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RATE STRUCTURES FOR CUSTOMERS WITH ONSITE GENERATION: PRACTICE AND INNOVATION

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National Renewable Energy Laboratory

Innovation for Our Energy Future

Rate Structures for Customers With Onsite Generation: Practice and Innovation

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Subcontract Report
NREL/SR-560-39142
December 2005

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Abstract

In the late 1990s, state and federal policymakers began to address the challenges that were preventing DG from becoming an integral part of the traditional transmission and distribution grid. Although the actual scale of DG deployment has not yet met expectations, there have been significant increases in DG installations in the past decade. 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. However, receiving electrical service from utilities means utilities must plan for partially serving these DG customers. To do so, utilities have implemented standby rates to recuperate the system and electricity costs they incur.

By reviewing a dozen states' regulatory proceedings, tariffs, publications, and interviews with experts, the researchers attempted to answer the following questions: 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 utility system and other ratepayers? How should standby rates be designed to reflect these benefits and encourage customers to maximize the value of DG for themselves, the utility system and other ratepayers?

This report assesses a number of approaches to standby and associated rates that deserve policymakers' attention if they are to promote the deployment of cost-effective DG in their states.

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Executive Summary

In the late 1990s, widespread publicity surrounded the commercial introduction of microturbines, and new market developments appeared likely to vastly increase the deployment of distributed generation (DG). In this environment, state and federal policymakers began to address the challenges that were preventing DG from becoming an integral part of the traditional transmission and distribution grid. The expectation was that more and more commercial and industrial users of electricity would use onsite generation, often in combined heat and power configurations. Although the actual scale of DG deployment has not met these hopes—and current natural gas prices are making the future more uncertain—there have been significant increases in DG installations in the past decade.

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.[1]

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.

California and a handful of other states have begun, as part of broader efforts to diversify and improve the efficiency and environmental performance of their electric systems, to develop ratemaking policies for standby service for customers with onsite DG. Recognizing that innovation and good public policy do not always proclaim themselves, Synapse Energy Economics and the Regulatory Assistance Project, under a contract with the California Energy Commission (CEC) and the National Renewable Energy Laboratory (NREL), undertook a survey of state policies on rates for partial-requirements customers.

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[1] Historically, customer-sited generation was usually big enough to warrant special regulatory consideration (rules or tariffs for multi-megawatt cogeneration or "qualifying facilities" under the Public Utilities Regulatory Policy Act proceedings) or special contracts (sometimes combined with economic development rates), or alternatively, it was small and rare enough to be ignored. However, technological advances have begun to change the markets for DG and, as the potential for deployment grows, the DG industry, customers, and regulators are looking for new policy tools to facilitate this transformation.

The survey investigated a dozen or so states. These varied both in geography and the structures of their electric industries. By reviewing regulatory proceedings, tariffs, publications, and interviews, the researchers identified a number of approaches to standby and associated rates—many promising but some that are perhaps not—that deserve policymakers' attention if they are to promote the deployment of cost-effective DG in their states.

The final judgments, however, are more limited. The researchers did not examine the cost bases of the rate structures. (Indeed, in most cases, there were none). Also, they did not test the cost-effectiveness of hypothetical DG installations against different tariffs; this was beyond the scope of this work. Even so, important findings and insights can be drawn from the survey.

Among the key findings are:

- An array of rate-related options is available to states, and is under development by states, that are pursuing DG as a resource in the electric system.
- States have implemented a variety of approaches for determining an individual customer's load for standby rates, developing service offerings that permit customers to choose service appropriate to their circumstances, incorporating analysis of diversity and probability in cost allocation, and creating DG performance incentives that align rates with cost causation.
- States may consider a "policy overlay," in which state policy goals are allowed to shape rate treatment. In this vein, states can use performance-based revenue cap regulation to break the link between a utility's profitability and volumetric sales and thus avoid a financial disincentive to enable customer-sited DG.
- States can, and have, adopted exemptions from standby rates as well as incentives to encourage DG deployment.
- Options for further development include increasing the proportion of costs collected through volumetric rates in recognition of the long-term volumetric nature of costs that appear fixed in the short-term (such as some infrastructure costs) and developing favorable treatment for DG resources that meet threshold environmental criteria. Many states have explicit policy goals of fostering customer-sited DG as an integral part of a customer's electricity service.
- States justify their policy goals through the individual customer benefits of having DG as a viable service choice and anticipated system benefits of a proliferation of customer-sited DG installations.
- Unfortunately, the available data and analysis of costs, system benefits, and power system integration details make the development of standby service options and associated rates difficult and somewhat rough when compared with earlier visions of an electric sector transformed through the integration of distributed resources.

- Fortunately, utilities, customers, the private sector, and policymakers are gaining valuable experience and undertaking an array of research projects that will permit an increasingly sophisticated approach to developing standby rates for customers with onsite DG. California is one of the leaders—both in the development of regulatory policy to integrate DG and other distributed energy resources as components of the electric system and in research that will inform improvements in rate treatment and other policies.
- Developing innovative ratemaking for customers with onsite DG will require further exploration, evaluation, and understanding of cost causation issues and policy overlays. DG customers, utilities, and other stakeholders will benefit immensely from coordination among state policies to reduce policy conflicts, confusion, and costs.

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Introduction

Distributed generation (DG) has become a focus of technological and policy innovation over the past decade. Included within the broader category of distributed energy resources (DER), which includes combined heat and power (CHP) technologies, DG is "modular electric generation or storage located near the point of use."[2]

DG is now widely regarded as an important, though relatively small, component of the nation's electric system. Customers view it as a means to otherwise unattainable reliability and as a cost-reducing and efficiency-enhancing energy resource. System operators are increasingly seeking to integrate DG for its real-time operation and reliability properties. Distribution utilities see it, in certain instances, as a meaningful alternative to new investment in poles and wires. Advocates tout its environmental attributes. And many policymakers speak of it as an essential element of a diversified, resilient, and least-cost electric portfolio.

However, as is the case for all popular new ideas, the achievement of such benefits can be difficult and is often contingent on circumstances. Against these expectations for DG are arrayed real challenges that belie the promise and raise costs. These challenges include interconnection and interoperability with the grid, emissions, safety, and (of interest here) the availability and cost of grid-supplied power.

DG can provide real benefits to the electric system, but capturing those benefits depends, in some measure, on appropriate policy treatment by utility and environmental regulators—treatment that deals with grid interconnection requirements, dispatch rules, siting, emissions standards, and equally importantly, the rates of standby (or backup) services desired by DG owners.[3]

A good deal of work has already been done at the state and national levels to address the interconnection, emissions, and wholesale market issues concerning DG. In several states, attention has now turned to the question of standby service—how pricing can encourage or discourage deployment of clean DG resources and what policy options are available to satisfy the sometimes competing objectives of, among others, fairness, revenue sufficiency, and promotion of environmentally sustainable DG systems throughout the US electric grid.

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[2] Department of Energy (DOE) definition found at http://www.eren.doe.gov/distributedpower/whatis_main.html in 2002:

> Distributed systems include biomass-based generators, combustion turbines, concentrating solar power and photovoltaic systems, fuel cells, wind turbines, microturbines, engines/generator sets, and storage and control technologies. Distributed resources can either be grid-connected or operate independently of the grid. Those connected to the grid are typically interfaced at the distribution system. In contrast to large, central-station power plants, distributed power systems typically range from less than a kilowatt (kW) to tens of megawatts (MW) in size.

[3] In this report, the term *distributed generation* and its acronym, *DG*, mean all customer-sited, non-emergency generation, whether configured in a CHP mode or not.

On behalf of the California Energy Commission (CEC) and under a contract with the National Renewable Energy Laboratory (NREL), Synapse Energy Economics and the Regulatory Assistance Project surveyed state policies on standby rates for customer-sited DG systems.[4] The purpose of this study is to identify the suite of ratemaking policies that will best support the deployment of clean DG systems when balanced against other legitimate objectives—such as equity, economic efficiency, and cost recovery—of setting utility rates. The study constitutes one element of research under the CEC Distributed Energy Resources Integration Program.

1.1. Key Questions for the Project

This study, though intended to inform discussion of DG ratemaking throughout the country, is driven in large part from ongoing work in California. The California 2003 Energy Action Plan (EAP) stated that it developed an approach sensitive to the implications of energy policy on global climate change and the environment generally.[5] One of the six goals of the plan was to promote customer- and utility-owned DG. The plan stated that DG could enhance reliability and provide high-quality power and that the state was promoting and encouraging clean and renewable customer- and utility-owned DG.

Some of the tasks for DG development included:

- Promoting small, clean DG at load centers
- Determining how to hold DG customers responsible for costs associated with power purchases by the Department of Water Resources
- Determining the system benefits of DG and related costs
- Enabling DG participation in the renewable portfolio standard
- Standardizing DG definitions across agencies to promote coordination
- Collaborating with the California Air Resources Board to integrate air quality and energy policies.

California's Energy Action Plan II, adopted in October 2005, identifies the DG-related achievements and efforts in progress resulting from the implementation of the first EAP.[6] It also contains additional DG-related goals that build on the efforts of 2003.

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[4] This study does not address net-metering policies. A great deal of attention has already been given to net-metering arrangements, and they are in place in many states. The resources of this project are dedicated to enhancing the understanding of standby rate policies, which are not as pervasive.

[5] The EAP was adopted in April and May of 2003. California Public Utilities Commission commissioners Lynch and Wood did not sign the EAP because they believed it reached conclusions that should more appropriately be reached through regulatory proceedings. The EAP was a collaborative effort among the CEC, the California Public Utilities Commission, and the now-dissolved Consumer Power and Conservation Financing Authority.

[6] California Public Utilities Commission and California Energy Commission, *Energy Action Plan II: Implementation Roadmap for Energy Policies*, October 2005.

In its Order Instituting Rulemaking Regarding Policies, Procedures, and Incentives for Distributed Generation and Distributed Energy Resources (R.04-03-017), the California Public Utilities Commission (CPUC) identified other issues. Among them are questions pertaining to:

- The temporal and geographic characteristics of DG and how best to reflect those in rates
- The quantification of costs and benefits of DG
- Appropriate rate design
- Consistency with other state policies.

In more detail, the CPUC is striving to answer questions such as:

- Are there examples of cost-benefit methods that are informative?
- Do other states use avoided-cost determinations for energy efficiency in DG cost-benefit analysis?
- What positive and negative aspects of DG additions need to be monetized?
- Are there specific approaches to DG and net metering cost-benefit analyses that could be informative to California?
- How can standby rates reflect and incorporate temporal and geographic characteristics of DG?
- Can standby rates provide aggressive energy peak demand reduction? If so, how?
- Are there examples of tariffs that provide recognition of, and compensation for, distribution deferral?
- How can rates and tariffs reflect reduced grid use by DG customers?
- Are standby charges and reserve requirements properly assessed and applied to DG projects?
- Have other states established separate customer classes to encompass DG installations and contain net costs and benefits within each class?
- Could tariffs or rates be crafted to provide better retail price transparency to DG? Could participation costs be reduced? Could the full range of DG participate?
- What are practices regarding metering requirements?
- How can standby rates be aligned with air quality and environmental goals?

Although these questions are far broader than the limited focus of this paper, many served as the basis for questions pursued in the survey and interviews.

1.2. Study Methods

This report is based on a series of state surveys and interviews conducted during the second half of 2004 and the first half of 2005. The researchers began by surveying a sample of states that are diverse in geography and electric sector structure and varied in their approaches to DG and rate design. In particular, they looked at states that have conducted or begun regulatory proceedings on DG rate policies in which the full range of issues were or are under consideration and also at states that, by not taking action, have, in effect, adopted *de facto* policies worthy of examination (for their virtues as well as their vices). It was beyond the scope of this work to survey the standby rates and policies of every state, or even most states, in the union.

The researchers reviewed regulatory decisions, tariffs, legislation, and other policy documents in Arizona, California, Indiana, Massachusetts, Minnesota, New York, Oregon, Rhode Island, Texas, and Vermont. Those with ongoing or completed DG ratemaking proceedings are New York, Texas, California, Massachusetts, and Minnesota. Others are examining ratemaking issues in one way or another but not in a general proceeding. This group consists of Oregon, Rhode Island, Vermont, Arizona, and Indiana. In most cases, the researchers found a tariff element or methodological approach to the rates that was of particular interest—an intriguing new twist on an older theme. In one or two instances, they came across features that caught their attention for their apparent antagonism to customer-sited resources and thus warranted a closer look. In all cases, what they discovered gave them a greater appreciation for the complexity of the issue.

The surveys provided an understanding of the status of ratemaking treatment for DG and enabled the researchers to identify important issues and various policy responses to them. They followed the surveys with interviews of more than 30 people with professional interest in the issue. These included staff of public utilities commissions (PUCs), DG developers, and engine manufacturers as well as utility officials, representatives of trade organizations, advocates, consultants, and other experts from across the country. They found general agreement on the benefits and opportunities for customer-sited generation but, in the details, a diversity of opinion that, in some respects, does not seem capable of being reconciled. Like most controversies in the electric industry, the debate centers on the essential questions of costs, benefits, cost allocation, and the structure of prices.

2. Current Rate Design Practices for Partial-Requirements Customers

With the installation of onsite generation, a customer will rarely go entirely "off grid." Grid-supplied power retains value in a number of ways. For example, in a typical installation, the DG is sized to serve less than the total load at the customer site. A facility with an average load of 25 kW that installs a 10-kW DG system to provide higher-reliability service for "critical" loads will require 15 kW in addition. But even a facility with onsite capacity sufficient to meet all of its demand will want or need to take power from the grid at times.

This may be done to:

- Serve needs in excess of that supplied by the DG system on average, to meet short-term or seasonal peaks, or, in certain cases, to serve the momentary need for increased power associated with DG start-up
- Supply power during scheduled outages of the DG system, most often for maintenance
- Supply power during unscheduled outages because of equipment failure, loss of fuel supplies, or other problems
- Purchase power at prices below the operating cost of the DG system, typically during off-peak periods when the local system is in surplus.

The term *standby rate* is often used as shorthand for the full set of retail products that customers with onsite, non-emergency generation (whom this paper refers to as "partial-requirements customers") typically desire. Reasonable and nondiscriminatory standby rates for certain customers were first required under the Public Utilities Regulatory Policy Act of 1978. Most of the states reviewed for this report (e.g., utilities in Minnesota, Texas, Arizona, and Indiana) distinguish among three types of service in their tariffs: supplemental, backup, and maintenance. Some tariffs (e.g., those of Narragansett Electric in Rhode Island and Tucson Electric Power in Arizona) differentiate only between backup/standby service and supplemental service.

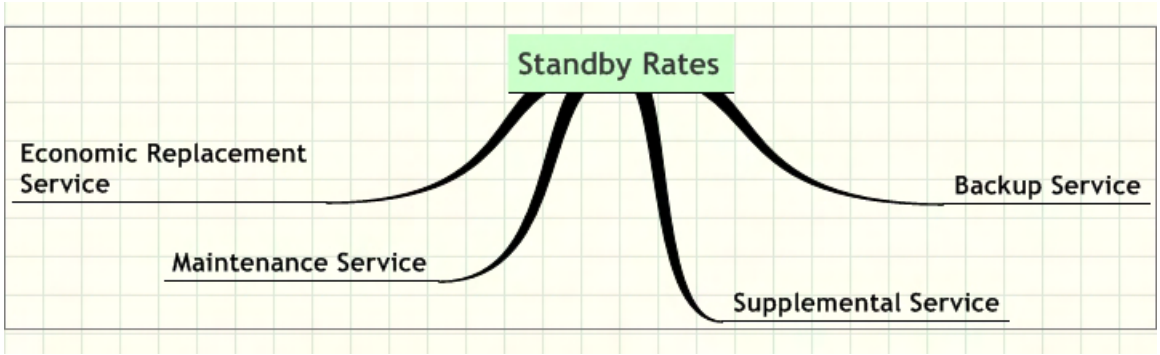

Figure 1. Basic services for partial-requirements customers

The following are the basic services for partial-requirements customers as defined in this report:

1. Backup service
   Backup service, also called "standby service," serves a customer load that would otherwise be served by onsite generation during unscheduled outages of the onsite generation.
2. Supplemental service
   Supplemental service is for customers whose onsite generation does not meet all of their needs. In most cases (and as in Oregon), it is provided under the otherwise-applicable full requirements tariff.
3. Scheduled maintenance service
   Scheduled maintenance service is taken when a customer's onsite generation is due to be out of service for checkup and repair. In general, because this service can be scheduled for non-peak times, it is deemed to impose few marginal costs on the utility's system, so tariffs are typically structured to exempt the customer from capacity-related costs (e.g., reservation charges or ratchets for either generation or delivery).
4. Economic replacement power
   Some utilities offer economic replacement power, or electricity at times when the cost of producing and delivering it are less than that of the onsite source.

Although not all states, utilities, or tariffs reviewed make these distinctions in the same way, these terms do, for the most part, appropriately describe the range of services typically offered.[7]

Electric industry restructuring and the unbundling of the system has, in some states, added a complicating layer to rate design. Whereas the prices of vertically integrated utilities often are all-inclusive of generation, transmission, and distribution charges, the separation of these functions in restructured states has led to the parallel separation of charges for them. This can cause confusion when comparing different rate elements and, in particular, their ratchet elements and exemptions.

2.1. Costs of Partial-Requirements Service

PUCs and electric companies approach partial-requirements service in much the same way as they do full service. That is, standby tariffs typically reflect the traditional function and allocation of costs according to their relationship to changes in demand for energy and capacity. The costs that a partial-requirements customer imposes on the system are described, for the most part, along the same dimensions and in the same terms as the costs that any other customer might cause. These are (1) generation, transmission, distribution, and customer and (2) fixed and variable, dedicated and shared, and embedded and marginal costs.

[7] Customers with onsite generation intended only for use in the event of an electric system interruption or failure are full-requirements customers and, for rate design purposes, are treated no differently than customers without onsite generation. Consequently, customers with emergency onsite generation are not a focus of this report.

Interestingly, little detailed analysis has been performed on the nature and types of costs imposed on the grid for standby service or on the benefits that DG bestows in return.[8] In fact, the lack of specific cost analysis of the effects of DG installations on distribution systems is emerging as one of the stumbling blocks in the design of DG-specific cost-based standby tariffs. Inferences, of course, can be drawn from the design of tariffs, and one is not surprised to see that the implied characteristics of DG costs are those of the electric system generally. In New York, Massachusetts, and Oregon, utilities used existing cost-of-service studies to determine DG standby rates. The availability, or lack, of specific cost analysis has been cited as a concern in a number of jurisdictions.

2.1.1. General Cost Categories

It bears repeating that electricity is a product that, on the one hand, must be available on demand and, on the other, can only be produced when demanded. Out of the combination of these unusual legal and physical properties flow the complex questions of cost causation that make rate design so vexing at times. At a rarefied level of generalization, the problems and their solutions can be easily described. Partial-requirements customers, like other customers, demand services that require use of the various components of the electric system—generation, transmission, and distribution—and a customer's share of these costs depends on a host of factors, including customer peak demand, coincidence of customer demand with relevant peaks (such as system, transmission, and local facilities), and load factors. Debate arises when discussion turns from the general to the specific: Do—and, if so, how do—the usage characteristics of individual or groups of partial-requirements customers differ from those of other customer classes, and are those differences accompanied by measurably different costs (or costs avoided) that then justify alternative rate treatment?

2.1.1.1. Generation

Partial-requirements customers call on the grid to supply electricity for a variety of needs, such as during an unscheduled outage of their onsite generation, when their onsite generation has scheduled maintenance performed, and for loads in excess of those served by the onsite facility. This paper is interested primarily in the first instance because it is the unpredictable nature of demand for backup service that creates its cost conundrum. The second and third cases also raise cost questions, but they are, for the most part, less controversially resolved. It is unexpected demand for which the utility (or default service provider or some other entity) must have in reserve some amount of generation capacity, and it is the probability and timing of that demand that determine both the amount and cost of the capacity.

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[8] California is the exception. Cost-of-service analyses by its utilities have returned useful information, and recently, the studies performed under the CEC's Public Interest Energy Research program have revealed significant system benefits from strategically deployed DG. The Massachusetts DG Collaborative will take up issues associated with the costs and benefits of DG installations during the second half of 2005.

