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# Cost Recovery for Standby and Ancillary Services for Distributed Generation

## Considerations for New Mexico

**July 2018**

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U.S. DEPARTMENT OF
ENERGY

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# Executive Summary

A New Mexico statute ([62-13-13.2](#)) allows investor-owned utilities to recover costs of "standby and ancillary services", or "services that are essential to maintain electric system reliability", resulting from interconnecting distributed generation customers. Standby rates are traditionally used for large industrial combined heat and power systems, and threshold system size levels are often used in determining applicability of standby rates. In attempting to characterize the costs and benefits of distributed generation, it is important to recognize both the physical and economic impacts, positive and negative, that distributed generation creates.

Distributed generation has different impacts on standby and ancillary services depending on location, capacity, and production patterns of interconnected systems. Low penetrations of small distributed generation systems will not create significant impacts for utilities. The system impacts of fluctuations in distributed generation (DG) production may be no larger than normal fluctuations caused by customer demand, such as an air conditioner cycling. However, as higher penetrations and larger DG systems may produce noticeable impacts, magnitude is critical when determining any additional utility costs. 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. Hosting capacity analyses can help determine how much DG can be interconnected at specific locations before impacts to reliability become substantive.

Relative to the provision of standby services, understanding specific events that create concern for utilities (e.g., community DG system outage, cascading event, clouds, or eclipse) is critical to developing an appropriate rate mechanism. Whatever rate structure is ultimately adopted for DG should reflect the value that smart inverters or storage coupled with distributed generation 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 benefit the utility system and utility customers overall. Appropriate incentives—through rates, rebates, etc.—could be a low-cost way of acquiring additional grid support services.

Utilities can recover their fixed costs in a variety of ways, and some are better suited for DG than others. Beyond charging for standby and ancillary services, other options include fixed customer charges, demand charges, minimum bills, time-of-use rates, and updated net energy metering policies. Studies and analyses of the specific impacts that DG has on the grid should inform utilities' decision-making process because DG creates both costs and benefits for the grid. Any charge specific to DG customers should be based on transparent analysis.

At the heart of this conversation is identifying the appropriate means for a utility to recover its fixed costs. Allowing utilities to recover all stranded, fixed costs can negatively affect long-term market efficiency by blunting utility incentives to lower costs and acting as a barrier to entry and exit. The current status of New Mexico's grid, impending infrastructure updates, and likely customer adoption patterns for DG (backed up by transparent analysis) should remain at the forefront when considering charges for standby and ancillary services.

It is recommended that applications for cost recovery mechanisms for DG-related standby or ancillary services be thoroughly reviewed by an experienced economist and distribution system engineer, either on staff or contracted.

# Acknowledgments

# Acronyms and Abbreviations

| | |
|---|---|
| CHP | combined heat and power |
| CPUC | California Public Utilities Commission |
| CSS | customer self-supply |
| DER | distributed energy resources |
| DG | distributed generation |
| NEM | net energy metering |
| NM PRC | New Mexico Public Regulation Commission |
| PV | photovoltaic (solar power generation) |
| SETO | Solar Energy Technologies Office |

# Contents

# 1.0    Introduction

New Mexico Statute 62-13-13.2 allows investor-owned utilities to recover costs of "standby and ancillary services" resulting from distributed generation (DG) customers connected to the grid. This report recommends approaches and processes, and provides examples, to guide the New Mexico Public Regulation Commission (NM PRC) as it considers utility proposals for recovering costs of standby and ancillary services resulting from DG. This report addresses the following:

- Physical and economic implications of DG

- Assessing the impact of DG on ancillary services

- Traditional use of standby services and charges

- Magnitude of DG penetration

- Thresholds for charging DG customers for standby and ancillary services

- Other options for recovering fixed costs

- Discretion in implementation

- Additional considerations.

