



Chapter 2. Design of Standby Rates

2.1 Overview

A primary motivation for industrial and commercial customers to install CHP systems is to meet electricity and thermal energy needs at a lower cost. One potential impediment to the adoption of CHP³⁶ is standby rates, or partial requirements service, which the utility charges to compensate for providing certain services and which can affect CHP customer cost savings.³⁷ Utility rates should optimally allocate the total cost of service for a utility to recover costs from customer classes, reflecting each class's use of the system. This principle of "cost causation" is implemented through rate designs that fairly allocate costs based on measureable customer characteristics.

Utility standby rates cover some or all of the following services:

- *Backup power* during an unplanned generator outage
- *Maintenance power* during scheduled generator service for routine maintenance and repair
- *Supplemental power* for customers whose on-site generation under normal operation does not meet all of their energy needs, typically provided under the full requirements tariff for the customer's rate class
- *Economic replacement power* when it costs less than on-site generation
- *Delivery* associated with these energy services.

In the rate design process, utility costs are allocated to various components of customer services, including charges for billing and metering, energy, distribution, and transmission. Costs for each of these components are based on an average user profile for each customer rate class, such as large nonresidential customers, rather than customized for individual users.

For large customers, costs of utility service are separated into customer, energy, and demand charges. Customer charges are designed to recover costs incurred to provide metering and billing services and service drop facilities. Energy charges recover the variable costs incurred to generate electricity (i.e., chiefly fuel cost).³⁸ Demand charges are designed to recover the utility investment cost incurred to provide generating, transmission, and distribution capacity and may vary by season and time of day.³⁹ Generation costs may also vary by season and time of day.

Commonly, demand charges in standby rates are "ratcheted," meaning the utility continues to apply some percentage (often as high as 100%) of the customer's highest peak demand in a single billing month up to a year after its occurrence. The use of ratchets can be controversial—some view them as increasing the equity of fixed cost allocation, while others view them as barriers to economic applications by CHP customers. Although demand ratchets may be appropriate for recovering the cost of delivery facilities closest to the customer-generator, they arguably do not reflect cost causation for *shared* distribution and transmission facilities, which are farther removed from the customer. Distribution and transmission facilities are designed to serve a pool of customers with diverse loads, not a single customer's needs, and coincident outages drive their costs. In addition, unplanned CHP system outages occur randomly; CHP systems will not all fail at the same time or during the utility system's peak. Further, the customer's use of standby service may not coincide with the peak demand of the utility facility providing the service.⁴⁰ Use of standby service by CHP customers with low forced outage⁴¹ rates typically is significantly less likely to coincide with the utility's peak demand than peak use by a full requirements customer. Arguably, billings based

³⁶ U.S. EPA. *Standby Rates for Customer-Sited Resources—Issues, Considerations, and the Elements of Model Tariffs*. December 2009. www.epa.gov/chp/documents/standby_rates.pdf.


³⁷ In restructured states, the utility may provide only delivery services and provider-of-last-resort energy service.

³⁸ Some fixed costs may be recovered through variable energy charges.

³⁹ In restructured markets, generation-related costs are not recovered in regulated revenue requirements, but in market-based supply prices.

⁴⁰ See Regulatory Assistance Project. "Distribution System Cost Methodologies for Distributed Generation." 2001. www.raonline.org/docs/RAP_Shirley_DistributionCostMethodologiesforDistributedGeneration_2001_09.pdf.

⁴¹ Forced outages are unplanned or unscheduled outages of the CHP system due to equipment failure.



on ratcheted demands fail to recognize the diversity in load among CHP customers and the cost savings associated with that diversity, particularly as regards shared T&D facilities. Requiring CHP customers to pay ratcheted demands may result in CHP customers overpaying for utility-supplied electricity relative to full requirements customers.

