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Subject: **Distributed Generation Cost-Benefit and Ratemaking Considerations for Idaho**

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Background

This memo was completed through the Grid Modernization Laboratory Consortium (GMLC), a strategic partnership between the U.S. Department of Energy (DOE) and the national laboratories to bring together leading experts, technologies, and resources to collaborate on the goal of modernizing the nation's grid. The GMLC was established as part of the DOE Grid Modernization Initiative to accelerate the development of technology, modeling analysis, tools, and frameworks to help enable grid modernization. Special thanks to DOE project leads, Larry Mansueti and Elaine Ulrich, and the laboratory project lead for this effort, Peter Cappers from Lawrence Berkeley National Laboratory (LBNL).

The Idaho Public Utility Commission (IPUC) Staff requested this technical assistance to improve their understanding of the emerging, complex, and consequential issues around distributed energy resource (DER) rate design to help the staff achieve its goal of making a fair, just, and reasonable rate design recommendation with respect to Order 34147 under Case No. IPC-E-17-13.

In Case No. IPC-E-17-13, Idaho Power requested authorization from the IPUC to establish new rate schedules for residential and small general service customers with on-site generation.

The IPUC's Order No. 34046 of May 9, 2018 authorized Idaho Power to (IPUC 2018a):

- Close Schedule 84 and create Schedule 6 for residential on-site generators and Schedule 8 for small general service on-site generators[1]
- Acknowledge smart inverter technology
- Make proposed revisions to interconnection Schedule 72
- Open an Idaho Power-specific docket to "to comprehensively study the costs and benefits of on-site generation on Idaho Power's system, as well as proper rates and rate design, transitional rates, and related issues of compensation for net excess energy provided as a resource" to Idaho Power
- File a study with the IPUC "exploring fixed-cost recovery in basic charges and other rate design options prior to its next general rate case."

Vote Solar filed a Petition for Reconsideration of Order No. 34046 asking the Commission to require Idaho Power to revise the new Schedules 6 and 8 to apply only to customers who export electricity (IPUC 2018b). Consequently, IPUC issued a final reconsideration Order 34147 on September 21, 2018 that requires Idaho Power to study a non-export option for feasibility alongside the original order parameters (IPUC 2018b).

IPUC staff specifically requested that the following subjects be addressed in this memo:

- Best practices around rate design for DER, for both consumption and exported energy, with specific examples of successes and failures.
- How cost-of-service can apply for DER customers and non-DER customers in a consistent and non-preferential way.
- A summary of what has been tried elsewhere, what other commissions have had an appetite for, and what the results have been.

Key Takeaways

Categorized below are PNNL's key takeaways for IPUC staff from this memo. IPUC staff may wish to consider these overarching issues as they address DER rate design. Also, a summary of DG compensation strategies in other states is included in this report.

Cost Causation

- **Cost causation is not an exact science**. Any cost allocation rule involves some kind of judgment and ordering of costs. Rate design offers the chance to align policy goals based on established principles.
- **Distributed generation creates both costs and benefits to the grid.** Detailed analyses and studies can characterize costs and benefits that can be used to inform rate design.

[1] "…we reiterate that this Order does not change rates, rate design, or the current compensation credit structure for on-site generation customers. Rather, this Order only changes how these customers are classified for purposes of the requisite analysis to be conducted in the company specific on-site generation docket we address below."

- **Time and location characteristics of distributed generation (DG) impact costs and savings.** Time-varying rates and critical peak pricing type programs are ways to move more toward cost-of-service rates. Locational value assessments and compensation schemes are emerging in New York and California and, although new and somewhat experimental, may become more prominent over time.

Cost-Benefit Analysis

- **Cost-benefit analysis (CBA) and cost-shifting analysis** are distinct analyses. CBA evaluates whether net energy metering (NEM) programs are in the public interest, whereas cost-shifting analysis indicates distributional impacts that regulators can consider and, if necessary, find ways to mitigate.
- Some states are **hiring independent consultants** to conduct a CBA of NEM programs. Regulators have an important role to play in outlining which costs and benefits are considered and how they are evaluated.
- It is important to consider both the **short-run and long-run marginal costs** when evaluating the costs and benefits of distributed generation in order to encourage efficient price signals, investment in cost-effective resources, and lower electricity costs for customers.

Cost Shifts

- Many **existing utility investments result in cost shifts** between customers. These investments can be weighed when considering cost shifts relative to NEM.
- **Cost shifts can go both ways with NEM**. In some cases, NEM customers benefit from cost shifts, while in other cases, non-NEM customers benefit.

Rate Design Considerations

- **Rate design is more of an art than a science**. Designing rates that seek to balance utility revenues and growth of distributed generation is complicated and challenging.
- In general, the literature supports a trend toward **time-varying rates** as a way to maximize the value of DG to the grid, support cost-of-service regulation, and minimize cross-subsidization (Faruqui 2018a, Linvill et al. 2017).
- **Increasing cost recovery through fixed charges** reduces financial risk to utility revenues, but may have implications to resource efficiency and ratepayer equity.
- There is a disagreement in the literature about the use of **demand charges**. Some think demand charges should be used to recover all or most of the costs a customer imposes on the grid during peak demand periods (EEI 2016), others think time-varying rates rather than demand charges should be used to recover generation and transmission capacity costs (Linvill et al. 2017), while others see demand charges and time-varying rates as compliments rather than substitutes and think both should be used (Faruqui 2018a).
- States are taking various approaches to establishing an **export or outflow rate**. Some states continue to credit exported energy at the full retail rate, while others are moving toward avoided costs, wholesale prices, embedded cost-of-service rates, locational marginal prices, a resource comparison proxy, an Inflow & Outflow methodology, or one of these plus an adder.

Transitions

- Well-designed **transition programs** for new rate design structures and NEM policies can facilitate customer acceptance of these changes. Lessons learned from rate transition examples described in this report include: the importance of carefully considering how existing/grandfathered systems will be handled, providing sufficient upfront education and communication, and using phased tranches and incremental compensation changes to smooth transitions.

Issues for Consideration

Based on input from Idaho PUC staff and PNNL's knowledge of NEM changes in other states, the following subjects, discussed in subsequent sections, are recommended issues for the IPUC staff to consider:

- Cost causation
- CBA and cost shifting
- Rate design considerations
  - Principles
  - Time-of-use rates
  - Fixed charges and demand charges
  - Ancillary services and standby rates
  - Inflow & Outflow methodology and export rates
- DG compensation in other states
- Transitions

Cost Causation

Cost causation is not an exact science. Any cost allocation rule involves some kind of judgment and ordering of costs. For the cost of the grid itself, there are many different ways to allocate costs. Rate design offers the chance to align policy goals with rates and established principles (Beecher 2017). As customers increasingly have opportunities to generate and store electricity, cost causation is becoming more complex and difficult to determine.

In his article, *Rate Design 3.0*, Faruqui (2018a) points to James C. Bonbright's seminal work, "Principles of Public Utility Rates." Bonbright identifies cost-of-service as the most important principle of rate design. Cost-of-service is the concept that the ratepayer or customer that receives a service and causes the cost to be incurred should be the one who pays for the service. According to Faruqui, Bonbright argued against purely volumetric rates because they assume the total costs of the utility vary directly with the changes in energy output. Bonbright supported a rate example that included demand charges in combination with volumetric charges because it "distinguishes between the two most important cost functions of an electric utility system: between those costs that vary with changes in the system's output of energy, and those costs that vary with plant capacity and hence with the maximum demands on the system (and subsystem) that the company must be prepared to meet..." (Faruqui 2018a).

Edison Electric Institute (EEI) suggests reducing the use of volumetric, per kWh, charges for recovering fixed costs and increasing the use of fixed charges. EEI asserts that recovering the vast majority of costs through volumetric rates does not work with distributed generation because a customer's use of the grid is no longer proportional to the number of kWh the customer buys (EEI 2016).