In conducting research for this document, we spoke with national experts in electric distribution systems, standby charges, ancillary services, and rate-making and utility regulation. What follows is a compilation of suggestions and examples from the authors augmented by input from these experts. The authors thank the following individuals for their insights:

- Janice Beecher - Institute of Public Utilities at Michigan State University

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- Kevin Schneider –Pacific Northwest National Laboratory (PNNL)

- Lisa Schwartz – Lawrence Berkeley National Laboratory (LBNL).

# 2.0    Physical and Economic Implications of Distributed Generation

The primary physical grid impact of DG has to do with voltage regulation. The grid is designed so voltage is controlled by substations that respond to load. DG can modify the voltage on the system, but voltage levels still need to remain within acceptable values at all locations in the distribution system. Maintaining voltage at acceptable levels is not a significant issue at low DG penetration levels. However, at higher levels, equipment can be damaged and new equipment, such as additional voltage regulators, capacitors, or bigger wires may be required. Variable DG power production can also lead to increased wear and tear on switches and voltage-control equipment.

Protection coordination is also affected by DG. Relays and other equipment were designed to have fault current going from the substation to the fault.[1] However, with DG, it is possible for the fault current to travel the other way. The type of inverter used can make a big difference; some inverters generate a lot of fault current while others do not.

Another physical impact to the grid resulting from DG at high penetration levels is the increased need for regulation services to address minute-to-minute variations and ramping services. Utilities must be able to respond to varying energy generation and demand, provide active and reactive power, and start up or increase power generation at a moment's notice. The costs of providing ancillary services, including regulation services for DG, vary greatly based on location. For example, in the Pacific Northwest, regulation services are low in cost due to the large amount of hydropower available.

In terms of ramping services, costs increase if the "duck curve" phenomenon is pronounced. The duck curve describes the rapid ramp in net load (total customer load minus behind the meter generation) that utilities must serve when transitioning from high solar production during the day coupled with moderate loads to increased evening loads coincident with loss of solar production as the sun goes down.[2] If the duck curve phenomenon is not significant in an area, it is less likely the costs for ramping services will be significant.

The ability to reliably schedule power is also important and has potential cost implications. It is more expensive for a utility to purchase energy from the spot market if a DG system does not produce as expected than it is to secure power 48 hours in advance. Paying another generator (potentially one owned by someone other than the utility) to start up suddenly to make up for power that was expected from DG can also be more expensive than normal market rates.

# 3.0    Ancillary Services

Ancillary services, also referred to as grid support services, enable the grid to operate reliably; they serve as a support system to help with fluctuations on the grid. Ancillary services typically include operating reserves, reactive supply and voltage control, frequency regulation, energy imbalance, and scheduling (Hansen et al. 2013). Operating reserves address short-term (typically 10-minute and 30-minute (IESO 2018)) variability and plant outages (Denholm et al. 2014). Reactive supply or frequency regulation are necessary to prevent imbalance when variable energy generation exists on the grid. Spinning reserves must also be online to immediately serve the load in case of unexpected contingency. Contingency reserves, regulation reserves, and flexibility reserves are often characterized as operating reserves. The two grid support services most commonly associated with DG are voltage control and operating reserves.

DG's impact on ancillary services depends upon the capacity, location, and production patterns of the interconnected systems. If DG customers are to be charged for ancillary services, understanding DG's effects is critical in creating fair prices.

*Modeling the Impacts of Distributed Generation* (Denholm et al. 2014) proposed three approaches to estimating the impact of distributed solar PV on ancillary services value (see Table 1). The first approach is to assume no impact due to the penetration of PV being too small to have a quantifiable impact and/or due to the fact that PV's impact on ancillary services is poorly understood. The second approach is the

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[1] A fault current is abnormal electric current caused by a fault condition, such as a power line hitting the ground, or a lightning strike or a car hitting a pole.

[2] For more information on the duck curve see
https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

use of simple cost-based methods that estimate changes in ancillary service requirements (such as DG resulting in a reduced spinning reserve requirement as a result of reduction in net load) and apply cost estimates or market prices for corresponding services. The third approach is a detailed cost-benefit analysis that includes running simulations with increasing DG and calculating the impacts on reserve requirements and ancillary services provided by the DG.