2.2 Improving Standby Rates

Standby rates were originally designed to reflect an environment in which a utility operated within a fairly closed system with a few inter-ties with other utilities for backup emergency purposes. Today, many utilities rely on and participate in regional markets where electricity and capacity are pooled and can be purchased with relative ease. The ability to more easily transact energy and capacity allows a utility to take account of the probability of various CHP loads needing standby service at the same time, which will lower ratcheted demand charges.

Working with utilities and other stakeholders, some state utility regulators have improved the nexus between standby tariffs and cost causation, provided customer-generators with options to avoid charges when they do not impose costs, and established a reasonable balance between variable charges versus contract demand or reservation charges.

For standby or “partial requirements” customers, the following service components are the most common:⁴²

- **Backup Service.** Backup or standby service supports a customer’s load that would otherwise be served by DG, during unscheduled outages of the on-site generation.
- **Scheduled Maintenance Service.** Scheduled maintenance service is taken when the customer’s DG is due to be out of service for routine maintenance and repairs.
- **Supplemental Service.** Supplemental service provides additional electricity supply for customers whose on-site generation does not meet all of their needs. In many cases, it is provided under the otherwise applicable full requirements tariff.
- **Economic Replacement Power.** Some utilities offer economic replacement power—electricity at times when the cost of producing and delivering it is below that of the on-site source.

Together, the following features encourage customer-generators to use electric service most efficiently and minimize costs they impose on the electric system:⁴³

- **Reflect load diversity of CHP customers in charges for shared delivery facilities.** Charges for transmission facilities and shared distribution facilities such as substations and primary feeders should reflect that they are designed to serve customers with diverse loads. Load diversity can be recognized by designing demand charges on a coincident peak demand basis as well as the customer’s own peak demand and by allocating demand costs primarily or exclusively to usage during on-peak hours. Differentiating on-peak demand from off-peak demand provides standby customers with an incentive to shift their use of the utility’s assets to off-peak hours, when the marginal cost of providing service is typically much lower.
- **Allow the customer to provide the utility with a load reduction plan.** The plan should demonstrate its ability to reduce load within a required timeframe and at a specified amount to mitigate all, or a portion of, backup demand charges for local facilities. This allows the standby customer to use demand response to meet all, or a portion of, its standby needs. The utility would approve the load reduction plan, evaluating whether it provides sufficiently timely load shedding to avoid reserve costs incurred by the utility. The utility would approve the load reduction plan after evaluating and determining that it provides sufficiently timely load shedding to avoid reserve costs incurred by the utility.

⁴² The four bulleted service components are not necessarily subject to a demand charge. It depends on the utility’s rate structure. www.epa.gov/chp/documents/standby_rates.pdf.

⁴³ For more on alignment of standby rates with rate design principles, see *Standby Rates for Customer-Sited Resources: Issues, Considerations and the Elements of Model Tariffs*, prepared by Regulatory Assistance Project and ICF International for the U.S. Environmental Protection Agency. December 2009. www.epa.gov/chp/documents/standby_rates.pdf.

- **In states with retail competition, offer a self-supply option for reserves.** This can be in the context of the load reduction plan discussed above, through utility-controlled interruptible load, or some other means that can both save costs for the customer and avoid costs for the utility. The self-supply plan can be structured to reflect actual performance of the customer over time.
- **Offer daily, or at least monthly, as-used demand charges for backup power and shared transmission and distribution facilities.** Moving away from annual ratcheted charges gives the CHP customer a chance to recover from an unscheduled outage without eroding savings for an entire year. Daily charges encourage customers to get their generators back online as quickly as possible. Daily charges for backup power should be market-based to provide appropriate price signals to CHP customers.
- **In states with retail competition, allow customer-generators the option to buy all of their backup power at market prices.**⁴⁴ The customer can avoid any utility reservation charge for generation service because the utility is relieved of the obligation to acquire capacity to supply energy during unscheduled outages of the customer's CHP unit.
- **Schedule maintenance service at nonpeak times.** In general, because this service can be scheduled for nonpeak times, it is considered to create few additional or marginal costs to the utility's system, and tariffs are typically structured to exempt the customer from capacity-related costs (e.g., reservation charges or ratchets, for either generation or delivery).
- **Provide an opportunity to purchase economic replacement power.** During times of the year when energy prices are low, the utility can provide on-site generators energy at market-based prices at a cost that is less than it costs to operate their CHP systems, and at no harm to other ratepayers. Such arrangements must be compatible with the structure of retail access programs, which the CHP customer may otherwise be relying on, and should allocate any incremental utility costs of purchasing such power (including general and administrative fees) to the CHP customer.

