Electric Utility Standby Rates: Updates for Today and Tomorrow

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Executive Summary

A standby rate is paid by an electric utility customer who is served in part by on-site generation and in part by services delivered through the electric grid. Such customers are sometimes referred to as *partial requirements service customers*, and the associated tariffs are sometimes called *partial requirements service tariffs*. Customers pay standby charges so that, in the event of an outage of the customer's on-site generator, either planned or unplanned, the customer has the guaranteed ability and the right to purchase power to replace what would normally be self-generated. Customers pay standby charges either to a utility company, according to the terms and conditions of an approved standby tariff; or to a competitive service provider under a contractually determined or market-price-determined rate. A customer-generator still has to pay for their use of local distribution facilities, however, even if they buy power from an alternative energy supplier. The federal Public Utility Regulatory Policy Act (PURPA, 18 CFR § 292.305) requires utilities to provide certain services, including standby service, to customers with Qualifying Facilities.[1] The rates, terms, and conditions of such service are generally set by state public utility regulatory commissions.[2]

Standby rates have often been contentious. US DOE (2007, p. 8-6) offers this concise overview of the long-standing standby rates debate:

> The installation of DG reduces utility power sales revenues, may cause the utility to incur costs for power purchases or losses on power sales for power expected to be used by the DG customer, reduces rate revenue from non-power related charges in rates (such as "wires" charges and general and administrative expenses included in a kWh rate), and so on. These costs would shift to other, non-DG customers if the utility did not recover them specifically from DG customers. This constitutes a subsidy of DG customers by other rate payers. By the same token, DG systems provide potential benefits to the utility and, by extension, other ratepayers… . Accordingly, DG customers feel they are subsidizing the utility and other ratepayers.

This characterization, though, highlights the dangers of over-generalizing. Whether a subsidy or cross-subsidy occurs depends on the long-run marginal costs of providing the different utility services in question. It should also be noted that the same general concerns apply to energy-efficiency improvements and that the associated costs can differ widely depending on the specific location and mode of operation of a DG system. In addition, customer bills for those utility services depend on the details of rate design, including standby rate design.

Distributed generation (DG) advocates have sought minimal standby rates, based on the premise that DG installations provide grid benefits in the form of deferred or permanent

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1 18CFR §292.303(b) *Obligation to sell to qualifying facilities*. Each electric utility shall sell to any qualifying facility… energy and capacity requested by the qualifying facility.

2 PURPA applies to some utilities that are not regulated by state public utility commissions. Examples include some municipal (city-owned) utilities and cooperative (member-owned) utilities. *See* US DOE, 2009, *List of covered electric utilities.*

reductions in the need for utility-provided generation, transmission, and distribution capacity. Utilities and others have argued that the theoretical benefits from DG are insubstantial, if not immaterial or even chimerical if located in an unsuitable area or operated erratically, and that low standby rates can result in DG customers avoiding payments to cover infrastructure costs associated with backup generation and wires services and thus raise rates for non-participating customers.

The utility concern regarding infrastructure charges is especially acute for most residential and small commercial customers whose rates do not include fixed demand (i.e., kW) charges, but rather have all but a small portion of their charges (i.e., monthly customer-service charges, nominally covering only metering and billing costs) expressed as volumetric (kWh) fees. Standby rates do not always apply to small customers, however. Net metering statutes often prohibit standby charges, and standby rates are sometimes designed only for large customers.

This paper reviews current practices for standby tariffs and presents options and recommendations about how to determine an appropriate standby rate, reflecting differences among generators (such as size and type of generator) and how the generators are regularly operated, and particularly exploring and reporting on differences between vertically integrated monopoly and competitive electricity markets. But standby rate design needs to be evaluated in the context of overall rate design. Standby charges vary, as they should, depending on overall rate design and on the regular service rate the customer is on.

The paper makes two major recommendations: (1) Existing standby rates can and should be modeled, using pro forma estimates of charges under a variety of scenarios and supplemented by case studies of actual customers; and (2) data should be gathered and analyzed about the classes of DG customers—both those paying standby charges and also any who are exempted—to assess accurately the present and future utility-system costs and benefits associated with DG installations. The first type of modeling is needed to determine how close the rates come to meeting their design expectations and how the rates affect DG-customer economics. The second type will better assess the relationship between DG installations and utility-system costs. Depending on the modeling results, standby rates can be adjusted to most accurately reflect the costs and benefits associated with DG installations and operations.

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I. Introduction

Utility standby rates are common, if not ubiquitous. As more and varied types of distributed generation (DG) seek to interconnect with the electric grid, standby rates take on increasing importance. In a 2005 report, Johnston et al. (p. iii) introduced the subject:

> Customers with onsite generation typically remain connected with the grid to meet electrical needs that exceed the capacity of their DG facilities and to ensure, through diversity of supply, the reliability of their electric service in the event that their units are not available because of maintenance or some other reason. Grid-supplied service to these "partial requirements" customers comes in many forms—standby (or backup), scheduled maintenance, and supplemental—and, as the deployment of DG systems has increased, the urgency of resolving the difficult questions about their rates and rate structures has become more acute.
>
> What does it cost the electric system to provide standby service for partial-requirements customers, and how should these costs be recovered? What are the benefits of DG to the system? How should standby rates be designed to reflect these benefits and encourage customers to maximize the value of DG for themselves and the system? The decisions made today will have long-term strategic consequences. [fn omitted]

What is noteworthy, almost eight years after publication of Johnston et al.'s report, is the extent to which these same questions still remain unanswered. This paper reviews the current status of standby tariffs and presents options about how to determine an appropriate standby rate.

Under the Public Utilities Regulatory Policy Act (PURPA) regulations (18 CFR § 292.305), some utilities are required to provide supplementary, backup, maintenance, and interruptible power to a "qualifying cogeneration facility or… small power facility" ("QF"). This requirement was first established with the initial passage of PURPA in 1978 and was amended in 2005. An alternative provided by the 2005 amendment is that a utility's obligation can be terminated by the Federal Energy Regulatory Commission (FERC), at the utility's request, if FERC determines that:

> Competing retail electric suppliers are willing and able to sell and deliver electric energy to the qualifying cogeneration facility or qualifying small power production facility; and (2) The electric utility is not required by State law to sell electric energy in its service territory. (18 CFR § 292.312 and FERC Order 688, 71 FR 64372, Nov. 1, 2006; 71 FR 75662, Dec. 18, 2006).

If FERC does terminate a utility's obligation, however, to date the determination has been applicable only to generators larger than 20 MW in net capacity. The rebuttable presumption is that smaller generators might "not have non-discriminatory access to markets." Thus, FERC has determined that a utility's obligations remain in effect "for all QFs with a net capacity of 20 MW or smaller… .” FERC treats this as a rebuttable presumption, subject to a “showing that a small QF does in fact have nondiscriminatory access to the relevant market.”[3]

These four different services—supplementary, backup, maintenance, and interruptible power—are often grouped together in a single utility tariff, typically called a *standby tariff*.[4] Standby tariffs establish the rates, terms, and conditions of service by which a self-generating customer secures ongoing eligibility to obtain utility services when needed.

PURPA Section 305 states, in part:

> (c) Rates for sales of back-up and maintenance power. The rate for sales of back-up power or maintenance power:
>
> (1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and
>
> (2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

The design and setting of standby rates has often been contentious. As Hurd (2009, pp. 240-241) explains:

> [M]ost parties agree that there should be a standby rate structure based on cost causation principles, meaning the rate should allow the utilities to recover all costs that the distributed generation customers impose on the system but nothing more. There is considerable disagreement, however, as to what costs and benefits the distributed generation project actually imposes on the distribution system. Also, the parties dispute how and to what extent such costs and benefits should be incorporated into the standby rate structure. … Utility providers and distributed generation advocates vastly disagree over the factors that should be included in the standby rates. [footnotes omitted]

The gist of the contentious issues has always been:

- Participating customers (and the manufacturers and developers of DG facilities who serve the customers) generally favor standby rates that do not defer or prevent establishing DG facilities that would otherwise be fully economical, but for the existence of standby charges. In addition, DG advocates are concerned, as US DOE (2007, p. 8-8) notes, that standby rates too often “impose disproportionate costs on

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[3] FERC, 2007, RM06-10-001, Order No. 688-A, pp. 53, 59.

[4] A fifth service called economic replacement power is offered by some utilities. This is a variation of supplementary and interruptible power. A utility can offer to produce and deliver electricity when it costs less than the on-site resource. (*See* Regulatory Assistance Project and ICF International, 2009, p. 5).

the customer for facilities that are only rarely used."

- Participating customers desire cost-based, flexible rates that give options for determining the quantities and qualities of their purchases of standby services.

- Non-participating customers and utility shareholders do not want to subsidize participating customers. Their general point of view is that if standby rates are too low, participating customers will utilize utility resources without adequately compensating the utility.

- Depending on the incentives and market structure present, an electric utility might seek to prevent bypass, which represents the loss of sales and diminished revenues associated with customer self-generation. Utilities sometimes also explicitly seek to prevent uneconomic bypass.[5]

- Again, depending on the incentives and market structure present, natural gas utilities could support minimal electric utility standby rates because on-site generation using gas-fired equipment often represents an opportunity for increased gas utility sales.

- A variety of social interests can also play a role. Lower standby charges would generally serve to promote goals such as diversifying electric generating resources, helping to meet renewable energy portfolio standards, or providing another type of customer choice in competitive electricity services.[6] Higher standby charges would generally help to prevent uneconomic bypass and ensure that utility capital resources will be more fully utilized.