Table 1.    Approaches for Estimating Impact of Distributed PV on Ancillary Services (Denholm et al. 2014)

| Name | Description | Tools Required |
|---|---|---|
| 1.  Assumes no impact | Assumes PV penetration is too small to have a quantifiable impact | None |
| 2.  Simple cost-based methods | Estimates change in ancillary service requirements and applies cost estimates or market prices for corresponding services | Excel |
| 3.  Detailed cost-benefit analysis | Performs system simulations with added solar and calculates the impact of added reserves requirements; considers the impact of distributed-generation photovoltaics providing ancillary services | Multiple tools for transmission- and distribution-level simulations, possibly including production cost modeling, AC power flow, and distribution power flow tools |

Determining the impact of DG on ancillary services is a nuanced concept, and the addition of smart inverters and energy storage creates another layer of consideration. Compensating customer-generators for providing ancillary services is still a new and emerging area of research and application.

## 3.1   Hosting Capacity as a Threshold

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. A hosting capacity analysis indicates the maximum amount of DG that specific locations on the distribution grid can safely accommodate without requiring infrastructure upgrades that may be needed to avoid voltage violations, power quality issues, protection problems, or exceeding thermal limits (Homer et al. 2017). 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.

## 3.2   Impacts of Smart Inverters and Storage

While DG has both economic and physical impacts for the grid and ancillary services, those impacts are different with the introduction of smart inverters and energy storage systems.

The primary purpose of an inverter connected to a DG system is to convert direct current from a generating source to an alternating current that can serve the interconnection to a local load or the utility. Historically, inverters built into distributed solar PV systems could not provide ancillary services; they could only put active power on the system by converting direct current to alternating current. New inverters, however, can provide ancillary services including regulation. Smart inverters can obviate

voltage problems created by DG and even support the grid more generally, potentially avoiding new investments in voltage management equipment (Denholm et al. 2014). When reactive power is provided by smart inverters, it reduces the amount of reactive power that is required from large central generators, allowing them to operate at more efficient (real) power output levels, thus reducing transmission losses and increasing the (real) power capacity of transmission lines (Denholm et al. 2014).

Similarly, solar PV systems with storage have different implications for the grid than stand-alone solar PV systems, since storage can help mitigate any utility system impacts due to generation fluctuations. Modeling or characterization of impacts on ancillary services or standby costs of DG should explicitly consider the presence or absence of storage. Without doing so, the cost may neglect significant benefits that the grid is receiving from customer-generators, ultimately overcharging them. Pairing distributed solar PV (and DG in general) with storage creates a situation unique from that of PV on its own, and it warrants individualized consideration.

Whatever rate structure is ultimately adopted for DG should reflect the value that smart inverters or storage coupled with distributed generation 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 benefit the utility system and utility customers overall. Appropriate incentives—through rates, rebates, etc.—could be a low-cost way of acquiring additional grid support services.

## 3.3   Analysis as the Basis for Charges

As noted in the National Association of Regulatory Utility Commissioners (NARUC) distributed energy resources (DER[3]) manual, "without a study of the actual costs of additional reserves required for system reliability, it is possible that a naïve calculation of the standby charge may overstate the actual costs to the system and the needs of the customers. Any charge would need to be justified directly and not be allowed to discourage the investment by customers" (NARUC 2016).