The need for generation (and reserves) is causally related to system peak demand, which is the sum of the diversified demands of all customers on a system. It is called *diversified demand* because it may be (and often is) that any one customer's individual peak does not occur at the same time as the system peak. A customer's contribution to the need for generation capacity, therefore, is not defined by his own peak but rather by his demand at the time of system peak, i.e., his "coincident peak." One can imagine that the probabilities of calls for standby service at the time of system peak differ wildly among partial-requirements customers—in the same way that the load profiles of full-requirements customers in a particular rate class differ—but when taken as a whole, they render a usage pattern that is, for the utility, both predictable and manageable.

2.1.1.2. Transmission

Transmission serves a variety of needs. Like generation, it is configured to reliably serve overall system peak. Ideally, the system is designed to do so in the most economic manner possible and to assure that electricity can flow from generators to loads, meet minimum reliability standards, and minimize congestion.[9] It has other values as well:

1. It enables system operators to optimize the operations of the grid
2. It facilitates bulk transactions that lower overall power costs
3. In dedicated deployments, it connects remote generation to demand.[10]

Although for ratemaking purposes, transmission might bear a strong resemblance to generation (its capacity is driven by peak demand, but it also serves energy needs), in reality, it is often priced in ways that do not fully reflect its cost drivers (e.g., postage-stamp pricing that does not account for congestion). Typically, transmission costs are included in the delivered price of generation and, thus, in retail prices, are covered in the charges for generation capacity and energy.

2.1.1.3. Distribution

Regulatory and utility practice has traditionally seen distribution investment as driven by two causes: customers and demand. Customer-related costs are those incurred to serve individual customers—for example, the costs of meters, service drops, and some transformers (even whole substations for large customers)—and are either shared among them (as a function of numbers of customers in each class) or allocated to each directly. Costs incurred to meet peaks loads—where and when they occur can vary wildly across the lower-voltage network—are deemed demand-related and are allocated according to customers' contribution.

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[9] Implicit here is the recognition that transmission needs, like those of generation and distribution, can be met in a variety of ways. The least-cost solution to a transmission problem might not be to string additional wires but rather to invest in end-use energy efficiency, DG, or other forms of demand response. Under certain circumstances, the various components of the electric system can act as substitutes for one another. See Brown, M., and Sedano, R. "Electricity Transmission: A Primer." National Council on Electricity Policy, www.ncouncil.org. Denver. National Conference of State Legislatures, June 2004. In rate design, then, it is an asset's function, not its form, that determines how its costs are categorized and allocated.

[10] National Association of Electric Utility Commissioners. *Electric Utility Cost Allocation Manual*. Washington, DC: January 1992; pp. 69–85, 127–135.

There are two general types of demand-related distribution costs: local (or "dedicated") and shared. Local facilities costs are attributed exclusively or nearly exclusively to a single customer, and shared facilities costs are those costs incurred to meet the coincident peak demand of customers on a particular part of the system. The determination of whether particular facilities are dedicated or shared—and, if shared, the appropriate allocations of costs among customers—is critical to the setting of rates for both full- and partial-requirements customers. The allocations could, conceivably, vary from circuit to circuit. Although these are demand-related costs, they are not related to system demand, and consequently, customer class non-coincident peaks and individual customer maximum demands are typically used to allocate them. The weightings of the allocation factors are affected by the diversity of customer loads on the nearby circuits and facilities; as one moves closer to an individual customer, diversity in customer load diminishes and costs can be more directly assigned to each customer.[11] It is in these allocations that challenge and controversy lie.[12]

2.1.2. Types of Costs

2.1.2.1. Fixed and Variable Costs

Fixed costs do not—in the short run, at least—vary with demand.[13] In standby tariffs, these appear in fixed, recurring customer charges and sometimes in local facilities charges and reservation fees. Monthly (or daily) customer charges cover the costs of facilities and services—e.g., line extensions (or drops), meters, and account administration—that are dedicated to the customer only and whose need and size are not linked to variations in usage (although these naturally affect the original sizing of facilities).

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[11] National Association of Regulatory Utility Commissioners. *Electric Utility Cost Allocation Manual*. pp. 86–101, 136–146.

[12] Not surprisingly, determining the allocation between these two costs for standby rates was one of the most controversial issues among stakeholders in New York. Utilities in New York established a contract demand charge for local facilities costs and an on-peak, daily as-used demand charge for shared facilities costs. More specifically, a contract demand charge in New York is based on a customer's potential maximum electric load, which is typically determined by the utility and set yearly. The as-used demand charge is charged during daytime (e.g., from 8 a.m. to 10 p.m.) and for the daily standby service demand (kW) a customer uses.

[13] Whether a cost is fixed is, for economists, a debate over the distinction between the short run (in which productive capacity cannot be altered) and the long run (in which all factors of production are variable). The arguments in favor of pricing electric utility services to reflect the long-term cost characteristics of the system are, in the authors' view, persuasive. See:

- Bonbright, J.C. *Principles of Public Utility Rates*. Public Utilities Reports Inc. New York: Columbia University Press, 1960; pp. 300–304, 317–336, 396.
- Boiteaux, M. "Peak-Load Pricing." *Journal of Business of the University of Chicago*; Vol. 30, 1960 (translated by H.W. Izzard); p. 165–167. (This is an update of the author's earlier paper "La Tarification des demandes en pointe: application de la théorie de la vente au coût marginal." *Revue générale de l'électricité* ; Vol.58, 1949.)
- Kahn, A.E. *The Economics of Regulation*, Vol. I. Cambridge, MA: The MIT Press, 1988; pp. 71–87.
- Bonbright, J.C.; Danielsen, A.L.; Kamerschen, D.R. *Principles of Public Utility Rates*. Arlington, VA: Public Utilities Reports Inc., 1988; pp. 467–468.

That said, the long-standing tradition in utility rate-making that treats certain minimum customer costs as, in essence, fixed and unavoidable has a practical appeal that will not be challenged here.

The variable costs of standby service are, as they are for fully tariffed service, energy- and demand-related. Ultimately, customers demand electricity to provide end-user services—such as lighting, refrigeration, cooling, and information processing—that they value. In this context, demand for electricity can be seen as driven altogether by the need for energy because it is kilowatt-hours, not kilowatts, that animate their end-uses. However, energy-producing and energy-transporting facilities are sized to meet peak coincident demand on the relevant system, and a customer's contribution to that peak can be measured and billed.[14]

Local facilities charges cover the costs of those components of the distribution and, in certain cases, transmission network that, but for the customer, would be unnecessary. Rates for shared facilities (if differentiated from local) pay for those portions of the distribution system that serve multiple customers and whose sizing reflects load diversity on the system. Both costs, as described above, are largely driven by peak demand (of individuals and groups) and, thus, are usually allocated on a per-kilowatt basis. Because demand is variable, a customer's contribution to peak is variable. However, once built, local and shared facilities are, for the most part, fixed and long-lived. In this, rate-making confronts at once the problem of historic ("embedded") cost recovery and economically efficient pricing because, in most cases, both the short- and long-run costs of new distribution investment are likely to be less than the historic costs.[15] Determining the share of these costs allocable to DG customers and the degree to which those costs are avoidable—i.e., How does the presence of onsite generation change, if at all, the cost-causative properties of the customer's need for shared local facilities?—is among the more challenging aspects of setting standby rates.

The demand for generation and transmission capacity is likewise variable, and these services are allocated and traded on a per-kilowatt basis. To what degree has the utility incurred capacity costs to serve the partial-requirements customer? How do the diversity of overall demand on the system and the probability of a call for standby service affect cost allocation?

2.1.2.2. Incremental and Embedded Costs

There is no need to revisit the arguments that favor, or disfavor, incremental cost-based or market-based pricing structures to embedded-cost ones. The long history of utility case law and ratemaking practice in this country has, more or less, settled the issue. Simply put, providers of monopoly utility services are to be given a reasonable opportunity to recover their investments dedicated to public service and to earn a fair rate of return on those investments.

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[14] As a practical matter of metering and rate design, the customer's non-coincident peak demand typically is measured and billed. To the extent that the class average customer's usage corresponds to the overall system load profile, this approach to pricing is effective. As metering and billing technologies advance, new approaches, such as critical peak and real-time pricing, can provide more economically efficient prices (notwithstanding external costs).

[15] In the absence of capacity constraints (an important caveat), short-run marginal distribution costs are close to zero. In the long run, marginal costs will depend on growth on the circuit and the timing of replacement of existing facilities. (The farther into the future the costs are expected to be incurred, the more they are discounted in today's dollars.)

For ratemaking, this has been interpreted as requiring that prices be sufficient to cover the prudent historic, or embedded, costs of service.[16] This prerequisite, however, has not constrained rate design to average cost prices, and much of the second half of the 20th century has been marked by regulatory and utility endeavors to develop rate structures that reflect marginal costs for marginal consumption while prices for customers' less elastic demand are adjusted to ensure against over- or under-collection of the embedded cost of service. In standby rates, this often manifests itself in embedded cost pricing for the fixed-cost components of service and some manner of marginal cost pricing (e.g., seasonal or time-of-use, in the short or long run) for the variable. There is, of course, no hard-and-fast rule about this.

2.2. Basic Elements of Rate Design

In their general characteristics, the rates for partial-requirements customers look the same as those for full-requirements customers. The same components of the network provide the two services, so standby and related rates are typically broken out along the traditional lines suggested by the preceding discussion. There are fixed, recurring customer charges; demand charges for capacity (generation, transmission, and distribution, bundled or unbundled) that may or may not vary with demand; and energy charges for the actual amounts of electricity purchased.[17] The following subsections provide a general description of the components of rates and rate design.

2.2.1. Customer Charges

Customer charges are monthly or daily fixed, recurring charges that are typically intended to recover the costs of metering, billing, and service drop facilities and which must be paid regardless of whether any electric service is taken. In this sense, they can be seen as a kind of access fee.

2.2.2. Demand Charges

As described above, the electric system is designed to meet a variety of peak loads: that of the system as a whole, those of customers served by discrete parts of the network, and those of individual customers. The costs of capacity can be included in per-kilowatt-hour energy charges, as they often are for lower-volume residential and small commercial consumers. But for larger-volume users, standard practice is to separate the charges for capacity and energy.

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[16] State utility regulators today rely on the historic (accounting) costs of investments, rather than their market value, to calculate utility rate bases (i.e., assets for the provision of the public service) for a variety of reasons, such as the reliability of the numbers, the stability of the resultant prices, and the difficulty of determining the market value of the assets. Regulators are not, however, required to approach rate base valuation in this manner. If there are alternative approaches that yield a better end result, they are acceptable under the law. *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) and *Duquesne Light Company v. Barasch*, 488 U.S. 299 (1989).

[17] This discussion operates on the assumption that partial-requirements customers have, by and large, demands of sufficient size to warrant, or require, the taking of service under differentiated demand and energy rates (sometimes referred to as "two-part rates") rather than under all-inclusive energy rates (as most low-volume residential and small commercial customers do). In their surveys, the researchers did not find any one-part standby rates.

Capacity, or demand, charges are a means of allocating and recovering the costs of the capacity, measured in kilowatts, to serve those peaks. They are deemed to give the larger users stronger incentives to manage their peak demand most efficiently and thus minimize the investment in fixed facilities that the utility must make on their behalf. Given that such facilities are long-lived and unvarying with demand for energy in the short run, capacity charges are often "ratcheted" by some multiplier of customer peak demand for a specified number of months after the incurrence of that peak.[18]

Ratchets have the effect of turning a fee (the product of the rate and monthly peak) that would otherwise vary with changes in demand into something more of a fixed charge that locks a customer into a minimum monthly payment for the duration of the ratchet. Although there is a certain logic behind ratchets (i.e., the linking of customer charges to the longer-term nature of the capacity obligations incurred by the utility), they can constitute financial barriers for customers that seek alternative and more efficient means of meeting their energy needs.

2.2.2.1. Distribution

Distribution system investment is driven by a combination of factors. For dedicated facilities, it is a customer's non-coincident peak demand, and for shared facilities, it is the coincident peak demand of the customers served. Although the costs are separable, they are typically combined within one demand charge (or set of charges) for distribution service and priced on a per-kilowatt-month basis. Simplicity is one reason for this. The lack of a metering and data management capability that measures both customer coincident and non-coincident peaks on discrete sections of the distribution system is another. A third reason is that, although the occurrence of coincident peaks is highly variable, for the purposes of distribution planning and investment, timing is less important than magnitude.

The distribution demand charge is multiplied by the customer's billing demand, which is one (or some variation) of several quantities: the customer's monthly non-coincident peak demand, its maximum potential demand, or an agreed-upon contract demand (usually accompanied by the customer's promise not to exceed it). Not all utilities offer these options; each has its own approach.

It is in the computation of rates that the art and science of rate design combine. Dedicated facilities must be sized to serve the maximum demand a customer will impose, and non-coincident demand (or contract or maximum potential) is the appropriate measure for this. Costs for the facilities can be expressed on a unit (per-kilowatt) basis, which for all intents and purposes will comprise this portion of the distribution rate. However, when it comes to shared facilities, this measure is, at best, a proxy for the customer's contribution to coincident demand. Customer class load data will reveal a generalized relationship between a customer's peak demand and its share of coincident peak, and from this adjustment, factors can be computed and applied to the unitized costs for shared facilities to calculate this part of the overall distribution rate.

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[18] A typical ratchet calls for the customer to be billed, in each of the 11 months following its peak demand, for either 80% of that peak demand or the peak in that month, whichever is greater. If a higher peak occurs, that new demand forms the basis of a new ratchet, which then extends for the following 11 months.

2.2.2.2. Generation

Rates for generation are separated into demand and energy charges. Demand charges are designed to recover the costs for capacity that were incurred to serve a customer or, more accurately, a customer class. Because generation needs are driven primarily by system coincident peak, it is a customer's contribution to that coincident peak that should determine its cost responsibility. But, as with distribution, a customer's contribution to coincident peak (in this case, system peak, not local area peak) is neither readily measured nor, for rate design generally, a practical necessity. In designing rates, generation demand charges are adjusted to reflect the relationship of class coincident peak with the average customer's non-coincident peak, so customer bills calculated on the basis of non-coincident peak will cover costs that are, in reality, associated with coincident peak.

Each customer class imposes unique demands on the system, and the tariffs drawn up to reflect these differing characteristics provide, in effect, different services suited to the needs of the classes. Similarly, partial-requirements customers can be seen as a class of customers. Their needs for generation services, at least for that portion of their loads that are served primarily by their onsite generation, differ (presumably) from those of full-requirements customers, and so do the cost impacts. A standard tariff element for standby service is the reservation fee, which ostensibly covers the costs of the capacity that the utility must have entitlements to if it is to cover the call for unscheduled service, even if it is never made. Typically, it is applied against monthly billing demand (contract, maximum potential, or ratcheted) and, therefore, looks very much like a fixed recurring fee that accords a customer the right to take standby service. What matters most under this scheme is the per-kilowatt reservation charge. If it approximates the generation component of the otherwise-applicable full-requirements tariff and makes no provision for the probability that the service will not be needed, it is likely to result in total costs that will render most onsite generation projects uneconomic.[19]

A variation on the reservation charge is a fee for contingency reserves, the amount of operating reserves that must be available to meet load in the event that the customer unexpectedly takes energy from the grid (i.e., when its onsite generation suffers an unscheduled outage). This approach imposes on the customer the same obligation that other load-serving entities have—namely, sufficient operating reserves to cover the load in cases of an unplanned outage of any of the resources serving that load.

2.2.2.3. Transmission

In most rate structures, transmission costs are included bundled demand charges or are included in generation demand charges. Some tariffs, such as PGE's (Oregon) partial-requirements service, set separate demand charges for transmission service.[20]

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[19] Whether this will be the case depends on the relationship between the capital and operating costs of the DG system and the demand and energy costs of grid-supplied power.

[20] Transmission charges for PGE's partial-requirements customers are the same as those paid by full-requirements customers.

2.2.3. Energy Charges

Energy is priced on a per-kilowatt-hour basis. Full-requirements customers purchase energy at tariffed rates. They may be differentiated by time of use, season, block, or some other means. The same may be true for standby service. More likely, however, are energy rates that are in some manner tied to short-term wholesale market prices. In addition, there may be additions or surcharges to cover related operational costs and risks.

2.2.4. Other Charges

A number of other charges may be applicable to partial-requirements customers. They are not the focus of this study, but they should not go unacknowledged, as they may have significant effects on the economics of onsite generation.

2.2.4.1. Interconnection

Interconnecting customers with onsite generation with the grid imposes additional costs. The Texas Interconnection Manual states that all distribution customers shall pay the costs of distribution interconnection, including any needed distribution system upgrades. DG customers may pay for interconnection studies, line extensions, and equipment specific to their installation. In Arizona, Tucson Electric Power requires customers to pay, in advance, the estimated interconnection construction costs. The customer receives a refund of up to 40% of the revenue associated with such facilities for each of the first 5 years of metered use; this is capped at a maximum equal to the advance. The customer must furnish, install, and maintain "incremental non-distribution or non-transmission system" equipment at its own expense. The tariffs also include a provision for the customer to pay incremental interconnection costs if its 15-minute billing demand in a month or its maximum 15-minute billing demand in the previous 23 months exceeds the maximum contract demand, when such billing demand requires the company to expand facilities.[21]

2.2.4.2. Costs of Studies

In several jurisdictions, customers may be charged for studies to determine the effect of their load and generation on the power system. For example, in Minnesota customers are eligible for credits for avoided distributed costs and avoided line losses. However, to receive these credits, a customer must fund a study by the utility to determine whether its load and generation profiles justify the credits. In Texas, the PUC's DG manual states that customers are responsible for the cost of a variety of studies pertaining to DG installations. These study costs can be quite high for a DG owner.

[21] This is, in effect, a severe financial penalty for failing to maintain one's demand below an agreed-on level and worthy of including in a discussion of using contracts and penalties to affect customer peak demand. This is an alternative to physical assurance.

2.2.4.3. Metering Costs

States and tariffs have different approaches to metering, but in general, a customer must, at its own cost, install one or more meters that meet specific standards. Tucson Electric Power requires "appropriate interval metering equipment." California utilities also have specific metering requirements for DG customers. For example, PG&E Schedule S includes a time-of-use meter charge, a non-firm meter charge, and a load profile meter charge. New York requires interval metering for customers whose DG is more than 50 kW. The New York Public Service Commission's Standby Rate Guidelines requires interval metering for all customers with contract demands at or more than 50 kW to implement its rate design policy, which includes a daily "as-used demand charge" on the basis of daily customer demand during peak system times.[22]

2.3. Features of Tariffs for Partial-Requirements Service

In general, tariffs for standby service differ from their full-requirements equivalents not in general features but rather in the rate levels themselves, their applicability, the means by which they are assessed, and, often, their exemptions.

2.3.1. Applicability

The policies and tariffs reviewed reveal a variety of approaches for determining the characteristics that affect the nature of standby service. Some customer-specific characteristics, such as customer size, affect charges. In addition, some characteristics of the service that the customer requests, such as season and time of use or size of the customer's load for standby service, affect charges.

2.3.1.1. Customer Size

Like other tariffs, many DG standby tariffs vary according to the size of the customer. In some instances, customer size determines eligibility for, or exemptions from (see "Exemptions" below), standby service. In Minnesota, the legislature directed the PUC to undertake proceedings to investigate interconnection and tariffs for natural gas-fired or renewable DG up to 10 MW; DG facilities of 60 kW or less are exempt from paying standby charges.[23] Similarly, the Texas PUC restricts interconnection of onsite DG to units 10 MW or less. However, renewable DG that does not export to the grid is considered "energy efficiency;" therefore, customers with renewable DG may avoid interconnection costs that other DG customers would incur. In New York, the standby tariffs of the investor-owned utilities (IOUs) do not apply to either non-demand-metered standby customers or standby customers whose contract demand is less than 50 kW.[24]

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[22] New York Public Service Commission. *Opinion No. 01-4, Opinion and Order Approving Guidelines for the Design of Standby Service Rates*. Oct. 26, 2001; p. 9.

[23] Minnesota Statute 216B.1611. The commission's order in Docket No. E-999/CI-01-1023 states that backup generation is beyond the scope of the proceeding. "In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities under Minnesota Laws 2001, Chapter 212." Sept. 28, 2004. http://www.puc.state.mn.us/docs/orders/04-0131.pdf.

[24] Actually, they have the option of taking service under the tariffs or being exempted from them. Presumably, one's choice will depend on whether it is less expensive to take service under the otherwise applicable tariffs, which itself will be a function of the performance characteristics of the onsite facility.

