer is not taking service from the utility – it is

[31] See Arizona Corporation Commission (ACC) Docket No. E-01933A-15-0322 (Phase 2 of the Tucson Electric Power [TEP] rate case), TEP Rebuttal Testimony of Dallas Dukes, at p. 22; also, TEP Rebuttal Testimony of Craig Jones, at p. 19. This testimony was served August 28, 2017.

providing a service (generation) to the utility for which it is compensated by running the meter backward.

Q: So if a NEM customer ends up with a small, zero, or even negative bill at the end of a month, does this mean that the NEM customer is not paying for the utility service the customer is receiving?

A: Absolutely not. First, whenever the solar customer uses the utility system (by importing power and rolling the meter forward), the solar customer pays fully for the use of the utility system, at the same rate as any other customer. If the solar customer ends the month with a small or zero bill from the utility, this is the result of crediting the customer for the value of the power which the customer supplies to the utility (from exporting power and running the meter backwards). These credits can offset the solar customer's costs of utility service when the customer imports power and the meter runs forward. However, these credits are not the result of the solar customer's use of the utility system; instead, they are the means to account for the exported generation which the solar customer has provided to the utility at the meter. Thus, the solar customer has paid fully for all actual use which the customer has made of the utility system, even though the customer's net bill at the end of the year may be small or even zero. The key public policy issue is whether the bill credits for exported power at the retail rate are the right credit for those exports – and the upcoming benefit / cost study should be designed to determine this – but this does not change the fact that the solar customer has paid fully for his or her actual use of the utility system.

Q: Does the utility incur costs to "stand by" to serve a solar customer when the solar customer is exporting power to the grid?

A: No. The costs which the utility incurs to serve a solar customer are no different than those it incurs to stand by to serve a regular utility customer whose usage for periods may be very low – for example, in the middle of the day when the occupants of a house are away at work and school – but who may suddenly impose a load on the system. As a consumer, a solar customer looks like a customer who uses power in the morning, evening, and at night, but who turns everything off in the middle of the day, as illustrated by the dashed "Load on the Grid" line in Figure 1. Such a customer may come home unexpectedly in the middle of the day, turn on lights, a computer, and run an appliance, and produce a sudden spike in usage. But these load fluctuations are something the utility is well-prepared to serve on an aggregate basis, and the costs of such normal "stand by" service are included in the utility's regular rates. Similarly, a solar customer may suddenly impose a demand on the system if a cloud temporarily covers the sun in the middle of the day. Again, however, this variability is manageable due to the small sizes, large numbers, and geographic diversity of solar DG systems – for example, at the time one PV system is being shaded, another will be coming back into full sunlight.[32]

Q: Doesn't the utility incur costs to store the excess kWh produced by NEM systems, allowing the NEM customer to "bank" kWh which the customer uses later when the meter is rolling forward?

A: No. Net metering does not involve the storage of electricity, or of energy in any form. This idea is one of the common myths of net metering. Again, the NEM customer is both a consumer and generator of electricity. When the NEM customer is a generator, exporting power in excess of the onsite load, as a matter of physics that generation is immediately consumed by nearby customers. In no way is the power stored for later use. When the solar customer later consumes power from the grid – for example, after the sun sets – the power used is generated and transmitted by the utility at that time. The fact that NEM credits from exports are used to offset the costs of subsequent usage simply represents an accounting transaction – offsetting a credit with a debit on the customer's account by changing the direction that the meter is recording; it does not represent any actual use of the grid to "store" or "bank" electrons or energy.

[32] It is possible that, as solar penetration increases, the aggregate variability of all solar customers' electric output may add to the variability of the power demand that the utility must serve, and impose additional costs for regulation and operating reserves on the system operator. The costs of meeting this added variability is one of the factors considered in solar integration studies. Generally, these studies show that such costs are low at the current level of solar DG penetration. See, for example, *Duke Energy Photovoltaic Integration Study: Carolinas Service Areas* (Battelle Northwest National Laboratory, March 2014), calculating that, with 673 MW of PV capacity on the Duke utility systems in 2014, integration costs are about $0.0015 per kWh. See Table 2.5 and Figure 2.51. It is my understanding that Idaho Power completed a Solar Integration Study in April 2016 that calculated an integration cost of $0.56 per MWh, for projects beginning in 2018 at the Company's current solar penetration level of 301-400 MW.

Q: But doesn't the DG customer, as a generator, derive some benefit and bear some responsibility for the fact that the utility builds and maintains a T&D system that is able to accept the DG customer's exported generation?

A: Yes. When a generator of any size – including DG – is seeking to connect to the T&D system, it is the purpose of the interconnection process to ensure that the grid is able to accept the new generator's exports to the grid. If a new generator seeks to interconnect to the utility system in a location that does not have adequate capacity to accept the incremental generation, then the generator must pay the system upgrade costs required to provide adequate capacity. However, once they have interconnected, generators are not required to pay for the delivery capacity that the utility then uses to deliver the generators' output to the utility's customers. The ongoing delivery of power is a service that the utility provides to its end use customers who consume power; it is not a service that the utility provides to generators who produce power. The utility's interconnection process determines whether the utility has adequate capacity to allow deliveries of exports (and the generator must pay upfront for the necessary capacity if the utility does not). Once it is determined that the utility has adequate capacity to accept the new generation, the utility does not continue to charge the generator for delivery capacity on an ongoing basis.