For instance, if it is determined through a study that reliability would suffer without increased reserves due to the introduction of DERs, then DER customers should pay for the service, but not otherwise (NARUC 2016). Determining both the positive and negative impacts of DERs on the system is critical in determining appropriate and fair prices. This requires location-specific studies of transmission and distribution systems as grid and DER conditions vary across time and space.
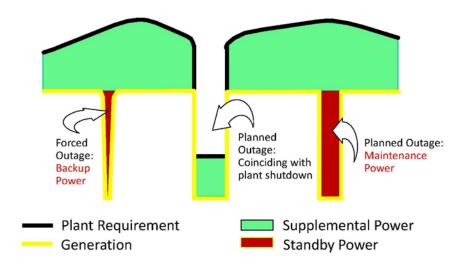
It is important that both positive and negative impacts of DG be weighed appropriately in considering value and the commensurate charge or compensation for DG. Customer adoption models may be utilized to determine the likelihood, location, and extent of DG adoption. Time-series power flow analysis can be used to conduct simulations and calculate impacts of DG. Validated and calibrated distribution system models are a prerequisite for performing time-series power flow model simulations needed to characterize the system impacts of DG.

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[3] "A DER is a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE) (NARUC 2016)."

# 4.0    Traditional Use of Standby Services and Charges

Standby rates, or partial requirements services, are traditionally created for larger industrial customers with combined heat and power (CHP) systems and have been utilized since the introduction of the Public Utility Regulatory Policies Act (PURPA).[4] The objective of standby charges is to recover the costs that utilities incur to remain ready to provide services when a customer-hosted electric generation system is not operating (during an unscheduled outage or scheduled maintenance), as well as to provide any supplemental power the customer needs beyond what the customer's generation system provides during normal operation. Standby charges can be designed to cover the costs for backup power, maintenance power, supplemental power, economic replacement power, and delivery services (see Figure 1). These categories can be summarized as:

- Backup power during an unplanned generator outage

- Maintenance power during scheduled generator service for routine maintenance and repairs

- Supplemental power for customers whose onsite generation under normal operation does not meet all of their energy needs—typically provided under the full requirements tariff for the customer's rate class

- Economic replacement power when utility power costs less than onsite CHP [or other distributed] generation

- Delivery associated with these energy services (Selecky 2014).



Figure 1. Components of standby services (Selecky 2014).

The theory of standby rates is that the cost causer pays the utility to have standby power ready in case customer-generator units fail. Large industrial CHP systems are much larger than residential solar photovoltaic (PV) systems, putting more stress on the utility than residential DGs would if their systems

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[4] The Public Utility Regulatory Policies Act (**PURPA**, Pub.L. 95–617, 92 Stat. 3117, enacted November 9, 1978) is a United States Act passed as part of the National Energy Act. It was meant to promote energy conservation (reduce demand) and promote greater use of domestic energy and renewable energy (increase supply). *[https://en.wikipedia.org/wiki/Public_Utility_Regulatory_Policies_Act]*

unexpectedly go down. Small DER systems that inject intermittent energy into the grid create a different type of burden at low penetration levels, so standby charges do not directly translate between technologies. This fact highlights the importance of considering system size and DG penetration on the grid when considering the applicability of standby rates.

A threshold for system size is typically used for traditional standby power situations, on the assumption that systems below the threshold would not create a noticeable contingency for the utility if they experienced an outage. However, intermittent DERs in aggregate could potentially create a noticeable contingency if they are acting at the same time. Instituting a standby charge threshold for individual DG system size and cumulate DG penetration on a feeder could mitigate the risk of smaller DG customers paying for a cost that they are not actually imposing on the utility. This subject is addressed in more detail in section 5.0.

## 4.1   Coincidence

Utilities may attempt to plan for coincident outages in designing their standby charges. In fact, coincident outages are often the drivers of standby charges and they occur when multiple non-utility owned generators go down at the same time. Such outages could pose a problem if the plants involved are large and co-located. Smaller, geographically diverse DG systems are much less likely to create a noticeably negative coincident occurrence, so developing a standby charge around those conditions may not accurately reflect the service the utilities are providing (Selecky 2014). This is one reason that standby rates may not translate well to low penetrations of DG.

