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REAL TIME PRICING AS A DEFAULT OR OPTIONAL SERVICE FOR COMMERCIAL AND INDUSTRIAL CUSTOMERS:

A COMPARATIVE ANALYSIS OF EIGHT CASE STUDIES

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Acronyms and Abbreviations

ALM	Active Load Management
BGE	Baltimore Gas & Electric
C&I	commercial & industrial
CBL	customer baseline load
CG&E	Cincinnati Gas & Electric
CHG&E	Central Hudson Gas & Electric
ComEd	Commonwealth Edison
ConEd	Consolidated Edison
COS	cost of service
DADRP	Day-Ahead Demand Response Program
DLC	Duquesne Light Company
DR	demand response
DRSP	demand response service provider
DSM	demand side management
EDRP	Emergency Demand Response Program
ESCO	energy services company
FERC	Federal Energy Regulatory Commission
GPC	Georgia Power Company
GPSC	Georgia Public Service Commission
GW	gigawatt
ICAP	Installed capacity
ICAP/SCR	Installed Capacity/Special Case Resources
ICC	Illinois Commerce Commission
IOU	investor-owned utility
IRP	integrated resource plan
ISO	independent system operator
ISO-NE	Independent System Operator – New England
JCP&L	Jersey Central Power & Light
kW	kilowatt
kWh	kilowatt-hour
LBNL	Lawrence Berkeley National Laboratory
LSE	load serving entity
MADRI	Mid-Atlantic Distributed Resources Initiative
MDPSC	Maryland Public Service Commission
MISO	Midwest Independent System Operator
MW	megawatt
MWa	average megawatt
MWh	megawatt-hour
NJBPU	New Jersey Board of Public Utilities
NMPC	Niagara Mohawk Power Company
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission
NYSEG	New York State Electric & Gas
NYSERDA	New York State Energy Research and Development Authority
O&R	Orange & Rockland

OII	order instituting investigation
OIR	order instituting rulemaking
OPUC	Oregon Public Utilities Commission
PGE	Portland General Electric
POLR	provider of last resort
PPUC	Pennsylvania Public Utilities Commission
PSC	public service commission
PSE&G	Public Service Electric & Gas
PUC	public utilities commission
PUCO	Public Utilities Commission of Ohio
RG&E	Rochester Gas & Electric
RTO	regional transmission organization
RTP	real time pricing
T&D	transmission & distribution
TOU	time of use

Executive Summary

Demand response (DR) is broadly recognized to be an integral component of well-functioning electricity markets, but currently underdeveloped in most regions. In recent years, there has been renewed interest among a number of public utility commissions (PUC) and utilities in implementing real-time pricing (RTP), typically for large commercial and industrial (C&I) customers, as a strategy for developing greater levels of DR. Such efforts typically face a set of key policy and program design issues, including:

- How to organize the process for developing and implementing RTP in a manner that facilitates productive participation by the relevant stakeholder groups;
- Whether to designate RTP as an optional or default service, and for which customer classes;[1]
- What type of tariff design to adopt given prevailing policy objectives, wholesale market structure, ratemaking practices and standards, and customer preferences; and
- What types of supplemental activities (e.g., customer education, deployment of enabling technologies) are appropriate to facilitate customer participation and price response.

Given resolution of these design and implementation issues, a key question for policymakers is how much DR can ultimately be expected from RTP, which requires analyzing customers' willingness to be exposed to dynamic hourly prices over a sustained time period and their actual price responsiveness.

State agencies, utilities, and customer groups in California have been engaged in an ongoing process to develop retail mechanisms for DR, including consideration of utility RTP tariffs. To provide information to policymakers and stakeholders in California and other jurisdictions, we conducted a comparative review of eight case study states where RTP has been implemented as a default and/or optional service for commercial and industrial (C&I) customers. Each state has established some form of retail competition, although there are significant differences in regulatory and market environments.

For each case study, we reviewed related regulatory filings and other public documents and interviewed PUC staff, utilities, and competitive retail suppliers active in that state. We summarize and identify key trends related to:

- The policy context and objectives underlying RTP implementation;
- The regulatory process used to design and implement RTP;
- The level of support from and key positions of stakeholder groups;
- The RTP tariff structure;
- Enabling technology deployment and customer education efforts conducted to support RTP implementation;
- Enrollment in RTP and price response from participating customers;
- Utility and ISO/RTO DR program enrollment and load reductions; and
- DR impacts of products and services offered by competitive retail suppliers.

Drawing from these findings, we identify and discuss recommendations for policymakers seeking to support the development of DR in both competitive and regulated retail markets.

[1] We use *default service* to refer to any rate on which customers are automatically placed if they do not affirmatively choose some other option; and we use *optional service* to refer to any rate on which customers are placed only if they affirmatively choose that option. Said differently, an optional service is one where a customer must opt *in*. A default service is one where a customer would have to opt *out*, if such an option is offered.

ES-1. Overview of Case Studies: Regulatory and Market Context

The eight case studies profiled in this report include default and optional RTP tariffs that have been adopted either by individual utilities or all investor-owned utilities in a particular state (see Table ES-1).

Table ES-1. Eight Case Studies of Default or Optional RTP

State	Utilities	Default RTP	Optional RTP
New Jersey	All investor-owned utilities	Implemented (2003)	Implemented (2003)
Maryland	All investor-owned utilities	Implemented (2005)	Implemented (2004)
Pennsylvania	Duquesne Light Company (DLC)	Implemented (2005)	-
New York	Niagara Mohawk Power Company (NMPC)	Implemented (1998)	-
	All other investor-owned utilities	Considered (2003)	Implemented (2001)
	Central Hudson Gas & Electric (CHG&E)	Implemented (2005)	Implemented (2001)
Illinois	Commonwealth Edison (ComEd)	Planned (2006)	Implemented (1998)
Ohio	Cincinnati Gas & Electric (CG&E)	Implemented (2005)	Proposed (2003)
Oregon	Portland General Electric (PGE)	-	Implemented (2004)
Georgia	Georgia Power Company (GPC)	-	Implemented (1992)

In six states (New Jersey, Maryland, Pennsylvania, New York, Illinois, and Ohio), full retail access is currently in place for all customers of the investor-owned utilities (IOU). In Oregon, only non-residential customers currently have retail choice. And in Georgia, a limited form of retail competition was established in 1973, whereby most new facilities with a connected load >900 kW have a one-time choice of supplier, and the state's regulated IOUs are allowed to compete for this load.

New Jersey: In 2003, RTP became the only supply option for customers in the high voltage classes that had not contracted with a competitive supplier. In 2004 and 2005, the size threshold for default service RTP was reduced to 1,500 kW and 1,250 kW, respectively. For other, smaller C&I customers, the default service is an auction-based fixed-price rate although they are allowed to voluntarily opt onto RTP.

Maryland: In July 2002, RTP became the only supply option for customers of Baltimore Gas & Electric (BGE) with a peak demand >1,500 kW that had not contracted with a competitive supplier. This tariff was then supplanted by a statewide default service beginning in July 2004. All customers with a peak demand >600 kW in Maryland were offered a temporary fixed-price default service for one year. During this period, RTP was available to customers in this class as an optional service. When the fixed price default service for customers >600 kW ended in June 2005, RTP then became the default service for this group of customers.

Pennsylvania: In 2005, RTP became the default service for customers of Duquesne Light Company (DLC) with a peak demand >300 kW. An auction-based, fixed-price option is also available to this customer class, as an alternative to RTP, until mid-2007.

New York: RTP is currently the only utility supply option for Niagara Mohawk Power Company (NMPC) customers with a peak demand >2,000 kW that have not switched to a competitive supplier. Since 2001, RTP has been offered as an optional service by the state's other five IOUs, and in 2003, the NYPSC considered making RTP mandatory for some of their customers, but decided against doing so. In 2005, the NYPSC adopted a proposal by Central Hudson Gas &

Electric (CHG&E) to make RTP the only utility supply option for its customers with a peak demand >1,000 kW that have not switched to a competitive supplier.

Illinois: ComEd has offered RTP as an optional service for all non-residential customers since 1998. In 2003, RTP became the only utility supply option for *new* ComEd customers with a peak demand >3,000 kW; and in 2007, it will become the only utility supply option for all ComEd customers with a peak demand >3,000 kW (new *and existing*).

Ohio: In 2003, Cincinnati Gas & Electric (CG&E) proposed a portfolio of utility supply options, including several optional RTP tariffs, to be offered following the end of their rate cap period. This proposal was not adopted and, instead, a "market-based" fixed-price rate was adopted as the only utility supply option for customers with a peak demand >100 kW as of January 2005. RTP was adopted as the only utility supply option for customers *returning* to CG&E from a competitive supplier after that date.

Oregon: In 2004, Portland General Electric (PGE) introduced an optional RTP tariff for customers with a peak demand >1,000 kW. It is currently a pilot and is limited to a maximum of six customers.

Georgia: Georgia Power Company (GPC) began offering RTP in 1992 and currently offers two optional RTP tariffs, one with day-ahead price notice available to customers with a billing demand >250 kW and another with hour-ahead price notice available to customers with a billing demand >5,000 kW.

The policy context surrounding implementation of RTP as well as the retail/wholesale market structure and status differs somewhat among the cases (see Figure ES-1). The basic context in states where *default* RTP was adopted was that the state's transition period, during which the utility offered an administratively-determined supply option after restructuring, was coming to an end. This condition prompted some type of regulatory process to establish the terms of the supply service to be provided thereafter to customers not taking their supply from a competitive retail supplier. As such, the primary policy objective guiding this process was to support retail market development; and DR was at most a secondary objective, although in many of these states it was being actively pursued through parallel policy initiatives.

In contrast, the *optional* RTP tariffs adopted by PGE and by IOUs in New York were developed in what might be broadly characterized as a resource planning or resource adequacy context, and the potential for RTP to induce DR was the key driving force behind its implementation.

Lastly, GPC developed its optional RTP tariffs in a rather unique context. Prior to introducing RTP, GPC offered a curtailable (i.e., interruptible) rate for large C&I customers, whereby customers purchased their non-firm load at fixed, marginal cost-based prices, and the utility could call for curtailments for reliability and economic reasons. Facing the prospect of increased economic curtailment hours in the early 1990s, the utility developed its initial RTP pilot as an experimental rate design that would allow customers to continue purchasing a portion of their load at marginal cost based prices, but that would allow customers to buy-through economic curtailment periods at the utility's short-run avoided cost. As GPC's RTP program has grown and matured, the utility has also recognized its value as a tool for load management, recruitment of new customer load, and economic development.

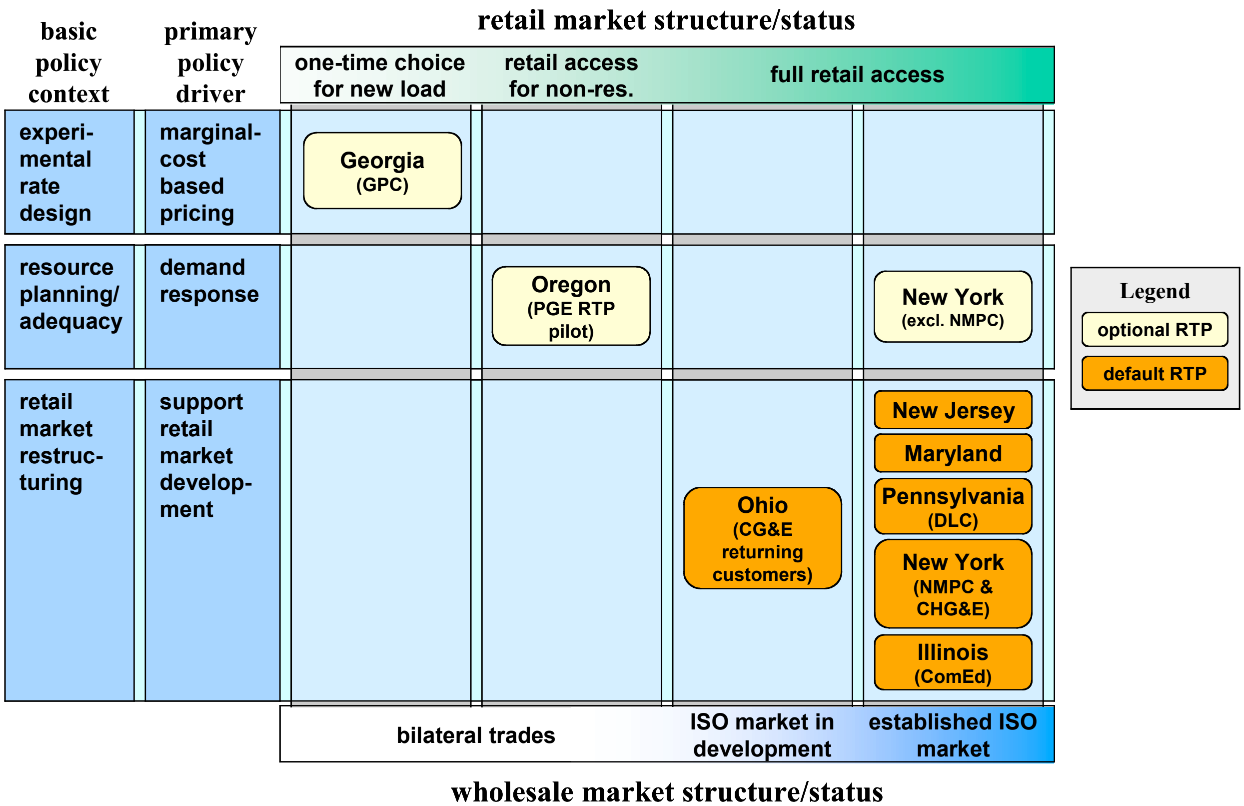

Figure ES-1. Regulatory and Market Context

ES-2. RTP Tariff Design

The eight case studies represent a range of RTP tariff designs. Most of the RTP tariffs have a one-part commodity charge, where customers face hourly prices for all of their hourly usage, with additional, unbundled billing components (i.e., demand charges or other volumetric charges) for non-commodity related costs. GPC and PGE are the only cases involving a two-part, CBL-based RTP tariff design.[2] A key difference between these two tariffs is the procedure used to set and maintain each customer's CBL. In PGE's case, each customer receives a CBL at the time of their enrollment that represents their typical hourly usage pattern, and the tariff specifies that the utility will review each customer's CBL every three years and may make adjustments. In GPC's case, all participants are allowed to maintain their CBL indefinitely over the term of their service, even if they permanently increase their load. Also, some customers are able to receive, at the time that they initially enroll in RTP, a CBL that is less than their typical usage level. First, customers that were previously on the utility's Supplemental Energy tariff were able to receive a CBL equal to their previous firm service level, if they switched to RTP. Second, *industrial* customers with *new* load receive, by default, a CBL equal to 60% of their projected load if they enroll in RTP. Finally, all new customers (industrial and commercial) can

[2] With this type of tariff design, each participant is assigned an individual customer baseline load (CBL) profile, which consists of a set of hourly loads for a full year. The participant's monthly bill is calculated by applying the standard, non-RTP tariff billing components to the customer's CBL, and applying hourly prices to the *difference* between the customer's actual usage and its CBL in each hour.

receive a CBL below their default level if they can demonstrate an ability to shed their load by a proportional amount over a two hour period or if an another facility with the same footprint (e.g., another outlet of a particular retail chain) has already performed such a demonstration.

The hourly prices for each RTP tariff are typically derived from the most transparent of three different types of sources: the clearing price in a centralized spot market administered by an independent system operator or regional transmission organization (ISO/RTO); proprietary indices of bilateral bulk power transactions at regional trading hubs; or internal calculations by the utility of their marginal operating cost (the utility's "system lambda"). The RTP tariffs provide participating customers with different degrees of advance notice of hourly prices. The RTP tariffs adopted in New Jersey, Maryland, and Pennsylvania are all indexed to the PJM real time spot market, where hourly prices are determined after-the-fact; thus participating customers do not have any advance notice of firm hourly prices, although they could use day-ahead market prices as a proxy. Most of the other RTP tariffs provide day-ahead advance notice.

ES-3. Key Findings: DR Impacts of RTP and Other DR Mechanisms

Various mechanisms can be implemented at the retail level to induce DR from electricity consumers, including: RTP offered by utilities, spot market indexed pricing options offered by competitive retail suppliers, and DR programs offered by ISO/RTOs and/or utilities. The impact of each mechanism on the development of DR depends on, first, how much load is exposed to that particular mechanism and, second, how price responsive those customers are.

(1) *With the exception of Georgia Power, optional RTP tariffs have generated limited levels of participation.*

In five of the six optional RTP tariffs included in our case studies, less than 2% of the eligible customers have enrolled. In contrast, more than 40% of eligible customers have enrolled in GPC's RTP tariffs, comprising more than 80% of the eligible load (see Figure ES-2). The notable success of GPC can be attributed to a number of factors, namely: most customers on RTP can reasonably expect to achieve long-run bill savings, regardless of whether or not they are price responsive; GPC has aggressively marketed RTP for more than a decade to a broad group of C&I customers; and their tariff design allows customers to hedge a portion of their load at a fixed price.

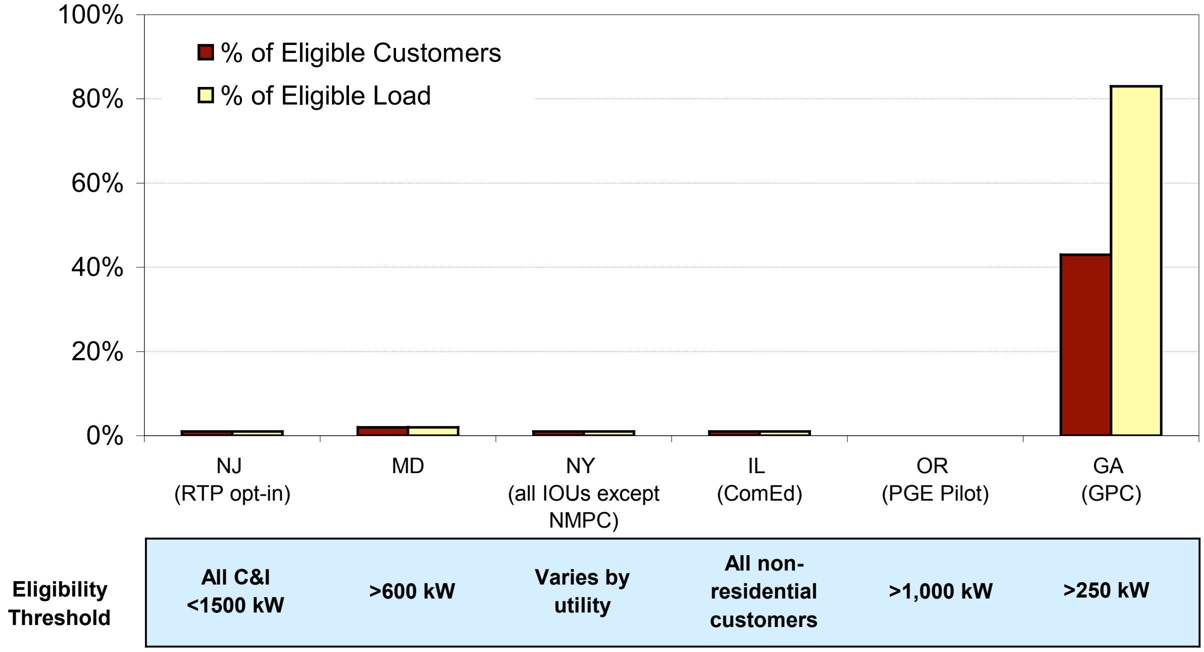

Figure ES-2. Enrollment in Optional RTP Tariffs in Late 2004/Early 2005

(2) *In each of the three default RTP tariffs in place in early 2005, most of the load has switched to a different supply option, although the percentage remaining on RTP varies significantly.*

In DLC's service territory, only 3% of the load in the default RTP class is enrolled in RTP, while 34% and 16% of the load in the default RTP classes in NMPC's service territory and New Jersey, respectively, have remained on RTP (see Figure ES-3). Differences in participation rates among these three cases may reflect a number of factors related to tariff design and retail market development, such as: the amount of advance notice with which customers have knowledge of hourly prices (day-ahead for NMPC vs. after-the-fact for New Jersey and DLC); the availability of an alternative fixed price supply option with the utility (which only DLC offers); the size of the default RTP threshold (300 kW for DLC, compared to 1,500 kW and 2,000 kW for New Jersey and NMPC, respectively); and the availability of competitive retail supply offers.

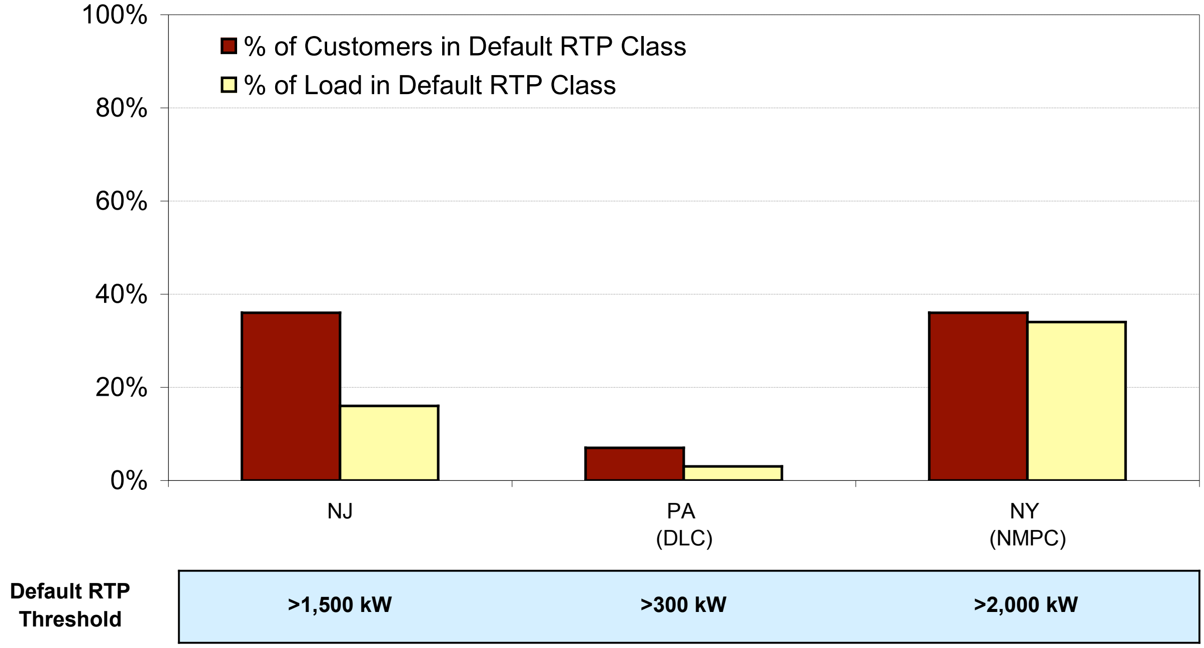

Figure ES-3. Enrollment in Default RTP Tariffs in Late 2004/Early 2005

(3) *The case studies revealed several indirect impacts that default RTP might have on the development of DR in competitive retail markets; however more formal analysis is needed before firm conclusions can be drawn.*

The case studies highlight three plausible (but untested) *indirect* positive impacts that default RTP might have on the development of DR in competitive retail markets. First, having RTP as the default service may create demand for spot market indexed pricing options offered by competitive suppliers that otherwise might not evolve, because customers use the default rate as a benchmark and seek out competitive supply contracts with a comparable pricing structure but lower prices.[3] Second, customer demand for spot market indexed pricing may also be enhanced as a result of customer experience on default RTP and education/training activities conducted in concert with default RTP implementation. Third, several states have deployed interval meters across a wide population of C&I customers as part of default RTP implementation.

(4) *Competitive retail suppliers reported a wide range of values for the market penetration of spot market indexed pricing options, ranging from 5% to 75% of their C&I load in different regions.*

The eight competitive retail suppliers interviewed for this project provided information on the penetration of spot market indexed pricing arrangements (i.e., a full pass through of spot market prices for all commodity requirements and block-and-index pricing arrangements) among large C&I customers in various regions. The three suppliers that reported market penetration rates for New Jersey, specifically, indicated that a relatively large fraction (50-75%) of their large C&I load in the state has opted for a spot market indexed supply contract. The values that suppliers

[3] In the case of default RTP service, competitive suppliers may be able to offer lower prices for ICAP or ancillary services charges, or a smaller mark-up on commodity charges than the default service retail adder.

reported for other regions varied between 5% and 25%. Several factors may account for the differences in reported market penetration rates, including: the customer size threshold used to define the large C&I market in different regions (i.e., 1,500 kW in New Jersey vs. 600 kW in Maryland), the types of C&I customers targeted by particular suppliers, regional differences in the mix of customers, and the availability of hedged utility supply options. Many of the suppliers we interviewed indicated their belief that much of the current interest in spot market-indexed products was temporary, due to low spot market volatility and mild weather, and that more customers would start locking-in fixed price contracts if price volatility increases.

(5) *From one to ten percent (1-10%) of the system load in several retail markets appears to be exposed to spot market prices, although there is significant uncertainty in these estimates.*

Very little information is available in the public domain about the amount of load in competitive retail markets that faces hourly spot market prices through their retail supply contract. To fill this void, we developed lower and upper bound estimates of the amount of load that has switched to spot market indexed contracts with a competitive retail supplier in three large C&I markets: the New Jersey CIEP class (all customers >1,500 kW), the Maryland Type III class (all customers >600 kW), and the NMPC SC-3A class (all customers >2,000 kW). We combined these estimates with data on enrollment in optional and/or default RTP tariffs offered by utilities in these states, in order to derive an estimate of the total load in each state exposed to hourly spot market prices.[4]

Based on this approach, we estimate that, as of early 2005, 1-4% of the system peak load in Maryland, 6% in NMPC's service territory, and 6-10% in New Jersey was facing hourly spot market prices through either a utility RTP tariff or a retail supply contract with a competitive provider (see Figure ES-4). One key driver for the relatively low percentage of system peak load exposed to spot market prices in each of these markets is that the default RTP class only accounts for 10-20% of the total system load. The relatively low exposure to spot market pricing in Maryland primarily reflects the fact that, during the period for which these estimates were developed, RTP was an optional service for large C&I customers in Maryland but was the default service for large C&I customers in the other two regions.

[4] Note that we do not include in this analysis any estimate of the amount of load exposed to spot market indexed competitive supply contracts among customers *smaller* than the default RTP size threshold.

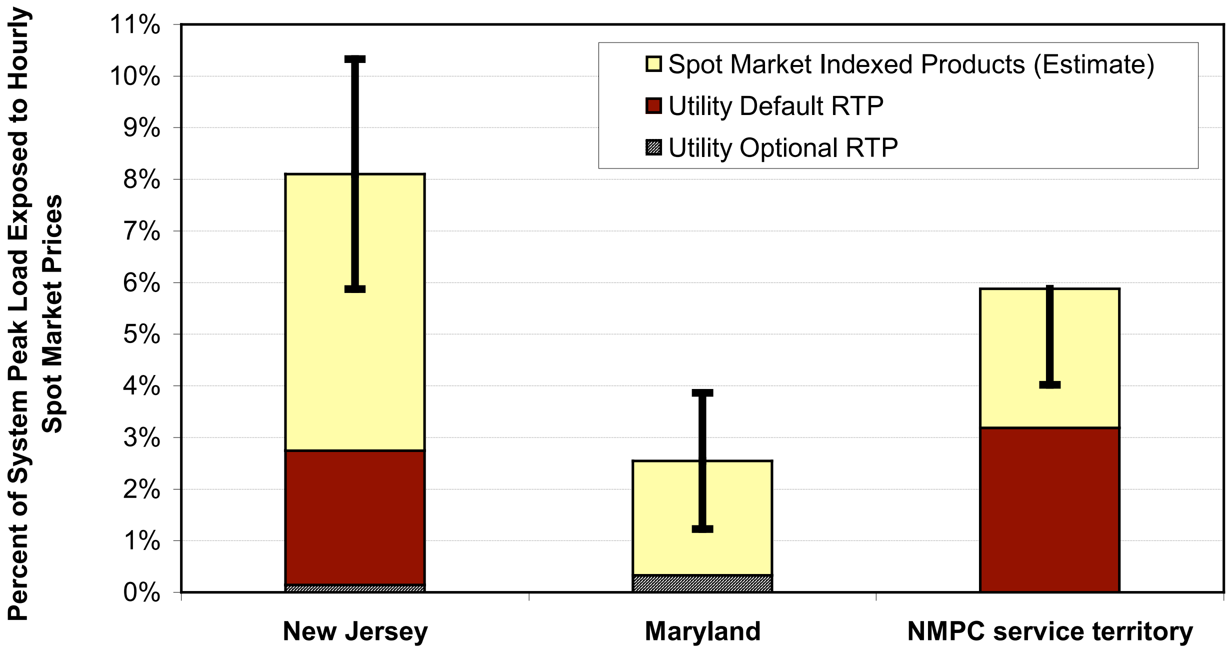

Figure ES-4. Percent of System Peak Load Exposed to Hourly Spot Market Prices in Three Regions [5]

(6) *RTP tariffs that provide advance notice of prices have elicited load reductions in the range of 10-15% of participants' aggregate billing demand at very high prices.*

Of the case studies examined in this report, formal analyses of customers' price responsiveness have been performed only for NMPC and GPC. Goldman et al. (2005) estimated the substitutional price elasticities of customers in NMPC's default RTP class using five years' of hourly billing data. Using these estimates, NMPC customers are expected to reduce their load by an amount equal to approximately 10% of their combined billing demand, when peak period prices are five times greater than off-peak prices (e.g., a peak period price of $0.50/kWh and an off-peak price of $0.10/kWh).[6] Based on the amount of load remaining on NMPC's RTP tariff in 2004, this load reduction corresponds to approximately 0.3% of the utility's system peak.

Braithwait and O'Sheasy (2001) estimated the price elasticities of customers on GPC's RTP tariffs. Based on these estimates, on one particular day when customers on the day-ahead RTP rate faced a maximum price of $1.93/kWh and customers on the hour-ahead RTP rate faced a maximum price of $6.43/kWh, they reduced their load by approximately 750 MW in total, equal to approximately 15% of their aggregate billing demand or about 5% of the utility's system peak load.

[5] For New Jersey and Maryland, the vertical bars represent our upper and lower bound estimates for the amount of load exposed to spot market prices through a competitive supply contract, and the yellow bar represents the average of these two values. For NMPC, the yellow bar represents our best estimate of the amount of load exposed to spot market prices through a competitive supply contract, and the single vertical bar is our lower bound estimate. See Section 5.2.2 for further details.

[6] At NMPC, peak period prices were five times higher than off-peak period prices on only 2 days between summer 2000 and summer 2004.

(7) *Little is currently known about the price responsiveness of customers participating in RTP tariffs that are indexed to real time spot markets.*

The RTP tariffs that have been recently implemented in New Jersey, Maryland, and DLC's service territory employ prices that are indexed to the PJM real time spot market, and these prices are not known until after the applicable hour has elapsed. To date, no formal evaluations have been conducted to assess the extent to which customers remaining on these default RTP tariffs respond to hourly prices. Thus, without any analysis, no definitive conclusions can be drawn at this point about the extent to which RTP tariffs of this type might induce price response. Utility and regulatory staff in New Jersey, Maryland, and Pennsylvania generally doubted whether customers on RTP in their state actively monitor or respond to hourly prices.

(8) *Little is currently known about the price responsiveness of customers that purchase their supply through a spot market indexed contract with a competitive retail supplier.*

Most of the competitive retail suppliers we interviewed stated their belief that the vast majority of customers on spot market indexed pricing options do not monitor or respond to hourly prices, although none of the suppliers had systematically examined the question. Accordingly, they indicated that, for the most part, they do not account for price response from customers facing hourly spot market prices in their scheduling and procurement activities. In general, competitive retail suppliers do not currently view spot market indexed pricing options in terms of an opportunity for customers to reduce their energy costs through responding to hourly prices. Suppliers typically do not focus on DR in marketing these service offerings, except perhaps to customers with onsite generation. And the suppliers offer few services to assist customers with responding to hourly prices. This lack of emphasis on DR in relation to spot market indexed pricing may partly reflect the relatively stable prices characteristic of current market conditions.

(9) *A variety of DR programs offered by utilities and ISO/RTOs have demonstrated the ability to elicit load reductions in the range of 1-3% of the respective entities' system peak.*

In all of the case studies, utilities or an ISO/RTO offers a variety of DR programs to C&I customers. In 2004, participation in most of these DR programs (reported in terms of customers' contracted or nominated load reduction quantity) was in the range of 1-4% of the utility or statewide system peak load.[7] Operational activity in many programs has been limited in recent years due to an absence of system reliability contingencies and/or low spot market prices. Those DR programs for which recent performance data is available have demonstrated load reductions in the range of 1-3% of the system peak.

ES-4. Policy Implications for Competitive Retail Markets

(1) *Day-ahead default RTP can be an effective strategy for simultaneously meeting retail market development and DR-related goals.*

RTP has been adopted as the default service in a number of states primarily to facilitate retail market development, because it always reflects current market conditions, does not require the use of class average load profiles for setting the commodity charge, and is does not require

[7] Note the difference in how participation is reported for DR program compared to RTP – i.e., customers' contracted or nominated load reduction as opposed to customers' combined billing demand or coincident peak demand.

imposing switching restrictions. At the same time, default service RTP also has the potential to stimulate DR, both from customers that remain on the default service and from those that seek out a competitive supply arrangement with a similar pricing structure to the default service. Evidence to date suggests that default RTP tariffs that are indexed to the *day-ahead* energy market may be more effective at stimulating DR than default RTP tariffs that are indexed to the *real-time* spot market, because the former provides customers with a greater level of advance notice.

(2) *State regulators and utilities should consider installing interval meters over a wider population of C&I customers than just the default RTP class, and should also consider including features in the metering infrastructure that facilitate DR*.

Large scale deployment of interval metering among C&I customers has been conducted in several states to support implementation of default RTP. Such efforts represent another opportunity to leverage DR goals with retail market restructuring activities, in this case by installing interval meters across a wider customer population than the default RTP class, as was done in New Jersey, and by specifying metering systems with features that facilitate price response.[8] Policymakers should consider whether these incremental measures are warranted, in light of the potential benefits they could yield in terms of the development of DR (e.g., by facilitating participation in ISO/RTO DR programs and/or bolstering the price responsiveness of customers facing hourly spot market prices through default RTP or a competitive supply contract).

(3) *Rigorous collection and analysis of data related to customer exposure and response to spot market-indexed competitive supply contracts is needed.*

A variety of policy and planning decisions (e.g., related to continuation of wholesale market price caps or certain types of DR programs) hinge upon assumptions about the price responsiveness of retail electricity consumers. Yet, little information is currently being collected in regulated or competitive markets to measure how and why customers respond to prices. Federal and state regulators and ISO/RTOs should consider undertaking efforts to regularly collect and analyze data on retail customers' supply arrangements and response to hourly pricing and other dynamic pricing options, to support policy and planning decisions that require knowledge about the price responsiveness of retail consumers. Given the sensitive nature of this information, appropriate measures would be required to ensure that data released to the public does not compromise the position of individual suppliers or customers.

(4) *The development of DR in competitive retail markets may require addressing market barriers.*

Competitive retail suppliers currently offer few services to help customers identify, analyze, or implement load response strategies and report a perceived lack of customer demand for these services. The potential for DR to develop in competitive retail markets will likely be limited in

[8] Advanced metering infrastructure features that could enhance DR capability include hardware or software that allow customers to directly access their metered usage data at frequent (e.g., hourly) intervals, meters with data ports that allow customers to directly download data from their meter for an EMCS, EIS, or load control device, and training on optimizing energy information systems (EIS) and energy management control systems for DR applications.

the near-to-mid term without a concerted effort on the part of some entity to help customers develop their load response capabilities. Some set of policy interventions may therefore be warranted to enhance customers' capability and willingness to respond to dynamic prices. In many states that have implemented customer choice, the state regulatory commission and/or utilities have conducted general customer education activities to provide basic information about restructuring and/or default service. Policymakers should consider incorporating into these activities information to help customers better understand the potential cost savings and risk management benefits associated with load response to hourly spot market prices as well as technical information to help customers identify load response strategies. Additional programmatic efforts, such as facility DR audits and financial assistance with DR enabling technologies may also be warranted.

ES-5. Policy Implications for Regulated Retail Markets

(1) *The implications of implementing default RTP in a regulated market, in terms of customer acceptance and DR impacts, depend on what types of hedging options are offered to customers in the default RTP class.*

To implement RTP as the default service in *regulated* retail markets, political considerations are likely to require that customers in the default RTP class be afforded some opportunity to financially hedge their exposure to price risk. One option is to allow customers to opt out of RTP onto an alternative, fixed price rate. Experiences in competitive retail markets where customers have been offered a choice between an unhedged RTP tariff and a full-requirements, fixed price service have suggested that the large majority of customers will choose the fixed price service. Thus, if the goal is to stimulate DR, this approach does not seem particularly promising.

A second option is to structure the default RTP tariff as a traditional two-part RTP tariff, where each customer receives a CBL equal to their historical usage profile. The advantage of this approach is that customers' bills and the utility's revenues are affected only to the extent that customers' usage patterns change. However, the process of developing an hourly load profile for each individual customer to serve as their CBL can be quite time consuming, prone to contention, and, for new customers and others without an established history of interval load data, rather subjective.

A third option, which avoids some of the difficulties associated with the CBL-based tariff design, is to implement a default RTP tariff similar to the block and index type of arrangements available in competitive markets, where customers can nominate blocks of on-peak and off-peak load to purchase at a fixed price and face hourly prices for the remaining portion of their load. Little experience has been accumulated with such an approach in regulated, cost-of-service settings, although a host of potential issues can be identified, such as how to structure the load blocks and how to determine their price (i.e., based on embedded costs or some representation of a market-based risk premium).

(2) *If RTP is to provide a significant source of DR in regulated retail markets, the RTP tariff needs to offer, to a wide range of customers, substantial and/or fairly predictable financial benefits compared to fixed price tariff options available to the same customer class.*

A key lesson to emerge from GPC's experience is that, to attract a substantial fraction of the system load to an optional RTP tariff, it may be necessary for the tariff design to incorporate a fairly *predictable* financial benefit for a large population of customers. Customers benefit from participating in GPC's RTP tariffs in several ways. As with all RTP tariffs, customers can accrue bill savings by adjusting their usage in response to prevailing hourly prices (e.g., shedding load during high priced periods and/or rescheduling load from high to low priced periods). Customers in GPC's program also benefit by maintaining a CBL that is less their typical usage (see Section ES-2), thereby purchasing some portion of their usage (40%, on average) at marginal cost based prices that, on average, are less than the utility's embedded cost based rates. As a result, many customers can expect bill savings over the long-run that are independent of their load response to high or volatile hourly prices.[9]

Can GPC's approach be directly translated to traditional, regulated retail settings? GPC's practice of offering new customers the option to receive a reduced CBL constitutes a departure from traditional, cost-of-service ratemaking practices by allowing some customers to make a smaller contribution to embedded costs in exchange for accepting greater price risk.[10] The utility has successfully defended this practice on the grounds that it is necessary for the company to successfully recruit customer choice load, which benefits all ratepayers by spreading embedded costs over a larger amount of load. However, in most monopoly retail markets, where the utility already has the exclusive right to serve new customers, this particular line of reasoning would presumably be less compelling.

A fundamental question for regulators in traditional regulated markets that want to encourage the development of price response, then, is: Can some type of fairly predictable financial benefit for RTP participants be justified on the grounds that all ratepayers benefit from RTP participants' price response or that risk is transferred from other ratepayers to RTP participants? If so, how large of an incentive or discount is warranted (i.e., what is it worth to all ratepayers to have a significant subset of them be price-responsive)? And is that level of financial benefit likely to induce widespread participation in RTP? Finally, how best to structure the incentive? In GPC's case, the discount is provided implicitly by applying a different cost responsibility standard to incremental RTP load than to load billed under other rates. An alternative approach that policymakers may want to consider is to explicitly link the "incentives" offered to customers to enroll in RTP to their response during high price periods.

[9] So that customers can shield some of their exposed load from hourly price volatility, GPC also offers a variety of financial hedges ("Price Protection Products") and allows customers to temporarily adjust their CBL up or down, with a resulting charge or credit based on the utility's forecast of marginal costs over the applicable period.

[10] For the purpose of establishing retail rates, Georgia Power allocates embedded costs to RTP customers based on their CBL profile, not their actual load. However, the company determines their long term resource requirements based on RTP customers' total load.

1. Introduction

Demand response (DR) has been broadly recognized to be an integral component of well-functioning electricity markets, although currently underdeveloped in most regions. Among the various initiatives undertaken to remedy this deficiency, public utility commissions (PUC) and utilities have considered implementing dynamic pricing tariffs, such as real-time pricing (RTP), and other retail pricing mechanisms that communicate an incentive for electricity consumers to reduce their usage during periods of high generation supply costs or system reliability contingencies.

Efforts to introduce DR into retail electricity markets confront a range of basic policy issues. First, a fundamental issue in any market context is how to organize the process for developing and implementing DR mechanisms in a manner that facilitates productive participation by affected stakeholder groups. Second, in regions with retail choice, policymakers and stakeholders face the threshold question of whether it is appropriate for utilities to offer a range of dynamic pricing tariffs and DR programs, or just "plain vanilla" default service. Although positions on this issue may be based primarily on principle, two empirical questions may have some bearing – namely, what level of price response can be expected through the competitive retail market, and whether establishing RTP as the default service is likely to result in an appreciable level of DR? Third, if utilities are to have a direct role in developing DR, what types of retail pricing mechanisms are most appropriate and likely to have the desired policy impact (e.g., RTP, other dynamic pricing options, DR programs, or some combination)?[11]

Given a decision to develop utility RTP tariffs, three basic implementation issues require attention. First, should it be a default or optional tariff, and for which customer classes? Second, what types of tariff design is most appropriate, given prevailing policy objectives, wholesale market structure, ratemaking practices and standards, and customer preferences? Third, if a primary goal for RTP implementation is to induce DR, what types of supplemental activities are warranted to support customer participation and price response (e.g., interval metering deployment, customer education, and technical assistance)?

<u>Project Description</u>

State agencies, utilities, and customer groups in California have been engaged in an ongoing process to develop retail mechanisms for DR, including consideration of utility RTP tariffs. To provide information to participants in this process, as well as to policymakers and stakeholders in other jurisdictions, Lawrence Berkeley National Laboratory (LBNL) and Neenan Associates conducted a comparative review of eight case study states, representing a cross-section of regulatory and market environments, where RTP has been implemented as a default and/or optional service for commercial and industrial (C&I) customers (see Table 1-1).

[11] The viability of DR programs in the retail market may hinge on how load reductions are valued in the wholesale market, in particular, whether electricity consumers can bid load curtailments into centralized wholesale markets or only participate as price takers, responding to market prices.

Table 1-1. Eight Case Studies of Default or Optional RTP

State	Utilities	Default RTP	Optional RTP
New Jersey	All investor-owned utilities	Implemented (2003)	Implemented (2003)
Maryland	All investor-owned utilities	Implemented (2005)	Implemented (2004)
Pennsylvania	Duquesne Light Company (DLC)	Implemented (2005)	-
New York	Niagara Mohawk Power Company (NMPC)	Implemented (1998)	-
	All other investor-owned utilities	Considered (2003)	Implemented (2001)
	Central Hudson Gas & Electric (CHG&E)	Implemented (2005)	Implemented (2001)
Illinois	Commonwealth Edison (ComEd)	Planned (2006)	Implemented (1998)
Ohio	Cincinnati Gas & Electric (CG&E)	Implemented (2005)	Proposed (2003)
Oregon	Portland General Electric (PGE)	-	Implemented (2004)
Georgia	Georgia Power Company (GPC)	-	Implemented (1992)

Based on a detailed review of the regulatory history in these eight states and interviews with key stakeholders, we characterize and compare their experience in terms of the market and regulatory context, implementation process and stakeholder support, tariff design, and actual or anticipated impacts on the development of DR. Drawing from this synthesis, we identify key policy and technical issues and assess the potential role of RTP as a strategy for developing DR in different types of regulatory and market settings.

Report Overview

The remainder of this report is organized as follows:

- **Chapter 2** describes our research approach.
- **Chapter 3** presents an overview of the key concepts and terminology related to default service and demand response used in this report.
- **Chapter 4** presents a comparative summary of the eight case studies, which are included in the report as Appendix A.
- **Chapter 5** presents the findings from our interviews with competitive retail suppliers.
- **Chapter 6** contains a discussion of policy implications and recommendations.
- **Appendix A** consists of the eight in-depth case study summaries.

2. Approach

Policymakers that are considering RTP can look to other jurisdictions where similar initiatives have been pursued, to better understand the relevant policy and implementation issues and to gauge their expectations about the likely impacts of RTP. However, the fundamental challenge in undertaking such a comparison is that each jurisdiction represents a unique and complex set of circumstances, which typically must be understood in some detail in order to draw lessons that are applicable more generally or to other specific contexts.

<u>Case Study Design</u>

We conducted a detailed examination of eight case study regions (i.e., states or utility service territories) where RTP has been implemented or considered as a default or optional service for C&I customers. Our examination of each case study focused on a number of topical areas, including:

- The retail and wholesale market structure and its stage of development;
- The policy context and objectives underlying RTP implementation;
- The regulatory process used to design and implement RTP;
- The level of support and key positions of stakeholder groups participating in the RTP tariff design and implementation process;
- The RTP tariff structure;
- Interval metering and other enabling technology deployment;
- Customer education and other activities conducted to support participation in RTP and price response from participating customers;
- The impact of RTP on the development of DR (actual or anticipated); and
- The role of other DR mechanisms, including utility DR programs and interruptible tariffs, ISO/RTO DR programs, and dynamic pricing options offered by competitive retail suppliers.

<u>Literature Review and Stakeholder Interview Process</u>

We obtained information on these topics through a detailed review of the public documents related to implementation of RTP and/or default service in each state, including regulatory filings, PUC orders and decisions, legislative documents, reports and studies by state agencies and regional transmission organizations (RTO), utility tariff sheets, trade press articles, and workshop presentations.

We then conducted telephone interviews with PUC staff, utilities, and competitive retail suppliers active in each state (see Table 2-1). The purpose of these interviews was to characterize their views on key policy and technical issues and to obtain information not available in the public domain. For our interviews with regulatory staff and utilities, we targeted those individuals that have been most closely involved in the process of developing and implementing RTP or default service in each state. For our interviews with competitive retail suppliers, we targeted individuals who are responsible, at either the managerial or executive level, for pricing and product design, and also, when possible, senior members of the regulatory affairs department.

The interviews were conducted using a survey protocol developed for each type of stakeholder group, distributed to interview subjects in advance. The protocols included approximately 25-30 questions related to the case study topical areas listed above. Following each interview, respondents were given an opportunity to review our written interview notes and identify any incorrect or incomplete characterization of their responses.