The areas of contention often center on analysis of the costs and benefits associated with DG installation and operation. For example, DG advocates expect that utility capital costs will be reduced, while utilities typically expect the opposite. Utilities sometimes acknowledge that DG installations could result in temporary distribution system deferrals, but utilities also point out that customers with DG systems have no obligation to serve. If a customer decides to discontinue DG operations at any time, the utility could theoretically be unable to serve the full loads in that area, or at a minimum costs could increase and reliability be reduced. Absent detailed analysis of large numbers of DG installations over a sufficiently long time, it is practically impossible to know just where the truth lies in such different perspectives. Nevertheless, rate structures do affect DG deployment decisions and DG operations, and listed utilities are required by PURPA to offer standby rates. Therefore, standby rate decisions need to be made based on the best available information.

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[5] *Uneconomic bypass* refers to the situation in which a customer's alternative source of on-site generation has a marginal cost that is lower than the customer's avoided utility rate but higher than the utility's marginal cost. *See* Rose, 1996.

[6] *See*, for example: National Action Plan for Energy Efficiency, 2008, pp. 2-14, D-6; and US EPA Combined Heat and Power Partnership, 2008.

II. What's New? Why Revisit Standby Rates Today?

Several reasons exist for reviewing standby tariffs now. These include: (a) increasing energy efficiency; (b) reducing negative environmental impacts associated with electricity production and use; (c) supporting other DG-promoting policies; and (d) achieving the benefits of smarter-grid implementation.

Energy efficiency is an important goal for ratemaking. As The Regulatory Assistance Project (RAP) and ICF International (2009, p. 5) explain:

> [B]etter rate designs… give customers a strong incentive to use electric service most efficiently, to minimize the costs they impose on the system, and to avoid charges when service is not taken.

DG frequently contributes to higher energy efficiency, for three major reasons.[7] One is that line losses are reduced when electricity is generated at or near the point of end use. Second, the large quantities of heat usually associated with electricity production can be put to good use in customer facilities. Energy that would otherwise be dissipated as waste heat, when produced at a central power plant far from loads, frequently can provide useful space or water heating and cooling or industrial-process heat when generated at or near customer end-use facilities. The ready ability to use the waste heat from electricity production for on-site end uses, or to use otherwise-wasted thermal energy to produce electricity can often result in a doubling of the total efficiency of converting the energy inherent in a fuel to useful purposes, compared to the separate production of electricity in a central utility plant and thermal energy in on-site facilities.[8] In addition, DG can provide practical opportunities for generating and using direct-current (DC) energy on site without converting it to or from alternating current (AC), which can also lead to efficiency improvements.[9] Third, customers who utilize on-site generation often demonstrate increased interest in their energy uses and costs. They often invest in higher-efficiency end-use equipment as a means of reducing their capital investments in on-site generation and are at least somewhat more likely to manage their loads in ways that maximize their use of on-site generation and reduce their use of utility grid resources. They are also likely to be early adopters who will utilize other technologies to reduce their energy costs, including, for example, electrical and thermal energy storage, automated energy-management systems, and automated demand response.

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[7] Lovins et al. (2002) detail dozens of specific mechanisms by which distributed energy resources can help to achieve higher efficiency and thus higher economic value.

[8] The combined generation of electricity and thermal energy in a cogeneration or combined heat and power (CHP) facility can be accomplished in either sequence. Systems that generate electricity first and then use thermal energy are called *topping cycles*, and systems that generate thermal energy first and then use what would otherwise have been wasted heat to generate electricity are called *bottoming cycles*. *See* http://www.epa.gov/chp/documents/faq.pdf.

[9] Galvin and Yeager, 2009, pp. 93, 95. *See also* http://www.emergealliance.org/.

New and emerging environmental regulations covering air emissions, wastes, and water use and discharge are also producing changes in the electricity industry, especially the steam electric power generating industry.[10] This includes some changes that will eventually lend support to different types of DG. For example, stricter air quality requirements will generally support no-emissions (i.e., geothermal, hydro, solar, and wind) and low-emissions (e.g., high-efficiency natural gas and some bio-fueled) electric generators. Also, a US EPA-proposed rulemaking could change the way that stationary emergency backup generators are regulated for national emissions standards for hazardous air pollutants under the Clean Air Act, to allow for their use in peak shaving and both emergency and non-emergency demand response.[11] Another example is the expected US EPA rule that would require major industrial and commercial boilers to utilize maximum available control technology (MACT) to reduce hazardous air pollutant emissions.[12]

Some states and the federal government are also implementing a variety of policies that specifically support DG. These include, for example, special treatment of or separate requirements for DG in state renewable portfolio standards and financial incentives, including property tax exemptions in some states.[13] At the federal level, FERC has approved standard interconnection agreements and procedures for large and small generators, and has established rules governing the sale of ancillary services in transmission markets. For the success of such policies, just and reasonable standby rates serve a modest supporting role, along with just and reasonable PURPA buyback rates, interconnection and net metering policies, and competitive bidding or other policies supporting a utility's procurement of new electric power generation.

Also important are the multiple ways that technologies enabling a smarter electric grid are expected to support the more widespread use of DG. Smarter-grid infrastructure will enable higher efficiency and better utilization of grid resources by facilitating the control and blending of DG system output with demand subscriptions, load management, demand response,[14] and

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[10] *See* http://www.epa.gov/lawsregs/sectors/electric.html and http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm. *See also* Regulatory Assistance Project, 2003a and 2003b.

[11] 40 CFR Part 63, Docket No. EPA-HQ-OAR-2008-0708, http://www.epa.gov/ttn/oarpg/t3/fr_notices/rice_neshap_recon_prop_052212.pdf.

[12] *See* http://www.epa.gov/ttn/atw/boiler/boilerpg.html.

[13] *See* DSIRE, 2012b; http://www.epa.gov/chp/state-policy/; and US EPA Combined Heat and Power Partnership, 2008.

[14] Load management and demand response are not always consistently defined. *Load management* usually implies utility control of certain end use equipment, as a means of managing peak loads. Examples include interruptible water heaters and air conditioners. *Demand response* usually implies consumer responses to price signals, with higher prices reflecting peak load periods. Demand response can be automated, but is usually distinguished from utility-directed load management by remaining under customer control.

electric and thermal storage. Smarter-grid controls, combined with time-varying pricing and near-real-time communications will further facilitate multiple operating options for variable output, baseload, intermediate, peaking, and emergency-backup DG. This multiplicity of options leads to questions of whether and how to: (a) alter standby tariffs based on the different modes of DG operation, and (b) offer choices so that standby services can be tailored to meet various customers' specific operational needs. The bottom line is that system operators need to deploy a wide array of tools to provide customers with economic incentives to encourage DG operations that produce the best supports for the electric grid as a whole.

Another important reason to review standby rates now is the near-term abundance and low cost of U.S. and North American natural gas resources. With natural gas presently under intense focus as a fuel of choice for electricity generation, it is important to consider using this valuable fossil fuel most efficiently. Use in distributed combined heat and power (CHP) systems makes sense, because such systems can offer up to 90% efficiency in the conversion of fuel energy to useful electricity plus thermal energy. It would be counterproductive if excessive standby charges were to prevent the development of otherwise economical, high-efficiency CHP.

Lastly, it is important to recognize that DG equipment is frequently small scale, modular, and subject to technological improvements and cost reductions associated with economies of manufacturing. Many DG technologies are continuing to improve in efficiency, reliability, and cost-effectiveness, making DG increasingly attractive to consumers.[15] And, at least in some applications, DG is already or soon could be a low-cost resource for meeting electric-utility system needs.

A most important question is whether current utility standby tariffs, given the total rate picture including the utility parent tariffs, distort the costs and benefits of DG operations, in ways that affect the customer's or utility's selection of technologies or operating strategies.

Rates that accurately compensate DG resources for the time value of capacity and energy produced will help signal DG developers and managers about how to most economically operate their systems. In theory, both the benefits and costs associated with DG resources should be reflected in tariffs. For example, DG operators deserve fair compensation for the value of the utility system benefits they produce and deliver, including capacity, energy, and ancillary services. At a minimum, when a DG system is operating it reduces the need for an equivalent amount of generation, plus line losses and spinning reserves (Lovins et al., 2002, pp. 201-207). At a maximum, DG is theoretically capable of producing a broad array of utility system benefits, but these benefits depend upon pricing structures that optimize DG operation for the grid and customer. US DOE (2007, p. v) concludes:

> Calculating DG benefits is complicated, and ultimately requires a complete dataset of site-specific operational characteristics and circumstances. This renders the possibility of utilizing a single, comprehensive analysis tool, model, or methodology to estimate national or regional benefits of DG highly improbable. However, methodologies exist for

[15] *See*, for example: Colatat, 2009; Hoffman and Molinski, 2009; Lins, 2010; National Research Council, 2010, pp. 172-180.

accurately evaluating "local" costs and benefits (such as DG to support a distribution feeder). It is also possible to develop comprehensive methods for aggregating local DG costs and benefits for substations, local utility service areas, states, regional transmission organizations, and the nation as a whole.

In earlier studies of standby rates, Fox-Penner (1990) found that decisions about whether to invest in on-site generation were dominated by the influences of rate designs. Ferrey (2000) questioned whether standby charges were not exit fees in disguise, designed to prevent customers from installing and operating self-generation equipment. Jackson (2007) modeled the potential impacts of standby rates on customer adoption of combined heat and power systems. He concluded that standby rates were acting as a barrier to adoption and that an appropriate goal would be "reducing standby rates to reflect the cost of serving a large number of small, spatially clustered [combined heat and power (CHP)] systems…" (Jackson, 2007, p. 1896). More recently, and in a similar vein, Basu, Chowdhury et al. (2011) questioned whether "standby rates are a barometer of a state's general receptivity to DG, meaning that states with 'good' standby rates have more DG and states with 'bad' standby rates less DG."

