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Issues for Pricing Electricity Standby Services for the Competitive Marketplace

Dr. Lori M. Megdal
Megdal & Associates
131 Guggins Lane
Boxborough, MA 01719
Telephone: 508/266-9420, E-Mail: megdal@tiac.net

Eric Ackerman
Edison Electric Institute

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The Necessity of Addressing Standby Pricing to Achieve An Efficient Market

Standby pricing has, to-date, often been given only secondary attention. Yet, the quantity of power and capacity obtained as standby services are increasing and expected to increase more rapidly with the move to more competitive markets. The design of efficient markets (i.e., markets that minimize total cost to society) requires including efficient pricing of standby services.

Efficient resource decisions for generation and transmission can not occur unless there is efficient pricing in transmission, generation, ancillary, and standby services. Standby and ancillary services complete the package of the services provided, whether in the retail or wholesale market. The markets for either transmission or generation can not have efficient pricing if their standby services are not also efficiently priced. This principle has been recognized, to some extent, by the competitive market reforms taking place in Europe. For example, in an examination of the reform policies being examined in Finland, Osmo Rännäri, of the Helsinki Energy Board, stated that “For plants to be competitive, the costs of generation, including some system for the cost of standby generation capacity must be minimized[1]”.

The greatest lesson to be learned from the retail experience to-date is that standby pricing should be taken more seriously, and examined more closely early on. In comparison, the state level experience shows more problems than successes with regard to standby pricing. All too often standby services have been underpriced. Also, there are states in which standby services are not priced separately; creating potential subsidies to these customers from the other customers in their rate class (i.e., intra-class equity problems). One can, however, learn from these mistakes. Additionally, an attempt to correct these problems can be made while unbundling prices and developing prices (and contracts) for the new competitive market place.

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1 Rännäri, Osmo. “Reform of the Finnish Electricity Market,” within Competition in the Electricity Supply Industry: Experience from Europe and the United States, (ed.) Ole Jess Olsen, DJØF Publishing, Copenhagen, Denmark, 1995.

Provision of Standby Services As a Market Niche

Standby services provide insurance (i.e., reduce risks) for either a self-generator, or an entity purchasing power from an unfamiliar source. As a greater number of purchases occur outside the framework of a vertically integrated supply system reliability may decline (or perceived as being less reliable), and the desire for insurance for these power contracts may expand. Standby contracting will be used by power purchasers to avoid purchasing emergency or backup power from the spot market.

In an open access regime it is more likely that standby contracting will expand to services being provided by a party other than the host utility. If a third party utility wants to supply only standby service to a purchaser, it is all the more important that standby service be priced appropriately. For some utilities with high priced supplies, greatest profitability might be achieved by concentrating on expanding transmission and standby services while letting power supplies become a much smaller part of their business.

The Obligation to Serve and the Need for Proper Pricing of Standby Services

To the extent that competition exists in generation and transmission access is developed, utilities should have no obligation to provide either generation or standby services, i.e., standby services should be supplied through market-based rates. An obligation to serve requires that prices be regulated with at least a floor price to protect captive customers from subsidizing those customers capable of receiving alternative primary sources of power and receiving only standby services (power insurance) from their native utility.

The Public Utility Regulatory Policies Act of 1978 (PURPA), with FERC application, required that interruptible backup (standby) services be provided to Qualifying Facilities (QF). The application of this requirement at the state level has varied considerably. Yet, there have been four different interpretations made, in different states, as to the PURPA requirements of standby service for QFs. These are:

1. The utility must offer only interruptible standby service with the price of this service incorporating appropriate cost-of-service fees.
2. The utility will not be required to provide firm or interruptible standby services, if the utility proves to the state regulatory body that doing so would harm its customers.
3. The utility must provide firm standby service with the price incorporating cost-of-service and reservation fees.
4. The utility must provide firm standby service under its normal pricing schedules (i.e., without reservation fees).

The above interpretations are ordered by the amount of potential costs they impose on the utility's captive customers. That is, the first interpretation offers the maximum protection to captive customers while the last offers the least. These differences in costs to captive customers result from a lack of clarity in the obligation to serve clause for providing standby services to QFs. They are not due to purposeful actions by state regulatory authorities to place captive customers at risk. In fact, this lack of clarity was specifically cited by the Michigan Public Service Commission as the reason for not approving a standby service rate request.