E. PURPA Considerations

Q: Do most customers who install DG have status as "qualifying facilities" (QFs) under the Public Utilities Regulatory Policies Act of 1978 (PURPA)?

A: Yes. I am not a lawyer, but I have done a significant amount of work for QF clients, and it is my understanding that renewable DG customers typically have legal status as "small power producer" QFs under PURPA.[33] As a result of DG customers' QF status, the serving utility is required under this federal law to do the following:

[33] For a customer installing a renewable DG facility with a net power production of 1 MW of less, it is my understanding that the designation as a qualifying small power production facility (and therefore a QF) is automatic with no filing at the Federal Energy Regulatory Commission (FERC) required.

- to interconnect with a customer's renewable DG system,
- to allow a DG customer to use the output of his system to offset his on-site load, and
- to purchase excess power exported from such systems at a state-regulated price that is based on the utility's avoided costs.[34]

These provisions of federal law are independent of whether a state has adopted net metering. Thus, the adoption of NEM only impacts the accounting credits which the customer-generator receives for power exports to the grid.

Q: Does PURPA also have requirements concerning the sale of power from utilities to QFs?

A: Yes. The rates for the sale of power from an electric utility to the QFs on its system must comply with the FERC rules implementing PURPA. Generally, these rules specify that the rates for sales to QFs must be non-discriminatory. QFs have the right to purchase supplementary power (defined as the power the QF needs beyond what the QF's own on-site generator can supply) at rates which are just and reasonable, that do not discriminate against QFs in comparison to the utility's other retail rates, and that are based on accurate data and consistent system-wide costing principles.[35] Significantly, the FERC rules create a safe harbor against claims of discrimination to the extent that QFs pay the same rates as similar customers:

> *Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.*

The creation of separate DG/QF customer classes with distinct rates from other residential and small commercial customers represents a move away from this safe harbor. For example, residential customers who install DG (and thus who become QFs and move into a possible new class of partial requirements, QF/DG customers) would no

[34] The PURPA requirements can be found in 18 CFR §292.303.

[35] 18 CFR §292.305(a) and (b). Also see "What are the benefits of QF status?" on the FERC website: http://www.ferc.gov/industries/electric/gen-info/qual-fac/benefits.asp. Supplementary power is power that the QF/DG customer regularly purchases from the utility in addition to its on-site production.

longer be considered “similar” to, and may no longer pay the same rates as, other residential customers.

Q: Are there circumstances under which Idaho Power’s proposed residential and small commercial DG classes may be considered discriminatory under PURPA?

A: Yes. For example, as discussed above, if DG customers are charged costs to deliver the generation that they export in addition to the delivery service which they take from the utility, the resulting rates for DG customers could violate the non-discrimination standards of PURPA. The cost-based rates for DG customers, like the rates for all other customer classes, should be based on the service which the utility actually provides to solar customers – in other words, on the delivered loads which DG customers take from the Idaho Power system. Rates for DG customers that are set on any other basis may violate requirements that the rates for sales to QFs (i.e. to DG customers) must not discriminate against such customers. Establishing a separate customer class for DG customers does not solve this problem for the utility. If no other partial requirements customers of Idaho Power are charged or allocated costs based on the amount of power that they export to the utility, then the utility cannot lawfully charge DG customers rates that are calculated based on the power that the DG customers export to the utility.

Q: How should Idaho Power set rates for DG customers?

A: Idaho Power should calculate the cost of service for all DER customers based on the loads which the utility actually delivers to DG customers, just as the company does for all other customers. Idaho Power’s delivered loads include all solar customers' actual demand on the system, including the effect of added demand when a solar system is out of service or when it is cloudy. The delivered load data is the evidence-based, PURPA-compliant foundation for allocating costs because it "reflects the probability that the [QF customer] will or will not contribute to the need for and the use of utility capacity."[36]

[36] *See* 45 Fed. Reg. at 12228.

F. DERs Provide Distribution System Benefits.

Q: Mr. Angell argues that increases in the installation of solar will reduce local distribution infrastructure investment only in very limited circumstances. Please respond.

A: Mr. Angell's conclusions are based on a study comparing solar output profiles to a single selected distribution circuit in the Treasure Valley that serves primarily residential customers.[37] However, I would draw different conclusions from this study than Mr. Angell does:

- Figures 3 and 4 of the study actually show 10% reductions in circuit peak loads as a result of the solar DERs. If load on the circuit is growing at 2% per year, such reductions in peak loads could defer an upgrade by at least four years.

- Circuits serving a higher proportion of commercial loads would peak earlier in the day, would be a better match for DG solar output, and could show even longer deferrals.

- In the future, the pairing of solar plus storage, or solar plus demand response technologies, has the potential to allow DER output to closely match distribution substation or circuit needs, providing even greater distribution benefits than illustrated in this study.

Q: Mr. Angell also asserts that any distribution benefits will be limited to the five-year period in which Idaho Power plans distribution upgrades and expansions.[38] Do you agree with this point?