Table 2-1. Sample of Stakeholders Interviewed

Stakeholder Group	Number of Organizations Represented*	Description of Sample Frame
Regulatory Staff	8	Interviewed senior staff at PUC in each of the eight case study states
Utilities	10	Interviewed one or more utility in each case study state
Competitive Retail Suppliers	8	Interviewed major competitive retail suppliers active in one or more case study state

* We interviewed multiple individuals at many of these organizations, either jointly or separately, depending on scheduling availability.

3. Conceptual Background

Policy discussions of default service and demand response do not always use consistent terminology or a common conceptual framework. Thus, in the interest of clarity, in this chapter we introduce and define the essential concepts and terminology used in this report.

3.1 Default Service

Default vs. Optional Service

We use the term *default service* to refer to any retail electricity service onto which customers are automatically placed if they do not affirmatively choose some other option. In other words, customers receive that service unless they opt out, provided that some other option is offered. Conversely, we use the term *optional service* to refer to any retail electricity service onto which customers are placed only if they affirmatively choose that option. In other words, customers must opt onto the service. This is different from the distinction between mandatory and voluntary service, as a default service is mandatory only in the limiting case where it is provided by a monopoly utility with no alternative rate options or competitive alternatives for the customer class.

Default Service in Competitive Retail Markets

Default service, as we define it, is applicable in both monopoly and competitive retail markets. However, it often has a more specific meaning in the context of competitive retail markets, referring to the retail supply service onto which customers are placed if they are not under contract with a competitive supplier. It is sometimes used in an even more restricted manner to refer to the retail supply service onto which customers are placed if they are not presently *and have never been* under contract with a competitive retail supplier. Other terminology, such as *Standard Offer Service*, *Provider of Last Resort (POLR) service*, and *Basic Generation Service*, is used in many of our case study states to refer to the retail supply service provided under either of these conditions. For simplicity, we use the term default service in these cases as well, even though, strictly speaking, they are special cases of the definition stipulated above.

3.2 Typology of Retail Demand Response Mechanisms

We use the term *demand response* (DR) in this report to refer to temporary customer load reductions induced in response to high market prices or system reliability conditions.[12,13] In this section, we present a hierarchy of the *retail* mechanisms that can be used to induce customers to reduce their load during such periods. This is distinct from a description of *wholesale* mechanisms, which relate to the incentives faced by load serving entities (LSE) and other wholesale market participants, to facilitate and encourage demand response.[14]

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[12] We include the operation of onsite generation in our definition of *load reduction*.
[13] Broader definitions of demand response have been used elsewhere, e.g., by the U.S. Demand Response Coordinating Council and the New England Demand Response Initiative (NEDRI 2003).
[14] There are important interrelationships between wholesale and retail DR mechanisms (as there are between wholesale and retail market structures, more generally).

At the highest level, we distinguish between *financial* and *non-financial* retail DR mechanisms. Financial mechanisms consist of a monetary incentive for DR. Non-financial mechanisms, which are not discussed further, include all other forms of inducement (e.g., public appeals or involuntary curtailments). Among financial DR mechanisms, we make a basic distinction between (a) those that communicate a monetary incentive for DR through dynamic pricing of one or more of the components of retail electricity service, and (b) those that communicate the incentive through a separate DR program that is "unbundled" from the provision of retail electricity services (see Figure 3-1).

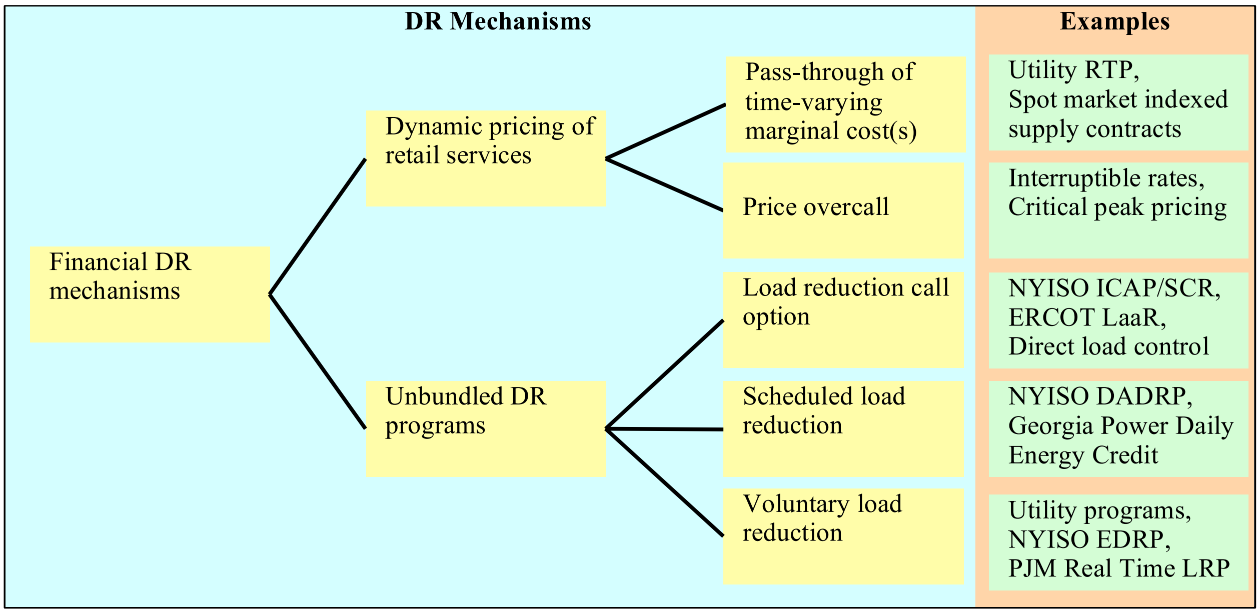

Figure 3-1. Typology of Retail DR Mechanisms

3.2.1 Dynamic Pricing of Retail Services

Retail electricity service consists of various components that the service provider must either provide directly with company-owned assets or procure. These include: generation supply (which may consist of distinct energy and capacity components), transmission, ancillary services, distribution, and metering and billing. In monopoly retail markets, all of these components are typically provided to the retail customer as a bundled service by the local utility. In competitive retail markets, these services are unbundled, with the local utility providing distribution services, and the other components provided by either a competitive supplier or by the designated default service provider (often the local distribution utility). Whatever type of market structure is in place, load reductions can be induced during periods of high market prices or system reliability contingencies by contemporaneous changes in the price charged to retail customers for one or more components of their retail electricity service – i.e., through *dynamic pricing of retail services*. Two basic types of dynamic retail pricing mechanisms have been used, which we describe below: a pass-through of time-varying marginal costs and price overcalls.

<u>Pass-through of time-varying marginal costs</u>

Certain components of retail electricity service are characterized by short-run marginal costs that can vary significantly over small time scales (e.g., minutes or hours). Chief among these time-varying marginal costs is the operating cost of electricity generation in a vertically-integrated setting, or analogously, the spot market price of energy in a competitive wholesale environment. In addition, as demand for electricity approaches the limits of generation or T&D capacity, changes in demand impose a marginal outage cost associated with the incremental increase in the risk of involuntary curtailments.[15] Retail pricing arrangements that pass through time-varying marginal costs (or some proxy or projection thereof) in real time or near-real time impart a financial incentive for customers to reduce their load when these costs are high. The essential feature of this type of DR mechanism is that the customer faces *marginal* prices (i.e., the per kWh change in their bill for incremental changes in usage) that vary over short time intervals.

Real-time pricing (RTP) is the term typically used to describe this type of retail pricing arrangement when offered by a regulated utility. Traditionally, RTP rates offered by vertically-integrated utilities have passed through the utility's marginal operating cost (fuel and variable O&M), referred to as their "system lambda". Some utilities have also incorporated adders to capture the marginal outage cost and/or the marginal capacity cost of generation, transmission, or distribution facilities (Barbose et al. 2004). As centralized spot markets have become prevalent, utilities have increasingly offered RTP tariffs that pass through the day-ahead or real-time spot market price. Competitive retail suppliers also offer similar types of pricing options (as discussed in Chapter 5), whereby the customer purchases some or all of the commodity component of their retail supply service at a price that is indexed to the day-ahead or real-time spot market.

Price overcall

Rather than exposing the customer to prices that change frequently (e.g., every hour), retail electricity services can be priced at a fixed rate with a price overcall option, which gives the service provider the right to temporarily increase the price applicable during a short period of time (e.g., several hours). The classic example of this type of pricing arrangement is an interruptible service tariff, whereby, during utility-specified interruption events, the customer faces a very high price (the non-compliance penalty) for usage above their firm load level. In markets where retail services are unbundled and where the ISO or RTO imposes installed capacity (ICAP) requirements, some LSEs may offer a limited variation of an interruptible service tariff consisting of non-firm pricing for the ICAP component of retail service.[16] Although interruptible-type pricing options are typically used to respond to reliability events, price overcalls may also be exercised in response to high spot market prices. For example, some competitive retail suppliers offer customized structured contracts, whereby the customer can receive a discounted fixed price for their commodity charge in exchange for giving the supplier the option to overcall that price on some number of occasions (e.g., by passing through the spot market price). Regulated utilities may also offer standardized versions of this type of pricing arrangement, for example critical peak pricing, which is similar to a time-of-use (TOU) rate, except that the utility has the option to overcall the standard on-peak price with a higher "critical-peak" price during some limited number of hours per year.

[15] The standard definition of the marginal outage cost is the change in Loss of Load Probability multiplied by the Value of Lost Load.
[16] A customer taking service on such an option is assessed ICAP charges only for their firm load, but is subject to a penalty charge for usage above their firm load level if the ISO/RTO recalls ICAP resources, which occurs during specified system reliability conditions.

3.2.2 Unbundled DR Programs

Unbundled DR programs provide explicit payments for load reductions (or derivatives thereof), which are financially and contractually separate from the provision of any retail electricity service. DR programs can originate in the retail market in one of two ways.

First, ISOs or RTOs may develop and administer DR programs. Very large electricity consumers may be able to directly participate in these programs, however, end-users typically participate in these programs via an intermediary *demand response service provider* (DRSP) that acts as their agent for transactions with the ISO/RTO and that passes through (some portion of) the DR program payments. Depending on the ISO/RTO DR program rules and structure, different types of entities may be able to serve as a DRSP – not just an individual consumer's LSE, but other LSEs, distribution utilities, dedicated DR aggregators, energy service companies (ESCO), or DR technology vendors.[17] In theory, the DR programs offered to electricity consumers by DRSPs could have a much different structure than the associated ISO/RTO program; however, in practice, this is usually not the case.[18]

Second, retail electricity service providers (i.e., vertically-integrated utilities, distribution utilities, default suppliers, or competitive retail suppliers) may develop and operate DR programs independent of any ISO program, which they offer exclusively to their customers. In markets where ISO/RTO DR programs are not offered, these are the only types of DR programs available in the retail market. However, even where ISO/RTO DR programs are offered, retail service providers may continue to independently develop and administer DR programs. For example, because ISO/RTO programs do not account for the distribution system benefits of peak period load reductions, a distribution utility might offer its own DR program to respond to distribution system contingencies.

Regardless of which of these two "paths" for retail DR program development are followed, most programs can be distinguished in terms of several basic program features related to the structure of the financial incentive faced by the retail customer – in particular, the nature of the customer's commitment to reduce their load, the form of the payment provided to customers for reducing their load, and whether a penalty is assessed if a customer fails to fully comply with their commitment (see Table 3-1). Based on these program features, we differentiate between three types of unbundled DR programs: load reduction call options, scheduled load reductions, and voluntary load reductions.

[17] We use the term *energy service company* to refer to an entity that provides energy management related services to retail customers (e.g., energy efficiency improvements, energy management and information systems).
[18] Thus, for simplicity, we often refer to individual ISO/RTO-administered DR programs as a proxy for the associated programs available to retail customers.

Table 3-1. Unbundled DR Program Features.

Unbundled DR Program Type	Key Program Features		
	Customer Commitment	**DR Payment Form**	**Penalty Provisions**
Load reduction call options	Standing commitment over a designated time period to reduce load upon notification, subject to specified limitations	Reservation payments based on callable load reduction (MW). Performance payment may also be provided based on actual reductions in energy usage or average demand (MWh or MWa)	Non-compliance penalties
Scheduled load reductions	Commitment, made up to several days in advance, to reduce load during a specific time period	Payments for actual or scheduled reduction in energy usage (MWh)	Non-compliance penalties and/or imbalance charges
Voluntary load reductions	None	Performance payments based on actual reduction in energy usage or average demand (MWh or MWa)	None

Load reduction call option programs

The distinguishing features of load reduction call option programs are that customers: make a standing commitment over some time period to reduce their load when notified; receive an up-front payment in exchange for this commitment and in some cases additional payments for actual load reductions; and are subject to penalties if they fail to fully comply with load reduction requests. In essence, the customer sells a call option on a particular load reduction quantity, which the entity offering the program can exercise, up to some number of pre-specified occasions, during a designated time frame.

Load reduction call option programs often serve as a capacity resource in the planning operations of the retail service provider or ISO/RTO and, as such, have an exercise period of at least several months (e.g., a summer season), if not a year or more.[19] Both the NYISO and PJM offer programs of this type, as do a number of utilities, which typically have evolved out of their interruptible service tariffs. Many direct load control programs could also be best categorized as a load reduction call option program, albeit with a number of caveats.

Scheduled load reduction programs

The distinguishing features of scheduled load reduction programs are that customers: make a commitment, typically one day or less in advance, to reduce their load during a *specific time period*; receive a payment based on their scheduled commitment or actual performance; and are subject to penalties and/or imbalance charges if they do not fulfill their commitments.

NYISO and PJM both offer programs of this type, which allow customers or DRSPs to submit load reduction bids as a resource into the day-ahead energy market. If their bid clears the market, the load reduction is scheduled, and the customer is paid for their scheduled or actual

[19] The Electric Reliability Council of Texas (ERCOT) offers the Load Acting as a Resource (LaaR) program, which allows customers to submit load reduction bids into the spot markets for certain ancillary services. A unique feature of this program is that it is a call option load program, but the exercise period may be as short as one day.

load reduction amount based on the day-ahead locational market clearing price. If the customer (or DRSP) fails to fully deliver the scheduled load reduction, they are assessed imbalance-related charges for the deficient quantity (in NYISO, the higher of day-ahead or real-time spot market price, and in PJM, real time spot market prices and also possibly operating reserve balancing charges).

A few utilities have also offered scheduled load reduction DR programs. These programs generally differ from the NYISO and PJM programs in several ways. First, the transactions generally are initiated by the utility, which notifies participants of the price and/or the specific time period during which it is willing to pay for load reductions; and participants can then choose whether or not to affirmatively accept the offer. Second, customers that fail to perform as scheduled are typically assessed an administratively-determined penalty (similar to an interruptible service tariff), which may or may not reflect the actual cost or value of the replacement energy.

<u>Voluntary load reduction programs</u>

The distinguishing features of voluntary load reduction programs are that customers: make no firm commitment to reduce their load, receive payment based on their actual performance, and are not subject to any penalties. In most programs of this type, the program administrator (e.g., utility or ISO/RTO) designates a "window" during which payments for load reductions are offered.[20] The "opening" of a load reduction window may be linked to either reliability or market conditions, and is typically designated one day or less in advance. The three eastern ISO/RTOs offer DR programs that provide payments for voluntary load reductions during emergency events declared by the ISO/RTO (typically triggered by inadequate operating reserves). ISO-NE also offers a program that provides payments, based on the prevailing real time spot market price, for voluntary load reductions occurring on days that the ISO-NE forecasts spot market prices to exceed $100/MWh. Vertically-integrated utilities have also increasingly developed voluntary load reduction programs to avoid costly off-system purchases and/or to manage system reliability.

3.3 Accounting for DR Resources

The retail DR mechanisms described in the previous section represent distinct categories in terms of the structure of the financial incentive faced by the retail customer. However, an individual customer may be exposed to multiple mechanisms simultaneously. Thus, from the perspective of an entity responsible for system operations, planning, or oversight (e.g., utility, ISO/RTO, state or federal regulator), there may be a significant degree of overlap among the various DR mechanisms in terms of the quantity of demand response available in a given market. Naturally, the complexity of this overlap depends on key features of the wholesale and retail market structure. In this section, we describe the two boundary cases: a traditional industry structure with a single, vertically-integrated utility with a monopoly service franchise; and competitive market with competitive retail suppliers, a default service provider, distribution utilities, and an ISO or RTO that administers DR programs.

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[20] PJM's Economic Load Response Program – Real Time Option is a unique example of a voluntary load reduction program, as it has no designated payment window. Rather, participants can receive payments for load reductions occurring at any point in time, based on the prevailing real time spot market price.

In a traditional electricity market with a single entity providing all components of the retail electricity service to all customers in a region, and no grid operator or wholesale market administrator to offer wholesale DR programs, accounting for DR resources is relatively straightforward (see Figure 3-2). In this case, the local utility may offer different dynamic pricing options for the bundled retail service as well as separate DR programs. Depending on eligibility rules, some customers may participate in a combination of dynamic pricing options and/or DR programs, for example, an interruptible service tariff and a voluntary load reduction program.

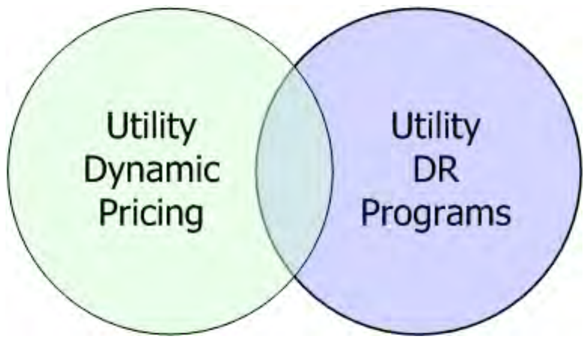

Figure 3-2. Customer populations exposed to price incentives for DR in vertically-integrated markets

In contrast, the picture is considerably more complex in a competitive retail market setting where an ISO or RTO also offers DR programs (see Figure 3-3). Just as in the traditional industry setting, a single customer may be exposed to financial incentives for DR through a combination of dynamic pricing options and unbundled DR programs. However, unlike the traditional industry setting, a multitude of different types of entities may each offer dynamic pricing options and/or unbundled DR programs. In particular:

- *DRSPs* may offer ISO/RTO DR programs to retail customers.
- *The default service provider* may offer dynamic pricing for the commodity portion of default service (e.g., a pass-through of spot market prices). They could also potentially offer unbundled DR programs that are independent of any ISO DR program, for example, if state regulators required that the default service provider engage in a portfolio management process that includes demand-side strategies.[21]
- *Competitive retail suppliers* may offer various dynamic pricing options and independent unbundled DR programs.
- *The distribution utility* may also offer dynamic pricing for the distribution service (e.g., an interruptible service tariff) and/or independent unbundled DR programs aimed at maintaining distribution system reliability in a least-cost manner.

In principle, an individual customer could face price incentives for DR from up to three of these entities simultaneously: i.e., a DRSP, their distribution utility, and either the default service provider or a competitive retail supplier.

[21] In practice, the range of DR program options offered by the default service provider may be constrained if policymakers view such options as impeding the development of retail competition.

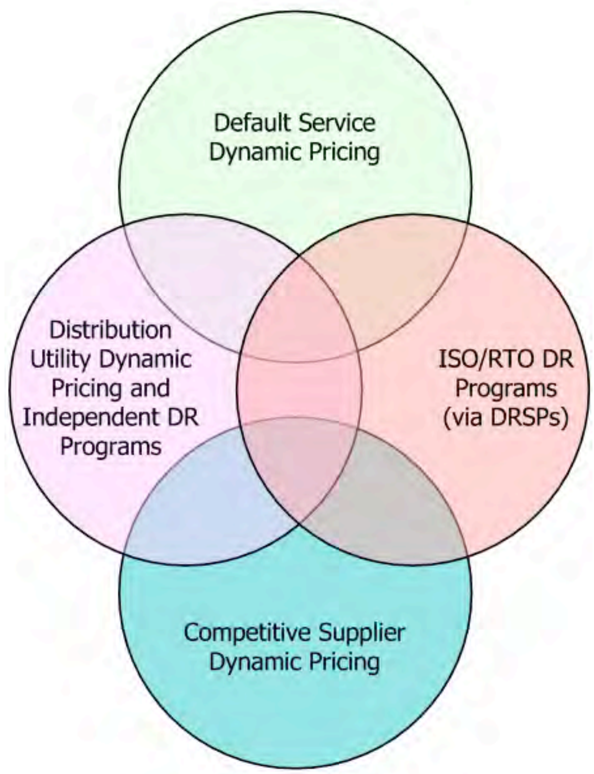

Figure 3-3. Customer populations exposed to price incentives for DR in competitive retail and wholesale markets

4. RTP as a Default or Optional Utility Service: Comparative Case Study Analysis

In this chapter, we examine the experience in eight states with some form of retail competition, where RTP has been implemented or considered for either the default service for large customers or an optional utility service. Drawing upon interviews with state regulatory staff and utilities, and a review of regulatory documents and other literature, we summarize and identify key trends related to:

- the regulatory and market contexts in which RTP was considered in each state;
- the process through which the decision was made to implement RTP and the tariff design was established;
- key positions of stakeholders participating in the RTP implementation process;
- key elements of tariff design and administration;
- customer enrollment in RTP;
- actual or anticipated load reductions from RTP; and
- customer enrollment in, and actual load reductions from, other utility and ISO/RTO DR programs in each state.

This summary is based on the set of case studies included in Appendix A, which contain more in-depth description and discussion of the topics summarized in this chapter.[22]

4.1 Case Study Overview

The case studies all share the common feature that they represent an effort in an individual state to implement RTP for C&I customers taking their retail supply service from an investor-owned utility (IOU). However, they differ from one another in several important respects (see Table 4-1).

Statewide vs. utility-specific. In some case study states, efforts to implement RTP have been statewide, while in others, they have been limited to an individual utility or sub-set of the state's utilities.

Default (opt-out) vs. optional (opt-in). In some states, RTP has been designated or proposed as the default service for a particular customer class; i.e., the rate on which those customers are automatically placed if they do not choose a competitive supply arrangement or another utility rate (if offered). In other cases, RTP has been implemented or proposed as an optional tariff, on which customers are placed only if they affirmatively opt in.

Applicable customer class. Each RTP tariff is applicable to customers larger than some peak demand level, but the size of this threshold varies considerably across the case studies, from 100 kW to 3,000 kW.

Non-RTP utility supply options. Customers for whom RTP is optional, by definition, have other utility supply options available; customers for whom RTP is the default tariff may also have alternative utility supply options, if only for a temporary period of time. Among the case studies where customers have a choice between RTP and other utility rates, the non-RTP options include

[22] The case study for New York describes the efforts to implement RTP by all of the state's utilities, except Niagara Mohawk Power Company (NMPC); for a detailed review of NMPC's experience with default RTP, refer to Goldman et al. (2005).

capped or frozen rates, cost-of-service (COS) based rates, and market-based rates developed from an auction or that pass through the costs, on a class average basis, of direct market purchases over some intermediate time interval (e.g., monthly, seasonally, annually).

Implementation status. RTP has been fully implemented in several of these states, while in others, it has not yet been phased in, and in one case (Ohio), RTP was implemented, but for a much narrower class of customers than initially proposed.

Table 4-1. Overview of RTP Case Studies

State	Utilities	Tariff Type	Applicable Customers	Non-RTP Utility Supply Options	History and Status
New Jersey	Statewide	Default RTP	>1250 kW	None	Implemented in 2003 for high voltage class; expanded to all C&I >1,250 kW in 2005.
Maryland	Statewide	Default RTP	>600 kW	Auction-based fixed-price option (temporary)	Implemented for BGE Schedule P customer class in 2002. Implemented statewide as optional service in 2004 and default in 2005.
Pennsylvania	DLC	Default RTP	>300 kW	Auction-based fixed-price option (temporary)	Implemented in 2005. Fixed-price option expires in 2007
New York	NMPC	Default RTP	>2000 kW	None	Implemented in 1998.
	All IOUs other than NMPC	Optional RTP	Varies by utility	Varies by utility	Implemented in 2001. Proposal to make RTP mandatory rejected in 2003.
	CHG&E	Default RTP	>1,000 kW	None	Implemented in 2005.
Illinois	ComEd	Default RTP	>3000 kW	None	Implemented for new customers in 2003. To be implemented for existing customers in 2007.
Ohio	CG&E	Default RTP	>100 kW returning customers	None	Implemented in 2005.
		Default Fixed Price	>100 kW existing customers		
Oregon	PGE	Optional RTP pilot	>1000 kW	COS-based, fixed price and several market-based options	Implemented in 2004.
		Optional daily TOU pricing	All non-residential		Implemented in 2002.
Georgia	GPC	Optional RTP	>250 kW	Multiple COS-based, fixed-price options	Implemented in 1993.

In brief, the eight case studies profiled in this chapter are the following:

<u>New Jersey</u>: In 2003, RTP became the only supply option for customers in the high voltage classes that had not contracted with a competitive supplier. The class of applicable customers was expanded, in 2004, to all customers with a peak demand greater than 1,500 kW, and again in 2005, to all customers larger than 1,250 kW. All other C&I customers, for whom the default service is an auction-based fixed-price rate, are allowed to voluntarily opt onto RTP.

Maryland: From July 2002 – June 2003, RTP was the only supply option for customers of Baltimore Gas & Electric (BGE) with a peak demand greater than 1,500 kW (Schedule P) that had not contracted with a competitive supplier. This default service tariff was then supplanted by the statewide default service. From July 2004 – May 2005, RTP was an optional service for all customers in the state with a peak demand greater than 600 kW. During this period, the default service for customers in this class that had not contracted with a competitive supplier was an auction-based, fixed-price service. In June 2005, RTP became the default and only supply option for customers >600 kW that have not contracted with a competitive supplier.

Pennsylvania: In 2005, RTP became the default service for customers of Duquesne Light Company (DLC) with a peak demand greater than 300 kW. An auction-based, fixed-price option is also available to this customer class, as an alternative to RTP, until mid-2007.

New York: RTP is currently the only utility supply option for Niagara Mohawk Power Company (NMPC) customers with a peak demand greater than 2,000 kW. RTP is also currently offered as an optional service by the state's other five IOUs, including Central Hudson Gas & Electric (CHG&E), Consolidated Edison (ConEd), New York State Electric and Gas (NYSEG), Orange & Rockland (O&R), and Rockland Gas & Electric (RG&E). In 2003, the New York Public Service Commission (NYPSC) considered a proposal to designate RTP as "mandatory" for certain customer classes of these utilities, but decided against doing so. In 2005, the NYPSC adopted a proposal by Central Hudson Gas & Electric (CHG&E) to make RTP the only utility supply option for its customers with a peak demand greater than 1,000 kW.

Illinois: ComEd has offered RTP as an optional service for all non-residential customers since 1998. RTP is also currently the only utility supply option for *new* ComEd customers with a peak demand greater than 3,000 kW. In 2007, RTP will become the only utility supply option for all ComEd customers with a peak demand greater than 3,000 kW (new *and existing*). The Illinois Commerce Commission (ICC) is also currently engaged in a process to develop uniform requirements for all of the utilities in the state, regarding the form and function of utility supply service to be offered following the state's statutory transitional period, which ends in 2006.

Ohio: Cincinnati Gas & Electric (CG&E), Cinergy's utility in southern Ohio, proposed a set of optional RTP tariffs as part of a portfolio of utility supply options to be offered following the end of their rate cap period in 2004. This proposal ultimately was not adopted and, instead, a "market-based" fixed-price rate was adopted as the only utility supply option for customers with a peak demand greater than 100 kW that were taking their supply from the utility as of January 2, 2005. For customers that *return* to CG&E from a competitive supplier after that date, RTP is the only utility supply option available.

Oregon: Portland General Electric (PGE) offers an optional RTP tariff for customers with a peak demand greater than 1,000 kW. It is currently a pilot and is limited to a maximum of six customers. PGE also offers an optional, market-based service, similar to RTP, which has peak and off-peak prices that vary on a daily basis. This is one of several market-based options offered by the utility that have TOU prices fixed over different time intervals (daily, monthly, and quarterly). Customers that have provided notice during the annual open enrollment period that they plan to leave PGE's cost of service option but have not made an arrangement by year end must transfer to one of these market-based options, and are automatically transferred to the daily pricing option if they don't specify otherwise.

Georgia: Georgia Power Company (GPC) offers two optional RTP tariffs with day-ahead and hour-ahead price notice, which are available to customers with a peak demand greater than 250 kW and 5,000 kW, respectively. Although not typically considered a customer choice state, Georgia has had a limited form of retail choice in place since 1973, and this market structure has played a critical role in GPC's experience with RTP.

4.2 Market and Regulatory Context

The prevailing regulatory and market structure in each case study state provides important context for understanding the experience with RTP implementation (see Figure 4-1).

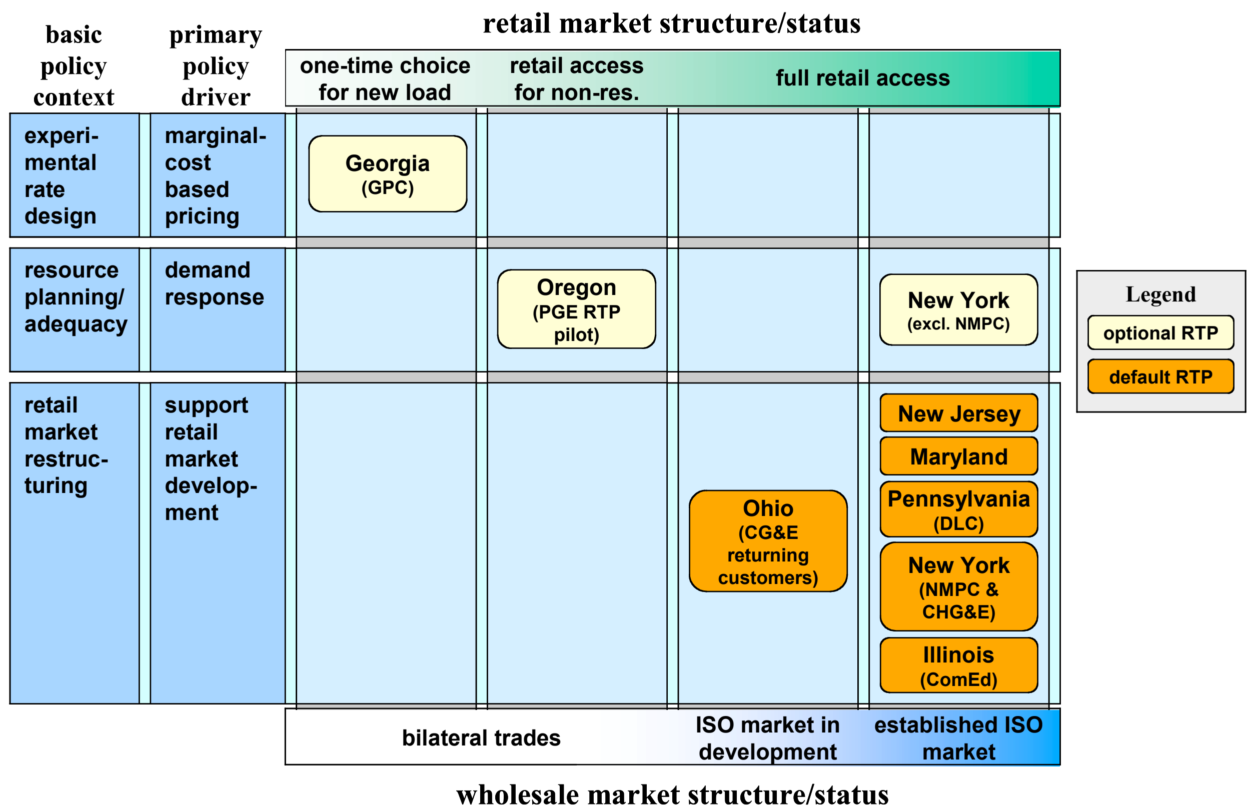

Figure 4-1. Regulatory and Market Context

4.2.1 Retail market structure and development

Full retail choice for all customers is currently in place in six of the eight case study states (New Jersey, Maryland, Pennsylvania, New York, Ohio, and Illinois), although the extent of retail market activity varies significantly across these six states. As of the end of 2004, the C&I switching rates in these six states, in terms of percent of total C&I load, was: 28% in New Jersey, 41% in Maryland, 42% in DLC's service territory, 36%/65% (C/I) in New York, 38%/62% (C/I) in ComEd's service territory, and 18% in CG&E's service territory (Kema 2005). Utilities in most of these states are prohibited from directly competing for customer choice load, either by statute (e.g., New Jersey and Maryland) or by regulatory agreement (Pennsylvania, New York, Illinois).

Most of these states established a transition period during which the utilities offered administratively-priced (i.e., frozen, capped, or cost-of-service based) retail supply service to customers that have not switched to a competitive supplier.[23] Utilities in New Jersey, Maryland, and Pennsylvania (DLC) have completed their transitional periods, and now offer only market-based supply options to large C&I customers that have not switched. In Ohio, the statutory "market development period" has expired, but the PUCO has effectively extended the transition period by requiring most utilities to offer fixed prices through 2008.[24] In Illinois, the transitional period is not scheduled to expire until the end of 2006, although the supply service that ComEd will offer to customers >3 MW after that point has already been established.

The other two states, Oregon and Georgia, have a more limited form of retail competition. Oregon currently has retail choice only for non-residential customers, and a modest amount of switching has occurred.[25] The IOUs in Oregon are required to continue offering cost-of-service based rates to all customers during the state's indefinite transitional period, which will end only when a broad set of conditions related to the development of the retail market are satisfied. In Georgia, a limited form of retail competition was established in 1973, whereby most new facilities with a connected load greater than 900 kW have a one-time choice of supplier. GPC is permitted to compete for this load, while continuing to operate under an obligation to serve all other customers in its service territory at cost-of-service based rates.

4.2.2 Wholesale market structure and development

The utilities in five of the case studies – New Jersey, Maryland, Pennsylvania (DLC), New York, and Illinois (ComEd) – operate in regions with an established, wholesale power exchange administered by an independent system operator (ISO) or regional transmission organization (RTO). These utilities have also divested most or all of their generating assets to merchant generating companies or transferred them to an affiliate or parent company. The utilities in the other three case studies – Ohio (CG&E), Oregon (PGE), and Georgia (GPC) – are vertically integrated and operate in regions with no ISO/RTO power markets or, in the case of CG&E, recently established RTO markets.[26]

4.2.3 Policy Context and Impetus for RTP Implementation

The eight case studies can be distinguished in terms of the policy context surrounding the efforts to implement RTP. In most of the states where default RTP was considered and/or adopted, the basic context was that the state's transition period had come (or was coming) to an end. This condition prompted some type of regulatory process to establish the terms of the supply service

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[23] The end of the transitional period was defined by different types of conditions among the case studies. In New Jersey, Maryland, and Ohio, it was defined by statute. In Pennsylvania, the end of DLC's transitional period was defined by completion of the utility's stranded cost recovery and expiration of POLR service contracts. In Illinois, the end of the transition period for ComEd's customer class >3 MW was defined by demonstration that the retail market for these customers was sufficiently competitive.

[24] CG&E's default RTP rate for returning customers is an exception.

[25] As of the end of 2004, 7% of PGE's C&I customers had switched (OPUC 2005).

[26] The Midwest Independent System Operator (MISO) launched their day-ahead and real-time energy markets on April 1, 2005.

to be provided thereafter to customers not taking their supply from a competitive provider. In most of these states, this regulatory process encompassed a wide range of issues beyond just the development of RTP tariffs, and the general policy objective underlying these initiatives was to facilitate the development of the competitive retail market. Many of these efforts were guided by broad statutory mandates related to the character of the post-transition default service (e.g., that it be "market-based"). The policy context of the default RTP tariffs implemented by NMPC and recently proposed by CHG&E was similar in the sense that both utilities proposed default RTP in the context of efforts to support the development of the retail market. However, these proposals were not prompted specifically in response to the end of a formal transition period; but rather, in the case of NMPC, as part of their initial restructuring settlement process, and in the case of CHG&E, in response to a policy directive issued by the NYPSC requiring the state's utilities to develop plans to promote retail choice.

PGE's RTP pilot and the statewide optional RTP tariffs in New York were developed in what might be broadly characterized as a resource planning or resource adequacy context, with the primary policy objective being to stimulate demand response. In Oregon, interest in RTP and DR more generally intensified in the aftermath of the Western electricity crisis in 2000/2001. In 2003, OPUC staff issued a white paper on DR recommending, among other things, that the state's IOUs develop optional RTP tariffs, and the OPUC adopted this recommendation. In New York, the NYPSC was engaged in a broad set of initiatives to identify and implement strategies to mitigate projected supply shortfalls, and as part of these efforts, they issued an order requiring that all of the utilities in the state develop optional RTP tariffs (with the exception of NMPC, which already had implemented default RTP).

The context within which GPC developed their RTP tariffs was unique among the case studies. GPC previously offered a curtailable (i.e., interruptible) rate option for large C&I customers that incorporated marginal cost based pricing for non-firm load. Some of the customers on that rate expressed interest in an alternative rate option that would also incorporate marginal cost based pricing, but without a non-firm provision. Responding to this customer interest, as well as to the general nationwide trend towards retail competition and market-based retail pricing, the utility developed their initial RTP pilot as an experimental rate design intended to test an alternative (more refined) approach to marginal cost based pricing.

4.2.4 State Regulatory Policies on Demand Response

Policymakers and regulatory agencies in many of the case study states have adopted policies or engaged in processes to develop DR, even if RTP was not implemented for this particular purpose (see Table 4-2).[27] In New Jersey, Maryland, and Pennsylvania, much of the policy activities for DR programs targeted to large C&I customers have migrated from the state public utility commissions to PJM, which conducts planning and evaluation associated with its DR programs. However, regulators in these states have continued to support the development of DR at the regional level, through participation in the Mid-Atlantic Distributed Resources Initiative (MADRI), a collaborative between state public utility commissions, PJM, and DOE to coordinate DR policies and markets in the Mid-Atlantic region. In New York, the NYISO conducts planning and evaluation of DR programs, while New York State Energy Research and Development Authority (NYSERDA) conducts a corresponding set of activities for DR enabling

[27] We focus specifically on activities targeted or policies that impact large C&I customers.

technology programs funded through the state's system benefits charge. The NYPSC has continued to maintain an active role in the development of DR in New York by requiring the state's investor-owned utilities to offer retail tariffs that facilitate DR (i.e., optional RTP and the NYISO DR programs) and to perform associated marketing and customer education activities.

In Illinois, the utilities have historically assumed primary responsibility for developing DR programs, based on their own financial motivation. However, in early 2005, the governor issued a Sustainable Energy Plan, outlining a number of policies intended to spur the development of renewable energy, energy efficiency, and demand response in the state. The ICC has subsequently initiated a process for implementing this plan, including the formation of an Energy Efficiency and Demand Response working group to solicit guidance from stakeholders and industry experts. Policy issues related to DR were also taken up, albeit secondarily, in the course of the post-2006 initiative, a series of workshops where stakeholders discussed a broad range of issues related to the end of the state's statutory transition period.

In Ohio, the state regulatory commission has not recently engaged in any efforts explicitly for the purpose of developing DR. Staff at the Public Utility Commission of Ohio (PUCO) expressed the view that DR is a value-added service best provided by the competitive market, not by state regulations or programmatic activity (PUCO, 2004c).

In Oregon and Georgia, investor-owned utilities are required to conduct integrated resource planning and to include cost effective DSM measures in their resource strategies. In 2003, the Oregon Public Utilities Commission (OPUC) required that "the utilities Integrated Resource Plans should evaluate demand response programs on par with other options for meeting energy and capacity needs," following the recommendations in OPUC staff's DR white paper earlier that year (OPUC 2003). The utilities in Georgia are not subject to any similar requirement related to DR specifically, and historically, GPC has not included DR programs for large customers as an explicit resource option in their IRP.[28] Rather, evaluation of DR programs has generally occurred within separate proceedings of more limited scope, such as when GPC restructured their interruptible/curtailable program in 2001.

[28] GPC accounts for their existing DR programs for large customers in their IRP in terms of a stipulated reduction in their peak demand forecast. The utility has included a direct load control program for residential customers as a DSM measure in their IRP.

Table 4-2. DR-related policy activities in case study states

State	DR-related Policy Activities
New Jersey Maryland Pennsylvania (DLC)	• PJM conducts ongoing planning for and evaluation of DR programs • State utility regulatory agencies are participating in the Mid-Atlantic Distributed Resources Initiative • The Pennsylvania Renewable Portfolio Standard (currently under development) includes DR among the resources that can be used to meet the standard.
New York	• NYISO conducts ongoing planning for and evaluation of DR programs • The NYPSC ordered utilities to participate in NYISO DR programs and offer optional RTP tariffs, and later investigated modifications to optional RTP tariffs to increase participation, ordering the utilities to enhance marketing/customer assistance • NYSERDA provides financial incentives ($6-10M/year) for DR enabling technologies and conducts ongoing planning for and evaluation of DR enabling technology programs
Illinois (ComEd)	• The ICC is in the early stages of implementing the governor's Sustainable Energy Plan, issued in early 2005, which calls for the development of renewables, energy efficiency, and DR. • DR was discussed (albeit secondarily) within the post-2006 initiative, a series of workshops in which stakeholders discussed a broad set of issues associated with the end of the state's transition period in 2006.
Ohio (CG&E)	• None (recently)
Oregon (PGE)	• PGE conducts IRP and has historically included DSM. Following recommendations by OPUC staff, the OPUC recently directed the utilities to include DR in their IRP and to file an RTP or critical peak pricing tariff for non-residential customers. • The OPUC is investigating policies to facilitate advanced metering infrastructure to support DR efforts
Georgia (GPC)	• GPC conducts IRP and is required to evaluate DSM. However, DR programs for large C&I customers have historically been evaluated outside of the IRP process.

4.3 RTP Implementation Process and Stakeholder Support

In each case study, the decision to implement RTP was made and the RTP tariff design was established within some process or combination of processes involving a number of different stakeholder groups. In several cases, substantive issues related to RTP were also addressed within regulatory proceedings following the initial implementation phase. In this section, we compare the implementation process undertaken in each state in terms of the structure of the process and the support and positions of major stakeholders.

4.3.1 Process Structure

In all of the case study states, the decision whether or not to implement RTP and the initial adoption of a particular rate design were codified through a regulatory order. However, the structure of the process culminating in that regulatory order varied in several basic ways (see Table 4-3).

Table 4-3. Regulatory Process for RTP Implementation

State	Tariff	Regulatory Process			
		Type	Scope	Key Components	Duration
New Jersey	Statewide default RTP	OII/OIR (recurring annually)	Establish default service rates and procurement process for all customers in the state, for the following year	Public hearings Joint utility rate proposal Public comment period	6 months
Maryland	Statewide default RTP	OII/OIR	Establish post-transition period default service rates and procurement process for all customers in the state	Negotiated settlements (Phase I and II)	16 months
Pennsylvania	DLC default RTP	Rate Case	Establish post-transition period default service rates and procurement process for all DLC customers	Technical conferences Litigated hearings and public comment period Negotiation between DLC and customer groups	9 months
New York	NMPC default RTP	Rate case	Establish utility rate options (incl. default service) for NMPC customers for the transition and post-transition periods	Settlement agreement between industrial customers and utility	~1 yr
	Statewide optional RTP	OII/OIR	Implement statewide optional RTP	Public comment period	5 months
	CHG&E default RTP	Utility application	Implement RTP as the only utility supply option for large customers	Utility filings	6 months
Illinois	ComEd default RTP	Rate case	Establish whether retail market for ComEd customers >3 MW should be "declared competitive" and if so, establish post-transition period utility supply service for this customer class	Litigated hearings and public comment period Negotiated stipulation between ComEd and competitive suppliers	9 months
Ohio	CG&E default RTP	Utility application	Establish post-transition period utility supply service for all CG&E customers >100 kW	Rate proposal Negotiated stipulation between CG&E and stakeholder groups	27 months
Oregon	PGE optional RTP	Advice filing	Consider RTP pilot proposal	Utility advice filing Public comment period Negotiation between PGE and PUC staff	2 months
	PGE optional daily TOU pricing	Rate case	Establish transition period utility supply options for all PGE non-residential customers	*No data*	*No data*
Georgia	GPC optional RTP	Advice filings	Consider pilot/permanent RTP tariff proposals	Public comment period	<1 yr[a]

a. Duration of the advice filing process for implementing permanent RTP tariffs

Process Scope

The scope of the RTP implementation processes differed in terms of the range of issues addressed and whether the process was statewide or utility-specific. Where RTP has been proposed in the context of developing the post-transition period default supply service, a wide range of both policy and technical issues have typically been addressed, extending beyond simply the development of RTP tariffs for large C&I customers.[29] In some of these states (New Jersey and Maryland), all issues were addressed at a statewide level, while in others (Pennsylvania, Illinois, Ohio, and, to a lesser extent, New York), broad policy issues were addressed at a statewide level, but tariff designs were developed within utility-specific regulatory processes. In contrast to the aforementioned cases, where the context was *not* the development of the post-transition period default supply service (i.e., optional RTP in New York, Oregon, and Georgia), the process scope has been much narrower, focusing primarily on issues related to RTP tariff design and administration.

Process Type

The type of regulatory process conducted in each state to initially implement RTP reflects the scope (statewide or utility-specific) and the type (default or optional) of RTP tariff under consideration.[30] The *statewide RTP* tariffs, both default and optional, were implemented through Order Instituting Investigation or Order Instituting Rulemaking (OII/OIR) type processes. The *utility-specific default* RTP tariffs were implemented through either rate cases or utility applications. Finally, the *utility-specific optional* RTP tariffs were initially implemented through advice filings.

Process Components

In most of the cases involving the development of the post-transition period default service, the core process consisted of an initial proposal issued by the utility, followed by a public comment period and, in the two rate cases, litigated hearings. One variant on this basic process (e.g., New Jersey and Pennsylvania) involved technical conferences or public hearings held prior to the formal regulatory proceeding, so that the utility could receive preliminary feedback on its forthcoming proposal. Another variant (e.g., Pennsylvania, Ohio, and Illinois) involved negotiations between the utility and a small number of stakeholder groups following the utility's initial proposal, resulting in a jointly-issued, revised proposal for the commission's consideration.

[29] For example: what entity is to provide default service, what types of default service are to be offered to different customer classes, and how to procure generation supply for default service customers.
[30] We categorize the process in each state according to the categories used by the California Public Utilities Commission. *Orders Instituting Investigation or Orders Instituting Rulemaking* (OII/OIR) are commission-initiated processes to set basic policy rules (OIR) or to conduct preliminary information gathering (OII). *Rate cases* are conducted to address major changes to capital expenditures, rates, and/or revenue requirements, and can be initiated either at the utility's request, by a third party, or, in some states, automatically every few years. *Utility applications* involve requests by the utility for approval of a specific activity (e.g., an IRP filing) and are similar to rate cases, except that they can be initiated only utilities. *Advice letters* and *advice filings* are also utility-initiated processes but generally involve minor activities that do not significantly impact rates or revenue requirements.