Relative to the design of standby rates, it is important to identify which specific event or types of events are of particular concern. Is it a single DG project outage, and at what project size? Or is the primary concern that a series of residential systems would simultaneously experience outages, or that a community solar or wind project goes down? Is it a cloud passing over or an eclipse? Is it a cascading series of events? These are questions regulators might ask the utilities who are proposing standby rates for DG. It is important that utilities explicitly identify the contingency for which they are preparing and which the proposed rate is designed to address.

## 4.2   Ratcheted Demand Charges

Demand is the rate at which customers consume electricity, or the amount of power needed by a customer at any given point in time. Demand charges are based on the highest level of electricity supplied at one time during the billing period. Demand charges are very uncommon for residential customers but more common for commercial and industrial customers. Where they do exist, it is common for demand charges to be ratcheted.

A ratchet means that a utility continues to apply some percentage of the customer's highest peak demand in a single billing month up to a year after the last peak demand occurred (SEEAction 2013). Some experts view such a billing component as increasing the equity of fixed-cost allocation among ratepayers, while others see them as economic barriers for DG development. Since shared distribution and transmission infrastructure is developed for many customers, as well as a range of customer types, rather than for a single self-generating customer, ratchet clauses may result in DG customers overpaying for utility-supplied electricity relative to their full-requirement counterparts. Some DG systems experience outages at random, so it is highly unlikely for all DG systems on a feeder to simultaneously experience failure during a utility's peak (SEEAction 2013). If a standby rate that includes a ratchet clause is applied to DG systems in general, the diversity in load of those customers needs to be recognized to prevent them from overpaying.

## 4.3  Load-Reduction Plans

Load-reduction plans can be part of the implementation and use of standby charges. These plans specify the level of backup service a customer would receive if their generator goes offline, allowing customers to implement demand-response practices instead of requiring a utility to provide *all* of the customer's power in a backup event (SEEAction 2013).

A customer committed to a load-reduction plan is required to reduce their load to an agreed-upon level and faces additional charges if they do not meet the plan's requirements. This type of agreement requires coordination between the utility and the customer-generator. The customer-generator needs to be able to periodically demonstrate its ability to reduce its load by a specified amount within a given timeframe to mitigate all or a portion of its backup demand (SEEAction 2013). Load-reduction plans can ultimately minimize the costs that customer-generators impose on the electric system and the costs that customer-generators pay for standby service.

# 5.0    Magnitude of DG Penetration

Magnitude is important when it comes to providing standby services. For example, if a 5 kW rooftop solar array located on a substation that can handle one megawatt goes offline, its impact is similar to that of an individual turning on an air conditioner at a given moment[5].

When a state has a relatively low level of DG adoption, there are most likely no incremental fixed costs unless all of the systems are highly concentrated on a limited number of substations or circuits. Any production variation would not noticeably differ from normal fluctuation created by consumer demand, and the cost impact would be less than that caused by a rounding error.

## 5.1  Modeling DG Penetration Levels

If a utility currently has very low penetrations of DG, but wants to institute a charge to recover incremental fixed costs or standby costs due to projected future DG levels that will impose costs on the system, the utility should be able to provide analysis showing the projected increases in DG and the projected impacts. Additionally, as a matter of equity, current customer-generators should not pay for costs or be paid for benefits generated by future customer-generators.

A variety of methods can be used to project DG levels in the near- and long-term future. These include time series-based, goal-based, and customer adoption models (Mills et al. 2016). While time series-based and goal-based approaches are often easier to implement, customer adoption models produce more robust and applicable results for planning purposes. Customer adoption models consider historical DER deployment, location-specific technical potential, technology-specific economic considerations, and end-user behavior, producing results that reflect consumer decision-making (Mills et al. 2016).

When considering whether a standby or ancillary service charge is needed in a certain area, it may be important to determine whether the utilities' analysis of customer adoption models indicates a likelihood of significant DG penetration on certain feeders. This would allow regulators to determine the likelihood of simultaneous outages, threshold concerns, and diversity issues. Absent this type of analysis or

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[5] For example, 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.

justification, standby and ancillary services charges may not be justifiable at existing, relatively low penetration levels.