> "What is lacking is clarity about the legal requirements imposed by federal and state law and a quantification of the effects on Consumers [Consumers Power Company], its standby customers, and other customers of the variety of ways that standby service might be offered and priced.

> Consequently, the commission finds that the record is not adequate to resolve these issues in a manner that balances the interests of all parties or serves the public interest."[2]

The Connecticut Department of Public Utility Control (DPUC) provides an example of the first PURPA interpretation listed above. The DPUC does not require firm standby service, and they allow reservation fees to capture the benefits of capacity that is provided to standby customers who receive interruptible service. In a Connecticut Light and Power Company case in 1988, the DPUC stated:

> "Based on the record, we believe the minimum demand charge proposed by CL&P is supportable. It is true there is not a great deal of cost of service data available regarding this class because of the newness of the rate and the immaturity of the subscriber class, but cost of service is not the sole basis upon which to predicate rates. Under exclusive cost of service principles intermittent users and interruptible customers might bear insignificant responsibility for demand related charges. Nonetheless, both classes of customers achieve substantial value from the service being provided and both classes of customers impose substantial duty to serve obligations upon the utility provider. A charge that is reflective not only of costs but of these other considerations is appropriate."[3,4]

Offering only interruptible standby is equivalent to not requiring utilities to provide capacity to serve standby demand loads. United Illuminating Company, also in Connecticut, offers four levels of interruptible service but no firm service as part of their standby service rate tariff. Several jurisdictions and standby rates do not require the utility to offer firm standby service. For example, the Idaho PUC directly addressed this issue in Order No. 22887 in December 1989, regarding the Idaho Power Company's standby rate proposal. They said that "contract demand bears a meaningful and direct relationship to the utility's obligation to serve."[5]

In California, Pacific Gas and Electric Company (PG&E) has an approved standby tariff that specifically addresses its right to refuse standby service. This special condition grandfathers all current load, but says that PG&E reserves the right to deny standby service to new or increased loads, if serving this load may jeopardize service to existing customers. (PG&E will notify the California Public Utilities Commission (CPUC) of any decisions it makes to not serve this reservation load.) This new standby load will be subject to CPUC approval for reservation capacity over one megawatt, or combined reservation capacity across customers that exceed one megawatt from any single non-utility plant.

The relationship between contracting for standby and the obligation to serve can also be seen in state experience in natural gas standby pricing. In an order regarding Arkansas Western Gas Company, the Arkansas Public Service Commission stated, "Customers opting for transportation which do not pay standby charges will be referred to as non-core customers and will have no rights to system supply gas."[6]

Similarly in California, the California Public Utilities Commission stated that, "Standby service shall have the lowest priority during periods of curtailment," in its decision regarding Natural Gas Procurement and System Reliability[7].

The Texas Public Utility Commission provides us with an example of the second interpretation of PURPA. It requires utilities to provide standby and supplemental services to QFs. Yet, the utility is not required to provide this service(s) if, "after notice ... and opportunity for public comment, the electric utility demonstrates and the commission finds that provision of such power will: impair the electric

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2 PURbase©, 48417, 151 PUR4th 374, Case No. U-10335, Michigan Public Service Commission, May 10, 1994.

3 PURbase©, 18129, 97 PUR4th 525, Docket No. 87-07-01, Phase II, June 22, 1988.

4 This does not mean, however, that the captive customers are completely protected in Connecticut. This is because the standby rates in Connecticut have a fatal flaw seen in several states: they are not mandatory.