These features can create a standby rate regime consistent with standard ratemaking principles, avoiding cost shifting from CHP customers to other customers, while providing appropriate incentives to operate CHP facilities in a manner most efficient for the utility system as a whole, by aligning the economics for the CHP facility with the cost to serve that customer.

2.3 Successful Implementation Approaches


Pacific Power—Oregon Partial Requirements Service

Pacific Power provides standby services in Oregon under four primary tariffs and riders.⁴⁵ Taken together, this set of tariffs provides many of the customer-generator benefits discussed above, while allowing recovery of actual costs incurred by the utility and protecting other customers.

- The utility assesses charges for shared distribution facilities such as substations and transmission facilities based on the customer's actual 15-minute net demand recorded for the month during on-peak hours, using the same rate and billing determinants as the full requirements tariff. There is no annual ratchet.
- Cost recovery for local distribution facilities—those designed solely to serve the customer as well as those closest to end-users, such as transformers and low voltage lines—is based on the average of the two highest non-zero monthly on-peak demands for the past 12 months, same as for full requirements customers. The starting point and minimum level for the charge is the “baseline”—the customer's peak demand on the utility system assuming normal operation of the customer's generator. However, the

⁴⁴ This guide does not explore the merits or problems with the development of standby rates; it identifies how standby rate policies can be successfully implemented to facilitate CHP.

⁴⁵ These four tariffs include Schedule 48: Large General Service Partial Requirements 1,000 kW and Over Delivery Service, Schedule 76R: Large General Service Partial Requirements Service Economic Replacement Power Rider Delivery Service, Schedule 247: Partial Requirements Supply Service, and Schedule 276R: Large General Service Partial Requirements Service Economic Replacement Power Rider Supply Service. “Oregon Regulatory Information.” Pacific Power. www.pacificpower.net/about/rr/ori.html.



baseline can be adjusted with a load curtailment plan for generator outages, installation of energy efficiency measures, and to accommodate planned, long-term changes in loads or generator operations.

- The customer's baseline also sets charges for reserves the utility holds to maintain capability to serve loads during outages of the on-site generator. The tariff provides self-supply options for reserves, including through an approved load reduction plan for supplemental reserve requirements.
- Scheduled maintenance service must be scheduled 30 days in advance, in take-or-pay blocks at a forward market-based price. Pacific Power also offers partial requirements customers the option to buy replacement energy (usage above baseline) at market prices when beneficial for the customer. For a CHP customer, the determination of favorable conditions includes the total benefits derived from the CHP system (electricity plus heat) compared with advantageously priced replacement power and boiler fuel.
- Energy service for unscheduled outages is based on real-time market prices. Importantly, demand and transmission charges for scheduled maintenance, economic replacement power and unscheduled outage service are based on daily demands and do not affect charges for distribution and transmission services under the base standby tariff.

Consolidated Edison Partial Requirements Service

Consolidated Edison offers replacement or supplemental service for approved projects for self-generation customers whose generation capacity is greater than 15% of their potential load. Pricing for this service is based on a contract demand representing the highest demand the facility is likely to meet for the customer under any circumstances. The charge for the contract demand reflects both the customer's contribution to local facilities used on a regular basis for baseload demand, as well as customer-specific infrastructure necessary to meet the maximum potential demand with or without the customer's generation in service. The rate for the entire contract demand is generally lower than the otherwise applicable rate. If the customer selects a contract demand level, the utility applies penalties if the maximum demand exceeds the contract demand by more than 10% or 20%.⁴⁶ If the contract demand level is utility-determined there is no penalty for exceeding that level. In both cases, when the original contract demand is exceeded, contract demand is re-set to the new highest demand.