# 6.0    Thresholds

Utilities have created a range of thresholds for applying standby rates. Below these thresholds (for individual installations), standby rates do not apply. Several examples of standby rate thresholds for New Mexico to consider are listed below.

Southern California Edison uses a 500 kW threshold for standby rates. Southern California Edison requires all self-generating customers who are not enrolled in an NEM to take standby service, but has different schedules for customers with combined maximum demand and standby demand falling above the 500 kW threshold than for those who fall below it. Customers below the threshold pay their otherwise-applicable tariffs in addition to a standby charge, and customers above the threshold have a schedule that bundles all service charges into a single rate schedule (Southern California Edison 2016, 2017).

Minnesota and Oregon also use thresholds for applying standby charges, but their thresholds are 100 kW and 1,000 kW of system rated capacity, respectively. Minnesota allows larger customers to opt out of the schedule if they can provide physical assurance[6] that they will not take standby services (Minnesota Power 2009). Pacific Power and Portland General Electric in Oregon have a threshold of 1,000 kW for standby services provided to large, nonresidential customers. Customers that do not surpass this threshold are served at their applicable general service schedule (Oregon Pacific Power 2013).

Xcel in Colorado has a size threshold of 10 kW for standby service for commercial and industrial customers with electric generating equipment that normally operates in parallel with the utility system. Xcel also utilizes standby charges for their recycled energy customers who produce electricity from waste resources. Customers with a standby capacity need between 500 kW and 10 MW are eligible for the recycled energy rate schedule, which also includes a capped $500/kW recycled energy incentive. Customers may elect the recycled energy rate schedule if they are not contracted in a net energy metering (NEM) agreement with the utility. These customers are otherwise placed on their default rate schedules (PSCC 2016).

In addition to a size per project threshold for standby rates and charges, a threshold based on the amount of MW of installed DG by circuit may also be considered. The cumulative penetration threshold should be based on analysis rather than conjecture with identification of the specific contingency condition that is proposed to be mitigated by contracting and payment for standby services.

# 7.0    Other Options for Recovering Fixed Costs

There are a variety of mechanisms that utilities can use to recover fixed costs, which may be better suited for DG than standby charges and/or charges for ancillary services. Other options utilities around the country use include increasing fixed customer charges, demand charges, minimum bills, and NEM 2.0. Each are briefly described below.

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[6] Physical assurance is defined as "special load-limiting facilities" that will ensure the customer-generator will not take standby charges (U.S. EPA 2009).

## 7.1  Fixed Customer Charge

Fixed customer charges are also referred to as customer charges, basic charges, or access fees. Customers have a predetermined fee on their bill each billing cycle. Fixed charges guarantee that a utility will recover a certain amount of their fixed costs from every customer. Fixed charges, as implemented today, are much lower than the utility's cost of providing grid services, including transmission, distribution, generation capacity, and ancillary and balancing services. Some argue that increasing the ratio of fixed to variable charges on utility bills is an important step toward cost causation and cost-based rate design (Wood et al 2016).

There has been a trend toward increasing fixed charges as a percent of the overall utility bills in recent years (Nowak 2014). However, some are opposed to increasing fixed charges, citing concerns about bill impacts to low-usage and low income customers, reducing incentives for energy efficiency and requiring DG customers to pay for grid services proportionately more than they are using them (Wood et al 2016).

## 7.2  Demand Charge

Demand charges, which are charges based on the highest level of electricity supplied at one time during the billing period, serve as a way to ensure that capacity is available when customers need it. Demand charges are typically only used for commercial and industrial customers, although in recent years there has been a controversial push to apply demand charges more broadly (Trabish 2016). The demand charge is dependent on the customer's peak consumption in kilowatts, and is intended to recover capacity costs for which that customer is responsible. For customer-generators, a demand charge "recovers the cost of maintaining peak distribution and generation capacity to accommodate the self-generation customer in the event of a backup" (Faruqui 2016). This charge is in addition to the fixed and volumetric energy charge on the bill.