5 PURbase©.

6 PURbase©, 26787, 97 PUR4th, Docket No. 92-028-U and Docket No. 90-004-U, February 14, 1992.

7 PURbase©, 19211, 99 PUR4th 41, Decision 88-12-099, December 19, 1988.

utility's ability to render adequate service to its customers; or place an undue burden on the electric utility."[8]

Interpretation four has been seen in Massachusetts. For example, standby rates in Massachusetts were eliminated by the Massachusetts Department of Public Utilities (DPU) in the mid-1980s with criteria for an auxiliary service rate set forth in Boston Edison Company, DPU 1720 (1984). This was followed by the disallowance of auxiliary service rates in Cambridge Electric Light Company, DPU 84-165-A (1985) and Massachusetts Electric Company, DPU 85-146. Both of these cases cited the need for greater proof of the differences in costs between standby and non-standby customers. Standby rates were also eliminated in Massachusetts in the mid-1980s, as part of the removal of demand ratchets from all rates in Massachusetts. Massachusetts Electric's auxiliary service rate, in place from 1982 until the above case in 1985, was a modified general service rate. The general service rate applied for all customer charges and standby customers also faced an auxiliary service charge. This service charge was a demand ratchet substituting for a reservation fee. All demand ratchets were disapproved by the Massachusetts DPU; as they were believed to lower the incentive for energy efficiency investments.[9]

In North Carolina, Carolina Power and Light Company offers both firm and interruptible standby services. Nevertheless, standby service is limited to protect the captive customers by limiting its availability to amounts less than or equal to 50 mWs[10].

The Florida Public Service Commission approved Florida Power and Light's (FPL) request that customers with contracts to sell firm capacity and/or energy to FPL, and who cannot restart their generation equipment without power supplied by FPL, would be excluded from being able to take interruptible standby and supplemental service. This restriction protects native customers who rely on the power being sold to FPL by these customers, and assures these standby customers have the power to restart their generators during times when FPL needs this power and interruptible customers are being curtailed.[11]

The foregoing variations in PURPA interpretations demonstrate the importance of fully defining the obligation to serve that will exist in any new regime. It also shows the importance of balancing any obligation to serve with a pricing mechanism that ensures captive customers are protected.

Capacity Pricing and Contracting

The basic issue for standby pricing is the recovery of fixed costs. Unless additional charges are built into a distinct standby rate, the customer charge and reservation fee (or access fee) are the only bill components of a standby rate that are set-up for the collection of fixed costs. The other components, demand charges and energy charges, are dependent upon usage and, therefore, should only cover variable costs.

The importance of designing a standby price to cover fixed costs can also be seen in the pricing of natural gas standby service. The New Hampshire Public Utilities Commission supported a standby schedule to recover fixed costs. This ruling was as follows:

> "Usage data provided by the Company show that a limited number of customers with alternate fuel capability are meeting most of their energy needs with alternate fuel and using the gas distribution system for back-up or standby purposes. Consequently, the average annual consumption of gas by these "standby customers" is considerably lower than the average annual

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8 Substantive Rule 23.66, page 13, Public Utility Commission of Texas, Effective date 12/27/1993.

9 Western Massachusetts Electric did manage to obtain a backup rate in settlement with the Energy Consortium. Other backup rates, though small or applicable to only a few customers, have also been obtained by Boston Edison Company, and, recently, by Cambridge Electric for one customer situation.

10 PURbase©, 26401, PUR4th, Docket No. E-2, Sub 615, North Carolina Utilities Commission, January 14, 1992.

11 PURbase©, 45314, PUR4th, Docket No. 930929-EI, February 17, 1994.

consumption that underlies the applicable rate schedule. As a result, the Company has been unable to recover from these customers its fixed costs. In light of this, the settlement parties recommend that the Company be authorized to replace the current applicable schedule with a standby schedule designed to recover the fixed costs of standing ready to serve."[12]

Standby contracts are the largest mechanism by which partial requirements' customers are placed on a standby rate. Contract length varies from being unidentified to five years. Standby rates may also have required notices to leave standby service.

As a fixed fee, there is a price incentive for customers to underestimate their contract demand needs, if the utility will serve whatever demand is as used. If this is done systematically, there will still be an intra-class equity problem. Very large customers can also cause the utility more difficulties and create greater costs if utility's planned demand is too low due to the contract demand being too low. To prevent these problems some utilities provide penalties for excess demand, as-used demand greater than contract demand.

One of the heaviest penalties are those contained in Niagara Mohawk Power Corporation's (NMPC) standby tariff. NMPC has a two-tier excess demand penalty clause. If the as-used demand exceeds the contract demand by ten percent the penalty is twelve times the reservation fee, and if the as-used demand exceeds the contract demand by twenty percent the penalty rises to twenty-four times the reservation fee.