A: No, I do not. Many types of DERs have useful lives well beyond five years, and thus will reduce peak loads on the distribution system for longer than five years. For example, solar DG has a useful life of 20-30 years, today's commercial storage units are expected to operate for 10 years, and energy efficiency measures can have lives in excess of 10 years. As a result, DERs can avoid future distribution upgrade costs that are not within the shorter time horizons that utilities use for distribution planning. Similarly, new

[37] Idaho Power testimony (Angell), at pp. 15-20.
[38] *Ibid.*, at pp. 18-19.

independent wholesale generation (e.g. QFs) or customer-sited resources (e.g. DERs) that are built today will impact the utility's future load and resource projections for the full planning period in its next Integrated Resource Plan (IRP), and thus can defer or displace generation resources that are not planned to be operational for many years.

Even within the shorter-term planning processes for distribution, utilities in many areas of the U.S. increasingly are incorporating DERs as "non-wires alternatives" that can be less expensive than distribution upgrades. This represents a natural extension of the well-accepted use of EE and DR resources to "manage" the growth of the demands for electric energy and capacity, thus avoiding the need to build more generation and transmission infrastructure.

Q: Have you conducted, or are you aware of, studies of the benefits of DG that have looked at a broad range of load profiles across the distribution system and which have found that DG can allow a utility to avoid significant long-term distribution capacity costs?

A: Yes. The "Public Tool" benefit/cost model of renewable DG developed by Energy and Environmental Economics (E3) for the California Public Utilities Commission ("CPUC") includes a calculation of the benefits of DG in avoiding sub-transmission and distribution capacity costs for the California utilities.[39] This model begins with the utilities' long-run marginal sub-transmission and distribution capacity costs, which are calculated through a regression of at least 15 years of historical and forecasted T&D investments as a function of peak demand. These avoided sub-transmission and distribution capacity costs then are allocated to each hour of the year using a set of "peak capacity allocation factors" ("PCAFs") based on hourly data on each utility's substation loads. The PCAFs are hourly allocation factors that give a non-zero weight only to those substation loads that are within 10% of the annual peak load at each substation, using this formula:

[39] The CPUC's Public Tool model and the association documentation are available at http://www.cpuc.ca.gov/general.aspx?id=3934. The marginal subtransmission and distribution costs are shown in Lines 323-350 of the "Avoided Cost Calcs" tab; the PCAF allocation factors by TOU period are listed in Lines 352-371 of the same tab.

$$PCAFs(h)=Loads(h)-Thresholdsk=18760\ Max[0,(Loadsk-Thresholds)]$$

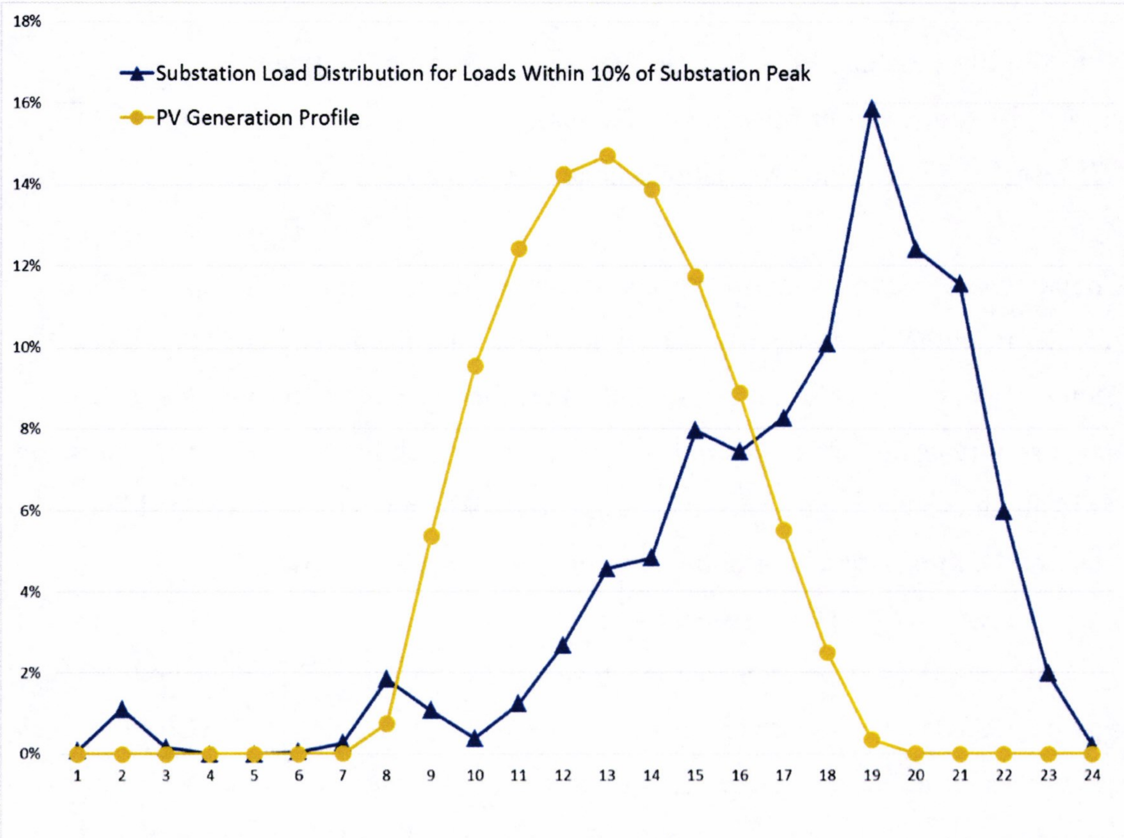
where:

$PCAF_s(h)$ = peak capacity allocation factor for substation *s* in hour *h*,
$Load_s(h)$ = the load for substation *s* in hour *h*, and
$Threshold_s$ = 90% of the substation *s* annual peak load.