Maryland is unique among those cases involving the development of post-transition period default service. All of the details of the default service implementation, including the rate structure for various customer classes and the procurement process, were developed and agreed upon through a negotiated settlement process involving approximately 25 stakeholder groups, representing a diverse set of interests. The settlement was then submitted to the MDPSC for approval, with a limited public comment period consisting of a set of briefs filed by the various parties to the settlement.

In the cases involving optional RTP, the initial implementation process was comparatively less structured. In all of these cases, the utility submitted an initial tariff proposal, followed by a limited amount of public comment or, in the case of PGE's RTP pilot, negotiations with PUC staff regarding several specific tariff provisions. GPC's RTP tariffs were also initially implemented in this manner, but have received a great deal of substantive attention in a variety of subsequent rate cases and other litigated proceedings.

<u>Duration</u>

Most of the case studies had a relatively brief (<1 year) implementation phase, even where a broad range of issues were considered. The principal exception is Ohio, where CG&E's default service application was pending before the commission for more than two years. In part, the process was delayed because the separate rulemaking to define the broad statewide terms for default service had not yet concluded. However, the length of the process could perhaps also be attributed to the divergent objectives of its key participants: CG&E sought to continue providing retail supply and maintain its market share, while competitive suppliers sought to promote the development of a competitive retail market.

4.3.2 Stakeholder Support for Default and Optional RTP

In general, one or more identifiable party in each case study was chiefly responsible for initially recommending or proposing that RTP be implemented as a default or optional tariff, and in the course of the ensuing regulatory process, other stakeholders expressed their overall support for or opposition to the proposal, distinct from their position on specific, technical details (see Table 4-4).[31]

[31] Thus, we distinguish between positions on *whether* optional or default RTP should be implemented from positions on *how* it should be implemented (e.g., related to tariff design and administration), discussed in Section 4.4.

Table 4-4. Stakeholder Support for RTP

State	RTP Proposal	Stakeholder Group			
		Utilities	**Regulatory Staff**	**Large Customer Groups**	**Competitive Retail Suppliers**
New Jersey	Statewide default RTP	Proposed	Supported	Supported	Supported
Maryland	Statewide default RTP	Supported	Supported	Supported	Supported
Pennsylvania	DLC default RTP	Supported optional RTP; opposed default RTP	Supported default RTP	Encouraged utility to propose optional RTP; opposed default RTP	Proposed default RTP, instead of optional RTP
New York	NMPC default RTP	Proposed	Supported	Supported; proposed fixed price alternative	Not actively involved in 1998
	Statewide optional RTP	Mixed support for default RTP	Proposed optional RTP and initiated investigation of default RTP	Opposed default RTP proposal	Supported default RTP proposal
	CHG&E default RTP	Proposed	*No data*	*No data*	*No data*
Illinois	ComEd default RTP	Proposed	Opposed	Opposed	Supported
Ohio	CG&E options for existing customers[a]	Proposed optional RTP and opposed default "variable rate"	Opposed optional and default RTP	Opposed default "variable rate"	Opposed default "variable rate"
Oregon	PGE optional RTP	Jointly proposed optional RTP with PUC staff	Jointly proposed optional RTP with utility	No public comment	No public comment
	PGE optional daily TOU pricing	Proposed market-based options (incl. daily TOU pricing)	Supported	Supported	Concerned that set of market-based options replicates competitive offers
Georgia	GPC optional RTP	Proposed	Supported	Supported	No public comment

a. For Ohio, we focus on stakeholder support related to RTP for existing utility customers. Ultimately, a fixed-price default service was approved for these customers, and RTP was implemented as the default service for returning customers only.

Utilities

Utilities have generally supported *default* RTP proposals in cases where they have divested their generation assets and where established state regulatory policies have clearly prohibited their participation in the competitive retail market. Their support for default RTP stems from a number of considerations, perhaps the most important of which is that, by passing through spot market prices to default service customers, utilities can avoid many of the risks and costs that they would bear if they were to provide fixed price default service.[32] Some utilities may also have a strategic interest in encouraging customers to switch to a competitive supplier (which default RTP is presumed to stimulate), depending on the particular regulatory incentives that the

[32] A provider of fixed price default service faces risks associated with balancing and load migration, and administrative costs associated with procuring long term supply resources.

utility faces as a default service provider and whether the company has an affiliated competitive retail supplier operating in the same market.

Utilities in several states (Pennsylvania, New York, and Ohio) have opposed default RTP proposals, even though all have supported optional RTP. In general, their opposition to default RTP derives from some level of interest in continuing to supply retail load, expressed in terms of "maintaining a level playing field" with competitive suppliers and/or "not limiting customer choice." For example, in its opposition to the PUCO draft order mandating a variable rate default service, CG&E asserted that it should be able to adjust its retail service offerings as necessary to maintain market share.

Utilities have supported optional RTP proposals in all cases where it has been considered. Their support rests upon two fundamental categories of benefits that optional RTP can potentially yield for utilities. The first set of benefits derives from the value of RTP as a tool for load management and risk management. Specifically, by encouraging load shifting, load growth, and peak shaving, RTP can improve the utility's system load factor, utilize excess generation capacity, and/or reduce reliance upon spot market purchases during peak periods, all of which help to reduce and/or stabilize the utility's average costs. The second set of benefits derives from the value of RTP as a tool for customer retention and retail competition. Some customers prefer RTP, particularly when it can be combined with flexible hedging options, and utilities that are seeking to maintain a long run presence in the retail market recognize that, by making such options available, they can better retain existing customers and attract new ones. Both CG&E and DLC included RTP as an option in their default service proposals for similar reasons, and GPC has maintained strong support for RTP because of its indispensable role in helping the utility compete for customer choice load in Georgia.

<u>Regulatory Staff</u>

Support for *default* RTP by regulatory staff has generally been founded on a broader interest in facilitating retail market development and successfully implementing the post-transitional phase in the state's restructuring process In particular, they have supported default RTP because: it is market-based (often a statutory requirement), eliminates the need for class-average load profiles for commodity pricing (and the associated cross-subsidies and cost shifting that are presumed to distort the retail market), mitigates administrative complications associated with managing and accounting for load migration (e.g., switching restrictions), and is generally deemed to encourage switching and attract retailers to the region (on the presumption that most customers want greater price certainty).

Support for *optional* RTP by regulatory staff has generally been driven by policy goals related to resource adequacy and cost-effective resource acquisition (e.g., in Oregon and New York). In Georgia, economic development has also been a key factor underlying GPSC staffs' support for GPC's RTP tariffs; the state's industrial sector has been contracting, and RTP is considerably less costly for many industrial customers, compared to the utility's standard, embedded cost based rates.[33]

[33] As described more fully in the Georgia Power case study, most industrial customers have a CBL that is equal to approximately 60% of their typical load. Because RTP prices are, on average, well below standard, embedded cost based rates, the customer is able to save significantly on the remaining 40% of their load.

In several states, regulatory staff opposed or had reservations about instituting RTP. In Illinois, regulatory staff did not consider the marketplace for ComEd's large customers sufficiently competitive to subject these customers to default RTP. In Ohio, regulatory staff opposed RTP for existing utility customers (default or optional) on the grounds that it would inhibit the development of retail competition. In their view, RTP and interval metering are value-added services and, as such, are to be provided by competitive retail entities. Furthermore, if RTP is designated as the default service, it erodes the opportunity for competitive suppliers to "cherry pick" customers with inexpensive load profiles who would otherwise cross-subsidize other customers in their rate class if the default service were instead based on a class average load profile. Finally, in New York, regulatory staff supported implementation of the statewide optional RTP tariffs, but ultimately opposed making the tariffs mandatory for certain customer classes given the ardent opposition to default RTP by many customer groups. NYPSC staff concluded that forcing customers onto RTP was premature at that point in time, and that a more effective strategy for developing demand response would be to first focus on educating customers about the benefits and risks associated with RTP.

Large Customers

Support for *default* RTP by large customer groups has been mixed, and tends to reflect the maturity of the competitive retail market and/or the availability of alternative fixed-price utility supply options. For example, large customer groups in New Jersey, Maryland, and NMPC's service territory have supported the default RTP proposals. In Maryland and DLC's service territory, the C&I retail market had already reached a relatively mature state at the time that the default service proceedings were underway, with approximately 30% of all C&I load already switched to a competitive supplier. The Maryland and NMPC default RTP proposals also incorporated temporary fixed-price utility supply options (in NMPC's case, at the behest of customer groups), which presumably allayed concerns about the immediate availability of competitive hedged supply options. In contrast, customers in Pennsylvania (DLC), Illinois (ComEd), Ohio, and New York (statewide RTP) voiced strong opposition to default RTP, citing various interrelated concerns, such as the lack of a robust retail market, undue risk exposure, potential negative bill impacts, and the need for greater customer education and time to adapt.

In cases where optional RTP has been proposed, large customers groups have generally come out in support, and in several cases, they have been instrumental in initiating the proposal. In Georgia, particularly, large customer groups have been avid supporters of RTP, notwithstanding various technical issues they have raised with respect to specific tariff provisions or administrative procedures. In Pennsylvania, large customers were active in encouraging DLC to include RTP as an option in its default service proposal, although, as mentioned above, they opposed default RTP.

Competitive Retail Suppliers

Competitive retail suppliers have consistently supported default RTP, identifying several ways in which it serves to promote retail competition. First, provided that the default RTP tariff is a full pass-through of spot market prices with no hedge, it creates an opportunity for competitive suppliers to offer supply products that incorporate risk management options. Second, because RTP always reflects the current state of the market (unlike default service options developed through an auction or RFP mechanism), suppliers have greater assurance that they will continue to have enough headroom, even if wholesale market costs rise.

Given their strong support for default RTP, competitive suppliers have generally expressed reservations about utilities offering RTP as an optional service (since the two are mutually exclusive). Furthermore, many competitive suppliers are categorically opposed to *any* optional utility service for customers with retail choice. In their opinion, utilities should offer only one basic default service, and alternatives to that service should be offered only by competitive retail suppliers.

4.4 Tariff Design and Implementation Details

Once the threshold decision is made to implement RTP, a number of basic tariff design and implementation details remain to be addressed.[34] First, what customers will be eligible for and, in the case of default service, automatically placed on RTP? Second, what additional metering or other infrastructure will be required for RTP implementation, and how will the incremental cost be recovered? Third, what pricing structure and terms will be adopted? And finally, what, if any, supplemental activities to support customer participation and price response will be conducted, and by whom?

4.4.1 Customer Size Threshold

Two different customer groups are relevant to a description of RTP tariffs: (1) those customers that, in the case of default RTP, are *automatically* placed onto the tariff; and (2) those customers that, for either default or optional RTP, are allowed to *voluntarily* select the tariff. Typically, these groups are defined in terms of a minimum peak demand level. As a convention, we will refer to the minimum peak demand level defining these two groups as the *default threshold* and the *eligibility threshold*, respectively. For default RTP, the two thresholds may be one and the same; that is, the only customers that are allowed on the rate are those that are automatically transferred onto it. Or, the eligibility threshold may be lower than the default threshold, in which case some customers that are not automatically transferred can voluntarily enroll (e.g., as in New Jersey and Illinois). Although the particular peak demand level chosen for the default threshold arguably has greater political ramifications than that for the eligibility threshold, both have potential implications for cost recovery (e.g., related to infrastructure deployment), demand response, and a variety of other important policy and ratemaking issues.

The eligibility and default thresholds adopted in the case studies vary across a wide range, from all non-residential customers to 5,000 kW (eligibility thresholds), and from 100 kW to 3,000 kW (default thresholds) [see Table 4-5]. In many cases, the threshold has been reduced over time, or there is some likelihood that it may be reduced in the future. For example, the eligibility thresholds for Georgia Power's optional day-ahead and hour-ahead RTP programs were reduced from initial levels of 1,000 kW and 10,000 kW to 250 kW and 5,000 kW, respectively. In New Jersey, the class of default RTP customers has been expanded on several occasions: first, from the highest voltage classes to all customers >1,500 kW, and in 2005, it will be expanded to all customers >1,250 kW. BPU staff indicated that, at some time in the future, the threshold might

[34] This distinction between the threshold decision to implement RTP and specific tariff design and implementation details is a heuristic device. In practice, proposals to implement RTP typically specify or assume various tariff design and implementation details.

be reduced further, to as low as 750 kW (NJBPU 2004). In Maryland, the default threshold was reduced from 1,500 kW, when initially implemented for BGE's Schedule P customer class, to the current level of 600 kW.

Different factors have been relevant to the choice of a particular threshold in the various case studies. In many cases, the initial choice was largely determined by pre-existing tariff classifications and/or pre-existing interval metering installations (e.g., NMPC, CHG&E's proposal, the initial New Jersey default RTP tariff, BGE Schedule P customers in Maryland). In some cases, though, particularly those involving default RTP, the specific threshold chosen reflects some assessment about how large a customer should be for RTP to be *appropriate*. These assessments were typically based on some evaluation of the range of competitive alternatives available, customers' sophistication, and/or the cost of additional metering or other infrastructure.

In regions with retail choice, larger customers are often deemed more likely to receive attractive offers from competitive suppliers, and therefore establishing RTP as the default service for these customers is less likely to impose an undue risk by "forcing" these customers onto RTP. A fundamental complication involved in making this kind of judgment is that the degree of competition in the retail market for large customers is, itself, potentially affected by the decision to make RTP the default service (i.e., a "chicken and egg" problem). Perhaps because of this complication, in most cases where the issue was considered, it was done informally. Illinois was unique in this regard, as the particular default threshold for ComEd's RTP tariff (3,000 kW) was linked to a formal process to establish whether or not the retail market for these customers could be "declared competitive."[35]

Larger customers are also often judged to have a greater level of sophistication in terms of: their familiarity with energy markets and with technologies and strategies to manage their load (perhaps because the organization has a dedicated energy manager or purchaser); their ability to assess rate and contract alternatives and negotiate with retailers; and their financial wherewithal to invest in enabling technologies or other load response strategies. These various dimensions of a customer's sophistication are relevant both to demand response related goals and, in the case of default RTP, to issues of fairness. Typical practice has been to use customer size as a proxy for sophistication; however, when the NYPSC considered statewide mandatory RTP, some customers objected to the use of a specific peak demand threshold, arguing that industry classifications would be a much better indicator of customers' ability to adjust their load in response to time varying prices.[36]

The third issue often considered in assessing the appropriateness of RTP for different customer groups has to do with the incremental cost of deploying the necessary metering infrastructure. Large customers are fewer in number and have larger loads than smaller customers, so the cost

[35] The Illinois Public Utilities Act established the following criteria by which the ICC determines whether a tariffed utility service has become a competitive service: 1) the service or a reasonably equivalent substitute service is reasonably available at a comparable price from one or more providers other than the electric utility or an affiliate of the electric utility, 2) the electric utility has lost or there is a reasonable likelihood that the electric utility will lose business for the service to the other provider or providers, and 3) there is adequate transmission capacity into the service area to make electric power and energy reasonably available to the customer segment or group from one or more providers other than the electric utility or an affiliate of the electric utility (ILCS, 2005).

[36] That being said, some large customer groups further argued that, regardless of their "sophistication," many customers would incur excessive costs to respond or other negative impacts on their business.

of installing advanced meters for these customers is lower, both in aggregate and on a per-kW basis. In states where interval meters have already been upgraded for large customers prior to RTP being considered, the incremental costs are limited to changes required in customer information and billing systems.

Table 4-5. Customer Size Threshold and Interval Metering Deployment

State	RTP Tariff	Default Threshold	Eligibility Threshold	Interval Metering Deployment
New Jersey	Statewide default RTP	1500 kW	all non-residential	Utilities directed to install metering for all customers >750 kW; cost recovery to be determined in future rate cases.
Maryland	Statewide default RTP	600 kW	600 kW	Utilities directed to install metering for all customers >600 kW; customers billed for costs through pre-existing metering tariff.
Pennsylvania	DLC default RTP	300 kW	300 kW	Default customers already have interval meters
New York	NMPC default RTP	2000 kW	2000 kW	Default/eligible customers already have interval meters
	Statewide optional RTP	n/a	varies by utility [a]	Meters installed on an as-needed basis. NYSERDA offers SBC-funded rebates.
	CHG&E default RTP	1000 kW	all non-residential	Default customers already have interval meters.
Illinois	ComEd default RTP	3000 kW	all non-residential	Meters installed on an as-needed basis. All RTP customers pay an itemized metering charge.
Ohio	CG&E default RTP for returning customers	100 kW	100 kW	Meters installed on an as-needed basis; only customers <500 kW charged for installation cost
Oregon	PGE optional RTP	n/a	1000 kW	Eligible customers already have interval meters.
	PGE optional daily TOU pricing	n/a	all non-residential	Meters installed on an as-needed basis. [b]
Georgia	GPC optional RTP	n/a	250 kW (DA) 5000 kW (HA)	Meters installed on an as-needed basis. All RTP customers pay an administrative charge, which covers metering costs.

a. CHG&E, NYSEG, and O&R permit any non-residential customer to enroll in RTP, while ConEd and RGE have eligibility thresholds of 100 kW and 300 kW, respectively.
b. The OPUC is also investigating policies to facilitate advanced metering infrastructure to support DR efforts.

4.4.2 Interval Metering Deployment

Interval meters capable of recording electricity usage in hourly or sub-hourly increments are required for RTP, yet, often, some or all of the eligible customers lack the necessary metering. Whether to install interval meters across a broad customer population (e.g., all eligible customers) or only on an as-needed basis, and how the associated costs should be recovered, are important issues in the RTP implementation process, with implications for demand response, ratemaking, and the development of competitive retail markets for commodity services and metering.

Our case studies fall into four categories with respect to interval metering deployment and cost recovery (see Table 4-5). First, for PGE (RTP pilot), NMPC, and DLC, interval meters had already been installed for the eligible customer classes prior to RTP implementation, thus no further deployment activities were required. CHG&E's default RTP proposal also applies only to customers already equipped with interval meters. Second, in Georgia and Illinois, interval metering is installed on an as-needed basis, and costs are recovered through monthly administrative or metering charges assessed on all RTP customers. In New York, meters are also installed on an as-needed basis for customers that enroll in the optional RTP tariffs, and customers are charged individually; however, NYSERDA offers rebates, funded through the state System Benefit Charge, to defray a significant portion of these costs.[37] Third, in Maryland, utilities were directed to install interval meters for the entire class of customers that default to RTP (i.e., all customers >600 kW), and to seek cost recovery in their rate cases. Smaller customers are also eligible for RTP, but must pay individually for their meters. Finally, in New Jersey, utilities were directed to install meters for all default customers as well as all for other eligible customers >750 kW and to seek cost recovery in their upcoming general rate cases. According to BPU staff, the decision to install meters for customers below the default threshold at that time (i.e., with a peak demand of 750-1,500 kW) was, in part, based on the rationale that the meters would facilitate peak demand reductions and thus benefit all ratepayers (NJBPU 2004). Doing so would also facilitate reducing the default threshold further in the future, as entertained in recent regulatory proceedings.

4.4.3 Pricing Structure and Terms

RTP tariffs can be characterized by a number of basic pricing-related provisions (see Figure 4-2). The pricing structure of RTP tariffs is defined by two distinctions (see Text Box 1): whether the various cost elements are bundled or unbundled, and whether all of the customer's load is subject to time-varying prices or only deviations from their customer baseline load (CBL). Other key pricing-related tariff provisions include: the source of, or method for deriving, time-varying prices; the amount of advance notice with which firm prices are quoted; and whether retail adders are applied to the time-varying price, and if so, at what level the adder is set.

[37] Rebates for up to 65% of the total installation meter cost are offered through NYSERDA's Peak Load Reduction Program. A total of $7.5 million in funding for various peak load reduction measures is offered through this program in 2005.

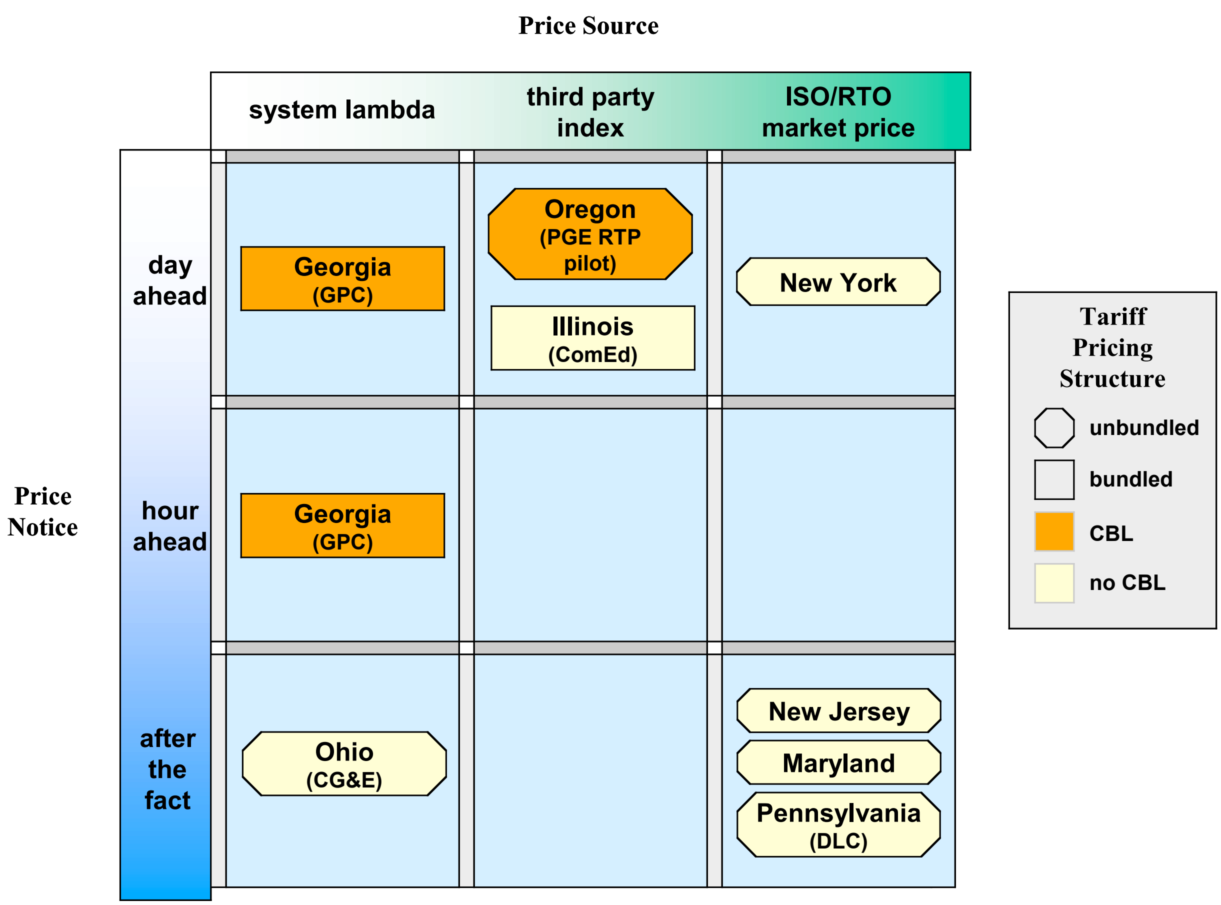

Figure 4-2. RTP Tariff Design Features

Pricing Structure

Almost all of the case study RTP tariffs are unbundled, a consequence of the broader unbundling process undertaken in most of these states, usually prior to the opening of the retail market. In these cases, RTP participants are billed for generation service under the RTP tariff, and for the utility delivery service under a separate, delivery services tariff, which typically consists of some combination of billing demand, volumetric, and customer charges. ComEd has not formally unbundled; however, their RTP tariff does contain distinct, itemized charges for energy and the various delivery service components (transmission, distribution, metering, etc.). Only Georgia has a fully bundled tariff, where delivery service charges are embedded in the billing components of the non-RTP tariff applied to RTP customer's CBL.

Most of the RTP tariffs have no CBL component; that is, participants are assessed time-varying prices for all of their usage. All of these tariffs, with the exception of the optional RTP tariffs in New York, were implemented in the context of developing the post-transition period default service (see Section 4.2.3). Although a CBL-based design was never explicitly considered in most of these cases, there are several reasons why RTP with a CBL is an unlikely candidate in this particular policy context. Perhaps the most fundamental reason is that making the rate more attractive to customers – in this case, by allowing them to hedge part of their load through their CBL – is contrary to one of the primary objectives of these default service tariffs, which is to encourage (or at least to *not discourage*) customer switching. Moreover, utility-supplied hedges of any type are likely to be viewed by many stakeholders as contrary to the model of a competitive retail market in which risk management is one of the key services to be supplied by competitive entities.[38]

The only RTP tariffs with a CBL among the case studies are those offered by GPC and PGE, as well as the optional RTP rate included in CG&E's initial default service proposal (but later superseded by the approved default rates).[39] The underlying rationale for the CBL-based design in all of these cases is that the parties responsible for developing the tariff design had an interest in promoting customer acceptance of RTP, either for load management and/or customer retention and recruitment. The optional RTP tariffs in New York were also developed with an interest in promoting customer acceptance; however the utilities and PSC staff opted against implementing a CBL-based tariff design in light of difficulties encountered with the CBL-based tariff offered by NMPC in the late 1980s and early 1990s (NYPSC 2004).[40]

Text Box 4-1. Overview of RTP Tariff Pricing Structure

RTP tariffs can be classified according to whether they are bundled or unbundled and whether they consist of a one-part or multi-part pricing structure. Multi-part tariffs can be further classified according to whether or not they incorporate a customer baseline load (CBL).

Bundled vs. Unbundled. Bundled tariffs, which are the standard in states that have retained a traditional industry structure with vertically integrated monopolies, do not have a one-to-one relationship between individual rate elements (e.g., demand, energy, and customer charges) and cost elements (i.e., generation, transmission, distribution). Unbundled tariffs, common in states that have introduced retail access, align functional costs with distinct billing elements. Unbundling is typically undertaken so that customers can directly compare offers by competitive retail suppliers to the default supply service.

One-part vs. Multi-part. One-part RTP tariffs assess only a volumetric (per kWh) charge to recover both fixed and variable costs, while multi-part tariffs have non-volumetric charge (e.g., demand charges or access charges) to collect some or all of the fixed costs associated with serving a particular customer.

A special case of the multi-part RTP tariff is the two-part RTP tariff with a customer baseline load (CBL) component. The CBL is a customer-specific hourly usage profile. Time-varying prices are applied only to the deviation between the customer's actual hourly load and their CBL. The customer is also assessed an access charge by applying the standard, non-RTP tariff billing components (e.g., energy and billing demand charges) to their CBL. The benefit to the customer of the CBL-based tariff is that it hedges a portion of their load at a fixed price rate, thereby reducing their exposure to price risk. The corresponding benefit for the utility is that it stabilizes their revenues, since some of the customer's charges are fixed.

CBL-related issues have come up in a number of other case studies as well and, to some extent, are endemic to this type of tariff design, particularly when implemented in a cost-of-service

[38] A number of other reasons why these tariffs do not incorporate a CBL can also be identified. First, CBL-based tariffs are more difficult for customers to understand and to compare to competitive offers, and therefore less appropriate for a default service tariff. Second, they are more complicated to administer: for example, some process would be required to set the CBL for each customer transferred to the tariff, and in cases where the utility has divested its generation, some process would need to be developed to procure the fixed price generation supply for the CBL portion of customer's load. Third, one of the primary motivations for the CBL design – utility revenue stability – is accomplished much more directly by unbundling the distribution costs and passing through wholesale commodity and transmission costs, thus obviating this particular rationale for a CBL.

[39] PGE's tariff was explicitly modeled after GPC's. Although PGE has unbundled, the RTP tariff specifies that delivery service charges are assessed on the customer's CBL, not on their actual usage. Thus, incremental load above the CBL is not subject to T&D related charges.

[40] The utilities in New York are also subject to many of the same policy and administrative feasibility issues discussed above in connection with the default RTP tariffs included in the case studies.

regulatory environment. PGE staff have expressed concern that, because RTP prices are expected to be higher than the cost-of-service (CBL) prices in 2005, customers that are already planning on reducing their load would be able to receive payments for these load reductions by switching to RTP, in effect, "free-riding". In Georgia, customer groups and PSC staff have also raised several issues related to the utility's process for setting and adjusting the CBL. GPC allows new customers to receive a CBL below their projected load, and does not require that any RTP customer's CBL be updated if the customer permanently increases their load. The net effect of these two factors is that approximately 40% of RTP customers' combined load is "incremental" load above their individual CBLs, and is therefore billed at marginal cost based rates not subject to the same embedded cost allocation as the utility's standard tariffs. PSC staff raised concern in the company's recent rate case that this condition has led to a significant revenue deficiency for the RTP tariff class and a corresponding disparity between the contribution of RTP customers and non-RTP customers to the company's embedded cost recovery and profits.[41] At the same time, however, the company's approach to setting and maintaining CBLs is what makes the average price paid by customers on RTP much less than what they would pay under a standard tariff, and is thus a significant reason for the large number of customers enrolled in RTP (see Appendix A).

Source of Hourly Prices

Three sources of hourly prices are used among the case studies (see Figure 4-2): the locational market clearing price in an energy market administered by a regional transmission organizations (RTO) or independent system operators (ISO); indices of bilateral bulk power transactions at regional trading hubs published by third parties (e.g., ICE, Dow Jones, Platts, etc.); and internal calculations by the utility of their marginal operating cost, referred to as their system lambda. These alternative approaches differ from one another in several significant respects, including their transparency and efficiency.[42] However, not all options are feasible in each case, depending on whether the RTP tariff is offered in a region with an ISO/RTO or a liquid bilateral trading hub, and whether the utility offering the tariff is vertically integrated (since only those utilities calculate a system lambda).

In general, the most transparent source of prices available is used among the case studies. Thus, in regions with an ISO or RTO, the RTP price is indexed to the ISO/RTO locational market clearing price (e.g., New York, Pennsylvania, New Jersey, Maryland). ComEd is an exception, although only temporarily. Their RTP tariff was designed before the utility joined PJM and uses a different approach to derive hourly RTP prices, which involves shaping peak and off-peak bilateral index prices into hourly prices using PJM historical hourly price profiles. However, now that ComEd has been integrated into PJM, the company is planning to revise its RTP tariff so that the hourly prices are indexed directly to the PJM locational market clearing price.

PGE and Georgia Power, neither of which are a part of an ISO/RTO, also use the most transparent methods available. For their RTP pilot, PGE uses a combination of third-party

[41] The CBL-related issue that has received more attention, but which is peculiar to GPC and not inherent in CBL-based designs, is that some customers have objected that the company's practice of allowing only new customers to receive a reduced CBL constitutes unjust discrimination.
[42] ISO/RTO market clearing prices are public available and therefore highly transparent. Third-party indices are proprietary and therefore less transparent. The system lambda approach is the least transparent of the three, as utilities generally do not publicly disclose their procurement and dispatch decisions.

indices of bilateral trades in the region, in order to derive distinct *hourly* prices that are provided to customers with *day-ahead* notice. They start with peak and off-peak prices published each day by the Intercontinental Exchange (ICE) for firm delivery on the following day at the Mid-Columbia (Mid-C) trading hub.[43] The company then shapes these into hourly prices using Dow Jones indices for hourly spot market transactions at Mid-C on the previous day.

There are no published indices of bilateral trades in Georgia; thus GPC uses the system lambda approach. According to GPC staff, customers have generally found this approach acceptable, in part because the CBL-based design essentially requires that the utility be willing to "buy back" power at the RTP price if a customer reduces their load below their CBL (GPC 2004b). Several large customer groups have raised a number of specific concerns, particularly with respect to the treatment of off-system spot market purchases (see Appendix A). Prior to 2000, the hourly RTP price was based on the cost of the most expensive unit of energy produced or purchased. Large industrial and manufacturing customer groups objected that this method did not communicate a strong enough incentive for the utility to minimize the cost of off-system purchases, and they asked the PSC to require GPC to modify their approach (e.g., by excluding off-system purchases from their system lambda calculation) and also to disclose their procurement practices so that customers could verify that the utility minimized its supply costs (GMTA and GIG 1999, Pollack 2000). In response, the GPSC required that GPC modify their price calculation method by averaging the cost of all purchased power above system generation in their resource stack, but they did not require that the utility disclose their procurement practices.

CG&E is the only example among our case studies where the most transparent source of prices was not used. The Midwestern ISO (MISO), of which CG&E is a part, began operating day-ahead and real-time energy markets in 2005; and various third-party indices are also published for bilateral transactions at the Cinergy hub. However, CG&E uses the system lambda approach for their default RTP tariff for returning customers, with a price floor equal to the fixed-price rate of the default tariff for existing customers (see Appendix A).

Advance Notice of Hourly Prices

The amount of advance notice with which firm RTP prices are quoted has significance for a number of important issues, and involves several tradeoffs. With more advance notice, customers have more time to plan and execute their load response strategy.[44] However, the more advance notice, the less the price will reflect actual real time conditions (e.g., price spikes and reliability constraints). The amount of advance notice also affects the distribution of risk between RTP participants and the utility, with the utility bearing an increasing amount of forecasting risk, the more advance notice of RTP prices they provide.[45]

The case study RTP tariffs include three different levels of advance notice: day-ahead, hour-ahead, and after-the-fact (see Figure 4-2). GPC, PGE, ComEd, and all of the New York utilities

[43] ICE publishes their price indices at 1:30 PM CST on the day that the transaction occurred. Thus, prices for day-ahead transactions are published the day prior to delivery. In contrast, Dow Jones publishes their index prices for day-ahead transactions on the day *after* the transaction – i.e., on the *same* day as delivery.
[44] Evidence from several studies also suggests that many customers require knowledge that prices will remain high for several hours at a time to make responding worthwhile (Goldman et al. 2004, Neenan et al. 2003).
[45] It should be noted that, relative to traditional embedded-cost ratemaking, even day-ahead RTP constitutes a substantial transfer of risk away from load-serving entities onto customers.

offer RTP with day-ahead price notice. CG&E also included an optional RTP rate with day-ahead notice in its initial default service proposal (not shown in Figure 4-2). The use of day-ahead pricing reflects several considerations. In several cases (GPC, PGE, and CG&E, particularly), the parties responsible for developing RTP had an interest, for load management and/or customer retention and recruitment purposes, in offering a tariff that customers would find attractive and that would provide them with enough advance notice of high prices to respond. In New York, the utilities procure a significant share of their power in the day-ahead market, thus using day-ahead market prices for RTP customers (rather than real time market prices) is more compatible with their existing scheduling and procurement processes. Finally, for ComEd, the adoption of day-ahead pricing was partially driven by the fact that the indices used to derive RTP prices, which track bilateral transactions for day-ahead delivery, are published either at the end of the trading day or the beginning of the following day.

One complication with quoting firm prices on a day-ahead or hour-ahead basis is that it potentially exposes the utility to costs and risks associated with balancing RTP customers' load in real time. This issue takes on added significance in customer choice settings, since retail suppliers and other stakeholders may have an interest in ensuring that utility RTP rates reflect the full market costs, including any risk premium associated with providing firm price quotes a day in advance. This issue recently arose in New York, and in response, CHG&E has proposed passing through their actual balancing costs for their entire retail load through a uniform, per kWh charge assessed on all of their retail customers (CHG&E 2005).[46] GPC and PGE, which operate in regions with no transparent balancing market, incorporate a rather arbitrary "risk adder" into their hourly prices. In Georgia, the size of the risk adder has been the subject of some dispute in rate cases and other proceedings, with customers periodically arguing for a smaller adder, and utilities arguing for a larger one.[47]

The remaining case study RTP tariffs all provide price notification after-the-fact, that is, after the applicable time period has elapsed. The default RTP tariffs offered in New Jersey, Maryland, and Pennsylvania (DLC) are all indexed to the average hourly locational market-clearing price in the PJM real time spot market, which is not determined until after the hour has elapsed. This tariff design reflects several specific design objectives, all of which derive from the basic policy context of implementing the post-transition period default service in a manner that supports the development of the competitive retail market. Indexing to the real-time market, rather than to the day-ahead market, is simpler to administer, since it avoids any separate balancing process and corresponding mechanism for distributing balancing costs. It also encourages customer switching, to the extent that it exposes customers to greater risk. Given that customers on these default RTP tariffs do not know the prices until after their consumption has occurred, they have a limited ability to provide demand response. To the extent that other indicators, such as weather or day-ahead market prices, are correlated to real-time market prices, customers may be able to deduce when real-time market prices are high and respond accordingly.[48]

[46] Competitive retail suppliers wanted the charge to be determined on a customer-specific basis, rather than on a class average basis, as CHG&E has proposed (CHG&E 2005).
[47] GPC's risk adder was originally intended to compensate the utility for forecasting risk and to contribute to fixed cost recovery; however, GPC staff indicated that currently it serves to recover certain marginal operating costs not included in the system lambda calculation.
[48] LBNL calculated a correlation coefficient of 0.744 between the PJM day-ahead and real-time spot market prices (PSEG pricing zone) during summer peak periods in 2001-2003.

Retail Adders

RTP tariffs include a variety of charges in addition to commodity-related charges, including those for transmission, ancillary services, distribution, metering, etc. One special type of charge that is unique to utility tariffs implemented in customer choice markets is the retail adder. Unlike other charges, which are intended to recover *actual* costs born by the utility, the retail adder is intended to represent the *hypothetical* retailing costs (e.g., marketing, administrative expenses, profit margin, etc.) that a competitive supplier would incur to provide a similar product.[49] Retail adders are not specific to RTP, but rather, they are an artifact of any default service tariff that directly passes through wholesale market costs, whether on an hourly basis or over some longer time interval (e.g., monthly). Their purpose is to provide a level playing field between the default tariff and similarly-structured competitive products.

The default RTP tariffs offered by New Jersey and Maryland utilities and by DLC in Pennsylvania all incorporate retail adders ranging from 2.25 to 5 mills. In New York, customers that switch receive a shopping credit that varies among utilities (e.g., 2 mills for NMPC), which serves to provide headroom for competitive retailer suppliers. ComEd's default RTP tariff does not, strictly speaking, have a retail adder, but it does include a 10% "adder" for fixed cost recovery, which also serves to provide headroom for competitive suppliers, even if not intended for that purpose.

4.5 Customer Education and Assistance to Support RTP Participation and Price Response

A variety of programmatic and administrative activities can be conducted in concert with offering an RTP tariff, to encourage customers to participate and to facilitate price response from participating customers. Such activities include: (1) marketing efforts to inform customers about RTP and explain tariff provisions; (2) customer education about the fundamentals of electricity markets; (3) technical assistance to help customers identify, analyze, and implement load response strategies; and (4) financial assistance with the purchase and installation of enabling technologies for load response. Some of these types of activities may be provided in the marketplace by competitive retail suppliers, ESCOs, technology vendors, and other private entities. However, we focus here on public or ratepayer-funded activities, which are typically conducted by utilities or state agencies (see Table 4-6).

[49] In some cases, a portion of the revenues from the retail adder does also serve to compensate the utility for actual administrative costs that they bear as the default service provider.

Table 4-6. Publicly- and Ratepayer-Funded Activities Conducted in Support of RTP

State	RTP Tariff	Marketing of RTP	Education about Electricity Markets	Technical Assistance with Load Response	Financial Assistance with End-Use Technology
New Jersey	Statewide default RTP	-	Utilities & BPU	-	-
Maryland	Statewide default RTP	-	Utilities & PSC	-	-
Pennsylvania	DLC default RTP	-	-	-	-
New York	NMPC default RTP	-	Utilities & NYSERDA	NYSERDA	NYSERDA
	Statewide optional RTP	Utilities			
	CHG&E default RTP	-			
Illinois	ComEd default RTP	-	-	-	-
Ohio	CG&E default RTP	-	-	-	-
Oregon	PGE optional RTP	Utility	Utility and OPUC	Utility	-
	PGE optional daily TOU pricing	-	-	-	-
Georgia	GPC optional RTP	Utility	Utility	-	-

The optional RTP tariffs have been marketed to varying degrees. (For obvious reasons, RTP tariffs offered only as a default service do not require any marketing.) GPC has made RTP a central element in their efforts to recruit new C&I customers, most of which have a choice of supplier, by constructing offers for these customers based on RTP with different CBL levels. The company also markets RTP to existing customers that are expanding their operations, but does not formally market RTP to other existing customers (most of whom are presumed to already be familiar with the RTP rates given their considerable notoriety). PGE marketed their RTP pilot through customer account representatives for several months in 2004, after the program was first launched. The company has since discontinued any active marketing for the program, having reevaluated its viability and appropriateness in light of current market conditions (PGE 2004).[50] In New York, the utilities were recently ordered by the NYPSC to step up customer education and marketing activities for their optional RTP tariffs, in order to boost participation. ComEd, whose RTP tariff has been offered on an optional basis since 1998, has conducted no marketing for RTP. The state's restructuring law requires utilities to choose whether or not they will compete for retail load; and if they choose not to compete (i.e., to become an Integrated Distribution Company), as ComEd has done, they are prohibited from actively seeking to recruit or retain customers, which effectively limits any marketing for RTP.

Among the case studies with optional RTP, customer education about electricity markets (e.g., market structure, price trends, fundamentals, hedging options, etc.) is typically integrated to some extent into the marketing process. GPC also provides a high level of ongoing customer support and education for its RTP participants. Once per year, the utility invites all RTP customers to an "RTP Forum", where GPC staff provide training on the rate and talk about expected conditions and pricing for the next year. Each RTP customer is also assigned a client manager, who serves as their point of contact for questions about RTP and can provide some

[50] RTP prices are expected to be higher, on average, than the cost-of-service (CBL) rate in 2005, thus diminishing much of the potential load building benefits that customers could obtain and raising potential free-rider problems associated with customers that are planning to reduce load regardless of pricing enrolling in the tariff and thereby receiving payments for load reductions they were already planning on making. Also, in response to the Western electricity crisis in 2000/2001 and the subsequent rate hikes, PGE is emphasizing a commitment to providing stable and predictable electricity prices, with which RTP is potentially at odds.

help with developing strategies for managing exposure to price risk. Finally, GPC sends out information and warnings to RTP customers if a big change in prices has occurred or is anticipated. In several of the default RTP cases, utilities or the PSC have held workshops to inform affected customers about the default rate, market prices, and alternative supply options available. However, the emphasis of these activities typically has been to make sure that customers have enough information to make informed decisions about their supplier, rather than to help them develop effective risk management strategies that might facilitate continued enrollment in default RTP.

The only examples among the case studies where any type of technical or financial assistance has been offered are New York and Oregon. In New York, NYSERDA offers several programs, funded through the System Benefits Charge, that provide technical assistance and financial incentives for enabling technologies (e.g., interval meters, EMS, load controls, EIS, and DG). These programs were developed to facilitate demand response in the state and are targeted not only to customers on RTP, but also to participants in the NYISO demand response programs. In Oregon, PGE offers a limited form of technical assistance, incorporated into their marketing efforts, by helping prospective participants analyze the potential bill impacts of different scenarios.[51]

The lack of technical and financial assistance in the other states reflects several factors. In cases involving default RTP, demand response has generally not been a primary goal, and therefore there hasn't been a compelling motivation for offering such programs. Several of these states also lack some of the infrastructure necessary for delivering technical or financial assistance, for example, if utilities are prohibited or discouraged from offering DSM programs or other "behind-the-meter" services, and no independent program administrator (such as NYSERDA) has been designated.

4.6 Customer Participation in RTP

In an environment where customers have a choice between RTP and alternative supply options, the amount of load participating in RTP is one of the key determinants, along with customers' price elasticity, driving the overall magnitude of load response to spot market price volatility. In any given market, RTP participants might include: customers that have voluntarily opted onto a utility RTP tariff; customers that were automatically transferred to a default RTP tariff and have not switched to a competitive supplier or transferred to an alternative utility option; and customers that have switched to a competitive supplier under an arrangement where the price for some or all of their usage is indexed to the spot market. The first two groups are the subjects of this section; the third group is addressed in Chapter 5.

For each case study, we obtained data on RTP participation, in terms of the number of customers enrolled (as of some recent date) and their combined peak demand, as well as corresponding data on the population of eligible and/or default customers (see Table 4-7).

[51] The Energy Trust of Oregon, the independent administrator of ratepayer-funded energy efficiency and renewable energy programs in Oregon, does not currently offer programs targeting DR enabling technology adoption.

Table 4-7. Optional and Default RTP Customer Population and Participation in Early 2005

State	RTP Tariff	Start Date	Default/*Eligible* Customers		Participating Customers	
			No. of Customers or Accounts	Peak Load (MW)	No. of Customers or Accounts	Peak Load (MW)
NJ	Statewide Default RTP[a]	8/03	1,877	2,920	677	461
	Eligible to opt-in	8/03	*482,000*	*9,500*	61	25
MD	Statewide Default RTP	6/05	1,539	2,383	NI	NI
	Eligible to opt-in[b]	7/04	*1,539*	*2,383*	27	42
PA	DLC Default RTP[c]	1/05	860	1,050	59	35
NY	NMPC Default RTP[d]	11/98	149	545	49	183
	Statewide Optional RTP[e]	5/01	*No data*	*5,000*	32	No data
	CHG&E Default RTP	4/05	62	340	NI	NI
IL	ComEd Default RTP[f]	1/07	350	2,500	NI	NI
	Eligible to opt-in	10/98	*347,000*	*12,500*	40	No data
OH	CG&E Default RTP	1/05	NA	NA	No data	No data
OR	PGE Optional RTP Pilot[g]	1/04	*150*	*400*	0	0
	PGE Daily TOU Option[g]	3/02	*14,384*	*1,887*	20	25
GA	GPC Optional RTP[h]	1993	*3,880*	*6,100*	1,664	5,050

Notes: NI = not yet implemented in early 2005, NA = not applicable

a. Switching statistics for CIEP class dated February 28, 2005 (NJBPU, 2005). Optional participation by eligible customers dated January 19, 2005 (BGS Auction 2005).
b. Optional participation by eligible customers dated February 2005 (MDPSC 2005).
c. Switching statistics dated March 2005 (DLC 2005).
d. Switching statistics dated August 2004 (Goldman et al. 2005)
e. Participation as of September 2004 (NYPSC 2004b)
f. Participation as of January 2005 (ComEd 2005)
g. Participation as of December 2004 (PGE 2004)
h. Participation as of November 2004 (GPC 2004)

4.6.1 Eligible/Default Customer Population

Each RTP tariff (default and optional) has an *eligibility threshold* that defines the population of customers eligible for the tariff, and each *default* RTP tariff has a *default threshold* that defines the population of customers for which RTP is the default service (which may be the same as, or a sub-set of, the eligible customer population). Understanding the size of these populations gives some measure of the technical potential for RTP participation and provides context for interpreting market penetration rates.