Another reason for reviewing standby rates now is that DG is generally becoming more attractive to larger numbers of potential customers. Several DG technologies are continuing to improve in reliability and efficiency, and manufacturing improvements are gradually reducing equipment costs, thus leading to growing DG markets. In addition, the variety of aforementioned state and federal policies produce incentives for and heighten interest in DG. As the numbers of customers using DG technologies and the diversity of DG applications increase, standby costs and benefits change, too, based on the increasing populations of and load diversity among standby customers. The increased variability in customers' use of standby resources ought to be reflected in rates.

A decade ago, Morrison (2003, p. 76) found that the actuarial mathematics needed to calculate the costs associated with providing standby service were lacking; not enough was known about DG technology performance and operating characteristics to determine accurately the risks of unexpected outages, let alone unexpected outages during peak load conditions. Johnston et al. (2005, p. iv) also lamented the general lack of data and analysis available to support standby rate design. A pertinent question for today is whether that circumstance still exists. Are adequate data available or readily obtainable, to provide the actuarial evidence needed to determine appropriate, accurate standby rates? Or if such data are not already available, will they become available soon as smarter-grid systems are deployed in more utility service territories? If so, what recommendations might commissions follow in the near term, to ensure that the relevant data will be collected and made available?

Finally, PURPA was amended by the Energy Policy Act of 2005 to add the new requirement in Section 305(c) (18 CFR § 292.305(c)), that rates take into account the diversity of self-generators and the variability and timing of "forced outages or reductions in electric output by all qualifying facilities." Long before the PURPA amendments passed in 2005, Berry reported (1989, p. 479) that "standby charges are not explicitly based on the probability of outages and do not reflect… the costs of providing standby service." If states have not already done so, existing standby rates should be reviewed to make sure this 2005 PURPA requirement is met.

III. Understanding Standby Charges

This part of the paper lists the main categories and components of standby charges and describes the major goals that are important to consider when designing standby rates.

By way of introduction, standby service customers are called *partial-requirements customers*. These customers provide some of their requirements using their on-site generators and purchase the remainder under a stand-alone standby tariff or contract, or through a combination of some standard-service utility tariff or contract in conjunction with a standby tariff or contract. Partial-requirements customers still purchase delivery service from a utility, even if they buy energy from a competitive supplier. They are differentiated from full-service customers who buy all of their electricity services from a utility, or obtain delivery services from a utility and all their energy from a competitive electricity service provider. Designing standby rates basically involves analyzing the costs of providing partial (as compared to full requirements) service and then designing rates to collect the revenue requirement associated with those costs.[16] These issues are much the same in all rate design, but complexities and difficulties are added when analyzing partial requirements services, because of the lack of *a priori* knowledge about the timing and duration of DG unplanned outages.

When reviewing standby rate design, though, keep in mind that standby rates depend to a large extent on full service rate design. Partial-requirements customers typically receive some service from a standard utility tariff designed for full-service customers, which this paper calls a "parent" tariff. Thus, some details that are present in some standby tariffs could be found in a utility's full service tariffs, and vice versa.

A. Major categories and components of standby rates

Firestone, Marnay, and Maribu (2006, pp. 5-6) explain the three main categories of standby charges:

- *Fixed charges ($/month)* are invariant fees. They are intended to cover infrastructure supply and delivery costs required by the customer regardless of the customer's monthly use of energy and capacity demands.

- *Volumetric charges ($/kWh)* are in proportion to energy consumed and may fluctuate by time of day within the month. They cover the variable costs of producing electricity, such as fuel charges and variable maintenance expenses. Volumetric charges can be metered as a flat tariff, as time-of-use (TOU) with a different price during on-peak and off-peak periods, or as real-time pricing (RTP) with a different price each hour.

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[16] For further explanation of standby rate design issues, *see*: Berry (1989); Gordon, Olson, and Nieto (2006); and Morrison (2003).

• *Demand charges ($/kW)* are levied on the maximum power used during a specified time range, such as over the on-peak hours of a month, regardless of the duration or frequency of that level of consumption. Demand charges are intended to collect the fixed costs of infrastructure shared with other customers in proportion to the capacity each requires.[17]

Fixed charges generally reflect costs that are associated with customer service and do not vary depending on customer usage. This typically includes charges for metering and billing, and for the utility's customer service facilities and personnel. A pertinent question for standby rates is whether standby customers should pay the same as full service customers, or a higher charge to reflect the additional complexities involved in their metering and billing. It is not uncommon for customers to be directly charged for the metering equipment and sometimes meter reading and billing for their on-site generator(s), in addition to the parent tariff charges for metering and billing.

Demand charges are often used to collect infrastructure costs associated with power-supply (generation) capacity and distribution (delivery) service capacity. The same power-supply resources can be used to provide standby service to multiple standby customers, because it is unlikely that all the generators for which standby service is reserved will fail simultaneously. Consequently, the demand charges for power-supply capacity should be lower than the demand charges for power-supply capacity contained in a standard tariff. The distribution system must be constructed to serve the maximum demand. Some localized capacity additions may be delayed and some existing localized capacity could be stranded. Some variable costs may be reduced due to reduced losses, and some variable costs could increase due to the need to remove labor saving devices that are not compatible with localized generation. Consequently, demand charges for distribution service cannot be significantly reduced.

Power-supply-resource and distribution-resource costs that are a function of capacity are commonly recovered with energy charges when the cost of demand metering is prohibitive. Historically, that has been the case for most residential and small commercial customers. This complicates the design of standby charges, because some mechanism is required in standby chares for recovering distribution fixed charges (which remain relatively unchanged by the installation of onsite generation). The typical full-service rate that collects infrastructure costs using volumetric charges must be replaced by some mechanism to collect infrastructure costs on significantly reduced energy deliveries.

Many other details are typically included in standby tariffs. They include, for example: the circumstances under which standby customers will take (and pay for) service under the utility's standard tariff for similarly situated customers who do not have on-site generation; differentiating among standby, backup, supplemental, and maintenance service; differentiating based on the size, type, and normal operations of on-site generators; provisions for DG metering and interconnection; compensation for electricity a DG customer sells to the utility or a wholesale market participant; liability and indemnification provisions; how minimum monthly

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[17] Demand charges are sometimes also used to collect charges for delivery facilities that are built to serve only a single customer.

charges will be determined; details about how demand charges will be determined, including the applications of demand ratchets;[18] and provisions for dispute resolution.

Several of these issues can be and sometimes are included in a utility's standard parent tariffs, and could be considered misplaced if they do appear in standby tariffs. Examples include interconnection rules and procedures, compensation for electricity sales, liability and indemnification provisions, and provisions for dispute resolution.

B. Major goals for standby rate design

The goals for the design of standby rates are generally the same as for all rate design. Those goals, first articulated by James Bonbright in 1961, emphasize, among other things, economic efficiency, fairness, simplicity, and transparency.[19] To these, standby rate designers might add promoting efficiency and electric system reliability and standardizing markets. It is important to understand that these goals sometimes conflict with one another, and it is no simple matter to determine the optimum rate design that will maximize achievement of all these goals.[20] This part of the report reviews these goals and how they relate to standby rate design.

1. Economic efficiency

Economic efficiency basically means setting prices so that they are closely related to marginal costs. Economic efficiency also supports the premise that standby charges should not discourage on-site generation that is fully economical and cost-effective but for the inclusion of standby charges (Firestone, Marnay, and Maribu, 2006, pp. 14-15).

Hurd (2009, p. 952) describes "the ideal standby rate":

> The ideal standby rate design should incorporate cost causation principles. Specifically, the rates should be neither a barrier to new distributed generation projects nor a subsidy to standby customers by requiring non-standby customers to cover costs through increased rates. A standby policy should adhere to the central principle of requiring standby customers to cover any costs that they impose on the distribution system, while allowing them to recover for any benefit *actually* conferred. [footnote omitted, emphasis in original].

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[18] *Demand ratchets* are a method of establishing the level of demand that a customer must pay for through a demand charge. The ratchet sets the level of demand for computing a customer's monthly demand charge equal to the highest level of demand (kW) utilized at any point during a preceding time period (e.g., one year) (Edison Electric Institute, 2005).

[19] For a concise review of Bonbright's principles, *see* US DOE, 2007, p. 8-4.

[20] For a primer about basic rate design, *see* RAP and ICF International, Dec 2009, Appendix B.

The question of what constitutes a subsidy is more difficult than it first appears. Subsidy is an economic concept; consumers are *subsidized* when the price they pay is less than the long-run marginal cost of producing the good or service they receive. Cost shifting between different ratepayer groups does not necessarily equate to cross-subsidies. It is possible that a utility will receive less revenue from a participating standby customer than from a similarly situated customer without a DG installation. However, as an economic principle, if the participant's standby rates are above long-run marginal cost, their cost savings is not a subsidy *per se*. In that case, non-participating customers may have a legitimate complaint about fairness, but not about subsidy. Another complication, sometimes directly relevant to DG systems, is that existing prices do not incorporate charges to account for negative environmental externalities. Should the externalities be construed as a subsidy for traditional electric generation? Determining whether subsidies are present in standby rates is beyond the scope of this paper, but the modeling recommended in this paper (see Part V) should go a long way towards exploring that question in more detail.

Berry (1989, pp. 477-481) listed some of the foundational principles for designing standby charges to reflect the costs associated with providing the service. One important aspect is the probability of each standby customer using backup service on-peak. Another is the probably of a population of standby customers using backup service on-peak and the coincidence of that population's supply and demand compared to the utility service territory as a whole. A third is the actual use of standby service, with lower charges for lower use and higher charges for higher use, for both individual customers and for the entire class of standby customers. Berry (1989, p. 477) also explained how standby charges are conceptually similar to avoided costs and further noted that avoided costs vary depending on the "time of day, season of the year, interruptibility of power, and other factors."

2. Fairness

Fairness means making rates just and reasonable for both customers and utilities. Among other things, that means that the rates are as low as they can be while still enabling the utility to collect revenues sufficient to cover its costs and attract capital. One of the objectives for fairness in ratemaking is revenue sufficiency, meaning that the total amount collected by the standby tariff will be equal to the total revenues the utility requires to provide the service.