All hours where the substation load is below 90% of the annual peak have a PCAF of zero. The resulting hourly distributions of marginal sub-transmission and distribution capacity costs are applied to the hourly output profile of solar DG resources to calculate avoided sub-transmission and distribution costs. The resulting avoided sub-transmission and distribution capacity costs are about $0.03 per kWh (not including avoided line losses) for the three major California investor-owned electric utilities.

As another example from Colorado, we applied the same PCAF method to hourly substation load data that we obtained from Public Service of Colorado (PSCo) for the 58 distribution substations at which a majority (55%) of the solar DG on the PSCo system was installed. For each substation we developed the hourly PCAF allocation that measures, in each hour, how close that substation is to its annual peak, for all hours with loads within 10% of the annual peak hour load. **Figure 3** shows the resulting average PCAF allocation for each hour of the day across all 58 substations, weighted by the amount of solar DG installed at each substation. The figure also shows a typical south-facing PV output profile for Boulder, Colorado. As the figure shows, the substation peaks tend to occur later in the day, with the peak in the allocation around 7 p.m., due to substations that largely serve residential load. We applied this allocation to the typical hourly PV output profile for Boulder to determine the portion of PSCo's marginal distribution capacity costs that DG can avoid. The result is that one kW of DG nameplate capacity (south-facing) can avoid 0.23 kW of PSCo's marginal distribution capacity costs. This can be considered a measure of the "effective load carrying capacity" (ELCC) of solar DG with respect to PSCo's distribution capacity costs.[40]

Figure 3: *PSCo Substation PCAF Distribution of Loads within 10% of Substation Peak*



Q: Do you have comparable data for substations on Idaho Power's system?

A: Yes. In discovery, the Company provided hourly loading data for 2016 for 12 substations on its system for which it is undertaking upgrade projects. We derived an hourly PCAF allocation based on the loads at these substations that are within 10% of the annual peak hour load. This result is shown in the solid black line in **Figure 4**, which also shows the hourly output profiles for south- and west-facing PV arrays in Boise. Based on our analysis of this limited sample of substations, we obtained similar results to our PSCo analysis. For these Idaho Power substations, one kW of DG nameplate capacity (south-

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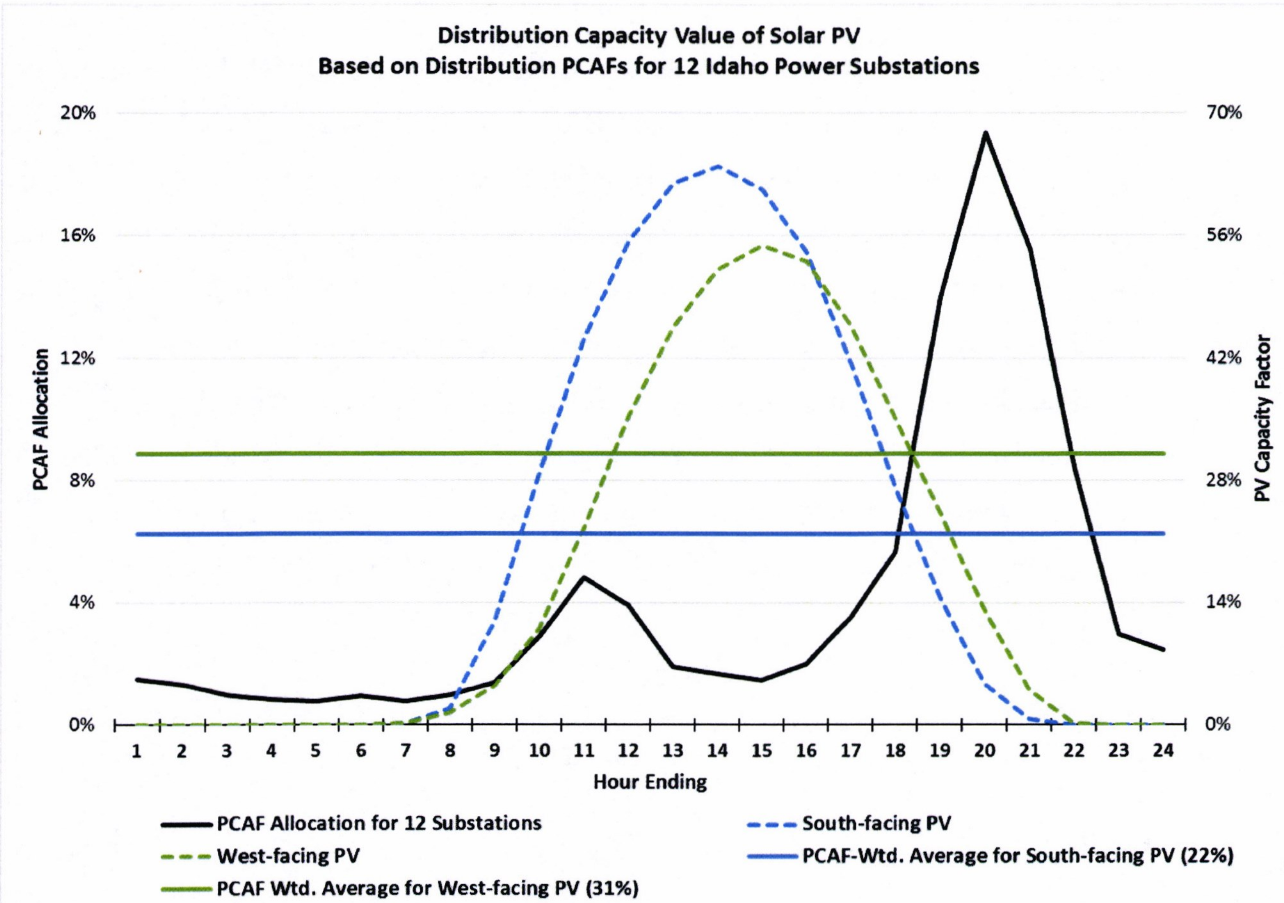
[40] Crossborder Energy, *Benefits and Costs of Solar Distributed Generation for the Public Service Company of Colorado: A Critique of PSCo's Distributed Solar Generation Study* at 9-11 (December 2, 2013). This study was filed in Colorado Public Utilities Commission Docket No. 13A-0836E on behalf of The Alliance for Solar Choice.