The Idaho Public Utility Commission, in its 1989 Order No. 22887[13] concerning the Idaho Power Company's proposed standby rate, stated that the utility had four alternatives available for addressing excess demand over contract demand. These alternatives were given as the following: contract demand ratchet; load limiting; disconnection; and excess or over-run charge. The standby rate for Idaho Power Company set in 1989 allows a five percent excess demand with a five-dollar excess charge per excess kilowatt plus a fifty-cent excess demand fee for daily kilowatt of excess demand. The PUC also stated that the utility had no obligation to serve above the contract demand.

A contract demand ratchet is a relatively common feature among standby rates. One prominent difference in the standby rate contract demand ratchet and a common demand ratchet is that almost half of utilities with ratchets do not specify a ratchet time period. The contract demand ratchet clause often states that if the as-used demand exceeds the contract demand, the as-used demand becomes the new contract demand. This is equivalent for most of these utilities to a twelve-month ratchet since the contracts tend to be one year contracts.

Another method that can operate as a demand ratchet is to provide the demand fees on a kilowatt basis differentiated by categories of demand use. The categorization is based upon contract or highest as-used demand during the contract period, normally one year. Fees based upon brackets of demand are used in the standby rate design of NMPC and Pacific Gas and Electric Company by kilowatt, and by kilovolt-amperes for Houston Lighting and Power Company's proposed standby rate.

Unbundling and Flexible Pricing--Lessons from Retail Standby Pricing

There is a definite trend in retail standby rate design towards greater disaggregation of the costs imposed by these customers. As we have already seen, these customers may have the most complex set of issues in retail pricing, with regard to cost causation and alternatives available to them. They are also normally the utility's largest retail customers with the greatest access to sophisticated cost, engineering and accounting experts.

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[12] PURbase©, 36729, PUR4th, DR 90-183, Supplemental Order No. 20,542, EnergyNorth Natural Gas Inc., July 20, 1992.

[13] Source: Public Utility Reports, PURbase©, mid-1994.

There are four general categories of costs in retail standby rates (not including categories of customer charges). These are whether the standby rate differentiates between rates for the following types of disaggregation:

- backup service versus maintenance service (the value of knowing when backup service will be taken);
- standby service (backup and maintenance) versus supplemental service[14];
- by transmission and distribution service level (e.g., primary, secondary); and
- by voltage level, categories of kiloVolt-amperes.

There can also be many divisions in each of these four categories. Given all these factors, retail standby rates could become some of the more complicated rate tariffs created by a utility. As such, their disaggregation, or unbundling, can provide a basis from which to examine the level of unbundling that is desired at the wholesale level. It can also provide clues as to pricing an unbundled package of services and what may be missing from the current pricing designs. The increasing complexity is easily seen in the standby tariff of Niagara Mohawk Power Corporation (NMPC). The NMPC standby tariff has 13 primary elements.

Another example of a disaggregated, or unbundled, standby tariff is that for Pacific Gas and Electric Company (PG&E). This one tariff is itself nine pages in length. PG&E has 11 elements in their tariff but a much greater number of segmentations within these elements than that of NMPC. Many utilities also have a power factor requirement but do not offer the customer the option to pay more for a different power factor. This option has been included in PG&E's standby service tariff. Another interesting element of PG&E's standby rate is that it allows for different customer charges for fifteen customer classes. These include customer charges for small businesses and residential. These classes have not to-date been normally included as part of the standby customer class. Yet, PG&E’s standby tariff appears to be prepared to meet new and changing needs for this type of service.