One example of fairness is applying cost-causation principles to assign costs to differently situated customers. Morrison (2003) points out that customers without DG would subsidize customers with DG, if the latter did not pay for the benefits they receive by virtue of being interconnected with the grid.

Another aspect of fairness is treating benefits and costs symmetrically, giving customers credit for the benefits they provide to the utility system under terms and conditions that are similar to those used to assign costs to the same customers. Jackson (2007, p. 1903) recommends, "[A]ppropriate standby rate design should take into account all of the costs and benefits associated with CHP systems… ." RAP and ICF International (2009, p. 2) outline the kinds of benefits to be considered:

> The many benefits accrue both to the owners of the onsite resources—through cost savings from avoided purchases of grid-supplied power, improved reliability, reduced thermal (e.g., boiler) energy consumption, and lower overall energy costs—and to the electric system as a whole—through reduced demands for power, avoided investments in generation and delivery capacity, improved operational efficiencies, increased system reliability, and lower total system energy consumption, costs, and emissions.

Yet another example of fairness is in assigning benefits and costs to all the various services that together comprise the full relationship between a utility and a self-generating customer. In addition to standby tariffs, these can include: the rates, terms and conditions of standard utility service; DG interconnection rules and standards; net metering rules; rates for interruptible loads; and rates for energy storage, load-management, demand response, and ancillary services.

Meeting this goal also implies fairness to both individual partial-requirements customers and to the class(es) of such customers. It can be important to consider tariff variations based on, for example, the regular operations of the on-site generating equipment and the timing and duration of outages. A relevant example is establishing financial penalties for non-compliance with specific tariff provisions, rather than allowing a single non-compliance episode to result in a cancellation of a customer's right to obtain standby service.[21]

3. Simplicity and transparency

Achieving simplicity and transparency in standby rate design is not easy, but it is a goal that deserves ongoing attention. Simplicity means making the rates easy to understand and administer, and transparency means designing the rates so that prospective users can most easily estimate what their charges will be, based on a few known cost determinants.

Ideally, standby service prices will precisely reflect the costs associated with each component of utility service: generation, transmission, distribution, and customer service (such as billing and metering). Complexity exists due to the desirability of assigning direct versus joint or common costs, and accurately assigning cost responsibility for peak-demand versus total usage of generation, transmission, and distribution (Conkling, 2011, pp. 72-77). Disaggregating all the various cost components, though, can make the rate structure highly complex and confusing. Particular examples are the complexities of applying standby rates to customers hosting more than one on-site generator, and even multiple generators that use different technologies with different operating characteristics.[22]

It should also be noted that leaving details to be determined by the utility conflicts with the goal of transparency. One prominent example is the workings of reserve capacity and

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[21] Examples can be seen in standby tariffs from PPL Electric Utilities (2004-2011, p. 10C) and Pacific Gas and Electric (2009-2012, Sheet 12).

[22] *See*, for example, Pacific Gas & Electric (2009-2012, Sheet 13).

demand ratchets, where some tariffs leave decisions to the utility's discretion.[23] It is preferable for the tariff itself to be clear and complete. If a utility will determine certain charges, though, then at a minimum the customer should be able to (a) request and obtain the utility's determination in a timely basis, and (b) understand how changes to the utility's determination, if any, will be triggered and decided.

At any rate, tension is likely between the goals of economic efficiency and simplicity and transparency. The more costs are differentiated and tariffs designed to accurately collect charges for each cost component, the more complex the resulting tariff. Ideally, the customer (or at least the customer's agent) will be able to understand, and thereby anticipate and accurately estimate, the customer's liabilities under the standby rate. For better or worse, utility rates are often already too complex for average customers to correctly model. Various efforts are underway, however, to help consumers with this task.[24]

4. Promoting efficiency and reliability

Rate structures can have significant impact on the economics of distributed generation, as noted by US DOE (2007, pp. 8-1–8-2), Firestone, Marnay, and Maribu (2006, pp. 10, 14-15) and RAP and ICF International (2009, p. 2). Based on the different ways in which standby rates can be designed to assign costs to fixed versus variable charges, the tariffs can affect the amount of cost savings that results when a customer reduces their grid-purchases. Thus, the tariffs can affect the customer's selection of on-site generation type, size, and operating strategy. RAP and ICF International (2009, p. 17) explain:

> Rate designs that have a reasonable balance between energy and demand or reservation charges will naturally be more amenable to the broad policy goal of encouraging clean, efficient DG. Rate designs that reward reliable operation can encourage the development of a diversified, more reliable electric grid. The review of tariffs and operation on peak in this report suggests that the more favorable rate designs share common and central characteristics: they are designed to give customers a strong incentive to use electric service most efficiently, to minimize the costs they impose on the system, and to avoid charges when service is not taken. Put another way, they reward customers for maintaining and operating their onsite generation.

Another aspect of efficiency and reliability can be the relationship between standby rates and the various other government policies intended to support DG. Policy makers and interest groups sometimes favor the idea of tilting standby rates higher or lower.[25] Grace, Donovan, and

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[23] *See*, for example, Pacific Gas & Electric (2009-2012, Sheet 8).

[24] Prominent examples include the Green Button initiative (http://energy.gov/articles/green-button-data-more-power-you) and many software products from Clean Power Research (http://www.cleanpower.com/products/) and the National Renewable Energy Laboratory (http://www.nrel.gov/applying_technologies/models_tools.html).

[25] *See* DSIRE, 2012b, for several examples of state policies favoring solar and distributed generation (DG) technologies.

Melnick (2011) use the term “tilt” to describe policies intended to favor certain technologies. Johnston et al. (2005, pp. iv, v) describe these as “policy overlays.” For example, in several states net metering customers are exempted from paying standby charges.

However, Hurd (2009, p. 956) concludes that standby rates, per se, should not be used to tilt DG policies in any particular direction. He states, “Standby rates are an inappropriate method of spurring new distributed generation… .” Hurd recommends that means other than standby rate tilting should be used to provide incentives for DG. For example, he recommends grants, low interest loans, and tax credits. “Proper incentives,” Hurd opines, “will promote new distributed generation and raise penetration to levels sufficient to provide measurable benefits.”

5. Market standardization

Another important goal for standby tariffs can be to standardize markets. The greater the differences in DG tariffs between utilities, states, and regional transmission operating regions, the more difficult it is for the suppliers of distributed generation to successfully market their equipment and services. This same concern applies to energy efficiency products and services, and is widely recognized in the design of utility programs that acknowledge the goal of standardization to help consumers, equipment vendors, and retailers. Thus, an appropriate goal that a commission might consider is the extent to which standby rates in its jurisdiction can be made as similar as practical for all regulated utilities in the state. However, unless the base rates for full service customers are similarly designed from utility to utility, it will prove difficult to design similar standby service rates.

Another important example of market standardization is making partial-requirements rate designs as similar as practical to full-requirements rates. Meeting this goal might include, for example, assigning power factor charges in the same manner and offering the same choices for time-of-use or real-time rates to both full- and partial-requirements customers.[26] This is not to imply that the charges will be the same, but only that they will be calculated in the same manner.

[26] As an example, NStar Electric (2006, pp. 2, 3, 6) utilizes the customer’s standard rate schedule for determining several charges.

IV. The Current Situation

This part of the report looks at standby tariffs for utilities in a dozen states. The tariffs selected for review do not represent any kind of scientific sample. The survey includes some of the largest utilities in the country.[27] States were selected to include broad geographic diversity and both regulated and restructured electric industries (EIA, 2010).

Tariffs were reviewed from Alliant Energy (Wisconsin Power and Light); Arizona Public Service; Connecticut Light & Power; Consolidated Edison (New York); Consumers Energy (Michigan); Detroit Edison (Michigan); Georgia Power; Hawaii Electric; NStar Electric (Boston Edison); Pacific Gas and Electric (California); Pacific Power (Oregon); Portland General Electric (Oregon); and PPL Electric (Pennsylvania).

The purpose is not to identify an ideal standby tariff. Rather, it is to seek out and relate examples that illustrate important principles in standby rate designs, identify a range of responses to key regulatory issues, and provide references to those features found in specific tariffs so that anyone grappling with similar issues can easily find examples to serve as a guide. The topics include:

- capacity levels and demand ratchets;
- scheduled versus unscheduled use of power;
- time-varying rates;
- metering and billing;
- minimum monthly charges;
- compensation for generation and ancillary services that DG supplies to the grid;
- specific generator types or sizes;
- liability and insurance requirements;
- dispute resolution;
- wires-only companies; and
- other DG tariff provisions.

What follows in the remainder of Part IV is a brief discussion of each issue, with examples drawn from the tariffs reviewed for this study, including general guidance about tariff details that are most likely to support achieving the five major goals identified in Part III.

A. Capacity levels and demand ratchets

The methods that standby tariffs use to assign capacity levels and demand ratchets vary widely among US utilities. Some companies define standby demands based on metered

[27] *See also* US DOE, 2007, pp. 8-9–8-34 for a review of DG ratemaking issues, focusing on California, New York, Oregon, and Minnesota, but also drawing examples from many other states.

maximum demand ratchets that cover the current and preceding 11 billing months. These include Alliant Energy (2002-2005, Sheet 7.29) and Connecticut Light & Power (2006, pp. 1-2). Arizona Public Service (2007-2010, p. 3) sets a new total contract demand with any increase, and the increase remains in effect "for the term of the contract, unless superseded by subsequent increases… ."

At Alliant, standby reservation demand is set based on the size of the customer's generating unit(s).