The largest *eligible customer populations* (on the order of 10 GW each) are in New Jersey and ComEd's service territory, where all non-residential customers are eligible for RTP, and in New York, where all utilities except NMPC offer optional RTP with relatively low eligibility thresholds. GPC, which has a low eligibility threshold and a large system load, has an eligible customer population of approximately 6 GW. PGE is a much smaller utility and has an eligible customer population of 1.6 GW for their daily TOU pricing option and just 700 MW for their RTP pilot (although the tariff currently has a enrollment cap of six customers).

In 2004, the combined peak demand of the default customer populations was 4,500 MW, across the three case studies with default RTP in place: New Jersey, Pennsylvania (DLC), and New York (NMPC). This total will reach 6,900 MW after RTP becomes the default service in

Maryland in 2005, and 9,700 MW when and if RTP becomes the default service for customers of CHG&E and ComEd, as currently planned. The largest default customer populations are in New Jersey, Maryland, and ComEd, reflecting the relatively large size of the total system load in these cases.[52]

4.6.2 RTP Participation

Among the three default RTP tariffs in place in the U.S. in early 2005 (New Jersey, DLC, and NMPC), approximately 700 MW remained on the rate, equal to about 15% of the total load (27% of customers) in the default RTP customer classes.[53] The remaining 73% of customers in these default customer classes has either switched to a competitive supplier or, in the case of DLC, has opted onto another utility rate. Of these three cases, New Jersey and NMPC have relatively high participation levels, each with >30% of customers in the default RTP class remaining on RTP (see Figure 4-3). In comparison, within only months after implementation, only 7% of the applicable customers in DLC's service territory have remained on default RTP.

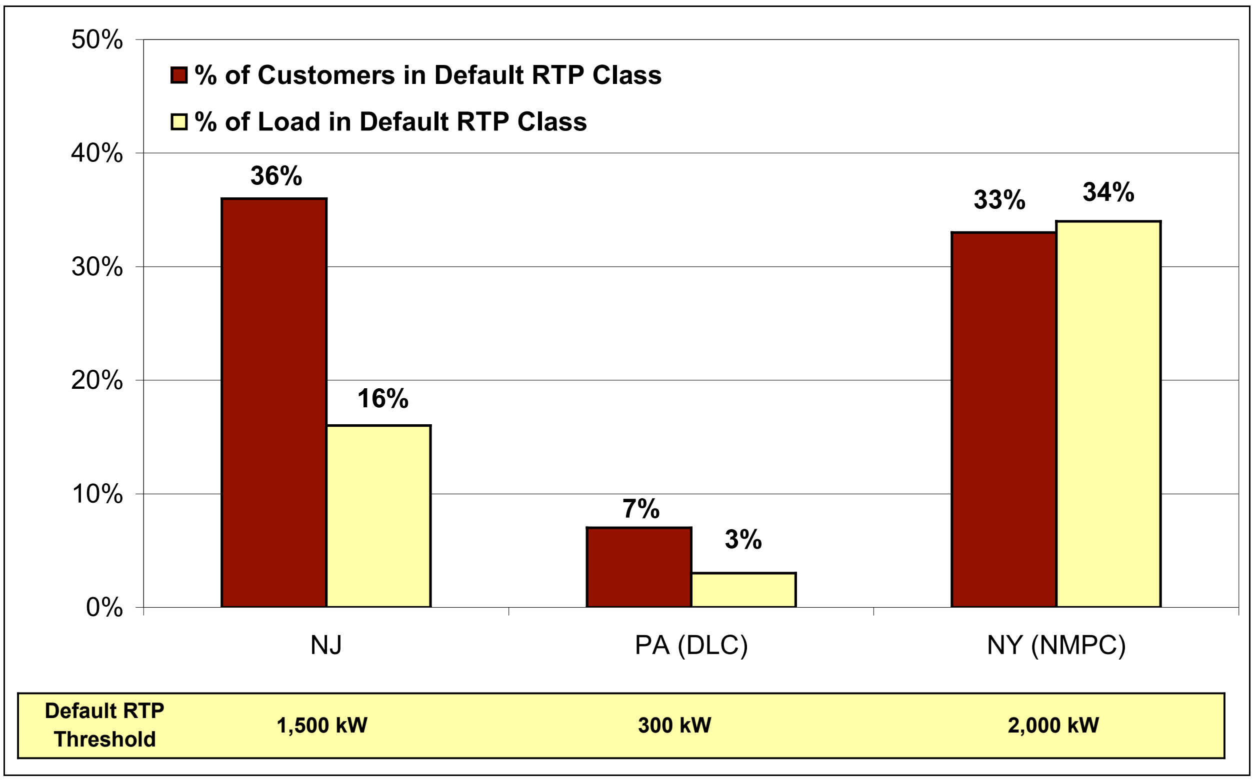

Figure 4-3. Customer Participation Rates in Default RTP in Early 2005

Several tariff design issues may contribute to these differences. First, DLC is temporarily offering an alternative, fixed price utility supply option for customers in the default RTP class that are unable to procure a competitive supply contract and do not want to remain on the default

[52] System peak demand is approximately 18 GW in New Jersey, 15 GW in Maryland, and 22 GW in ComEd's service territory.

[53] In comparison, Barbose et al. (2004) reports that, in 2003, a total of approximately 11,000 MW was enrolled in optional RTP tariffs in the U.S.

rate. As of early 2005, 88% of the load in the default RTP class that had not switched to a competitive supplier had opted onto the fixed price alternative. Second, the DLC default threshold is much lower than in New Jersey and for NMPC (300 kW, compared to 1,500 kW and 2,000 kW, respectively). If, as many suppose, smaller customers are less predisposed than larger customers to RTP, then, all other things equal, one would expect lower participation rates among DLC customers.[54] Third, NMPC's RTP tariff provides price notification on a day-ahead, rather than after-the-fact, basis; survey results reported in Goldman et al. (2005) indicate that NMPC customers are more willing to remain on RTP with this greater advance notice.

The differences in participation rates among RTP tariffs offered on an optional basis are quite stark. GPC, which has received much recognition for the popularity of its RTP program, has the largest amount of load on RTP of any optional or default RTP tariff in the country (Barbose et al. 2004). Several factors have contributed to their success: the tariffs have been available for more than a decade; the utility aggressively markets RTP and provides a high level of ongoing customer support; and, perhaps most importantly, GPC's procedure for establishing customers' CBL enables participants to obtain significant bill savings relative to their other tariffs, by purchasing a substantial portion of their total energy usage at marginal cost based rates, not subject to the same embedded cost responsibility as the standard, non-RTP tariff rate.[55]

In comparison, the other RTP tariffs offered on an optional basis have generated quite limited participation (see Figure 4-4). Only a handful of customers have enrolled on the optional RTP tariffs in New York, despite being having been available to the vast majority of non-residential customers for more than four years.[56] NYPSC staff attributes the low participation to a lack of customer understanding of RTP (in particular, an overstated sense of the associated risk) and also to the limited potential bill savings, citing analyses performed by utilities showing that only a small percentage of eligible customers would have lower bills on RTP, absent load shifting (NYPSC 2004b). In Oregon, no customers have enrolled in PGE's RTP pilot. Market prices in the region are currently higher than the utility's cost-of-service rate, thus dampening customers' potential benefits from building load at marginal cost-based market prices. ComEd's RTP tariff, which has been offered on an optional basis to all non-residential customers since 1998, currently has about 40 customers enrolled, comprising less than 1% of the eligible customer population. As discussed in Section 4.5, ComEd is prohibited from actively seeking to retain or recruit customers, which constrains the extent to which it can conduct any overt marketing for RTP. Utility staff suggested that, of those customers that have enrolled, some may have done so to take advantage of the lower average prices on RTP compared to the utility's standard tariff, or to accrue bill savings by running onsite generation during high price periods. Other participants are among the limited class of customers that are currently ineligible for any of the utility's other rates.[57]

[54] One might argue that, at the same time, smaller customers are likely to face more difficulty attracting competitive alternatives, which would tend to have a countervailing effect. However, the high switching rates for Maryland and DLC C&I customers, across all size ranges, suggests that this has not been a dominant issue.

[55] Three specific aspects of the CBL provisions are important in this regard. First, new industrial customers receive, by default, a CBL equal to 60% of their projected load. Second, all new customers (industrial and commercial) are able to receive a CBL below the default level if they can satisfy the demonstration requirements. Third, all RTP participants (new and existing) can maintain their initial CBL indefinitely over the term of their enrollment.

[56] In fact, the vast majority of those that have enrolled are on NYSEG's tariff, which provides only a shadow bill based on RTP prices, but continues to bill customers based on standard tariff rates.

[57] Currently, new customers >3 MW and customers that returned to ComEd from a competitive supplier and opted for a fixed multi-year Customer Transition Charge are eligible only for RTP.

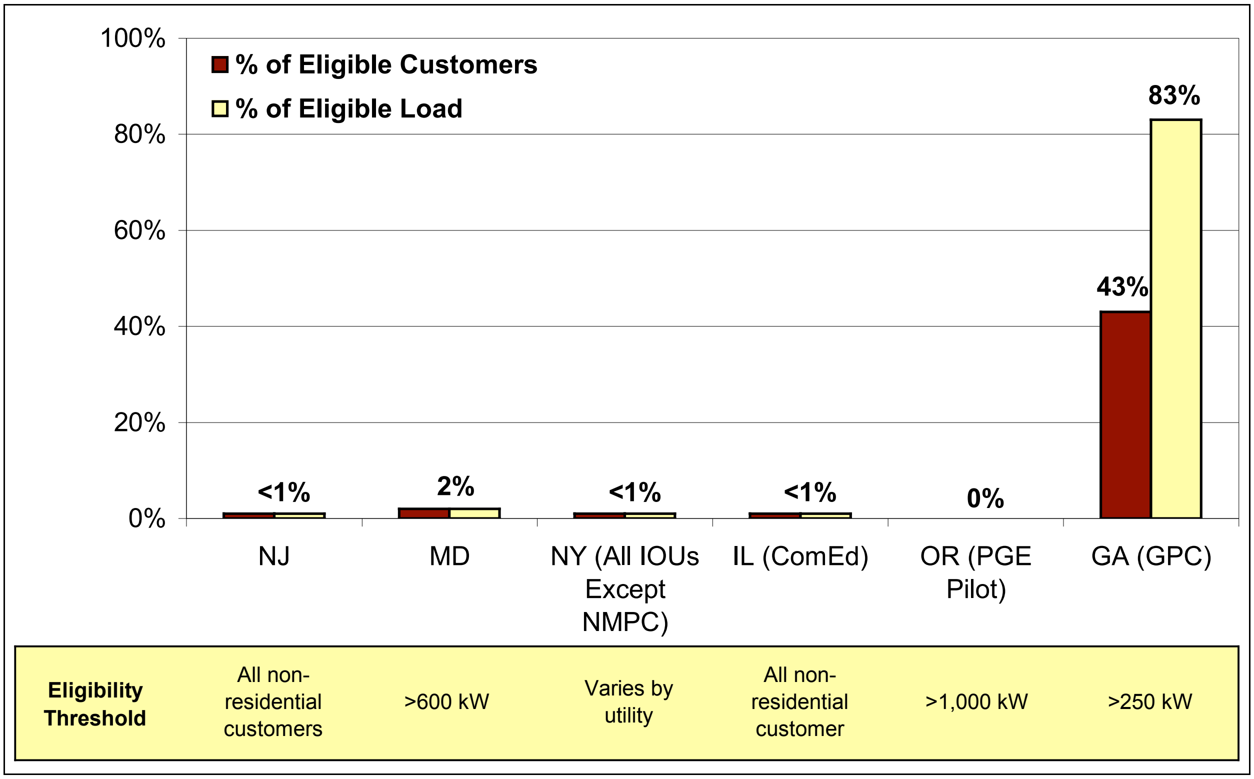

Figure 4-4. Customer Participation in Optional RTP in Early 2005

4.7 Price Response from RTP Participants

For six of the case studies (NJ, MD, PA, IL, OH, and OR), the price responsiveness of, or load reductions from, RTP participants has not yet been analyzed, according to the regulatory staff and utilities interviewed. Many of these tariffs have only recently been implemented and/or few customers have participated; thus there may not yet have been enough experience to warrant analysis. However, based on our discussions with regulatory staff in many of the states with default RTP, it is not clear that there is a perceived need for analyzing the DR impacts of default RTP tariffs or who should bear that responsibility.

GPC has commissioned several studies to estimate the price response of customers on their day-ahead and hour-ahead RTP tariffs. An analysis of summer 1999 experience estimated that the combined load reduction across participants in both tariffs was 750-800 MW when hourly prices reached \$1.93/kWh for RTP-DA and \$6.43/kWh for RTP-HA.[58] Approximately two-thirds of this load reduction was associated with RTP-DA participants, and the remaining third was from RTP-HA participants. An analysis of summer 2000, when prices were less extreme than summer 1999, found that the RTP customers produced a maximum load reduction of 482 MW (GPC 2004c). This is approximately the peak load reduction that the utility attributes to their RTP tariffs in their IRP load forecasts, assuming typical summer conditions. GPC reports that most

[58] These were the maximum hourly prices on the day that this load reduction occurred. The average peak period prices on this day were approximately \$1.50/kWh for RTP-DA and \$2.00/kWh for RTP-HA.

RTP customers require a price of at least $0.20-0.30/kWh before they respond, although some customers, particularly those with onsite generation, respond to lower prices (GPC 2004b).[59]

In addition to temporary load reductions, there is anecdotal evidence to suggest that some of GPC's RTP customers have also undertaken various permanent load modifications. Representatives of four large retail and department store chains (BJ's, Kohl's, Lowe's, and Wal-Mart) testified in GPC's 2004 rate case that, as a result of taking service on RTP, their companies have installed a range of permanent measures to reduce peak electricity demand and to take advantage of low off-peak prices, including: high efficiency air-conditioning and building envelope components; fuel switching (e.g., gas-driven desiccant cooling systems); and electric heating (Civic et al. 2004).

Notwithstanding the substantial load response that customers enrolled in GPC's RTP tariffs have demonstrated, GPSC staff has raised several issues regarding the value of RTP as a load management tool. One concern is that, despite the sizable aggregate load response, many RTP customers appear to not respond to hourly prices. PSC staff suggested that the fact that many customers can reduce their energy costs on RTP compared to the standard tariff without responding to hourly prices "may induce customers to simply 'ride through' limited hours of higher prices" (Best et al. 2004). As a result, additional generation capacity may be required, reducing hourly prices and further dampening the incentive for RTP customers to reduce their peak demand (GPSC 2004a). PSC staff also raised the concern that, "since it appears that RTP is being used to compete for new loads, the Company's claims of peak load reduction benefits to its system really do not exist," or in other words, that the overall load growth facilitated by RTP may offset the temporary load reductions induced by high RTP prices (Best et al. 2004). Despite these concerns, staff acknowledged that the RTP tariffs serve a variety of purposes other than peak load management, such as allowing the utility to compete for new loads and promoting economic development (Cearfoss and Wilson 2004).

The price responsiveness of customers on NMPC's default RTP tariff was analyzed by Goldman et al. (2005). This evaluation included an analysis of hourly usage and price data for five summers (2000-2004), supplemented by customer surveys and interviews that provided information about customer characteristics and circumstances, load response strategies, and their supply arrangements with ESCOs (e.g. whether they had hedged contracts). Major findings of this study related to the price responsiveness of the default RTP customer class are as follows:

- The load-weighted average elasticity of substitution of the class is estimated to be 0.11 (e.g. a doubling of the peak price relative to the off-peak price that day would result in an 11% reduction in peak electricity usage). This price response is associated with both those customers that have remained on the default service RTP rate as well as from those that have switched to a competitive supplier and signed a contract that exposes them to hourly spot market prices.
- At the highest peak to off-peak price ratio observed during the five summers (5:1), the 119 accounts are estimated to reduce their usage on peak by about 50 MW, an 11% reduction from their typical usage.

[59] Load reductions associated with onsite generation account for approximately 100-200 MW of the total RTP load response (GPC 2004b). Much of the current RTP response from onsite generation is associated with pulp and paper mills that increase electricity production from their cogeneration units during high price periods, to displace purchases from the utility.

- The approximately 20% of customers that are most price responsive (i.e. with an elasticity of substitution greater than 0.10) account for about 80% of the estimated aggregate load response of the class.

4.8 Other DR Mechanisms for Large C&I Customers

Default and optional RTP tariffs are but one type of mechanism that can be incorporated into retail electricity markets to induce DR (see Chapter 3). Understanding what other DR mechanisms are available in the case study states, and how they have performed, provides important context and a useful point of comparison for understanding the role of RTP as a strategy for developing DR. In this section, we describe the DR mechanisms other than RTP that were offered by *utilities* and *ISO/RTOs* in the case study states in 2004; DR mechanisms offered by *competitive retail suppliers* are the subject of Chapter 5.

4.8.1 DR programs and interruptible service rates offered in case study states in 2004

In each of the case study states, multiple DR programs were available to large C&I customers in 2004 (see Table 4-8). In all of the regions that were part of an ISO/RTO market in 2004 (New Jersey, Maryland, New York, and ComEd's service territory in Illinois), C&I customers could participate in various ISO/RTO DR programs (see Text Box 4-2).[60, 61] Most of these programs have been introduced during the past 4-5 years in an effort to improve wholesale market performance and system reliability, consistent with FERC's policy directives for RTOs to integrate DR into wholesale market design. Most utilities in these states have registered with the ISO/RTO as a DRSP, and offer the programs to their customers under nearly identical terms as the ISO/RTO program, perhaps retaining a portion of the incentive payment to cover administrative costs and/or offering the program with expanded curtailment hours to respond to T&D system contingencies.[62] Various unregulated entities, including competitive retail suppliers and dedicated DR aggregators, also participate in the ISO/RTO DR programs, although the terms and conditions under which they offer programs to retail customers are not public.

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[60] DLC joined PJM at the start of 2005.

[61] PJM's ALM program is not exclusively for large C&I customers; it includes a large number of utility direct load control programs for residential and small C&I customers as well.

[62] The NYPSC issued an order in 2000 requiring that all of the state's investor-owned utilities offer tariffs that allow retail customers to participate in NYISO's DR programs.

Table 4-8. Utility and ISO/RTO DR Programs Applicable to C&I Customers in 2004

State (Utility)	DR Mechanism Type		
	Call Option Load Reduction Programs and Interruptible Tariffs	**Scheduled Load Reduction Programs**	**Voluntary Load Reduction Programs**
New Jersey (statewide) Maryland (statewide)	PJM ALM Program	PJM Economic LRP – Day-Ahead Option	PJM Economic LRP – Real Time Option, PJM Emergency LRP
Pennsylvania (DLC)	Interruptible service [a]	-	Energy Exchange
New York (statewide)	NYISO ICAP/SCR Program	NYISO DADRP	NYISO EDRP
Illinois (ComEd)	ComEd Rider 26 (Interruptible Service) ComEd Rider 27 (Displacement of Self Generation) ComEd Rider 30 (The Alliance) PJM ALM Program	PJM Economic LRP – Day-Ahead Option	ComEd Early Advantage ComEd Rider 32 (Energy Cooperative) ComEd Voluntary Load Response Program PJM Emergency LRP PJM Economic LRP – Real Time Option
Ohio (CG&E)	PowerShare – CallOption, Interruptible contracts	-	PowerShare – QuoteOption
Oregon (PGE)	Dispatchable Standby Generation Program	-	Demand Buy Back Program
Georgia (GPC)	Demand Plus Energy Credit Rider	(Day-Ahead) Daily Energy Credit Rider	-

a. DLC cancelled their interruptible service tariffs in 2005.

Utilities in New Jersey, Maryland, and New York have phased out their legacy load management programs for C&I customers or integrated them into the ISO/RTO DR programs. In contrast, ComEd, which has built up a broad portfolio of DR programs over the past decade, is in the process of integrating these programs into the PJM market framework. According to utility staff, the company is planning a transition and partial exit from DR program responsibilities over the next three years – phasing out some of their legacy load management programs, aligning customer incentives for the remaining programs with the PJM framework, and possibly seeking cost recovery for DR programs that are not self-funding. As part of this transitional process, ComEd modified its Voluntary Load Response (VLR) Program in 2004 so that it would become the vehicle through which customers could participate in PJM's Emergency Load Response Program. VLR participants are now called for curtailments by PJM during Emergency LRP program events, and the full PJM incentive payments are passed through to the customer. ComEd has also retained the capability to call for load curtailments through the VLR program independent of PJM, to mitigate reliability conditions in their T&D system and provide a separate T&D-related incentive payment.

The four utilities in the remaining case studies (DLC, CG&E, PGE, and GPC), have all introduced new DR programs or substantially revised existing programs in the past five or so years (in some cases also continuing their legacy interruptible service rates). All four utilities have recently launched "economic" DR programs that provide performance-based payments for load reductions during periods when marginal supply costs or spot market prices are projected to be high. GPC's program (Daily Energy Credit rider) requires that customers commit on an event-by-event basis; the other three (DLC's Energy Exchange, CG&E's *PowerShare* – QuoteOption, and PGE's Demand Buy Back) require no commitment. Most of these new programs were introduced during or immediately following periods of unprecedented volatility in the spot market in each region, and were motivated by an enhanced recognition of the potential role for DR to displace short-term market purchases (in addition to the established role of DR as a long-term capacity resource).[63]

CG&E and GPC have both also introduced programs during the last five years that represent a new generation of interruptible service (*PowerShare* – CallOption and Demand Plus Energy Credit, respectively). Unlike traditional interruptible rates, which provide payments entirely based on a customer's contracted load response capability and have rigid commitment terms, these new programs provide both capacity and energy payments, and offer participants several options with respect to the number of curtailment hours and the frequency of curtailment calls.

Text Box 4-2. PJM and NYISO DR Programs

PJM DR Programs

- Active Load Management (ALM) Program. The program provides LSEs with a credit against their capacity obligation for committing to provide load reductions during emergency events declared by PJM. Participants that fail to comply with their load reduction commitment are assessed a deficiency penalty.
- Economic Load Response Program – Day-Ahead Option. The program offers participants the option to submit load reduction bids into the day-ahead energy market. If their bid is accepted, they are paid for their accepted bid, based on the day-ahead market clearing price. If a participant's load reduction is less than their accepted bid, they are charged for the difference at the real-time market clearing price and are assessed charges for balancing operating reserves.
- Economic Load Response Program – Real-Time Option. Program participants can choose to provide load reductions at any time or be dispatched by PJM in the real time market, and are paid for their measured load reduction at the real-time market clearing price.
- Emergency Load Response Program. Program participants are paid for load reductions during emergency events declared by PJM. Payments are based on participants' measured load reduction and the greater of the real time market clearing price or $500/MWh. No penalties are assessed if participants do not respond.

NYISO DR Programs

- Installed Capacity/Special Case Resources (ICAP/SCR) Program. Program participants receive an up-front reservation payment for committing to provide load reductions during emergency events declared by NYISO. Participants receive additional payments for actual load reductions, based on the amount curtailed and the greater of the prevailing real time market clearing price or the participant's designated strike price. Participants that fail to comply with their load reduction commitment are de-rated for future reservation payments and may be assessed a deficiency penalty.
- Day-Ahead Demand Response Program (DADRP). The program offers participants the option to submit load reduction bids into the day-ahead energy market. If their bid is accepted, they are paid for their accepted load reduction bid based on the day-ahead market clearing price. Any imbalance between a participant's actual load reduction and their accepted bid is settled at the higher of the day-ahead and real-time market clearing prices.
- Emergency Demand Response Program (EDRP). Program participants are paid for load reductions during emergency events declared by NYISO, at a price equal to the greater of the real time market clearing price or $500/MWh. No penalties are assessed if participants do not respond.

[63] In GPC's case, the connection with spot market volatility was indirect. In 1999, hourly prices reached unprecedented levels of $6.43/kWh for RTP-HA and $1.93/kWh for RTP-DA. In the course of a proceeding in the following year, GPC indicated that RTP prices could be substantially reduced if interruptible customers were called in response to economic conditions (Hinson et al 2000). In response, the PSC ordered GPC to introduce a new set of interruptible service options that would allow for load curtailments to be dispatched on an economic basis.

4.8.2 DR program participation and demonstrated load reductions

Several DR programs offered by utilities and ISO/RTOs in the case studies had substantial levels of participation in 2004 (see Figure 4-5 and

Table 4-9).[64] NYISO has built up a large base of participants in its programs. Its two reliability programs, ICAP/SCR and EDRP, together constitute a contracted or nominated load reduction capability equal to about 5% of the system peak demand, while customers enrolled in NYISO's economic program, DADRP, have nominated a combined load reduction capability equal to about 1% of the statewide system peak. ComEd also has a sizable base of C&I load (a subscribed load reduction potential of approximately 1,200 MW) across its portfolio of DR programs. Their largest program, VLR, doubled in size from 2001-2004, to approximately 800 MW. Finally, two utilities, DLC and Georgia Power, had relatively sizable interruptible/curtailable rates in 2004, which constituted a contracted interruptible load equal to 3-4% of each utility's total system peak demand.[65]

Other utility DR programs among the case studies have attracted more modest levels of participation (e.g., DLC's Energy Exchange program and GPC's Daily Energy Credit rider) or have experienced a significant decline in participation over the past several years (e.g., CG&E's PowerShare programs and PGE's Demand Buy Back program). Utility staff attributed this to several factors, including low spot market prices and correspondingly low incentives over the past several years, as well as competition from other suppliers or other utility DR programs. For example, GPC staff indicated that, since their Daily Energy Credit (DEC) program was introduced in 2001, the incentives offered for load reductions have generally remained below a level of \$0.15-\$0.25/kWh deemed necessary for customers to respond. Perhaps more fundamentally, GPC staff also suggested that most of the company's price responsive customers are already enrolled on RTP and the DEC program rules are such that RTP customers would have little financial incentive to participate in the DEC program.[66]

In addition to participation data, we collected a limited amount of information about the actual load reductions achieved by some of these DR programs over the past 3-4 years (see Figure 4-6 and

Table 4-9). Many of the programs have had little operational experience in recent years, because spot market prices have been low and system operators have had few occasions where load reductions were required for reliability purposes. In general, the largest load reductions have occurred among those programs that have had the largest participation levels. In terms of programs' actual load reductions *relative to participants' subscribed load reduction amount*, call option programs have generally performed best, because of participants' incentive to avoid non-compliance penalties. Voluntary load reduction programs have also generated significant load reductions when incentive payments have been large enough (e.g., NYISO's EDRP, which offers

[64] DR program participation is denominated in terms of customers' contracted or nominated load reduction (i.e., the load reduction amount that, upon enrolling in the program, customers indicate they are willing to provide), and is therefore not directly comparable to the RTP participation statistics presented in Section 4.6, which are denominated in terms of customers' combined peak or billing demand.
[65] DLC cancelled their interruptible tariff in 2005, upon joining PJM.
[66] Specifically, customers cannot receive a bill credit for the same load reduction quantity under both the DEC rider and RTP.

a minimum incentive of $500/MWh, or PGE's Demand Buy Back Program, which elicited large load reductions during the Western electricity crisis in 2000/2001). In contrast, the scheduled load reduction programs have yet to demonstrate an ability to elicit sizable load reductions, even if a large amount of load has enrolled in the program. In part, this may be a symptom of temporary market conditions (i.e., low prices). In the case of those programs that require customers to submit load reduction bids, it may also reflect market barriers, such as many participants' difficulty in precisely and reliably estimating the value of specific load curtailment strategies (Neenan et al. 2003).

Table 4-9. Demand Response Program Enrollment and Actual Performance

State (Utility)	Program	Participants' Contracted/ Nominated Load Reduction in 2004 (MW)	Demonstrated Load Reduction (MW)
Load Reduction Call Option Program			
PJM Region [a]	ALM Program [b]	1,806	1,775 (2002)
Pennsylvania (DLC)	Interruptible service	111	*No Data*
New York (statewide)	NYISO ICAP/SCR Program	981	~350 (2003)
Illinois (Com Ed)	Rider 26 (Interruptible Service)	162 [c]	*No Data*
	Rider 27 (Displacement of Self Generation)	68 [c]	*No Data*
	Rider 30 (The Alliance)	71 [c]	*No Data*
Ohio (CG&E)	PowerShare – CallOption	*No Data* [d]	*No Data*
	Interruptible contracts	*No Data*	*No Data*
Oregon (PGE)	Dispatchable Standby Generation	24	*No Data*
Georgia (GPC)	Demand Plus Energy Credit Rider	~400[e]	541 (2000) [e]
Scheduled Load Reduction Program			
PJM Region [a]	PJM Economic LRP – Day-Ahead Option	*No Data* [f]	*No Data*
New York (statewide)	NYISO DADRP	377	~10-15 (2002)
Georgia (GPC)	Daily Energy Credit Rider	*No Data*	NE
Voluntary Load Reduction Programs			
PJM Region [a]	PJM Economic LRP – Real Time Option	*No Data* [f]	168 (2004)
	PJM Emergency LRP	1385	76 (2002)
Pennsylvania (DLC)	DLC Energy Exchange	32	NE
New York (statewide)	NYISO EDRP	581	457 (2003)
Illinois (Com Ed)	Voluntary Load Response Program	787 [c]	176 (1999)
	Early Advantage	72 [c]	*No Data*
	Rider 32 (Energy Cooperative)	64 [c]	*No Data*
Ohio (CG&E)	CG&E PowerShare – QuoteOption	*No Data* [g]	*No Data* [h]
Oregon (PGE)	Demand Buy Back Program	~50	~162 (2001) [i]

Notes: NE = No recent events

[a] PJM does not publish or track participation in or load reductions from their DR programs on a state-by-state basis.

[b] A substantial portion of ALM program resources consists of direct load control programs for residential and small C&I customers.

[c] Source: McNeil (2004).

[d] In 2001, enrollment in the PowerShare – CallOption program was 190 MW, throughout all three of Cinergy's utility service territories (CG&E, PSI, and UHL&P). Enrollment in the PSI service territory (Indiana) declined from 137 MW to 4 MW between 2001 and 2003 (Rogers 2001 and Rogers 2003).

[e] Participants' contracted load reduction based on approximate value used in most recent IRP peak demand forecast (GPC 2004b). Actual load reduction based on load response data in 2001 IRP filing (GPC 2001).

[f] PJM does not enrollment data for Day-Ahead and Real-Time options, separately. The total enrollment in the PJM Economic Load Response Program in 2004, including both the Day-Ahead and Real-Time options, was 724 MW (PJM 2005b).

[g] In 2001, enrollment in the PowerShare – QuoteOption program was 274 MW, throughout all three of Cinergy's utility service territories (CG&E, PSI, and UHL&P); enrollment in the PSI service territory (Indiana) declined from 148 MW to 38 MW between 2001 and 2003 (Rogers 2001 and Rogers 2003).

[h] Cinergy reports that this program produced a load reduction of 50 MW in their PSI service territory (Indiana) during the first program event in February 2003 (Rogers 2003).[i]

[I] As of September 2001, the program had 26 participants with 175 MW of potential curtailable load (Goldman et al. 2002).

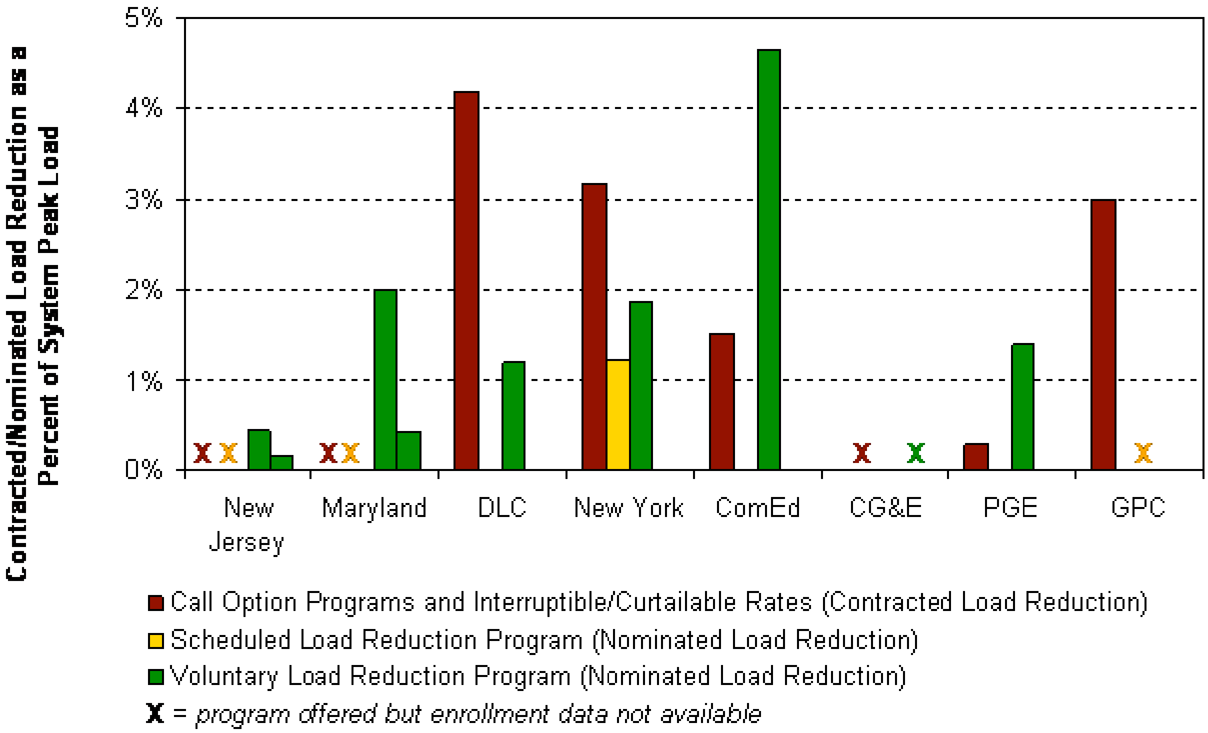


Figure 4-5. DR Program Enrollment in 2004 as a Percent of System Peak Load

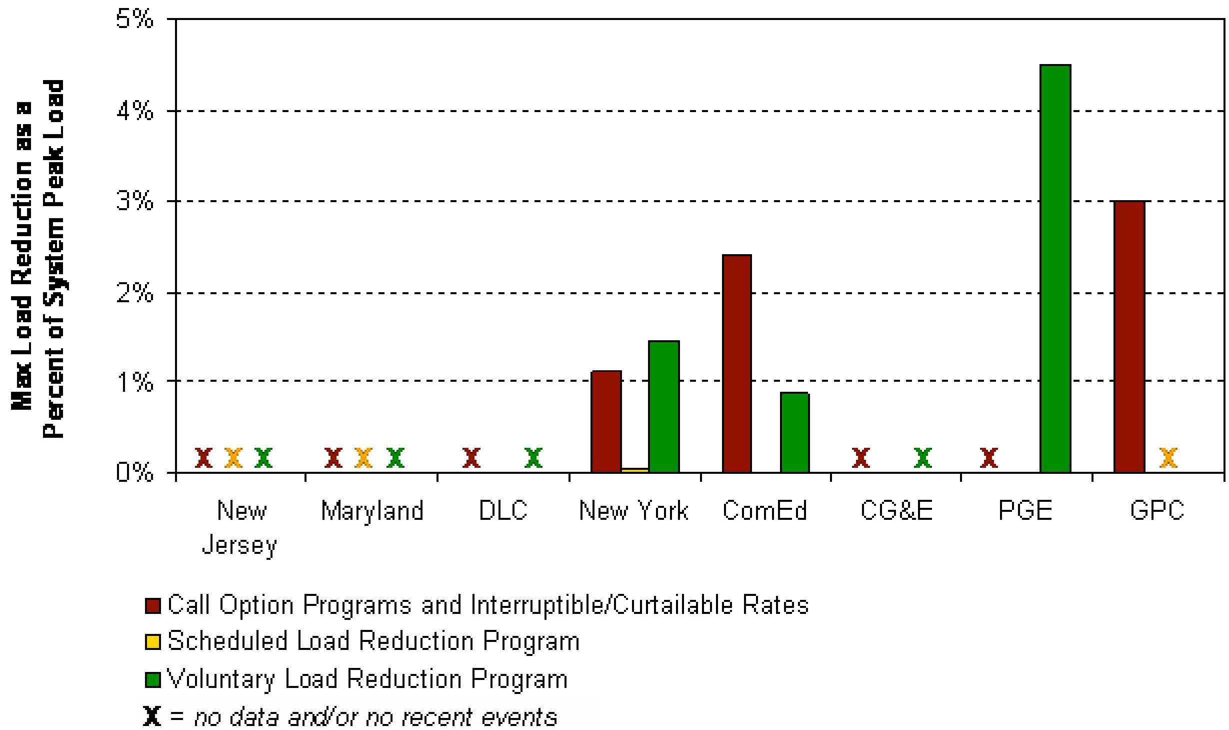


Figure 4-6. DR Program Maximum Load Reductions as a Percent of System Peak Load

5. Demand Response from Competitive Retail Supplier Product Offerings

In this chapter, we present the findings from interviews conducted with competitive retail suppliers that serve C&I customers in the case study states (see Table 5-1) and that have participated in regulatory proceedings associated with default service implementation.[67] The eight retail suppliers in our interview sample include both national and regional suppliers, which, together, represented about 60-65% of competitive C&I sales in the U.S. in 2004.

In this chapter, we summarize findings from the interviews related to:

- The types of pricing options and DR-related products and services offered by competitive retail suppliers;
- The market penetration rates among C&I customers for pricing options and other competitive retail services that potentially facilitate DR; and
- General market and policy issues affecting the development of DR in competitive retail markets.

Our interviews with competitive retail suppliers also included questions related to default service design; findings from these questions are incorporated into Section 4.3.2.

Table 5-1. C&I Market Share of Competitive Suppliers in Sample (2003)

State	Percent of Total Competitive C&I Sales (2003)[a]
New Jersey	53%
Maryland	54% [b]
Pennsylvania	56%
New York	47%
Illinois	28%
Ohio	19%
Oregon	Not Available [c]
Georgia	0% [d]

[a] Data source: EIA (2005), Tables C2 and C3

[b] Based on data reported by KEMA (2004c), these suppliers' share of the C&I market in Maryland rose to 74% by May 2004.

[c] EIA (2005) does not include data on competitive retail sales in Oregon. One of the suppliers interviewed indicated that they are active in Oregon, but we have no information about their market share.

[d] None of the suppliers indicated that they are active in Georgia. The limited customer choice market in Georgia is dominated by the investor owned utilities, municipal utilities, and co-operatives.

[67] See Appendix B for a copy of the questionnaire.

5.1 DR-Related Products and Services Offered by Competitive Retail Suppliers

Competitive retail suppliers can facilitate DR through three general types of product or service offerings:

(1) Dynamic retail supply pricing arrangements that communicate a price incentive for DR (e.g., by passing-through spot market prices or by incorporating a price overcall feature);
(2) DR programs that provide payments for load reductions that are financially and contractually unbundled from the provision of retail supply; and
(3) Products and services that enhance customers' ability to modify their load on short notice in response to price signals (e.g., technical assistance).

In this section, we describe the products and services in each of these three categories offered by our sample of competitive retail suppliers.

5.1.1 Pricing Options for Retail Supply

We asked competitive suppliers to describe the pricing options that they offer to C&I customers, and organized their responses into six types of pricing options (see Table 5-2). We counted a supplier as offering a particular product only if it is one of their "standard" product offerings and/or if they have customers that are currently taking their supply under such an arrangement.[68]

Table 5-2. Retail Supply Pricing Options Offered by Retail Suppliers Interviewed

Pricing Options	Number of Suppliers that Offer This Type of Pricing Option (n=8)
Fixed price	8
Indexed to fixed-price default service rate	3
Indexed to spot market	8
Block and index (a.k.a. "block and swing")	8
Indexed to spot market with price cap or collar	3[a]
Price overcall for energy and/or capacity component	4[a]

a. Only seven of the eight suppliers would confirm whether or not their company offered such an option.

<u>Fixed price</u>

All of the competitive suppliers interviewed offer a fixed-price retail supply option. For large C&I customers with interval metering, fixed price offers are typically developed for each customer based on their specific load profile.[69] Fixed-price offers may be structured as a single, *flat* price applicable in all hours over the contract term, or they may be structured as a schedule of fixed prices differentiated by time of use (TOU) or season. All suppliers in our sample offer the first of these two (i.e., flat price arrangements). This flat price may constitute a single charge for all components of full-requirements service (e.g., energy, capacity, transmission, ancillary services, etc.); although in other cases, separate demand or customer charges are included to cover one or more of the non-energy components. Three suppliers also offer fixed-price options

[68] Thus, we did not count a supplier as offering a particular product if they indicated that they *would* provide such a product if a customer asked, but that it is *not* a standard product and that none of their current customers have such an arrangement.

[69] This contrasts with regulated utilities' rates, which are designed around a class average load profile and thereby incorporate intra-class cross-subsidies.

with a TOU-based price schedule. One supplier indicated that they offer this product primarily so that customers with a TOU-based utility tariff can easily compare pricing terms.[70]

Several suppliers incorporate a volume band into their fixed price contracts. With this type of arrangement, the customer pays a pre-specified contract price so long as their usage over a pre-specified period falls within the agreed upon volume range. Usage in excess of the upper limit is settled at a market indexed price. If the customer's usage is less than the lower limit of the volume band, the customer purchases the minimum volume at the contract price, and is credited for the difference between that volume and their actual usage at a market indexed price. The suppliers offer varying degrees of flexibility with respect to the width of the band and the length of the period over which imbalances are accrued. For example, one supplier offers balancing on either a monthly or annual basis, and any imbalance above or below the volume band is settled at the average spot market price during that period. Another supplier offers balancing on an hourly interval; customers on this type of contract are therefore directly exposed to hourly spot market prices for their marginal usage outside of their volume band.

Indexed to fixed default service rate

Three suppliers offer retail supply contracts with a price that is indexed to the default service rate, with some fixed discount (either in price or percentage). These types of products are often marketed as a "Guaranteed Savings" option, because they provide customers with a guaranteed level of savings off of the default rate. All of the suppliers that offer this type of product do so in markets where the default service rate is fixed for one-month periods or longer (e.g., most utility service territories in New York). Thus, the price of the Guaranteed Savings options offered by competitive retail suppliers in these regions is fixed over the same period and adjusted in unison with the default rate.

Indexed to spot market

All suppliers offer a retail supply option that "passes through" the spot market price of energy for all of the customer's hourly energy usage (i.e., "real time pricing"), although several offer it only in specific markets.[71] For example, one supplier offers spot market indexed pricing only as the version of its Guaranteed Savings product offered to customers for whom the default service is a spot market-indexed rate (e.g., customers in the CIEP class in New Jersey). Two other suppliers do not offer spot market indexed products in several regions where they are active, because they are not in close proximity to a liquid trading hub.

Most of the spot market indexed products described by the suppliers in our sample are indexed to the locational market clearing price in the regional ISO/RTO day-ahead or real-time energy market. Only one interviewee described spot market indexed products outside of an ISO region;

[70] Because flat, fixed-price offers are developed based on the customer's individual load profile, customers with relatively flat load profiles don't have the same opportunity as they would in regulated settings to arbitrage between the flat price and the TOU-based pricing option.
[71] Other components of the retail service, such as capacity and ancillary services, may continue to be offered at a hedged price.

prices for this product are indexed to published market data (e.g., Dow Jones or ICE price indices) for bilateral spot market transactions at nearby trading hubs.[72]

All suppliers offer spot market pricing indexed to the ISO/RTO *real-time* spot market. Although less common, a number of suppliers also offer products indexed to the ISO/RTO *day-ahead* energy market, at least within specific regions. For example, one supplier offers a Guaranteed Savings product in NMPC's service territory, where the default service is a pass-through of day-ahead spot market prices, and thus so is the supplier's product offering. Another supplier offers day-ahead pricing for their customers in New England because of a peculiarity in the ISO-NE's market that makes purchasing in the real time market more expensive.[73] A third supplier offers customers the option of scheduling their load in the day-ahead market and paying the day-ahead spot market price for their scheduled load, with any imbalance from the scheduled amount settled at the real-time spot market price.

<u>Block and index</u>

All suppliers in our sample offer a product that allows customers to purchase blocks of load at a fixed price and "float" the remaining portion of their load at the real-time or day-ahead market price. Customers typically have a high degree of flexibility regarding the size of the load block relative to their total load, as well as some choice regarding the shape of the load block (i.e., the hours and days of the week covered by the block). One supplier, which offers fixed price blocks for peak and off-peak periods, indicated that their customers typically purchase a load block that covers at least 75% of their peak usage.[74]

Different suppliers offer different pricing terms associated with how load reductions *below* the block level are settled. Some suppliers offer *symmetric* pricing around the block level, whereby the customer purchases the entire load block regardless of how much energy they actually consume, and if they consume less than the block amount, they are credited for the difference at the prevailing spot market price (just as the customer is charged for consumption above the block at the spot market price). Alternatively, some suppliers offer *asymmetric* pricing around the block level. One example is where the customer is credited back at the fixed load block price, i.e., they simply pay for whatever portion of the load block they actually consume at the fixed price, and pay for additional energy at the spot market price. Another example is a take-or-pay contract, where the customer pays for the entire load block, regardless of how much they consume, but receives no credit for load reductions below the block level. Depending on which of these types of pricing terms apply, the customer faces a different price incentive for load reductions below their block level. From the perspective of communicating a price incentive for DR (and an efficient price signal, more generally), the most desirable arrangement is where load reductions below the block level are credited back at the spot market price, since the customer then faces the hourly spot market price on the margin at all times, no matter what their usage level.

[72] Most of suppliers interviewed are active only in regions with an ISO/RTO, or the individual interviewed was familiar with the company's product offerings only in those regions.
[73] In particular, regulation costs are allocated to load serving entities proportionally based on the volume of load purchased in the real-time market.
[74] This is consistent with the analysis of Goldman et al. (2005), which found that Niagara Mohawk's large C&I customers, who were offered a one-time choice to hedge a portion of their load at a fixed-price and float the remaining portion at the day-ahead spot market price, typically chose to hedge 60-80% of their peak period load.

Indexed to hourly spot market with price cap or collar

Three suppliers offer other types of financial hedging options in combination with spot market indexed pricing, such as price caps and collars, to their largest customers in particular regions. Several suppliers that do not offer such financial hedging products explained that the administrative cost of developing these products and the lack of liquidity in the wholesale market for energy derivatives make these types of products too costly for most retail consumers.