In other instances, a customer's size determines what charges it is assessed, with tariffs reflecting different charges for customers of different sizes. In Indianapolis Power and Light Co.'s territory, large customers must take backup service in increments of 100 kW, with a minimum contracted amount of 500 kW. Smaller customers take backup, maintenance, and supplemental service under their otherwise-applicable tariffs. Indiana Michigan Power Co. (an AEP company) also has minimum contract demands for small and large customers. In Arizona, the tariffs of Tucson Electric Power Co. and Arizona Public Service (APS) recognize three size categories.

2.3.1.2. DG Technologies

In certain instances, the technology of the onsite generation determines whether rate elements apply to a customer's usage. Regulators and utilities in some states recognize that cleaner, lower-emitting DG technologies, especially renewables, will provide significant public benefits. To encourage use of the preferred technologies or fuels, some states offer special rate treatment, primarily in the form of tariff exemptions. (See the section on exemptions for details.) These policies are usually found in states in which complementary actions in support of renewables (e.g., portfolio standards and system benefits funds) have been taken.

2.3.2. Time

Rates for partial-requirements customers are often differentiated by the timing of demand for service. Demands in seasonal and daily peak periods are accompanied by higher-than-average rates that reflect the time-dependent drivers of the underlying costs.

2.3.2.1. Seasonality

Some states and utilities assess charges that depend on the season. In its guidelines, the Minnesota PUC states that tariffs should reflect, to the extent practical, seasonal variations in costs. The NSTAR settlement, for example, sets higher distribution demand charges for the summer peak season than for the non-peak period. The same is true for Consolidated Edison (Con Edison) and Orange and Rockland Utilities (O&R) in New York. Con Edison has a standby rate category, the monthly adjustment clause, that adjusts prices for loads on the system in different periods. The monthly adjustment clause is an additional charge per kilowatt during a certain period and is applied to the customer charge, the contract demand charge, and the as-used, daily contract demand charge. O&R does not have a monthly adjustment clause, but it provides seasonally differentiated, as-used, daily contract demand charges. Other utilities, including those in Arizona and California, also vary standby rates by season.

2.3.2.2. Time of Use

Although some tariffs reflect only seasonal periods, other policies and tariffs include greater specificity as to time of use. In its guidelines, the Minnesota PUC states that tariffs should reflect, to the extent practical, time-of-use variations. APS tariffs have different rates for each season for on-peak and off-peak energy use. Similarly, utilities in California have tariffs that distinguish between peak and off-peak periods (e.g., PG&E's Schedule S). IOUs in New York also have time-differentiated standby rates. New York utilities have an as-used, daily demand charge as one component of standby rates. This charge is applied only to peak hours, which start at 7 a.m. or 8 a.m. and end around 10 p.m. or 11 p.m. Monday through Friday.

2.3.3. Service Characteristics

2.3.3.1. Type of Service

As noted at the beginning of this chapter, partial-requirements customers make use, most often, of three types of service: backup, supplemental, and scheduled maintenance. Some utilities add economic replacement power to the menu. Supplemental service is, in most cases, simply electric service provided under the full-requirements tariff that would otherwise apply to the customer. Although for ratemaking it presents the same questions about cost causation and allocation, they are unrelated to the manner and extent to which the customer's onsite generation is operated and therefore do not merit special attention here. Scheduled maintenance, because dispatchable, can be managed to not contribute to the need for capacity and, consequently, can be priced to cover the variable short-run costs of energy and delivery.

The differentiations among these services are, in certain instances, less clear than this brief description suggests. Utilities in Arizona, for example, differentiate between standby and supplemental service not on the basis of the onsite generation's maximum capacity (or some other agreed-upon method of determining what portion of the customer's load is served by the onsite facility) but rather on the basis of the generation's operating characteristics. Tucson Electric Power uses a methodology called the partial-requirements usage percentage to determine, in part, whether a customer takes service under the standby tariff or the supplemental tariff. This method, in effect, ensures that a customer can rely on backup power only for a small number of hours per billing period. Otherwise, the customer must use the higher-cost supplemental service.[25] In contrast, the New York Public Service Commission (PSC) does not distinguish among these categories of service on the grounds that the costs of building and maintaining distribution facilities for standby customers do not differ according to the portion of the customer's load served by DG or whether an outage is scheduled or unscheduled.[26]

Finally, some tariffs set out separate charges for reactive power. Reactive power is the power in electric fields that is developed when transmitting alternating current power, and it affects and is affected by equipment that relies on magnetic fields for the production of induced electric currents (e.g., motors, transformers, pumps, and air conditioning).[27]

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[25] The partial-requirements usage percentage is the ratio of backup energy purchased to the product of billing demand for standby service and hours in the billing period. If the partial-requirements usage percentage exceeds 5% in a period, the customer's energy charge is converted to the supplemental service energy charge for all kilowatt-hours in excess of the 5%. APS has a similar standby tariff, which also makes the availability of standby service subject to achievement of a minimum capacity factor (18-month rolling average) for the customer DG of 75%.

[26] New York Public Service Commission. *Opinion and Order Approving Guidelines for the Design of Standby Service Rates, Opinion No. 01-4*. Oct. 26, 2001; p. 21–22. Also see the commission's order of July 29, 2003, in cases 02-E-0780 and 02-E-0781, page 21–22 of Attachment A – The Joint Proposal by Con Edison and Orange & Rockland.

[27] Brown and Sedano. *Electricity Transmission: A Primer.* pp. 35, 64. For example, New York State Electric and Gas Corp. (NYSE&G) charges standby customers $0.00095 per reactive kilovolt-ampere hours. Niagara Mohawk Power Corp. establishes two different charges ($0.85 for one customer and $1.02 for another customer class) for each chargeable reactive kilovolt-ampere of lagging reactive demand (Service Classification No. 7, Leaf No. 106 and 106A).

2.3.3.2. Firm and Non-Firm Service

Some tariffs provide a choice between firm and non-firm (or interruptible) service. In Oregon, if low-cost power is available, PGE is free to offer it to DG customers on an interruptible basis. It is called "economic replacement power," and it is intended to displace onsite generation when it is cost-effective to do so. Such "generation displacement" rates are not uncommon. In Vermont, they are available on a special contract basis; there are, however, no separate standby tariffs for DG owners in the state. Customers with onsite generation take standby service under the applicable full requirements tariffs or, in at least one case, under special contract.

Interruptible economic replacement power is not available for unscheduled standby service, but, in several states at least, there are options for non-firm standby service, which is to say that it will only be provided if it is available (i.e., if it imposes no incremental capacity costs on the supplier). In Minnesota, the PUC guidelines for serving partial-requirements customers provide for different treatment of firm service customers and non-firm service customers. Non-firm service customers do not incur reservation charges for generation capacity or energy or for transmission charges, but there is no discount for distribution services. Firm service customers must pay reservation charges for generation, capacity, transmission, and distribution. In 1985, the Indiana PUC identified interruptible service as one of the service options that utilities should offer customers. The NSTAR settlement in Massachusetts provides a non-firm service option to customers. Terms of interruption are negotiated on a case-by-case basis between the distribution company and the customer.

2.3.4. Critical Tariff Provisions: Billing Determinants

How the components of a tariff are applied, the mechanics of billing, vary from state to state. Chief among the key tariff provisions are those that determine the level of billing demand because this invariably has the largest effect on a partial-requirements customer's monthly bill. Also important are provisions that offer exemptions and set performance or technology requirements.

2.3.4.1. Billing Demand

In some jurisdictions, tariffs contain provisions for setting bounds on the standby service for which a customer may contract rather than simply requiring that a customer's billing demand for standby service be determined by the capacity of its DG installation (on the assumption that it will always, or only, be needed at system peak times) or by a measurement of non-coincident peak demand within a given period. These provisions include mechanisms to ensure the customer relies on the utility for only a portion of its load, recognize the diversity of DG installations on the distribution system, and limit the hours during which the customer can request certain services. Accounting for reliability of the customer's DG installation is also factored into certain tariffs, as discussed in the section on DG performance.

Utilities have a variety of methods for determining a partial-requirements customer's billing demand, and different billing demands are used for different service components (e.g., dedicated and shared distribution facilities, transmission, and generation). Some tariffs tie portions of a customer's billing demand to its non-coincident peak demand (e.g., to cover the costs of dedicated facilities) and other portions to demand coincident with daily peak periods of usage (e.g., Rhode Island, Texas, Minnesota, and Oregon). Some of these demand charges are levied on a daily or monthly as-used basis; others are ratcheted. For example, under Tucson Electric Power's tariffs, billing demand is tied to the greater of the maximum 15-minute demand in a month or in 23 months. In New York, billing demand is not differentiated among backup, supplemental, and maintenance service, and it is tied to the customer's maximum potential demand or customer-nominated demand. In either case, customers have a chance to change their billing demand once every 12 months if they can demonstrate real load reductions (such as through removal of equipment or the installation of energy-efficiency equipment) based on an engineering analysis submitted to the utility. NSTAR in Massachusetts, pursuant to its recent settlement, provides standby and supplemental service to most partial-requirements customers. NSTAR's billing demand for backup service is tied to the generating capability of the customer's DG units.

In Indiana, the 1985 rules governing provision of service to qualifying facilities state:

> … a rate for backup and maintenance power shall not presume (unless supported by factual data) that a forced outage or other reduction in the electrical output of each qualifying facility on the electric utility's system will occur simultaneously or during the system peak, or both, and may take into account the extent to which a scheduled outage of the qualifying facility can be usefully coordinated with a scheduled outage of the utility's facility.[28]

As a result, for example, Northern Indiana Public Service Co. ties billing demand to the higher of the customer's highest billing determinant in a month or 80% of the highest billing determinant in the past 11 months.

In Texas, where transmission and distribution utilities (TDUs) have no tariffs specifically for DG standby service, customers are charged under full tariffs for the power they take from the grid and are subject to demand ratchet provisions. There does not appear to be an option for customers to nominate specified levels of service. However, retail electric providers may design rates to be attractive to larger customers with onsite DG.[29]

Some utilities allow the customer to set bounds on the reservation. In Minnesota, the PUC specifically states that customers are not obliged to buy standby service. It notes, however, that if such service is not purchased, it may not be available.

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[28] 170 IAC 4-4.1-5(b).

[29] What is important to note here is that, in Texas, TDUs do not charge retail rates to end-use customers. Instead, the TDU charges the retail electric provider for the delivery services it provides, and the retail electric provider is free to recover those costs from its retail customers however it chooses, and is able, to do so.

2.3.4.2. Level of Billing Demand and Physical Assurance

Several of the tariffs reviewed provide options for determining the level of a customer's demand. In some instances, billing demand can be utility-nominated or customer-nominated. Some policies provide the option of using "physical assurance" to limit standby service to a specified portion of the customer's load.[30] These options allow the customer greater flexibility in defining the level of service it needs and, thus, gives it additional means of controlling its costs of service.

Some tariffs allow the customer to determine a specific capacity for standby service. For example, Pacific Gas and Electric (PG&E) in California allows customers to specify desired levels of "physical assurance." In its guidelines, the Minnesota PUC states that a customer is not obliged to purchase standby service for the full capacity of its DG, but it requires a guarantee that the facility will not take more than its contracted demand level. The PUC also states that a "physical assurance" option for customers that elect not to take standby service should be offered; however, the details of the option are worked out in individual utility tariff proceedings. The settlement on Narragansett Electric's rates in Rhode Island provides that a customer may configure its system, with the agreement of the Company, to effect a lower demand determination.

In New York, utility standby tariffs give customers the option of setting their own level of contract demand. This option includes a ratchet and strict financial penalties for exceeding the level.[31] For example, in Con Edison's and O&R's service territory, if the excess is 10%–20%, the penalty will be 12 times the applicable contract demand charges for the excess demand.[32] If the excess is more than 20%, the penalty will be 24 times the applicable contract demand charges for the excess demand.[33] Other New York utilities charge penalties for excess even less than 10%.[34]

The NSTAR settlement in Massachusetts allows customers to nominate a contract demand level. The customer nomination, to be memorialized in a special contract that includes penalties for exceeding the contract demand level, can be rejected by the company and must be approved by the PUC.

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[30] The California PUC adopted the following definition of "physical assurance":

> … the application of devices and equipment that interrupt a distributed generation customer's normal load when distributed generation does not perform as contracted. An equal amount of customer load to the distributed generation capacity would be interrupted to prevent adverse consequences to the distribution system and to other customers.

CPUC. *Decision No. 03-02-068 Order Instituting Rulemaking into Distributed Generation*. Rulemaking No. 99-10-025, Feb. 27, 2003.

[31] Harsh penalties for exceeding a customer-nominated level of contract demand deter many customers from nominating their contract demand level (personal contact with Chris Young on Dec. 13, 2004).

[32] New York Public Service Commission. *Case 02-E-0780 et. al., Order Establishing Electric Standby Rates*. July 29, 2003; p. 11; Attachment A, Joint Proposal by Con Ed and O&R, p. 4; O&R's service classification No. 25, leaf No. 133; Con Edison's service classification No. 14-RA, leaf No. 139.

[33] *Id.*

[34] See O&R SC No. 25; Con Edison SC No. 14-RA; RG&E SC No. 14; Central Hudson SC No. 14; NYSE&G SC No. 11; and Niagara Mohawk SC No. 7.

In Minnesota, the PUC determined that the monthly reservation fee for generation should be based on a percentage of the planned reserve margin times the tariffed rate. This is similar to the PGE approach in Oregon. PGE calculates reserved capacity for the purpose of determining a customer's contingency reserves obligation (see the description in a later section). The Minnesota PUC declined to provide a discount on T&D costs for firm service customers.

2.3.4.3. Determination of Specific Hours for Standby Service

To limit the use of standby service and give owners of onsite generation a strong incentive to maintain and operate their facilities, APS allows its customers to identify specific periods and hours of a month when standby service will be required. APS sets a floor for the minimum number of designated standby service hours.[35] This option is only for customers whose standby service requirements are less than 3 MW. If a customer takes standby service during non-designated hours more than two times in any rolling 12-month period, the customer is deemed to require standby service in all hours of the month for the next 3 months.

2.3.4.4. Performance

Some tariffs include minimum performance requirements, which can make load associated with DG installations more predictable. If the DG installation does not meet the requirements, the customer can be assessed stiff financial penalties or made ineligible for certain services. Capacity factor is one metric that affects the charges. For example, APS DG customers must maintain a 75% capacity factor over a rolling 18-month period; otherwise, APS assesses a significantly higher monthly reservation charge (Tariff E-55 and E-52). APS states that the purpose of this requirement is to address "substandard operational performance" of DG installations.[36] The calculation of capacity factor under APS's tariffs allows for the possibility that a customer will not require standby service to replace the full output of its DG installation. Under APS's tariffs, monthly reservation charges (dollars per kilowatt of contract standby capacity) decrease as the onsite resource's capacity factor increases to 80%–95%.

In New York, small, efficient CHP units are exempt from standby demand rates if they meet certain performance criteria, specifically:

1. A unit's annual overall efficiency shall be greater than or equal to 60% HHV of the fuel input.
2. A minimum of 20% of the annual energy output of the unit will serve a thermal load.
3. Nitrogen oxide emissions shall not exceed 4.4 lbs/MWh.
4. The facility has a capacity of 1 MW or less, and it serves no more than 100% of the customer's maximum potential demand.[37]

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[35] Under Tariff E-55, it is 365 designated standby service hours /month. Under Tariff E-52, it is 280 designated standby service hours /month.

[36] See, e.g., Tariff E-55, Section VIII.

[37] New York Public Service Commission. *Order Directing Modifications to Standby Service Tariffs, Case 02-E-0551 et. al,* Jan. 23, 2004; pp. 10–13.

Power factor, a complex measure of power quality and the need for reactive power, is also considered in some tariffs. For example, Tucson Electric Power customers receive a discount or are subject to an additional charge for each 1% variation from 90%, up to a maximum discount.[38] Although applicable only to qualifying facilities under the Public Utilities Regulatory Policy Act, under Northern Indiana Public Service's tariff, a customer's billing demand is the same as its billing determinant if the qualifying facility has a power factor of 85% or more.

2.3.4.5. Exemptions

Some states have policies or guidelines for exempting customers with onsite generation from rates for certain components (generally one or another of the demand charges) of partial-requirements service. Typically, there are two kinds of eligibility for the exemptions: size and technology.

Examples of exemptions based on the size (in kilowatts) of the onsite facility include:

- The Minnesota PUC requires that facilities of 60 kW or less be exempt from the payment of reservation fees.[39]
- Under the PGE settlement in Oregon, the first 1,000 kW of load served by onsite generation is exempt from demand charges for contingency reserves.
- In Texas, onsite generation of 10 MW or less is exempt from stranded cost charges.
- In New York, there is a "small customer exemption" from contract demand charges if the onsite facility is 50 kW or less or if it serves no more than 15% of onsite load.[40]
- Under the June 2004 settlement in Massachusetts, NSTAR exempts from its delivery (distribution) charges:
    - Any onsite generation between 250 kW and 1,000 kW that serves less than 30% of a customer's overall load
    - Onsite generation with a nameplate capacity of 250 kW or less
    - Onsite generation that would be operational as of Dec. 31, 2004 (Dec. 31, 2005, for certain public schools that had binding financial commitments in place as of Dec. 31, 2004).[41]

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38 Tucson Electric Power Tariffs PRS-10, 13, and 14.

39 The PUC's policy guidelines also state that the reservation rate shall be "equal to the percentage of the planned reserve margin of the utility times the applicable capacity tariffed rates." This would then be multiplied by the number of kilowatts of load to be served in the event of an unscheduled outage of the onsite generation to produce a monthly total reservation charge.

40 Customers have the option of signing up for the exemptions, and there are limits to them. Depending on the utility, they will no longer be available after specified dates (mid-2006 or early 2007) or after a specified number of customers sign up.

41 Massachusetts Department of Telecommunications and Energy. *Investigation by the Department of Telecommunications and Energy on Its Own Motion as to the Propriety of Rates and Charges—NSTAR Electric*. Docket 03-121, at 17. July 23, 2004.

Regulators and utilities in some states recognize that cleaner, less-emitting DG technologies, especially renewables, will provide significant public benefits. Because of these public benefits, some states offer special treatment for specific technologies and fuels. For example:

- Under the Massachusetts NSTAR settlement, all onsite generation that qualifies as "renewable energy technologies" under state law is exempt from standby delivery charges.[42]
- In New York, "designated technologies" (which include fuel cells, wind turbines, solar thermal installations, photovoltaics, and sustainably managed biomass, tidal, geothermal, and methane waste facilities) are exempt from contract demand and daily as-used demand charges.[43] They must have come online on or after July 29, 2003.[44]
- In Rhode Island, "eligible renewable energy resources" up to an aggregate statewide cap of 3 MW are exempt from distribution demand charges for standby service.

2.3.5. Other Tariff Provisions: Public Purpose Programs and Stranded Costs

A number of states generate revenue for public purpose programs (e.g., energy-efficiency, renewables, and low-income assistance programs) or, in some cases of electric sector restructuring, stranded cost recovery through charges that are separate from the rates paid for electricity itself.[45] These charges are typically set on unit bases—per kilowatt-hour or per kilowatt—and, thus, as one's consumption rises and falls, so does one's contributions to these purposes. In certain states, stranded costs charges are assessed against all electricity production, both onsite and grid-supplied, so there is no avoiding them by the installation of DG. Although one might conclude that, as a general matter, such unavoidable charges should not affect DG cost-effectiveness relative to grid power (unless they are applied disproportionately to standby service), whether this is true will depend on the specifics of each case.

In Texas, DG customers cannot avoid payment of stranded cost recovery charges by installing DG. In contrast, Rhode Island does not have any exit fees. Massachusetts law stipulates that DG customers are exempt from exit fees if they (1) operate or purchase electricity from DG units of 60 kW or less (i.e., the capacity eligible for net metering) and (2) notify the distribution company and DTE, at least 6 months in advance, of plans to install or purchase electricity from onsite renewable energy technologies, fuel cells, or cogeneration (of at least 50% efficiency).[46] However, in both cases, if the total revenue reduction because such customers leave the system during a 3-year period exceeds more than 10% of annual revenue, such customers are subject to exit fees.

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42 *Ibid.*

43 New York Public Service Commission, *Order Establishing Electric Standby Rates, Case 02-E-0780 et. al.*, July 29, 2003.