## 7.3  Minimum Bills

Minimum bills allow a utility to recover a minimum amount of funding for electricity services from a customer-generator every year, even if their energy usage is zero (Lazar 2014). Solar PV advocates are often in favor of minimum bills because they usually only affect customers with generation systems that are relatively large relative to their loads. In essence, a threshold of energy consumption is set, and if a customer does not reach that threshold over a specified period of time, then they must pay the minimum bill. However, when a customer exceeds that level of consumption, their minimum bill "disappears," and instead they effectively pay a volumetric rate to cover power supply and distribution costs (Lazar 2014).

This practice has been implemented in Hawaii, where the Hawaiian Electric Company explains to their NEM customers that "you will be billed a minimum charge plus applicable surcharges if in a given month your net kWh use is zero or a negative number, or if your net kilowatt-hours use is so low that the sum of the customer charge, non-fuel energy charge, base fuel energy charge, plus applicable surcharges is lower than the minimum charge" (HEC 2012).

## 7.4  Time-of-Use Rates

Time-of-use rate schedules charge customers varying prices according to the hour, day, and time of year depending on the demand at the time. Thus, if a customer-generator produces all of its energy during the time of day where overall demand is highest and only requires the utility to provide them power during times where electricity prices are low, they are paying proportionally for the burden they are imposing. In

this example, the customer-generator is helping to reduce the peak load that the utility must serve. Conversely, if a customer-generator is not generating, but rather using power during the peak demand period, they are charged a higher rate for that peak-time usage. Examples of time-of-use rates include time-of-use pricing, real-time pricing, variable peak pricing, critical peak pricing, and peak-time rebates.

## 7.5  Net Energy Metering 2.0

Some states are revamping NEM policies. For example, California has adopted "a NEM successor tariff that continues the existing NEM structure while making adjustments to align the costs of NEM successor customers more closely with those of non-NEM customers" (CPUC 2016). New York has also created a "value stack tariff" to replace net metering for larger-scale community solar PV projects in the short term. Eventually, all DG systems on the grid will transition to this tariff, which is intended to better value a DG system's time and locational impacts.

There are a few key differences between California's initial NEM policy and its successor—a smart inverter is required for all interconnection applications and participating NEM 2.0 customers must take a time-of-use rate in which the price of electricity varies throughout the day (Southern California Edison). 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)

Any customer-generator applying for NEM 2.0 will pay a one-time interconnection fee and pay non-bypassable charges, including their Public Purpose Program Charge, Nuclear Decommissioning Charge, Competition Transition Charge, and Department of Water Resources bond charges (Southern California Edison).

Maine, Hawaii, Indiana, Mississippi, and Arizona have all transitioned away from full retail net metering, and in most instances, avoided costs are the basis of payments to customers for excess generation rather than the full retail rate (Orrell et al. 2018). In Indiana a 25% adder is applied to average wholesale electricity prices and in Mississippi a 2.5 cents/kWh adder is applied to avoided cost rates. These adders appear to have been established through policy directives rather than comprehensive cost-of-service valuations.

Hawaii has created three new post-NEM tariffs for PV owners (HPUC 2015):

- customer self-supply (CSS), for customers that do not need to export excess energy to the grid

- customer grid-supply (CGS), a program similar to NEM that includes a reduced credit rate that is closer to Hawaiian Electric Companies' avoided cost rate and a minimum residential customer bill

- a time-of-use tariff that shifts energy demand to the middle of the day.

# 8.0    Discretion in Implementation

Regulators considering DG valuation and associated credits and/or charges need to make a number of judgment calls. Different economic models (or the same economic model run with different information) could produce varying, but nonetheless legitimate, results. Easy solutions do not exist and there are no widely accepted formulas or standard answers to these questions.

When utilities are recovering costs from self-generating customers, it is important to recall that current rates assigned to non-DG customers also do not have perfect cost causation. It is extremely difficult to assess the actual costs of serving DG customers. Accurately quantifying the actual variability, flexibility, and ramping costs would require detailed time-series simulations and full production cost models.