Other companies allow customers more latitude in determining standby service capacity. The gist of these options is to allow customers to set their standby capacity and then manage their use of on-site generation and supplemental capacity to best meet their needs. By managing energy use during times when on-site capacity is unavailable, customers can reduce their total capacity below what would otherwise be the simple sum of their on-site generating capacity plus supplemental service (typically the parent rate) demand ratchet. For example:

- Consolidated Edison (2011-2012, Leaf 164–Leaf167) sets demand charges based on a contract demand delivery charge plus an as-used daily demand delivery charge. New standby customers can request a specific quantity of contract demand which the company can then "reasonably adjust" or the contract demand will be "reasonably determined through the company's engineering analysis… ." If the customer decides the contract demand and then actual demand exceeds the contract demand by 10% or more, then the customer will owe a surcharge (penalty) for the excess capacity. Consolidated Edison (2011-2012, Leaf 161) also exempts from standby-demand charges customers whose on-site generator(s) provides not more than 15% of the customer's maximum demand and customers with contract demand less than 50 kW.

- Detroit Edison (2012, Sheet D-73.00) subtracts a continuously adjusting standby capacity from maximum annual site demand to set parent tariff maximum annual demand, so that the customer's total demand for distribution charges is effectively the sum of standby capacity plus supplemental demand. Detroit Edison offers an optional pricing method for power supply charges, which uses the real-time Midwest Independent [Transmission] System Operator (MISO) market-based pricing mechanism.

- Georgia Power (2012, p. 2) defines standby power demand in a billing period as the "the maximum metered demand measured during the time standby service is being taken, less the maximum metered demand during the time intervals in the billing period (or the most recent month) when standby service is not being taken." Georgia Power (2012, p. 2) also adjusts parent tariff demand, in three steps, depending on the total duration of standby service a customer requires over the course of a year. In that way, the more the customer uses standby service, the less credit the customer receives in this calculation for their non-standby service billing demand.

- Pacific Gas and Electric (2009-2012, Sheet 8) allows the customer to make the initial determination of reservation capacity, and then makes "adjustments as warranted" consistent with specific criteria. In addition, for customers whose loads regularly exceed their on-site generating capacity, reservation capacity takes into account the number, size, and outage diversity of the customer's generating unit(s), and "any reduction of customer load commensurate with [on-site] generator capacity outages."

- Pacific Gas and Electric (2009-2012, Sheet 7) also allows customers to receive standby service under a "physical assurance" contract. Under this type of standby service, the customer's load must "automatically and instantaneously drop in an amount equal to the energy shortfall arising from a reduction in the on-site generator's output." Customers fulfilling the physical assurance performance requirements do not pay a reservation charge for the amount of capacity designated.

- Pacific Power (2011-2012, p. 2) bases its charges on a combination of on-peak demand (measured at 15-minute intervals), plus baseline demand reflecting the expected operations of the customers DG unit(s), and a facility capacity reflecting the "two greatest non-zero monthly demands" over the past year.

B. Scheduled versus unscheduled use of power

Many standby rates include provisions for scheduling the use of power during planned maintenance periods. In addition, some standby tariffs allow customers to purchase economic replacement power, which means the utility offers to produce and deliver electricity when it costs less than the generation from the customer's on-site resource (RAP and ICF International, 2009, p. 5). These are examples of scheduled uses that typically cost less than unscheduled use during unplanned outages. Often, standby-demand charges are waived for scheduled maintenance power. The logic for this exemption is that the utility has sufficient opportunity to plan for providing maintenance power, so that it is not actually providing that service in a standby mode.

Unscheduled uses are either explicitly for standby service when a customer's generator has an unplanned outage, or for supplemental service that is typically billed under a parent tariff. Supplemental service is what the customer regularly needs, during normal DG operation, because the DG unit(s) do not always provide all the energy that the customer demands.

For maintenance service, Alliant (Sheet 7.728) requires "written notice 3 months in advance… for generators… less than 25 megawatts and 9 months for all other generators" and limits maintenance to "a 6-week period per generator per year." Alliant can also require generators larger than 25 MW to defer maintenance. Arizona Public Service (2007-2010, p. 3) limits maintenance to 30 days per unit per year, which must be scheduled during non-summer months with 90 days' advance notice to the utility so that the utility can coordinate with its scheduled maintenance. Detroit Edison (2012, Sheet D-79.00) requires customers to schedule a year at a time. Hawaii Electric (2008-2012, Sheets 75H-I) limits customers to not more than 300 hours of on-peak scheduled maintenance service in a year, and requires requests in writing four weeks in advance; for off-peak scheduled maintenance, there is no maximum limit and requests need be only two weeks in advance. PPL (2004-2011, p. 1) allows maintenance power use not more than 70-days per year, to be scheduled during "March 16 to May 31, and September 16 to November 30," with 60-day prior notice in writing.

Detroit Edison (2012, Sheet D-73.00), Georgia Power (2012a, pp. 1, 3), and NStar Electric (2006, p. 7) have options for interruptible, non-firm standby service. That is a lower-cost option for unscheduled service, because it gives the utility a right to interrupt service if system demands require it. Detroit Edison waives daily demand charges if the customer's standby service is interrupted. For its interruptible standby service, NStar Electric charges a monthly standby customer charge and then bills all of the customer's scheduled usage on the parent tariff.

Consolidated Edison (2011-2012, Leaf 78) allows customers to use on-site generators to provide emergency power without contracting for standby service, but self-generated emergency power can be used only during company outages. The logic is that this is an unscheduled use that does not require any standby service from the utility.

C. Time-varying rates

Utilities that offer time-of-use or other time-varying rates usually offer similar options for standby customers. Examples include Georgia Power (2012, p. 2), Consumers Energy (2012, p. D-43.00), and Pacific Gas and Electric ((2009-2012, Sheet 1). Time-varying rates for service have the potential to encourage customers to operate DG equipment so that it produces the most system benefits. Being able to use economic replacement power is one example.

Consumers Energy (2012, p. D-43.00) has a standby energy charge provision based on the MISO locational marginal price.

Pacific Gas & Electric (2009-2012, Sheet 1) has special offerings for DG customers who take service under time-of-use rates. Those customers pay time-of-use meter charges but are exempted from paying standby reservation charges.

D. Metering and billing

It is common for utilities to charge customers with DG some metering or metering and billing charges in excess of the charges for customers without DG. Examples include Connecticut Light & Power (2006, p. 2), Consolidated Edison (2011-2012, Leaf 160), Detroit Edison, and Pacific Gas and Electric. These provisions are to measure the generator output, rather than the energy and demand the utility supplies the customer. This provides the utility with detailed information about the operations of the DG unit(s). In some tariffs, standby charges depend on the amount of capacity being used during times when the customer's generating unit(s) are out of service, in which case the data about DG unit(s) operation is required.

Alliant Energy (1987-2007, Sheet 7.76; 1997-2003, Sheet 7.81) allows its customers to pay for their additional metering and service facilities, including financing cost, over a period not to exceed two years.

Detroit Edison requires standby customers to have demand metering on generation, inflow, and outflow, if applicable. Detroit Edison (2012, Sheet D-74.00) will provide standby customers with monthly data reports on load and generation, upon request, for a charge of $10 per meter per month.

Pacific Gas and Electric (2009-2012, Sheets 2, 5) requires an extra time-of-use meter charge for customers with reservation capacity less than 500 kW. Pacific Gas and Electric customers are normally metered on 15-minute intervals, but if customer use is "intermittent or subject to severe fluctuations" (including also special provisions for welding loads), shorter time intervals may be used.

It is also fairly common for utilities to require real-time communications capabilities between DG units and the company's operations center.

Alliant (2002-2005, Sheet 7.291) requires the customer to notify the company "immediately" if they require standby power and the expected duration of their need. The customer is further directed to "record the date and time of the beginning and end of each time period of standby service use, and send such recording to the Company within 24 hours of the end of that standby use period." However, the company, at its discretion, "may require that Company-owned metering be installed to monitor each of the customer's electric generating units."

Connecticut Light & Power Co. (2006, pp. 2-3) requires each generating unit to be separately metered, "on a measured time-of-use basis." In addition, customers must provide either a dedicated analog phone line or another "mutually agreed communication technology" to allow continuous remote communication access by the utility.

Pacific Power (2011-2012, p. 5) requires company-approved interval metering and meter communications to be in place prior to initiation of service, including metering that measures the net quantity and direction of flow at the point of delivery and total generator output.

As an alternative, Georgia Power (2012a, pp. 1, 3) requires customers to notify the company about the customer's use of standby service. The customer must notify the company within 24 hours of taking firm back-up service, and within 24 hours of the end of each billing period the customer must provide to the company a log of all generating equipment down-time. If that log is not provided, the utility will assume that the customer's generating equipment was down during the entire billing period.

E. Minimum monthly charges

Like most utility tariffs, standby tariffs usually specify minimum monthly charges. That is good practice and supports the goal of providing transparency. Minimum monthly charges establish a practical hurdle rate for DG economics, though. Modeling of minimum charges will provide all parties with a clear picture of the minimum size and performance that an on-site generator would need to meet, in order to result in customer cost savings. Examples include:

- Alliant (1994-2005, Sheet 7.672), where the "minimum monthly bill is the applicable customer charge and customer demand charge plus the standby demand charge."

- Detroit Edison, where minimum bills include the applicable customer charge, a standby generation reservation fee, and a charge for delivery. Both the standby generation fee and delivery charge are based on a continuously adjusting standby contract capacity, designed to set standby contract capacity as close as practical to the actual operating level of the generation. Detroit Edison also sets a maximum charge for primary voltage standby demand charges. That charge is designed to limit demand charges to the levels that would have been paid (neglecting ratchets) for the standby demands under the standard primary service tariff offered by the company.

- Georgia Power (2012, p. 2), which includes a customer charge of $184.00 per month, plus $1.57/kW firm standby reserve charge and $1.27/kW local facilities charge.