44 New York Public Service Commission. *Order Directing Modifications to Standby Service Tariffs, Case 02-E-0551et. al.* Jan. 23, 2004; p. 6. CHP has to meet specified efficiency and emissions standards. Also, in Niagara Mohawk's service territory, the criteria for designated technologies are slightly different and stricter. See Niagara Mohawk tariff SC No. 7 on Leaf No. 102B.

45 "Stranded costs" represent the above-market value of utility investments that, through restructuring, may no longer be recoverable in electric rates.

46 Massachusetts General Laws c. 164, § 1G(g).

In New York, the PSC stated in comments on its restructuring rules that exit fees would be prohibited; however, it allowed Niagara Mohawk to charge exit fees:

> … to discourage total bypass of the company's retail distribution services and charges where such bypass is not economic from society's standpoint and to prevent the shifting of the company's transition costs to other stakeholders … .

as it anticipated would occur in such circumstances.[47]

However, the company may not charge exit fees "if a self-generating customer completely isolates itself from the Niagara Mohawk system or if its electricity is supplied by an on-site third party that installed its generating capacity after January 1, 2000 and serves only a single customer."[48]

2.4. Summary of Partial-Requirements Service Practices in Selected States

A number of states have taken steps to address the rate design and utility revenue issues associated with standby service for customers with DG. Table 1 offers brief descriptions of interesting features (whether good or ill) of tariffs for partial-requirements customers, policy guidelines for such tariffs, and proposals for new tariffs in several states that are taking steps to promote deployment of efficient DG.

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[47] Energy and Environmental Analysis. "Regulatory Requirements Database for Small Electric Generators – NY Section." Available at http://www.eea-inc.com/rrdb/DGRegProject/States/NY.html.

[48] *Id*.

Table 1. Summary Matrix of Selected States and Utilities

State	Subject	Regulatory and Industry Structure	Applicability	Rate Design for Partial Requirements Service				
				Stand-By Service				
				Service	Customer Charges	Distribution Charges	Generation Capacity Charges	Energy Charges
NY	Investor-owned utlities	The electric sector has been restructured. Delivery service is provided by regulated distribution companies. Electricity is supplied by competitive or default service providers.	Partial requirements customers with on-site generation of 50 kW. Some existing customers and all customers with renewable technologies have exemption an phase-in options.	Delivery only	Fixed monthly fee	1. Monthly per-kW charge to cover costs of local facilities, applied to potential maximum load or customer-nominate contract level. 2. Daily as-used per-kW charge to cover costs of shared facilities, applied to peak demand during specified daily peak hours.	NA.	NA. Stand-by energy is provided by competitive or default service providers.
MA	NSTAR	The electric sector has been restructured. Delivery service is provided by regulated distribution companies. Electricity is supplied by competitive or default service providers.	To all partial requirements customers.	Delivery only	Fixed monthly fee	Monthly per-kW charge, seasonally differentiated. Contract demand negotiated or set equal to generator capacity. 100% ratchet.	NA.	NA. Stand-by energy is provided by competitive or default service providers.
OR	PGE	The electric sector has been restructured. Delivery service is provided by regulated distribution companies. Electricity is supplied by competitive or default service providers.	To all partial requirements customers.	Delivery and generation (contingency reserves and energy)	Fixed monthly fee	1. Ratcheted monthly charge per kW of peak demand, to cover dedicated facilities. 2. Monthly as-used charge per kW of highest demand during on-peak hours in the month, to cover shared facilities.	Monthly per-kW spinning and supplemental reserve charges, assessed against load to be served during unscheduled outage (nameplate capacity of on-site generation or negotiated load)	Priced at hourly market rates per kWh, adjusted for wheeling, risk, and losses.
CA		The electric sector was restructured; however direct retail access was suspended in September 2001. Electricity is supplied by regulated utilities unless a customer had a contract in place prior to the suspension date.	Partial requirements customers that do not qualify for size and/or technology exemptions	Delivery only.	Fixed monthly fee	1. Ratcheted monthly reservation charge reflecting distribution infrastructure costs that don't vary with usage. 2. Volumetric rate based on actual usage that includes variable distribution costs including peak demand-related costs.	Utilities directed to develop an "electricity procurement rate option" to ensure generation capacity charges not bundled in standby rates.	Utilities directed to develop an "electricity procurement rate option" to ensure energy charges not bundled in standby rates.
HI	County of Maui proposal for MECO	Vertically integrated utility	To all partial requirements customers.	Delivery and generation	Fixed monthly fee	Yearly charge per kW of stand-by load to cover 50% of T&D costs (can include ancillary services provided at all times).	Daily as-used charge per kW of demand, to cover remaining demand-related costs. As an option, "best efforts" service, under which stand-by service is provided only if capacity is available.	Charge per kWh to cover variable costs of supplying energy.

2.4.1. California

The State of California has multiple policies that apply to facets of ratemaking for DG and CHP. The policies address standby charges and exit fees for a variety of DG types. Overall, the policies are designed to encourage the installation of clean, customer-sited DG by giving favorable rate treatment to technologies that meet specified performance standards.

The CPUC has a policy on backup and standby rates for DG. In October 1999, the CPUC initiated a rulemaking on DG, R.99-10-025. The purpose of the rulemaking was to develop specific policies and rules to facilitate the deployment of DG in California. The policy goals for the rates portion of the proceeding were:

1. To provide for fair cost allocation among customers
2. To allow the utility adequate cost recovery while minimizing costs to customers
3. To facilitate customer-side DG deployment
4. To send proper price signals to prospective purchasers of DG.[49]

The commission issued its Interim Decision Adopting Standby Rate Design Policies, D.01-07-027, on July 12, 2001.[50] This decision provided general policy guidelines and guidance regarding standby rate design for DG and CHP. The commission adopted the decision on an interim basis in recognition of the possibility that other policy decisions and events in the electric sector might necessitate changes to the rate design policy.[51]

In its decision, the commission determined that "most of the distribution system costs to serve standby customers appear to be fixed in nature."[52] These fixed costs include facilities-related costs such as poles and wires, which are independent of usage in the short term. The commission also recognized that certain infrastructure costs are variable, such as substation capacity and transformation costs. However, the record was not sufficient to specify which costs are fixed and which are variable.[53] Although the distinction is hard to draw based on available information, the commission stated that both types would be low for a customer that provides "physical assurance" (the immediate reduction of all or part of the load served by the customer's generation when that generation is not operating).[54]

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[49] CPUC. *ALJ Scoping Ruling, R.99-10-025*. April 14, 2000.

[50] CPUC. *Decision 01-07-027, Interim Decision Adopting Rate Design Policies*, *R.99-10-025*. July 12, 2001.

[51] *Id.*, p. 5.

[52] *Id.*, p. 57.

[53] *Id.*, p. 58.

[54] *Id.*, p. 58.

Accordingly, a customer should be able to contract with a utility for a specified capacity for which it will provide physical assurance.[55] The customer "should not pay standby charges designed to recover the fixed costs associated with distribution service for the amount of capacity it provides to the utility with physical assurance."[56] The commission determined that financial penalties would not be sufficient to enable customers to enjoy reduced standby rates.

The commission distinguished among three types of standby service—supplemental, backup, and maintenance—and stated that standby rates should reflect the different costs associated with these types of service. Supplemental service, which supplies the portion of a customer's load that is not regularly supplied by the DG unit, is no different from full-requirements service and should be priced according to the customer's otherwise-applicable tariff.[57] The commission characterized backup and maintenance service as intermittent services. The commission concluded that backup demand, which is by nature unanticipated, results in higher costs than maintenance service, which can be scheduled in advance to avoid peak demand times. Although the commission recognized that diversity of DG installations on a distribution circuit can affect distribution costs, the record was insufficient to determine the degree of diversity that exists today. The commission directed electric utilities to provide information about diversity in their standby rate filings.

Because of its goal of cost-based rates, the commission rejected proposals for usage-only standby rates as well as reservation fee-only rates.[58] The CPUC provided utilities the option, but not the obligation, to provide interruptible service or non-firm standby rates. The CPUC determined that rates should be based on embedded costs rather than incremental costs. The commission adopted the Independent Clean Energy Tariff (ICE-T) that exempts from any new or additional demand, standby, customer, minimum monthly, and interconnection charges any solar generating facility up to 1 MW that does not export power to the grid and is ineligible for net metering. The CPUC directed utilities to file standby rates within 60 days; however, the commission subsequently directed utilities to file standby rates within their next general rate case.[59]

In 2001, the California legislature established a short-term policy pertaining to standby charges for onsite generation. The policy exempted most onsite generators 5 MW or smaller that went into operation between May 1, 2001, and June 1, 2003, from standby charges for at least 10 years.[60] Diesel generators are not eligible for the exemption.

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55 The CPUC defines "physical assurance" as "the application of devices and equipment that interrupt a distributed generation customer's normal load when the distributed generation does not operate." D.01-07-027. July 12, 2001; p. 79.

56 CPUC. *Decision 01-07-027, Interim Decision Adopting Rate Design Policies, R.99-10-025*. July 12, 2001; p. 81.

57 *Id.*, page 60.

58 *Id.*, p. 64ff.

59 CPUC. *Decision 02-09-037*. Sept. 20, 2002.

60 To obtain the exemption, the onsite generator must be 5 MW or smaller, use a fuel other than diesel, comply with emissions standards established by the California State Air Resources Board, and meet other criteria. Gas-fired generators that do not operate in a CHP application must commence commercial

The commission extended the exemption in D. 03-04-060 "The Standby Charge Exemption" in Rulemaking (R.) 99-10-025 on April 17, 2003. This decision extended a waiver of standby charges for two categories of DG sized 5 MW or smaller:

1. Renewables and CHP (as defined in D. 02-10-062) installed between May 2001 and Dec. 31, 2004
2. Ultra-clean DG units [as defined in PUC Code 352.2(a)] installed between Jan. 1, 2003, and Dec. 31, 2005.

Pursuant to this decision, the above resources would be served under the same rates as customers with similar load profiles that do not install DG. The commission has also exempted certain DG customers from paying exit fees or "cost responsibility surcharges." In April 2003, the CPUC created an exemption for certain DG resources based on their emissions characteristics.[61]

All three regulated electric companies have filed general rate cases. The CPUC approved San Diego Gas and Electric's Settlement of Rate Design Window issues in D.04-04-042, April 22, 2004. The commission approved Southern California Edison's settlement of revenue requirement allocation and rate design in D.05-03-022, March 17, 2005. PG&E submitted a settlement in Phase 2 of its general rate case (A. 04-06-024) on May 13, 2005. The commission is currently considering that settlement.[62]

2.4.2. Massachusetts

In June 2002, the Massachusetts Department of Telecommunications and Energy (DTE) opened Docket DTE 02-38, an investigation into regulatory policies for DG. The scope of the investigation was broad, but among the key issues were:

> … (1) the development of interconnection standards and practices that do not threaten the reliability or safety of existing distribution systems, but also do not present undue barriers to the installation of distributed generation; (2) the appropriate method for the calculation of standby or backup rates and other charges associated with the installation of distributed generation; and (3) the appropriate role of distributed generation in distribution company resource planning.[63]

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operation no later than Sept. 1, 2002. The specific requirements are set out in Section 351.1 of the California Public Utilities Code. The legislation is SB X1 28 (Stats 2001, Chap. 12).

[61] CPUC. Opinion on Cost Responsibility Surcharge Mechanisms for Customer Generation Departing Load, R.02-01-011. April 3, 2003.

[62] California Public Utilities Roadmap. September 2005.

[63] Docket DTE 02-38, *Investigation by the Department of Telecommunications and Energy on its own Motion into Distributed Generation*. Order of June 13, 2002; p. 2.

The docket focused primarily on interconnection issues. In January 2004, NSTAR Electric—which serves Boston, Cambridge, and other areas in eastern Massachusetts—filed its own standby tariffs for large- and medium-sized commercial and industrial customers with onsite generation. This filing triggered Docket DTE 02-121. A month later, in an order on interconnection in DTE 02-38, the DTE stated that, in the NSTAR standby rate case, it would consider, among other things:

> … whether: (1) a distribution company should recover its costs through fixed or variable charges; (2) standby rates should reflect embedded or incremental costs; and (3) a distribution company should offer firm and non-firm standby service.[64]

On June 4, 2004, NSTAR, the Massachusetts Division of Energy Resources, and other interested parties submitted a joint motion for approval of settlement agreement and an offer of settlement agreement ("settlement").[65] The settlement resolved outstanding issues among the signatories and proposed a set of standby rates for NSTAR. It was approved by the DTE a month later,[66] and the rates went into effect in August 2004.

The electric industry in Massachusetts was restructured in the late 1990s, and the state's distribution companies no longer provide integrated generation and delivery services. NSTAR's standby tariff is for delivery service only; energy is purchased from default service or competitive providers. In defending the settlement, NSTAR stated that the proposed rates were based on the same cost-of-service study that was used to establish the current rate schedules for all other classes of service. The company argued this was appropriate.

> Because the distribution company must construct its circuits to be of sufficient size to meet the peak load of the internal requirements of all customers (including those with self-generation in the event the self-generation is not available), the Company builds its distribution system no differently to serve its continuous-load customers or customers with self-generation. Accordingly, the Company designed its proposed standby rates to reflect the same level of cost recovery for standby service based upon the same cost-of-service study as is reflected by the otherwise applicable continuous-service rate schedules.[67]

The DTE accepted these arguments and approved the settlement. No study was performed to test the premise that the delivery cost characteristics of partial-requirements customers are indistinguishable from those of full-requirements customers.[68]

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64 Massachusetts DTE. Docket D.T.E. 02-38-B. Order of February 24, 2004; p. 37–38.

65 Joint Motion for Approval of Settlement Agreement and the Settlement Agreement entered into by Boston Edison Company, Cambridge. Available at http://www.mass.gov/dte/catalog/7206.htm.

66 Docket DTE 03-121. Order of July 23, 2004.

67 Docket DTE 03-121, Reply Comments of NSTAR Electric on the Settlement Agreement. June 18, 2004; p. 15 (citations to the record omitted).

68 Docket DTE 03-121. Order of July 23, 2004; p. 38–39.

NSTAR's tariff for customers with onsite generation has two basic components. The first is firm standby delivery service with two charges: a fixed monthly customer charge (equal to that in the otherwise-applicable tariff) and a recurring contract demand charge. The second is supplemental delivery service. It covers that portion of the customer's load not served by onsite generation, and it is taken under the otherwise-applicable tariff, which makes use of a monthly as-used demand charge. No scheduled maintenance service is offered.

The contract demand charges are set "equal to the generating capability or the expected output of the Customer's Generation Unit(s), but shall not exceed the Customer's maximum internal load."[69] Although there are conditions under which the contract demand increases or decreases (e.g., it is set at the maximum actual output of the generation in that month or the 11 months preceding), the general requirement is, in effect, a 100% ratchet.[70] In contrast, there is no ratchet under the corresponding tariff for full-requirements customers (Rate G-3); instead, charges are assessed against each month's peak demand as it occurs in specified hours of the day (i.e., morning to evening on weekdays).[71] The standby contract demand charges, like the full-requirements demand charges, vary by season. They are higher during the peak summer months of June through September.[72]

As an alternative to company-determined contract demand, a customer may ask to negotiate a special contract under which the customer can specify, or "nominate," the level of its contract demand. There is no guarantee the request will be granted, however. If a contract is signed, it must be filed with and approved by the DTE. If the customer and the company cannot reach an agreement, the customer is free to file a petition with the DTE.[73]

There is also a non-firm service alternative to firm standby. Non-firm service is provided as an option upon request by a customer through a separate contract that specifies terms of interruption. In this service, standby service is provided when local distribution capacity is available. When distribution capacity is not available, the customer under this service must forego or interrupt its demand for standby service. NSTAR will bill the customer:

> … the monthly standby customer charge and the demand and energy charges under the otherwise applicable rate schedule on an "as-used" basis for any distribution service actually taken.[74]

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69 DTE 03-121, "Rate Per Month" section in *Compliance Filing Tariffs*. July 29.

70 This is, presumably, one reason no scheduled maintenance service is offered. The tariff assumes there are no distribution capacity costs to be avoided through the scheduling of delivery at off-peak times. Another is that, because NSTAR does not provide generation services, there is no low-cost, off-peak energy to offer either.

71 The absence of a ratchet for full-requirements customers has two effects. The first is that it spares customers a year-long financial penalty for a spike in their demand. The second is that it encourages them to shift loads to off-peak periods.

72 Docket DTE 03-121, Reply Comments of NSTAR Electric on the Settlement Agreement. June 18, 2004; p. 6.

73 Docket DTE 03-121, *Compliance Filing Tariffs.* July 29, 2004.

74 *Id*.

Customers with specified types of onsite generation are exempt from the new standby tariff and will take service under the applicable full-requirements tariff. This includes:

- Onsite generation whose capacity is less than or equal to 250 kW
- A combination of onsite generation units whose aggregate capacity is 251–1,000 kW and that serve less than 30% of the customer's internal electric load
- Renewable technologies as defined in Massachusetts law, with the exception of certain fuel cell units that primarily use natural gas
- Any onsite generation that came online before January 2005 and any public school-sited generation that comes on line before January 2006.[75]

Table 2 provides the prices for firm standby service under NSTAR's Rate SB-3.

Table 2. NSTAR Rate SB-3 (Delivery Only)

Customer Charge, per Month	As Per Applicable Rate Schedule	
Monthly Distribution Charge, per kW	October–May	June–September
Contract Demand <1,000 kW	$ 3.58	$ 6.65
Contract Demand ≥1,000 kW	$ 5.02	$ 9.33
Transmission	No charge	
Transition	No charge	

Massachusetts Electric Co., a National Grid company, does not have a separate tariff for standby service. Customers with onsite generation take service under the tariffs that would otherwise be applicable to them. Western Massachusetts Electric Co. (WMECO), a subsidiary of Northeast Utilities, does have a standby tariff. In its general features, it resembles that of NSTAR: It provides for firm backup and supplemental delivery services. WMECO's firm backup service is notable in that its demand charges are applied on a monthly as-used basis (i.e., not ratcheted). The rate, however, is not available to new applicants after Sept. 17, 1999. The absence of a replacement tariff indicates that new customers receive backup service under the applicable full-requirements tariff.[76]

[75] *Id*.

[76] WMECO Schedule PR.

2.4.3. New York

The PSC of New York has used a combination of generic proceedings and utility-specific proceedings to develop its policies. The PSC adopted interconnection standards for small DG units in 1999.[77] In 1999, the PSC opened a generic proceeding in response to complaints from independent power producers that standby rates were unduly high and should instead be cost-based using a uniform method across the utilities in New York. The commission approved Guidelines for the Design of Standby Service Rates, which established state-wide guidelines on the design of standby rates, on Oct. 26, 2001.[78]

Subsequently, the commission approved "joint proposals" for standby tariffs in compliance with the Standby Rate Guidelines from six electric companies in 2002 and 2003.[79] On Jan. 23, 2004, the commission refined its policies on the phase-in period for DG to shift to full standby service rates and DG criteria related to exemption from standby rates in utility-specific proceedings.[80] Standby tariffs established by all utilities are now approved by the commission.

The PSC has also been investigating issues associated with integrating DG into distribution system planning. In Case 00-E-0005 – Proceeding on Motion of the Commission to Examine Costs, Benefits, and Rates Regarding Distributed Generation, the commission directed utilities to conduct a 3-year pilot program starting in 2001.[81]

In May 2003, the commission initiated another DG-related proceeding, Case 03-E-0640.[82] This proceeding investigates whether current electric delivery tariffs present disincentives to DG, renewable technologies, or energy efficiency. The commission seeks to align current rate incentives and delivery rate structures with policy goals—such as the promotion of energy conservation, renewable energy, and DG—that it has pursued over decades.

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[77] New York PSC. *Opinion No. 99-13, Case 94-E-0952, Competitive Opportunities for Electric Service*. Dec. 31, 1999.

[78] New York PSC. *Case 99-E-1470, Opinion No. 01-04, Opinion and Order Approving Guidelines for the Design of Standby Service Rates*. Oct. 26, 2001.

[79] New York PSC.

- *Case 02-E-0551, supra, Order Establishing Electric Standby Rates*. July 29, 2003.
- *Case 02-E-0779, supra, Order Establishing Electric Standby Rates*. July 30, 2003.
- *Case 02-E-0780, et al., supra, Order Establishing Electric Standby Rate*. July 29, 2003.
- *Case 02-E-1108, supra, Order Establishing Electric Standby Rates*. Dec. 4, 2003.