Differentiation between back-up, maintenance, and supplemental service pricing has also caused utilities to need to provide mechanisms for estimating and controlling the level of each of these types of usages. A possible service alternative to some of the control mechanisms might be found by offering different levels of standby service. This alternative is being used by Virginia Electric and Power Company who offers five ascending blocks of standby service with each offering more hours of standby service.[15]

The disaggregation of these costs also makes the criterion for defining which type of service is being taken as more important. Some utilities have required meters at both the customer generation and the customer’s site of utility power. The Missouri Public Service Commission accepted a standby rate that was higher than that acceptable to the industrials. This was due to the fact that the PSC agreed with Union Electric that it was impractical for the utility to have to conduct analyses of customer outages.[16] Oklahoma Gas and Electric has a provision in its standby rate that allows a flexible maintenance service but limits maintenance service to up to 120 hours with at least seven days notice to the utility.[17] Consumers Power allows up to 20 days of scheduled maintenance and five days of unscheduled “maintenance” (backup). Consumers Power also was allowed by the Michigan Public Service

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[14] Supplemental service is often priced at general service rates or differentiated due to the ability for this service to have load profiles like that of non-standby customers. Supplemental service may have standard year-round load profiles or may be like the non-standby seasonal customers, such schools or ski resorts. Both backup and maintenance service, on the other hand, are short-duration loads. These loads move from zero load state to maximum and back to zero load state in a short period of time, such as a few hours or a week. Backup and maintenance service are differentiated due to the ability to plan maintenance service and have it not occur coincident to system peak hours.

[15] Source: Public Utility Reports, PURbase©, mid-1994.

[16] Edison Electric Institute's Standby Rate: Methods and Descriptions, April, 1991, p. 30.

[17] Case Nos. EO-85-17 and ER-85-160. Source: Public Utility Reports, PURbase©, mid-1994.

Commission to charge the customers for placing meters on both the utility service and the customer generation, as these were needed for billing and load research.[18] (The customer intervenors wanted only a sample of customers to have meters on customer-owned generation to be used for load research.) On the other hand, Duke Power offers customers the option of installing meters at the point of their generation in order to obtain a different priced electricity service.

Back-up service is an insurance policy the standby customer is buying to reserve generation and transmission capacity. All previously made investments incremental to providing service to that customer are at fixed costs. These costs should be recovered from this customer and priced as fixed costs. The distribution demand capacity for a customer is a fixed cost that should be recovered from that customer, regardless of the level of future demand or energy usage. If the customer is a transmission level customer and is large enough to have changed transmission siting and costs, then these costs are customer fixed costs.

Green Mountain Power has a Special Equipment Tariff that has the customer pay for fixed equipment costs with a financing of these costs. "This tariff is applicable to any special contract, interruptible load, dispatchable power, standby service, or other special rate customer for whom normal billings on the applicable tariff do not yield a proper return on the Company's investment in local distribution facilities and/or special equipment. ...[Charges are determined by] (a) determining the Company's investment in facilities to serve the customer's peak demand, that are not used at any other time; (b)...multiplying investment total by annual carrying charge.. (22.91 percent); and (c) determination of the monthly bill by dividing the annual charge by twelve."[19]

This concept could be expanded to incorporate a fuller assessment of fixed costs. It is also applicable to transmission level services, and standby fixed costs.

Depending on the policy perspective, operating and maintenance costs for maintaining transmission and distribution (T&D) equipment specific to that customer may be viewed as fixed costs. These costs are non-discretionary costs in order to maintain that customer as part of the system. Future customer growth as it affects future additional transmission and distribution costs could be variable or discretionary costs.

The perspectives of discretionary versus non-discretionary costs in viewing what are fixed customer costs also have implications for customer or access fee charges versus demand and energy fee charges. In-place fixed distribution costs need to be recovered from the customer, regardless of their usage. This implies that commonly used contract demand, as used demand charges, and demand ratchets should be designed for recovery of only generation and non-customer-specific T&D costs.

This perspective also has implications for energy efficiency investments. These investments can be beneficial. Postponement of non-customer specific transmission and distribution costs can have a system benefit. There can also be a utility and customer savings for the postponement of new T&D expenses to meet load growth above the capacity-level of the current T&D capability to that customer. Rate design incentives for energy efficiency investments, such as ratchet forgiveness[20], demand forgiveness[21], and other pricing schemes should target those discretionary T&D costs (as well as

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18 Order No. 380443. Source: Public Utility Reports, PURbase©, mid-1994.