- Pacific Gas and Electric (2009-2012, Sheet 5), which treats its customer charge as a minimum for residential DG customers, stating, "Residential customers will pay a Customer Charge only in months when the Customer Charge exceeds the customer's [standby service] bill… ."

F. Compensation for generation and ancillary services that DG supplies

This is not a standby issue, *per se*, but it is included in the discussion here because it is an important consideration for DG economics and because it is sometimes included in standby tariffs themselves; standby tariffs sometimes include provisions for the compensation customers will receive for delivering energy to the utility or for sales to the wholesale market, if one is available. As US DOE explains (2009, p. 8-17), the price paid for DG output will impact economic viability and the lack of a fair price will act as an "impediment or barrier" to development. Prices paid for DG output are determined by a variety of compensation mechanisms. The most common ones include variations of net metering,[28] sales to utilities under some definition of avoided cost, and sales to wholesale markets at market-based prices (US DOE, 2009, pp. 8-17–8-25).

In states where there are active wholesale markets, it is not uncommon for customers to be compensated based on wholesale market prices. For example, Consumers Energy (2012, p. D-44.00) provides for either negotiated energy purchases, or for purchases bought at the MISO real-time LMP, less an administrative charge of $0.005/kWh. And, for small DG producers,

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[28] Net metering options presently exist for at least some utility customers in 46 states and the District of Columbia (DSIRE, 2012a). Most programs allow customers to net their energy purchases and deliveries in each billing period, at least until their net usage reaches zero. If the customer produces and delivers more energy than what they consume from the utility in a billing period, however, the state programs differ in the way that customers are compensated for excess generation delivered to utilities. Some programs effectively donate excess generation to the utility, with no customer compensation.

<100 kW generators at a single location for specific technologies and renewable resources, Detroit Edison (2008d) will pay its top incremental cost – either monthly average, time-of-day monthly average, or hourly, depending on the customer's generation meter type.

Compensation based on area wholesale market prices can be understood as an approach that is aimed at fairly allocating risks to both participating and non-participating customers. That approach does offer limited predictability, though, and therefore heightens DG developer risk and reduces transparency compared to fixed-price offerings.

G. Specific generator types or sizes

Many utility tariffs exempt specific generator types or sizes from standby charges. Such provisions are sometimes included in standby tariffs, but they may instead be included in other DG tariffs, net metering programs, and the like. These are examples of promotional policies. They can also be seen as examples of policies intending to serve the goal of simplicity, by waiving standby charges for small DG, where the cost of determining and collecting standby charges could outweigh the revenues received.

For example, Consolidated Edison (2011-2012, Leaf 161 and Leaf 162) exempts customers whose on-site generator(s) provide no more than 15% of their demand, and allows exemptions for specific generating technologies if installed and operating by May 31, 2015. The latter constitutes a promotional rate for "fuel cells, wind, solar thermal, photovoltaics, sustainably-managed biomass, tidal, geothermal, or methane waste, or… small, efficient types of combined heat and power generation that do not exceed 1 MW of capacity in aggregate… ." Also, Consolidated Edison customers with standby contract demand less than 50 kW can choose whether or not to take standby service.

Detroit Edison (2009) exempts from standby charges net metering sites with capacity no greater than150 kW.

Similarly, California regulated utilities exempt certain qualifying distributed energy resources from standby charges. Pacific Gas and Electric's standby tariff (2009-2012, Sheet 1) exempts solar generation participating in the company's net metering tariffs or less than or equal to 1 MW, and either not selling power or making only incidental export of power. Detroit Edison (2008d) has a separate tariff, Rider DG, which exempts selected renewable and other small generators (<100 kW).

Pacific Power (2011-2012, p. 1) exempts customers with DG under 1 MW, who are instead served "under the applicable general service tariff."

Portland General Electric (2007-2012a, Sheet 75-1) exempts customers with DG under 2 MW.

H. Liability and insurance requirements

Standby service and other DG tariffs also frequently include provisions regarding liabilities and indemnification for the utility and customer and insurance requirements for customers. These provisions are sometimes found in other DG tariffs, or in state statutes, rather than in standby rate tariffs.

Network for New Energy Choices (2011, pp. 20-21) and Thornton and Monroy (2011, p. 4815) both caution against overly-strict and one-sided requirements that protect only the utility and not the customer. They claim that overreaching in liability and insurance requirements can act as a barrier to DG adoption. Thornton and Monroy point out that utilities worry about being forced to pay for any damages, "because they have 'deep pockets'." However, Network for New Energy Choices (2011, p. 21) explains:

> [T]o the authors' knowledge there has never been a documented case of a small, net-metered system causing electrical failure or creating potential personal injury or property damage liabilities for a utility. Renewable energy technologies manufactured and installed in compliance with technical interconnection guidelines significantly reduce the risk of potential safety issues.
>
> Excessive insurance requirements only serve to discourage customers from investing… . Requiring customer-sited generators – especially those with relatively small DG systems – to obtain and maintain million-dollar insurance policies is impractical, because the high premiums will likely exceed the economic benefits… ."

Detroit Edison (2012, Sheet D-67.00) requires customers with larger DG units to carry "comprehensive general liability insurance in the amount of $2.5 million per occurrence, with the Company named as an additional insured." For smaller (<100 kW) systems, however, Detroit Edison (2008d, Sheet D-97.00) simply cautions, "The customer is advised to consult its insurers and insurance policies regarding the existence of coverage for on-site distributed generation resources."

Detroit Edison's standby tariff (2012, Sheet D-67.00) also includes an indemnification provision that applies equally to the company and customer.

I. Wires-only companies

States with unbundled electricity rates typically have standby tariffs that have separate charges for wires (delivery) service and generation (energy and power) service. Customers buying electricity through the competitive market still have to pay for distribution service (delivery) from the utility, so there are usually standby rates for the wires-only service. In these situations, the customer can purchase generation standby service from a competitive market supplier, the default service provider, or the open, competitive spot market. Energy charges for competitive spot-market generation service vary depending on the time and location of use and do not include any explicitly differentiated capacity component.

It is also common in states with unbundled rates for standby service wires charges to be differentiated by service voltage, based on the same cost-of-service studies that determine distribution charges for full-service customers. Examples include Detroit Edison (2012, Sheet D-72.00) and Pacific Gas and Electric (2009-2012, Sheets 2-3). However, there is no reason why rates cannot be unbundled in states with hybrid[29] or vertically integrated markets. RAP and ICF International (2009, p. B-4) report:

> [T]he structure of the electric industry in a state might affect the nature of partial requirements service, like that of full requirements service. If multiple competitive suppliers provide generation services, distribution utilities will provide only delivery service and regulatory interest in standby will be, accordingly, restricted to that component of service. Restructuring accelerated the movement to unbundled pricing for the various components of service (i.e., separate prices for the differentiable elements of service—generation, transmission, and distribution), but nothing about vertically integrated industry structures prevents a similar unbundling of rates. Unbundling makes the nature of costs more transparent and, if done properly, greatly reduces or even eliminates the potential for the cross-subsidization of one service by another.

In some restructured states, the utility offers to purchase for customers standby service from the open market. Alliant (1987-2007, Sheet 7.721) and Detroit Edison (2012, Sheet D-72.00, 2008a, Sheet D-80.00, 2008b, Sheet D-83, and 2008d, Sheet D-97.00) both offer such options. Detroit Edison adds a per-kWh administration charge for that service. In New York, standby customers can choose their energy supplier, with rates set by bilateral contract. If the customer specifies default service from the utility, then the utility will procure the standby service from the competitive market.[30]

Consolidated Edison's standby tariff (2011-2012, Leaf 169) also has a provision for negotiated rates, which includes a requirement for the company to "respond with either an offer or a written explanation for rejection" within 60 days of receiving a customer's application for a negotiated rate agreement.

J. Other DG tariff provisions

US DOE (2007) reports on two other kinds of DG tariff provisions: (1) special natural gas rates for fueling DG systems; and (2) DG disincentive rates, also known as deferral rates and frequently taking the form of special contracts between a utility and an individual customer.

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[29] Michigan's electricity market is a hybrid, with regulated utilities providing both distribution and generation service, most transmission under independent ownership, and a portion of customers able to buy generation service from competitive suppliers. *See* http://www.michigan.gov/mpsc/0,4639,7-159-16377_17111---,00.html.

[30] Personal communications with Edward B. Kear, On-Site Power Team Leader, New York State Energy Research and Development Authority, 30 May 2012.

The basis for special natural gas rates (US DOE, 2007, pp. 8-15–8-16) is that in regulated natural gas markets customers fueling their DG units with gas would otherwise have to pay retail residential or commercial prices for their fuel. As US DOE explains,

> Distributed generation systems use considerably more fuel than a home or office furnace, and these higher volumes and load factors justify lower unit costs for natural gas than comparable non-DG customers. … In many instances, the difference between wholesale and retail rates are sufficient to eliminate any financial savings the project may have generated… .

US DOE (DOE 2007, p. 8-16) cites New York and New Jersey as states where natural gas utilities offer special wholesale rates for customers with DG units.

Also, US DOE (2007, p. 8-18) describes DG disincentive rates, stating that "utilities and regulators have historically allowed co-generation deferral rates to actively discourage DG." U.S. DOE states (2009, p. 8-24):

> Under state retail regulation, utilities typically request approval from state commissions to offer deferral rates to customers that would otherwise generate locally for some portion of supply. Approval is needed because offering a price break to an individual customer means that the customer would be paying rates that are less than those paid by other, like customers; the state regulatory commission determines whether the legal criteria that would justify a deviation from tariffs have been met. Any reduction in sales means that, all else being equal, the remaining customers in the rate class will be asked to pay a larger share of class-related costs to cover the portion no longer paid by the selected customer. It is up to regulators to determine whether there are any, or a sufficient level of, net system benefits to justify the discounted rates.