[80] New York PSC. *Order Directing Modifications to Standby Service Tariffs*. Cases 02-E-0551 et. al. Jan. 23, 2004.

[81] New York Public Service Commission, Case 00-E-0005, Opinion No. 01-5, *Opinion and Order Approving Pilot Program For Use of Distributed Generation in the Utility Distribution System Planning Process,* October 26, 2001.

[82] New York PSC. *Case 03-E-640, Order Instituting Proceeding, Proceeding on Motion of Commission to Investigate Potential Electric Delivery Rate Disincentive Against the Promotion of Energy Efficiency, Renewable Energy, and Distributed Generation*. May 2, 2003.

Three of the most interesting aspects of standby tariffs in New York are the:

- Design of standby rates (fixed contract demand charge and as-used daily demand) and rejection of establishing supplemental and maintenance charges
- Standby rate applicability and exemption and phase-in policies for certain DG customers
- Treatment of revenue loss and gains associated with DG installation.

The guidelines state that standby rates must reflect the cost of serving the standby customer and "should provide neither a barrier nor an unwarranted incentive" to DG customers.[83] New York IOU's did not conduct new cost-of-service studies to establish standby tariffs; instead, New York IOUs set their standby tariffs based on recent cost-of-service studies. The commission determined that:

> … [p]ending appropriate cost of service analyses, costs now allocated to each standard service classification … serve as the basis for the design of class-specific, revenue-neutral, standby service delivery charges.[84]

Although several stakeholders argued that benefits of DG, such as low emissions and reduced line congestion, should be considered in standby rates, the commission determined that public policy values or benefits to utilities from DG were extraneous to the development of standby delivery rates and should be considered and applied, if appropriate, in the context of a utility's distribution planning process.[85] Nevertheless, the commission approved exemption and phase-in policies for small DG as well as renewable energy-based DG to recognize the benefits of those DG units (see description below). Further, the commission later argued that "the economic 'benefits' of reduced or avoided utility delivery system costs are reflected in the standby rates" in the form of on-peak, as-used demand charges that reflect "the lower cost responsibility of standby customers for service classification coincident peak loads."[86]

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[83] New York PSC. *Opinion No. 01-4, Opinion and Order Approving Guidelines for the Design of Standby Service Rates*. Oct. 26, 2001; p. 11.

[84] *Id.;* Appendix A, p. 2.

[85] New York PSC. *Opinion No. 01-04*. Oct. 26, 2001; p. 27

[86] *Id.*, p. 11.

Standby rates in New York include a customer charge; a fixed, contract demand charge; and a variable, daily as-used demand charge. Standby costs are recovered through per-kilowatt charges based on the standby customer's demand "because the local costs of providing delivery service correlate with the size of the facilities needed to meet the generating customer's maximum demand for delivery service."[87] The contract demand charge recovers the costs of local facilities that are "attributed exclusively or nearly exclusively to the customer involved."[88] Costs associated with "shared" facilities are recovered through a daily as-used demand charge, which applies to the customer's daily maximum metered demand that occurs during the utility's system peak periods.[89]

Table 3 shows examples of this allocation by four IOUs as presented in their joint proposals. It is important to note that several stakeholders complained that the percentage currently set for shared facilities is still too small and the amount of fixed, contract demand charge is too high.

Table 3. Percent of Contract Demand/Percent of As-Used Demand for Utilities in New York

Utilities	System Facilities	Secondary Customers	Primary Customers	Substation Customers	Transmission Customers
O&R Standby Service	Secondary	100%/0%			
	Primary	50%/50%	75%/25%		
	Substation	0%/100%	50%/50%		
	Transmission	0%/100%	0%/100%	25%/75%	25%/75%
Con Edison Standby Service	Secondary	75%/25%*			
	Primary	25%/75%*	75%/25%	100%/0%**	
	Substation	0%/100%	50%/50%	100%/0%**	
	Transmission	0%/100%	0%/100%	25%/75%**	
NYSE&G Standby Service	Secondary	100%/0%			
	Primary	75%/25%	75%/25%		
	Substation	25%/75%	50%/50%	75%/25%	
	Transmission	0%/100%	15%/85%	15%/85%	15%/85%
Central Hudson Standby Service	Secondary	100%/0%			
	Primary	75%/25%	90%/10%		
	Substation	50%/50%	75%/25%	90%/10%	
	Transmission	0%/100%	9%/91%	7%/93%	10%/90%

*Con Edison has a larger percentage in the shared facilities than other utilities. This is because its jurisdiction has more secondary network distribution systems (in which a large number of customers share a distribution system) than other jurisdictions.[90]
**Includes only 138-kV facilities for "138 kV and above" customers

[87] *Id.*, p. 12.

[88] *Id.*, p. 13.

[89] *Id.*, Appendix A. p. 4.

[90] Personal contact with Chris Young at Pace Energy Project on Dec. 1, 2004.

Customers can either set the contract demand level themselves or accept the contract demand level determined by their utility. The contract demand level includes a ratchet regardless of which party sets the customer's contract demand.[91] If the utility sets the contract demand level, customers do not pay a surcharge when their demand exceeds it. However, at least one company requires customers to notify the company of installation or removal of equipment that could change demand significantly (e.g., more than 12.5%).[92] Customers who set the contract demand level and subsequently exceed it incur a significant penalty. In the case of Con Edison and O&R, if the excess is 10%–20%, the penalty is 12 times the applicable contract demand charges for the excess demand.[93] If the excess is more than 20%, the penalty is 24 times the applicable contract demand charges for the excess demand.[94] Other utilities charge penalties for excess even less than 10%.[95] Customers who set their contract level can reduce it once every 12 months if they can demonstrate that:

> ... electricity-consuming equipment is removed or abandoned in place, or permanent energy efficiency or load limiter equipment is installed, based on an engineering analysis submitted to the utility.[96]

The contract demand level by the utility will be the customer's maximum total demand that reflects all sources, including the utility's system and DG units. This contract demand will be adjusted upward or downward if there is any permanent change to the customer's electrical load because of changes in equipment. This adjustment is made by the utility's engineering analysis and information the customer provides. Customers and a utility may enter into an individually negotiated agreement under certain conditions (such as economic isolation from the grid, physical isolation from the grid, or sale of 90% to the market or a third party), provided that the negotiated agreement provides a reasonable contribution to the recovery of fixed costs.[97]

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91 New York PSC. *Case 02-E-0780 et. al., Order Establishing Electric Standby Rates*. July 29, 2003; p. 11, Attachment A, pp. 4–5.

92 NYSE&G, SC 11, Leaf 290.

93 New York PSC. *Case 02-E-0780 et. al., Order Establishing Electric Standby Rates*. July 29, 2003; p. 11; Attachment A, p. 4; O&R's service classification No. 25, leaf No. 133; Con Edison's service classification No. 14-RA, leaf No. 139.

94 Ibid.

95 See O&R SC No. 25, Con Edison SC No. 14-RA, RG&E SC No. 14, Central Hudson SC No. 14, NYSE&G SC No. 11,Niagara Mohawk SC No. 7.

96 New York PSC. *Case 02-E-0780 et. al., Order Establishing Electric Standby Rates*. July 29, 2003; p. 11; Attachment A, Joint Proposal by Con Edison and O&R, p. 5. Also see the tariffs mentioned above. Note that Niagara Mohawk's standby tariff does not specify how to demonstrate the reduced contract demand.

97 Quote from Con Edison's service classification No. 14-RA, leaf No. 180 C; the same rules can be found in all IOUs' standby tariffs mentioned above.

The commission does not differentiate, as others do, among types of standby service for partial-requirements customers. The commission denied a proposal for a split rate containing a supplemental charge and a backup charge on the ground that:

> … [t]he Guidelines provide cost-based delivery service rates that apply to the entire delivery service taken by a customer with an OSG regardless of whether the OSG serves all or only a portion of that customer's load.[98]

The commission rejected Niagara Mohawk's proposal to establish additional charges for scheduled maintenance because it reasoned that the cost of building and maintaining delivery facilities does not vary according to whether an outage is scheduled or unscheduled. Otherwise, the commission stated, "adequate energy supply, including a customer's discretionary importation of lower cost off-peak energy during a scheduled outage, cannot be delivered."[99] Customers with a DG unit larger than 1 MW are still required to notify the utility of its annual schedule of planned maintenance outages.

The commission has approved exemption and phase-in provisions for small customers and clean DG technologies. The commission agreed to approve the exemption and phase-in policies proposed by various stakeholders because:

1. There are possible public benefits associated with diverse generating technologies.
2. Exemptions and phase-in policies are in non-cost criteria and adjuncts to the cost-based rate design.
3. The standby rate guideline presupposes that remedial action may be taken "if justified upon a party's showing that a standby rate unintentionally creates 'a barrier' to OSG."[100]
4. Such policies can "safeguard against unduly harsh impacts on the affected customers or industries during the initial transition to standby rates."[101]

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[98] New York PSC. *Opinion No. 01-4*. Oct. 26, 2001; p. 21–22. Also see New York PSC. *Case 02-E-0780 et. al., Order Establishing Electric Standby Rates*. July 29, 2003; p. 11; Attachment A, Joint Proposal by Con Edison and O&R, pp. 21–22.

[99] New York PSC. *Case 01-E-1847, Order Clarifying Prior Order and Directing Tariff Modifications*. Jan. 13, 2003; p. 12.

[100] New York PSC. *Case 02-E-0780 et. al., Order Establishing Electric Standby Rates*. July 29, 2003; p. 17.

[101] *Ibid.*

Customers with demand metering and a contract demand less than 50 kW, as well as all non-demand metered customers, can be exempt from standby tariffs in New York.[102] However, most utilities provide a time limit and customer number limit for new, small, non-demand metered customers to be exempted from standby rates. The commission and utilities will review the effect of exemptions at the periods when such limits are reached and may discontinue the exemptions.[103]

Table 4. Time Limit and Customer Limit for Small Customer Exemption in New York

	Time Limit	Customer Limit
Con Edison[104]	May 31, 2006	15,000 customers
O&R[105]	May 31, 2006	1,500 customers
NYSE&G[106]	Jan. 1, 2007	200 customers on east of Total East or 250 customers on west of Total East
RG&E[107]	Jan. 1, 2007	150 customers
Central Hudson[108]	A review is initiated in Case 02-E-0780/1	100 customers

Furthermore, all IOUs except Niagara Mohawk provided an exemption to standby customers whose onsite generation provides no more than 15 % of the customer's maximum potential demand.[109] In the case of Niagara Mohawk's standby tariff, customers with onsite generation that provides less than 15% of their maximum potential demand must pay contract demand charges according to the nameplate capacity of the generation.[110]

Existing OSG customers have the option of an 8-year phase-in to the full standby rates or paying the full standby rates as of the date the rates take effect. Existing OSG customers are defined as customers whose OSG facility had achieved certain milestones by January 2003.[111]

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102 New York PSC. *Opinion No. 01-4*. Oct. 26, 2001; p. 9.

103 Although several tariffs mention utilities will discontinue exemptions at a certain time, the commission mentions in the Standby Rate Orders that it and utilities will examine the effects of the exemption and determine whether to discontinue it.

104 New York PSC. *Case 02-E-0780 et. al., Order Establishing Electric Standby Rates*. July 29, 2003; p. 19.

105 *Ibid.*

106 O&R SC No. 25, leaf No. 137.

107 NYSE&G SC No. 11, leaf No. 294.1.

108 Central Hudson SC No. 14, leaf No. 272.1.

109 O&R SC No. 25, leaf No. 137; Con Edison SC No. 14-RA, leaf No. 174; RG&E SC No. 14, leaf No. 237; Central Hudson SC No. 14, leaf No. 272; NYSE&G SC No. 11, leaf No. 282.

110 Niagara Mohawk SC No. 7, leaf No. 106-J.

111 New York PSC. *Order Directing Modifications to Standby Service Tariffs, Cases 02-E-0551 et. al.* Jan. 23, 2004; p. 4.

Customers with "designated technologies" have three options:

1. Exemption from standby charges if they entered service after June 29, 2003, and before May 1, 2006
2. An 8-year phase-in
3. A move to the new standby charges.

Designated technologies are generally fuel cells, wind turbines, solar thermal installations, photovoltaics, and sustainably managed biomass, tidal, geothermal, or methane waste units.[112] In addition to these renewable energy technologies, designated technologies include small, efficient CHP that meets certain efficiency, emissions, and capacity criteria.[113]

The commission's decisions include provisions for addressing revenue losses and gains resulting from the standby rates. For example, the most recent order by the commission on Central Hudson's standby rates, issued December 2004, contains the following provision for allocating gains and losses between shareholders and customers:

> In any 12 month period ending June 30 in which the algebraic sum of the monthly net differences exceeds $75,000, the amount above $75,000 will be treated as shown in the table below [where the return on equity (ROE) is "post-sharing" under the existing rate plan].[114]

Table 5. Allocation of Gains and Losses – Central Hudson, New York

	ROE Less Than 11.3%	ROE 11.3%–14.0%	ROE greater than 14.0%
Standby Revenue Gain	100% of gain to shareholders	50% to shareholders, 50% to customers	100% of gain to customers
Standby Revenue Loss	100% recovery from customers	50% recovery from customers, 50% borne by shareholders	100% borne by shareholders

[112] New York PSC. *Case 02-E-0780 et. al., Order Establishing Electric Standby Rates*. July 29, 2003; Attachment A, Joint Proposal by Con Edison and Orange & Rockland Utilities, p. 11.

[113] New York PSC. *Order Directing Modifications to Standby Service Tariffs, Cases 02-E-0551 et. al.* Jan. 23, 2004.

[114] See page 9 of the joint proposal by Central Hudson under Case 02-E-1108.

2.4.4. Oregon

In 2004, the Oregon Public Utility Commission approved a settlement on Portland General Electric Co.'s (PGE's) tariffs for partial-requirements customers. In the wake of the state's industry restructuring, Oregon's electric rates have been fully unbundled. Generation, transmission, and distribution services are all priced separately, and each generates revenues to cover its full embedded costs of service.

Under the settlement, partial-requirements customers, like all others, pay the full charges for distribution investments dedicated solely to them. These are recovered in a monthly per-kilowatt demand charge assessed against what is called "facility capacity," which is the average of the two greatest non-zero monthly demands established during the 12-month period that includes and ends with the current billing month. (The minimum facility capacity is the customer's demand for grid—i.e., supplemental—power when the onsite generator is operating.) The costs of shared distribution and transmission facilities are paid according to the probability of the average customer in the large non-residential class causing new investment. These, too, are recovered in monthly per-kilowatt demand charges, but they differ in that they are assessed against the customer's on-peak monthly demand (which may or may not equal facility capacity). Peak hours are between 6 a.m. and 10 p.m. Monday through Saturday.[115] With one small (one penny) exception for the shared distribution facilities charges, the several T&D fees are essentially the same for partial- as for full-requirements customers.[116]

Where the PGE settlement is innovative is in its treatment of standby generation capacity. The load served by the onsite generation is treated in the same manner as any other load on the system, which, under Oregon rules, is obligated to have (or contract for) its share of contingency reserves. The onsite generation is, in effect, both contributing to and deriving benefits from the system's overall reserve margin. The PGE tariff differentiates between two types of contingency reserves: the spinning reserves needed to instantaneously serve the load that is exposed when the onsite generation fails and the supplemental (or "10-minute") reserves that will come online shortly thereafter.

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[115] Shared T&D costs that are covered in monthly, rather than daily, as-used demand charges were not uncontroversial. Arguments in favor of daily as-used demand charges, as in New York, were made, but PUC staff did not believe there were sufficient numbers of or diversity among customers with onsite generation to justify such a rate design. (Communication with Lisa Schwartz, Oregon PUC staff, Feb. 11, 2005.

[116] PGE schedules 75 and 83; pre-filed testimony of Ted Drennan and Lisa Schwartz, Oregon PUC Docket UE-158, June 28, 2004. The one difference between the partial- and full-requirements T&D charges is the calculation of monthly demand. The partial-requirements tariff uses the highest monthly on-peak demand, whereas the full-requirements tariff simply uses the highest monthly demand. *Id*.

Under the new rates (a similar pricing package is under development by PacifiCorp, the state's largest IOU), the partial-requirements customer must pay or contract for contingency reserves equal to 7% (3.5% each for spinning and supplemental reserves) of the "reserve capacity" (i.e., either the nameplate capacity of the onsite unit or, in the alternative, of the load it does not want to lose in case of an unscheduled outage). (If the customer is able to shed load at the time its unit goes down, it will be able to reduce the contingency reserves it must carry).

To simplify billing, the monthly demand fees for the two reserves are equal to 3.5% of their full cost. There are separate charges for the two types of reserves, but the charges are the same. All but the first 1,000 kW of reserved capacity required for customers with onsite generation is subject to the contingency reserve charges. The charges for the contingency reserves are multiplied by the reserve capacity. Mathematically the effect of this approach is the same as multiplying the full charges for the reserves by 3.5% of the needed capacity. If the customer so chooses, it may forego purchasing contingency reserves from PGE and, instead, purchase them from other providers in the market.

The actual energy received under unscheduled service is priced at an indexed hourly wholesale price that is adjusted for wheeling, risk (to compensate PGE for any differences between the actual and indexed prices), and losses.

Electric needs in excess of the demand served by the onsite generator are provided under the applicable full-requirements tariff. Maintenance service is also available for up to 744 hours per year. It must be scheduled at least 30 days in advance. The timing and demand will determine whether incremental monthly as-used T&D charges will be incurred.

The effect of the PGE rate design is to give the partial-requirements customer a strong financial incentive to operate its onsite generation, particularly during on-peak times. The energy charges and the charges for shared T&D facilities—significant portions of the cost of standby service—are avoidable through the reliable operation of the onsite generation. The costs of dedicated distribution facilities and contingency reserves are, in effect, access fees and, as they cannot be avoided by the full-requirements customer, neither can they be by the partial.[117]

[117] We note, however, that the method by which revenues to cover the costs of contingency reserves are collected from partial-requirements customers differs from that for full. Whereas partial-requirements customers pay monthly demand charges for contingency reserves, the cost of contingency reserves for full-requirements customers is included in their energy prices. (Communication with Lisa Schwartz, Oregon PUC staff, Feb. 11 2005.)

Table 6. PGE Schedule 75, Partial-Requirements Service

	Delivery Voltage		
	Secondary	**Primary**	**Sub-Transmission**
Basic Monthly Charge			
Single-Phase Service	$20.00		
Three-Phase Service	$25.00	$150.00	$500.00
Transmission & Related Services			
Per Kilowatt of Monthly Demand	$0.78	$0.78	$0.78
Distribution Charges The Sum of the Following, per Month:			
Per Kilowatt of Facility Capacity	$2.27	$1.65	$0.32
Per Kilowatt of Monthly Demand			
First 30 kW	$0.56	$1.90	$1.06
More Than 30 kW	$1.90	$1.90	$1.06
Generation Contingency Reserves			
Spinning Reserves Per Kilowatt of Reserved Capacity >1,000 kW	$0.234	$0.234	$0.234
Supplemental Reserves Per Kilowatt of Reserved Capacity >1,000 kW	$0.234	$0.234	$0.234
System Usage Charge			
Per Kilowatt-Hour	$0.00485	$0.00354	$0.00257
Energy Charge			
Baseline Energy	Per Schedule 83		
Scheduled Maintenance, Max 744 Hrs/ Calendar Year	Daily or Monthly Fixed, per Schedule 83		
Unscheduled	Dow Jones Mid-Columbia Hourly Firm Electricity Price Index, plus wheeling charges and a $0.003/kWh recovery charge, and adjusted for losses		

2.4.5. Hawaii

The Hawaii PUC is in the midst of an investigation into DG and the policy actions it can take to promote the cost-effective deployment of such resources. Among the issues being tackled is ratemaking for partial-requirements customers. Of particular interest in the proceeding (briefs have been filed, and a decision is pending) is the proposal of the County of Maui (COM). COM has urged the PUC to establish cost-based standby rates that recover a small portion of the bundled (generation, transmission, and distribution) demand-related costs of standby resources through a yearly (or monthly) demand charge and the majority of those costs through a daily demand charge incurred when standby service is actually used. Variable costs would be recovered in a time-of-use energy charge. This approach is intended to fairly allocate the cost of standby resources among the many standby customers who can share the standby resources and capture the diversity benefits (i.e., the low probability of simultaneous or peak-coincident unscheduled outages) that they provide.[118]

COM argued, citing evidence provided by Hawaii Electric Co. (HECO, operating as Maui Electric Co. on that island), that it is flawed logic that holds that DG requires grid backup of equal capacity. Rather, contended COM, a well-developed DG industry, with tens or even hundreds of installations in a service territory, would require that each partial-requirements customer pay for only a small share of the total backup capacity held by the utility. Evidence in the record showed that the forced outage rate for CHP systems in HECO's territory is on the order of 5%. Consequently, COM argued that reserves equal to only 5% of the aggregate nameplate capacity (or firm standby load)[119] of all the partial-requirements customers need be held by the utility and that, therefore, each DG customer need only cover its share of the costs of that reserve.[120] The logic, the same as that underpinning the contingency reserves element of the PGE (Oregon) tariff (as well as any utility's own reserve planning), is that not every DG customer will suffer simultaneous failures, and therefore, the utility needs only a fraction of the total DG capacity in reserve to provide reliable service. This is the diversity benefit.[121]

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[118] County of Maui. *Brief, Docket 03-0371, In re Instituting a Proceeding to Investigate Distributed Generation in Hawaii*. March 7, 2005; p. 24

[119] By "firm," COM means the load that a customer would expect to be served by the utility during an unscheduled outage of the onsite generation, regardless of when it occurs.