facing) can avoid 0.22 kW of marginal distribution capacity costs; one kW of west-facing DG capacity avoids 0.31 kW of marginal distribution capacity costs.

Figure 4:



Q: How can DERs maximize the distribution benefits that they provide to the utility?

A: There are several ways to maximize these benefits. First, time-of-use (TOU) rates can be designed that encourage DERs to reduce customers' loads and/or increase exports to the grid during times when the local distribution circuit is expected to peak. For example, looking at Figure 4, Idaho Power could design on-peak TOU hours and rates that focus on late afternoon hours. This would encourage new DER customers to orient their solar systems to the west, or to install on-site storage, so that DER output is maximized in the hours when it is most effective at reducing peak distribution system loads.

In addition, some distribution substations and circuits are closer to capacity than others, and DERs installed on those constrained parts of the distribution system will provide greater benefits than in other locations. In other words, there is significant variation in marginal distribution costs by location, and constrained parts of the distribution system will have marginal costs that are far higher than the system average. **Figure 5** shows the marginal distribution costs of the three large California electric utilities disaggregated by distribution planning area (DPA).[41] Some DPAs have marginal distribution costs that are significantly greater than other DPAs and larger than the overall system average. Studies of other utilities in the U.S. also have demonstrated a wide range of marginal distribution costs.[42] **Table 3** shows similar disaggregated data for Pacific Gas & Electric (PG&E).[43] PG&E's system average marginal primary distribution cost is $39.43 per kW-year (see the bottom line of the table), but some of its divisions have much higher marginal distribution costs. Thus, if DERs can be targeted to the parts of the system where they are most needed, i.e. where marginal distribution costs are the highest, they can produce significantly greater benefits than what are estimated using system-wide marginal distribution costs.

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[41] Energy & Environmental Economics, *Workshop Discussion: California Locational Net Benefits Analysis Update* (September 20, 2017 presentation in the New York REV process), at Slide 21.
[42] *Ibid.*, at Slide 14.
[43] PG&E Testimony in CPUC Docket A. 16-06-013, Exhibit PG&E-9, Chapter 6, at p. 6-2 (Table 6-1), served December 2, 2016.

Figure 5:

Distribution Avoided Costs by Planning Area ($/kW-year):