US DOE recommends (2009, pp. 8-24–8-25) that commissions consider DG deployment "in the context of least-cost provision of service… [and] allow pricing flexibility in low-cost areas of the distribution system only if the utility increases rates in high-cost areas." This implies a fine-tuning of the cost-causation principle to reflect differential costs in specific areas of a utility service territory. US DOE further recommends that the issue of utility lost revenues associated with DG be dealt with separately, by considering "performance-based regulation (PBR), sharing of savings between [the] utility and customer DG, [and] de-averaging buy-back rates for DG." Other mechanisms that can help address utility lost revenues include decoupling and lost revenue adjustment mechanisms.

As a final note, Detroit Edison (2008c), Hawaiian Electric (2008-2012, Sheet 75E) and Portland General Electric (2007) have tariffs that compensate customers for dispatchable standby generation. These tariffs are not directly related to standby service, but similar variations could be applied to standby service customers in the future. Both Detroit Edison and Portland General Electric contracts for this service are for customers with at least 250 kW of generation at a single location and its contracts are arranged through bilateral negotiations. Portland General Electric's tariff (2007, Sheet 200-1) requires that the utility will fuel, maintain, and test the generators so that the utility can be assured that the generators will respond when called upon. Also, Georgia

Power (2012b) reports providing standby generators to Johnson & Johnson, which the utility "maintains, tests, and dispatches… in case of emergencies."

V. Going Forward

A recommended approach for addressing standby tariffs in the near future is to obtain and analyze pricing structures and data about the current situation and use that analysis to determine whether changes are warranted. Data would be analyzed for two major purposes: (1) modeling the effects on individual customers to assess fairness and ascertain whether the rates are promoting efficiency and reliability; and (2) evaluating standby tariffs from the standpoint of economic efficiency. The first type of analysis will model how standby charges are presently affecting the economics of individual DG system installations. The second will investigate broader classes of DG customers, by utility (and, perhaps later by state and region), to check on progress and understand in more detail how standby rates, terms, and conditions of service are affecting DG markets. Based on such analysis, rates can be adjusted, if necessary, to align them with the goals of economic efficiency, fairness, simplicity and transparency, promoting efficiency and reliability, and market standardization (*see* Part III.B.)

The first type of analysis can employ both theoretical modeling and actual, case-study reviews of customer experiences with standby tariffs. RAP and ICF International (2009) and Firestone, Marnay, and Maribu (2006) provide examples of the requisite kinds of modeling. A micro-computer software model that is at least partially applicable to this effort, Distributed Energy Resources Customer Adoption Model (DER-CAM), is readily accessible from Lawrence Berkeley National Laboratory. Firestone, Marnay, and Maribu (2006) use the DER-CAM model for their analysis.[31]

Kear recommends modeling standby charges for a customer with on-site generation, pretending that the generator never operates over the course of a year.[32] The purpose would be to see, for a standby customer purchasing 100% of its requirements from the utility, how its bill would compare to a similarly situated full-requirements customer (who does not have on-site generation and similarly purchases all requirements from the utility). In theory, under a reasonable standby rate the annual charges would be close to the same in these two circumstances.

Similarly, for a partial-requirements customer whose on-site generator produces 100% of its annual needs, the charge should be close to the minimum charge for a similarly situated full-requirements customer. Modeling usage in between these extremes, at 25%, 50%, and 75% self-

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[31] *See* http://der.lbl.gov/der-cam. The website already indexes several DER-CAM case study reports. In addition, a forthcoming report (RAP and Brubaker & Associates, in press) will include spreadsheet modeling of standby rates for proxy industrial customers of regulated utilities in up to five states. This report analyzes standby tariffs and their efficacy for various CHP system sizes under several outage scenarios, recommends potential tariff improvements, and summarizes best practices.

[32] Personal communications with Edward B. Kear, On-Site Power Team Leader, New York State Energy Research and Development Authority, 30 May 2012.

supply for example, should help to demonstrate how well the standby charges track customer usage of standby services.

RAP and ICF International (2009, p. 9) recommend standby rate designs that allow customers to avoid approximately 90% or more of the full retail rate charges, for each kilowatt-hour of energy generated and used on-site. That implies limiting fixed monthly charges and demand charges so that they are a modest percentage of total standby charges, and assigning more standby costs to volumetric charges, including, if appropriate, as-used demand charges. Such cost allocations to the various rate components will have different effects on customers with on-site generators, depending on the nature of their operations. Modeling will help demonstrate the cost avoidance for various customers. Customer-specific case studies can be employed, using actual billing data to verify the models and reveal important patterns among standby service users. Customers with efficiently managed and well-maintained on-site generation should see higher percentage cost reductions. And, rates that achieve this recommended goal can be evaluated to determine whether the resulting revenues are sufficient to meet the goal of economic efficiency.

In addition to modeling the effects of standby rates on individual customers, it is important to obtain and analyze system-wide data. Some relevant data are available from public sources,[33] but presently only utilities have access to much or all of the data necessary to evaluate standby rates.[34] Commissions can request and obtain from utilities the kinds of data necessary to evaluate standby tariffs, either on a case-by-case basis as needed to support periodic analysis, in regularly scheduled reports, or both.

What kinds of data are necessary to evaluate standby rates? The general purpose for the data collection and analysis should be to compare the theoretical basis for standby rates to actual experience and enable refining standby rates as needed to keep them reasonably accurate. Of course the costs of data collection, analysis, reporting, and evaluation need to be considered in light of the likely benefits. Bear in mind, though, that there are costs associated with inaccurate standby charges; negative results can be either too little DG installed and operated—leading to higher total system costs for all utility customers—or too much, including at least some uneconomical systems, possibly leading to cross-subsidization by non-participating customers

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[33] Examples of publicly available data sources related to standby rates include a database of combined heat and power installations (www.eea-inc.com/chpdata/), net metering program data (www.eia.gov/todayinenergy/index.cfm?tg= net metering and www.eia.gov/renewable/annual/greenpricing/), and information about PURPA QFs (www.eia.gov/electricity/data.cfm#gencapacity, www.eia.gov/cneaf/electricity/page/eia826.html, and www.eia.gov/cneaf/electricity/page/eia861.html, Files 5 and 6). Some relevant data on power purchases from QFs is also published in annual reports from major electric utilities (Form No. 1) to the Federal Energy Regulatory Commission (FERC). However, some of this data is reported and made publicly available only after substantial time lags and none of it is explicitly geared towards analyzing and understanding standby rates.

[34] *See* Kassakian and Schmalensee, 2011, p. 177, for a cogent discussion of the information asymmetry between utilities and regulators.

and higher costs for all customers. Therefore, at least modest efforts to gather and analyze the relevant system-wide data appear worthwhile.

Demographic information about the numbers and types of customers using on-site generation, along with the size and types of generators in use, is a starting point.[35] Then, as much as is practical, it is important to try to obtain data about how much standby service was used, when, and for what purposes. Evaluators should consider the various billing determinants, and then explore how the utility can aggregate the relevant data and make them available for analysis. Commissions should consider having these data available for analysis so that they can be aggregated for review by customer type (e.g., residential, commercial, industrial), generator type, generator size, and geographic location. Some tariffs differentiate between standby, supplemental, and maintenance service, in which case collecting and reporting each type of use is warranted. Since some standby tariffs are associated with interconnection rules that apply contractual terms regarding liability, indemnification, and insurance, data collection and reporting about any circumstances that result in those contractual terms being brought into play is also warranted. Also, since many states exempt net metering customers or other specific types of on-site generation from standby charges, data about those customers' uses of utility service can be relevant to understanding whether such exemptions are resulting in cross-subsidization by non-participating customers.

In addition, in states with competitive markets for retail electricity service there is a need to review usage patterns and costs for partial-requirements customers who receive generation service from competitive suppliers, as opposed to regulated utilities. In theory, if the non-wires benefits of DG are sufficient to support fully cost-effective installations, then competitive suppliers might offer DG services as a means of differentiating themselves in the market. To date, however, it does not appear that any data are publicly available about the numbers or types of customers served by both DG and competitive suppliers; nor is there any analysis of this class of customers (assuming such a class exists), which would be useful in analyzing their use of standby wires-only services and contributions towards wires-service infrastructure. This analysis of standby use by partial-requirements customers who receive generation service from competitive suppliers could be needed, if any meaningful numbers of such customers exist, in order to establish accurate standby rates for wires-only service.

From the outset, the underlying theory for standby rates is that standby customers do impose costs on utilities, due to the nature of full-service rate structures that recover at least some, if not most, infrastructure (that is, non-fuel and operating) costs through volumetric charges and explicitly because of the utility's need to produce and make available for use back-up resources for the supply of generation, transmission, and distribution necessary to serve standby customers when called upon.

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[35] Of course, care must be taken to protect the customer's right to privacy. It is important to protect customer-specific data from release without the customer's prior authorization. In some circumstances, it can be desirable to ask for customer permission, on an opt-in basis, for legitimate investigators who agree not to reveal customer-specific information to contact customers for survey purposes. Utilities providing data can easily remove or redact any customer-identification information.