In terms of additional costs being created by customers with distributed generation, existing electric systems include margins for increasing and decreasing electrical output and ancillary services to ensure power quality is maintained system wide. At low DER penetrations, impacts may be insignificant and within the margins already established (NARUC 2016). Studies and analyses of the specific impacts that DG has on the grid can inform rate design because DG creates both costs and benefits for the grid. A best practice is to base any charge, specific to DG customers or otherwise, on transparent analysis. By doing so, rate structures reflect the value that DG, potentially coupled with smart inverters or storage, can provide. This is not just a matter of fairness, but also will help provide appropriate price signals for DG customers to invest in technology that benefits the utility system and utility customers overall. Appropriate incentives—through rates, rebates, and other options—could be a low-cost way of acquiring additional grid support services.

An Inflow & Outflow mechanism has been developed by Michigan PSC Staff and is being described as the only alternative to NEM that is truly based on cost-of-service (Ozar 2016). This mechanism is described in more detail in the Rate Design Considerations section of this report.

Time and location characteristics of DER impact costs and savings. Locational value assessments are emerging in New York and California and, although somewhat new and experimental, will become more prominent over time.[2]

Cost-Benefit Analysis and Cost Shifting

CBA and cost-shifting analysis are two distinct analyses. CBA traditionally evaluates whether NEM programs are in the public interest, whereas a cost-shifting analysis indicates distributional impacts that regulators can consider and, if necessary, find ways to mitigate. Both are described in subsections below.

Cost-Benefit Analysis

Various states have performed cost-benefit analyses of net metering programs. Each state has taken a different approach. Two key approaches and studies are summarized here, although there are many others that have been performed and are available. In many cases a state has hired an independent third party to conduct a cost-effectiveness study to determine whether distributed generation under current rate structures imposes a net benefit or net cost on ratepayers and how total system costs are impacted. Regulators have an important role to play in these studies by standardizing which costs and benefits are considered and how they are evaluated.

E3 Study for Nevada

A study was conducted by the consulting firm Energy and Environmental Economics, Inc. (E3) for the Public Utilities Commission of Nevada (PUCN) to forecast the costs and benefits of renewable

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[2] California's Locational Net Benefits Methodology and New York's Value Stack Tariff approach are described in this document developed by PNNL for the Illinois Commerce Commission:
Illinois Distributed Generation Rebate – Preliminary Stakeholder Input and Calculation Considerations

generation systems that qualify for the state's NEM program. The methods used by E3 may be instructive to Idaho. The study was commissioned by PUCN in response to Nevada Assembly Bill (A.B.) 428. E3's approach was to conduct the following analyses (E3 2014):

- CBA using five different cost tests that are typically used for energy efficiency - E3 looked at a base case and sensitivities (including impact of rate designs, capturing more costs in fixed charges, and reducing demand charges).
- Macroeconomic impacts assessment – considered the impact of NEM on jobs and the economy.
- Demographic analysis – compared median income of NEM participants to state's median income.

E3 elected to evaluate the cost-effectiveness of NEM generation from five different perspectives in order to provide a comprehensive assessment of the costs and benefits. The five different cost tests are used to answer five fundamentally different questions, as follows (E3 2014):

1. *Is renewable self-generation cost-effective for the customers who install systems? (Participant Cost Test or "PCT")*
2. *What is the rate impact on non-participating utility customers? (Ratepayer Impact Measure or "RIM")*
3. *Recognizing that some utility bills may go down and others may go up, does the NEM program reduce utility costs overall? (Program Administrator Cost Test or "PACT")*
4. *Does NEM generation reduce the overall cost of energy for Nevada? (Total Resource Cost Test or "TRC")*
5. *Does NEM generation provide net societal benefits considering the cost and externalities such as the health impacts from NEM? (Societal Cost Test or "SCT")*

The overall results of the cost tests show that, based on $2014 solar panel costs, NEM participating customers paid more per kWh to participate in net metering than not, non-participating customers saved money due to the presence of NEM, less money was required to be collected from ratepayers by the utilities with NEM, and the sum of all costs to society were slightly higher with NEM than without because of the presence of a Renewable Portfolio Standard and the relative difference in the cost of utility-scale vs. residential solar systems (E3 2014). In a 2016 update to the E3 Study for PUCN, E3 showed that NEM participating customers continued to pay slightly more per kWh to participate in net metering than not, there was a $36 million per year cost shift from NEM participants to non-participants, and with NEM, the utility was required to collect $13 million less from ratepayers than without it (E3 2016).

The macroeconomic impact of NEM can be important for policy makers to consider. In order to assess macroeconomic impact, E3 conducted a literature review and leveraged existing studies of impacts of renewable and greenhouse gas policies. E3's demographic analysis compared the income of NEM participants (based on census block) to the state's median income. More information on methods and results are available at E3 2014.

Pacificorp's CBA of Net Metering for Utah

PacifiCorp put forward a CBA of net metering in Utah that was highly contested in a Utah PSC proceeding. It is instructional to consider feedback/responses to PacifiCorp's original net metering CBA filing. Tim Woolf, from Synapse, on behalf of Utah Clean Energy, provided a detailed assessment of PacifiCorp's initial net metering CBA for Utah that contained some specific, potentially helpful suggestions and considerations for these types of analyses. Below is a summary of his key findings and recommendations (Woolf 2017):

- A typical utility CBA compares the utility's revenue requirements under a scenario without the program or resource to a scenario that includes the program or resource. "One or more future scenarios including the resource is compared with one or more future scenarios excluding the resource, and the difference between the scenarios with and without the resource indicates the net costs or net benefits of the resource in question" (Woolf 2017).
- Time periods typically used in these NEM CBA type analyses are long enough to capture at least the operating life of the resource. Woolf recommends that studies include a 20-year study period to account for distributed generation costs and benefits that extend beyond a single year. It is preferred that long-term resource planning be used to inform rate design and DG compensation mechanisms (by indicating cost-effectiveness of different resources) and not just cost-of-service studies. If rate designs (and DG compensation) do not account for the long-term impacts of resource options, customers may not receive efficient price signals, may not invest in cost-effective resources, and customers as a whole may incur higher electricity costs.
- The present value of revenue requirement is a good metric to use for both integrated resource planning (IRP) and CBA for DER. This is necessary to evaluate both types of resources consistently and comparably.
- CBA identifies costs and benefits of a particular investment, project, or program to customers as a whole, without distinguishing which customers experience which costs or benefits. CBA is used to identify whether the investment, project, or program is in the public interest.
- In contrast to CBA, a cost-shifting analysis indicates the distributional impacts of a particular investment, project, or program, and whether some customers' costs might increase, even though other customers' costs might decrease. Distributional, or cost shifting, analysis is helpful when regulators want to know how the resource or program might affect some customers differently than others. Distributional impacts are best considered separately from a CBA in order to determine whether there is a problem and what the right solution might be if a problem exists. If an analysis of net metering conflates the CBA with cost shifting, the result is an analysis that does not provide useful information on either.
- The results of both CBA and cost-shifting analyses can be used to strike the appropriate balance between promoting cost-effective resources or programs and mitigating distributional concerns.
- It is recommended that bill credits to DG customers not be included as a cost in a CBA.[3] CBA is typically based on revenue requirements, and bill credits to DG customers are not directly related to revenue requirements. It is true that bill credits are lost revenues, but they are not a cost-of-service. That is, bill credits are not costs borne by the utility in order to service customers. Bill credits are relevant when considering potential cost shifts. A separate cost-shifting analysis should account for the impacts of bill credits. More details on this are found in Woolf 2017.

[3] Bill credits are the amount of revenues that are not collected from DG customers as a result of their generation. Or the difference between what they would have used absent DG and what they used, multiplied by the corresponding energy charges.

Although initially PacifiCorp did not include a long-term evaluation of the impacts of NEM, Tom Woolf points to their 2017 IRP to suggest that DG will likely avoid future utility costs over the long-term. PacifiCorp's 2017 IRP, Volume I, pp. 250-251 shows that Base Case Solar DG saves $168 million relative to the Low Solar DG case, and the High Solar DG case saves $440 million relative to the Low Solar DG case (Woolf 2017). If these long-term benefits are not accounted for, Woolf argues that DG will be undervalued.