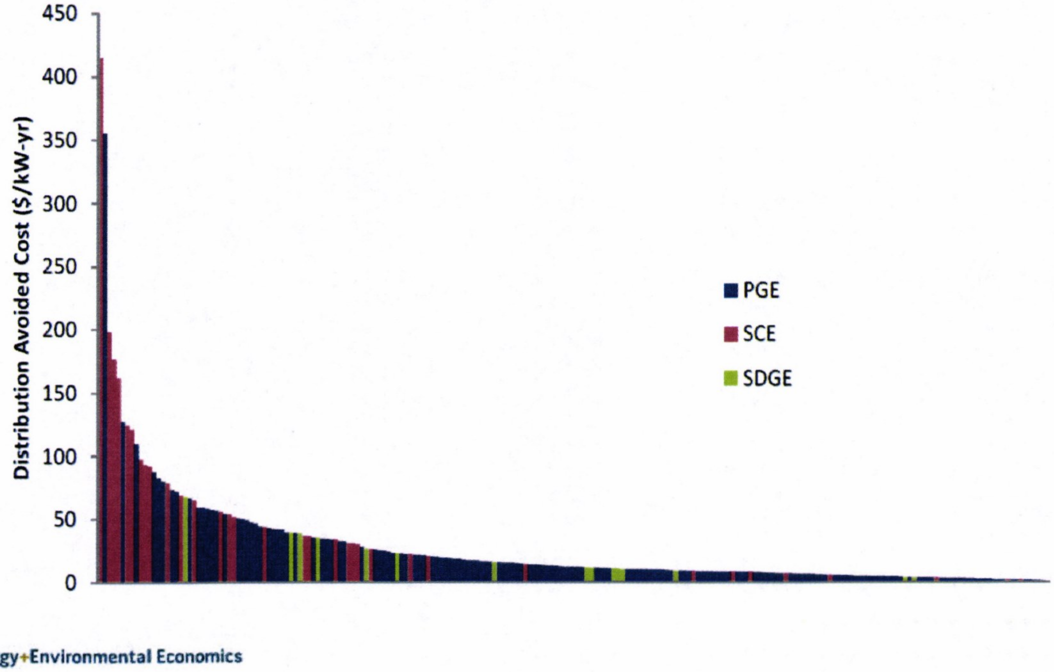

Table 3: *PG&E Marginal Distribution Costs by Division*

TABLE 6-1
MARGINAL DEMAND-RELATED PRIMARY AND SECONDARY DISTRIBUTION CAPACITY COSTS BY DIVISION AND SYSTEM AVERAGE

Line No.	Division	Primary Distribution $/PCAF kW	New Business on Primary Distribution $/FLT kW	Secondary Distribution $/FLT kW
1	Central Coast	$69.09	$14.53	$1.04
2	De Anza	$35.65	$19.66	$1.01
3	Diablo	$17.78	$23.20	$1.56
4	East Bay	$19.99	$18.07	$0.88
5	Fresno	$39.52	$15.81	$1.36
6	Humboldt	$73.97	$14.20	$1.12
7	Kern	$34.07	$16.08	$1.23
8	Los Padres	$56.49	$14.41	$1.06
9	Mission	$13.63	$16.37	$0.97
10	North Bay	$29.42	$14.62	$1.75
11	North Valley	$53.40	$19.23	$1.26
12	Peninsula	$31.79	$14.02	$1.06
13	Sacramento	$40.91	$16.49	$1.22
14	San Francisco	$40.41	$19.69	$1.52
15	San Jose	$40.12	$17.45	$1.16
16	Sierra	$30.65	$20.07	$1.25
17	Sonoma	$121.98	$16.65	$1.28
18	Stockton	$33.36	$15.13	$1.34
19	Yosemite	$60.18	$15.63	$1.56
20	System	$39.43	$16.42	$1.25

III. PROVIDING CERTAINTY FOR DG CUSTOMERS

Q: Idaho Power proposes that existing NEM customers should be able to stay under current net metering rules (i.e. should be "grandfathered"), but only for a period to be determined in a future rate proceeding.[44] Please comment.

A: The utility suggests, but does not propose, that the period of grandfathering might be based on the payback period for a residential solar facility in Boise, which the utility calculates to be approximately 15 years.[45] From my review of the utility's 15-year payback calculation,[46] Idaho Power uses a simple payback calculation which underestimates a realistic payback period by failing to discount the customer's future bill savings. When the DG customer's time value of money is included in the bill savings calculation by discounting future bill savings to recognize their present value, the realistic payback period exceeds 20 years and thus is likely to require the full economic life of the solar DG system.

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[44] Idaho Power testimony (Tatum), at pp. 23-25.
[45] *Ibid.*, at p. 24.
[46] Provided in response to Vote Solar Request No. 48.

Q: What are your views on the grandfathering policy that the Commission should adopt for existing NEM customers?

A: Grandfathering policy is very important, for both existing and new DER customers, given the rapid changes occurring in the utility industry. DERs represent long-term economic investments by utility customers in new clean energy infrastructure. Just as a utility will not invest in new facilities unless it has a reasonable and certain opportunity to recover those investments over the long term, with an adequate return, customers will be reluctant to make long-term investments in DERs unless they have a reasonable understanding of the economics and an acceptable level of certainty in those economics. Net metering has been a successful policy nationally in large part because it is simple and understandable for customers. Customers understand that the level of their rates will change under NEM, and are familiar with how their utility rates have escalated in the past. A key to providing the needed certainty for NEM customers is adopting a grandfathering policy that ensures that DG customers can remain under the rules and rate structure that applied when they originally made their investment, for the reasonable economic life of the system.

Q: What has been the experience with grandfathering policies in other states with much higher penetrations of DERs?