Price overcall on energy or capacity charge

Four suppliers offer a discounted energy and/or capacity charge for customers that are willing to give the supplier the option to overcall that fixed price. Most of these product offerings are affiliated with PJM's ALM program, which allows LSEs to deduct interruptible load from their installed capacity requirements. LSEs typically translate this wholesale market mechanism into a retail product by offering customers the option to nominate a portion of their load as firm and avoid or receive a discount on capacity charges for load above their firm load level. Alternatively, customers with onsite generation may receive a discount based on the capacity of their generator. The size of the discount in either case reflects the market value of capacity over the duration of the non-firm retail supply contract. Several suppliers indicated that they do not offer non-firm pricing options specifically because, in their view, the market value of capacity in the PJM region has been too low to attract customer interest in non-firm pricing, given the magnitude of the non-compliance penalties associated with the ALM program. Another supplier indicated that they previously offered a non-firm pricing option, but that these options could not compete with utility interruptible tariffs that provided larger discounts.

5.1.2 Unbundled DR Programs

Competitive suppliers can also motivate DR by offering unbundled DR programs that provide payments or bill credits for load reductions separate from the provision of retail supply. All competitive suppliers in our sample offer some type of unbundled DR product in at least one of the regions where they are active. With only one exception, these unbundled DR products are associated with an ISO/RTO-administered DR program, whereby the supplier serves as the DRSP for the retail customer and offers a retail product with similar, if not identical, terms to the ISO/RTO program (see Text Box 4-2 in Section 4.8.1).[75] The types of unbundled DR programs offered by retail suppliers in our sample is therefore a function of three basic factors: 1) the ISO/RTO regions in which the suppliers are active, 2) the types of DR programs offered by these ISOs/RTOs, and 3) which ISO/RTO DR programs the suppliers choose to offer to their retail customers (see Table 5-3). We count a supplier as "participating in", or "offering", a particular ISO/RTO DR program if the company is currently registered with the ISO/RTO as a DRSP *and* if the individual interviewed confirmed that the company is actually willing to serve as a DRSP for that program.

[75] The one program not associated with an ISO-administered DR program is a voluntary DR program offered by a supplier operating in ComEd's service territory in northern Illinois. However, now that this region has been integrated into PJM, the supplier indicated that they are planning to phase out the existing program and replace it with a new set of products linked with the PJM DR programs.

Table 5-3. ISO/RTO DR Program Participation among Retail Suppliers Interviewed

Supplier Number	PJM				NYISO		
	ALM	Economic Program Day Ahead Option	Economic Program Real Time Option	Emergency Load Response Program	ICAP/SCR	DADRP	EDRP
1	x	x	x	x	x	x	x
2	x	x	x	x			x
3						*not active in region*	
4	x	x	x	x	x	x	x
5			x				
6	x	x	x	x		*not active in region*	
7					x		x
8							
Totals	**4**	**4**	**5**	**4**	**3**	**2**	**4**

Notes: "x" indicates that the supplier is registered as a DRSP with the ISO/RTO and offers that program to their customers.

Of the eight supplies interviewed, all are active in the PJM footprint and six are active in New York. In both regions, some suppliers offer all, some offer none, and some offer a subset of the ISO/RTO DR programs. Several of the individuals interviewed offered explanations for why their company does not participate in particular DR programs. For example, one supplier that is not participating in any of PJM's DR programs explained that the company decided that there is not enough money in the programs to make participation worthwhile. Another offered a similar comment, suggesting that the administrative costs associated with the settlement process are prohibitive, given the limited revenue potential. (During the past several years, the PJM Emergency program has not been called; and energy and capacity prices have been low compared to historical levels, dampening customers' financial incentive to participate in the Economic and ALM programs.) Suppliers also cited issues associated with competition from utility programs; e.g., one supplier suggested that when state regulators require utilities to offer a retail tariff that allows customers to participate in ISO/RTO DR programs and pass through all or most of the incentive payment, the opportunity for competitive suppliers to offer such products is eroded.

5.1.3 Products and Services to Build DR Capabilities

The third general category of DR-related products or services that might be provided by competitive retail supplies are those that enhance customers' *capability* to modify their load, on short notice, in response to information about market prices or system reliability. We asked suppliers to describe the services of this type that they integrate into their retail supply service or DR programs. In general, the individuals interviewed indicated that their company offers few, if any, services of this type, and many cited a lack of customer demand as the fundamental cause.

Three types of DR-enabling services were offered by one or more suppliers in our sample (see Table 5-4). Three suppliers offer customers internet-based access to their hourly interval load data with a one-day or shorter time delay, in most cases for an additional fee. One supplier commented that a very small portion of their customers on hourly pricing have shown an interest in the EIS product. Four suppliers indicated that they offer a price alert service whereby they notify customers, via email or pager, if hourly prices reach a threshold level specified by the customer. One of the suppliers offering this service indicated that it was most popular among customers that are participating in ISO/RTO economic DR programs. Finally, one supplier indicated that they have recently started to offer technical assistance to customers enrolled in the ISO-NE DR programs, to help them develop and/or implement load curtailment strategies.

Table 5-4. Products and Services to Build DR Capabilities

Product or Service	Number of Suppliers Interviewed that Offer This Type of Product (n=7)
Internet-based access to hourly load data	3
Price alert	4
Technical assistance	1

Most of the suppliers in our sample do have a separate energy services group within the company or an affiliated ESCO that offers various technical services to help customers reduce their energy costs. However, many of the suppliers indicated that their ESCO affiliate or group focuses primarily on energy efficiency measures, not DR. Moreover, none of these companies currently integrate their ESCO services with their retail supply function or have any formal process for marketing ESCO services to customers on hourly pricing or vice-versa. Two suppliers indicated that, in the past, they tried to more formally integrate these two parts of their business, but that customer interest in the ESCO services was insufficient. Another supplier suggested that integrating ESCO services with retail supply was inherently challenging as a result of the fact that the payback period for most energy efficiency and demand response measures is much longer than typical retail supply contract terms.

5.2 DR from Customers on Spot Market Indexed Contracts with Competitive Suppliers

The extent to which spot market pricing options offered by competitive retail suppliers contribute to the development of DR depends, first, on how many customers opt for these types of pricing arrangements and, second, on the price responsiveness of those customers. To gauge each of these parameters, we asked suppliers to estimate the market penetration of spot market indexed pricing options among their C&I customers and to describe the extent to which customers that have opted for these arrangements appear to respond to hourly prices. As a point of comparison, we also asked suppliers to estimate the market penetration of DR programs among their C&I customers.[76]

5.2.1 Market Penetration of Spot Market Indexed Pricing and DR Programs Reported by Individual Suppliers

Six suppliers provided estimates of the percentage of their large C&I load in various geographical markets that is purchasing their commodity requirements either entirely at hourly spot market prices or on a block-and-index type product as well as the percentage that is participating in each DR program offered by the supplier (see Table 5-5).[77] When possible, market penetration estimates were obtained specifically for the large C&I customer classes in particular states for which RTP has been established as the default service (e.g., New Jersey CIEP, Maryland Type III, and NMPC SC-3A). However, given the limitations of individuals'

[76] More comprehensive data on ISO/RTO DR program enrollment and customer price response is published by the ISO/RTOs, some of which is summarized in Section 4.8.2

off-hand knowledge at the time of the interview and/or their willingness to divulge information about contracts in specific geographical markets, some of the market penetration estimates apply to relatively broad regions and/or to the loosely-defined class of "large C&I customers".

Table 5-5. Market Penetration of Spot Market Indexed Pricing and DR Programs offered by Competitive Retail Suppliers

Supplier	Large C&I Market	% of Total C&I Load			
		Hourly spot-market indexed pricing for retail supply	Price overcall or load reduction call option program [d]	Scheduled load reduction program [e]	Voluntary load reduction program [f]
1	ComEd service territory	not offered	not offered	not offered	5%
	ISO-NE region	10%	not offered	not offered	2%
2	NMPC SC-3A class [a]	>90%	<1%	<1%	<1%
	New Jersey CIEP class [b]	75%	0%	0%	<1%
3	PJM region	10%	not offered	not offered	not offered
4	PJM region	<25%	not offered	not offered	<10%
5	New Jersey CIEP class [b]	50-60%	0%	0%	0%
	Maryland Type III class [c]	5%			
6	New Jersey CIEP class [b]	50%	not offered	not offered	not offered
	Maryland Type III class [c]	20%			
	NYISO region	10-15%			

a. C&I customers >2,000 kW in Niagara Mohawk Power Company's service territory in New York, for whom the default service is a pass-through of day-ahead spot market prices
b. C&I customers >1,500 kW in New Jersey, for whom the default service is a pass-through of real-time spot market prices
c. C&I customers >600 kW in Maryland, for whom the default service (starting in June 2005) is a pass-through of real-time spot market prices
d. PJM ALM program and NYISO ICAP/SCR program
e. PJM Economic Load Reduction Program – Day-Ahead Option and NYISO DADRP
f. PJM Economic Load Reduction Program – Real-Time Option, PJM Emergency Load Reduction Program, NYISO EDRP, ISO-NE Real-Time Demand Response Program, ISO-NE Real-Time Price Response Program, and an independent voluntary load reduction program offered by a supplier in ComEd's service territory

Spot Market-Indexed Pricing

Suppliers reported a wide range in the market penetration of spot market indexed pricing among large C&I customers, which, to some extent, vary according to the corresponding region. Specifically, suppliers reported relatively high market penetration rates, ranging from 50% to >90%, for large C&I customers in New Jersey and in NMPC's service territory in New York. In comparison, the estimates for other markets (i.e., large C&I customers in Maryland, PJM as a

[77] For the purpose of summarizing DR program market penetration, we use the three basic categories of DR programs defined in Section 3.2.2.

whole, New York state as a whole, and the ISO-NE region) were consistently lower, ranging from 5% to 25%.

Differences in the reported market penetration rates may reflect a number of factors related to customer demographics. First, we defined the large C&I market to correspond to the default RTP threshold in each applicable state (i.e., 2,000 kW in NMPC's service territory, 1,500 kW in New Jersey, and 600 kW in Maryland). Second, different suppliers specialize in different types of C&I customers, which may have systematic differences in their propensity for spot market indexed pricing. Finally, the different geographical regions may, themselves, have characteristic differences in the make-up of their large C&I customer class.

Suppliers identified several general factors driving demand for spot market indexed pricing. First, some customers reportedly have a preference for competitive retail pricing arrangements that provide predictable savings off of the default rate. Thus, in regions where RTP has been established as the default service, some customers have opted for spot market indexed pricing arrangements with a guaranteed savings on ICAP charges or the retail adder. Second, some suppliers expressed the opinion that some fraction of customers currently on spot market indexed pricing arrangements are simply "riding the market" and waiting until fixed price offers drop to an attractive level before moving to a hedged supply option.[78] Accordingly, many suppliers indicated their belief that much of the current demand was temporary, due to mild weather and low spot market volatility, and that customers would start locking-in fixed price contracts if price volatility increased.[79] Finally, a few suppliers suggested that some customers have opted to purchase all of their commodity requirements at hourly spot market prices to avoid the risk premium incorporated into a fixed price service, although most mentioning this factor doubted whether this particular source of demand would persist once more typical levels of price volatility returned. When asked, all of the suppliers doubted whether potential cost savings from responding to hourly prices was a significant driver behind customer demand for hourly pricing, perhaps with the rare exception of customers with on-site generation that could be used for price response.

Price overcall and load reduction call option programs

Suppliers offering price overcall arrangements (e.g., interruptible contracts) and/or call option type load reduction programs all reported that either none or a very small percentage of their C&I load had elected such an option. They cited several factors affecting the market penetration of these types of pricing arrangements. Several suppliers operating in PJM explained that customer interest has been limited as a result of low ICAP prices during the past several years and/or unfavorable terms associated with PJM's ALM program (e.g., penalty size, program complexity).[80] Another supplier cited competition from utility interruptible tariffs.

[78] A key question here is whether these customers will move predominately to full-requirements fixed supply arrangements or to block and index type products.

[79] One might also draw the opposite conclusion: that demand for spot market indexed prices will *increase* with spot market volatility as customers find that they can hedge their exposure more cost-effectively by adjusting their load in response to hourly prices than with a financial hedge or fixed price supply contract. If movement occurs in both directions, the net impact on market penetration will simply depend on the relative magnitude of each effect.

[80] Interruptible load customers that qualify as an ALM resource receive a credit from their load serving entity based on the avoided ICAP purchases. In 2003 and 2004, the average price of capacity in PJM capacity markets has been less than $20/MW-day, compared three to five times as much in years past (PJM 2005).

Scheduled load reduction programs

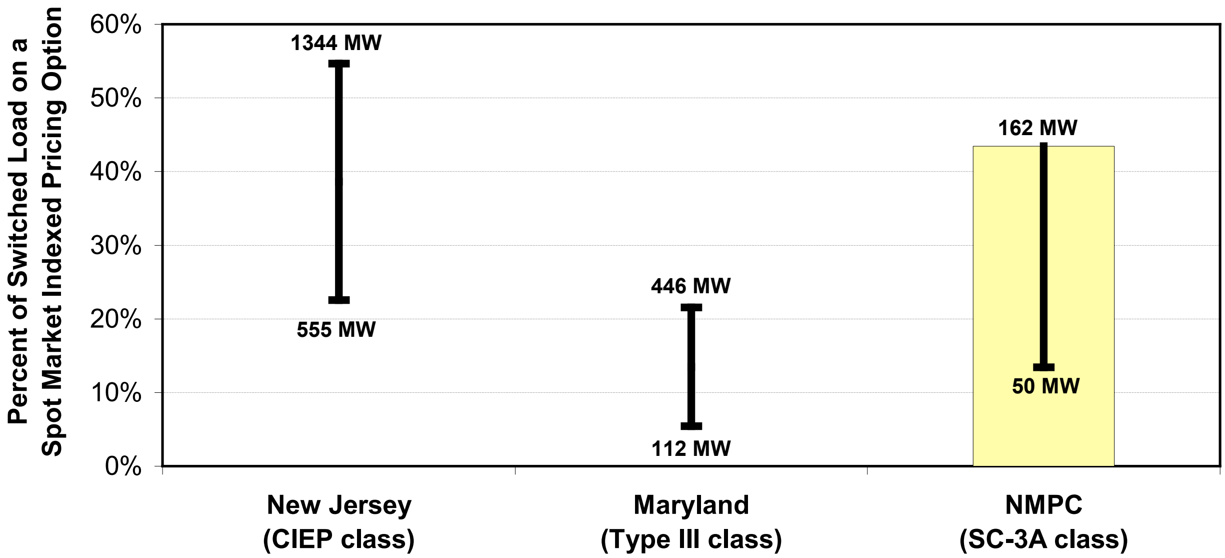
Suppliers participating in PJM's Economic Load Reduction Program – Day Ahead option and/or NYISO's Day-Ahead Demand Bidding Program all reported that either none or a very small percentage of their C&I customers were enrolled in these programs. The dominant factor cited by these suppliers is that low price volatility in PJM and New York in recent years has significantly dampened interest in these programs. In PJM, for example, the real-time spot market price has exceeded $200/MWh in only one hour during 2003-2004, and exceeded $150/MWh in only 22 hours (PJM 2005).

Voluntary load reduction programs

The market penetration rates reported for voluntary load reduction programs are generally higher than those reported for the other types of DR programs, but are still relatively low (<10%). Several suppliers expressed the view that voluntary DR programs offer the greatest prospect for widespread adoption, given customers' reluctance to subject themselves to the risk of non-performance penalties, with one supplier estimating that a 15% market penetration rate for voluntary DR programs is plausible over the longer term.

5.2.2 Estimated Total Market Penetration of Spot Market Indexed Pricing in Three Large C&I Markets

We estimated the *total* market penetration of spot market indexed pricing among load served by competitive suppliers in three large C&I markets: the New Jersey CIEP class, the Maryland Type III class, and the NMPC SC-3A class (see Figure 5-1). Based on the methodology described below, we estimate that 23-55% of the load in New Jersey's CIEP class that has switched to a competitive supplier has opted for spot market indexed supply contracts, and 5-22% of the switched load in Maryland's Type III class has opted for such arrangements. We estimate that 43% of NMPC SC-3A load that has switched has opted for a spot market indexed contract, and can definitively assert that at least 13% has opted for this type of arrangement. Given the large range in our estimates, it would be advisable for state and federal policymakers to collect information periodically that would allow for more definitive estimates of the amount of load served by competitive retailers that is exposed to hourly prices, if demand response is an important policy goal.



Customer Class Size Threshold	>1,500 kW	>600 kW	>2,000 kW

Figure 5-1. Estimated Market Penetration of Spot Market Indexed Pricing Arrangements in Three Large C&I Markets in Late 2004/Early 2005

For the New Jersey and Maryland classes, we estimated the C&I load on spot market indexed pricing served by the suppliers in our interview sample, based on their reported market penetration rates (see Table 5-5) and their market share in each state.[81] For suppliers that reported market penetration rates only for the PJM region as a whole, and not for NJ and MD separately, we estimated state-specific values based on the supplier's C&I load in each market and the differences in the penetration of spot market pricing in the two markets reported by other suppliers. For several suppliers in our sample, we stipulated their market penetration values based on relevant quantitative or qualitative information provided by the supplier.[82] We extrapolated to the remaining portion of the switched C&I load in each state (38% in NJ and 47% in MD) by stipulating upper and lower bounds for the market penetration of spot market indexed pricing: 60% and 20% for NJ CIEP, and 20% and 5% for MD Type III.

We used a different, and presumably more reliable, approach to estimating the total market penetration of spot market pricing among customers in NMPC's SC-3A class. Goldman et al. (2005) interviewed SC-3A customers and asked those that had switched to a competitive supplier about the structure of their supply contract. Approximately 30% of the customers (in terms of total billing demand) that had switched to a competitive supplier in 2004 could identify the

[81] For suppliers' market share in New Jersey, we used 2003 C&I sales data reported by EIA (2005), and for Maryland, we used May 2004 estimates reported by KEMA (2004c). Several suppliers in our sample had no C&I load in these markets at the time that these data were collected but have since entered the market and have signed up customers, in which case we stipulated their market share (1-5%, depending on the supplier).
[82] For example, one supplier operating in New Jersey indicated that "very few" of their C&I customers were on a spot market indexed product, and based on this information, we assumed that 5-10% of their C&I load is on such an arrangement. Another supplier indicated that 5-10% of their C&I customers nationally are on some type of dynamic pricing arrangement; based on this information, we assumed that 5-20% of their NJ C&I load and 5-10% of their MD C&I load is on such an arrangement.

pricing structure of their supply contract, and, of those, 43% opted for some type of spot market indexed arrangement. Given the information available, our best estimate is that the same percentage (43%) of *all* SC-3A customers that have switched have opted for a spot market indexed contract. As a lower bound, we assume that *only* those customers that positively confirmed that they were on a spot market indexed contract were on such an arrangement, which corresponds to 13% of the switched load (see Figure 5-1).

5.2.3 Price Responsiveness of Customers on Spot Market Indexed Contracts

We asked suppliers a series of questions related to the load response (e.g., load shedding) from customers facing spot market prices on the margin, including:

- The extent to which the company focuses on cost savings opportunities associated with load response in their marketing activities;
- Whether the company has analyzed the load response from customers facing spot market prices on the margin, and if so, what magnitude of load response has been observed; and
- Whether the company incorporates price response from these customers into their scheduling and procurement activities.

All suppliers indicated that, when discussing potential pricing options with prospective customers, they typically do not emphasize or substantively discuss cost savings opportunities associated with load response. Several suppliers indicated that they may do this on a very limited basis, for example, with customers who have backup generation onsite or who, for other reasons, are deemed to be particularly capable of price response. However, it is not part of their routine marketing activities.

All of the suppliers indicated that they have not formally analyzed the load response of their customers on hourly pricing. Nevertheless, most did state their belief that their customers on hourly pricing do not modify their usage in response to these prices, and that most customers do not even regularly monitor spot market prices. A few suppliers did suggest that they have a small number of customers that do respond to spot market prices in a very discrete manner (e.g., by running onsite generation or altering a specific production process), but that these customers are an exception. To explain this apparent lack of price response by most customers, many of the suppliers cited the low spot market price volatility in PJM and the Northeast in recent years. However, many also seemed to think that customers on these pricing options are, in general, not particularly interested in or capable of actively managing their load in response to spot market prices.[83] Given that the suppliers don't attribute a high degree of price responsiveness to their customers on hourly pricing, it is not surprising that they all indicated that their company does not incorporate load response from these customers into their scheduling and procurement activities beyond those few customers who are known to respond in some discrete manner.

[83] For example, one supplier indicated that most of their customers are commercial real estate, and that, in their opinion, these customers cannot respond without sacrificing tenant comfort, which they are unwilling to do. Another supplier suggested that, in general, their customers on hourly pricing are much more concerned about potential revenue loss associated with load response than they are with any associated savings on energy costs. The same supplier related these customers' apparent lack of price responsiveness to a belief that their choice of supply products mainly has to do with their view of whether the market is going up or down, and that they don't think about spot market indexed products in terms of cost savings associated with load response.

6. Discussion

In this section, we summarize key findings related to the development of DR in the eight case study states and identify implications for policymakers and other stakeholders seeking to develop DR in both regulated and competitive retail markets.

6.1 Key Findings

(1) *With the exception of Georgia Power (GPC), optional RTP tariffs have generated relatively limited levels of participation.*

In five of the six optional RTP tariffs included in our case studies, less than 2% of the load of eligible customers enrolled in RTP. The reasons for low participation rates include factors such as: RTP provides minimal bill savings relative to the tariff alternative at current market prices, except for those customers that undertake substantial load modifications (New York and PGE); the tariff has only been available and actively marketed over a short period of time (all cases except GPC); and the tariff design is based on a one-part commodity charge and thus exposes participants' entire load to volatile prices (New Jersey, Maryland, New York, and ComEd).

In contrast, 83% of the eligible load is enrolled in Georgia Power's RTP tariffs. The notable success of GPC in enrolling customers in RTP can be attributed largely to the opposite set of factors, namely: most customers on RTP can reasonably expect to achieve long-run bill savings, regardless of whether or not they are price responsive (see Text Box 6-1 for details); GPC has aggressively marketed RTP for more than a decade to a broad group of C&I customers, and the tariff design allows customers to hedge a portion of their load at a fixed price.

Text Box 6-1. How has Georgia Power been so successful with RTP?

GPC's success with RTP derives fundamentally from the unique retail market structure in Georgia, where most *new* facilities with a connected load >900 kW have a one time choice of supplier, and all of the state's regulated utilities are allowed to compete for this load. In the 1990s, GPC recognized that RTP could play an integral role in their efforts to compete for customer choice load and, as a result, adopted an RTP tariff design that allowed them to be competitive, where conventional rates were not. GPC also committed significant resources in the form of aggressive marketing efforts and ongoing customer support activities.

Three specific elements of GPC's RTP tariff design have been critical to its success.

- Two-part, tariff design with a CBL. Customers participating in GPC's RTP tariffs purchase a portion of their load (their CBL) at one of the utility's fixed, cost-of-service based rates, and face hourly RTP energy prices for deviations from their CBL. This type of tariff structure exposes customers to less price risk than one that assesses hourly-varying prices on all of the customer's load.
- Procedures for establishing and maintaining each customer's CBL. GPC allows many of its RTP participants to establish and/or maintain a CBL that is below their normal load. Three specific tariff provisions are important in this regard. First, all RTP participants are allowed expand their facilities or add load without adjusting their CBL upward. Second, customers that were previously on the utility's Supplemental Energy tariff (a curtailable rate) were able to receive, when they enrolled in RTP, a CBL equal to their previous firm service level. Finally, new *industrial* customers receive, by default, a CBL equal to 60% of their projected load, and all new customers (industrial and commercial) are eligible for a CBL below their default level if they can demonstrate that they are able to reduce their load by a proportional amount. The net effect of these tariff provisions is that RTP participants have an average CBL equal to 60% of their total load and purchase the remaining 40% at marginal cost-based hourly prices. Because these prices have historically been lower, on average, than the all-in (energy plus demand) price of the utility's standard cost-of-service based rates, RTP participants are able to accrue bill savings compared to what they would pay if their CBL were equal to 100% of their typical load.
- Supplemental financial risk management products. The utility offers a wide range of supplemental financial risk management products that customers can purchase to reduce their exposure of their incremental RTP load to hourly price volatility. The value of these products is heightened by the fact that many RTP participants have a large fraction of their load exposed to hourly prices.

(2) *In each of the three default RTP tariffs in place in early 2005, most of the load has switched to a different supply option, although the percentage remaining on RTP varies significantly*.

In DLC's service territory, only 3% of the load in the default RTP class is enrolled in RTP; the remaining customers have switched to either a competitive supplier or to the temporary fixed price alternative offered by the utility. In comparison, a larger fraction of the load in the NMPC and, to a lesser extent, New Jersey default RTP classes have remained on RTP (34% and 16%, respectively). Differences in participation rates among these three cases reflect a number of factors related to tariff design and retail market development: the amount of advance notice with which customers have knowledge of hourly prices (day-ahead for NMPC vs. real- time, after-the-fact for the other two cases); the availability of an alternative fixed price supply option with the utility (which only DLC offers); the size of the default threshold (300 kW for DLC, compared to 1,500 kW and 2,000 kW for New Jersey and NMPC, respectively); and the general availability of competitive retail supply offers.

Some of the switching activity in these three case studies likely reflects many customers' aversion to being exposed to hourly pricing; however that does not fully account for or explain the switching behavior. First, in DLC's case, much of the switching in the default RTP class occurred prior to the introduction of default RTP.[84] Second, we know from our supplier interviews that some customers have switched to competitive supply contracts that incorporate hourly spot market pricing for some or all of their usage (i.e., either a full pass through of spot market prices for all of the customer's commodity requirements or a block-and-index type product where customers purchase a portion of their load at a fixed price and their residual load at spot market prices).

(3) *The case studies revealed several indirect impacts that default RTP might have on the development of DR in competitive retail markets; however more formal analysis is needed before firm conclusions can be drawn*.

The amount of load remaining on the default RTP rate represents a small fraction of the system peak (<3%) in all three cases where default RTP has been implemented. Thus, the potential *direct* impact of these RTP tariffs on the development of DR has necessarily been limited. However, the case studies highlight three plausible (but untested) *indirect* positive impacts that default RTP might have on the development of DR in competitive retail markets. First, having RTP as the default service may create additional demand for spot market indexed pricing options offered by competitive suppliers, because some customers use the default rate as a benchmark and seek out competitive supply contracts with a comparable pricing structure but lower prices.[85] Recognizing this market dynamic, a number of suppliers explicitly market their spot market indexed pricing option as a "Guaranteed Savings" product in states with default RTP. Second, customer demand for spot market indexed pricing may also be enhanced as a result of customer education and training activities conducted in concert with default RTP implementation, as well

[84] One year prior to default RTP implementation, 32% of all C&I load in DLC's service territory had switched to a competitive supplier, compared to 52% three months after implementation (POCA 2005). Note that these switching trends are for *all* C&I customers; data on switching trends in DLC's default RTP class does not appear to be publicly available.

[85] In the case of default RTP, competitive suppliers may be able to offer a fixed discount on ICAP or ancillary services charges, or a mark-up on the commodity charges that is smaller than the default service retail adder.

as from customers' direct experience on the default RTP tariff. Through these experiences, customers that might otherwise be unfamiliar with, or disinclined towards, hourly pricing may become more knowledgeable about the potential benefits and the range of risk management options available.[86] Third, several states have deployed interval meters across a wide base of C&I customers as part of their implementation of default RTP. As a result, some customers that might otherwise be deterred because of metering costs may decide to participate in DR programs or may opt for retail supply contracts with dynamic pricing elements.

(4) *Competitive retail suppliers reported a wide range of values for the market penetration of spot market indexed pricing options, ranging from 5% to 75% of their C&I load in different regions.*

The competitive retail suppliers we interviewed all offer spot market indexed retail supply contracts to C&I customers, including arrangements where the customer purchases *all* of their commodity requirements at hourly prices indexed to the real-time or day-ahead spot market as well as block-and-index type products (i.e., the customer purchases blocks of load at a fixed price and pays hourly spot market prices for their additional usage). The reported market penetration rates for spot market indexed pricing options varied substantially among the different suppliers, depending in part on the particular region. Three suppliers reported that, in New Jersey, 50% to 75% of their C&I load in the default RTP class has opted for a spot market-indexed supply contract. In comparison, two suppliers reported market penetration rates of 5% and 20% among the default RTP class in Maryland. The values for C&I customers in other regions (e.g., PJM as a whole, New York, and the ISO-NE region) varied between 10% and 25%. We believe that several factors may account for differences in reported market penetration rates: size threshold of the default customer class (e.g., >1.5 MW in New Jersey vs. >600 kW in Maryland), the types of C&I customers targeted by particular suppliers (e.g., mid-market C&I vs. exclusive focus on large industrials), regional differences in mix and type of customers (e.g., higher concentration of industrial customers in New Jersey vs. New England) and default service tariff options (e.g., default RTP with or without a utility hedged tariff alternative).

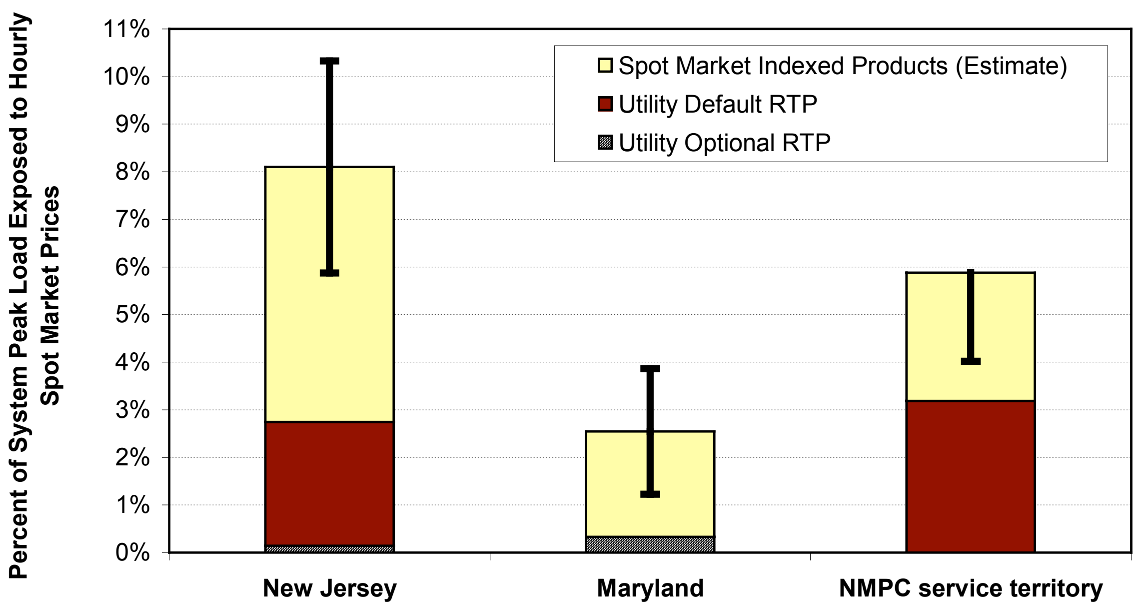
Comments by suppliers provide insight into several dynamics driving the current demand for spot market indexed products. First, some C&I customers seek out a guaranteed discount off of their default service rate. Second, some customers with spot market indexed supply contracts are reportedly riding the market, waiting until fixed price offers drop to an attractive level before moving to a hedged supply option.[87] Third, a number of suppliers suggested that some customers were willing to buy some or all of their loads at spot market prices to avoid the risk premium incorporated into a fixed price, full-requirements service. All suppliers doubted whether cost savings from DR was a significant driver behind customer demand for hourly pricing, perhaps with the exception of customers with on-site generation. Some suppliers also indicated their belief that much of the current interest in RTP-type products was temporary, due to mild weather and low spot market volatility, and that more customers would start locking-in fixed price contracts if price volatility increases.

[86] For example, one supplier indicated that some customers that had inadvertently remained on default RTP in New Jersey decided that facing hourly spot market prices was acceptable and, when they switched to a competitive supplier, sought out a similar pricing arrangement. A comprehensive study of NMPC RTP experience found many customers switched from default RTP to a similar arrangement with a competitive supplier (Goldman et. al, 2005).
[87] A key question here is whether these customers will move predominately to full-requirements fixed supply arrangements or to block and index type products.

(5) *From one to ten percent (1-10%) of the system load in several retail markets appears to be exposed to spot market prices, although there is significant uncertainty in these estimates.*

Very little information is available in the public domain regarding the amount of load in competitive retail markets facing hourly spot market prices through their retail supply contract. As an initial step towards filling this void, we estimated the amount of load in three large C&I markets (the New Jersey CIEP class, the Maryland Type III class, and the NMPC SC-3A class) that has switched to a spot market indexed competitive supply contract (see Section 5.2.2). We combined these estimates with data on enrollment in optional and/or default RTP tariffs offered by utilities in these states in order to provide an indication of the total load exposed to hourly spot market prices.

Based on this approach, we estimate that, as of early 2005, 1-4% of the system peak load in Maryland, 6% in NMPC's service territory and 6-10% in New Jersey was facing hourly spot market prices on the margin through either a utility RTP tariff or a retail supply contract with a competitive provider (see Figure 6-1).[88] One key driver for the relatively low percentage of system peak load exposed to spot market prices in each of these markets is that the default RTP class only accounts for 10-20% of the total system load. The fact that the exposure to spot market pricing is lower in Maryland than in the other two cases primarily reflects the fact that, during the period for which these estimates were developed, RTP was an optional service for large C&I customers in Maryland but was the default service for large C&I customers in the other two regions.



[88] In Figure 6-1, the yellow bars for New Jersey and Maryland are the averages of the upper and lower bound estimates for the load exposed to hourly spot market prices through competitive retail supply contracts. The yellow bar for NMPC represents our best estimate of the load facing hourly spot market prices through a competitive supply contract in NMPC's service territory, based on extrapolating the survey results of Goldman et al. (2005). Refer to Section 5.2.2 for a full explanation of our approach.

Figure 6-1. Percent of System Peak Load Exposed to Hourly Spot Market Prices in Three Regions

(6) *RTP tariffs that provide C&I customers with advance notice of prices have demonstrated the capability of eliciting load reductions in the range of 10-15% of participants' aggregate billing demand at very high prices.*

Of the case studies examined in this report, formal analyses of customers' price responsiveness have been performed only for NMPC and GPC. Goldman et al. (2005) estimated the substitutional price elasticities of customers in NMPC's default RTP class, using five years' of hourly billing data. Based on these estimates, customers remaining on RTP in 2004 would be expected to reduce their peak load by approximately 10%, in total, when peak period prices are five times greater than off-peak prices (e.g., a peak period price of $0.50/kWh and an off-peak price of $0.10/kWh), which represents the extreme level of NYISO day-ahead prices to date.[89]

GPC has reported, albeit in a less detailed manner, on its evaluation of the price responsiveness of customers on their RTP tariffs. The utility attributes approximately a 500 MW peak load reduction to their RTP tariffs, under expected summer peak-coincident prices, as part of its system planning process (i.e., integrated resource plan filings). This corresponds to roughly 10% of RTP participants' aggregate billing demand. Braithwait and O'Sheasy (2001) used customer price elasticity estimates to calculate the load reduction on one day when customers on the day-ahead RTP rate faced a maximum hourly price of $1.93/kWh, and customers on the hour-ahead RTP rate faced a maximum hourly price of $6.43/kWh. They estimate that day-ahead and hour-ahead RTP customers reduced their load by approximately 500 MW and 250 MW, respectively. The combined 750 MW load reduction is equal to approximately 15% of RTP participants' aggregate billing demand.

Goldman et al (2005) forecast the aggregate DR impacts of NMPC's customers that faced hourly prices and estimated that they would reduce their peak demand by ~50 MW (which is 0.8% of NMPC's system peak) during periods when peak period prices were five times higher than off-peak prices.[90] If we extrapolate from the NMPC and Georgia Power RTP study results, their experience suggests that large C&I customers representing about 10% of system peak load and that are exposed to hourly spot market prices with advance notice (i.e., day-ahead) may be able to reduce system peak load by ~1-1.5% at high prices.

(7) *Little is currently known about the price responsiveness of customers participating in RTP tariffs that are indexed to real time spot markets, although regulatory staff and utilities in states with RTP tariffs of this type generally expressed the belief that few customers actively monitor or respond to hourly prices.*

RTP tariffs that have been recently implemented in New Jersey, Maryland, and DLC's service territory employ prices that are indexed to the PJM real time spot market, and these prices are not known until after the applicable hour has elapsed. To date, no formal evaluations have been

[89] At NMPC, peak period prices were five times higher than off-peak period prices on only 2 days during summer 2000-2004.

[90] The NMPC RTP study population included 149 SC-3A customer accounts with ~550 MW of aggregate billing demand; about 120 accounts were excluded by NMPC because of confidentiality or data availability concerns (e.g. individually negotiated contracts, customers with New York Power Authority allocations) [see Goldman et al 2004].

conducted to assess the extent to which customers remaining on these default RTP tariffs respond to hourly prices. Thus, without any analysis, no definitive conclusions can be drawn at this point about the extent to which RTP tariffs of this type might induce price response from participating customers. Utility and regulatory staff in New Jersey, Maryland, and Pennsylvania generally doubted whether customers on the default RTP tariffs in these states are actively monitoring or responding to hourly prices.[91]

(8) *The competitive retail suppliers interviewed indicated that they have not formally analyzed the price response of their customers with spot market indexed supply contracts; however, all expressed the belief that no more than a handful of these customers currently monitor or respond to hourly prices*.

Most of the suppliers we interviewed stated their belief that the vast majority of customers on spot market indexed pricing options do not monitor or respond to hourly prices, although none had systematically examined the question. Accordingly, they indicated that they do not account for price response from customers facing hourly spot market prices in their scheduling and procurement activities, other than for perhaps a small handful of customers with pre-established load response routines (e.g., customers that operate on-site generation when spot market prices reach some threshold level).

In general, competitive retail suppliers and, by their account, customers do not view spot market indexed pricing options as an opportunity for customers to reduce their energy costs by responding to hourly prices. Suppliers typically do not focus on DR in marketing these product offerings, except perhaps to customers with onsite generation, and offer few products and services to assist customers in responding to hourly prices. This lack of emphasis on DR in connection with spot market indexed pricing may partly reflect current market conditions, characterized by relatively stable prices. Perhaps greater levels of price volatility will spur customer interest in price response, and prompt suppliers to more aggressively offer products and services to help customers respond or adapt.

(9) *A variety of DR programs offered by utilities and ISO/RTOs have demonstrated the ability to elicit load reductions in the range of 1-3% of the respective entities' system peak.*

In all of the case studies, utilities or an ISO/RTO offers a variety of DR programs to C&I customers. In 2004, participation in most of these DR programs (reported in terms of customers' contracted or nominated load reduction quantity) was in the range of 1-4% of the utility or statewide system peak load in each case study (see section 4.8.2).[92] Participation in most of the DR programs offered by NYISO and PJM has grown significantly during the last 3-4 years.

[91] To the extent that this characterization is accurate, it may reflect the moderate price volatility in the PJM real-time spot market over the past several years. More fundamentally, it is questionable what level of price response might reasonably be expected from customers that have no advance notice of firm prices. To make an informed decision about when load reductions would be economically justified, customers would need to derive or purchase a forecast of hourly spot market prices (e.g., based on a correlation between day-ahead and real-time market prices), which increases the uncertainty in the financial benefits of, and/or the costs associated with, load response.

[92] Note the difference in how participation is reported for DR program compared to RTP – i.e., customers' contracted or nominated load reduction as opposed to customers' combined billing demand or coincident peak demand.

Participation trends for DR programs offered by utilities in our case study states are generally less bullish.[93]

Operational activity in many programs has been limited in recent years due to an absence of system reliability contingencies and/or low spot market prices. The call option/interruptible type programs and voluntary load reduction programs for which recent performance data is available have demonstrated load reductions in the range of 1-3% of the system peak. Call option/interruptible programs have historically elicited load reductions at or near participants' contracted level, because of customers' incentive to avoid non-compliance penalties. Voluntary emergency load reduction programs that offer relatively high incentive payments when called (e.g.., $500/MWh floor price offered by NYISO EDRP) have also generated a substantial load response. In contrast, scheduled load reduction programs thus far have not demonstrated an ability to elicit load reductions on the same order of magnitude as the other types of DR programs, either because little load has enrolled or because the customers that have enrolled have not actively participated. In part, this may be attributable to low spot market prices prevailing since these programs have been introduced and market barriers related to customers' knowledge of electricity markets and load response strategies (Neenan et al. 2003).

6.2 Policy Implications and Recommendations for Competitive Retail Markets

In states that have restructured their electricity markets, development of default service has been primarily driven by policy objectives related to retail market development rather than DR. However, there are a number of opportunities for policymakers that are also interested in stimulating the development of DR to integrate these policy goals into the design and implementation of default service.

(1) *Day-ahead default RTP can be an effective strategy for simultaneously meeting retail market development and DR-related goals*.

In those states that have adopted RTP as the default service primarily to facilitate retail market development, this type of tariff has been attractive because it always reflects current market conditions, does not require the use of class average load profiles for setting the commodity charge, and is amenable to limited switching restrictions. At the same time, default RTP has the potential to stimulate DR, both from customers that remain on the default service and from those that switch to a competitive supply arrangement that is indexed to the default service. Evidence to date suggests that default RTP that is indexed to the *day-ahead* energy market may be more effective at stimulating DR than default RTP that is indexed to the *real-time* spot market, because it provides customers with greater levels of advance notice. Day-ahead default RTP may therefore be one potential strategy for simultaneously advancing retail market development and DR-related goals.[94]

[93] Some utilities reported a decline in participation due to customer migration to competitive suppliers or reduced program incentives as a result of lower market prices or a re-evaluation of program costs and benefits. A number of utilities have recently canceled their DR programs or limit their offerings to those implemented by the ISO.

[94] If day-ahead default RTP is established as the default service, and the utility is responsible for scheduling and procurement, policymakers should ensure that appropriate charges are included to account for any costs and risks associated with forecasting the default service load a day in advance. Otherwise, competitive retail suppliers' ability to offer similar pricing arrangements may be negatively affected.

(2) *If C&I customers in the default RTP class are to be offered a temporary fixed price hedge for a multi-year period, policymakers should consider structuring this hedge as a fixed price load block rather than as a full-requirements hedged service.*

Policymakers in several states (e.g. Maryland, Pennsylvania, and New York) that have adopted default RTP have deemed it necessary to also offer the affected customers some type of fixed price hedge for a defined transitional time period. In Maryland and New York, this feature was an important element of the consensus settlement reached by the parties and adopted by the regulatory commissions. The rationales for offering a fixed price option during a transition period are that the retail market may not be sufficiently mature to offer a variety of service offerings or that some customers, particularly smaller C&I customers, won't find an acceptable offer for hedged service from a competitive supplier, either because they lack the savvy or because few retailers serve that segment. The primary argument against offering a hedged, fixed price option is that it may slow the entry of competitive suppliers into the market and deter customer switching.

If regulators decide that utilities should offer a hedged service during a transition period, key issues to consider are the duration of that transitional period and how to structure the hedged service option. In Maryland, customers in the default RTP class were offered a separate, full requirements hedged service for a one-year period, while DLC's default RTP customers are offered a similar hedged option for a two-and-a-half year period. NMPC opted for a different approach, offering customers in the default RTP class a one-time, up-front option to purchase a fixed price load block (under take-or-pay terms) for up to five years and purchase their residual load either through the default RTP tariff or from a competitive supplier. From a demand response perspective, the advantage of this latter approach is that customers that opt for the temporary hedge are potentially exposed to spot market prices on the margin. Thus, in the short-run, these customers may still have an incentive to respond to hourly price changes. In the long-run, introducing customers to block-and-index type pricing arrangements through the default service may stimulate adoption of such pricing arrangements in the competitive market. The disadvantage of this approach is that it may be more complicated to implement (e.g., the procurement process and billing system). Thus, if the transition period is relatively long (e.g. 3-5 years), it may be worth considering whether to structure the hedge as a block-and-index type arrangement, given the potential DR-related benefits. On the other hand, if the transition period is only one year, then the added complication of such an approach may not be warranted.

(3) *State regulators and utilities should consider installing interval meters over a wider population of C&I customers than just the default RTP class, and should also consider specifying features in the metering infrastructure that facilitate DR.*

Large scale deployment of interval metering among C&I customers has been conducted in several states to support implementation of default RTP. Such efforts represent another opportunity to leverage DR goals with retail market restructuring activities, in this case by installing interval meters across a wider customer population than the default RTP class, as was done in New Jersey, and by specifying metering systems with features that facilitate price response.[95] Policymakers should consider whether these incremental measures are warranted, in

[95] Advanced metering infrastructure features that could enhance DR capability include hardware or software that allows customers to directly access their own metered usage data at intervals more frequently than once during each

light of the potential benefits they could yield in terms of the development of DR (e.g., by facilitating participation in ISO/RTO DR programs and/or bolstering the price responsiveness of customers facing hourly spot market prices through default RTP or a competitive supply contract).

(4) *Rigorous collection and analysis of data related to customer exposure and response to spot market-indexed competitive supply contracts is needed.*

A variety of policy and planning decisions (e.g., related to continuation of wholesale market price caps or certain types of DR programs) hinge upon assumptions about the price responsiveness of retail electricity consumers. Yet, little information is currently being collected in regulated or competitive markets to measure how and why customers respond to prices. Federal and state regulators and ISO/RTOs should consider undertaking efforts to regularly collect and analyze data on retail customers' supply arrangements and response to hourly pricing and other dynamic pricing options, to support policy and planning decisions that require knowledge about the price responsiveness of retail consumers. Given the sensitive nature of this information, appropriate measures would need to be taken to ensure that data released to the public does not compromise the position of individual suppliers or customers.

(5) *The development of DR in competitive retail markets may require addressing market barriers.*

Spot market indexed pricing arrangements with flexible hedging options appear to be widely available in many competitive retail markets. However, competitive suppliers currently offer few services to help customers identify, analyze, or implement load response strategies. At this point, it is unclear to what extent this is a temporary condition (i.e., a natural response to low spot market prices and low price volatility) or a more fundamental feature of competitive retail markets. In either case, the potential for DR to develop in competitive retail markets will likely be limited in the near-to-mid term without a concerted effort on the part of some entity to help customers develop their load response capabilities.

Some set of policy interventions may therefore be warranted to enhance customers' capability and willingness to respond to dynamic prices. In many states that have implemented customer choice, the state regulatory commission and/or utilities have conducted general customer education activities to provide basic information about restructuring and/or default service. Policymakers should consider incorporating into these activities information to help customers better understand the potential cost savings and risk management benefits associated with load response to hourly spot market prices as well as technical information to help customers identify load response strategies. Additional programmatic efforts, such as facility DR audits and financial assistance with DR enabling technologies may also be warranted.

6.3 Policy Implications and Recommendations for Regulated Retail Markets

Our case studies of RTP experience are drawn from states where there is retail competition to serve large customer load and in most cases, where an ISO/RTO has been established to ensure

24 hour period, meters with data ports that allow customers to take a direct feed from their meter for an EMCS, EIS, or load control device, and training on optimizing energy information systems (EIS) and energy management control systems for DR applications.

system reliability and administer specified wholesale markets. In this section, we discuss whether and how these experiences are useful to policymakers in states without retail competition that are seeking to foster the development of DR.