[120] In addition, there would be scheduled outages for planned maintenance. COM proposed that the standby tariff require coordination of scheduled outages during off-peak times. In this way, the utility need only provide enough capacity to serve the expected forced outages at any point in time. COM Brief p. 26.

[121] *Id*., pp. 26–27. COM notes that there is also diversity at the transmission and distribution level and that it is a function of the number of partial-requirements customers served by a single transmission or distribution line. Pricing for these elements of standby service may need to be geographically differentiated given variations in numbers of DG customers and the sizes of individual backup loads.

COM proposed two options for standby service. The first was "firm" service, with the utility expected to plan for the statistical diversity of demand created by unexpected outages of DG systems. Given the assumption of a 5% forced outage rate on average, rates would be set so that each customer would pay for about 5% of the costs of the capacity used to provide backup service. Under COM's proposal, a small portion of this would be recovered through a monthly "reservation fee" per kilowatt of standby load (or nameplate capacity of the onsite generator) and the balance through daily as-used demand charges. Energy would be priced to recover the variable costs of production.

Specifically, the firm service would consist of:

- A capacity reservation charge

  This is a dollars-per-kilowatt-per-year charge that covers the costs of being connected to the utility, including net transmission and distribution capacity costs, that are customer-specific. This can include ancillary services that the utility provides at all times, such as spinning reserves. This should reflect the expectation that DG systems will bring transmission and distribution system benefits. It should be higher for customers served at secondary voltage than for those served at higher voltages. (COM recommended that, at least to start, this charge be set at 50% of the transmission and distribution charges already set in tariffs and thereby acknowledged that DG provides T & D diversity benefits.)

- An as-used daily standby demand charge

  This dollars-per-kilowatt-per-day charge covers the cost of the reserved generating capacity (calculated to reflect the diversity of the population of DG, as described above) that the customer actually uses. A customer that uses standby service 100 days per year pays five times as much under this approach as one that uses standby service only 20 days per year. Each standby customer therefore bears the cost of standby capacity in proportion to how often he uses it. This should be lower on days of the week and months of the year when demand is lower, and the utility does not need to reserve any otherwise-unneeded capacity to serve the diversified needs of standby customers (thus giving customers an incentive to schedule maintenance at such times).

- A standby energy charge.

  This is a dollars-per-kilowatt-hour charge that recovers the variable cost of the energy used by the standby customer. In New York, this is a real-time energy charge based on power pool dispatch conditions. In Hawaii, it would most logically be a time-of-use energy charge that is adjusted monthly for fuel costs.[122]

[122] Rebuttal testimony of Jim Lazar on behalf of the County of Maui. *Docket 03-0371, In re Instituting a Proceeding to Investigate Distributed Generation in Hawaii*. October 2004; pp. 18–21.

This rate design would:

1. Ensure that the utility fully recovered the costs of standby capacity without double-charging multiple customers for the same capacity
2. Provide an incentive for DG customers to schedule such things as oil changes at night or on weekends by allowing them to avoid a portion of the fixed standby costs
3. Ensure that those customers that use standby service many hours of the year make a larger contribution to the capacity costs than standby customers that take service only a few hours per year
4. Ensure that all standby power users pay the utility for the variable costs of their service.

The following is an example of the rate structure for firm service as COM proposed.[123]

Table 7. Illustrative Firm Standby Rate for Maui Electric Company

Standby Reservation Charge: (50% of T&D Cost)	$/kW/year	$32.88
As-Used Monday–Friday Daily Standby Demand Charge (100% of Remaining Demand-Related Costs/200 days/year)	$/kW/day	$0.98
As-Used Saturday–Sunday Standby Demand Charge	$/kW/day	$0.49
Standby Energy Charge (Computed Monthly Based on Current Fuel and Other Variable Energy Costs)	$/kWh	Monthly Variable Energy Costs

The second option was "best efforts" service, under which the utility provides service if it has generating capacity available. This service would be appropriate for loads that could be curtailed if necessary. Because the utility would not need to plan resources to serve a best efforts customer, there is no additional capacity cost required to make the service available. Even so, COM did not assert that the "best efforts" customer avoid capacity charges altogether. It argued instead that long-standing principles of ratemaking hold that any customer that uses utility capacity, at any hour, should make some contribution toward its costs. The reasoning is that the capacity has value to the customer, irrespective of its use at off-peak times, for which the customer should be willing to pay.[124]

[123] *Id*., p. 22.

[124] We add that this is especially true with respect to capacity whose costs were in part incurred to serve not peak demand but energy needs in other hours of the year (i.e., that portion of the cost that is in excess of the minimum cost of capacity). In support of its argument, COM cited Garfield and Lovejoy (Public Utility Economics. 1964; p. 163) and quoted Dr. Henry Herz, National Association of Regulatory Utility Commissioners Cost Allocation Committee: "All utility customers should contribute to capacity costs. The longer the period of time that a particular service pre-empts the use of capacity, the greater should be the amount of capacity costs allocated to that service. Service that can be restricted by the utility should be allocated less in demand cost as the degree of restriction increases." Rebuttal testimony of Jim Lazar, p. 24.

COM described such customers as "hitchhikers." It held that, as a matter of value and fairness, they should pay some portion of the costs of capacity they are using, even if their usage is not driving incremental investment. COM proposed that best efforts standby service be assessed one-fourth of the capacity cost assessed to a firm standby customer.[125]

In response to testimony of utility witnesses, COM suggested, in its brief, an alternative rate design that would meet the essential objectives of its original (and still preferred) proposal but would require only minimum changes to existing full-requirements tariffs (HECO Schedules J and P). This would have the advantage of simplicity because customers are familiar with the basic rate structure.

The COM alternative consisted of the following elements:

- A demand reservation charge equal to the Schedule J and P monthly demand charges

  These schedules recover a large portion (about one-third) of the fixed costs in energy charges, so they satisfy the goal of recovering only a portion of fixed costs in the (largely) unavoidable standby reservation charge. In addition, the demand ratchet should not apply, thereby giving partial-requirements customers a strong incentive to avoid standby service.
- Time-of-use energy charges designed to recover the remaining demand-related costs

  These time-of-use charges would replace HECO's "load factor" (in this case, declining) block rates. Under these rates, the majority of the demand-related costs should be recovered during the on-peak and mid-peak periods. A smaller portion would be recovered during the off-peak period.
- Time-of-use energy charges to recover the variable costs of service.[126]

COM argued that, like the original proposal, this rate design would ensure that those customers who cause a need for standby facilities (i.e., those increasing the utility's daytime loads) would pay the costs of those facilities. It would also ensure that the many customers sharing the standby facilities would also share their costs because each customer would pay for standby service on the days it uses it.

COM provided the following example of how the Schedule P rate could be converted: [127]

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[125] *Id.*, pp. 28–30.

[126] COM Brief, pp. 30–33.

[127] *Id.*, p. 32.

Table 8. Alternative Standby Rate Design for Maui Electric Company

Schedule P Rate Elements	Schedule P Rates (HECO, 2003)	Standby/TOU Rate Elements	Standby/TOU Rates
Demand Charge	$9.50	Demand Reservation Charge	$9.50
First 200 kWh/kW	$0.072	On-Peak kilowatt-hours	$0.095[128]
Next 200 kWh/kW	$0.064	Mid-Peak kilowatt-hours	$0.064
More Than 400 kWh/kW	$0.061	Off-Peak kilowatt-hours	$0.061
Energy	TOU charges/kWh	Energy	TOU Charges/ kilowatt-hour

COM also recommended that, if this alternative rate design is to be adopted, it be modified for a "best efforts" option. COM suggested that the same rate structure be used for best efforts service but that the demand reservation charge be reduced to one-half of the otherwise-applicable charge. The TOU energy-per-kilowatt charges would remain the same, as would the variable charges for energy. Under this approach, best efforts customers will impose no fixed costs on the utility but will contribute significantly to cost recovery of fixed costs. This will benefit non-participating ratepayers because these charges are used to offset costs that would otherwise be recovered from full-requirements service customers.[129]

[128] The on-peak charge is higher than the current charge for the first 200 kWh/kW because there are only approximately 90 on-peak hours per month (4 hours/day Monday–Friday). Because the same demand-related costs must be collected in a smaller number of hours, the rate must be higher.

[129] COM Brief, p. 33. COM also urged the Hawaii PUC to develop and implement a performance-based ratemaking mechanism as an alternative to traditional cost-of-service regulation, with the aim of breaking the link between utility sales and profits and thereby removing the utility's strong financial incentive to oppose deployment of customer-sited resources such as DG and end-use energy efficiency.

Pre-filed testimony of Jim Lazar on behalf of the County of Maui. *Docket 03-0371, In re Instituting a Proceeding to Investigate Distributed Generation in Hawaii*. July 2004; pp. 94–97.

3. Policy Issues

It might be flippant after 30 pages describing the arcana of electric utility rate design as it applies to customers with onsite generation to say that the debate, ultimately, comes down to money, but it would not be untrue. Across the states, the essential features of standby rates are the same, and what matters are the mechanics of their application and, more to the point, their absolute levels. The economics of DG are straightforward enough (setting aside reliability and other, less-quantifiable customer benefits): An installation will be cost-effective when it can displace grid-supplied service for less, *including the costs of standby*, than the cost of grid power.[130]

This does not diminish the import of a rate design. Rates structures can have profound effects on behavior—both of utilities and their customers—and the exercise should not be lightly dismissed. This review has revealed key areas of economic and policy debate that affect the outcome to this question. This chapter summarizes them and offers recommendations to address them.

3.1. DG Cost Causation

The question of cost causation—What are the nature and magnitude of the utility costs to serve partial-requirements customers?—is a fundamental debate among DG proponents, utilities, and regulators. Advocates argue that DG reduces demands on the system, improves overall reliability, and avoids new investment and operational costs. Utilities assert that DG has little or no effect on system planning and investment, particularly in the distribution system near the customer, where facilities still have to be sized to serve the customer's highest instantaneous loads, even if the frequency of their occurrence has been reduced by onsite generation.

There appears to be little dispute that the distribution facilities deployed to serve a single customer, sized to serve the potential maximum load of the customer, should be paid for by that customer.[131] Difficulty begins with shared facilities—wires, poles, transformers, and substations—that serve more than one customer. Traditional allocation methods rely on class contributions to coincident peak adjusted for, among other things, the mix of classes in areas of the system. How the standby requirements of customers with onsite generation affect the underlying costs defies easy generalization, particularly when there is not a significant penetration of DG on a system (or area of it).

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[130] Of course, a significant market niche for DG is supplying a particular kind of service—i.e., redundant DG to supply extremely reliable power—not available from the grid. Renewable energy is another product with a perceived quality that may not compete directly with grid power on the basis of price.

[131] Although the exceptions might be argued to swallow the rule, one of the oft-spoken principles of sound ratemaking is that the "cost causer should pay." The principle has the advantage of not only appearing fair on its face but also of avoiding the perverse results that can occur when the actor does not bear the cost responsibility for his actions—i.e., consumption of the good or service far in excess of what might be deemed economically efficient (assuming that all costs, internal and external, are reflected in price).

The argument that, in the aggregate, the load profiles of partial-requirements customers are reasonably similar to those of other customers in their classes has weight, although it may be more relevant with respect to facilities (e.g., transmission and central-station generation) whose characteristics are only marginally affected by the presence of customer-sited generation (i.e., benefiting more fully from the overall diversity of the system).[132] If so, what can one conclude about how rates should be set for DG customers? If they are no different from others of their class, though without DG, should they not pay the same rates? This, however, could subject them to ratchets—costly by virtue of the lower load factors of DG customers—and, moreover, fails to account for any benefits (such as avoided costs and improved reliability) that DG provides.

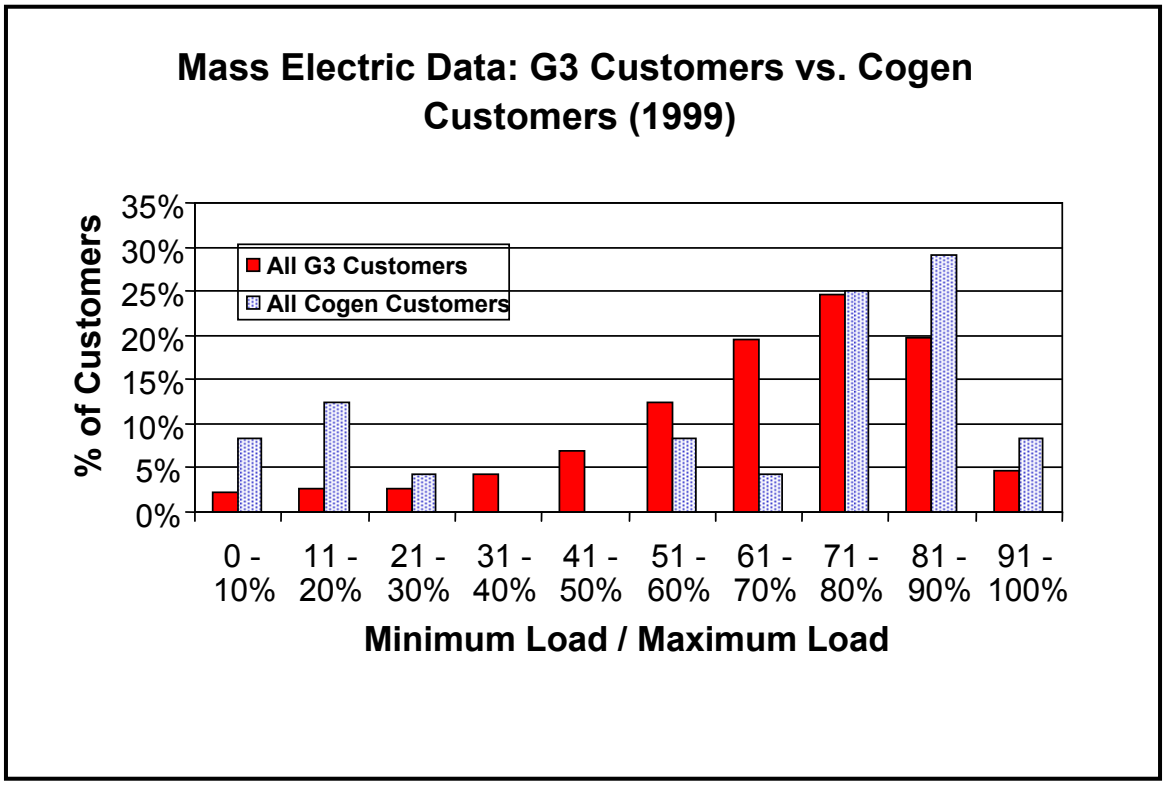

Figure 2. Class G3 customers versus cogeneration customers[133]

The debate about the cost-causative and cost-avoiding properties of onsite generation will not resolve itself easily without more empirical evidence on the performance of DG and its effects on the operations of, and investment in, the system. Even so, until such data are available, the probabilities of cost-causing and cost-saving events can be estimated for the purposes of ratemaking.

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132 This is, for instance, the logic implicit in the PGE standby rate design.

133 Casten, S. "NSTAR Proposed Standby Rate for Onsite Generators in MA Update on DTE Filing 03-121." Presentation to the Northeast Energy Commerce Association, 11th Annual Energy Conference. Boxborough, Mass., May 17, 2004.

3.2. DG Benefits

Traditionally, in the setting of fair and equitable rates for electric service, attention is given primarily to the costs incurred to provide the service because it is not generally the case that the taking of the service yields immediate and direct benefits (i.e., positive externalities) to other users of the grid.[134] However, customer-sited distributed resources have the potential to provide benefits to the system—through sales of excess energy to the grid, downward pressure on market prices, reduced loadings on stressed lines and substations, deferral or avoidance of distribution and transmission upgrades, diversity benefits, and the provision of reliability services—and, where those services are not in some manner valued and traded, it may be appropriate to recognize and credit them against the costs that standby prices cover.

Although the benefits of DG have been generally acknowledged by policymakers, methods for accounting for those benefits, in ratemaking as well as planning, are not yet well developed (with the exception of work conducted in California).[135] Nevertheless, many states provide exemptions or other favorable rate treatments based on anticipated benefits. These exemptions or special treatments are essentially a policy overlay on tariffs and justified by the broad expectation of public benefits, even though these benefits have not been quantified. Some states have also developed mechanisms for considering benefits for deferral of distribution system upgrades. One example of such an approach is de-averaged distribution credits or reduced charges for DG/CHP that defers or avoids higher-cost network investments in stressed, high-cost areas.

In its rulemaking on DG, the CPUC considers the question of a distribution-level diversity factor to set standby rates, and it notes stakeholder acceptance of the concept, though with utility admonitions that such factors accurately reflect DG's contribution to the utility's avoidance of distribution upgrades.[136]

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[134] For example, increased access to the telecommunications network (i.e., universal service) is seen as an overall benefit because it increases the number of people and businesses with which any one user can connect. Insofar as increased use of electricity is positively correlated with improved public health and safety, education, income, and a more stable society, it too provides external benefits. But this perspective is somewhat more narrowly constrained here. Also, some might argue that, insofar as increases in sales decrease the share per kilowatt-hour of fixed costs that customers must pay, greater use reduces costs, and all consumers benefit. The researchers do not find the argument persuasive, however. Increased demand, in fact, increases total costs—in the short run, by increasing fuel costs and, in the long run, by increasing capital investment. Moreover, to the degree that that incremental demand for energy service is not met in the most economically efficient manner, it is a misallocation of society's resources that could be put to more valued use elsewhere.

[135] The researchers note that NREL funded the following: Iannucci, Cibulka, Eyer, and Pupp. DER Benefits Analysis Studies: Final Report. NREL/SR-620-34636. Golden, CO: National Renewable Energy Laboratory, September 2003. This report contains summaries of multiple reports assessing benefits of distributed energy resources. See also California Energy Commission. *PIER Project 500-01-039, Optimal Portfolio Methodology for Assessing Distributed Energy Resources Benefits for the EnergynetSM*. There have been a number of other studies on the benefits of DG, but typically, they have not focused on the ratemaking implications of their findings. See, e.g., Kosanovic, Dragoljub, and Beebe. *System-Wide Economic Benefits of Distributed Generation in the New England Energy Market*. Center for Energy Efficiency and Renewable Energy, University of Massachusetts, Amherst, February 2005.

[136] CPUC. *Order Instituting Rulemaking into Distributed Generation*, R. 99-10-025, D. 01-07-027. July 12, 2001; page 14.

In its guidelines on standby rates for DG, the Minnesota PUC took a fairly broad approach to valuing and providing credit for benefits of DG. It stated that:

> Credits should be given to a DG customer if the installation of a DG facility reduces the utility's costs of providing the service. These lower costs could be generation, transmission, or distribution related costs.[137]

In particular, the Minnesota PUC created options for:

- Distribution credits based on the utility's avoided cost

  The utilities were directed to name substations or feeders that were identified through the regular planning process as potential candidates for distribution credits. Although a customer must fund the initial study pertaining to its own DG installation, the utility will fund a more in-depth study if the initial study shows that the specific DG installation holds promise.
- Line loss credits as determined through a customer-funded utility study
- Renewable credits when a DG installation allows the utility to avoid the purchase of "green power" elsewhere
- Emission credits when a DG installation allows the utility to capture the value of an emission credit in a tradable emission program.