19 Case No. U-10337, October 1993. Source: Public Utility Reports, PURbase©, mid-1994.

20 PURbase©, 27379, PUR4th, Docket No. 5532, Vermont Public Service Board, April 2, 1992.

21 In June of 1993 the Connecticut Department of Public Utility Control (DPUC), in Docket 92-11-11, allowed Connecticut Power & Light (CP&L) to separate the distribution demand charge from the production/transmission (P/T) demand charge and allowed an increased demand ratchet from six months to twelve months. The DPUC also ordered the company to add provisions to the tariffs to reduce ratchets for customers that make conservation and/or load management investments. They also approved a "Transitory Demand Rider" to provide relief to customers who infrequently need a very large, incremental amount of energy over a short period of time (such as when new and old equipment must be run simultaneously during a testing period), and the transitory higher demand will not result in any long-term consequences for the Company or its ratepayers. The demand ratchet would not apply to incremental loads scheduled and approved by the Company.

generation) while not placing the recovery of customer-specific non-discretionary T&D costs in jeopardy (i.e., requiring subsidization from other customers).

The obligation to serve also can become a component of how marginal costs should be determined as they apply to standby rates. If the customer leaves the system and the utility does not have an obligation to serve that customer, then customer-specific transmission and distribution maintenance could be foregone. This immediately infers the need to establish a reconnection fee. This fee would be required to recover investment costs needed to bring customer-specific transmission, and distribution facilities up to the necessary conditions to serve the returning customer. This fee could be part of the customer charge, or a separate fee either paid with reconnection, or financed by the utility and paid for by the customer in installments as part of their utility bill.

Unbundled standby pricing can examine each unbundled element as it applies to marginal cost versus fixed cost. This can then be used to construct a flexible pricing scheme for the service.

The natural gas industry is already facing open competition. This has created a greater need for flexible pricing of standby-type rates from the natural gas local distribution company (LDC) than what the electric utilities have generally seen thus far. For example, the Maryland Public Service Commission has approved a flexible pricing scheme for Baltimore Gas and Electric Company in its Order No. 70476 in April 1993.[22] BG&E's interruptible standby gas rate does not cover cost, and responsibility of the production and storage costs. The flexible interruptible standby rate has a floor price of the variable marginal cost of service. The standard rate is the rate as would normally be designated to capture cost recovery. The ceiling rate was then determined as the standard rate, plus the difference between the standard rate and the floor price. In this way, the BG&E and the PSC hope that BG&E will be made whole for cost recovery. Standby customers are also given the option to take service at a fixed rate if they contract not to switch fuels on the basis of price.

Stranded Costs and Standby Pricing

Standby services can be seen as the mid-ground between full requirements' customers and lost customers. This means that standby services' pricing needs to consider its position a possible transition state, in order for the pricing to protect native customers over time. For example, a full requirement's customer may take part of its energy needs from a third party and requires standby service for that generation. Later, it may then take all of its energy needs from other third party providers. When this customer becomes a standby service customer, some of its former revenue may leave stranded generation costs. Part of these potential stranded costs is picked up in their usage for standby service, whose fixed costs are (should be) recovered from this customer in its reservation fee. When the customer obtains all of its generation from third parties, the unrecovered fixed costs become stranded costs.

This reinforces the importance of the pricing of reservation fees or fixed-cost based pricing for standby services. It also points out the transient nature of the utility's level of stranded costs.

The Delaware Public Service Commission ordered 100% mandatory standby fees in order to protect native customers in a docket regarding a standby natural gas rate for Delmarva Power and Light Company.[23]

On the other hand, New York State Electric and Gas Corporation (NYSEG) recently changed their natural gas standby sales service from an all or nothing (0% or 100%) choice to allow customers any percentage of their daily load as standby. The standby quantity is made by a service agreement, designating the customer's maximum daily standby quantity (MDSQ). The service is firm up to the

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[22] For example, Wisconsin Electric Power Company has had a demand forgiveness clause for customers who made energy efficiency investments.

[23] PURbase©, 44960, PUR4th, Docket No. 91-24, Order No. 3709, November 23, 1993.