A: Customers who have gone through the process to make the long-term investment to install renewable DG or other types of DERs learn much about their energy use, about utility rates, 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.[47] As we have seen recently in Nevada, 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

[47] Emerging storage and energy management 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 traditional 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, it is critical for regulators and utilities to avoid alienating their most engaged and concerned customers.

in clean energy infrastructure that is provided to the utility's investments and contracts. As the experience in Nevada showed, what customers do not like is unexpected changes in the fundamental structure of NEM that substantially undermines the economics that they had depended on when they made the investment. Generally, regulators in states with high-penetrations of solar DG have uniformly adopted grandfathering policies that allow existing NEM customers to remain under the rules and rate structure that applied when they originally made their investment, for the reasonable economic life of the system, i.e. for at least 20 years. This includes grandfathering policies adopted in Arizona,[48] California,[49] Hawaii,[50] New Hampshire,[51] and Nevada[52] when each of these states has made changes in the terms and conditions of NEM.

Q: What is your recommendation for the NEM grandfathering policy that the Commission should adopt with respect to solar DG?

A: The Commission should establish a clear policy that existing NEM customers will be allowed to remain under the rules and rate structure[53] in effect when they originally applied for interconnection with the utility, for a 20-year period beginning on that application date. This grandfathering period is based on the reasonable economic life of a solar DG system. Finally, the customers eligible for grandfathering should be those who submit applications for interconnection on or before the date that falls 60 days after the Commission's decision implementing the change to net metering. I oppose the Company's proposal to make the date of eligibility for grandfathering retroactive to

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48 See ACC Decision No. 75859, at pp 155-156.

49 California PUC Decision No. 14-03-041 adopted a 20-year transition period for existing NEM customers, see pp. 2 and 38 (Ordering Paragraph No. 1). See http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K386/89386131.PDF.

50 Hawaii PUC Order 33258 at pp. 164-165 determined that existing NEM customer' agreements will continue. See http://puc.hawaii.gov/wp-content/uploads/2015/10/2014-0192-Order-Resolving-Phase-1-Issues-final.pdf.

51 See New Hampshire Public Utilities Commission, Order No. 26,029 (June 23, 2017), at pp. 2 and 51.

52 See http://www.rgj.com/story/money/business/2016/09/13/nv-energy-solarcity-deal-grandfather-residential-rooftop-solar-customers/90306788/.

53 Rate structure includes (1) the customer class for which the customer qualifies before installing the DER and (2) the type of charge (energy [$ per kWh], demand [$ per kW], or fixed monthly [$ per month]) used for each functional category of costs (customer, generation, transmission, distribution). Rate structure does not mean the <u>magnitude</u> of the rate.

January 1, 2018,[54] which means that customers now considering the installation of solar would be forced to make a long-term investment decision without knowing the rules or rate structures that will apply to them.

IV. LIMITATIONS OF COST-OF-SERVICE ANALYSIS, AND THE PROPER ROLE OF RATE CASES

Q: Idaho Power's annual net metering reports have used a cost-of-service analysis to calculate an alleged "cost shift" from net metering. Please provide your view on whether this analysis is accurate.

A: I have reviewed and support the critique of Idaho Power's NEM reports that Ms. Briana Kobor is submitting on behalf of Vote Solar. In particular, for the reasons explained at length above, the costs to serve net metered customers should be based on the service that Idaho Power provides to them, which is measured by the delivered power that the utility supplies, without including exported volumes (which are a service that the DG customer provides to the utility). When this fundamental error is corrected, Idaho Power's revenues per customer from serving DG customers appear to cover more of the utility's cost of service than is covered by standard residential customers, by $145 to $175 per customer per year. As Ms. Kobor notes, this analysis is only approximate and is not based on a full cost-of-service study, because Idaho Power's present NEM analyses use only incremental adjustments to a cost-of-service study that dates from its last rate case in 2011.

More broadly, cost-of-service analyses should not be used to evaluate the benefits and costs of NEM or to determine whether net metering results in any type of "cost shift." There are numerous reasons why cost-of-service analyses are inappropriate for these purposes:

- **Limited to a single test year.** DERs are long-term resources. Other resources with long useful lives are not judged based on their impacts on ratepayers in a single year. For example, a new utility generating plant or transmission line with

[54] Idaho Power testimony (Tatum), at pp. 7 and 25, proposing that all customers that request to interconnect DG after this date will be placed in the new DG customer classes that the utility proposes.

an economic life of 30-50 years is not judged based solely on its impact on the first-year revenue requirement.

- **The benefits of DERs are avoided costs; these are not the embedded, historical costs used in COS studies.** Avoided costs are, by definition, counterfactual – they are costs that the utility never incurs because it procures a service from another source. In the well-known formulation of avoided costs in PURPA, "avoided costs mean the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[55] As a result, it is questionable whether avoided costs can be measured accurately by the utility's embedded costs, which are not counterfactual but are the historical costs which the utility actually has incurred. Basic economics informs us that the more accurate way to measure avoided costs is to calculate the utility's long-run marginal costs, which measure how the utility's costs vary with the change in demand or supply that result from the addition of a new long-term resource such as DERs.

- **DERs produce certain direct, quantifiable benefits (avoided costs) for ratepayers that are not included in embedded cost rates.** These include avoiding the risk of volatile natural gas prices. Another such benefit is avoiding future compliance costs associated with reducing carbon dioxide emissions.[56] This is an avoided cost that can be reflected, when appropriate, in utility Integrated Resource Plans and in the cost-effectiveness evaluations of other types of demand-side resources.