The Minnesota PUC also stated, somewhat inexplicably, that DG should not be eligible for any "additional diversity credits."[138]

The Texas DG manual, Section 4.3, discusses the cost benefit effects of DG and describes, in many cases, how to calculate them. The manual lists costs and benefits for the TDU and for the customer as well as other costs and benefits.

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[137] *In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities Under Minnesota Laws 2001.* Chapter 212, Appendix 6. Sept. 28, 2004. http://www.puc.state.mn.us/docs/orders/04-0131.pdf.

[138] Minnesota PUC. *Docket No. E-999/CI-0101023 in re Establishing DG Standards*. Order of Sept. 28, 2004, Attachment 6. If calculated correctly, credits for avoided generation, transmission, and distribution costs should reflect the diversity benefits of DG. Although it is not clear what the Minnesota PUC means by additional diversity benefits, it is possible that it is referring here to other considerations such as fuel diversity. (The lion's share of the nation's DG is fired by natural gas.)

In Rhode Island, Massachusetts, and New York, utility tariffs have taken fairly broad-brush approaches to recognizing certain benefits of DG. Legislation in Rhode Island allows the PUC to discount backup service distribution rates in cases in which the public interest justifies the price reductions. Consideration of the public interest can include reduced environmental effects, increased energy efficiency, reduced transmission losses and congestion, and effects on electric system reliability. Lost revenue because of these discounts must be accounted for and recovered in rates assessed on all customers. The legislation further provided that the PUC may permit or require discounted backup distribution service rates to encourage economically efficient cogeneration or small power production projects.[139] Although the settlement with Narragansett Electric does not provide specific discounts associated with these factors, the settlement does include an exemption for renewable resources. According to the settlement, customers who install onsite non-emergency generating units powered by eligible renewable energy resources, as defined in 2004 R.I. Pub. Laws 205 and up to an aggregate nameplate capacity of 3 MW for all customers having installed such generation, shall be exempt from the backup rates.

In Massachusetts, the NSTAR settlement took a slightly different and much less specific approach. The approved standby tariffs exempt small DG units and most renewable DG technologies from standby tariffs because of the public benefits renewable technologies provide and because the financial effects that both types of technologies pose on distribution service were deemed to be relatively small. In addition, the settlement reduced the standby rates approximately 15% below tariffs initially proposed in recognition of the public benefits provided by these technologies.

Several states use exemptions from standby rates as a means of promoting the deployment of preferred resources types. California provides several exemptions:

- DG, 5 MW and less, that meets certain fuel and environmental criteria is exempt from standby charges.
- Solar generation of up to 1 MW that does not export to the grid is exempt from any additional charges.
- Other specified DG is exempt from exit fees or "cost responsibility surcharges."

In New York, customers with "designated technologies"—fuel cells, solar thermal installations, photovoltaics, and sustainably managed biomass, tidal, geothermal, and methane waste units as well as eligible CHP—that come online on or after July 29, 2003, must choose from three pricing options:

- Exemption from standby charges if they enter service by May 31, 2006
- An 8-year phase-in of standby charges
- Taking standby service under the new charges immediately.

[139] Rhode Island Title 39, Public Utilities and Carriers, § 39-2-1.4, Reasonable Backup or Supplemental Rates. Effective Jan. 1, 2005.

The New York PSC also allows standby rate exemptions to small DG and clean DG technologies (including CHP), or the standby rates can be phased in gradually. In its standby rate guidelines, the PSC stated that:

> … extraneous factors sought by various parties, such as public policy values or benefits to utilities from DG … do not belong in the development of standby delivery rates.[140]

The commission also said that "such factors should be considered and applied, if appropriate, in the context of a utility's distribution planning process."[141] However, later, the commission approved the exemptions and phase-in policies that stakeholders proposed.

- The commission acknowledged the possible public benefits of the diverse generating technologies.
- Exemptions and phase-in policies are recognized in non-cost criteria and adjuncts to the cost-based rate design.
- The standby rate guidelines presuppose that remedial action may be taken "if justified upon a party's showing that a standby rate unintentionally creates 'a barrier' to [onsite generation]."[142]
- Such policies can "safeguard against unduly harsh impacts on the affected customers or industries during the initial transition to standby rates."[143]

However, it is important to note that there are time and customer limits to the New York exemptions policy. When either of the limits is met, utilities and the commission review the effect and the effectiveness of the policy and determine whether to terminate it. In Texas, renewable energy DG technologies that do not export to the grid are considered "energy efficiency."

3.3. Rate Design Issues

Another issue concerns properly reflecting DG's benefits in rates. Cost-of-service studies that properly analyze the effects of DG customers on the system (in effect, that treat them as their own class) should identify the costs they impose on the system and the costs they avoid, and the rates (or credits) that emerge should likewise reflect those puts and takes. In the absence of such studies, reliance on existing rates, adjusted for expected effects, is a second-best solution. But even with cost studies in hand, much judgment is needed because the study methods themselves may be prisoners of the assumptions underpinning them.

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[140] New York PSC. *Opinion No. 01-4*. Oct. 26, 2001; p. 27.

[141] *Id.*, p. 27

[142] New York PSC, *Case 02-E-0780 et. al., Order Establishing Electric Standby Rates.* July 29, 2003; p. 17.

[143] *Id.*

Key issues in rate design for standby and related rates include:

- *Bundled or Unbundled Rates*

  The first question is how far to unbundle rates. This may depend, in part, on the status of the electric sector in a state—but not necessarily. The rates for the various services—generation, transmission, and distribution—of vertically integrated utilities can be separated (as they are, for example, in Oregon). The issue is one of value. What does such unbundling achieve? Do the differentiated rates positively affect the efficiency with which customers use the grid? Do the individual rates fully and fairly compensate the utility for the service provided?

- *Demand and Energy Charges*

  Although it is maximum instantaneous peak demand on a system or subsystem that determines its size, or capacity, it does not necessarily follow that the service that the system provides—e.g., generation or delivery—should be priced on a capacity, or demand-related (per-kilowatt), basis. For low-volume customers, primarily residential and small commercial, energy rates inclusive of capacity costs are the norm. The question for designers of standby rates is whether kilowatt rates produce the desired effects (behavioral and financial). The proposal currently in Hawaii, in which a significant portion of demand-driven costs would be collected in kilowatt-hour rates (which are avoidable if no standby service is taken), offers an alternative approach that is worth considering.

- *Ratchets*

  Without ratchets, per-kilowatt charges, such as "per kilowatt-hour," can be avoided or reduced by reductions in demand. A ratchet, depending on its size and duration, has the effect of placing relatively more emphasis on the peaks of demand. Although this is salutary in the sense that the fixed investment of a utility system has historically been driven by peak demands, it also has costs. By moving to a more capacity-driven rate structure, the resulting rates may reduce to some degree a customer's incentive to take more general, cost-effective, energy-saving steps. Some DG customers see ratchets as excessive charges for facilities that are only occasionally used. From the utility's perspective, a ratchet is simply a mechanism to allocate capacity-based charges to the cost-causer. This, of course, is only true to the extent that customer peaks correlate with the relevant system peak (generation, local distribution, etc.) to which the demand charges apply. Diversity of loads on circuits and substations should lead to a reduced need for ratchets—but to what degree remains to be seen. The objective for rate designers and their regulators is to find ways to assure reasonable cost recovery for utilities while providing strong cost-saving incentives for customers.

- *Generation Held in Reserve*

  For utilities that provide both standby delivery and generation services, there remains the question of how to charge partial-requirements customers for generation services. Although the general premise that a customer should pay for the generation capacity actually held on his behalf is widely accepted, the issue for partial-requirements customers is how that capacity—which serves standby, not full, requirements—should be determined. The key factor in the calculation is the likelihood that a partial requirements customer will need backup power at a time of system peak. What are the increased costs incurred because the DG customer and others of the class are interconnected with the system? What are the real implications for a utility's reserve requirements of a customer or customer class whose likelihood of drawing power during times of peak or other capacity constraint is measurably less than that of full-requirements customers? The argument that the potential for a DG facility to go off-line during a system peak is such that the utility must have in reserve enough capacity to meet the customer's full load seems unreasonable in light of the probabilities, especially in those cases in which there are more than one DG customer. The diversity of standby loads should be recognized, as it is for all other loads, in the setting of standby generation service. In Oregon, for example, this is achieved through the assignment of, in effect, the same probabilities of unscheduled outages to onsite generators as to central-station units, in that the tariffs require DG customers to maintain the same level of contingency reserves that other load-serving entities must have.[144]

[144] PGE's full-requirements customers do not pay separate demand charges for contingency reserves like partial-requirements customers do. The full-requirements customers do, nevertheless, pay for the contingency reserves held on their behalf. The charges for these reserves are included in the energy rates they pay.

4. Policy Recommendations

Throughout the state surveys and interviews with stakeholders, rate design for customers with onsite generation raised two broad sets of issues. The first involved ensuring that rates appropriately reflect the services that DG customers desire and that the costs associated with those services are recovered. The second concerned state policy, specifically governmental action in support of DG as an important element of customer choice, power system resilience, portfolio diversity, and clean generation supply.

The first set of issues requires the determination of how customers with onsite generation are different in their service needs from full-service customers, how they are the same, and how these factors affect ratemaking and design. For example, customers with onsite generation, by definition, do not purchase electricity from the utility to meet their full electrical demand. This can justify some differences in treatment for generation service, distribution service, and transmission service. However, the extent to which it does depends heavily on the degree to which these services are dedicated to the partial-requirements customer or are shared among some set, or sets, of customers. Many of the recent regulatory efforts in this matter have focused on determining the nature of service required or requested by DG customers, quantifying important determinants of that service request, and identifying the costs associated with the service. As discussed in more detail below, issues in this category involve determining whether to differentiate among standby, supplemental, and maintenance service; whether and how to enable customers to limit the demand they place on the utility's system; what costs and benefits DG customers create on the utility's system,[145] and whether the diversity and other benefits of DG installations can and, if so, should be somehow incorporated into tariff structures.

The second set of issues comprises an array of approaches that serve a broad set of policy goals beyond those of traditional ratemaking, at least as narrowly construed.[146] These can be characterized as a policy overlay, whereby a state establishes certain rate policies that are driven by broader goals such as environmental improvement, new technology development, the widening of customer choice, or the inter-class and inter-temporal shifting of revenue burdens in pursuit of long-term cost reductions or greater equity. In these instances, such rate treatments are justified by the ends they are intended to achieve rather than by the narrow application of ratemaking rules aimed solely at allocating costs according to their causes.[147]

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[145] Note that it is important in this context to differentiate between costs and benefits on the utility's system (such as reduced losses, reduced peak load, delayed infrastructure expenditures, and fuel and resource diversity) and costs and benefits to society as a whole (such as reduced emissions, effects on energy markets generally, and secondary economic benefits).

[146] As set out, for example, in Bonbright. Of course, policy goals have been inherent in the fabric of utility ratemaking. It started with the most basic assumption of policymakers in the 19th and 20th centuries that price-averaging made it possible for more customers to take service and thus increased the overall public good. "Utility service for all" remains a goal of public policy, but philosophies on how best to price it continue to evolve.

[147] This is not to say that such ratemaking is in any way cut-and-dried. A significant portion of electric utility costs are, in fact, "joint and common," the allocation of which economic theory offers little guidance.

This research revealed numerous examples in each of these areas that are worthy of further exploration and development.

4.1. Cost Causation

When a customer installs DG to supply a portion of its electrical load, the DG may substantially change the customer's load profile and the nature of utility service required for it. Such an installation may reduce, during many hours, the customer's grid-supplied electrical load. However, the possibility remains that during outages of the onsite generation, the customer's need for electricity from the grid will increase. Even so, it may not necessarily follow that DG customers have load profiles that are more costly to serve than those of customers without DG. In part, this is a question of the costs under consideration—distribution only, or generation and transmission, too?—and, in part, it has to do with the timing and duration of the customer's calls for unscheduled service. Does a particular kind of usage merit separate treatment under the tariffs, and, if so, how can rates be best structured to recover the costs of that service?

For the system as a whole, the better approach involves measuring or estimating the actual effect on the system because of the behavior of the group as a whole—in this case, customers with DG. That is, the coincidence of the group's actual or estimated aggregate (diversified) demand with the relevant system peaks should determine its share of the capacity costs (whether generation, transmission, or distribution), and the duration and timing of its demand for energy (in the case of vertically integrated utilities and load-serving entities) should drive its energy costs. With respect to specific and unique costs associated with the demands of individual customers—i.e., those for dedicated and local facilities designed (either entirely or substantially) to serve the peak demands of the individual customer—these may properly be charged directly to the individual customer, or not, depending on other policy objectives in the jurisdiction. One of the challenges of rate design for DG customers is identifying the billing determinants that best reflect the costs incurred to serve those customers.

4.1.1. Innovation and Regulator Willingness To Innovate

Addressing and accommodating a new application or technology, such as the relatively new demand for customer-sited DG, often requires innovation and change on the part of customers, utilities, and regulators so that the *status quo ante* is not inappropriately advantaged to the detriment of the overall public good. This sort of innovation can be difficult for regulators, who are often bound by custom and precedent. The general inclination of commissions to base their decisions on precedent, to be consistent with long-standing policies, in some ways leads to small increments of change rather than an overhaul of ratemaking approaches. Even more powerful can be the axioms and assumptions, implicit or explicit, contained in that body of knowledge that evolved in the context of regulating natural monopolies in essential services.[148]

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[148] For example, even progressive regulatory bodies have often allowed incumbent utilities to provide "special" discount rates to large customers considering cogeneration alternatives based on the idea that loss of the customer, by definition, would lead to increased rates for others. Not only is this not true in times of increasing demand, but it also has the unintended side effect of inhibiting increases in the overall efficiency of the nation's electrical system, which has remained at a dismal 33% for decades. Nakarado,

As a result, one of the challenges for state public utility commissions is determining to what extent established costing principles, and traditional ratemaking principles and precedents, are applicable in designing rates for DG customers. Additional information and data that emerge from research targeted at understanding specific DG installations and interaction with the electrical grid and utility systems will assist in determining how established costing principles can be applied and will facilitate and substantiate appropriate change and innovation in ratemaking for such customers.

4.1.2. Continue Analysis of Existing DG Installations and Rate Treatments

The first step in refining existing rate treatments and developing useful new approaches must be to ensure a thorough understanding of what is already in place. This report has primarily presented a survey of standby rate options for customers with DG. More detailed analysis is an important next step.

Many states, utilities, customers, and affected parties are grappling with the complex issues associated with the potential power system innovation offered by customer-sited DG installations. In honing policies designed to tap the promise of DG, states should initiate and continue efforts to better understand real DG installations in the field. Foremost among these efforts would be monitoring and measuring DG performance in the field, gathering more detailed load data for customers who install DG as well as those who do not, and assessing various DG technologies in specific states to inform policy questions surrounding least-cost DG options. In parallel with the attention to DG installations, states should pursue more detailed analyses of specific rate structures, using well-defined criteria for judgment. Examples of evaluation criteria include economic efficiency, minimization of cost shifting, consistency with cost causation principles, consistency with state policy goals (including energy, environmental, and economic), and acceptability to stakeholders.

4.1.3. Develop Mechanisms for Individual Customers to Determine Their Load

One of the key billing determinants in ratemaking is customer load. One of the simplest ways to address this issue for DG customers is to assume the customer's entire load served by DG could be shifted to the utility grid at any time, including during peak times. Some utilities (such as NSTAR in Massachusetts) have, in fact, based rates on just such an assumption by applying demand charges at the nameplate rating of the DG system. However, this type of assumption can lead to high demand ratchets for standby service that are not consistent with the way DG is likely to operate.

G.; Thomas, H. "Combined Heat and Power, Revisited." *Public Utilities Fortnightly*, Vol. 141, No. 16. September 2003.

One alternative being explored in California is a method for customers to limit the demand that they shift to the utility grid. This limitation would take the form of "physical assurance," in which a customer would permit the installation of technical devices that would instantaneously shed load in the event of a DG outage. Although the main driver behind such a provision is to prevent DG customers from creating a strain on the system during system peak, it also provides the technical basis for limiting or avoiding certain tariff elements or charges. Recent research by Southern California Edison has indicated that physical assurance is not necessary during all hours. In fact, such measures would be necessary only during a few hours of the year when the utility's distribution system must operate above 400 A—about 200 hours, or 2.2% of total annual hours.[149] Although many states have included provisions for physical assurance to limit a customer's demand, none have progressed as far as California in developing and defining the concept.

4.1.4. Develop Service Offerings for Individual Customers

Another alternative proposed in Hawaii is the concept of "best efforts" service, or non-premium service. The concept is to design service so the customer does not create any requirement for the utility to invest in any generation or transmission plant or equipment to provide standby service. The proponent of this approach (the COM) believes it could remove any basis for the as-used daily standby demand charge altogether; however, it recognizes that a precept of regulation is that any customer using system capacity, at any hour, should help pay for the cost of that capacity. Therefore, at least a nominal as-used demand charge could apply to best efforts standby service. For example, one-third of the normal standby demand charge (both standby reservation charge and as-used daily standby demand charge) could apply to best-efforts customers.

Customers with non-critical loads—such as industrial customers with process energy requirements or resort hotels that can interrupt service to their water features, laundry, and other noncritical loads—could choose best efforts service up to the level of those loads. If the customer's DG unit failed when the utility was not under stress, it would place that load on the utility and contribute financially to the cost of that capacity. If the utility were under stress at that particular hour or day, the load would go unserved until the utility's reserve margin recovered or the DG unit was again available. Because the probability of the failure of the customer's DG system at the same time the utility system is under stress is quite low, this might be a reasonable choice for some customers. To the extent that they choose this option, it would provide a contribution to the utility's fixed costs without actually imposing any corresponding cost on the utility. The utility's other customers would be made better off by the receipt of this revenue. One issue to resolve is how to ensure that the customer is not served during peak periods on the system. This would mostly likely require physical assurance.

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[149] Dossey, T. *Integrating Customer-Operated Distributed Generation Into Distribution Planning*. Southern California Edison presentation to the California Energy Commission DER Integration Workshop. Sacramento, CA; May 4, 2005.

4.1.5. Incorporate Diversity and Probability Analysis Into Cost Assignment

Physical assurance pertains to limiting the individual customer's demand on the utility system during certain key periods. Other promising approaches relate to analyzing and reflecting the combined effect of multiple DG customers on a portion of the distribution system. In concept, the probability of any one DG system failing at a time of system peak is low because outages at a DG unit would be random rather than tied to the factors driving system peak. The probability that many such systems will simultaneously fail at a time of system peak is even lower, therefore—particularly if the DG systems are technologically and fuel-diverse.[150] Finally, the probability that a DG customer's peak demand will coincide with system peak is even lower than it is with a full-requirements customer—again because outages would be random rather than tied to customer consumption patterns. Consequently, the standby capacity (shared delivery and generation) that each DG customer should be responsible for will, depending on the number and nature of the deployments, be relatively small (some fraction of the nameplate capacity of the onsite system). It seems clear that, as a matter of both fairness and electric system economics, it is inappropriate to allocate costs on the assumption that all DG units will fail at the same time.

Rate structures can be informed by probabilistic analysis of when DG will be on, how it will be used, and how multiple DG installations on a portion of the distribution system will affect the necessary capacity for that distribution system. For diversity to exist in sufficient depth to warrant the favorable adjustment to cost assignment, there should be:

1. Sufficient numbers of installations
2. Sufficient technical and, possibly, fuel-diversity (e.g., not all systems subject to the same failures)
3. Sufficient peak diversity (e.g., systems are not all dependent on sunshine, and, thus, have different outage patterns).

With sufficient diversity, generation capacity charges could be set so that each DG customer contributes a portion of the cost of owning and maintaining the capacity that collectively provides service to all DG customers in proportion to how much and how often the individual customers use that standby capacity. Where there will be many DG customers, and because DG systems are not all expected to be out of service simultaneously, it is necessary for the utility to have only a fraction of the combined DG capacity available in reserve to meet the standby needs of these customers. One does this the same way one estimates the capacity needed to serve firm customers. First, one looks at the combined individual loads of the individual customers on the system. Second, one looks at the probability, or "coincidence," that these loads will occur at the same time. Finally, one measures this coincidence of loads against the other loads on the system to determine if additional capacity is necessary.