MDSQ and interruptible for sales in excess of the MDSQ. There is a penalty for the taking of natural gas above the MDSQ in terms of interruption.[24]

Retail electric standby rates are also beginning to incorporate considerations for stranded costs. These can be seen in the standby rates proposed in 1995 by Consolidated Edison of New York, and Niagara Mohawk Power Corporation. The link between standby and the move to a competitive market was recognized in the Massachusetts DPU approval of a transition charge as part of a standby rate by Cambridge Electric Light Company in September, 1995, DPU 94-101/95-36. The DPU approved a "Customer Transition Charge" (CTC) as a wires charge (not an exit fee) to recover 75 percent of stranded costs from a move of MIT to QF power.[25]

The full range of stranded costs, the inter-relationship between stranded costs and reservation fees for standby customers, exit fees, and reconnection fees, however, have yet to be explored at either the retail or wholesale pricing level.

Sequencing of Pricing--Standby Pricing within the Menu of Service Pricing

The discussion of offering interruptible standby services and firm standby services; brings us to an issue that must be examined carefully in the pricing of the full range of services offered. Retail pricing of firm standby service and interruptible primary service has, at times, led to incompatibilities between these. Not allowing customers to receive both types of service is a result of the state experience with the pricing of standby services. A more appropriate solution might be that as pricing is designed, taking both services should be more expensive than obtaining firm service. Theoretically this should occur as there are greater administration costs to administering both services to a customer, while providing the same level of capacity and energy, than serving this customer with firm primary service. State experience has found the taking of both services to allow the customer to be receive a discount for what is essentially firm primary service. This indicates that the standby service probably is underpriced. (If not, the interruptible primary service is underpriced.)

It is recommended that utilities examine the pricing of services across the board and how they appear in sequence of the service offered. That is, firm primary service should cost more than interruptible, predictable (firm) primary service should cost less than the equivalent take of unpredictable firm (standby) service, and predictable service controllable as non-peak (maintenance service) should cost less than the equivalent take of generally predictable (firm) primary service. Additionally, utilities should examine their pricing as it is in sequence when combined. That is, a customer should not be able to obtain firm service for less cost, by combining interruptible primary service with a firm standby service for the interrupted periods from one utility provider. (Recognize, that open access and competition may allow a customer to achieve a lower cost by obtaining interruptible primary service from one utility, and firm standby service from another utility for the interrupted periods of the first utility. The sequencing of prices may still occur and be economically efficient from each utility.) In other words, sequencing of pricing is for the utility to insure its pricing and packaging makes sense, more service costs more than less service. Otherwise subsidies (or lost profitability in a purely competitive market) and economically inefficient decisions will occur.

Conclusions

1. Get standby pricing (retail and wholesale) right as early as possible in the transition to competitive prices.

[24] PURbase©, 47924, PUR4th, Case 93-G-0689, New York Department of Public Service, March 4, 1994.

[25] PUR Weekly, 10/27/95.

Competition in generation has been significantly impacted by technological changes and PURPA. As a result, pricing for standby services in retail markets has fluctuated and evolved significantly. Utilities, at first, were somewhat remiss in setting pricing for standby services, assuming that the impacts for inappropriate pricing would be minimal. In other cases, utilities attempted to achieve reservation charges, but were unable to get them approved given how much they increased costs for the standby customers. The importance of these services can be seen by their increasing usage. It is very difficult to raise rates that are priced inappropriately low in the beginning.

2. To the extent that competition exists in generation and transmission access is developed, utilities should have no obligation to provide standby services, i.e., standby services should be supplied through market-based rates.

3. To the extent that regulators (FERC for wholesale, and state regulators for retail) impose standby service obligations and regulate prices, regulators should:
   a) Allow the use of balancing accounts to track costs incurred in providing each standby-related service;
   b) Allow efficient sequencing of services and prices;
   c) Allow the use of a reservation fee to recover fixed costs, including the probability of usage and diversity of loads in the class to be incorporated into the rate;
   d) Allow the use of incentive pricing to discourage customers from shifting costs by purposely underestimating contract demand;
   e) Allow for the recovery of implicit standby costs created by maintaining an obligation to serve customers selecting power from alternative sources/suppliers; and
   f) Allow for the recovery of transitional stranded costs through a fixed fee, such as within the standby reservation fee.

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