When it comes to DG's impacts, there are two sides of the coin—the benefits and the costs. In addition to ancillary services, utilities must consider other value streams such as energy, environmental, transmission and distribution losses, generation capacity, and transmission and distribution capacity (Denholm et al. 2014) from DG. If DG customers are charged for their potentially negative impacts, a question arises about accounting for their benefits as well.

It is important to recognize that large, conventional power plants and transmission lines also unexpectedly go down from time to time. This fact should be considered in light of concerns around intermittency in DG power production, ancillary services required, and standby rates.

# 9.0    Additional Considerations

Establishing costs for providing standby and ancillary services should not just be a theoretical exercise; it should be a decision-making process that specifies what the standby and ancillary services charge is actually designed to mitigate, which must be rooted in analyses of DG integration patterns and capabilities of the distribution grid. However, there are larger regulatory issues related to utilities being allowed to recover fixed costs.

In the long run, all costs are variable. "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. Therefore, regulators must exercise judgment when allowing utilities to recover stranded costs, in determining what the actual costs are and the duration for 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. Rose (1996) cautions 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.

By design, regulation is largely a reactive process. Public utility commissions typically provide high level guidance and then evaluate utility proposals for compliance and prudence. It is recommended that proposals filed in New Mexico for mechanisms to recover costs for standby or ancillary services be thoroughly reviewed by an experienced economist and, if possible, by a distribution engineer to evaluate contingencies; this could be either in-house staff or a contractor.

Another helpful resource on the subject of standby rates is the following report written by Tom Stanton from National Regulatory Research Institute: [Electric Utility Standby Rates: Updates for Today and Tomorrow](#) (Stanton 2012).

# 10.0   Summary

As New Mexico proceeds with considering implications and application of the statute that allows utilities to recover costs of standby and ancillary services from interconnected customers with DG, the following are important considerations to take into account:

- DG has different impacts on ancillary services, depending on the location, capacity, and production patterns of the interconnected systems. Magnitude is critical when considering how utilities recover costs for ancillary and standby services. Low penetrations of small DG systems are unlikely to create significant contingencies.

- A hosting capacity analysis can help determine how much DG can be implemented before the impacts to system reliability become substantive.

- Relatively small, geographically diverse DG systems are unlikely to create a noticeable coincident outage, so developing a standby charge around a 100% simultaneous coincidence is not a reasonable assumption. Even still, individual lines and feeders may have substantial excess capacity during coincident outages and this should be considered.

- Utilities can recover fixed costs in a variety of ways besides charging for ancillary services or imposing standby charges. Some of these are better suited for DG than others. Options include fixed customer charges, demand charges, minimum bills, time-of-use rates, and updated NEM policies.

- Understanding which specific events create concern for utilities is essential to developing an appropriate rate mechanism. There are two sides of the coin in valuing DG, and it is necessary to understand and model both the positive and negative effects DG has on ancillary services, standby services, and the grid as a whole. If the delivery system is in need of upgrades and DG could defer those costs, the benefits could offset or exceed other costs.

- Implementation of DG in combination with smart inverters and energy storage creates different impacts than stand-alone DG. Smart inverters and storage can obviate voltage problems and mitigate generation fluctuations from variable energy. Tariffs should recognize and account for the full value proposition of DG plus smart inverters and storage.

- When implementing charges for DG customers, utilities should base their decisions on an analysis of DG penetration in the grid and its physical and economic impacts. Any incremental charges applied to the customer-generators need to be justified with thorough studies of the grid and customer adoption patterns.

- At the heart of this conversation is identifying the appropriate means for a utility to recover its fixed costs. Allowing utilities to recover all stranded fixed costs can negatively affect long-term market efficiency by blunting utility incentives to lower costs. This would act as a barrier to market entry and exit and create asymmetry between a utility's risk and reward.

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