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[150] The value of fuel diversity depends on the nature of the fuel and its delivery system. Systems that use natural gas delivered through a fixed network of pipes bear the risk of common supply disruptions. A large proportion of DG systems fueled in this fashion may, in fact, present a higher probability of failure on peak and thus increase, not decrease, the overall cost and reliability effects on the system. This, like many other questions raised in this report, requires further analysis before reasoned judgment can be made.

As discussed in the body of this paper, Oregon has adopted a version of this approach in its treatment of generation capacity charges for DG customers. In Oregon, PGE includes a provision for contingency reserves for generation. The idea is, in effect, to treat DG/CHP like any other generator on the system.[151]

The CEC is funding many analyses that will provide useful data on issues associated with the integration of DG into utility systems and diversity of DG on the system. These include:

- FOCUS PIER contracts monitoring commercially installed DG for grid interaction
- San Francisco DER test bed site monitoring and analysis of the effects of DER on two San Francisco distribution system feeders
- An optimal portfolio methodology for assessing DG benefits for the Energynet
- The distributed utility integration test
- The evaluation of policy effects on project economic viability.[152]

4.1.6. Incorporate DG Into Distribution System Planning

There is growing interest in identifying how DG can be incorporated into distribution system planning. Several states—including California, Vermont, New York, and Massachusetts—and individual utilities—such as Detroit Edison in Michigan and Conectiv Power Delivery in New Jersey—are exploring this approach.[153]

In a paper for NREL, the Regulatory Assistance Project determined that, because of the high variation from *average* cost that characterizes the different areas of a distribution system, it is not just the high average-cost utilities that might effectively use DG. For a low average-cost utility, although very short-duration deferrals would be unlikely to generate enough savings to justify DG, projects that obviate for longer periods the construction of new facilities might very well produce enough savings to make DG the economic choice from the utility's perspective when compared with a "wires and transformers" alternative.[154]

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[151] More precisely, it is to treat the load served by the DG the same as any other load on the system—namely, to assign to that load its share of system's reserves that are held to ensure reliable service.

[152] Presentations to the California Energy Commission DER Integration Workshop. Sacramento, CA: May 3–4, 2005:

- Prabhu, E. *Forging a Consensus on Utility System Integration, CEC PIER Contracts*
- Moss, S.; Price, S. *San Francisco as a Distributed Energy Resource "Test-Bed" Site*
- Evans, P. *Optimal Portfolio Methodology for Assessing Distributed Energy Resource Benefits for the Energynet*
- Horgan, S. *Distributed Utility Integration Test*
- Provol, S. *Evaluation of Policy Impacts on the Economic Viability of California Based DG/CHP from a Project Owner's Perspective.*

[153] Massachusetts Technology Collaborative; Navigant Consulting. Massachusetts Distributed Generation Collaborative Annual Report 2005. May 31, 2005. This source includes a detailed discussion of the integration of DG into distribution system planning at pages 122–150.

[154] Moskovitz et al. *State Electricity Regulatory Policy and Distributed Resources: Distribution System Cost Methodologies for Distributed Generation.* NREL/SR-560-32500. Golden, CO: National Renewable Energy Laboratory, October 2002.

The Electric Power Research Institute DER Public/Private Partnership is undertaking a collaborative stakeholder approach to identify methods for incorporating DER into distribution planning when it brings value. Through this process, stakeholders have resolved difficult issues, including how a distribution company can identify the value of deferring distribution upgrades. The stakeholders have agreed that a utility can disclose a market reference price based on the carrying cost of capital for distribution deferrals.[155]

Averaged distribution prices mask the wide geographic variation in distribution costs within an individual distribution company's service territory. One option is for the company to charge different customers different rates based on where they are on the distribution system, or de-averaging rates. Utility regulators have found this sort of de-averaging of rates to be unacceptable because it is hostile to the application of the traditional regulatory principles of equity, simplicity, and ease of administration. But there are practical alternatives to the de-averaging of distribution rates These are de-averaged distribution *credits* and distributed resource development zones.[156] A de-averaged distribution credit would allow a utility, as well as a DG customer, to benefit from the cost reduction associated with installation of DG in high-cost areas of the network, which thereby defers incremental distribution system investment.

> The term "de-averaged credits" is shorthand for a family of related policy options that provide cost-effective economic incentives to concentrate distributed resources in high-cost areas. Distributed resource development zones, for example, would designate geographic areas and set a standard credit for all qualifying distributed resources located in an area. A distribution value bidding scheme could be used to invite competitive proposals from distributed resource vendors. The amount of the credit requested in the bids would be one of the criteria used to select the winning distributed resources.[157]

Detroit Edison, an investor-owned, vertically integrated utility (a subsidiary of DTE Energy) has been taking a proactive approach for incorporating DG into the distribution planning process. Detroit Edison sees DG as one of the viable solutions for distribution planning. It also regards DG as "one way of delivering just-in-time and 'right-sized' capacity to resolve smaller short falls while minimizing the initial capital outlay."

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[155] Petrill, E. *Shaping a California DER Procurement Through Stakeholder Collaboration.* Presentation to the California Energy Commission DER Integration Workshop. Sacramento, CA; May 3, 2005.

[156] Moskovitz et al. *State Electricity Policy and Distributed Resources: Distributed Resource Distribution Credit Pilot Programs—Revealing the Value to Consumers and Vendors*. NREL/SR-560-32499. Golden, CO: National Renewable Energy Laboratory, October 2002.

[157] *Id*., p. 5.

The company considers DG in three areas of distribution planning: (1) internal to the distribution circuit, (2) at the substation, and (3) in an island mode for maintenance purposes. It is also partnering with customers on overloaded circuits and installing DG on such customer sites. Costs and benefits of such DG projects are shared with customers, and the onsite generation is owned and monitored by the company. For most DG applications, Detroit Edison has installed diesel and natural gas combustion engines. However, for technology demonstration purposes, it has installed alternative technologies such as fuel cells, photovoltaics, and flow batteries.[158]

The diversity and probability analysis discussed in the previous section is critical to fully evaluate the ability of DG to fulfill a role in utility resource planning.

4.1.7. Performance Incentives To Shape Customer Behavior

One option available to utilities is to design rates in a fashion that encourages customers to operate their DG as much as possible. This is available to utilities, which might seek to align a customer's incentives with minimization of impact on the distribution system, as well as regulatory bodies, which might seek to achieve other policy goals.

In Arizona, one utility charges higher reservation capacity charges to customers whose onsite generation does not maintain a 75% or better capacity factor. Another utility in the state provides a discount or charges a penalty based on the DG customer's power factor (a measure of power quality and the need for reactive power). But there are issues associated with this type of approach, including the treatment of DG operators that choose to run on an economic dispatch basis (i.e., shutting down during off-peak periods to take advantage of lower off-peak utility prices) and the possible correlation of higher DG capacity factors with lower load factors for utility-provided power, which affects cost separation between generation and distribution capacity cost avoidance versus displaced energy valuation.

Another option has been proposed in Hawaii. An unbundled rate for standby service would separate the customer-specific costs of connecting a customer with the utility grid from the costs of joint production and transmission facilities used by multiple customers. The customer would pay a fixed annual fee for the connection to the system (a "capacity reservation" payment) and a variable amount for actual standby service, depending on how much and how often the customer actually requires standby service. With this approach, a customer that used standby service very little (and therefore did not cause the utility to invest in facilities to provide standby service) would pay much less than one who relied on the utility frequently. It would provide an incentive for customers to install reliable equipment and maintain that equipment while ensuring that customers using standby service frequently fairly compensate the utility for providing firm year-round service.

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[158] Asgeirsson, H.; Seguin, R. "DG Comes to Detroit Edison." *Transmission & Distribution World*; October 2002. Available at http://tdworld.com/mag/power_dg_comes_detroit/.

Asgeirsson, H. "Detroit Edison Distributed Resources Utility Applications and Case Studies." Presentation at IEEE Power Engineering Society General Meeting; June 9, 2004.

Proponents of this approach believe that a rate that bundled the full annual costs of standby service for hundreds of days per year into a fixed fee that applies regardless of the frequency of standby use would be an inappropriate standby rate design. A customer that uses standby service frequently should pay a much higher cost than one who seldom requires service simply because the latter customer can "share" standby facilities with many more customers and should be allowed to share the cost of those facilities with other customers that use them.

One variant of this approach shows up in APS's tariff, which allows a customer to identify specific periods and hours of a month during which standby service is required. If a customer uses standby service during non-designated hours more than two times in any rolling 12-month period, the customer is deemed to require standby service in all hours of the month for the next 3 months. This provision provides a significant financial disincentive to use service from the utility in any but the customer's designated hours.

The converse of this approach is to penalize poor generation performance (or higher demand than anticipated). For example, in New York, utility standby tariffs give customers the option to set their own levels of contract demand; this option includes a ratchet and strict financial penalties. For example, in the O&R and Con Edison service territories, the penalty for a 10%–20% excess demand is *12* times the applicable demand charge for the excess demand. When demand exceeds the customer-nominated demand level by more than 20%, the penalty is *24* times the applicable contract demand charge for the excess.

4.2. Policy Overlay

The previous section addressed issues associated with identifying the services that DG customers request and designing rates to properly recover the costs of those services. In many states, DG ratemaking is being taken up as part a broader effort to develop a set of state policies to promote DG and capture its expected economic, environmental, and reliability benefits for customers, utilities, and society as a whole. These anticipated benefits go beyond a strict evaluation of electric system costs and benefits of a customer's individual installation. State regulatory agencies may want to design rate treatments to affirmatively promote distributed resources, including clean DG.

A recent report summarizes the mix of direct customer and dispersed societal benefits of DER, of which DG is a subset:

> The benefits associated with DER installations are often significant and numerous. They almost always provide tangible economic benefits, such as energy savings or transmission and distribution upgrade deferrals, as well as intangible benefits, such as power quality improvements that lengthen maintenance or repair intervals for power equipment. Also, the benefits routinely are dispersed among end users, utilities, and the public. For instance, an end user may use the DER to reduce peak demand and save money due to lower demand charges. Reduced end user peak demand, in turn, may lower a distribution system peak load such that upgrades are deferred or avoided. This could benefit other consumers by providing them with higher reliability and power quality as well as avoiding their cost share of a distribution system upgrade. In this example, the costs of the DER may be born by the end user, but that user reaps only a share of the benefits.[159]

In this context, many states will grapple with the following question: Do long-term system benefits and non-participant benefits justify any cost shifting—including exemptions from certain charges, favorable treatment for DG customers, or incursion of short-term costs to obtain anticipated long-term benefits?[160] A state can pursue several options for providing explicit rate treatment in recognition of the dispersed benefits associated with DG. In contrast, some states may determine that rates should be cost-based and that it will pursue other policy objectives through non-rate policies, such as distribution system planning.[161]

4.2.1. Align Utility Revenue Collection Incentive With Public Policy Goals

Provisions for utility cost recovery through regulated rates generally contain strong incentives that affect a utility's attitude toward customer installation of DER, including DG and energy efficiency, on the customer side of the meter. Traditionally, utility cost recovery ties utility profits to sales of kilowatt-hours. Thus, a utility's profitability is tied directly to its sales volume, which creates a disincentive to reduce sales (e.g., through energy efficiency or customer-sited DG) and an associated incentive to increase sales.

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[159] Poore et al. *Connecting Distributed Energy Resources to the Grid: Their Benefits to the DER Owner/Customer, Other Customers, the Utility, and Society.* ORNL/TM-2001/290. 2001, p. 13.

[160] The term "cost shifting" is used in the context of utility rate design to mean the allocation of particular costs of service to a class or classes of customers other than those that can credibly be argued to, in fact, cause those costs. Because the question of cost causation is, in many instances, debatable and other, non-economic bases on which to allocate costs must be relied on, it is probably more accurate to speak of the shifting of "revenue responsibilities."

[161] The New York Public Service Commission has taken this approach and will incorporate consideration of broader benefits into distribution system planning rather than modifying rate treatment. *New York Public Service Commission Opinion 01-04.* Oct. 26, 2001, page 27.

Because sales can often be increased in the short term with little or no increase in fixed costs, the profit margin on these sales is very large and constitutes a very powerful financial incentive for behavior that is inimical to improvements in the overall efficiency of the economy. Performance-based ratemaking that breaks the link between sales and profits can theoretically overcome a utility's natural disincentive to support customer load reductions (whether through efficiency or DER).[162]

There are two primary forms of performance-based ratemaking: price caps and revenue caps. Revenue caps are by far the better approach for breaking any link between installation of DG on the customer side of the meter and erosion of a utility's revenue. Under a revenue cap, the utility's revenues are fixed over a certain time period (typically 3–5 years). Because the revenues are fixed, the utility is indifferent, from a revenue perspective, to a customer's installation of DG. Under price cap regulation, where prices are fixed over a specified period of time, the utility's profits are still tied to sales volume, and the utility's profits are affected by reduced sales.

Similar in intent yet different in results is a "lost base revenue approach," which can be used to address a utility's disincentive to reduce throughput. Under this approach, a utility is essentially "made whole" for base revenue lost because of reduced sales corresponding to customer installation of DG. Although it compensates the utility for reduced sales, the lost revenue approach does not remove the utility's financial incentive to increase sales. This approach permits a targeted response to a specific initiative such as the installation of DG; however, it does not address incentives that affect other forms of DER such as energy efficiency.

4.2.2. Support Policy Goals With Explicit Exemptions and Incentives

The simplest kind of policy overlay is a state exemption of desirable DG installations from certain rate components. Previous sections of this paper presented several examples of this. Such favorable treatment for DER can thus provide a "jump start" to the resource. In some instances, this approach can be justified for consistency with other state policies that support clean energy technologies—particularly those that also receive support from state energy funds, thus lowering the cost to the state. Failure to give the exemptions means that the state has policies in place that may, in fact, counteract one another. The exemption can be tied to the date of the DG installation (e.g., as a transitional policy to encourage DG), the resource type (e.g., as a spur for certain types of installations), or to the emissions profile of the DG (e.g., to encourage "clean" DG). Many states are already providing exemptions for customers with DG resources that meet state-established criteria of size limits and technology specifications.

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[162] The Regulatory Assistance Project has written extensively on the subject of performance-based regulation, including approaches to "revenue decoupling." See the Web site at www.raponline.org for multiple publications on performance-based regulation.

As with exemptions, specific incentives can be a policy overlay to cost-based rates for DG customers. A recent paper from E2I discusses various types of incentive programs for DER, including ratepayer-funded direct payments to DG customers that install certain types of DG.[163] The costs and benefits of DG are different from the perspective of the individual customer, distribution and bulk power utilities, utility regulators, and other state policy leaders. Developing appropriate incentives requires careful evaluation of the cost-effectiveness of different options from a variety of perspectives. Although generic costs and benefits of DG installations are widely discussed, the development of specific incentives requires an assessment of the real value associated with specific installations within a real context of location on the delivery system, applicable tariffs, and other state policies. A regulatory agency or legislative body must take into account any potential shifts in class revenues burdens associated with any policy of exemptions or incentives.

4.2.3. Develop Volumetric Rates to Shape Customer Behavior

In many jurisdictions, utilities are favoring, and commissions are approving, recovery of higher proportions of distribution-related costs in fixed charges. The argument for this kind of pricing is that distribution costs are fixed rather than variable with energy consumption. Although this may be true in the short term, it is not in the long term. A long-term view of the distribution system justifies a different cost treatment. Although distribution facilities, like generation and transmission, must be sized to meet instantaneous peak demand, it is nevertheless the case that customers demand energy—and it is changes in the timing and amounts of that demand that drive investment in distribution system upgrades and expansion.

When distribution system costs are recovered in large proportion through fixed costs, customers have no financial incentive to modify their behavior by reducing their energy consumption. Historically, distribution system costs have been recovered through volumetric rates (both per-kilowatt-hour and per-kilowatt), and there is no reason to deviate from the practice. Such rates have the virtue of causing those who consume more to bear a higher proportion of costs and give an incentive to them to cost effectively manage their consumption.[164] Revenue-cap performance-based regulation with volumetric rates would ensure distribution companies fixed revenues while providing customers with incentives to modify their consumption.[165]

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[163] *A Framework for Developing Collaborative DER Programs: Working Tools for Stakeholders.* A report of the E2I Distributed Energy Resources Public/Private Partnership. 1011026. Palo Alto, California: E2I, 2004.

[164] For a fuller treatment of this issue, see Weston, F. *Charging for Distribution Utility Services: Issues in Rate Design*. The Regulatory Assistance Project, December 2001.

[165] Customer reductions in grid-supplied electricity, for whatever reason (DG, end-use efficiency, etc.) are likely to have greater short-term effects on the utility's revenues in cases in which rates recover a significant share of T&D costs through energy-based volumetric rates than in cases in which these costs are recovered through demand charges. In some cases, the customer bill reductions will exceed the short-run avoided costs (there will be a temporal mismatch between the bill savings and the capacity savings), and regulators may need to take remedial actions. Revenue-cap performance-based regulation, in fact, addresses this problem directly as it insulates the utility's bottom line from the effects from changes in sales.

4.2.4. Tie Rate Treatment to Emissions Threshold or Efficiency Threshold

To spur the installation of clean DG, a state can tie rate treatment to attainment of a specific emissions threshold. For example, a public utility commission, working with the state environmental agency, could determine that DG installations that meet an air quality-based emissions threshold should receive favorable treatment because they are consistent with the state's environmental policy goals. This sort of policy overlay uses a tool within one state agency's jurisdiction to reinforce another state policy.

A similar approach would determine that CHP applications that meet a certain efficiency standard could receive more favorable treatment than less-efficient applications or, conversely, that less-efficient applications should be required to pay higher rates than more-efficient ones. This sort of treatment would be an explicit decision by the state that greater efficiency in CHP applications justifies the more favorable rate treatment.

4.2.5. Strive for Coordination Among, and Consistency Within, State Policies

Many DG customers expressed frustration with inconsistencies among state policies pertaining to DG as well as with the unpredictability of state policies pertaining to DG. For example, customers stated that agency procedures that include long lead times for issuing permits or that included changes and revisions to standards conflict with a state's policy of supporting or encouraging DG installations. Furthermore, they indicated that when state regulations—such as emissions requirements—change, it makes a customer's cost-benefit analysis difficult. Better coordination among the rules of state agencies would facilitate DG adoption by customers. Without coordinated and consistent policies and without policy stability, it is difficult for customers to determine the cost-effectiveness of an installation.

Ideally, within a state, there would be a high-level commitment to the development of DG to meet state policy goals, and that commitment would translate into a mandate for all state agencies to review their policies and procedures to ensure they are consistent with the goal of increasing the penetration of, for example, clean, customer-sited DG. California is one state that has a high-level mandate for the introduction of DG, and it has developed an on-going coordination framework through the Distributed Energy Resources Web site. Even so, customers still find hurdles associated with conflicting and changing state policies. Massachusetts has an ongoing multi-stakeholder collaborative process; however, the state has not made a high-level commitment to DG. Having a DG champion within a state government can make a significant contribution to the development of effective and coordinated state policies.

Beyond policy coordination, it is important that there be coordination and consistency of data collection regarding the operation and performance of DG. Such data collection will assist state agencies in evaluating the success of implementation of policies and in further refining policies to achieve intended outcomes.

4.2.6. A Word on Carbon Policy

One of the policy drivers behind certain state policies on DG is the anticipation that increased penetration of clean DG will improve the environmental footprint of the electric system. State policy leaders desire to integrate energy and environmental policy because DG is widely perceived as providing significant potential for meeting economic and environmental policy goals. One of the most straightforward ways to ensure that energy and environmental policies are integrated would be to adopt a state-wide or nation-wide policy on carbon emissions. Carbon taxes and carbon cap-and-trade systems are comprehensive policies that could create incentives for efficient CHP, and clean DG, if a program took a broad look at all resources.

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List of Interviews

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Recognizing that innovation and good public policy do not always proclaim themselves, Synapse Energy Economics and the Regulatory Assistance Project, under a contract with the California Energy Commission (CEC) and the National Renewable Energy Laboratory (NREL), undertook a survey of state policies on rates for partial-requirements customers with onsite distributed generation. The survey investigated a dozen or so states. These varied in geography and the structures of their electric industries. By reviewing regulatory proceedings, tariffs, publications, and interviews, the researchers identified a number of approaches to standby and associated rates—many promising but some that are perhaps not—that deserve policymakers' attention if they are to promote the deployment of cost-effective DG in their states.

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distributed generation; DG; distributed energy resources; DER; interconnection; partial-requirements customers; tariffs; regulatory; National Renewable Energy Laboratory; NREL

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