Cost Shifts

The subject of cost shifting (or cross subsidies) is often discussed as a potential negative impact of NEM, but cost shifts can go both ways. As described below, in some cases, NEM customers benefit from cost shifts, while in other cases non-NEM customers benefit. In addition, many non-DER electric utility resource investments can lead to some amount of cost shifting between customers (NARUC 2016). Investments in generation, transmission, distribution, and demand-side resources can all have different distributional impacts. Regulators can chose which cross subsidies to support and to what extent. Non-DER investments may have a bigger impact on electricity rates than DER investments when DER adoption rates are still low (Barbose 2017). In their comments on NARUC's Draft Rate Design Manual, EEI confirms that cost shifts associated with NEM are real, sometimes favoring NEM customers and sometimes favoring non-NEM customers. The following are examples of distributional impacts of DG and NEM (EEI 2016; Muro and Saha 2016):

- 2013 E3 study for the California Public Utilities Commission showed NEM would result in $1.1 billion annual cost shift by 2020 from NEM to non-NEM customers in California if current policies were not reformed
- 2014 E3 study for PUCN showed $36 million lifecycle benefit of NEM qualified resources to non-solar customers; an update of this study in 2016 showed a cost to non-solar customers of $36 million per year
- 2014 E3 research in Hawaii found NEM customer had net benefit while non-NEM customers had net cost
- 2012 Navigant study for Arizona Public Service found customers with solar are subsidizing those without
- 2013 Vermont study showed cost shift from NEM customers to non-NEM customers
- 2015 Missouri study found net benefits of NEM to all customers regardless of whether they have rooftop solar
- 2015 Massachusetts study found that solar provides benefits to all ratepayers in excess of retail rates

NARUC's Rate Design Manual suggests asking the following questions relative to NEM successor tariff rate designs: (a) are possible cost shifts minor, reasonable, and non-regressive, and (b) to what extent are any cost shifts acceptable? (NARUC 2016).

The NARUC Rate Design Manual includes the following relative to cross subsidies (NARUC 2016):

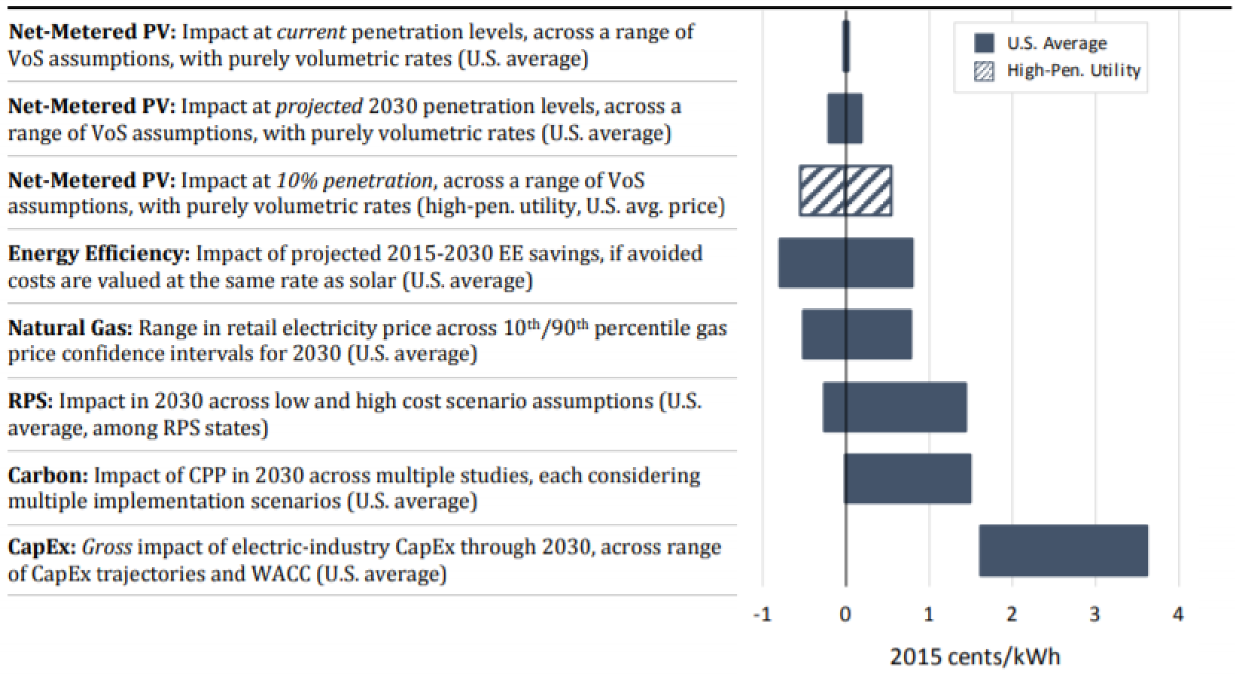
Cross subsidies, subsidies from one group of ratepayers to another, are endemic in all utility rate making as there are variations in consumption patterns within rate classes that cause one part of a rate class to subsidize another part, as well as differences among classes due not only to differential use but also differential impacts of utility rates. The classic cross-class subsidy is for C&I rate classes to subsidize the residential class (i.e., there are differential impacts of electricity costs). In the case of DER-owning customers, there is now a group of customers that differs significantly in both usage patterns and the effects of rate levels on decision making from others in the same class. Eliminating, or at least minimizing, the potential intra-class cross subsidies enjoyed by DER-owning customers has both efficiency implications and equity implications. If the cross subsidies are leading to uneconomic bypass (i.e., bypass that while decreasing costs for DER owners increases the overall cost to the general body of ratepayers), elimination of cross subsidies will increase economic efficiency. Reducing intra-class subsidies would minimize lower income ratepayers from subsidizing higher-income ratepayers.

In response to NARUC's rate design manual, some solar advocates stated that is should not be a foregone conclusion that DER and net metering will result in an inadequacy of cost recovery for the utility and shift of costs to non-participating customers. It was suggested that analysis is needed to evaluate all the benefits and costs and although the utility may be getting less money from DER customers in their bill payments, the utility can also save money overall as a result of customer owned generation, resulting in a net profit to the utility and non-DER-owning customers (SEIA 2016).

According to an Lawrence Berkeley National Laboratory paper by Barbose (2017), for the vast majority of states and utilities, the effects of distributed solar photovoltaics (PV) on retail electricity rates will remain negligible for the foreseeable future and will be small compared to many other impacts to electricity rates, such as energy efficiency programs, gas price changes, capital expansion expenditures, and potential state and federal carbon policies. Barbose estimates ranges of potential effects of distributed solar PV on retail electricity prices, at current and projected future penetration levels and compares those price impacts to the likely price impacts stemming from other important drivers of electricity prices (e.g., energy efficiency programs and policies, natural gas prices, renewable portfolio standards (RPS), state and federal carbon policies, and capital expenditures (CapEx) by electric utilities) (Barbose 2017). Figure 1 shows the relative magnitude of potential retail price effects of distributed solar compared to other potential drivers (Barbose 2017).[4]

[4] Barbose suggests that for the bulk of states and utilities, the effects of distributed solar on retail electricity prices will likely remain negligible for the foreseeable future. At penetration levels as of 2017 (0.4% of total U.S. retail electricity sales), distributed solar will likely entail no more than a 0.03 cent/kWh long-run increase in U.S. average retail electricity prices, and significantly smaller than that for most utilities. This is compared to the impacts of energy efficiency programs of +or- 0.8 cents/kWh impact to U.S. average retail electricity prices and the 0.8 cents/kWh potential increase in U.S. electricity prices due to gas prices being $1.9/MMBTu higher than expected by 2030. Even at projected national PV penetration levels in 2030, distributed solar would likely yield no more than roughly a 0.2 cent/kWh (in 2015$) increase in U.S. average retail electricity prices, and less than a 0.1 cent/kWh increase in most states, where distributed solar penetration is projected to remain below 1% of electricity sales. These estimates assume value of solar is equal to just 50% of the average utility cost of service, and full NEM with volumetric pricing (Barbose 2017).

According to Barbose, future electric capital expenditures will have a much larger potential impact on retail electricity prices than distributed solar PV. As such, regulatory oversight in resource planning and procurement processes represent a critical leverage point for future electricity prices, and a means for regulators to manage customers exposure to natural gas price risk, among others (Barbose 2017).



Notes: Current net-metered PV penetration equal to 0.4% of total U.S. retail electricity sales, as of year-end 2015. Projected 2030 net-metered PV penetration is 3.4%, based on Cole et al. (2016). VoS assumptions range from 50% to 150% of average cost-of-service. Please refer to the main body of the report for further details on how the ranges shown here were derived.