(1) *The implications of implementing default RTP in a regulated market, in terms of customer acceptance and DR impacts, depend on what types of hedging options are offered to customers in the default RTP class.*

In *competitive* retail markets where RTP has been established as the default service, concerns about the fairness of forcing customers to bear price risk have been tempered, as customers that prefer price certainty can choose to switch to a hedged retail supply contract with a competitive provider. In cases where there has been doubt about the immediate availability of competitively-priced hedged contracts, policymakers have required that the utility offer a temporary fixed price service, to give the retail market time to more fully develop.

In contrast, if RTP is established as the default service in *regulated* retail markets, the ability of customers in the default RTP class to financially hedge their exposure to price risk will depend largely on whether state regulators decide to make hedging options available. Several options are available for state policymakers that want to implement default RTP but do not want to force all customers in the default RTP class to face volatile prices for their entire load.

One option is to allow customers to opt out of RTP onto an alternative, fixed price rate. Experiences in competitive retail markets where customers have been offered a choice between an unhedged RTP tariff and a full-requirements, fixed price service have suggested that the large majority of customers will choose the fixed price service. Thus, if the goal is to stimulate DR, this approach does not seem particularly promising. Rather, if a significant portion of the applicable customer population is to remain on RTP with minimal objection, the RTP tariff must incorporate some type of hedge.

A second option is to structure the default RTP tariff as a traditional two-part RTP tariff, where each customer receives a CBL equal to their historical usage profile. The advantage of this approach is that customers' bills and the utility's revenues are affected only to the extent that customers' usage patterns change. However, the process of developing an hourly load profile for each individual customer can be quite time consuming, prone to contention, and, for new customers and other customers without an established history of interval load data, rather subjective.

A third option, which avoids some of the difficulties associated with the CBL-based tariff design, is to implement a default RTP tariff similar to the block and index type of arrangements available in competitive markets, where customers can nominate blocks of load to purchase at a fixed price and face hourly prices for the remaining portion of their load. Little experience has been accumulated with such an approach in regulated, cost-of-service settings, although a host of potential issues can be identified, such as: how to structure the load blocks and how to determine their price (i.e., based on embedded costs or some representation of a market-based risk premium).

(2) *If RTP is to provide a significant source of DR in regulated retail markets, the RTP tariff will need to offer, to a wide range of customers, substantial and/or fairly predictable financial benefits compared to fixed price tariff options available to the same customer class.*

Nearly all of the optional RTP tariffs in our case study states have generated limited levels of participation, which is consistent with the experience of most other utilities in the U.S. that have offered optional RTP (Barbose et al. 2004). Georgia Power Company's (GPC) RTP tariffs are a notable exception and provide an existence proof that high participation rates in optional RTP can be achieved.

A key lesson to emerge from GPC's experience is that, to attract a substantial fraction of the system load to an optional RTP tariff, it may be necessary for the tariff design to incorporate a fairly *predictable* financial benefit for a large population of customers. Customers benefit from participating in GPC's RTP tariffs by adjusting their usage in response to prevailing hourly prices (e.g., shedding load during high priced periods and/or rescheduling load from high to low priced periods). Customers also receive financial benefits as a result of the procedures GPC uses to establish and maintain participants' CBL. GPC allows certain customers to receive an initial CBL less than their typical or projected load and allows all customers to expand their facilities without adjusting their CBL upward.[96] The net result is that most RTP participants are able to purchase some fraction of their typical usage at marginal cost based prices that, on average, are less than the utility's embedded cost based rates, and thereby achieve cost savings over the long-run that are independent of their load response to high or volatile hourly prices. GPC also offers a variety of financial hedges that allow RTP participants the flexibility to temporarily adjust the amount of load exposed to hourly prices.[97]

Can GPC's approach be directly translated to traditional, regulated retail settings? GPC's practice of offering new customers the option to receive a reduced CBL constitutes a departure from traditional, cost-of-service ratemaking practices by allowing some customers to make a smaller contribution to embedded costs in exchange for accepting greater price risk.[98] The utility has successfully defended this practice on the grounds that it is necessary for the company to successfully recruit customer choice load, which benefits all ratepayers by spreading embedded costs over a larger amount of load. However, in most monopoly retail markets, where the utility already has the exclusive right to serve new customers, this particular line of reasoning would presumably be less compelling.[99]

A fundamental question for regulators in traditional regulated markets that want to encourage the development of price response, then, is: Can some type of fairly predictable financial benefit for RTP participants be justified on the grounds that all ratepayers benefit from RTP participants' price response, or that risk is transferred from other ratepayers to RTP participants? If so, how large of an incentive or discount is warranted – i.e., what is it worth to all ratepayers to have a

[96] This tariff design element is part of GPC's strategy for recruiting customer choice load.
[97] Customers can reduce the coverage by in effect buying out the desired level of typical load, thereby exposing more load to RTP prices. Alternatively, they can buy additional coverage that converts load exposed to RTP into typical load that is priced at the alternative tariff rates.
[98] For the purpose of establishing retail rates, Georgia Power allocates embedded costs to RTP customers based on their CBL profile, not their actual load. However, the company determines their long term resource requirements based on RTP customers' total load.
[99] However, it is worth noting that, even in monopoly retail markets, C&I customers do have choice to the extent that they can choose in which state to locate their facilities.

significant subset of them be price-responsive and how can that be dealt with in the design of an optional RTP tariff? And is that level of financial benefit likely to induce widespread participation in RTP? Finally, how best to structure the incentive? In GPC's case, the discount is provided implicitly by applying a different cost responsibility standard to incremental RTP load than to load billed under other rates. An alternative approach that policymakers may want to consider, and evaluate through pilot programs, is to explicitly link the "incentives" offered to customers to enroll in RTP to their response during high price periods.

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Appendix: Case Studies

Georgia – Georgia Power Company

Background: Market and Regulatory Context

The retail electricity industry in Georgia consists of two vertically-integrated, investor-owned utilities (IOUs), Georgia Power and Savannah Electric and Power (both subsidiaries of Southern Company), as well as a large number of electric membership cooperatives (EMCs) and municipal utilities. Retail customers in the state are supplied with generation owned (in some cases, jointly-owned) by various entities, including: the two investor-owned utilities; Oglethorpe Power Corporation, a cooperative which serves most of the state's EMCs; the Municipal Electric Authority of Georgia (MEAG), a public generation and transmission corporation that serves the state's municipal utilities; the Tennessee Valley Authority (TVA), which supplies power to a small number of EMCs in northern Georgia; and a number of independent power producers, including Southern Power, an unregulated subsidiary of Southern Company. As of its 2004 IRP filing, Georgia Power owned 14,905 MW of generation capacity, consisting largely of coal-fired, nuclear, and hydroelectric plants, and had a historical peak demand of 15,379 MW (GPC 2004a).

The Georgia Territorial Electric Service Act of 1973 ("the Territorial Act") established a limited form of retail competition in the state, whereby most new customers with a connected load greater than 900 kW have a one-time choice of supplier.[100] Based on these terms, approximately 100 MW of load is eligible for retail choice each year (GPC 2004b). In 1997, the Georgia Public Service Commission (GPSC) initiated a proceeding to investigate issues associated with further restructuring the state's electricity industry; however, no further efforts to restructure Georgia's retail electricity market have taken place (GPSC 1998). Georgia Power has therefore continued to operate as a vertically-integrated utility with an obligation to serve all customers in its service territory except for those that have chosen other suppliers under the terms of the Territorial Act. The company offers its large C&I customers a number of cost-of-service based tariff options, including declining block rates with a demand charge and time-of-use rates, in addition to its real time pricing tariffs.

Overview of electric industry structure and organization

Customer choice provisions	Transition period terms and timelines	Utility Participation in Retail Market	Wholesale market structure	Wholesale market organization
Most new customers with >900 kW connected load have a one-time choice of supplier	None	Utility can compete for all customer choice load and has obligation to serve all other customers in its service territory	Bilateral market only	Generation ownership by IOUs, cooperatives, municipal utilities, TVA, and independent power producers

Demand Response Related Policies

No formal policies or goals related to the development of demand response have been promulgated by state regulators, policymakers, or the IOUs. However, key personnel at both the PSC and GPC recognize demand response as a potentially significant, cost-effective alternative

[100] The Territorial Act distinguishes between new and existing *loads* (i.e., premises). However, for ease of exposition, we will adopt the convention within this case study of referring to this distinction in terms of new vs. existing *customers*.

to supply side resources (GPC 2004b, GPSC 2004a). The IOUs are required to submit triennial integrated resource plans (IRPs), and as part of their review of the IRPs, the PSC is responsible for ensuring that the utilities include cost-effective DSM activities in their resource strategies. However, RTP and DR programs for C&I customers (e.g., interruptible service and demand bidding programs) typically have not been incorporated into the IRPs as a DSM activity, but rather as a stipulated parameter in their peak demand forecast. The cost-effectiveness of the company's DR programs was assessed within a separate proceeding in 2001, when these programs were introduced.[101] The RTP tariffs, on the other hand, are not assessed in terms of cost-effectiveness, per se, but rather, in terms of the rate of return that the company earns on RTP sales.

The individuals interviewed for this project indicated that RTP is an important DR strategy, but that it is not acceptable for all customers, and thus other DR mechanisms are also necessary for all cost-effective demand response resources to be developed (GPC 2004b, GPSC 2004a). Consistent with this "portfolio" approach, GPC offers a number of programs and pricing options that serve to stimulate demand response. In addition to RTP, they offer two types of load curtailment riders for large C&I customers: a recently-revised interruptible program that provides bill credits to customers that agree to curtail their load to a firm demand level in response to system reliability conditions; and a scheduled load reduction program, whereby the utility may post a price for load curtailments during a particular period on the same or following day, and participants can decide whether to commit to providing a load reduction at that price.[102] Georgia Power also offers a residential air-conditioner cycling program.

Tariff Design and Implementation

Georgia Power offers two variations on the same basic RTP program design. One program, RTP-DA-2, is available to customers that maintain a monthly peak greater than 250 kW and provides firm hourly prices on a day-ahead basis. The other, RTP-HA-2, is available to customers that maintain a monthly peak greater than 5 MW and provides firm prices on an hour-ahead basis. Both programs are based upon a two-part RTP tariff design. The first part of the customer's bill consists of a customer-specific access charge, developed by applying the standard tariff billing demand and energy charges to a pre-established hourly load shape, referred to as the customer baseline load (CBL). The second part of the customer's bill consists of the sum, over all hours in the billing period, of the difference between the customer's actual load and their CBL, multiplied by the prevailing hourly price. The hourly energy prices are based on projections of the system lambda for the entire Southern Company system, plus adjustments for line losses and a risk recovery factor (currently 2 mills for RTP-HA and 3 mills for RTP-DA).[103] Transmission and generation reliability adders are included in the hourly price during conditions when constraints on the transmission network or generation supply are projected.[104] The RTP

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[101] In 2001, GPC began the process of phasing out their prior interruptible service options and replacing them with a new set of load curtailment riders (Docket 13140-U). One motivation for doing so was a concern that their previous interruptible service options were not cost-effective.

[102] The interruptible program and the scheduled load reduction program are known, respectively, as the Demand Plus Energy Credit (DPEC) rider and the Daily Energy Credit (DEC) rider.

[103] The Southern Company system includes the service territories of Georgia Power, Gulf Power, Alabama Power, and Mississippi Power, and Savannah Electric and Power.

[104] The value of the transmission reliability adder is calculated based on an algorithm linked to temperature and load, and is typically imposed 150-200 hours per year. The value of the generation reliability adder is calculated based on

tariffs include monthly administrative charges of $155 - $175 for RTP-DA and $850 for RTP-HA. Both tariffs require a five-year contract term.

RTP Tariff Design

	Applicable Customers	Pricing Structure	Derivation of Hourly Prices	Advance Notice	Other Key Provisions
RTP-DA	>250 kW monthly peak	Two-part rate with CBL. Incremental load subject to hourly prices only.	System lambda for Southern Co. System, plus adders.	4 PM day-ahead	5 yr contract term. Joint participation in load curtailment riders permitted.
RTP-HA	>5 MW monthly peak			One-hour ahead	

Developing a CBL

The process for developing each customer's CBL differs depending on whether they are an existing or a new customer, as defined by the Territorial Act.[105] For existing customers, the CBL is an estimate of their typical historical load profile, derived from recent interval load data (if available). For new customers, the CBL is established by first developing an estimate of their projected load profile, based on a standardized load shape, an engineering estimate, or some combination of the two. New commercial facilities and new industrial customers receive, by default, a CBL equal to 100% and 60%, respectively, of their estimated load profile. However, all new customers can request a CBL below their default level. To qualify for a reduced CBL, they must demonstrate that they can reduce their load to the reduced level, unless other facilities with an equivalent footprint have already demonstrated that capability.[106] A reduced CBL must also pass several financial tests, including the Ratepayer Impact Measure (RIM) test, to show that the cost of service for that customer will be adequately recovered.[107] Once any customer enrolls in RTP and reaches an agreement with Georgia Power about their initial CBL, that CBL remains fixed for the duration of their service on RTP, unless the customer requests an adjustment due to permanent changes in their facility (e.g., energy efficiency improvements or additional equipment).

Price Protection Products and Other Risk Management Options

Georgia Power offers RTP customers several types of options for customizing their exposure to price volatility. Under the Adjustable CBL tariffs, RTP-DAA-2 and RTP-HAA-2, customers can *temporarily* increase or decrease their CBL, and the resulting charge (for an increase) or credit (for a decrease) is based on the company's forecast of hourly prices at the time of the transaction. GPC also offers RTP customers a variety of financial risk management products for blocks of incremental RTP load, including caps, collars, and contracts for differences. Like the adjustable CBL options, these financial products are priced based on the company's projection of hourly prices and incorporate a risk-based price premium (GPC 2004b). Finally, customers that want to

the Loss of Load Probability and the marginal cost of generation capacity; and is typically imposed approximately 50 hours per year (Kubler 2003).

105 The RTP tariffs define New Load to mean "load not previously served by Georgia Power at any specific location; or load at a specific location where such locations has been vacant for at least twelve months; or load at a specific location that has been vacant less than twelve months, provided that the operation is not similar in nature to the previous operation which occurred at that location."

106 To demonstrate their load reduction capability, a customer is given four opportunities to reduce their load to the targeted level for two consecutive hours during a summer month.

107 If the RIM test is not initially passed, an upfront contribution in aid of construction or monthly rental fee may be required to achieve positive results (GPSC 2003).

eliminate all of their exposure can switch to the Fixed Price Alternative (FPA) tariff, a TOU-based rate that maintains revenue neutrality with the customer's projected bill under RTP by utilizing a customer-specific off-peak rate.

Joint Participation in RTP and DR Programs

RTP customers are allowed to participate in both of the load curtailment riders, although several special provisions apply. These riders require that participating customers nominate a firm demand level (FDL) to which they agree to reduce their load during curtailment periods. To participate in either of these programs, RTP customers must nominate an FDL below their CBL, and they receive credits under the load curtailment rider based on the difference between their CBL and FDL. During load curtailment events, an RTP customer's CBL is temporarily reduced to their FDL, so that they are not credited for the same load reduction under both the RTP tariff and the load curtailment rider. Thus, if they exceed their FDL during a load curtailment event, they pay the hourly price for their excess load, in addition to any non-compliance penalty associated with the load curtailment rider.

Program Marketing and Customer Support

Georgia Power actively markets RTP to new customers, developing many of their initial offers to new customers based on RTP. The procedure for establishing a customer's CBL is particularly important in this regard, as it enables the company to construct offers around different CBL quantities, and thereby offer prospective customers lower average prices in exchange for bearing some additional level of risk. In general, the company does not formally market RTP to their existing customers, as these customers are presumed to already be familiar with the RTP rates, given the considerable notoriety that these rates have received. GPC does actively market RTP to existing customers that are expanding their operations, as RTP allows these customers to purchase incremental power at marginal cost based prices.

The company provides a high level of ongoing customer support and education for their RTP customers. Once per year, GPC invites all RTP customers to an "RTP Forum", where they provide training on the rate and talk about expected conditions and pricing for the next year. Each RTP customer is also assigned a client manager, who serves as their point of contact for questions about RTP and can provide some help with developing strategies for managing exposure to price risk. Finally, GPC sends out information and warnings to RTP customers, if a big change in prices has occurred or is anticipated.

GPC does not currently offer technical or financial assistance programs to help customers develop load curtailment strategies or install enabling technologies. They do offer several types of energy information systems that provide access to hourly prices and interval data, and which RTP customers can use to monitor and analyze their load response. The most basic service, which includes access to RTP prices, is available at no charge to RTP customers, but the more advanced packages that provide access to interval load data are available for a monthly fee. The original variation on this product offering was a software package that customers would install at their site, and which they could use to interrogate their meters and view their interval data in near-real-time. The company has since introduced a web-based version of this service that can provide access to interval data with as little as a one-hour lag. Many RTP customers, perhaps one-third to one-half, have purchased either the software-based or internet-based energy information service.

Activities Conducted to Support RTP Participation and Price Response

Customer Education	Technical Assistance	End-Use Technology Deployment	Interval Metering Deployment
Annual RTP Forums are held to explain the terms of the tariff to participating customers and to provide information on expected market conditions. Client managers are available to field questions about the tariff as well.	Not formally offered, although client managers can provide some limited assistance.	The company offers a fee-based service by which customers can download and view their interval load data, with as little as a one-hour lag.	Interval metering is installed on an as-needed basis, the cost of which is recovered through an administrative charge.

Tariff Development Process and Issues

Georgia Power first introduced RTP as a pilot program in 1992, with an initial enrollment cap of 25 customers. At that time, the electricity industry throughout the U.S. was progressing towards a more market-based structure. To keep pace with this general trend and to prepare for possible restructuring in Georgia, the utility wanted to offer customers "a preview" of the market and also to ultimately begin transitioning customers onto rates that provided efficient, marginal-cost based price signals. Georgia Power also had a specific interest in developing an alternative to its supplemental energy rate. This was a curtailable service tariff, on which customers would pay standard tariff rates for their firm load, and marginal cost based rates (structured as TOU charges) for their non-firm load. Supplemental energy customers could be called to curtail in response to both reliability and economic conditions. Customers that did not comply with curtailment requests were assessed a penalty and the amount of load that was not curtailed was transferred onto the standard, firm service tariff for a year, provided that the customer met future load curtailments during this year. Over time, the number of curtailments called in response to economic conditions began to increase, and many supplemental energy customers expressed an interest in having the option to "buy through" these economic curtailment periods at the incremental cost to the utility, rather than being forced to interrupt. RTP provided this opportunity by allowing supplemental energy customers to convert their firm load under the supplemental energy tariff into their CBL on the RTP tariff, and thus maintain a discount off of the standard firm service rate for the remaining portion of their load.

Based on favorable experience with the pilot, in 1993 Georgia Power expanded RTP into a permanent, full production tariff and introduced the companion, hour-ahead RTP program. In the following year, the eligibility thresholds for both tariffs were reduced from 1 MW for RTP-DA and 10 MW for RTP-HA, to 250 kW and 5 MW, respectively (the same as the current levels). In the mid-90s, the company began offering several types of risk management products, on a pilot basis, to RTP customers that wanted to reduce the risk exposure of their incremental load. In 2000, Georgia Power expanded their risk management product offering, introducing a number of new risk management products (referred to as Price Protection Products) as well as the Adjustable CBL tariff options. Following a successful two-year pilot period, these new products were made permanent in the company's 2001 general rate case.

Georgia Power's RTP tariffs have since been addressed in the company's general rate cases and IRP filings, as well as in several proceedings devoted specifically to issues associated with the

RTP tariffs. The stakeholders most actively involved in discussions related to RTP have included: Georgia Power, PSC staff, the Georgia Textile Manufacturers Association (GTMA), the Georgia Industrial Group (GIG), and Federated Department Stores. A number of other retail establishments (e.g., box store chains) and large industrial customers have also participated on a more limited basis. In general, all parties have consistently been quite supportive of RTP, however, they have raised a number of substantive issues, as follows.

Purpose of RTP

The question of what purpose the RTP tariffs serve has been the subject of some discussion within recent regulatory proceedings where potential revisions to the RTP tariffs were under consideration. The initial stated purpose of Georgia Power's RTP tariffs is to provide marginal cost based pricing. PSC staff and representatives of the utility have identified other important purposes that the tariffs also serve, including: allowing Georgia Power to compete for new loads, promoting economic development, and reducing load during peak periods (Cearfoss and Wilson 2004).

Rules for Setting the CBL

Issues regarding GPC's procedure for establishing customers' CBLs have been raised in a number of recent proceedings, including a 2003 proceeding solely focused on the subject, which was initiated in response to a petition brought by Federated Department Stores. In that proceeding, Federated argued that the utility's practice of allowing only new customers to receive a CBL below their projected load at the time of enrollment constituted unjust discrimination, as it allowed new customers to pay a lower average price than existing customers for the same service (Clarkson 2003, Chupka 2003). GPC argued that the rules reflect the distinction made by the Territorial Act, which allows competition, and hence lower prices based on marginal costs, only for new customers (Greene et al. 2004). GPC argued against any decision, outside of a formal rate case, to allow existing customers to receive a reduced CBL, as it would create a revenue deficiency. A resolution to this dispute was later reached in the company's 2004 rate case, in which parties to the rate design stipulation agreed that GPC would allow customers to move a limited amount of existing load (up to 90 MW) from embedded cost based rates to the incremental portion of the RTP.[108] This option was made available on a first-come, first-served basis and was fully subscribed of the first day of the offer.[109]

Cost allocation to RTP customers

Historically, GPC has allocated embedded costs to RTP customers based on their CBL, rather than their entire load. Using this approach in their 2004 rate case, GPC calculated the ROR for the RTP-DA and RTP-HA rate classes to be 7.60% and 6.02%, respectively. PSC staff argued that, for the purpose of measuring the rate of return (ROR) for each rate class, embedded costs should be allocated to RTP customers based on their total load, not their CBL. Using this cost allocation approach, PSC staff calculated a ROR of 2.16% for RTP-DA and -2.08% for RTP-HA, which they took to constitute a "significant revenue deficiency" (Cearfoss and Wilson 2004, GPSC 2004b). The difference between these two approaches is primarily attributable to the fact

[108] Customers taking advantage of this offer could reduce their CBL to no less than 80% of their historical load.
[109] Under the terms of the PSC-approved rate design stipulation, all customers who qualified and applied on the first day of the offer received some pro-rated amount of the 90 MW.

that approximately 40% of RTP customers' total load is billed as incremental RTP usage, which provides a smaller contribution to embedded cost, on a per kWh basis, than the standard tariff rates for large C&I customers. PSC staff suggested that this disparity could be lessened by requiring each RTP customer's CBL to be adjusted upward to at least 80% of their total load, absent a clear justification for maintaining a lower CBL (Cearfoss and Wilson 2004). However, this recommendation ultimately was not incorporated into the rate design stipulation approved by the PSC.

Net peak load reduction attributable to RTP

PSC staff raised a number of issues regarding the value of the RTP tariffs as a load management tool. One concern identified in the 2004 IRP proceeding was that many RTP customers appear to not respond to hourly prices. PSC staff suggested that the lower average prices faced by customers on RTP compared to standard tariffs "may induce customers to simply 'ride through' limited hours of higher prices" (Best et al. 2004). As a result, additional generation capacity may be required, reducing hourly prices and further dampening the incentive for RTP customers to reduce their peak demand (GPSC 2004a). PSC staff also raised the concern that, "since it appears that RTP is being used to compete for new loads, the Company's claims of peak load reduction benefits to its system really do not exist," or in other words, that the overall load growth facilitated by RTP may offset the temporary load reductions induced by high RTP prices (Best et al. 2004). PSC staff recommended that, if the PSC regards the purpose of RTP to be a load management tool, they should require more stringent load reduction demonstrations (Cearfoss and Wilson, 2004). However, staff acknowledged that RTP serves other purposes and that these should be given due consideration. This issue may be further explored in the future, following the updated RTP price response analysis that GPC is currently conducting, as part of their IRP process.

Risk recovery adder

The size of the risk recovery adder has been a perennial issue, with GTMA and GIG periodically arguing for a reduction in the risk recovery adder (or, alternatively, against proposals by GPC to increase the adder) and GPC taking the opposing position. The initial stated purpose of the adder was to provide a contribution to fixed costs and compensate GPC for the risks associated with forecasting hourly incremental costs and load response. In a proceeding in 2000, GTMA and GIG argued that adder was no longer needed, because revenues for fixed cost recovery are generated on infra-marginal RTP sales, and because GPC has accrued sufficient forecasting experience with RTP to no longer require compensation for the associated risk (Pollack 2000). GPC asserted that compensation for forecasting risk was still required, due to increased volatility in wholesale markets, and that the adder was also needed to recover certain *marginal* costs that are not incorporated into the system lambda calculation, including unit commitment costs and environmental compliance costs (Hinson et al. 2000). In the final order of the 2000 case, the PSC required GPC to reduce, but not eliminate, the adders.[110]

Method for deriving hourly prices

[110] More recently, in GPC's 2004 general rate case, the company initially requested that the adders be increased as a way of spreading their requested rate increase across their rate classes, and GTMA and GIG opposed this proposal. In the end, the PSC-approved rate design stipulation did not include an increase in the size of the risk recovery adders.

In 1999, GTMA and GIG petitioned the PSC to consider a number of changes to the RTP tariffs, citing rising average RTP prices, which they attributed to an increasing reliance by GPC on wholesale spot market purchases. They argued that charging all incremental RTP load at a price based on the utility's system lambda allows the company to earn excessive profits, because the system lambda is higher than the average variable cost to serve incremental RTP load. They requested that the PSC require GPC to modify their method for calculating hourly prices, either by excluding off-system purchases or by averaging the cost of the top 1,000 MW in the company's resource stack. The PSC granted a variation on the second option, requiring that GPC average the cost only of the purchased power above system generation in their resource stack (GPSC 2000).

In the same proceeding, GTMA and GIG also argued that the system lambda approach does not provide sufficient incentive for the company to minimize the cost of its off-system purchases (GTMA and GIG 1999, Pollack 2000). They cited a specific concern related to the accounting treatment of different types of purchased power agreements: namely, that GPC might have an incentive to favor short-term purchases over potentially less expensive longer-term contractual arrangements, because the kWh costs associated with short-term purchases are allocated to the Fuel Cost Recovery (FCR) balancing account, but the capacity and/or option payments associated with longer-term arrangements are charged against base revenues, thereby eating into the company's earnings. GTMA and GIG requested that the PSC require GPC to disclose its procurement practices, so that RTP customers can verify that the company minimizes its supply costs (GTMA and GIG 1999, Pollock 2000). GPC argued, and the PSC assented, that disclosure of procurement practices is unnecessary, as the PSC is responsible for reviewing the prudence of the company's transactions (Hinson et al. 2000). Notwithstanding the concerns raised in this proceeding, GPC suggested that, in general, customers have not been particularly concerned about the transparency of the procurement process, since the utility is willing to buy back power at the same hourly prices from customers that reduce their load below their CBL (GPC 2004b).

Interrelationship between RTP and interruptible programs

Prior to 2001, GPC's interruptible customers were called strictly for reliability reasons. In the course of a proceeding in 2000, GPC indicated that RTP prices could be substantially reduced if interruptible customers were called in response to economic conditions.[111] The PSC ordered GPC to introduce a new set of interruptible service options that would allow for load curtailments to be dispatched on an economic basis. To comply with this order, GPC introduced a new voluntary economic load curtailment program, whereby customers can be paid for load curtailments provided in response to prices quoted on the same day by the utility. GPC has also continued to offer an interruptible program whereby load curtailments can be initiated strictly in response to reliability conditions. RTP customers continue to be eligible for the interruptible program, provided that they satisfy all of the relevant participation requirements (e.g., that their firm demand is below their CBL).

<u>Performance</u>

[111] Hinson et al (2000) indicate that, based on expected prices for 2000, if interruptible customers were called whenever the marginal supply cost rose to $350/MWh or greater, it would result in just 6 additional hours of interruption for interruptible customers, but would reduce the annual average RTP price by almost 2 mills.

RTP Participation

A substantial portion of Georgia Power's C&I customers have chosen to participate in RTP. Overall, 43% of eligible customers and 82% of eligible load was enrolled in one of the two RTP tariffs in 2004. The market penetration rate for RTP-HA, alone, was even higher, with more than 90% of eligible customers and eligible load participating. RTP has been popular among all C&I customers, but it has had a particularly strong draw among new Georgia Power customers, since they are able to receive a reduced CBL when they enroll in RTP. Of the new customers that Georgia Power signs up each year that are eligible for RTP, typically 70-80% enroll in RTP (GPC 2004b). In comparison, the market penetration rate among customers that were previously on a different rate (and thus have not generally had the opportunity to receive a CBL below their historical firm load level) is closer to 25% (GPC 2004b).

RTP Participation Statistics

	Eligible Customers		**Participating Customers**	
	Number	**Load (MW)**	**Number**	**Load (MW)**
RTP-DA	3,880	6,100	1,580	4,250
RTP-HA	89	860	84	800
RTP-DA and RTP-HA	3,880	6,100	1,664	5,050

Participation in Price Protection Product Offerings

Most RTP customers have a significant portion of their normal load that is exposed to hourly prices, which has created demand for supplemental financial risk management products. On average, RTP customers' CBL is approximately equal to 60% of their total usage (GPC 2004c). In 2003, PSC staff reviewed a sample of 85 RTP accounts and found that, across these accounts, the CBLs ranged from 0% to 80% of customer's total load (GPSC 2003). Some of the lowest CBLs were for customers that were previously on the supplemental energy rate and had little or no firm load requirements.

RTP customers' interest in the various supplemental financial hedging products has been significant, but has diminished somewhat over time. In 2000, 620 accounts participated in one of the adjustable CBL tariff options, and 75 accounts purchased a price protection product (Kubler 2001). Currently, about half as many customers are purchasing these hedges (GPC 2004b). One possible reason is that the utility's marginal cost projections have been rising, and customers now perceive a greater likelihood that actual prices will be below the projections (GPC 2004b). Thus, the perceived downside risk of these hedges may be greater. Some of the earlier customer interest may also have been a response to the exceptional price spikes during summer 1999; since then, prices have been considerably less volatile.[112]

Load Reductions from RTP Participants

Georgia Power has commissioned several studies to estimate the price response of customers on RTP. One analysis of summer 1999 estimated that the combined load reduction across participants in both tariffs was 750-800 MW when hourly prices reached $1.93/kWh for RTP-DA and $6.43/kWh for RTP-HA. Approximately two-thirds of this load reduction was associated with RTP-DA participants, and the remaining third was from RTP-HA participants.

[112] The highest prices in 2002, 2003 and 2004 were 18.1¢, 13.5¢, and 23.6¢, respectively, for RTP-DA, and 12.2¢, 31.1¢, and 20.5¢ for RTP-HA (GPC 2004c).

An analysis of summer 2000, when prices were less extreme than the summer before, found that the RTP customers produced a maximum load reduction of 482 MW (GPC 2004c). More recent analyses have not yet been performed, although the company is in the process of conducting an updated study for use in future load forecasts and IRP filings. In general, RTP customers are assumed to require a fairly significant price (e.g., $0.20-0.30/kWh) before they respond, although some customers, particularly those with onsite generation, respond to lower prices (GPC 2004b). Load reductions associated with onsite generation, which have declined in recent years as a result of tightening air quality regulations in the Atlanta metropolitan area, account for approximately 100-200 MW of the total RTP load response (GPC 2004b). Much of the current RTP response from onsite generation is associated with pulp and paper mills that increase electricity production from their cogeneration units during high price periods, to displace purchases from the utility.

RTP Load Response Statistics

RTP Tariff	**Maximum Load Reduction (MW)**	**Corresponding Price ($/kWh)**
RTP-DA (day-ahead price notice)	~500	$1.93
RTP-HA (hour-ahead price notice)	~250	$6.43

In addition to the short-term response to price spikes, there is also anecdotal evidence to suggest that some customers on RTP have undertaken various permanent measures as a result of taking service on the rate. Representatives of four large retail and department store chains (BJ's, Kohl's, Lowe's, and Wal-Mart) testified in Georgia Power's 2004 rate case that, as a result of taking service on RTP, their companies have installed a range of permanent measures to reduce peak electricity demand and to take advantage of low off-peak prices, including: high efficiency air-conditioning and building envelope components; fuel switching (e.g., gas-driven desiccant cooling systems); and electric heating (Civic et al. 2004).

Load Reductions from DR Programs

Georgia Power's RTP tariffs are but one element in their portfolio of demand response related programs and pricing options. In their resource planning activities, the company counts a total of approximately 1,000 MW of peak load reduction from their various programs (GPC 2004b). RTP accounts for about half of this, based on expected summer peak period prices. Approximately 10% of the total peak load reduction is from their residential A/C cycling program, *Power Credit* (GPC 2004b). The remaining portion of their total peak load reduction is from the 180 or so interruptible service customers, who have provided load curtailments of as much as 541 MW, and in the range of 450-500 MW on a variety of other occasions (GPC 2001). GPC's Daily Energy Credit (DEC) rider, which provides bill credits to customers that commit to providing load reductions on an event-by-event basis based on a price quote posted by the utility, has also elicited little interest since being introduced in 2001. The utility staff interviewed attributes this to several factors. First, prices have generally remained below the $0.15-0.25/kWh level believed to be required for customers to respond. Secondly, most of the company's price responsive customers are already enrolled on one of their RTP tariffs and have little financial incentive to participate in the DEC program, because the program rules preclude RTP participants from receiving a bill credit for the same load reduction under both the RTP tariff and the DEC rider.

<u>Key Findings and Implications</u>

Importance of CBL Rules for Customer Acceptance and Ratemaking

Georgia Power offers new customers the option of receiving a CBL below their projected load when they enroll in RTP, and also allows all RTP customers to maintain their initial CBL indefinitely over their term of service on the rate. The net effect of these two provisions is that a large portion of RTP customers' total usage, about 40%, is "incremental" RTP load, which is billed at marginal cost based prices that are, on average, significantly less than the standard tariff rate. Over the long run, this factor has been the most significant source of bill savings for customers on RTP, and has undoubtedly been an important driver for the high participation levels (GPC 2004b).

These CBL provisions, which have been a decisive factor to the popularity of the RTP tariffs, have also brought forth a number of interrelated regulatory policy and ratemaking issues that, in part, simply reflect the inherent complexity of incorporating marginal cost based pricing into a cost of service based regulatory framework. The most fundamental of these issues is how to define cost responsibility for RTP load and how to allocate costs based on that standard.[113] On several occasions, PSC staff has indicated that the minimum standard of fairness, for any rate, is that it "should recover marginal costs created while providing some additional contribution toward embedded costs" (GPSC 2003). More recently, though, PSC staff suggested that there was a significant revenue deficiency within the RTP rate class, as a result of the lower contribution to fixed cost recovery made by incremental RTP compared to the other rate classes (Cearfoss and Wilson 2004). The rubber meets the road on this issue within the utility's cost of service studies, when determining how to allocate embedded costs to RTP load. For two-part RTP tariffs such as Georgia Power's, the key issue is whether to allocate embedded costs to RTP customers based on their total load or based just on their CBL load.

Policymakers in other states can draw several lessons from this aspect of Georgia Power's experience. The first thing to recognize is that some form of discount or other financial inducement, above and beyond the bill savings that might be obtained by actively responding to hourly prices, may be needed to entice a substantial number of customers to enroll in RTP. Such a discount should naturally arise in competitive retail market settings, as RTP prices should average out over time to be less than fixed price offers, due to the transfer of price and load shape risk from supplier to customer with RTP. A key question to consider, from the perspective of understanding the extent of demand response likely to develop in the competitive retail market, is what level of participation in RTP is likely to be elicited by this "risk transfer" discount of RTP. In a regulated cost-of-service context, the possible forms that this financial inducement might take are different. Some form of discount could be provided by applying a different cost responsibility standard to RTP load, and thus offering customers bill savings through a lower contribution to embedded costs than what they would otherwise make.[114] Alternatively, the financial inducement could be provided in the form of an explicit "incentive

[113] Related to embedded cost responsibility is the question of the utility's obligation to serve RTP load. Georgia Power has the same obligation to serve incremental RTP load as the rest of its retail load (e.g., the same reliability standards). If a utility's obligation to serve RTP load were defined differently than their obligation to serve non-RTP load, then this could have implications for the cost responsibility of RTP load.

[114] Another form of discount can arise (unintentionally) in regulated settings, in situations involving RTP tariffs with bill components that are designed to be revenue neutral based on a class average load shape (e.g., bundled, one-part RTP). In this situation, customers with a flatter load shape than the class average may be able to accrue bill savings by switching to RTP, in effect, by reducing the extent to which they cross-subsidize other customers whose loads are more coincident with the system peak.

payment." The latter approach is perhaps most relevant to contexts where RTP implementation is being driven by an explicit policy goal of developing greater levels of price responsive demand. If policymakers in this situation decide that some form of incentive payment is warranted on the grounds that price responsive load generates system benefits, they may want to weigh alternative incentive structures with respect to considerations such as their susceptibility to free-ridership and the ease with which they can be adjusted over time as the magnitude of non-participant benefits becomes better understood.

Customer Hedging Preferences and Risk Tolerance

The choice of most Georgia Power RTP customers to maintain a CBL well below their total load implies a general willingness among these customers to expose a rather large portion of their load to uncertain prices in exchange for a significant level of expected savings over the long run. Across the entire base of RTP participants, the average CBL is approximately 60% of each customer's total load, which is also consistent across the individual categories of commercial, industrial, RTP-DA, and RTP-HA participants.[115] Public data about the distribution of customers' CBL is limited to the findings reported in a 2003 PSC staff report, which indicated that, among a sample of 85 RTP contracts, each customer's CBL was between 0% and 80% of their total load. When GPC recently offered customers the opportunity to move existing load from an average cost based tariff onto the incremental portion of the RTP rate, the 90 MW subscription limit was reached within less than one day.

Customers' willingness to accept the additional risk associated with having a CBL below their normal load reflects the significant bill savings that they can obtain by purchasing the incremental RTP load at marginal cost, rather than average cost, based prices. These savings can be fairly substantial: on the order of $0.01-0.03/kWh or 20-40% off of the average cost of power under one of the standard, cost-of-service tariffs for these customers.[116] Naturally, for any particular customer, the size of this discount will depend on a variety of factors, such as that customer's particular load shape and the standard cost-of-service tariff under which they would otherwise take service.

Customers' choice of CBL level does not entirely capture their risk preferences, as many customers have purchased one of the various financial risk management products offered by GPC to hedge a portions of their incremental RTP load. Currently, approximately 15-20% of RTP participants are taking advantage of one these product offerings.

Reproducibility of GPC's Experience Elsewhere

Georgia Power's exceptional success with RTP has, to some significant extent, been made possible by the unique structure of the state's retail electricity market. In other settings, customers are unlikely to so easily find such large opportunities for bill savings on RTP, as either

[115] In 2003, Commercial RTP-DA customers had an average CBL of 61.07%, Industrial RTP-DA customers had an average CBL of 61.98%, Commercial RTP-HA customers had an average CBL of 64.82%, and Industrial RTP-HA customers had an average CBL of 60.46% (GPC 2004c).

[116] For the year ending July 2005, GPC forecasted an average base price (i.e., not including the fuel cost recovery component) of $0.0436/kWh for the commercial class, and an average base price of $0.0164/kWh for incremental RTP load among commercial RTP participants (GPC 2004d). For industrial customers, this difference was smaller: $0.0230/kWh for the industrial class as a whole, compared to $0.0155/kWh for incremental RTP load. The FCR component is approximately $0.019-$0.02/kWh during summer months, depending on the customer's voltage level.

the portion of their load that they could purchase at hourly prices, or the difference between fixed prices and average hourly prices, would likely be smaller. In a traditional regulated monopoly setting where no customers have a choice of supplier, the public service commission would presumably have a less compelling reason for allowing the utility to offer participants a CBL below their projected load, since the load building benefits to the utility and non-participants would be less apparent.[117] Conversely, in a fully competitive retail market, customers have a high degree of flexibility in terms of the amount of load to cover at fixed prices. However, the difference between fixed retail price offers and average hourly prices, which reflects the market-based risk premium incorporated into fixed prices, is unlikely to equal the sizable gap between a vertically-integrated utility's average cost-based tariffs and their marginal costs – particularly when the utility serves its load primarily with company-owned generation resources characterized by relatively high capital costs and low operating costs (i.e., coal, nuclear, and hydro).

Customer Acceptance of RTP with no Transparent Spot Market

One potential barrier to RTP implementation in California that has been cited by customer groups is that no transparent and liquid day-ahead spot market currently exists. While the transparency issue has surfaced to a limited extent in Georgia, ultimately it has not posed a significant barrier. Several possible explanations for this fact could be posed. First, Georgia Power meets regularly with customers to discuss projected market conditions and to help them plan accordingly (e.g., by purchasing financial risk management products).[118] Second, the 2-part rate structure may help instill confidence in the legitimacy of the quoted hourly prices, since the company is implicitly willing to buy back decremental usage at these prices. Third, because Georgia Power relies primarily on company-owned generation and long-term contract resources to serve their retail load, including incremental RTP load, their RTP customers have limited exposure to the spot market (and any associated risks related to market power, scarcity rents, etc.). Finally, the PSC continues to maintain responsibility for oversight and auditing of Georgia Power's procurement practices.

RTP as One Element in a DR Portfolio

Although Georgia Power views RTP as a key DR resource, the utility has continued to see a need to offer other types of DR programs. In particular, their interruptible tariff provides the utility with the ability to dispatch dependable load curtailments in response to reliability conditions, and their recently-introduced demand bidding style program provides an opportunity for customers that are unwilling to bear the risks of RTP to provide load curtailments in response to economic conditions. Thus, even where RTP is successfully implemented, other types of DR mechanisms may continue to be needed, both for operational purposes and to harness the full base of cost-effective DR potential available.

Complex Impacts of RTP on System Load Shape

[117] Specifically, Georgia Power has asserted that offering RTP with a reduced CBL enables the company to compete for customer choice load, which benefits their other customers by increasing the revenues available for embedded cost recovery.
[118] These discussions take place under a confidentiality agreement.

In addition to short-term load reductions elicited by temporary price spikes, informal evidence indicates that RTP has also induced a variety of long-term impacts, including load building (both off-peak and baseload), permanent load shifting, energy efficiency investments, and fuel switching. It is plausible, if not probable, that the net effect of these impacts on the system load and on social welfare could be of the same order of magnitude as that associated with the occasional load shedding induced by exceptionally high prices.[119] A more precise understanding of the magnitude and characteristics of these longer term load impacts may be needed for more robust analyses of the cost-effectiveness of RTP implementation and for effectively incorporating large scale RTP participation into resource planning processes (e.g., utility IRP and RTO transmission planning).[120]

[119] In other contexts, some of these effects may more or less significant. For example, the load building impact of RTP has perhaps been more significant for Georgia Power than it would for another utility operating in a region without any form of customer choice.

[120] For Georgia Power's resource planning, the long-term impacts of RTP are embedded within historical load data and are thereby incorporated implicitly into load forecasts.

Illinois – Commonwealth Edison

Background: Market and Regulatory Context

Illinois' electric restructuring legislation (HB362) was passed in 1997. Under HB362, retail competition was slated to begin in October 1999 for the largest commercial and industrial customers. Retail access for all other customer classes was to begin in May 2002 (IGA, 1997).

In 1999, the passage of SB24 amended the restructuring legislation to accelerate the phase-in of retail access for commercial and industrial customers. Under SB24, all customers with loads greater than 4 MW and customers with multi-site loads greater than 9.5 MW in aggregate were given access to competitive retail electricity service in October 1999. One-third of commercial and industrial customers with loads less than 4 MW (selected by lottery) were also given access to retail electric providers at the same moment. Another third of commercial and industrial customers less than 4 MW (again selected by lottery) were given retail access in June 2000, and the final third of commercial and industrial customers less than 4 MW were given retail access in October 2000.

Transition Period

During Illinois' transitional period, utilities must provide frozen bundled rates through 2006 to all customer classes or until a given service territory is deemed to be sufficiently competitive for a given customer class.[121] Residential utility customers received 15% rate reduction in August 1998 and an additional 1-5% reduction in October 2001 depending on the service territory. For customers taking unbundled delivery service (including those taking generation service from competitive suppliers), utilities also collect Competitive Transition Charges during the duration of the transitional period.

Wholesale Market Structure

When Illinois restructured, utilities could choose to compete for retail customers or not. If utilities chose to compete, they had to functionally separate their wires and commodity branches. If utilities chose not to compete, they had to agree not to actively retain customers or obtain new ones, not to sign special contracts with customers, and to remain a neutral party that would support development of a retail market. Additionally, in terms of divestiture, utilities were not explicitly required to sell any portion of their generation assets. Commonwealth Edison, AmerenIP (formerly Illinois Power), and AmerenCIPS (formerly the Central Illinois Public Service) all chose not to compete in retail markets and sold their generation assets to unregulated affiliates. However, AmerenCILCO (formerly the Central Illinois Light Company) chose to actively compete in retail markets and only partially divested their generation assets.

Illinois' wholesale markets were, until recently, composed of bilateral markets. Soon, however, the state will be served by two different RTOs – PJM and Midwest ISO (MISO) – both of which operate or will soon operate wholesale electricity exchanges. Commonwealth Edison (ComEd) joined the PJM Interconnect in May 2004, providing ComEd and retail suppliers in ComEd's service territory with access to all of PJM's energy and capacity markets. The other major IOUs

[121] In 2002, the passage of SB2081 further amended the restructuring legislation to extend the restructuring transitional period through the end of 2006, representing a two-year extension from the original date (IGA, 2002).

in Illinois are members of MISO, whose day-ahead and real-time electricity markets are currently set to be launched in March 2005.

Retail Market Development

On the retail side, market development in Illinois has been uneven across both customer classes and service territories. Fifteen suppliers are currently licensed to serve commercial and industrial customers in Illinois (ICC, 2005a). At the end of 2004, cumulative switch rates among large C&I customers in ComEd, AmerenCIPS, and AmerenIP were 61%, 26%, and 64% of total load, respectively. Switch rates among smaller nonresidential customers (<1 MW) are considerably lower, varying from 39% in ComEd to 6% in AmerenCIPS and 17% in AmerenIP (ICC, 2005b). In Illinois' other service territories, cumulative switch rates among all nonresidential customers are less than 1%. To date, no suppliers have applied to serve residential customers in Illinois.