- **Multiple perspectives.** An embedded COS analysis focuses solely on whether net metering is an equitable short-term allocation of existing costs among different classes of ratepayers. It does not consider other important perspectives – including the key long-term perspectives of whether DG is a reasonable long-term investment for the DG customer, for the utility system, and for society as a whole. It is the combination of all of these perspectives that constitutes the public interest in net metering.

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[55] *See* 18 C.F.R. Part 292.101(b)(6) (emphasis added).

[56] For example, Idaho Power's 2017 IRP, at p. 123, recognizes that "carbon-emission regulations in some form are likely during the next 20 years." Idaho Power is also building the Boardman-Hemingway transmission line to provide "access to the Pacific Northwest wholesale market and its attendant diverse mix of low-cost energy resources and abundant zero-carbon energy." 2017 IRP, at p. 121.

Q: When and where should the Commission determine whether DER customers should be placed into separate customer classes?

A: The first analysis should be a long-term benefit/cost analysis to determine whether DERs are a cost-effective resource under current NEM policies. If they are, then there may be no need for a near-term change in the compensation for DER customers. If there is a need to adjust the rates applicable to DER customers to restore an equitable balance among rate classes or types of customers, a rate case would be the correct forum in which to make such changes. I support Mr. Tatum's statement that the Company expects to request any modifications to the rates or compensation applicable to NEM customers in a rate case.[57] The Commission recognized in Order No. 32846, at page 12, that "dramatic changes [in NEM] should not be examined in isolation but should be fully vetted in a general rate case proceeding." That decision also found that the rate design changes which Idaho Power proposed in that case for net metering customers should be addressed in a rate case:

> To the extent the Company wishes to increase the monthly customer charge, or implement a BLC for the residential and small general service customer classes, it shall raise that issue in a general rate case.[58]

Q: Where should the Commission determine whether to have separate rate classes for DER technologies?

A: Rate cases also are the place to determine whether separate customer classes should be created. Extensive load research data to characterize different customer classes is produced as a matter of course in rate cases, data that may not be readily available in other proceedings.

Rate cases also will be the correct forum to respond to the proliferation of the many types of DERs technologies or potential combinations of DER technologies. Different DERs or combinations of DERs can produce significantly different load profiles and annual usage. For example, the pairing of solar with storage can shift the output of the DER system to exactly the time period when this output is most valuable to the utility system,

[57] Idaho Power Testimony (Tatum), at p. 22.
[58] *See* Order No. 32846, at p. 12.

increasing the value of the DER output. A proliferation of rate classes for all of the types and permutations of DER technologies would be confusing to customers and cumbersome for the utility to administer. A better approach is to develop cost-based, time-of-use (TOU) rates that signal more accurately to customers the cost consequences of any possible changes to the profiles of the delivered loads that the utility serves. Such a time-sensitive rate design, in conjunction with net metering, is the best and most cost-based means to accommodate a wide range and combination of DER technologies.

Q: Is it possible, and even likely, that a detailed cost-of-service analysis conducted in a rate case will show that DG customers are less expensive to serve than standard customers?

A: Yes, and this is what is shown in Ms. Kobor's revised analysis of Idaho Power's costs to serve existing NEM customers. The installation of solar DG can result in reductions in the DG customer's delivered loads in system coincident peak hours in the summer months that are 40% to 60% of the DG system's nameplate, even though the annual capacity factor for the DR array is much lower, about 20%. This results in a much lower allocation of production and transmission costs, per kWh, to solar DG customers than to standard customers. There also can be substantial reductions in DG customers' usage in the hour of the class coincident peak, resulting in a reduced responsibility for distribution costs. As an example from another state, in the Arizona Public Service (APS) rate case litigated earlier this year, the parties debated whether solar DG customers are more or less expensive to serve than standard non-DG customers, under a standard cost-of-service analysis.[59] The solar parties showed that residential solar customers are less expensive to serve, so long as such DG customers are allocated costs only for the power that the utility delivers to them, and are not charged inappropriately for the costs of delivering solar exports to other customers. That case was resolved through a settlement, approved by the

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[59] It is important to note that this rate case was conducted <u>after</u> the Arizona commission had established a new Value of Solar methodology for compensating solar customers. See ACC Decision No. 75859. That methodology is being implemented in subsequent individual utility rate cases, including this APS rate case.

Arizona commission, in which residential DG customers will be able to take service under the same TOU rate available to other residential customers.[60]

If DER customers indeed are less expensive to serve, then it is beneficial for non-participating ratepayers to keep DER and non-DER customers in the same class.

Q: Does this conclude your direct testimony?

A: Yes, it does.

[60] See ACC Decision No. 76295 (August 18, 2017) in Docket No. E-01345A-16-0036 (Arizona Public Service rate case). The settlement agreement is Exhibit A to that decision. See Sections 17-19 of the settlement, allowing residential DG customers to take service under the same TOU and demand-based rates available to other residential customers. For new DG customers that elect the residential TOU rate, there also was a small increase in a pre-existing monthly grid access charge.

CERTIFICATE OF SERVICE

I hereby certify that on this 22nd day of December, 2017, true and correct copies of the above THE DIRECT TESTIMONY OF R. THOMAS BEACH were sent to the following persons via the methods noted:

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