***Figure 1**. Indicative Ranges for Potential Effects on Average Retail Electricity Prices (Barbose 2017)*

At a low level of DER adoption, cost shifts may be viewed merely as another imperfection in rate design. However, at large levels of DER adoption, there is the potential for large amounts of costs to be shifted to other, non-DER customers in the same rate class (NARUC 2016). Scale is relevant and is important to consider relative to cost shifts.

Monitoring adoption rates of DG regularly in an ongoing way allows utilities to determine when the penetration is becoming more significant. Because all electric systems are impacted by DER increases differently, before moving forward with substantive rate reforms due to the growth of DER adoption, utilities and regulators may wish to look closely at data, analyses, and studies from their particular service area.

Rate Design Considerations

Rate design is more of an art than a science. Designing rates that seek to balance utility revenues and growth of distributed generation is complicated and challenging. If rates go too far toward volumetric energy charges, utilities can have trouble recovering costs when DERs reach higher levels of penetration. Conversely, if rates lean more toward fixed charges, it may allow utilities to more fully recover their costs, but may result in equity and resource efficiency implications and may reduce incentives for customers to install DERs that reduce costs and provide benefit the grid in the long-term. Effective rate design will convey price signals to the customer reflective of what the power system needs. There are a variety of considerations that guide rate design.

Principles

The Commission may want to consider overarching cost allocation principles as they move into considering NEM cost-effectiveness, cost shifts, and rate design. There are different approaches to allocating appropriate costs into rate components based on diverse, well-constructed rationales (e.g., cost causation principles, policy goals) which reasonable people can and will differ on, but regulators ultimately need to decide upon. Other principles might be adopted that focus on holding different customer types (DG owning and not-DG owning) to the same cost-of-service standard relative to rates.

Two perspectives are provided here as examples. The first is from the Regulatory Assistance Project (RAP) and the second is from Brattle Group's Ahmad Faruqui.

RAP has identified three ratemaking principles that they believe should apply to all customer classes in their report, Smart Rate Design for a Smart Future. These are listed below (Lazar and Gonzalez 2015).

- Principle 1: A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
- Principle 2: Customers should pay for grid services and power supply in proportion to how much they use and when they use it.
- Principle 3: Customers who provide services to the grid should be fairly compensated for the value of what they supply.

In what Faruqui (2018a) refers to as *Rate Design 3.0*, he suggests that a three part rate design with the following elements is more in line with cost-of-service regulation and would improve on traditional rate structures (Faruqui 2018a):

- **Fixed monthly charge** to recover the costs of billing, metering, and customer service. Potentially also include cost of line drop from transformer on the pole side to the customer's meter.
- **Demand charge** for recovering grid capacity costs. "Demand charges allow utilities to signal when and where there are supply or distribution constraints."
- **Time-varying energy charge** for recovering energy costs. "These allow utilities to signal when generation and distribution are least expensive."

Time-of-Use Rates

In general, the literature supports a trend toward time-of-use rates as a way to maximize the value of DG to the grid, support cost-of-service regulation, and minimize cross-subsidization. Time-varying pricing can better align private choice with the public interest and can support efficient utilization of capacity by reducing peak loads and improving load factors, which lowers average costs and better manages congestion. Dynamic pricing options, such as critical peak pricing, further refine price signals and are easy for customers to understand. Time-varying pricing is being looked at by more states recently, given the deployment of advanced metering infrastructure (Faruqui et al. 2014).

As an example of using time-of-use rates to support grid and public benefits, California is adapting time-of-use peak periods to match solar impacts, establishing default time-of-use rates and encouraging movement toward coincident demand rates (higher rates at the overall system peak) from non-coincident demand rates (based on the customer's highest demand, regardless of when it occurs) (Linvill et al. 2017).

That dynamic pricing is unfair, compared to flat rates, is a common perception. Consumer advocates, among others, argue that dynamic pricing inflicts harm on low-income customers, seniors, people with disabilities, people with young children, and small businesses. Faruqui (2018a) pushes back against assertions that low-income customers may not have the interest or know-how to curtail usage during peak pricing periods. He points to a dynamic pricing experiment carried out in DC in 2008 that included 857 residential participants, of which 118 were low-income. The lead researcher determined that the magnitude of demand response, as a percent of their peak load, was twice as large for low-income customers than non-low-income customers (Faruqui 2018a). Another study reviewed three dynamic pricing programs in Connecticut, DC, and Maryland as well as early results of a roll out in California. The core finding was that low-income customers are responsive to dynamic rates and that many low-income customers (between 65 and 79%) can benefit without even shifting load (Faruqui et al. 2010).

Fixed Charges and Demand Charges

This section addresses fixed charges and demand charges.

Fixed Charges

EEI suggests that the most straightforward way to move toward cost-based rate design for electricity and grid services is to ensure that fixed and variable charges are commensurate with the fixed and variable costs of serving each customer or customer class (EEI 2016). Conversely, Borenstein (2014) argues that from an economics perspective, there is no basis to the idea that the utility should cover fixed costs with fixed charges. The mere existence of system-wide fixed costs does not justify fixed charges (Borenstein 2014).

Kind (2015) points out that, although increasing fixed and demand charges reduces financial risk for utility revenue collections in the near term, there are potentially negative impacts, including the following:

- Fixed charges do not promote efficiency of energy resource demand and capital investment
- Fixed charges reduce a customer's control over energy costs
- Fixed charges may have a negative impact on low- or fixed-income customers
- Fixed charges may negatively impact all customers when select customers adopt DERs and potentially exit the system altogether, if high fixed charges are approved and the utility's costs increase.

Borenstein (2016) points out that from an economics and cost causation perspective, it makes sense that fixed charges are used for recovering customer-specific fixed costs, such as the service drop, metering, billing costs, and some customer service. However, unlike customer-specific fixed costs, system-wide fixed costs cannot be attributed to a specific customer, and from a cost causation perspective, it does not necessarily make sense to recover them via fixed costs (Borenstein 2016). When considering fixed charges to recover system-wide fixed costs and/or revenue shortfalls, there are important potential resource efficiency and equity impacts to be considered.

- **Resource efficiency** – Price signals guide consumer decisions regarding usage and utility decisions about production and investments. In the long-run, all costs are variable and variable charges reflect this dynamic world view (Beecher 2017).
- **Ratepayer equity** – A high fixed charge increases problems with existing regressive utility rates and reduced customer control over their bill. Regressive means taking a proportionally greater amount from those on lower incomes. Increasing fixed charges can disproportionately impact low energy use customers. If customer A uses 10 times more electricity than customer B, should they pay the same share of the system fixed costs through a fixed charge? (Borenstein 2014).

Table 1 compares general characteristics of, and considerations for, cost recovery based on fixed versus variable charges according to Beecher (2017).

***Table 1**. Comparing Cost Recovery from Fixed and Variable Charges (**Beecher 2017**)*

Comparing Cost Recovery from Fixed and Variable Charges	
Recovering more costs from fixed charges	**Recovering more costs from variable charges**
A static world view	A dynamic world view
Enhances revenue stability (less sales revenue risk)	Reduces revenue stability (more sales revenue risk)
Weakens price signals and customer control (less resource efficiency)	Strengthens price signals and customer control (more resource efficiency)
Less affordable for low-income households (more regressive)	More affordable for low-income households (less regressive)
May promote self supply and system defection (more expensive)	May limit self supply and system defection (less expensive)
Slight advantage for combined households (single customer charge)	Revenue stability from first blocks of usage (inelastic usage)

From a high-level regulatory theory perspective, the Commission may want to consider how issues of utility stranded costs will be handled. Stranded costs, or transition costs, are costs incurred by a utility to serve its customers that were once recovered in rates, but are no longer recovered due to the availability of lower-priced alternatives (Rose 1996). Stranded costs are not black and white in nature; they are created through utilities' interpretation of the burden they incur for providing power to their customers. Regulators must exercise judgment when allowing utilities to recover stranded costs, in determining what the actual costs are, and in determining the duration over which utilities should be allowed to charge for them. Whether a stranded cost was prudently incurred, and therefore eligible for recovery in rates, is a decision for regulators to make. Some authors caution against allowing utilities to indiscriminately recover stranded costs, indicating that doing so can impair the development of a competitive market by (a) blunting utility incentives to lower costs and mitigate transition costs, (b) acting as a barrier for DGs to enter the market, and (c) creating asymmetry between utility risk and reward (Rose 1996).