Default Service: Post Transition

The Illinois Commerce Commission (ICC) is charged with determining the default service obligations and rules for the post-transition period in Illinois. The original 1997 restructuring statute contains three explicit requirements: 1) that utilities make bundled service available to customers until the respective customer class and/or service territory is declared competitive; 2) that after a customer class is declared competitive, the utility make bundled service available to that customer class "based on market prices", and 3) that utilities provide unbundled delivery service and bundled, RTP-based tariffs to all customers (ICC, 2004a). In early 2004, the ICC convened a series of stakeholder workshops organized under the "Post-2006 Initiative" banner in order to address post-transition market rules and issues related to competition policy, utility ratemaking, utility obligations, default service, and procurement. The workshops were intended to be a consensus building exercise.

Workshop participants agreed that utilities must continue to provide fixed-price bundled service to customers in "non-competitive" classes and service territories after 2006. For customers in "competitive" classes, participants agreed that unless the statute is revised, utilities are currently only required to provide fixed-price bundled service for a three-year "grace period" after the competitive declaration is made and only to customers who were taking fixed-price bundled service at the time of competitive declaration. After the grace period (and for customers who were not taking bundled service at the time of competitive declaration), participants agreed that currently the only statutory utility obligation is the provision of an RTP-based service. Given the slow and uneven development of retail competition in Illinois, participants noted that these obligations did not guarantee that competitive offers would necessarily be available to customers on terms similar to current fixed-price bundled service when their class is declared competitive. This led to some discussion of the possibility of revising the statute to change these obligations, specifically to require utilities to provide optional fixed-price service to customer classes declared "competitive". Participants could not, however, reach a consensus on this issue. For its part, the Commission has yet to issue any formal proposals defining post-transition utility obligations and default service.

Utility Experience with RTP and Demand Response

Illinois utilities have offered RTP tariffs as optional service tariffs to nonresidential customers since the end of 1998, as mandated by the state's restructuring legislation. Demand response (DR) programs in Illinois have largely been initiated by the utilities themselves. ComEd has developed a number of programs since 1996 and currently administers several active incentive-based programs under the "Smart Returns" banner. Participation in ComEd's DR programs has grown steadily since inception, and current DR potential among program participants totals approximately 1300 MW (McNeil 2004). Among the Smart Returns programs are: Voluntary Load Response (VLR), Early Advantage (EA), the Alliance, and Energy Cooperative (EC) (ComEd, 2005b).[122] These four programs are described briefly below:

- *Voluntary Load Response* - All nonresidential customers in ComEd's service territory (including delivery service customers) that are able to reduce consumption by 10 kW or more and have interval meters installed are eligible to participate in the VLR program, which pays energy incentives of $0.15 per kWh with no firm commitments and no non-compliance penalties.[123]
- *Early Advantage* – This program allows nonresidential customers that can reduce consumption by 1 MW or more during high price or emergency events to earn larger incentive payments under contract terms negotiated on a customer-specific basis.
- *The Alliance and Energy Cooperative* – These two programs target large customers taking service under rates 6L or 6T that are able to easily reduce consumption to meet more frequent load reduction requests. In return for minimum contracts lengths, and longer curtailment durations,[124] these programs provide substantial incentive payments as well as some technical support services.[125]

Overview of electric industry structure and organization

Customer choice provisions	Transition period terms and timelines	Utility Participation in Retail Market	Wholesale market structure	Wholesale market organization
All customers now have retail choice (C&I customers since October 2000; residential customers since May 2002)	Bundled service rates are frozen until 2006 for all customer classes or until service is declared competitive	Designated as default service providers; required to provide unbundled delivery service; allowed to compete in retail markets (but only AmerenCILCO competes)	Previously only bilateral markets; ComEd joined PJM in May 2004; other utilities in MISO; MISO energy markets expect to open in March 2005	Divestiture not required by law but most IOUs have fully divested; generation largely owned by two unregulated affiliates - Exelon and Ameren

Tariff Design and Administration

In ComEd's service territory, the default service for nonresidential customers with loads up to 1 MW are served under Rate 6 (General Service). For customers with loads less than 500 kW,

[122] ComEd other DR programs include Rider 26 (interruptible service) and Rider 27 (self generation). However, these programs are closed to new enrollment and are expected to be discontinued in the future (ComEd, 2004a).
[123] Delivery service customers are eligible for "delivery service" incentive payments.
[124] The Alliance program has a minimum contract length of two years and allows for a maximum of 10 to 25 curtailment events to be called per year with a total duration of 60 to 150 hours. The EC program has a minimum contract length of five years and a maximum total curtailment of 120 hours per season.
[125] Participants in the Alliance program are eligible for payments of up to $10.42 per kW during summer periods and $2.23 per kW during non-summer periods. EC participants are eligible for payments averaging $35 per kW based on seasonal averages during load response hours.

default service is a bundled, inverted block-pricing tariff. For customers with loads greater than 500 kW and less than 1 MW, default service is a bundled, TOU tariff (ComEd 1999). For customers with loads greater than 1 MW and less than 3 MW, ComEd's default service falls under Rate 6L (Large General Service), which is a bundled, seasonal, inverted block-pricing tariff (ComEd, 2002).

In March 2003, ComEd won ICC approval to phase out its Rate 6L default service for customers with demands 3 MW and above, arguing that the retail market for this customer class was sufficiently competitive in its service territory. Customers who were taking service under Rate 6L on June 1, 2003 are eligible to continue service on this tariff until January 1, 2007 at which time they will be switched to ComEd's new default service, Rate HEP, if they have not chosen a competitive supplier. After June 2003 for new customers in ComEd's service territory with demands greater than 3 MW, the default service is Rate HEP (ComEd 2003a).

Rate HEP (Hourly Energy Pricing) is a hybrid one-part, bundled RTP tariff. Energy commodity charges are hourly during peak hours but flat during off-peak hours (ComEd 2003a). Both sets of prices are based on day-ahead peak and off-peak prices drawn from Power Markets Week's *Daily Price Report,* but in slightly different ways. To calculate hourly peak prices, ComEd uses two-year historical data of real-time hourly PJM West prices in order to shape day-ahead peak prices into day-ahead hourly peak prices. For off-peak prices, ComEd uses historical daily transaction data of the day-ahead spot market for off-peak power in order to calculate an average of daily transaction midpoints for the preceding month. ComEd publishes the next day's peak and off-peak prices by 7pm of the previous day on the utility's website.

Although Rate HEP is a bundled rate, it contains itemized charges in order to facilitate comparison to unbundled service offers. These itemized charges include a delivery service charge, a transmission and ancillary services charge, a metering charge, and a transition charge. Rate HEP also includes a 10% adder on the energy charges for fixed cost recovery.

Any customers of eligible size can take service on Rate HEP at any time with the sole exception of customers eligible to take service under Rate IPP (independent power producers). There is no minimum contract period for Rate HEP, but a written, 60-day opt-out notice is required. Per its agreement to act as a neutral party in retail markets, ComEd does not undertake any significant marketing activities in support of Rate HEP or actively recruit new customers (ComEd 2004).

RTP Tariff Design

Applicable Customers	Pricing Structure	Derivation of Prices	Advance Notice	Other Key Provisions
> 3 MW	Hybrid one-part bundled tariff with hourly peak prices	Power Markets Week's *Daily Price Report*	Posted on utility's website by 7pm of previous day	Off-peak prices are flat but change daily

Interval Metering Deployment

Deployment of Interval Metering	Estimated Cost of Deployment	Cost Recovery Mechanism of Metering Costs
ComEd requires installation of interval meters for Rate HEP customers; Rate 6L customers are not required to install interval meters		Rate HEP includes an itemized metering charge equivalent to ComEd's Rider 6 (Optional or Non-standard Facilities) and Rider 7 (Meter Lease)

Implementation Process and Issues

ComEd's 6L rate case was the first post-transition default service to be established in Illinois. ComEd initiated the case in July 2002, arguing that the retail market for 3 MW and above customers had developed sufficiently to be declared "competitive" under the terms of the restructuring statute, thus ending ComEd's obligation to provide fixed-price bundled service tariffs to that customer class. ComEd also proposed accompanying tariff amendments that would establish their Rate HEP as the new default service for that customer class (ICC, 2003).

Numerous parties intervened in response to ComEd's petition. On the customer side, interveners included the People of Cook County, the People of the State of Illinois, the Illinois Industrial Energy Consumers (IIEC), the U.S. Department of Energy (USDOE), the Citizens Utility Board (CUB), the Metropolitan Water and Reclamation District (MWRD), the Chicago Area Customer Coalition (CACC), and the Building Owners and Managers Association (BOMA). On the supplier side, interveners included Blackhawk Energy Services, MidAmerican Energy, the National Energy Marketers Association (NEMA), and Constellation NewEnergy. Illinois' other major IOUs – AmerenIP, Ameren CILCO, AmerenCIPS, and AmerenUE – also intervened in the case.

Following evidentiary hearings and testimony, the ICC issued an Interim Order on November 14, 2002 approving ComEd's competitive declaration and ordered ComEd to file compliance tariffs.[126] In early 2003, hearings were held on ComEd's compliance tariff filings, including the proposed changes to Rate HEP. Following initial testimony, ComEd negotiated a stipulation that proposed an alternative structure for Rate HEP in order to address concerns voiced mainly by competitive suppliers.[127] The Commission approved the alternative Rate HEP with minor modifications on March 28, 2003. Several aspects of ComEd's proposed rate design were at issue during the hearings:

- *Customer willingness to face price volatility*. IIEC contended that the low enrollment rate in Rate HEP prior to the 6L rate case was proof that customers are not interested in hourly price tariffs. Both IIEC and USDOE argued that ComEd's default service should be a fixed-price service (ICC, 2003). The Commission noted that given the declaration of Rate 6L as a competitive service, ComEd's only statutory obligation is to provide an hourly-priced service.
- *Switching provisions*. ComEd's original proposal included a minimum contract and a12-month stay-out provision for customers that leave Rate HEP service and wish to return. The alternative rate structure in ComEd's stipulation withdrew both of these requirements. The

[126] The Commission's Interim Order was fairly controversial, both among interveners in the case and within the Commission itself. The City of Chicago and the USDOE claimed that they were unable to find competitive offers to serve O'Hare International Airport and Argonne National Laboratory (KEMA 2003b). Two Commissioners dissented from the majority opinion, and Commissioner Kretschmer issued a dissenting opinion stating that the majority had clearly ignored overwhelming evidence that the retail market in ComEd's service territory is, in fact, far from competitive under the terms of Illinois' restructuring statute (ICC, 2002). In particular, Commissioner Kretschmer pointed to misleading switching statistics offered as evidence, noting that of the 70% of 3 MW and above customers that had switched to competitive suppliers, only 30% were taking service from suppliers not affiliated with ComEd. Commissioner Kretschmer also noted that on the retail side, only five of the fifteen certified competitive suppliers are actually active in the region and that, on the wholesale side, market concentration levels clearly pointed to the existence (or at least the strong possibility) of wholesale market power.

[127] Signatories to the stipulation included, BOMA, Constellation, NEMA, MidAmerican, and the City of Chicago

only switching provision in ComEd's final approved rate is a written, 60-day opt-out notice requirement.

- *Revenue neutrality with Rate 6L*. ComEd's original proposal included a Monthly Access Charge within Rate HEP's cost structure that was designed to provide for revenue neutrality with Rate 6L. ICC staff, IIEC, and USDOE objected to this charge and the revenue neutrality argument (ICC, 2003; ICC, 2004b). They argued that because ComEd's cost of service under Rate HEP is lower than under Rate 6L, maintaining revenue neutrality with 6L would simply allow ComEd to recover its costs plus a margin. Furthermore, they argued that there was no statutory basis to support a revenue neutrality requirement. The ICC agreed that there is no statutory requirement to maintain revenue neutrality and modified Rate HEP's cost structure to eliminate the implied margin.
- *Transparency of cost components*. In the initial compliance tariff hearings, competitive suppliers, ICC staff, and customer groups strongly objected to the lack of transparency in Rate HEP's bundled cost structure, arguing that it would inhibit the ability of customers to reasonably compare the cost components of Rate HEP with competitive offers (ICC, 2003; ICC, 2004b). ComEd accommodated these concerns by proposing an alternative structure for Rate HEP as part of its negotiated stipulation. Under this alternative cost structure, charges were itemized that they would be equivalent to: 1) unbundled delivery service charges as defined in Rate RCDS (Retail Customer Delivery Service), 2) unbundled transmission and ancillary services charges as defined in Rider ISS (Interim Supply Service), 3) metering charges as previously defined in Rate HEP, and 4) transition charges as defined in Rider PPO (Power Purchase Option) without contract-length adjustments and including a 10% increase to account for system average line losses (ICC, 2003).
- *Transition charges*. ComEd's proposed alternative rate structure included charges equivalent to the transition charges applied to delivery service customers. Both Commission staff and customer groups objected to the inclusion of these charges on the grounds that the statutes only allow transition charges to be applied to delivery service customers, not bundled tariff customers (ICC, 2003; ICC, 2004b). Moreover, they argued that these charges did not reflect any cost of service component. The ICC ruled in favor of including charges equivalent to transition charges, arguing that the exclusion of such charges would hinder the development of retail markets, since customers taking competitive supply will still be subject to transition charges through the end of 2006.

The fact that Rate 6L's successor, Rate HEP, had previously been approved by the ICC (particularly the pricing of the energy commodity) greatly expedited the process, despite the fact that ComEd had very few customers on Rate HEP prior to their 6L rate case (ICC, 2004b).

Enabling and/or promoting demand response was not a driving factor for either ComEd or the ICC in establishing Rate HEP as the default service for customers greater than 3 MW (ICC 2004b, ComEd 2004). The ICC's primary objective during the 6L proceedings was to ensure that the statutory requirements concerning post-transition utility obligations were fulfilled and to promote the development of the competitive retail market (ICC 2004b). From ComEd staff's perspective, the objective of proposing Rate HEP as a default service was to balance their role as a neutral party in retail markets (by encouraging customer switching away from default service) with the costs and risks associated with providing default service (ComEd 2004).

Stakeholder Perspectives on RTP and DR

Both ComEd and ICC staff consider demand response to be a critical component of well-functioning electricity markets and both consider RTP to be an important tool in achieving demand response (ICC 2004b, ComEd 2004). Neither believes, however, that RTP alone will be sufficient.

At the current time, the ICC is not interested in promoting or implementing DR programs at the state level. From the ICC's perspective, DR represents financial policy, not social policy, and is thus outside the purview of the Commission's mandate (ICC, 2004b). In the past, DR and DSM programs in Illinois have been initiated by the utilities themselves, and the ICC has served as a passive partner in these efforts. ICC staff does believe that, in theory, the competitive market will eventually be able to generate sufficient levels of demand response. However, because of the slow and uneven development of markets in Illinois thus far, it is unlikely that the competitive market will to be able to develop sufficient demand response on its own for some time.

In principle, ComEd staff also believes that the competitive market could potentially develop sufficient demand response products and resources on its own. However, ComEd administers nearly all of the DR programs currently active in its service territory and considers maintaining those demand responses resources to be important for the region (ComEd 2004). Looking forward over the short-term, therefore, ComEd will continue to play a lead role in developing and maintaining their portfolio of demand response programs until another entity demonstrates the interest and capability to assume the leadership role. In service territories without substantial demand response programs in place already, ComEd believes that utilities may not necessarily have to be involved in program development to achieve demand response goals, but they also point out that utilities in general have some advantageous efficiencies in such cases in terms of their existing customer relationships.

Default Service Implementation

Statutory Requirements	Implementation Process	Issues Addressed in Implementation Phase	Status
Before competitive declaration, utilities required to offer fixed-price, bundled service; after competitive declaration, only obligation is to offer RTP	Post-transition default service rate case initiated by the utility; energy commodity structure established under previous rate filing to satisfy statutory requirement to offer voluntary RTP rates	Switching provisions; revenue neutrality with outgoing default service; transparency of cost components of incoming bundled service; inclusion of transition charges in new default service	Commission approved modified, alternative RTP rate proposal in March 2003; tariffs went into effect on June 2003; existing customers >3 MW can continue fixed-price service until January 2007; new customers >3 MW assigned to new RTP service

Stakeholder Positions on RTP

PUC	Utilities	Competitive Suppliers	Customer Groups
RTP service is required by law; PUC not interested in explicitly promoting or developing RTP as a DR resource	Default RTP encourage customer switching, reduces costs and risks of provider, and is consistent with utility role as a neutral party in retail markets	Default RTP best serves the interest of promoting competitive markets	Customers do not want hourly prices in general; default RTP with an underdeveloped retail market threatens competitive positions of large customers

Performance

Of the 350 customers eligible, approximately 40 are currently taking service under Rate HEP (ComEd 2004). Current participation rates are attributed mainly to the lower average prices under Rate HEP compared to Rate 6L and other fixed-price offers, although ComEd proffers that several customers are likely taking Rate HEP service because they have onsite generation or good load response capabilities. Because historical participation rates in Rate HEP have been low, ComEd has not formally analyzed or monitored the price response of Rate HEP customers. ComEd noted that market prices have been quite low in recent years, and summer peak prices remained below $100/MWh in 2004 and below $80/MWh during the previous summer (ComEd 2004, ComEd 2005a).

RTP Participation Statistics

Eligible Customers		Participating Customers	
Number	**Combined Peak Load (MW)**	**Number**	**Combined Peak Load (MW)**
350	2500	~40	n/a

RTP Load Response Statistics

Maximum Load Reduction (MW)	Price ($/kWh)
n/a	n/a

All nonresidential customers that can reduce their load by at least 100 kW are eligible to participate in any of ComEd's DR programs. Since their inception, ComEd's Smart Returns programs have enrolled a significant amount of load, but the vast majority – 787 MW – of this load participates in the Voluntary Load Reduction program (McNeil 2004). ComEd did assess the load reductions realized from VLR participants during the capacity-constrained summer of 1999 and estimated that participants achieved a maximum load reduction of 176 MW (Eber 2004). Due to the relative low level and stability of prices in recent years, ComEd has not called any of the other Smart Returns programs, and thus estimates of the maximum load reductions attributable to these programs are currently unavailable.

Smart Returns Program Participation Statistics

Eligible Customers		Participating Customers	
Number	**Combined Peak Load (MW)**	**Number**	**Combined Peak Load (MW)**
all nonresidential customers who can curtail >100 kW	all nonresidential customers who can curtail >100 kW	n/a	VLR = 787 Early Advantage = 72 Rider 26 = 162 Rider 27 = 68 The Alliance = 71 Energy Cooperative = 64

VLR Program Load Response Statistics

Maximum Load Reduction (MW)	Price ($/kWh)
176 MW	n/a

Key Findings & Implications

Illinois' experience provides several interesting insights on RTP and DR program development in conjunction with restructuring. First, the process by which default RTP has been implemented for certain customers in Illinois was driven by largely statutory requirements and the policy goal of promoting retail market development – not by a desire to explicitly develop DR. Second, the lack, until very recently, of transparent wholesale market exchanges did not impede the consideration or implementation of default RTP tariffs. Lastly, there is considerable faith among Illinois regulators that the competitive retail market will be able to deliver adequate DR, despite the slow and uneven development of retail markets in Illinois.

The key findings drawn from Illinois' experience with default RTP are summarized below:

- There is a general consensus among stakeholders that currently the only statutory service obligation of utilities to customers that are declared "competitive" is explicitly RTP-based service, as opposed to "market-based" rates. However, there is considerable controversy concerning the current rules governing competitive declaration and the measures by which Illinois' competitive market is evaluated.
- ComEd's primary objective in designing its default service proposals was to encourage customer switching away from default service. As such, ComEd did not support fixed-price service or multiple POLR products. During the 6L rate case, ComEd negotiated the terms of their alternative proposal primarily with competitive suppliers and did not directly address the concerns voiced by the majority of customer groups.
- Historically, ICC support of DR programs to date has been passive. Existing DR and DSM programs in Illinois have been initiated and administered entirely by the utilities. ICC staff believe that eventually the competitive market will be able to provide enough attractive RTP products to generate a sufficient level of price response, but ICC staff acknowledge that the slow and uneven development of Illinois' retail market make such a scenario highly unlikely for some time.
- ComEd has developed a large portfolio of DR programs and participants over the last decade. Now structured as an integrated distribution company, it is no longer clearly in ComEd's business interests to continue these programs. However, ComEd staff acknowledges the importance of these DR resources to the region, and ComEd will continue to administer these programs until other entities demonstrate the interest and capability to assume the leadership role.
- ComEd staff believes that utilities may not necessarily have to be involved in program development to achieve sufficient levels of demand response in service territories without programs in place, although utilities have potential efficiencies stemming from their existing customer relationships that could be significant in terms of program development and administration.

Maryland – All IOUs

Background: Market and Regulatory Context

The Electric Customer Choice and Competition Act of 1999 (referred to as Electric Act) restructured the electric industry in Maryland. Under the terms of the Electric Act, utilities were required to unbundle their rate schedules into discrete categories. Consumer bills were required to separately list generation and distribution costs, allowing customers to compare prices of different retail suppliers of generation services (Maryland Code, 2005). The generation and supply of electricity became an unregulated market where consumers could shop for their preferred energy supplier (Maryland Code, 2005). The Electric Act also directed the Maryland Public Service Commission (PSC) to issue rules that would: 1) provide an orderly transition to competitive markets; 2) maintain electric system reliability; 3) ensure compliance with Federal and State environmental regulations; 4) be fair to customers, electric companies, their investors and suppliers; and 5) provide economic benefits to all customer classes.

Transition Period

Starting July 1, 2000, all customers of Maryland's four investor-owned utilities – Baltimore Gas & Electric (BGE), Allegheny Power (AP), Delmarva Power and Light Company (Delmarva), and Potomac Electric Power Company (PEPCO) – were given the opportunity to choose their electric suppliers. Under the terms of the Electric Act, retail electricity prices were frozen and capped by the PSC during the designated transition period (MD PSC, 2005a). The length of the transition period varied across utilities and customer classes. In BGE's service territory, price caps for the largest C&I customers expired in July 2002, those for remaining C&I customers expired in July 2004, but price caps remain in effect for residential customers through June 2006. In AP's service territory, price caps for C&I customers expired in December 2004 but remain in effect for residential customers through December 2008. In PEPCO and Delmarva, price caps for all customers classes expired in July 2004.

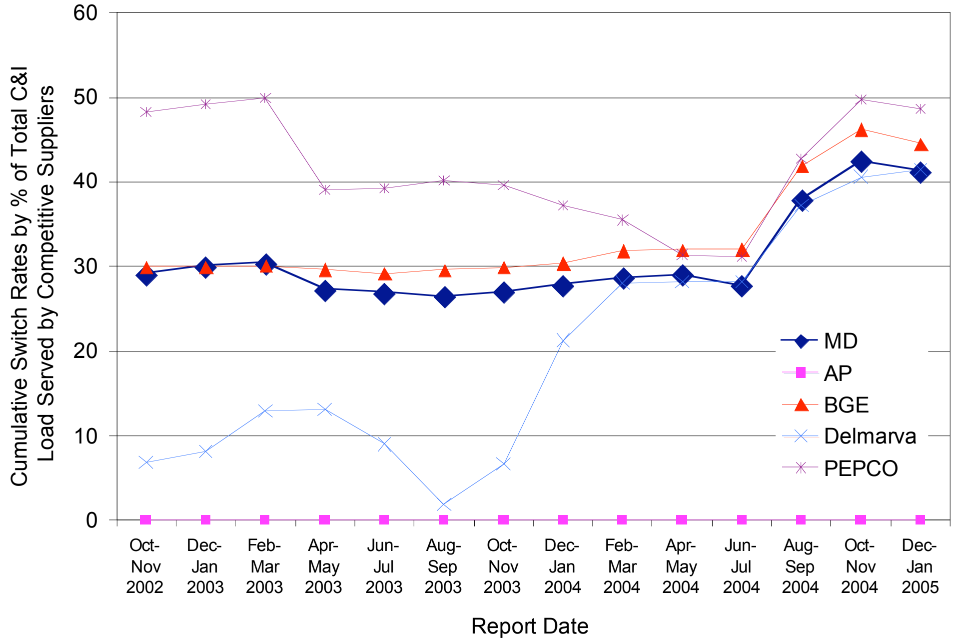
Wholesale Market Structure

In the Electric Act, existing utilities were envisioned to be fully regulated monopolies for the distribution of electricity. Consequently, utilities were statutorily mandated to divest their generation assets to unregulated affiliates and/or merchant generators and exit the business of generation supply completely (Maryland Code, 2005).

Retail Market Development

Since retail choice began, over 170 suppliers, aggregators, brokers, and marketers have been certified to operate in Maryland (MD PSC, 2005b). Through mid-2004, cumulative switching to competitive supply among C&I customers had stabilized at 27-32% of total C&I load (KEMA, 2004a). Following the expiration of price caps in July for all customers in PEPCO and Delmarva and small and medium C&I customers in BGE, however, switching activity increased in all three service territories. By the end of 2004, cumulative switch rates among C&I customers in PEPCO, BGE, and Delmarva were 48.6%, 44.5%, and 41.5% of total C&I load, respectively (KEMA, 2005). Switching activity in these three service territories has since stabilized but increased dramatically in AP's service territory where price caps for C&I customers expired in

December 2004. In the first four months of 2005, cumulative switching among C&I customers in AP's service territory has climbed from near zero to over 29% (MD PSC, 2005c).



Cumulative switching among C&I customers by service territory in Maryland.

Switching among large C&I customers in Maryland has been even stronger compared to the rest of the C&I customer class. At the end of 2004, cumulative switching among large C&I customers (>600 kW) were 87%, 92%, and 73% of total large C&I load in BGE, Delmarva, and PEPCO's service territories, respectively (KEMA, 2005). These switch rates increased slightly during the first four months of 2005, and switching among large C&I customers in AP's service territory increased dramatically from near zero to over 57% following the expiration of price caps in December (MD PSC, 2005c).

Default Service: Post Transition

Under the Electric Act, the utilities' obligation to provide SOS was set to expire following the end of the transition period, provided that Maryland's retail markets have become sufficiently competitive (MD PSC, 2002). In December 2001, the PSC initiated a proceeding to investigate the state of Maryland's retail markets and examine the statutory obligations of utilities in the post-transition era. During this proceeding, the PSC concluded that the statute clearly allows the PSC to extend the utilities' obligation to provide SOS to residential and small commercial customers beyond the end of the transition period (MD PSC, 2002). For larger customers, however, the PSC concluded that the language of the statute was unclear with respect to utilities' obligation to provide SOS and default service following the transition period (MD PSC, 2002). The PSC subsequently initiated a separate stakeholder discussion on post-transition default service obligations and issues. These discussions, and the multilateral negotiation process that followed, yielded Maryland's current default service rules and tariffs (including default RTP), the details of which are the focus of the remainder of this case study.

Utility Experience with RTP and Demand Response

Prior to restructuring, none of the utilities in Maryland had any direct experience with implementing or administering RTP tariffs, but some utilities administered demand-side management (DSM) programs that included direct load control measures. BGE currently operates two such DSM programs – an appliance cycling program and a water heater cycling program – that were designed and implemented before restructuring (BGE, 2004; BGE, 2005). However, because of PJM's role in capacity planning, BGE staff indicated that these DSM programs are no longer economic for the utility to operate (BGE, 2004). PEPCO staff indicated that their legacy DSM programs have already been discontinued (PEPCO, 2004).

Recently, BGE has begun to facilitate customer participation in PJM's Emergency Load Response Program as a registered CSP through its Rider 24. BGE staff indicated that this program is beneficial to customers and is profitable for BGE (BGE, 2004).

Overview of electric industry structure and organization

Customer choice provisions	**Transition period terms and timelines**	**Utility Participation in Retail Market**	**Wholesale market structure**	**Wholesale market organization**
All customers have had retail choice since July 1, 2000.	Prices frozen and capped during transition period; length of transition differs by customer class and service territory; transition period for all C&I customers ended in July 2004 in BGE, PEPCO, and Delmarva, and December 2004 in AP.	Utilities are required to provide default service and also to un-bundle their rates; utilities cannot market default service.	PJM-operated real-time and day-ahead energy markets. Also PJM-operated capacity markets.	Divestiture required by statute; utilities are regulated distribution-only companies.

<u>Tariff Design and Administration</u>

In April 2003, the PSC approved a settlement negotiated between stakeholders that established Maryland's current set of default service rules and tariffs (MD PSC, 2003a). The settlement established market-based, fixed-price SOS tariffs for residential, small C&I, medium C&I, and large C&I customers. These SOS tariffs are known as Residential SOS and Type I, II, and III Non-Residential SOS, respectively. Under the terms of the settlement, each of these fixed-price SOS tariffs is available only for a limited period, after which the PSC will assess whether and how SOS service will be continued (MD PSC, 2003a).[128]

For large C&I customers with demands greater than 600 kW, the settlement also established an optional RTP tariff referred to as Hourly-Priced Non-Residential Service (HPS). Existing utility customers could affirmatively elect to take service on HPS by May 31, 2004. Existing customers that failed to affirmatively choose HPS or competitive supply were automatically placed on Type III fixed-price service. In this scenario, therefore, Type III SOS is the default service and HPS is an optional service. For customers returning to utility service from a competitive supplier after July 1, 2004, HPS serves as the default service, after which customers have the option to take service on Type III SOS. Following the expiration of Type III SOS on May 31, 2005, HPS will

[128] Starting on July 1, 2004, the Residential and Type I SOS will be available for four years, the Type II SOS for two years, and the Type III SOS for one year.

become the sole utility service available to large C&I customers in Maryland. For large C&I customers, therefore, HPS can be characterized as being an optional utility service for the period July 1, 2004 to May 31, 2005 and the default utility service thereafter.

Under the terms of the settlement, generation supply for all fixed-price SOS is procured through a competitive auction where competitive suppliers bid on different blocks of SOS load. Bids are required to be differentiated by season, and preferably by time-of-use. Retail generation supply charges for SOS customers is then the load-weighted average of the utility's supply contracts for each year. To reflect seasonally-differentiated generation supply bids, the utilities are allowed to adjust SOS retail prices up to three times annually.

The other components of the fixed-price SOS tariffs include transmission and distribution charges and an administrative charge. The administrative charge includes cost recovery charges[129] as well as "return component" that provides the utilities a return on their SOS costs. This return component is thus analogous to a retail adder and only applies to SOS customers. The level of the return component was set at 2 mills for Type I and II customers and 3 mills for Type III customers.

For HPS, the generation supply component of HPS is structured as a one-part RTP tariff, based on a pass-through of PJM's hourly locational marginal price for energy. HPS also includes transmission and distribution cost components an administrative charge. The HPS administrative charge functions very similarly to the administrative charges in the fixed-price SOS tariffs, providing for incremental cost recovery and a return on utility SOS costs. The level of the HPS administrative charge was set between 2.25 mills/kWh and 3.0 mills/kWh, with the return component set at 2.25 mills/kWh.

HPS customers are not restricted from switching to fixed-price SOS or competitive supply at any time. However, the settlement prohibits fixed-price SOS customers from switching to HPS in order to guard against price arbitrage and the volumetric risks associated with frequent customer migration (MD PSC, 2003a).

Under the terms of the settlement, the utilities are responsible for installing interval meters for all customers taking service on HPS (MD PSC, 2003b). The installation costs were recovered by utilities through their respective rate cases. Currently, all large C&I customers in MD have hourly interval meters installed. Small and medium C&I customers are also eligible to have interval meters installed on an optional basis but must pay the installation costs (MD PSC, 2004).

Utilities are prohibited from marketing the SOS rates. Regulatory staff noted that the PSC's customer education budget had already been exhausted before the settlement came into effect but acknowledged that there is a critical need to educate customers about the SOS provisions and the retail market (MD PSC, 2004).

[129] For example, such actual incremental costs could include: actual uncollectible that were not being recovered in a utility's distribution rates; consultants, procurement processes; incremental system costs; bill inserts for education; transition costs; and cash working capital revenue requirements, subject to limitations as set forth in the Settlement.

RTP Tariff Design

Applicable Customers	Pricing Structure	Derivation of Prices	Advance Notice	Other Key Provisions
All non-residential Type III SOS customers with peak load demand of 600 kW and above	One-part, unbundled	PJM location-based real-time energy market prices	None	Fixed price option available until May 31, 2004

Interval Metering Deployment

Deployment of Interval Metering	Estimated Cost of Deployment	Cost Recovery Mechanism of Metering Costs
All non-residential customers >600kW have interval metering. Smaller non-residential customers can also get interval metering however, they would have to pay for it.	Not available	Cost recovered through rate case

Implementation Process and Issues

As part of its statutory responsibility, the PSC had to evaluate the development of the retail market to determine if that market has evolved sufficiently to relieve the utilities of any continued obligation to provide SOS. In May 2002, the PSC - after considering the testimonies of all stakeholders in the state – concluded that the electricity market was not competitive (MD PSC, 2002).

Subsequently, the PSC ordered a settlement process for all parties to reach consensus regarding how SOS will be provisioned in Maryland after utility restructuring rate caps expire. Between May 2002 and November 2002 stakeholders participated in an extensive negotiation process that yielded the final settlement on November 15, 2002.[130] Participants in the settlement process included the four investor-owned utilities, large industrial energy users, commercial energy users, competitive suppliers, energy marketers, PJM, and PSC staff. The PSC issued its Order 78400 that accepted the settlement agreement on April 29, 2003 (MD PSC, 2003a). This part of the settlement is referred to as Phase I.

The Phase I settlement set forth the terms and procedures for the provision of SOS to customers through the competitive selection of wholesale supply for various periods of time. The Phase II Settlement set forth the specific requirements and processes necessary to implement those policies described in Phase I. Testimonies by all stakeholders were filed for Phase II in July 2003 and hearings were held in August and September 2003. The PSC approved the Phase II Settlement on September 30, 2003 through its Order 78710 (MD PSC, 2003b).[131]

[130] One party – Washington Gas Energy Services, Inc. (WGES) opposed the Settlement. However, all stakeholders including the PSC rejected all of WGES's arguments.
[131] The main elements of the Phase II Settlement were: qualifications for those suppliers wishing to bid for a utility's SOS load obligations; details of the bid request process; an objective and fair bid evaluation methodology; a complete and thorough Full Requirements Service Agreement that would control the terms of service between the utility and a winning supplier; and individual Utility Bid Plans were approved that would be separately applicable in each of the four utility service territories in order to tailor this process to the unique characteristics and requirements for each utility and its customers.

In approving the settlement, the PSC was guided primarily by the statutory requirements explicit in the Electric Act (MD PSC, 2003a). First, the PSC found that, by providing temporary price stability through utility-supplied generation service option, the settlement adequately promotes an orderly transition to competitive electricity markets. Second, the PSC found that the competitive wholesale procurement process established by the settlement satisfies the reliability requirement of the statute by promoting diversity of SOS supply. The PSC also found that the competitive procurement process satisfied the Electric Act's overriding goal of promoting the development of competition among wholesale suppliers. Third, the PSC found that the pricing structure of both fixed-price SOS and HPS were adequately "market-based" as required by the statute, ensuring fair pricing for all customer classes and minimizing cross-subsidization while providing a temporary safety net as retail markets continue to develop. Finally, the PSC found that the settlement treats all stakeholders fairly, in that the SOS pricing structures ensure full and proper cost recovery for utilities while minimizing the risk of providing SOS service and allow opportunities for retail suppliers to offer competitive prices, benefiting customers and the overall development of the retail market.

Neither the Phase I nor the Phase II settlement negotiations were open to the public. As such, accounts of the various stakeholder positions pertaining to tariff design, cost recovery, cost shifting, or other issues are not available in the public domain. The design of the administrative charge proved to be the most contentious issue among all stakeholders (MD PSC, 2003a; MD PSC, 2004). Customer groups argued in favor of lowering or eliminating the administrative charge to allow more benefits to accrue to utility customers while competitive suppliers argued for higher administrative charges that allow adequate opportunities for suppliers to offer competitive prices (MD PSC, 2003a). In our interviews, utility staff also indicated that the choice of customer size thresholds for Type III customers was somewhat contentious, but less so than the level of the administrative charge (BGE, 2004; PEPCO, 2004). Although Orders 78400 and 78710 contain a summary of PSC staff testimony which indicated that "all" tariff designs were considered in the settlement process, specific alternative rate designs were never cited (MD PSC, 2003a; MD PSC, 2004b). When interviewed, utility staff indicated that they preferred using real-time prices as opposed to day-ahead prices for HPS rates primarily to facilitate administrative simplicity (BGE, 2004; PEPCO, 2004).

Stakeholder Perspectives on RTP and DR

Enabling and/or promoting demand response was not a driving factor for either the PSC or other stakeholders in establishing HPS as an optional utility service. Additionally, PSC staff indicated that they have no expectations that establishing HPS as a part of SOS service will result in increased levels of DR (MD PSC, 2004). PSC staff pointed out that the metering infrastructure currently in place already represents a "significant platform" upon which to build DR in Maryland but that they do not believe that DR must be built into default service (MD PSC, 2004).

Both PSC and utility staff view DR as an important component of well-functioning electricity markets, but they also indicated that RTP is only one in set of mechanisms that could achieve sufficient levels of DR (MD PSC, 2004; BGE, 2004; PEPCO, 2004). For its part, the PSC have actively promoted customer participation in PJM's Load Response Programs and currently participates in the Mid-Atlantic Distributed Resources Initiative (MADRI) – a collaborative effort between state public utility commissions, PJM, and DOE to promote the development of

DR resources in the Mid-Atlantic region through coordinated DR policies and markets. BGE staff indicated that they believe that utilities should play a direct role in facilitating DR and noted that BGE actively markets its Rider 24, which has proven profitable for BGE (BGE, 2004). Relative to RTP, BGE staff believes that participation is in large part dependent on individual customer load shapes and the availability of enabling technologies (BGE, 2004). Interestingly, neither BGE nor PEPCO staff support subsidies to encourage the adoption of enabling technologies (BGE, 2004; PEPCO, 2004). For its part, PEPCO staff stated that they do not believe that utilities should play a direct role in facilitating DR and that they expect the competitive market to facilitate adequate levels of DR (PEPCO, 2004).

Default Service Implementation

Statutory Requirements	Implementation Process	Issues Addressed in Implementation Phase	Status
Utilities provide default service. Supply procured via competitive bid process for blocks of default service load.	Settlement process	Competitive procurement process; size and components of administrative charge; duration of fixed-price service availability	Fixed-price SOS service available through May 2005 for large C&I; HPS becomes only default service for large C&I thereafter

Performance

Prior to the establishment of HPS, the only utility experience with RTP in Maryland was from July 2002 to June 2003 when BGE's Schedule P customers (>1.5 MW) were placed on RTP. However, 95% of this load subsequently switched to competitive supply contracts (KEMA, 2003a). It is not clear what the DR impacts of RTP were during this period, as the price-responsiveness of customers that stayed on RTP was not assessed.

Approximately 1380 customers in the large C&I class in Maryland, representing about 2800 MW of combined peak load, are eligible for HPS. Currently, only 23 customers take service on HPS, representing 38 MW of combined peak load (MD PSC, 2005c). Of these 23 customers, 22 of them are located in BGE's service territory. To put these statistics into perspective, it is important to note that 71% of eligible large C&I customers in Maryland have switched to competitive suppliers, accounting for 86% of the combined peak load eligible for HPS (MD PSC, 2005c). The PSC is not planning any quantitative assessments of price response by HPS customers (MD PSC, 2004).

HPS Participation Statistics

Eligible Customers		Participating Customers	
Number	Combined Peak Load (MW)	Number	Combined Peak Load (MW)
1380	2786	23	38.1

Maryland customers can also participate in PJM's Load Response Programs (LRP) via a registered Curtailment Service Provider. In 2004, Maryland customers participating in PJM's Economic LRP and Emergency LRP accounted for 252 MW and 53 MW of nominated load reduction capability, respectively (PJM, 2005). No load reduction events were called for the Emergency LRP in 2004. The Economic LRP is credited with having generated a maximum load reduction of 168 MW in 2004. However, this level of load reduction should be interpreted with caution, as the price level at which these reductions occurred was quite low (0.035 $/kWh) compared to the smaller load reduction events that occurred at much higher price levels.

PJM Load Response Program Participation Statistics

Eligible Customers		Participating Customers	
Number	**Combined Peak Load (MW)**	**Number**	**Combined Peak Load (MW)**
n/a	n/a	n/a	Economic = 252 MW Emergency = 53 MW

PJM Economic Load Response Program Load Response Statistics

Maximum Load Reduction (MW)	Price ($/kWh)
168 MW	0.035 $/kWh

Key Findings & Implications

Maryland's experience with implementing utility RTP tariffs occurred in anticipation of the end of the mandatory transition periods for large C&I customers. One of the unique features of Maryland's experience is the multilateral settlement process that yielded the post-transition default service structures and tariffs. The settlement negotiations involved 25 stakeholders (including PSC staff) and created a framework for which there was consensus support. For large C&I customers, the default service structures and tariffs that emerged provided for short-term availability of fixed-price service, with RTP becoming the sole default service available once the fixed-price services expire.

The key findings drawn from Maryland's experience with implementing utility RTP are summarized below:

- RTP was framed primarily in terms of the aspects of RTP that satisfy the statutory requirements of default service in Maryland. These aspects included minimizing utility risk, using market-based prices, eliminating cross subsidies, and promoting retail competition.
- Neither PSC nor utility staff expects default RTP to elicit significant DR. Over 85% of eligible load had already switched to competitive suppliers before RTP became sole default service in June 2005, and those who remained on SOS service are largely expected to seek out fixed-price competitive supply contracts.
- PSC staff does not believe default service needs to contain explicit DR components. Rather, the PSC actively supports customer participation in PJM DR programs and is participant in regional efforts to coordinate DR markets

New Jersey – All IOUs

Background: Market and Regulatory Context

In New Jersey, the Electric Discount and Energy Competition Act (EDECA) was approved on February 9, 1999. The main goal of EDECA was to create competition in the wholesale and retail electricity markets, allowing customers to shop for the cheapest generation source. It also provided for a smooth transition from a regulated to a competitive power supply marketplace. The Board of Public Utilities (BPU) was authorized to develop regulations that would achieve the goals laid out in EDECA (NJ BPU, 1999).

Under the terms of the EDECA, each utility had to unbundle its rate schedules such that discrete services and charges that were previously included in the bundled utility rate were separately identified and charged in its tariffs. Such discrete services and charges had to include, at a minimum, customer account services and charges, distribution and transmission services and charges, and generation services and charges. BPU could also require that additional services and charges be unbundled and separately billed (NJ BPU, 1999).

Transition Period

Retail choice for customers in all of New Jersey's four investor-owned utilities – Public Service Electric and Gas (PSE&G), Jersey Central Power & Light Corporation (JCP&L), Conectiv Power Delivery (Conectiv), and Orange and Rockland (Rockland) – began in November 1999. The EDECA established a transition period between November 1999 and July 2003 during which utility service rates were capped. Customers were guaranteed a rate reduction of 5% immediately when customer choice began and a further 10% over the next 4 years (NJ BPU, 2001).

Wholesale Market Structure

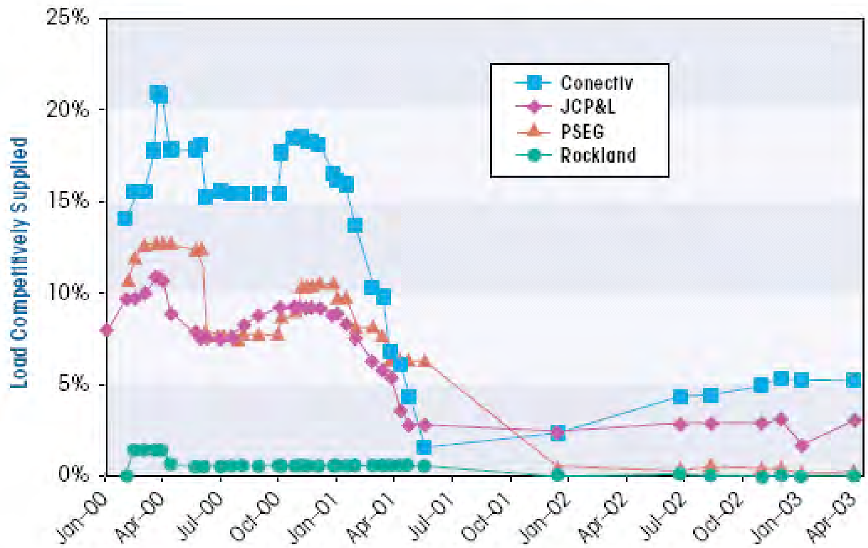
Under the terms of the EDECA, utilities that owned and operated the electric distribution lines were required to either divest their generation capacity or move the generation portion of their business to a separate entity. Utilities remain fully regulated monopoly providers of electricity distribution. Additionally, the statute prohibits utility participation in retail markets (NJ BPU, 1999).

All of Maryland's IOUs are members of the PJM Interconnect (PJM). As such, load serving entities have access to all of PJM's energy, capacity, and ancillary service markets as well as markets for regulation, spinning reserves, and financial transmission rights.

Retail Market Development

Since retail choice began, over 40 suppliers, aggregators, and brokers have been certified to operate in New Jersey (NJ BPU, 2005c). During the transition period, approximately 335 MW out of 18,000 MW of total load was served by competitive suppliers (KEMA, 2003). By the end of February 2005, customer switching had increased considerably with approximately 3,000 MW of load now being served competitive suppliers (NJ BPU, 2005b). The customer segment with the highest switching rates is large C&I customers, with roughly 2,500 MW out of 2,900 MW, or

84 % of total large C&I load (NJ BPU, 2005a). Customer switching outside of the large C&I customer class has been relatively minor, however, with about 500 MW out of 14,000 MW, or less than 4 % of total load, currently taking generation service from competitive suppliers (NJ BPU, 2005b).



Cumulative switching among C&I customers during New Jersey's transition period (KEMA, 2003).

Default Service: Post Transition

Under the terms of the statute, the utilities must provide default service to customers that do not choose a competitive supplier (NJ BPU, 1999). The statute grants the BPU the authority to establish default service rules and tariffs and revise them as necessary. The default service rules and tariffs put in place by the BPU following the end of the transition period are described in detail in later sections of this case study.

Utility Experience with RTP and Demand Response

Prior to restructuring, none of the utilities in New Jersey had any direct experience with implementing or administering RTP tariffs, but some utilities administered demand-side management (DSM) programs that included direct load control measures. Currently, both PSE&G and JCP&L operate legacy appliance-cycling programs that were designed and implemented as part of a DSM portfolio before restructuring began in New Jersey (JCP&L, 2004; PSE&G, 2004). Since 2001, most DSM-related programs in New Jersey have been consolidated under the auspices of the New Jersey Clean Energy Program, administered by the NJ BPU. Utility staff indicated that future DSM and DR-related program development will be led largely by the BPU and they do not anticipate offering independent DSM or DR programs (JCP&L, 2004, PSE&G, 2004).