In addition, the company assesses a demand charge based on the actual demand recorded each day. The rate varies by season and time of day—peak versus off-peak.^{47, 48} This variable charge recovers shared system (upstream) costs. It is calculated on a daily basis.

Georgia Power⁴⁹

Georgia Power provides backup service under a tariff rider. The rider allows a customer to contract for firm or interruptible standby capacity, or both, to replace capacity from a customer's generation when it is not in service. Customers may designate the level of service they wish to purchase from the utility. For firm backup power, the customer must provide notification within 24 hours of taking such service. Interruptible backup power requires advance permission from the company, except in the case of an unplanned outage where a 30-minute notice is required after beginning service.


Maintenance power, supplied for outages, must be scheduled 14 days in advance. Maintenance power is available as firm service during the off-peak months and as interruptible service during peak months. Customers purchase supplemental power (power required during normal operation of the generator and normal demands by the facility) at normally applicable rates.

⁴⁶ www.coned.com/documents/elecPSC10/GR1-23.pdf, leaf 164; No penalties are assessed if the utility determines the contract demand.

⁴⁷ www.coned.com/documents/elecPSC10/SCs.pdf, leaf 453.

⁴⁸ The charge is zero for off-peak hours.

⁴⁹ www.georgiapower.com/pricing/files/rates-and-schedules/12.30_BU-8.pdf.



The utility computes the level of standby power as the difference between the “maximum metered demand measured during the time standby service is being taken, less the maximum metered demand during the time in the billing period when standby service is not being taken.” This demand determination can be made on a peak versus off-peak basis.

All billing determinants are based on monthly values, with no ratchets. However, demand charges are subject to a standby demand adjustment factor, which adjusts the billed standby demand once a customer uses backup service for more than 876 hours during the most recent 12-month period. This provides an incentive for a customer to use standby service as efficiently as possible.

How the Criteria Are Addressed

Policy Intent. The policy intent is to charge CHP customers only for costs they impose on the system consistent with ratemaking principles, encourage customer-generators to use electric service most efficiently to minimize costs they impose on the electric system, and ensure that costs for backing up CHP customers are not passed on to non-CHP customers. The customer and the utility can work together to schedule planned outages at times that are best for the utility system.

Market Signals. CHP users and potential CHP adopters are motivated by expected cost savings available from their systems. By shifting risk to CHP users and appropriately charging for services actually rendered, both utilities and customers can benefit through appropriate market signals.

Ratepayer Indifference. By more accurately balancing the charges for service actually rendered with appropriate market signals and incentives for operational efficiencies, all customers should benefit from appropriately structured standby tariffs.

2.4 Conclusions

Standby charges should be designed to most closely preserve the nexus between charges and cost of service. Standby rates were originally designed to reflect an environment in which a utility operated within a fairly closed system with a few interties with other utilities for backup emergency purposes. Today, many utilities rely on and participate in regional markets where electricity and capacity are pooled and can be purchased with relative ease. The ability to more easily transact energy and capacity allows a utility to take into account the probability of various CHP loads needing standby service at the same time. Together, the features listed below encourage customer-generators to use electric service most efficiently and minimize costs they impose on the electric system.

KEY IMPLEMENTATION APPROACHES: DESIGN OF STANDBY RATES

- Offer daily or monthly as-used demand charges for backup power and shared transmission and distribution facilities.
- Reflect load diversity of CHP customers in charges for shared delivery facilities.
- Provide an opportunity to purchase economic replacement power.
- Allow customer-generators the option to buy all of their backup power at market prices.
- Allow the customer to provide the utility with a load reduction plan.
- Offer a self-supply option for reserves.