EEI points out that a grid access charge (in addition to a customer charge) is another option for ensuring that basic distribution grid costs are recovered from all customers who use the distribution grid, and points to the Ontario Energy Board's use of a fixed monthly charge for (after a four year gradual increase) recovering 100% of the distribution grid costs (EEI 2016).

Demand Charges

If demand charges are used, some suggest they should only be used for recovering the relatively small capacity costs of line transformers sized to the demand of individual customers (Linvill et al. 2017). Others suggest that demand charges can be applied more broadly, such as based on the cost a customer imposes on the grid during peak demand periods (EEI 2016).

EEI points to the following positive attributes of demand charges (EEI 2016):

- Demand charges ensure customers with higher load factors[5] will receive a lower bill.
- Demand charges provide distinct price signals for demand response and energy efficiency to reduce peak demand, which ultimately reduces the cost of the entire electricity system.
- Demand charges can be designed to be revenue neutral to customers and utilities through a commensurate reduction in energy charges.

RAP supports an emphasis on time-varying rates for recovering generation and transmission capacity costs rather than demand charges. RAP suggests dynamic pricing can better match price signals to system impacts than either non-coincident peak or coincident peak demand charges (Linvill et al. 2017).

Faruqui (2018a) suggests demand charges and dynamic pricing are compliments not substitutes. Table 2 shows one proposed rate design that illustrates Faruqui's proposed *Rate Design 3.0* and includes a monthly service charge, demand charges, and a time-varying energy charge (Faruqui 2018b).

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[5] Load factor refers to this ratio: (total energy used in a billing period (kWh))/(peak demand during the billing period (kW) x 24 x number of days in the billing period). The higher the number, the less peaky the load profile.

Table 2. *Example Rate Design Consistent with Rate Design 3.0 Principles (Faruqui 2018b)*

Parts	Cost Category	Rate Design Category
1	Meter Line drop Transformer Billing Customer care	Monthly service charge
2	Distribution capacity	Non-coincident peak (NCP) demand charge
	Transmission capacity	Mix of NCP demand charge and coincident peak (CP) demand charge
	Generation capacity	CP demand charge and/or time-varying energy charge
3	Energy	Time-varying energy charge

The Glasgow Electric Plant Board in Kentucky attempted to move from a flat rate tariff to a time-of-use rate tariff that included a coincident peak demand charge and faced much public outcry and opposition. Customer perception was that rates had increased and the new rate structure was hitting lower income residents the hardest. The coincident peak demand charge was the target of most of the opposition. This example is described in more detail in the Transitions section of this report.

Ancillary Services and Standby Rates

Some states and utilities are exploring explicit cost recovery for ancillary and standby services associated with distributed generation. New Mexico has a statute that allows investor-owned utilities to recover costs of “standby and ancillary services” or “services that are essential to maintain electric system reliability” that result from interconnecting DG customers (62-13-13.2). PNNL developed a report for the New Mexico Public Regulation Commission (PRC) on considerations for ancillary and standby services (Preziuso and Homer 2018). What follows are key considerations from that report.

Distributed generation has different impacts on ancillary services, depending on location, capacity, presence or absence of a smart inverter, and production patterns. Hosting capacity analyses[6] can help determine how much DG can be interconnected at specific locations without requiring infrastructure upgrades that may be needed to avoid voltage violations, power quality issues, protection problems, or exceeding thermal limits impacts. Although detailed studies are necessary for determining the specifics of DG’s impact on ancillary services as accurately as possible, a hosting capacity analysis can serve as a good starting point. At DG penetrations below a circuit’s hosting capacity, it can reasonably be assumed there are no significant impacts for which additional charges are warranted (Preziuso and Homer 2018). However, higher penetrations and larger DG systems may produce noticeable impacts. Impacts of DG on ancillary services is a relatively new and emerging area of study, and as such, there are not well-established formulas or protocols. Discretion is required.

[6] Hosting capacity is the amount of DERs that can be accommodated on the distribution system at a given time and location without sacrificing power quality or reliability or requiring additional investments.

Standby rates are traditionally used for large industrial combined heat and power systems. Threshold system size levels are often used in determining applicability of standby rates. If standby rates are used for DG, regulators could require utilities to demonstrate (a) specific events that create concern for utilities (e.g., community DG system outage, cascading event, clouds, or eclipse), (b) how DG is impacting the system more than standard load fluctuations, and (c) why the level of backup that must be provided for DG customers exceeds what customers are already paying for to serve full-requirements customers.

Magnitude is critical when considering if and how utilities recover costs for ancillary and standby services. Low penetrations of small DG systems are unlikely to create significant contingencies any larger than normal fluctuations caused by customer demand, such as an air conditioner cycling.[7] Smart inverters and energy storage change the impacts of DG on the grid and have the potential to transform a DG system from a burden on the grid to a support. Appropriate incentives—through rates, rebates, and other options—could be a low-cost way of acquiring additional grid support services (Preziuso and Homer 2018).

Inflow & Outflow and Export Rates

An Inflow & Outflow mechanism has been proposed in Michigan by a staff member of the Michigan PSC, who has described it as "the only regulator alternative to NEM that is a true cost-of-service based approach" (Ozar 2016). Robert Ozar, Assistant Director of the Electric Reliability Division of the Michigan PSC points out that NEM and alternatives, such as buy-all, sell-all, or minimum bills, are departures from cost-of-service. The Inflow & Outflow mechanism requires a bi-directional meter and is based on the actual metered power-inflows from the grid and actual metered outflows to the grid (Ozar 2016). In Michigan, all utilities must include the distributed generation compensation Inflow & Outflow methodology included in Docket 18383 in rate case filings. DTE Electric is the first utility to file a rate case (U-20162) that addresses these changes. DTE Electric proposes that all inflows would be charged at the full retail rate, while outflows from a customer's distributed generation system would be credited at the monthly average real-time locational marginal price at the relevant DTE node. New DG customers would also have to pay a system access charge of $2.31 per kW of capacity (DTE 2018a, DTE 2018b).[8]

Other states are also taking various approaches to establishing an export or outflow rate. Some states continue to credit exported energy at the full retail rate, while others are moving toward avoided costs, wholesale prices, embedded cost-of-service rate, locational marginal price, a resource comparison proxy, or one of these plus an adder. These are described in more detail in the following section.

Utah has an open proceeding to determine an export value for distributed generation based on detailed metering and analysis. Phase one entails developing a load research study plan and phase two entails determining the export credit rate to be paid to customer generators (PacifiCorp 2018). During phase one, PacifiCorp is conducting a detailed study to collect profiles for energy delivered to and exported

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[7] For example, the average residential solar system size in the U.S. is 5 kW according to SEIA. Assume a central air conditioner for a house uses 4 kW of energy at a given time and a 5 kW solar PV system operates at 80% efficiency during a sunny part of the day (5 kW × 80% = 4 kW), then the solar PV system not performing is equivalent to the air conditioner turning on.

[8] Robert Ozar, P.E., from the Michigan Public Service Commission, is the developer of the Inflow & Outflow methodology and has done trainings and roundtables on the method. If there is interest, he may be available to do a training in Idaho.

from customers with distributed generation from different customer classes. The purpose of the data collection is to study the customers' usage and exports in order to understand impacts to system peaks, class peaks, and individual customer demand. The company proposes to use this information to assess and allocate costs and design rates, plan for load, appropriately size grid equipment, and enhance customer service (PacifiCorp 2018).

Many states continue to have full retail rate net metering programs. Other states are using avoided cost as the basis of export energy compensation (e.g., LA, MO, NE, MN, ND, OK, RI). Arizona and Georgia are using a solar specific avoided cost rate for export energy compensation, which in Arizona is referred to as a resource comparison proxy. Other states are experimenting with buy-all, sell-all, or net billing (NJ, CT, VT, and ME, among others). A few states have tried or are moving toward demand charges for residential customers (KS, MT), while others are focusing on time-of-use rates in net metering successor programs (CA, MD). Some states are moving toward value-based tariffs (MN, MO, OR, NY), while others are using an export value equal to wholesale prices or average marginal costs plus an adder (IN, MS). Nevada, after a false start with eliminating net metering all together, is now phasing down export compensation over time, from 95% of full retail rate to 75%, as a result of legislation. New York is also using a market transition credit to help ease the transition from full retail rate net metering to its value stack tariff, for community solar customers. As mentioned above, Utah has an open proceeding to calculate an export rate.