Kassakian and Schmalensee (2011, Chapter 8) are critical of rate structures that recover most costs through variable (kWh) charges and little through fixed (kW) charges. These researchers (2011, p. 111) conclude, "[C]urrent rules allow customers with DG to avoid paying their share of fixed network costs." They also note that DG customers on increasing-block electricity tariffs can sometimes avoid the highest-priced energy, using their on-site generated power to replace high-price service while still taking advantage of a grid connection to obtain low-price energy. It should be noted, though, that Kassakian and Schmalensee's critique is not exclusively focused on standby rates. The situation with respect to DG is fundamentally no different from changes in customer usage that result from energy efficiency measures. Also, most large customer tariffs already include demand charges that address this issue. Still, Kassakian and Schmalensee propose a general change in ratemaking to address all customers' contributions to fixed costs. They say (2011, p. 175):

> Recovering a substantial portion of distribution and transmission network costs through volumetric kilowatt-hour-based rates distorts both utility and customer incentives and over time may create implicit cross-subsidies across subsets of customers. … [A]lternatives to volumetric charges are needed to mitigate distortions common to most utility rate structures, and we recommend that fixed transmission and distribution network charges be recovered largely through customer-level fixed charges. …

This highlights the long-standing dispute between advocates of straight fixed-variable rate design apparently supported by Kassakian and Schmalensee versus volumetric charges that provide price signals that more directly encourage consumers to reduce their energy usage (see Boonin, 2008). A counterpoint to the proposal for fixed charges is that costs are fixed only at a given point in time and for some specific duration. In the long run, all costs are variable. +++

On the other hand, Kassakian and Schmalensee (2011, p. 181) also recognize a counterpoint, which is that risk aversion "may make utilities excessively cautious." They explain:

> [E]arly adopters of new technologies and systems may end up incurring costs that are avoided in later adoptions through learning spillovers from early experiences. These considerations may bias investment toward the mature technologies and assets that are familiar to utilities and regulators. Such conservatism may dramatically retard the adoption of technologies to modernize the grid, even when deployment of those technologies is likely to be the most cost-effective path to accommodate the policy goals impressed on the system... . [footnote omitted]

This observation suggests that some policy intervention can be needed to counterbalance utility conservatism and ensure opportunities for customers to be early adopters of emerging cost-effective technologies, like DG.

Paradoxically, the more a utility needs new capacity, the more benefit is provided by DG customers. This means that the same analysis that supports higher estimates of standby costs could also lead to the opposite conclusion, that customers installing DG units are helping the utility avoid future expansion costs and thus reducing total system costs. Plus, the more DG customers there are, the more they can be considered as providing back-up generation service for one another, not requiring the utility to supply back-up generation. Jackson (2007, p. 1898) explains:

> The small size of new CHP systems, the random nature of likely unexpected CHP downtimes and spatial clustering of commercial establishments permits a probabilistic approach to determining the cost of providing unexpected energy and demand services to CHP service during unexpected systems downtimes.
>
> Most CHP prime mover specifications report average downtimes of less than 10 percent. By scheduling required maintenance during off-peak periods, unanticipated interruptions should be no more than 10 percent during periods where capacity limits are approached, consequently, an estimate of least cost backup rate schedule for widely distributed small CHP systems is specified as 10 percent of the standard large general service demand charge plus standard energy charges for kWh use to cover variable costs. … One important distinction between these rates is that the probabilistically determined rates require a sufficient (future) population of CHP systems to take advantage of the random nature of unexpected outages… .
>
> A "chicken and egg" problem exists here with CHP advocates arguing that long-run system cost optimization can be achieved only with current pricing that represents these longer-run conditions. Not surprisingly, utilities are more concerned with immediate revenue and revenue neutrality issues. The long-run standby rate argument is appropriate only if these rates result in the kind of clustered, small CHP population characteristics assumed above.

The probability of multiple DG systems requiring standby service at the same time, and of that time occurring on-peak, is generally based on multiplication of the individual probabilities, reflecting the general independence of DG outages. The probability of simultaneous, on-peak outages drops quickly as the total population of DG units increases (Lovins et al., 2002, pp. 181-185; Hoff, 1997, pp. 51-52). To be sure, some DG outages are correlated. For example, solar generators depend on the availability of solar radiation and wind generators depend on wind availability. Just as with central station generators, groups of DG systems can be affected simultaneously by problems with fuel availability, technical problems, and equipment failures. The probability of multiple DG system failures occurring simultaneously rapidly approaches zero, though, as the total number of generators and variety of technologies in the population increases. And, as the average size of generator in the total DG population is reduced, the quantity of power at risk in any simultaneous outage of multiple generators also rapidly approaches zero. Thus, an acute need for standby rate modeling is to periodically true-up standby capacity charges and evaluate the capacity-related benefits the class of DG customers provides, based on actual experience. Data from DG customer billing determinants should reveal details about the timing, durations, and quantities of standby generation service being produced and provided by the utility.

Benefits at the distribution service level are not as easy to ascertain and quantify. Unless it happens that multiple DG units are installed in a particular area of a utility's service territory, it is less likely that obvious, measurable benefits will accrue from the standpoint of avoided distribution system costs. This is not to say that such benefits are non-existent. The benefits depend on the types and modes of operation of the DG units and on qualities of each distribution circuit. Lovins et al. (2002, pp. 107-274) identify many sources of potential value in the realms of utility system planning, construction, and operation. Many of those benefits are difficult to model and quantify, however, compared to the relative ease of calculating the value of a population of DG in supporting a broad portfolio of generating resources. Plus, the detailed modeling of utility costs by substation and distribution circuit has not frequently been available for review by anyone outside of the utility's own operational staff.

As DG installations proliferate, however (along with other customer options for load management, demand-response, energy efficiency, and so forth), commissions might consider working with utilities to make sure relevant information is being analyzed on a location-specific basis. There are always likely to be some particular locations where DG could combine with other distributed energy resources to help defer or avoid needed distribution system upgrades. Commissions might ensure that the analysis by location is made publicly available, helping customers and developers to know where on the utility system distributed resources can reduce costs and conversely where it could be expensive for the utility system to install DG. Commissions might also bear in mind the capabilities of advanced metering infrastructure, as noted by Kassakian and Schmalensee (2011, p. 191-92), for gathering detailed locational, time-of-use, and time-of-production data for customers with on-site DG systems. As Hurd (2009, p. 956) proposes, once sufficient distributed resources exist on some individual circuits, "standby rate structures can be re-assessed in light of the new benefits." Smarter-grid implementation provides opportunities for such assessments to be conducted at low incremental cost.

If enough of these resources are concentrated in specific locations, then benefits will accrue in terms of avoided costs throughout the utility system, including distribution, transmission, and generation. Part of the impetus for FERC Order 1000 is to make sure that utility transmission planning takes into account the geographic distribution of resources, and the potential ability of options like load management, demand-response, energy efficiency, and DG to produce and deliver cost-effective non-transmission alternatives.[36] Thus, states might usefully consider how the planning requirements under FERC Order 1000 could create opportunities for utilities to gather and make public more detailed information about the costs and benefits associated with specific distributed resources in specific locations, which would also be useful for evaluating standby tariffs.

Relying on accurate aggregated data about DG customers' locations and the timing of their energy usage, on-site production, and use of standby resources, a thorough evaluation of standby charges can be completed. Such studies could then be informed by data about the costs associated with the utility services caused by the class(es) of partial-requirements customers, and the benefits, if any, that their DG operations provide to the utility system. As standby rate

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[36] *See* http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp, http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf, and http://www.ferc.gov/EventCalendar/Files/20111109080800-MIT_Afternoon_Class_Lecture_11-4-11.pdf. Related issues are also discussed in Stanton, 2012.

experience grows and evaluations produce useful information about DG costs and benefits, model tariff principles can be identified for states with each major type of market structure (e.g., vertically-integrated regulated monopoly states, versus restructured states with competitive service options, both with and without access to RTOs).

VI. Conclusions

Standby rates are only one factor that enters into considerations about DG investments. Customers will consider the entire economic picture, including all financial incentives; financing costs; their avoided cost of energy and capacity; DG system reliability, including warranty provisions and performance guarantees; environmental costs and benefits, including compliance with environmental regulations; and any other specific benefits, such as increased reliability and improved power quality, that the customer associates with the production and use of on-site generation. However, there is at least anecdotal evidence that in many locations in the U.S. standby rates are at least one of the deciding factors in DG deployment decisions. Excessive standby charges can have a chilling effect, deterring DG system developers from focusing efforts in those areas and discouraging customers from investigating DG options.

As outlined at the beginning of this paper, there are several reasons why the time is now ripe to reconsider and refine standby rates and their associated pricing structures. These include: (a) new and pending environmental regulations that are likely to increase the value of certain DG technologies; (b) smarter-grid infrastructure deployment that should simplify the collection of data necessary to evaluate standby rates; (c) the low price of natural gas; and (d) technological improvements and cost reductions that are making DG simultaneously more attractive to more customers and more capable of producing and delivering low-cost utility system benefits. There is also an added impetus in markets where ancillary services markets can add value to DG operations.

In addition, an array of federal, state, and sometimes local government incentives are presently increasing market attention to many selected DG technologies. Colatat (2009, p. 141) urges caution in applying learning-curve and technological-evolution principles indiscriminately, however. He recommends close attention to a variety of market dynamics, because, he says, "[I]t helps to focus…attention on more surgical interventions and provides alternatives to brute force intervention like offering larger and larger incentives." From this perspective, it is important for commissions to make sure that standby rates do not produce unintended subsidies. Commissions can also, at least to some extent, help ensure—either through direct commission action or by helping to inform other policy makers—that other market incentives are carefully targeted to produce the best long-term results for system efficiency and reliability.

Thornton and Monroy (2011, p. 4816) hold out California as a "role model" for solving problems and reducing barriers to DG. As these researchers note, California has developed a DG strategic plan (Tomashefsky, Marks, and Larson, 2002). California also provides a comprehensive on-line Distributed Energy Resource Guide,[37] where, Thornton and Monroy (2011, p. 4817) note,

> potential DG operators can find information on everything related to DG in California, including technology, research, example installations, economics analysis, state incentives, interconnection standards, permitting requirements, regulatory activity, and strategic planning.

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[37] *See* http://www.energy.ca.gov/distgen/

Taken as a whole, this all means the time is ripe to reconsider standby rates and refine them as necessary, so that they do not inadvertently either restrict the growth of cost-effective DG or promote uneconomic bypass. Setting accurate standby rates will play a supporting role in ongoing efforts towards the low-cost provision of safe and reliable electricity for all customers.

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