EEI, in their comments on the NARUC Rate Design Manual, points out that full NEM requires utilities to buy back all of a customer's exported energy (which EEI refer to as wholesale energy) at retail prices. EEI points out that all energy, including solar energy, is fungible and can be procured competitively in wholesale markets. EEI suggests a reasonable substitute (or proxy) value for customer exported generation could be utility-scale solar generation, for which prices are substantially below retail rates (EEI 2016). This concept is the basis of Arizona's Resource Comparison Proxy scheme where exported energy is compensated at the price of utility scale solar, described in more detail in Table 3.

Summary of DG Compensation in Other States

To improve the Idaho PUC staff's understanding of DER rate design, it is informative to look at what has been tried elsewhere. Figure 2 is a color-coded map categorizing each state by its current (as of September 2018) net metering and distributed generation compensation policies. Table 3 then provides more details for each state. Links to more information are provided in the table. California and Hawaii have expanded summaries to highlight key issues relevant to Idaho.

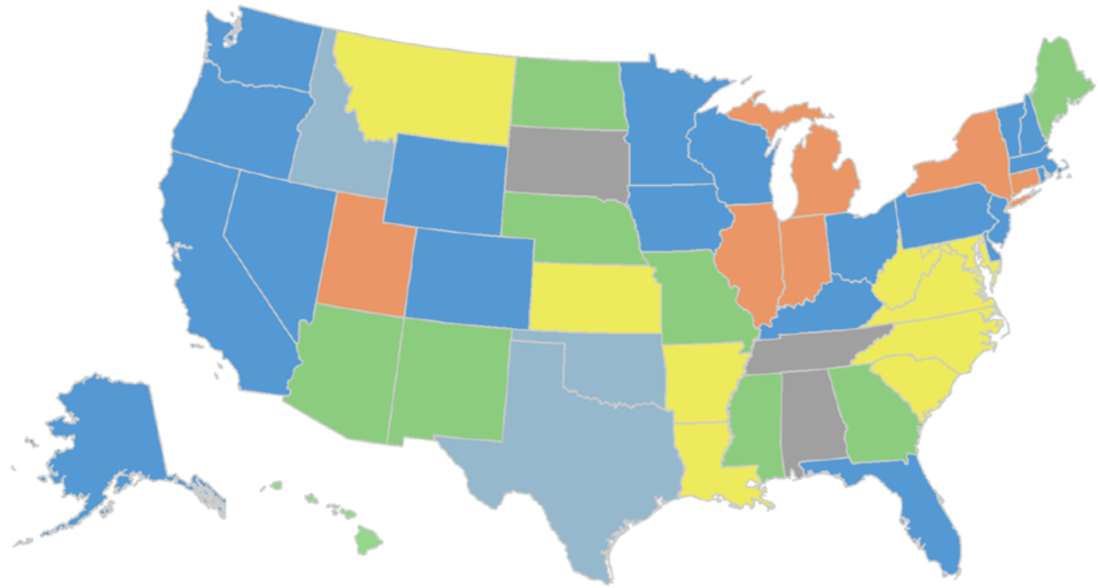

***Figure 2**. Distributed Generation Compensation across the States ([Proudlove et al. 2018](#))*

***Table 3**. State Distributed Generation Compensation Summaries*

State	Distributed Generation Compensation as of September 2018	Category
Alabama	No statewide policy.	
Alaska	Traditional retail rate compensation net metering policy for systems up to 25 kW.	
Arizona	The Arizona Corporation Commission has had many dockets related to net metering, the most recent being RU-00000A-18-0284. Exported energy from distributed generation is compensated at an avoided cost rate with different rates for different utilities based on a **resource comparison proxy** (RCP) methodology. The RCP rate may not be reduced more than 10% a year, is based on a rolling five-year weighted average cost of the utility's solar PV PPAs and utility-owned grid-scale solar PV facilities, and is applicable for 10 years. For projects installed through August 2019, Arizona Public Service's RCP rate for exports is, 11.61¢/kWh, Tucson Electric Power's is 9.64¢/kWh, and UNS Electric's is 11.5¢/kWh.	
Arkansas	Traditional retail rate compensation net metering policy for residential systems up to 25 kW and commercial systems up to 300 kW. But there is an open docket (16-027-R) exploring moving to net billing (or "2-channel billing")	

State	Distributed Generation Compensation as of September 2018	Category
	in which excess generation is credited at an **embedded cost-of-service rate** rather than the retail rate, and addressing any cost shifts.	
California	See summary on page 20.	
Colorado	Traditional retail rate compensation net metering policy that explicitly includes solar-plus-storage systems.	
Connecticut	S.B. 9, signed into law in May 2018, significantly changed net metering. Existing net metering customers will be grandfathered in until December 31, 2039. New net metering customers will be able to select a **buy-all, sell-all option or a net billing option**. These options are under development.	
Delaware	Traditional retail rate compensation net metering policy.	
District of Columbia	Traditional retail rate compensation net metering policy for systems up to 1 MW.	
Florida	Traditional retail rate compensation net metering policy for systems up to 2 MW. But the utility JEA has retired its traditional net metering program (with existing customers grandfathered for 20 year) and replaced it with a Distributed Generation Policy that compensates exported energy at the **utility's avoided cost, or "fuel charge."**	
Georgia	The Georgia Cogeneration and Distributed Generation Act of 2001 allows but does not require NEM to be adopted by utilities. Excess generation is credited to the customer's next bill at a predetermined rate filed with the Georgia PSC (this is currently the **Solar Avoided Cost** for Georgia Power).	
Hawaii	See summary on page 20.	
Idaho	See Background section on page 4.	
Illinois	Although the state currently has a traditional retail rate compensation net metering policy, the recently passed Future Energy Jobs Act (FEJA) requires a transition to a net metering successor policy that includes a distributed generation rebate program. Once a 5% state aggregate cap is reached, eligible customers who begin taking net metering shall only be eligible for energy-related value (no T&D related value). The new distributed generation rebate is intended to reflect the value of distributed generation to the distribution system. Preliminary consideration of rebate valuation is here.	
Indiana	S.B 309 enacted in May 2017 phases out traditional retail rate compensation net metering in Indiana. Distributed generation systems installed in 2018 through July 1, 2022 will receive the **full retail rate** compensation for 30 years. Excess generation from systems installed after July 1, 2022 will be compensated at the utility's **average marginal cost plus 25%.**	
Iowa	Traditional retail rate compensation net metering policy for systems up to 500 kW.	
Kansas	Traditional retail rate compensation net metering policy for systems. But Kansas City Power & Light has an open docket (18-KCPE-480-RTS) proposing to create a **residential sub-class** for new distributed generation customers that would include **lower energy rates**, a **lower fixed monthly charge**, and a **demand charge**.	
Kentucky	Traditional retail rate compensation net metering policy for systems up to 30 kW. (Also see Glasgow Electric Plant Board story on page 21.)	
Louisiana	Traditional retail rate compensation net metering policy. But there is an open docket (R-33929) to consider changes to the state's net metering rules and solar policies. Proposed modified rules under consideration include replacing net metering with **net billing**, crediting customers at the **avoided cost rate** for excess generation.	

State	Distributed Generation Compensation as of September 2018	Category
Maine	Maine replaced its net metering policy with a **distributed generation buy-all, sell-all** policy in 2017. Production and consumption are credited and billed at separate rates. The production rate is on a 10% annual decrease declining schedule. A group is challenging the legality of the program in the Maine Superior Court.	
Maryland	Traditional retail rate compensation net metering policy for systems up to 2 MW. A workgroup is developing **a time-of-use (TOU) pilot** program which would impact net metering customers. In September 2018, Daymark Energy Advisors provided the PSC with a report on the benefits and costs of utility-scale and behind-the-meter solar resources in Maryland.	
Massachusetts	Traditional retail rate compensation net metering policy. The state has many other programs as well, including the SMART solar incentive and the solar REC programs.	
Michigan	The 2016 Public Act 341 and 342 requires the implementation of a new Distributed Generation Program. The existing traditional net metering program will continue until the new program is in place as part of each utility's approved rate case. All utilities must include the distributed generation compensation **Inflow & Outflow methodology** included in Docket 18383 in rate case filings. DTE Electric is the first utility to file a rate case (U-20162) that addresses these changes. DTE Electric proposes that all inflows would be charged at the full retail rate, while outflows from a customer's distributed generation system would be credited at the **monthly average real-time locational marginal price (LMP)** at the relevant DTE node. New DG customers would also have to pay a **system access charge** of $2.31 per kW of capacity.	
Minnesota	Although the state has a traditional retail rate compensation net metering policy, Minnesota passed legislation in 2013 that allows IOUs to offer a **voluntary value of solar tariff (VOST) as an alternative** to traditional retail rate compensation net metering. The VOST has only been applied to community solar by Xcel Energy so far.	
Mississippi	On December 3, 2015, the PSC issued a final order under Docket 2011-AD-2 for new net metering rules. Excess generation is credited at a **wholesale avoided cost rate plus a 2.5¢/kWh premium**. Acadian Consulting was hired in 2018 to conduct a distributed generation benefits study for the PSC.	
Missouri	The state's current net metering policy credits excess generation at the **avoided cost rate**. An open docket (EW-2018-0078) to review changing current net metering rules, addressing potential cost shift issues, and undertaking a value of solar study.	
Montana	Traditional retail rate compensation net metering policy for systems up to 50 kW. But utility NorthWestern Energy has an open docket (D2018.2.12) proposing a new customer class for future residential net metering customers that would include an **$8.64/kW demand charge**.	
Nebraska	Excess generation is compensated at the utility's **avoided cost rate**.	
Nevada	Generally a traditional retail rate compensation net metering policy for systems up to 25 kW. The excess generation credit value is on a declining schedule from 95% of the retail rate to 75% eventually. See additional information on page 22.	
New Hampshire	Traditional retail rate compensation net metering policy for systems up to 1 MW. A law to expand net metering (S.B. 446) was vetoed by the governor in September 2018.	

State	Distributed Generation Compensation as of September 2018	Category
New Jersey	Generally a traditional retail rate compensation net metering policy, but **different excess generation compensation options** are available.	
New Mexico	Excess generation is compensated at the utility's **avoided cost rate**. In September 2018, the New Mexico PRC approved ending standby charge for distributed generation customers. The PRC plans to open a rulemaking to address standby charge issues.	
New York	New York is transitioning from a traditional retail rate compensation net metering policy to a value of DER tariff, or **value stack tariff**. During the transition, eligible customers can take the Phase One Net Energy Metering tariff which is identical to the previous program except the term is limited to 20 years. Other customers must be take the Phase One Value Stack tariff which can include a market transition credit. See additional information on page 22.	
North Carolina	Traditional retail rate compensation net metering policy until new rates are approved. H.B. 589, signed in July 2017, states that utilities must file revised, non-discriminatory net metering rates that ensures customers pay the full fixed cost of service (i.e., rates may include fixed monthly energy and demand charges). The rates can only be established after a costs and benefits investigation of customer-sited generation.	
North Dakota	Excess generation is compensated at the utility's **avoided cost rate**.	
Ohio	Traditional retail rate compensation net metering policy with a system size limit of 120% of a customer's average annual usage.	
Oklahoma	Utilities are not required to compensate excess generation, but if they do, compensation would be at the **utility's avoided cost rate**. Utilities can charge distributed generation customers a **fixed charge**.	
Oregon	Traditional retail rate compensation net metering policy. Oregon has an open docket (UM 1716) to determine the resource value of solar for community solar projects, and the resource value of solar is not intended as a net metering replacement.	
Pennsylvania	Traditional retail rate compensation net metering policy for residential systems up to 50 kW and non-residential systems up to 3 MW.	
Rhode Island	Excess generation is compensated at the **utility's avoided cost rate**.	
South Carolina	Traditional retail rate compensation net metering policy. But Duke Energy Carolinas has an open docket (2015-55-E) which is considering an alternate program for customers when net metering closes March 15, 2019.	
South Dakota	No statewide policy.	
Tennessee	No statewide policy.	
Texas	There is no statewide net metering policy, but some utilities offer net metering.	
Utah	Utah closed net metering to new customers on November 15, 2017. Existing customers are grandfathered in through through December 31, 2035. **New systems will receive an export credit**, to be determined in the open Export Credit Proceeding docket (17-035-61). In the interim, the Utah PSC established a transition program for new customers to participate in after the close of retail rate net metering and before the new export credit rate is decided. The transition program takes the form of **net billing**, rather than net metering, with an export credit rate of 9.2¢/kWh for residential customers.	
Vermont	The state's net metering program credits excess generation at the least "**residential blended rate**" based on three different calculation approaches.	
Virginia	Traditional retail rate compensation net metering policy with **one customer class that must pay a standby charge**. But S.B. 966, enacted in March 2018,	

State	Distributed Generation Compensation as of September 2018	Category
	requires utilities to investigate potential improvements to the state's net metering and community solar programs. Feedback from stakeholder meetings thus far indicates interest in exploring compensation alternatives to net metering, although stakeholders disagreed on the presence of cost shifting and whether the current compensation structure is fair. Alternative compensation models discussed include a buy-all, sell-all approach; value stack approach; net billing; and a separate rate class for distributed generation customers.	
Washington	Traditional retail rate compensation net metering policy for systems up to 100 kW.	
West Virginia	Traditional retail rate compensation net metering policy. But a docket opened in September 2018 (GO 258.3) is considering revisions to net metering and interconnection.	
Wisconsin	The Wisconsin PSC has not adopted administrative net metering rules, so utility net metering tariffs vary, but generally follow a traditional retail rate compensation net metering policy.	
Wyoming	Traditional retail rate compensation net metering policy for systems up to 25 kW, but law also allows for "other compensation" as well.	

California Net Metering Successor Tariff

California has adopted a net metering successor tariff that continues the existing net metering structure while making adjustments to align the costs of net metering successor customers more closely with those of non-participating customers (CPUC 2016).

There are a few key differences between California's initial policy and its successor. The successor tariff requires a smart inverter for all interconnection applications, and participating customers must take a time-of-use rate in which the price of electricity varies throughout the day (SCE 2018). Cost-based, time-of-use rates for all customers may serve as a more accurate and transparent approach for utilities to recover costs by incentivizing customers to shift usage away from peak demand times (Kennerly et al. 2014). Customers participating in the new net metering successor tariff will pay a one-time interconnection fee and non-bypassable charges, such as a Nuclear Decommissioning Charge (SCE 2018). In addition, the new tariff specifically prohibits new demand charges, grid access charges, standby fees, or similar fixed charges until the impacts of these charges are fully studied.

Hawaii

In response to increased solar PV penetration rates that Hawaii Electric claimed its circuits could not handle, the Hawaii Public Utilities Commission (HPUC) ended the state's net metering program in 2015 and replaced it with different on-site generation compensation options (DSIRE 2015; HPUC 2015a). Customers with existing net metering agreements or applications prior to the change had the option of keeping their original net metering program terms. All new private rooftop solar systems are required to have advanced inverter technology with specific grid support features activated. Some adjustments have been made since the decision, and Hawaii Electric Company (HECO) currently offers the following customer renewable programs (HECO 2018):

- **Net Energy Metering (NEM)** is closed to new applicants.
- **Net Energy Metering Plus (NEM Plus)** allows current NEM customers with a signed agreement to add additional non-export capacity to their system.

- **Customer Grid-Supply (CGS)** participants receive a PUC-approved credit for electricity sent to the grid and are billed at the retail rate for electricity they use from the grid. The program remains open until the installed capacity cap has been reached.
- **Customer Grid-Supply Plus (CGS Plus)** systems must include grid support technology to manage grid reliability and allow the utility to remotely monitor system performance, technical compliance, and, if necessary, control for grid stability.
- **Customer Self-Supply (CSS)** is intended only for private rooftop solar installations that are designed to not export any electricity to the grid. Customers are not compensated for any export of energy.
- **Smart Export** customers with a renewable system and battery energy storage system have the option to export energy to the grid from 4 p.m. to 9 a.m. Systems must include grid support technology to manage grid reliability and system performance.
- **Standard Interconnection Agreement (SIA)** is designed for larger customers who wish to offset their electricity bill with on-site generation.

Transitions

Well-designed **transition programs** for both new rate design structures and new NEM policies can facilitate customer acceptance of these changes. The Commission may wish to consider that any rate innovations be phased in. This section provides some examples of good and bad transitions.

In some states, significant rate innovations are being phased in, so that customers are given time to fully understand new rates before they go into effect. In his paper, *Rate Design 3.0*, Faruqui (2018a) makes the point that is important to avoid surprising customers. Consequently, his suggestions when transitioning to a new rate design include engaging customers to ensure they understand the rationale for the changes, conducting scientifically-designed pilots to test concepts and gauge customers understanding, and considering a longer timeline for changing rates that includes outreach and communications (Faruqui 2018a). Another transition option is to consider providing bill protection initially and then phasing out bill protection over time. For example, in year 1, customers could be guaranteed that their bills would be no higher than they would be otherwise. In year 2, bills would be no higher than 5 percent; in year three, no higher than 10 percent; and so on *(Faruqui et al 2010)*.

EEI agrees that customer education is important and suggests states address rate design issues as early as possible to provide more certainty for customers as they consider investments (EEI 2016).

PNNL supported the Illinois Commerce Commission with initial stakeholder engagement to advance the conversation around distributed generation valuation in anticipation of a formal distributed generation rebate valuation proceeding. In their comments, one of the stakeholders, Joint Solar Parties,[9] noted the importance of an interim approach when transitioning to new distribution generation compensation policies. The group suggested, "…when faced with significant unknowns, policymakers have chosen interim methods characterized by moderation, to wit, very modest (or no) reductions in compensation while further investigation takes place." Similarly, in their comments to NARUC on the Draft Rate Design Manual, SEIA suggest emphasizing gradualism, grandfathering, and predictability relative to rate design changes so sellers of retail energy services have a stable business climate in which to operate and

[9] The Solar Energy Industries Association, Illinois Solar Energy Association, and the Coalition for Community Solar Access are collectively known as Joint Solar Parties. Comments of the Joint Solar Parties are located here: https://icc.illinois.gov/Electricity/workshops/DistributedGenerationValuation.aspx

distributed generation customer investors have predictability to ensure they can lock-in value for the life of their systems (SEIA 2016).

Transition Examples

As shown in Figure 2, many states are transitioning from net metering policies to other distributed generation compensation policies, and many are just starting to explore new options. This section provides some transition examples as "lessons learned" to share with the IPUC. While this memo focuses on state efforts, what happened at Glasgow Electric Plant Board in Kentucky provides an illustrative example of a challenged transition. The lesson learned from the Glasgow example is the importance of upfront customer education and outreach. Nevada provides another example of a challenged transition. The lessons learned in Nevada are the need to carefully consider the sensitivity around how existing systems will be treated in a rate transition (i.e., if and how they will be grandfathered in) and the potential benefits of using deployment stages and incremental reductions to compensation. New York's transition to a value stack tariff, although not perfect, provides a more positive transition example that benefited from a long planning timeline, extensive stakeholder engagement and transition features in the tariff.

Glasgow Electric Plant Board

Glasgow Electric Plant Board (GEPB) is the municipal utility for Glasgow, Kentucky; it receives its wholesale electricity from the Tennessee Valley Authority (TVA).

In a series of articles published in The Glasgow Daily Times in August 2016, Melinda Overstreet reported the controversy surrounding the GEPB's attempt to move from a flat rate tariff to a time-of-use rate tariff that included a coincident peak demand charge. Customer perception was that rates had increased, and the new rate structure was hitting lower income residents the hardest.[10] The coincident peak demand charge was the target of most of the opposition. Proponents for the new rate structure argued that the new tariff better reflected actual costs from TVA and allowed customers the opportunity to save money by managing their electricity consumption.

Essentially, the GEPB customers were surprised. This rate change was introduced fairly quickly and the controversy could have likely been mitigated by more initial customer education and outreach.

The public opposition prompted the Kentucky Attorney General, Andy Beshear, to instruct his Office of Rate Intervention to get involved. The office reviewed documents and customer complaints and made recommendations to the GEPB.

Consequently, in September 2016, the GEPB adopted a default rate structure and an alternate rate structure to appease customers. Customers must opt-in to the alternate rate structure. The default rate structure contains a flat monthly charge, seasonal peak and off-peak per-kilowatt-hours usage charges at the TVA wholesale rate, and a coincident peak demand charge for the number of kilowatts (not kilowatt hours) used during the one hour each month that demand is at its highest. The alternate rate structure has a lower flat monthly charge and higher seasonal (but no peak or off-peak rates) per-kilowatt-hours usage charges set by the GEPB (GEPB 2016). The alternate rate structure is similar to the GEPB's past tariff structure.

[10] The perception that dynamic pricing is unfair is discussed in the Time-of-Use Rates section of this paper.

Nevada Net Metering Reversal

In December 2015, the Nevada PUC approved a new net metering tariff structure from NV Energy that increased the fixed service charge for net metering customers and gradually lowered the compensation rate for net excess generation from the retail rate to the wholesale rate. This policy change was applicable to both existing net metering customers and future customers (Pyper 2015). This was unusual because these types of changes are not typically applied retroactively to existing customers; existing customers are typically grandfathered in under the current program.

Because of strong public opposition, the Nevada Legislature restored net metering in 2017 with A.B. 405 (Pyper 2017). Under A.B. 405, for the first 80 MW of systems to apply, solar PV systems up to 25 kW in size can net excess generation monthly at a rate equal to 95% of the retail rate for 20 years. For all other systems, exported generation is credited at the avoided cost rate (DSIRE 2018). The new 80 MW capacity tranche approach progressively reduces the carryover rate for monthly excess generation from the full retail rate to 95% for the first tranche, 88% for the second tranche, 81% for the third tranche, and 75% for all new installations after the third tranche is filled (NPUC 2017).

Other relevant provisions in A.B. 405 include the following: 1) the legislation ensures that net metering will remain in place if Nevada voters decide to deregulate the state's electricity market and 2) the legislation mandates that net metering customers cannot be treated as a separate rate class, meaning net metering customers cannot be charged with any fees that are different than non-net-metering customers (Pyper 2017).

New York Market Transition Credit

In New York, the PSC ordered the implementation of a successor to NEM tariffs that will provide incentives reflecting the locational value of DER. New York's value of DER tariffs, also called value stack tariffs, are being designed to replace net metering for larger-scale community solar PV projects (up to 5 MW) in the short term, and will eventually be applied to all DERs across the grid (Orrell et al. 2018). The value stack tariff components include valuations for energy, capacity, environment, demand, and location.

As part of the transition from net metering to a value stack tariff, a market transition credit is also offered to community distributed generation projects. The intent of the market transition credit is to avoid market disturbance in the transition away from NEM. The market transition credit is calculated by the utility and applies for a full 25 years. The first tranche of value stack customers received a market transition credit that resulted in total compensation equal to previously applied full NEM compensation. In other words, the first tranche market transition credit was essentially equal to the difference between the base retail rate and the estimated value stack rate. The tranche 2 and tranche 3 market transition credits provided for total compensation of 95% and 90% of NEM compensation, respectively. Each utility has a capacity cap for each tranche of the market transition credit (NYPSC 2017).

The change to a successor NEM program in New York has not been without controversy or disagreement, but the long planning timeline, the transition features, and the extensive stakeholder engagement have enabled the state to continue to progress with its changes.

Conclusions

As the IPUC prepares to review CBA and rate design options, it has the benefit of learning both from what other states have already done and from the numerous studies and reports available from DG experts. Critical issues for consideration include cost causation; cost shifts (in both directions); pros and cons of fixed charges, variable charges, and demand charges; time-varying rates; and smooth transitions from one compensation mechanism to another. Understanding that cost causation is not an exact science, rate making can benefit from data-driven analysis to inform final decisions, and time-varying rate structures are being used to address cost causation concerns can help prepare the IPUC staff for the upcoming proceedings

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