Overview of electric industry structure and organization

Customer choice provisions	Transition period terms and timelines	Utility Participation in Retail Market	Wholesale market structure	Wholesale market organization
All customers have had retail choice since November 1999	Prices capped during transition period; all customers received 4% rate discount; transition period ended in July 2003	Utilities cannot directly participate in retail markets; utilities are statutorily obligated to provide distribution service for default service customers	PJM-operated day-ahead and real-time energy markets; also PJM-operated capacity markets	Divestiture required by statute; utilities are regulated, distribution-only companies

Tariff Design and Administration

In December 2001, the NJ BPU established New Jersey's current set of default service rules and tariffs (NJ BPU, 2001). For large C&I customers, the BPU established hourly pricing as the default service (known in New Jersey as "basic generation service" or BGS) following the end of the transition period in August 2003. This default service customer class is referred to as the Commercial and Industrial Electricity Price (CIEP) class. Under the terms of the BPU's default service rules, competitive suppliers bid to provide blocks of generation supply for BGS-CIEP customers in simultaneous, multi-round, descending-clock auctions held once per year (NJ BPU, 2001).

The pricing structure of BGS-CIEP generation service is a one-part RTP tariff, where retail energy charges are a pass-through of hourly locational marginal prices in PJM's real-time energy market. The other retail charges included in BGS-CIEP rates are transmission and distribution charges, capacity charges, ancillary service charges, a risk adder, and a retail adder.

Since August 2003, the BPU has authorized minor changes to the BGS-CIEP rate structure (e.g. which customer classes pay the retail adder). More significantly, however, the BPU has revised the definition of the CIEP customer class, and thus the size of the customer class for whom BGS-CIEP is the default service (see Table A-1). In the first year following the transition period, hourly-priced default service applied only the 1,750 largest C&I customers. In the second year, the threshold was defined as all C&I customers with peak demands greater than 1.5 MW, accounting for the 1,766 largest C&I customers. In the third year, this threshold was lowered to all C&I customers with peak demands greater than 1.25 MW, accounting for approximately the 1,900 largest C&I customers in New Jersey. Additionally, starting in the second year, all C&I customers that were taking fixed-price default service (i.e. BGS-FP) became eligible to opt into BGS-CIEP service. For these customers, therefore, BGS-CIEP is now an optional utility service.

Changes to BGS-CIEP eligible customer populations

	BGS-HEP	BGS-CIEP	BGS-CIEP
Procurement period:	August 1, 2003 – May 31, 2004	June 1, 2004 – May 31, 2005	June 1, 2005 – May 31, 2006
Customer size:	Not strictly defined	C&I customers > 1.5 MW	C&I customers > 1.25 MW
Customer class:	Default for 1,750 largest C&I customers	Default for 1,766 largest C&I customers Optional for C&I customers in the BGS-FP program	Default for 1,900 largest C&I customers Optional for C&I customers in the BGS-FP program

All CIEP customers are required to have interval meters installed. Initially, only one-third to one-half of the CIEP customers had meters (NJ BPU, 2004b). The BPU asked utilities to install meters for all CIEP default service customers and include the costs in their then ongoing rate cases (NJ BPU, 2004b). BPU also directed the EDCs to install the necessary metering and communications equipment for optional CIEP participants at no cost (NJ BPU, 2003).

The BPU also formally requested that the utilities hold public workshops to educate customers about hourly varying prices and retail competition. In contrast, there has been no formal technical or financial assistance offered by either the BPU or any of the utilities, and both utility and BPU staff indicated that they do not believe that enabling technology programs should be publicly funded or subsidized (PSE&G, 2004; JCP&L, 2004; NJ BPU, 2004b).

BGS-CIEP Tariff Design

Applicable Customers	Pricing Structure	Derivation of Prices	Advance Notice	Other Key Provisions
C&I customers with peak demand >1250 kW	One-part, unbundled RTP	PJM real-time hourly LMP	None	No switching restrictions; C&I customers not belonging to CIEP class can now opt-into BGS-CIEP service

Interval Metering Deployment

Deployment of Interval Metering	Estimated Cost of Deployment	Cost Recovery Mechanism of Metering Costs
All commercial and industrial customers > 750 kW now have interval metering installed	Not available	Costs recovered through rates cases

Implementation Process and Issues

EDECA mainly stipulated that rate caps would stay in place during the transition period and that BGS would be provided by the utilities (NJ BPU, 1999). Since the utilities were forced to divest their generation assets, it was not clear how the supply for BGS would be procured. The statute gave the BPU the responsibility of developing regulations that would govern the procurement of BGS supply once transitional rates expired in July 2003 (NJ BPU, 1999).

In June 2001, at the behest of the BPU, the utilities filed a joint proposal to implement a competitive bidding process for procuring BGS supply (NJ BPU, 2001). This bid process used a simultaneous, multi-round, descending-clock auction format to procure all BGS supply. In

October 2001, a public hearing was held where all parties could participate and present their comments (NJ BPU, 2001).

The stakeholders that testified during the hearing and/or provided comments to the BPU included: NERA (the consulting firm that designed the auction and eventually administered it), the four utilities, the New Jersey Rate-Payer Advocate, Enron, Green Mountain Power, Geophonic Networks, Inc., Mid-Atlantic Power Supply Association, New Power Company, and Shell. In December 2001, BPU issued the final order that approved the auction process for the procurement of BGS supply for the period starting in August 2002 to July 2003 (NJ BPU, 2001).

The same process was followed for the procurement of BGS supply for the next three years, and the process participants were essentially similar to those listed above. The outcome was also similar in the sense that the BPU approved the joint proposals offered by the four utilities in each year with minor changes.

In approving the BGS auction process and the associated BGS tariffs, the BPU was guided by several explicit goals of the restructuring statute. These included removing cross-subsidies among customer classes, encouraging peak load management, giving customers more control over their energy costs, eliminating switching restrictions, and providing transparent market-based prices (NJ BPU, 2004b). Overall, BPU staffThe primary goal was to improve the economic efficiency of the electricity system, including the level of retail and wholesale competition as well as demand response (NJ BPU, 2004b). They indicated that conveying real-time prices to customers would provide the truest possible price signal upon which customers could modify their behavior. Furthermore, BPU staff expected that at least some peak load reductions would occur as a result (NJ BPU, 2004b).

During the development of the BGS auction proposals, some points of contention arose between stakeholders. With respect to the hourly-priced service for CIEP customers, contentions centered on the procurement process, customer size thresholds, scope and size of the risk adder, and the scope and size of the retail adder. The main stakeholder arguments surrounding each of these issues are described briefly below:

Procurement Process

In 2001 when the auction process was a new concept in New Jersey, BPU received many arguments for alternate processes, alternative designs for the auction, and alternate procurement periods. BPU had considered all these alternatives and only then had chosen the EDC-proposed auction process. In 2002, BPU decided to split the 2001 auction into two individual auctions for different types of products and applicable to different classes of customers. By 2003, it was clear to all stakeholders that the auctions held in both 2001 and 2002 were successful. Consequently, no arguments for alternative mechanisms for procurement of BGS supply were made by any of the stakeholders in 2003 (NJ BPU, 2002, 2003, 2004a).

Customer Size Threshold

Most large customers did not oppose the establishment of RTP as the default rate. However, some large customers did object in 2003 when the BPU decided to change the customer class definition from a voltage-level to size, since this expanded the eligible customer population (NJ

BPU, 2003). The large customers who were initially eligible for RTP were part of the new CIEP class, but as a result of the new class definition, 128 other customers with peak demand >1.5 MW were added to the CIEP class. The same issue arose in 2004 when the BPU lowered the CIEP size threshold to 1.25 MW. Exemptions for hardship cases such as hospitals were sought during the hearings. However, BPU ruled against granting these exemptions (NJ BPU, 2003, 2004a).

Scope and Size of the Risk Adder

One issue that was contentious during the legislative hearings was the inclusion of a risk adder, known as the Default Supply Service Availability Charge (DSSAC). The utilities argued that the DSSAC was a necessary component to make BGS-CIEP an attractive product to competitive suppliers, who will be bidding for the right to wait to serve eligible customers who may never take BGS-CIEP service. Customer groups and some suppliers argued that the DSSAC was not necessary or alternatively should only apply to BGS-CIEP customers and not to eligible customers that had switched to competitive suppliers (NJ BPU, 2003). BPU staff suggested that the DSSAC should be set at 0.01 ¢/kWh.[132] Eventually, the BPU split the difference and set the DSSAC at 0.015 ¢/kWh which it estimated would produce revenues of approximately $1.8 million - adequate to attract bidder interest in providing the service. The BPU believed that structuring the BGS-CIEP auction to attract more bidders would result in lower bids for capacity, which, in turn, would potentially benefit all BGS-CIEP customers and offset the relatively minor DSSAC (NJ BPU, 2002).

Scope and Size of the Retail Adder

A number of stakeholders proposed that a retail adder be included in the price that BGS-CIEP customers pay. Competitive suppliers argued that it was necessary for BGS service to reflect the cost of providing electric service at retail, including marketing costs, risk and portfolio management costs, working capital costs, administrative expenses, and profit margin (NJ BPU, 2003). Utilities supported this position arguing that a higher retail adder would attract more bidders to the BGS auction. Customer groups were against the retail adder arguing that a sufficient number of bidders and competitive suppliers are already active in the NJ retail market (NJ BPU, 2003). The BPU decided in favor of the adder and imposed a retail margin of 5 mills per kWh on BGS-HEP customers.[133] The BPU also intended to gradually expand the number of customers on hourly pricing and wanted these larger customers to be given appropriate price signals to encourage the development of retail competition (NJ BPU, 2002).

[132]The level of the DSSAC was somewhat subjective, given the lack of actual experience in that area. BPU staff had calculated that a DSSAC of 0.01 ¢/kWh would produce approximately $1.5 million annually (or $1.2 million for the 10 month period proposed to synchronize with PJM) and should be sufficient for providing this service (NJ BPU, 2003).

[133]At that time, the BPU strongly believed that retail margin revenues received by utilities were customer supplied funds that must be returned to customers. However, the BPU did not make a determination as to how those funds should be returned to customers and directed the utilities to maintain the BGS-CIEP retail margin revenues in a deferred account with interest (NJ BPU, 2002).

Stakeholder Perspectives on RTP and DR

Both BPU and utility staff acknowledged that DR is an essential component of a well-functioning electricity market in addition to other components. However, they also noted that no subsidies or special attention are necessary to encourage DR in electricity markets (NJ BPU, 2004b; PSE&G, 2004; PSE&G, 2005; JCP&L, 2004). For its part, the BPU has actively promoted customer participation in PJM's Load Response Programs and currently participates in the Mid-Atlantic Distributed Resources Initiative (MADRI) – a collaborative effort between state public utility commissions, PJM, and DOE to promote the development of DR resources in the Mid-Atlantic region through coordinated DR policies and markets.

Both regulators and utility representatives note that RTP is only one of many ways for eliciting DR. PSE&G staff also pointed to the indirect effects of default RTP – that establishing RTP as the default rate has facilitated the deployment of interval meters for all C&I customers >750 kW which in turn has enabled these customers to participate in DR programs or take service on hourly pricing options with competitive suppliers (PSE&G, 2005). Similarly, PSE&G staff pointed out that customers are generally more well-informed now because of the educational workshops held by the utilities which have helped them to understand the consequences of being exposed to variable prices (PSE&G, 2005).

Utility staff rated availability of transparent prices, customer education, price volatility, and technical assistance as important conditions for customers to participate in RTP (PSE&G, 2004; PSE&G, 2005; JCP&L, 2004; JCP&L, 2005). PSE&G staff indicated that over the long-term, they expect that RTP offered by utilities and/or competitive suppliers could generate significant levels of DR (PSE&G, 2005). Overall, both PSE&G and JCP&L staff believe that utilities should have a direct role in developing DR via customer education and facilitating the adoption of enabling technologies (PSE&G, 2005; JCP&L, 2004).

Default Service Implementation

Statutory Requirements	**Implementation Process**	**Issues Addressed in Implementation Phase**	**Status**
Utility provides default service; statute gives BPU the authority to develop default service rules	Joint proposal from utilities followed by submittal to BPU and comments from all stakeholders	Procurement process; tariff design; customer eligibility thresholds	BGS-CIEP service established in August 2003; customer size threshold now stands at >1.25 MW

Performance

Approximately 1900 of the largest C&I customers in New Jersey, representing about 2900 MW of combined peak load, are eligible for BGS-CIEP default service. Currently, about 680 customers take service on BGS-CIEP. However, the majority of these customers are among the smallest in the CIEP class and account for only 461 MW of combined peak load. Utility staff indicated that the main reason these smaller customers have not left BGS is the lack of interest shown by the competitive suppliers (PSE&G, 2004; JCP&L, 2004).

A number of smaller customers outside of the CIEP customer class have opted into BGS-CIEP service since August 2004. Currently, 61 such customers, accounting for 25 MW of combined peak load, take service on BGS-CIEP. Interestingly, most of these opt-in customers have relatively small peak loads, and only 9 opt-in customers have peak loads that exceed 750 kW (BGS Auction, 2005).

Information about what portion of the load served by competitive suppliers is on an indexed rate is not available. Similarly, there have been no studies to estimate the DR impacts of the CIEP customers placed on the default rate (NJ BPU, 2004b).

BGS-CIEP Participation Statistics

Eligible Customers		Participating Customers	
Number	**Combined Peak Load (MW)**	**Number**	**Combined Peak Load (MW)**
Default = 1877 Eligible to opt-in = 482,000	Default = 2920 MW Eligible to opt-in = ??	Default = 677 Eligible to opt-in = 61	Default = 461 MW Eligible to opt-in = 25 MW

New Jersey customers can also participate in PJM's Load Response Programs via a registered Curtailment Service Provider. PJM recently estimated that customers of New Jersey's IOUs accounted for 80 MW and 26 MW of enrolled peak load in PJM's Economic Load Response Program and Emergency Load Response Program, respectively, in 2004 (PJM, 2005). PJM also estimated a maximum load reduction of 6 MW achieved by New Jersey participants in the Economic Program. However, this level of load reduction should be interpreted with caution, as the price level at which these reductions occurred was quite low ($0.45/kWh) compared to the smaller load reduction events that occurred in New Jersey at much higher price levels. It should also be noted that these enrollment and load reductions statistics include all customer classes and not just large C&I customers.

PJM Load Response Program Participation Statistics

Eligible Customers		Participating Customers	
Number	**Combined Peak Load (MW)**	**Number**	**Combined Peak Load (MW)**
n/a	n/a	n/a	Economic = 80 MW Emergency = 26 MW

PJM Economic Load Response Program Load Response Statistics

Maximum Load Reduction (MW)	Price ($/kWh)
6 MW	0.45 $/kWh

Key Findings & Implications

New Jersey's experience with implementing utility RTP tariffs occurred in anticipation of the end of the mandatory transition period. Having fully divested their generation assets, New Jersey's four IOU's jointly proposed establishing RTP, known as BGS-CIEP, as the sole default service for large C&I customers. This structure has since been adopted by the NJ BPU in each of the years since the end of the transition period in 2003. Additionally, the eligibility thresholds for default RTP have been successively lowered, and customers outside of the large C&I class have become eligible to voluntarily elect BGS-CIEP service. The total customer population eligible for BGS-CIEP service, therefore, has increased significantly since the time when the tariff was first implemented in New Jersey. Although stakeholders initially did not object to establishing RTP as the default service for large C&I customers, further expansion of the CIEP class may encounter some resistance from customer groups.

The other key findings drawn from New Jersey's experience with implementing default RTP are summarized below:

- The BPU's primary goal in establishing RTP as the sole default service for large C&I customers was to increase the economic efficiency of New Jersey's electricity markets, including the facilitation of DR and not simply the promotion of competitive retail and wholesale markets.
- Since the initial implementation of BGS-CIEP tariffs, most eligible customers have switched to competitive supply contracts. Of those customers that continue to take service on BGS-CIEP as default service, the majority are among the smallest in the CIEP customer class. Of the small population of customers outside the CIEP class that have opted onto BGS-CIEP service, the majority are smaller C&I customers with peak loads less than 750 kW.
- The BPU has taken the leadership role in developing DR and DSM programs in New Jersey. For their part, the utilities firmly believe that they should have a direct role in facilitating DR via customer education and deployment of enabling technologies, despite having fully divested their generation assets. Neither the utilities nor the BPU believe that enabling technologies should be subsidized, however.
- The BPU expected default RTP to induce some DR, but utility staff point to the importance of the indirect DR effects of default RTP in that it has facilitated deployment of metering infrastructure and increased the level of customer education and awareness regarding energy costs and hourly pricing.

New York – All IOUs Except Niagara Mohawk Power Company

Background: Market and Regulatory Context

Electric industry restructuring in New York was negotiated individually for each of the state's investor-owned utilities (IOUs). For most utilities, customer choice was introduced through a phased implementation beginning with the largest customer classes and ending with the smallest. The last transition periods ended in July 2001; all customers in New York have been able to choose their electric commodity supplier since then.

For most New York utilities, RTP was not considered for default service when restructuring was implemented (NYPSC 2004b). The exception is Niagara Mohawk Power Corporation (NMPC), which initiated and adopted day-ahead RTP as the default service for its largest customers in 1998. For the other utilities, RTP has been discussed and implemented in subsequent proceedings as interest in demand response (DR) and day-ahead market pricing has grown in New York subsequent to restructuring.

This case study focuses on the discussion and process under which RTP has been addressed for the non-NMPC New York utilities – Consolidated Edison Company (ConEd), New York State Electric and Gas Corporation (NYSEG), Central Hudson Gas & Electric (CHG&E), Orange & Rockland Utilities, Inc. (O&R) and Rochester Gas & Electric Corporation (RG&E).[134] Because default service does not include RTP and varies across these five utilities, we do not focus on the structure of these tariffs, except where they have direct bearing on RTP issues.

Wholesale Market Structure

A major facet of restructuring in New York was the establishment of the New York Independent System Operator (NYISO) and several wholesale power markets: the NYISO Day-Ahead Market (DAM), Real Time Market (RTM), Ancillary Services Market (ASM), and Installed Capacity (ICAP) Market. Though the details of each utility's restructuring provisions vary, all utilities divested over 90% of their generation assets, unbundled commodity from their other service components and the transitioned toward retail competition for all customer classes.[135] Ultimately, the end state in New York envisioned by regulators is to have electric commodity supplied primarily by competitive suppliers, with regulated utilities providing distribution services and default supply for those customers that need it (NYPSC 2004a, NYPSC 2004b, CHG&E 2005). Consistent with this goal, the utilities are moving away from earning profits on commodity provision, and default rates are increasingly designed to pass through the utility's market supply purchases. For the non-NMPC utilities, this is accomplished on an average, not hourly, basis, with rates re-set periodically (e.g., monthly, every 6 months or year) to reflect costs during the previous period.

Utility Experience with RTP and Demand Response

[134] The NMPC experience is the subject of another study (Goldman et al. 2004).

[135] NYPSC staff emphasize that full unbundling of all service components has not yet been implemented for most NY utilities, yet unbundling of the distribution service from commodity was necessary and completed to enable the transition to retail competition. In this case study, we consider NY utilities to be unbundled in this latter sense.

In 1998, when electric industry restructuring was implemented, demand response (DR) was not a major concern of New York Public Service Commission (NYPSC) staff because wholesale markets had not yet been established and prices were expected to be low (Goldman et al. 2004). Thus, RTP and other DR options were not considered for most New York utilities; it was only after price spikes and volatility were observed in wholesale markets that DR became a primary focus of NYPSC regulators.

Since 2000, several strategies have emerged in New York to deal with DR issues where large customers are concerned. The NYISO has established three statewide demand response programs: (1) the Emergency Demand Response Program (EDRP) is a voluntary program that pays a floor price of $500/MWh for curtailments during emergencies, (2) the Installed Capacity/Special Case Resource (ICAP/SCR) program allows customers to bid into capacity markets and (3) the Day-Ahead Demand Response Program (DADRP) allows customers to bid load curtailments into the NYISO day-ahead market.[136] During system emergencies, public appeals to conserve are issued from the governor's office or other state officials. Finally, the New York State Energy Research and Development Agency (NYSERDA) funds peak-load reduction and DR enabling technology investments at large customer sites through several ratepayer-funded programs.

Default Service: Post Transition

In 2000, the NYPSC ordered the utilities to develop and implement real-time-pricing (RTP) tariffs as an optional service for their large customers, as part of an effort to promote DR, provide economically efficient price signals to customers and promote the retail market. In 2003, very few customers had enrolled in these optional tariffs, and the Commission opened a proceeding to investigate making RTP the default service for large customers. After reviewing comments, the Commission decided to defer the question of default-service RTP and focus on more concentrated marketing and customer education for the existing optional tariffs.

At the same time, retail electricity markets in New York have not developed as initially hoped for. In August 2004, the NYPSC issued a policy statement directing the utilities to make plans to promote migration, particularly for larger customers, and to phase out hedging of utility-provided electric commodity service (NYPSC 2004a). On the subject of default-service rate design, it stated that, "rates should increasingly reflect market prices over time", and that, "in the final stage of a utility's offering of a competitive service, the rates for that service should closely track the unadjusted spot market price", but cautioned that, "customers should not be exposed solely to the spot market until other hedged services are generally available" (NYPSC 2004a). These issues and the utilities' retail access plans are among those discussed in a "Retail Access Collaborative" of utilities, competitive suppliers and other stakeholders.

CHG&E, as part of its compliance with this policy directive, recently filed a proposed tariff revision that would make RTP the default service for its largest customers (> 1,000 kW). In 2005, the NYPSC adopted the utility's proposal.

[136] ICAP/SCR and DADRP are considered firm resources in that they impose penalties for customers that fail to curtail as committed.

Overview of electric industry structure and organization

Customer choice provisions	Transition period terms and timelines	Utility Participation in Retail Market	Wholesale market structure	Wholesale market organization
Retail access implemented for all customers	1-3 year (depending on utility) phased implementation – all transition periods are complete	Utilities are required to provide default service. All have unbundled.	NYISO markets: day-ahead, real-time, ancillary services and installed capacity (ICAP)	Each utility negotiated separate divestiture plans.

Tariff Design and Administration

The optional RTP tariffs offered by the New York utilities are all of essentially the same structure as NMPC's default-service tariff. They are unbundled, one-part RTP tariffs, indexed to the NYISO day-ahead market.[137]

Certain tariff details, such as the specific non-commodity wires charges, vary by utility. The customer size threshold also varies – some utilities have designated RTP for only their largest customers while others have made it available to almost all non-residential customers (e.g., customers with peak demand > 5kW are eligible for NYSEG's tariff). Each utility adds some combination of ICAP or ancillary service charges to the commodity price.

NYSEG is unique among the New York utilities in offering RTP as an information-only tariff. Its RTP customers do not actually pay hourly-varying prices; instead, they pay the default rate and are presented with "shadow bills" that show them what they would have paid on an RTP tariff. The reason for this form of RTP implementation is that NYSEG's billing system has not been upgraded since restructuring and is not capable of handling hourly prices (NYPSC 2004b).

Many large customers already have interval meters installed. Any incremental metering costs are paid for by participating customers, although they may receive NYSERDA incentives to cover these costs (NYPSC 2004b). An ongoing competitive metering proceeding is examining meter deployment issues.

As the administrator of public benefits programs in New York, NYSERDA offers DR-enabling technology incentives and technical assistance to customers statewide. Some utilities also offer customer education on RTP and information systems. The Commission's 2003 Order encouraged the utilities to develop this type of assistance (NYPSC 2003b). For example, as part of CHG&E's transition to proposed default RTP, the company is offering education sessions to its large customers that discuss the procurement process, the wholesale market, RTP, DR and load management (CHG&E 2005). Central Hudson also intends to offer software to large C&I customers, free of charge for at least two years, that would allow them to view their interval data and prices on a day-after basis. Rather than interfering with the retail market, the goal of this assistance is to educate customers about prices and energy management so that they are better equipped to evaluate their choices.

RTP Tariff Design

Applicable Customers	Pricing Structure	Derivation of Prices	Advance Notice	Other Key Provisions

[137] Because the default service tariffs are unbundled, RTP customers pay the same wires charges as default-service customers. The only difference is in the commodity portion of the customer's bill, which is charged at the prevailing hourly rate.

Large, non-residential customers at all (non-NMPC) NY utilities (size class depends on utility)	Unbundled, one-part RTP	NYISO Day-Ahead market	Day-ahead	All RTP tariffs are currently optional. NYSEG's tariff consists of shadow bills only.

Interval Metering Deployment

Deployment of Interval Metering	Estimated Cost of Deployment	Cost Recovery Mechanism of Metering Costs
Large customers already have interval meters at most utilities.		Incremental meter costs are paid for by customers, but may be subsidized by NYSERDA incentives.

Implementation Process and Issues

Statewide Optional RTP

The optional-service RTP tariffs were adopted and subsequently re-examined through NYPSC proceedings. In the late 1990's and early 2000, in response to tight supply forecasts in ConEd's service territory (which includes New York City), the Commission directed ConEd to include load response, in addition to supply-side resources, into its solution to this problem, with a focus on hourly integrated pricing (NYPSC 2004b). This then evolved into a statewide push to expand RTP beyond NMPC's service territory and to offer standardized RTP rates across the state.

In December 2000, the NYPSC ordered all New York electric utilities except Niagara Mohawk to file RTP tariffs to be offered as an optional service (NYPSC 2003a). The Commission's primary goal for optional RTP was to offer customers programs that encourage reduced peak demand and corresponding direct bill reductions, regulate volatility in wholesale markets, and temper market power (NYPSC 2004b). The hope was that it would result in increased levels of DR; at the very least the Commission wanted to move toward efficient prices and observe the load response it provided.

Some of the utilities had issues with offering RTP tariffs (NYPSC 2004b). NYSEG still had bundled default service, so developing an RTP tariff was challenging – this was resolved by offering RTP as shadow bills rather than a billable tariff. ConEd didn't feel that customers would be interested in RTP. Some utilities were concerned about revenue erosion from optional tariffs resulting from self-selection bias by customers with favorable load profiles and would have preferred that RTP be the default service (NYPSC 2004b).

CHG&E supported optional-service RTP at the time, seeing it as an option for customers that would educate them about the retail market (CHG&E 2005). Ultimately, the company plans to exit the merchant function and sees RTP as a means to prepare customers for this by giving them an opportunity to learn about the market. The company did not expect significant incremental DR from optional RTP, since several of its large customers already participate in NYISO DR programs (CHG&E 2005).

Two-part RTP was not considered for any of the utilities. NMPC's prior experience with two-part RTP had raised issues around setting CBL levels and adjusting them going forward that all parties wished to avoid (NYPSC 2004b).

The utilities' filed tariffs were approved by the Commission in the spring of 2001 (NYPSC 2003a). Two years later, very few customers had enrolled; most were in NYSEG's program, which provides shadow prices (NYSPC 2003a). ConEd, with the most pressing need for price-responsive load, had no participants at all. At the same time, continued growth in demand, particularly downstate, and delays in constructing new generation had made supply and reliability concerns "of critical and major importance" (NYPSC 2003a). To address these concerns, the NYPSC initiated a proceeding in April 2003 to evaluate the need for changes in the programs including consideration of default-service RTP for certain customer classes.[138] The stated goals were "to improve the effectiveness of such rates and advance the public interest in demand shifts and usage reductions during peak periods" (NYPSC 2003a).

After a period of public comment, the Commission ruled in November 2003 not to impose default-service RTP and directed the utilities instead to focus their efforts to promote the optional RTP tariffs to their largest customers by targeting their customer outreach and education efforts, working with NYSERDA, training their account representatives and conducting bill impact analysis for individual customers (NYPSC 2003b). Commission staff say that the deciding factor in this ruling was customer comments that exhibited an intense aversion to RTP (NYPSC 2004b). The Order noted that many of the comments opposing default-service RTP were "premised more on a misunderstanding of and apprehension about RTP than on actual shortcomings of RTP" (NYPSC 2003b). In this climate, the Commission decided that making RTP the default service would create such a strong negative reaction that it would set RTP acceptance and response back even further, and that a more effective approach, in the near term, would be to focus more attention on educating customers about the potential benefits of RTP (NYPSC 2004b).

Ultimately, Commission staff would like to see more widespread application of RTP, when a better public reaction is perceived and RTP is better understood and accepted by customers (NYPSC 2004b). Some NYPSC staff believe that RTP would be better offered by competitive service providers, bundled as a package with energy management technologies that enable price response.

Utilities' comments in the default-service RTP proceeding were mixed. ConEd and O&R, filing comments together, opposed default-service RTP on the grounds it would likely elicit "adverse response" from their customers and advocated relying fully on utility or ISO demand response programs instead (NYPSC 2003b). NYSEG and RG&E, commenting together, also opposed RTP. Their arguments hinged on the notion that making RTP the default service would reduce customers' choices, forcing them either "remain with the utilities under a pricing regime unacceptable to the customers or switch to an ESCO".[139] They further contend that implementing default RTP would "create a potentially unlevel playing field between the utilities and ESCOs because the utilities would be directed to impose different, and more onerous, requirements on customers than would the ESCOs" (NYPSC 2003b).

NMPC commented in favor of default-service RTP, as did CHG&E. CHG&E staff explain that the company plans to exit the supply business, while still maintaining provider of last resort

[138] Default-service RTP was termed "mandatory" in the proceeding documents.
[139] In New York, competitive retail electricity suppliers are termed "ESCOs".

responsibilities, and is proactively involved in promoting customer choice (CHG&E 2005). The company's primary goal for default RTP would be to pass through commodity costs as purchased (rather than based on previous month's average purchases, as the default rate currently is), and ultimately encourage customers to migrate to competitive suppliers (CHG&E 2005).

All of the customers and customer representatives that commented in the proceeding were opposed to default-service RTP, primarily due to excessive risk exposure, the expected high cost of mitigating that risk and potential negative bill impacts. All of the comments from competitive suppliers were in favor of default RTP (NYPSC 2003b).

One of the questions explicitly explored in the proceeding was that of which customer classes are appropriate candidates for default-service RTP. Most parties that commented on this issue felt that large customers were the best candidates, asserting that they would be best able to absorb the risks and costs necessary to alter their usage patterns in response to RTP and might also see more significant savings opportunities (NYPSC 2003b). Metering costs also factored into this assessment – large customers in New York already have interval meters installed. Nonetheless, many parties noted that even large customers might not have the ability or willingness to face price risk or respond to RTP price signals. Some suggested that SIC code might be a better determinant than customer size (NYSPC 2003b).

According to Commission staff, very little progress had been made concerning optional-service RTP as of September 2004, as other issues had taken higher priority (NYPSC 2004b). However, in a separate proceeding, RTP has been incorporated as an optional feature on standby rates for customers with onsite generation at all New York utilities (NYPSC 2004b). These rates incorporate fixed "access" charges for the delivery component of service, and volumetric charges for commodity. Customers can choose to purchase commodity at RTP prices, or at a fixed rate. The intent of providing this option is to encourage customers to make more economically rational decisions about when to run their onsite generators. Commission staff note that it's too early to say how many customers are selecting the RTP option (NYPSC 2004b).

CHG&E Default RTP

In November 2004[140], CHG&E filed a proposed tariff revision with the NYPSC that would replace the current default service tariff for customers with peak demand greater than 1,000 kW with day-ahead hourly RTP (CHG&E 2004).[141]

CHG&E's goals in making RTP the default service for its largest customers are to pass through hourly commodity costs and encourage customer migration (CHG&E 2005). The initiative is a direct response to the NYPSC's retail access policy directive issued in August 2004. The company is currently holding seminars with large customers to explain the new rate and give them names of alternative suppliers (CHG&E 2005). With respect to DR, company staff expect

[140] According to CHG&E staff, the company has actually proposed default-service RTP for large customers on several occasions beginning in 2002. This initial proposal was not filed formally. It was discussed with senior NYPSC staff, who were more inclined to concentrate on retail access at the time and didn't feel that default-service RTP was needed or necessarily desirable (CHG&E 2005).

[141] Real-time market prices were not considered for this tariff because most of CHG&E's load is scheduled in the day-ahead market. Similarly, two-part RTP or other hedges were not considered because the focus was on pricing that reflects CHG&E's purchasing (CHG&E 2005).

that default RTP will make customers more aware of electricity pricing, but are unsure about price response because some customers have told them they can't or wouldn't shift load, even under default RTP (CHG&E 2005). CHG&E staff say that:

> *"…many customers have told us they want a fixed price and are willing to pay a premium for it. Nonetheless, they understand that the trend to push them into the retail market is industry-wide… Customers are happy that they're getting help from the utility" (CHG&E 2005).*

The optional RTP tariff will still be available for smaller non-residential customers. The company's decision to make RTP the default service for large customers only is purely practical – only these customers already have the necessary metering installed. CHG&E does not see any philosophical issues with respect to default RTP for certain size classes (CHG&E 2005).

The recent tariff filing also addressed several cost shifting issues that had arisen from the optional tariff, related to the allocation and collection of ICAP[142] and balancing costs.[143] Previously, ICAP costs, along with all other non-energy costs, were averaged across all of CHG&E's customers and collected through a uniform, per kWh charge. The recent filing proposes to determine the ICAP costs separately for the RTP customer class, based on its combined monthly ICAP requirements and the company's monthly average ICAP rate. It also proposes to introduce an energy-balancing component, to collect any costs associated with purchases in the real time energy market. These costs will be averaged over all retail load and allocated to all customers through a uniform per kWh charge. This change is in response to arguments from competitive suppliers participating in the Retail Access Collaborative that a balancing component should be added to reflect the cost that they would have to bear if they offered a day-ahead RTP product (CHG&E 2005).[144] According to CHG&E staff, the net effect of these changes will tend to benefit large customers, because the allocation of ICAP charges will more accurately reflect their relatively flat load shapes. As CHG&E does not profit on the provision of commodity service, any increases or decreases resulting from the implementation of default RTP will be "absorbed" by other full service customers (CHG&E 2005).

Default Service Implementation

Statutory Requirements	**Implementation Process**	**Issues Addressed in Implementation Phase**	**Status**
Regulated utilities provide default service, including optional RTP	NYPSC ordered utilities to develop optional RTP tariffs in 2000. In 2003, a proceeding considered making RTP the default service but decided against it due to customer reluctance.	N/A	Optional RTP tariffs are in place. Central Hudson recently filed a proposal to make RTP the default service for large customers.

Stakeholder Positions on RTP

PUC	**Utilities**	**Competitive Suppliers**	**Customer Groups**

[142] Technically speaking, the product purchased in the NYISO ICAP market is called UCAP (unforced capacity). For simplicity, we call it ICAP here to avoid confusion by those not familiar with this terminology.
[143] These changes, if accepted by the NYPSC, will apply not only to the default RTP tariff, but also to the optional RTP tariff that will continue to be offered to smaller customers.
[144] Competitive suppliers wanted the charge to be determined on a customer-specific basis, rather than on a class average basis, as CHG&E has proposed (CHG&E 2005).

Supports RTP and would prefer to make it the default for large customers. Goals include economic efficiency, DR and promoting retail market competition.	Central Hudson supports default RTP as being consistent with the goals of promoting retail competition and utility pass-through of commodity costs. Other utilities oppose it on the grounds that customers won't accept it.	Most support default-service RTP.	Oppose default-service RTP – concerned about risk and bill impacts.

Performance

Very few customers have opted to enroll in the RTP tariffs offered in New York. CHG&E, O&R and RG&E currently have no customers enrolled, and two customers have recently opted for ConEd's tariff (NYPSC 2004b). NYSEG's tariff has seen the largest subscription – about 30 customers – but as it only offers shadow bills it does not entail any risk to customers. NYPSC staff attribute low customer interest to the complexity of RTP and its unattractiveness relative to default service tariffs, noting that utility analyses found that only a small percentage of customers would have lower bills on RTP, absent load shifting (NYPSC 2004b). According to NYPSC staff,

> *"RTP is very complicated – customers need energy management systems and dedicated energy purchasers, and incur significant additional costs, to respond to it. Most don't view this as a priority – they focus instead on making widgets or whatever else they do. They expect the utility to provide the best price for reliable service. On the other hand, customers are willing to respond to public appeals to reduce usage." (NYPSC 2004b)*

The two customers that have recently signed up for ConEd's tariff provide an interesting case study. Both are residential housing co-operatives in New York City. They are master-metered on RTP, but the tenants' sub meters are on time-of-use rates with several time blocks. Signing up for RTP was a tenant initiative – they intend to shift load and save money (NYPSC 2004b). An issue that has arisen for the first of the two buildings to sign up is the potential disincentive to shift load posed by increases in the building's demand charge, even though the new demand charge is set on a Sunday afternoon when system load is low (Harper-Slaboszewicz 2004). To address this problem, the co-op has requested a change to the RTP rate schedule to make the demand charge be time-differentiated.

Although CHG&E's tariff currently has no customers enrolled, rate department staff say that customers have tried it and subsequently left (CHG&E 2005). Staff attribute this to two factors: (1) lack of customer understanding of the program, despite efforts to educate customers, and (2) difficulty comparing hourly pricing to default service rates. This difficulty stems from the fact that the default rate, which changes monthly, is based on the previous month's commodity purchases (e.g., November's market purchases are reflected in December's bill), while RTP prices are day-ahead. Customers that have experimented with the RTP rate naturally compare their RTP bill to what they would have paid on the default rate. According to rate department staff, some customers have gone on RTP for one month and paid high prices, but only because market prices were higher than the previous month. They don't understand that they need to take a longer-term view in comparing the rates (CHG&E 2005).

CHG&E staff expect that some customers, particularly smaller ones, might stay on the proposed default service RTP tariff, depending on the market for alternative pricing options offered by third party suppliers (CHG&E 2005). The level of price response would depend on how many, and which, customers migrate to a retail supplier, as well as the pricing options offered. While utility staff expect that default RTP should increase price and load profile awareness, ultimately, the amount of time that customers can spend managing energy will determine how much response is possible (CHG&E 2005).

While RTP has seen little customer interest in New York, the NYISO DR programs have been successful at attracting participants and delivering load reductions. The most recent program statistics show that the two emergency programs, ICAP/SCR and EDRP, have about 2000 customers enrolled statewide (NYISO 2004). Neither of these programs were called in 2004, but in previous years response has been significant (Neenan et al. 2003). DADRP, an economic bidding program, is less popular, with only 17 participants (NYISO 2004).

RTP Participation Statistics

Eligible Customers		**Participating Customers**	
Number	**Combined Peak Load (MW)**	**Number**	**Combined Peak Load (MW)**
CHG&E: ~10,000 demand metered accounts eligible for optional RTP; 62 accounts will be affected by default service RTP if approved	CHG&E: 340 MW will be affected by default service RTP if approved	CHG&E: 0*	CHG&E: 0 MW

* some large customers have opted in and then back out of CHG&E's optional RTP tariff, but currently there are no customers enrolled.

RTP Load Response Statistics

Maximum Load Reduction (MW)	**Price ($/kWh)**
No data	*No data*

Other Utility DR Program Participation Statistics

Eligible Customers		**Participating Customers**	
Number	**Combined Peak Load (MW)**	**Number**	**Combined Peak Load (MW)**
n/a	n/a	CHG&E has 12 customers enrolled in NYISO programs	*No data*

Other Utility DR Program Load Response Statistics

Maximum Load Reduction (MW)	**Price ($/kWh)**
No data	*No data*

Key Findings & Implications

Although restructuring in New York has not engendered the dramatic events faced in California, higher-than-expected prices and price volatility (particularly in the downstate region) and somewhat lackluster retail market development have created mixed response among customers. The process in which RTP is being pursued in New York – initiated by Commission proceedings, in large part to promote DR, and implemented by investor-owned utilities – is also similar. In addition, the mix of large customers in New York – industrial and government/educational facilities in the upstate region and large office buildings downstate – is probably more similar to California's large customer base than most other states.

Given these parallels, the following lessons from the New York experience are relevant to California's efforts to implement DR through dynamic pricing options:

1) Customer education takes time, and is critical to RTP success. Despite six years of retail and wholesale market exposure, there is consensus that most large customers in New York still lack the willingness and/or capability to face hourly prices and that many do not have the resources to manage energy usage. Although NYPSC regulators would prefer to implement default-service RTP, they acknowledge that without customer acceptance it will not achieve DR objectives.
2) Utilities' positions on RTP are defined by how they see their role in retail markets. In New York, the utilities most supportive of RTP are those that see themselves as distribution companies, not commodity providers (NMPC and CHG&E). Comments from other utilities that oppose RTP (e.g., on the grounds that it creates an uneven playing field) suggest they still see themselves as competing to retain customers for commodity service.
3) Default RTP is most tractable when implemented with retail market development as a primary goal. In New York, the most progress toward default RTP has been made when it is implemented as part of a strategy to provide pricing structures that complement and promote customer migration. Attempts to implement RTP for DR purposes have not been successful in the current climate.

Ohio – Cincinnati Gas & Electric

Background: Market and Regulatory Context

Ohio's electric restructuring legislation (SB3) was passed in 1999. Utilities were mandated to unbundle generation, transmission, and distribution charges and provide open access to other generation suppliers. Utilities were also mandated to file corporate separation plans to guard against unfair competitive advantage gained from corporate affiliation between utilities and competitive retail suppliers (ORC 2005a).

Transition Period

Customer choice began in January 1, 2001. This also marked the beginning of the Market Development Period (MDP) during which utilities were mandated to offer frozen retail service rates to all customers. This MDP was originally designated to be five years for all service territories with the exception of Cincinnati Gas & Electric (CG&E) for which MDP was to end on December 31, 2004.

In 2003, the Public Utilities Commission of Ohio (PUCO) judged that, in certain service territories, additional time was necessary beyond the MDP to allow the retail market to mature and wholesale electricity prices to stabilize (PUCO, 2003d). However, under SB3, the MDP cannot be extended beyond 2005. To accommodate this facet of the legislation, the PUC ordered Dayton Power & Light (DP&L), FirstEnergy, American Electric Power (AEP), and CG&E (in separate cases spanning the end of 2003 and the beginning of 2004) to submit rate stabilization plans. These plans are intended to provide fixed rates to customers through 2008 but would, in principle, allow utilities to adjust their rate structures to allow for changes in their cost of service since rates were frozen in 2001.

Wholesale Market Structure

Divestiture of generation assets was not an explicit requirement under the corporate separation rules of SB3. However, all of Ohio's utilities have divested at least part of their generation assets to unregulated affiliates or merchant generators. In terms of wholesale market exchanges, all of Ohio's service territories have recently become members of either the PJM Interconnect (DP&L and AEP) or the Midwest ISO (CG&E and FirstEnergy). PJM members have access to all PJM markets including hourly wholesale energy markets (real-time and day-ahead), capacity markets, and ancillary service markets. MISO members are scheduled to have access to MISO's newly established energy markets beginning in April 2005.

Retail Market Development

SB3 contains no explicit restrictions on utility participation in retail markets, but the PUCO promulgated rules in early 2000 which stipulated that utilities offering noncompetitive electric retail services may not also offer competitive electric retail services. The PUCO rules allow for some limited exceptions to this rule on a case-by-case basis. Since customer choice began, 34 competitive generation suppliers, aggregators, brokers, and marketers have been licensed to operate in Ohio (PUCO, 2003b). In addition, a large number of government and municipal aggregators have also been licensed as competitive suppliers and have accounted for a substantial portion of retail activity.

Statewide switch rates for residential and commercial customers were 22% and 23%, respectively, in terms of the number of customers taking service from a competitive retail provider as of March 31, 2004 (PUCO, 2004c). Among states with retail choice, these switch rates are comparably high. Nearly all of this switching has occurred in the service territories of FirstEnergy, however, and is primarily due to the success of government aggregation programs. Statewide, over 170 municipalities and local governments have participated in aggregation programs, the largest of which is the Northeast Ohio Public Energy Council (NOPEC). Outside of these programs, switch rates are modest at best compared to other states with retail choice, prompting the PUCO to effectively extend the MDP, via rate stabilization plans, to 2008 so as to allow for further development of the retail market.

Switch rates among industrial customers are significantly lower than for smaller customers – around 20% in terms of both customers and sales – a marked contrast from other states with retail competition where industrial switch rates are typically much higher (PUCO, 2004d). Again, industrial switching in Ohio is heavily linked to aggregation programs, although a third of industrial switching has occurred in DP&L's service territory where aggregation programs do not have a large presence.

Default Service: Post Transition

SB3 designates the distribution utilities as the default service provider following the MDP. SB3 defined default service as a choice between a "market-based standard service offer" (MBSSO) or a competitive retail service priced through a competitive bidding process (ORC 2005b). In August 2001, the PUCO initiated a proceeding to further define the terms of POLR and default service. In December 2003, the PUCO adopted rules which defined the market-based standard service offer as being "based upon a transparent forward, daily, and/or hourly market" (PUCO, 2003c; OAC 2005).

Utility Experience with RTP and Demand Response

CG&E's previous experience with RTP is limited to its voluntary, two-part RTP tariff, offered since 1996. CG&E began offering the voluntary tariff in anticipation of retail competition in Ohio with the intention of providing additional tariff options to customers that provided opportunities for energy cost savings, either through price response or building incremental load at lower average prices (Barbose et al, 2004). Before customer choice began in Ohio, approximately 250 customers were participating in CG&E's voluntary RTP tariff. Since then, many RTP customers have switched to competitive suppliers and current enrollment stands at approximately 140 customers. CG&E also offers a broad set of incentive-based demand response programs marketed under the "PowerShare" banner and include two basic program types – the Call Option and the Quote Option. Both programs provide payments for load reductions during events called by CG&E. The Call Option provides higher incentive payments but requires firm commitments and includes penalties for nonperformance. In contrast, the Quote Option is completely voluntary, with no firm load reduction commitments but lower incentives (Rogers 2002).

Overview of electric industry structure and organization

Customer choice provisions	Transition period terms and timelines	Utility Participation in Retail Market	Wholesale market structure	Wholesale market organization
All customer classes have had retail choice since January 1, 2001	Retail rates frozen through the end of the transition period (Dec 31, 2004 for CG&E, Dec 31, 2005 in all other service territories); rate stabilization ordered for an additional three years	Utilities required to unbundle retail services and file corporate separation plans; utilities offering noncompetitive retail services cannot also offer competitive services	All service territories are part of either PJM or MISO; liquid bilateral market	Divestiture not required by law, but all IOUs have at least partially divested; generation now owned by utilities, unregulated affiliates, and merchant generators

Tariff Design and Administration

With the prospect of rate stabilization plans effectively extending the MDP through 2008, the exact structure of post-MDP default service in Ohio remains uncertain. In the following section, we describe the default service framework established by the PUCO rulemaking as well as the default service proposal submitted by CG&E in early 2003. This comparison illustrates two very different visions of post-transition default service in Ohio's electricity market. Finally, we describe CG&E's new default service structure that resulted from a negotiated stipulation to its original proposal.

PUC Default Service Rules

Under the PUCO's December 2003 rulemaking, default service for residential and small commercial customers who do not actively choose a competitive retail provider at the end of the MDP is defined as a fixed rate established through a competitive bidding process (CBP) with the option to choose a market-based standard service offer (MBSSO) (PUCO, 2003c). The PUCO defined the MBSSO to be a variable rate "based upon a transparent forward, daily, and/or hourly market". Under POLR conditions, default service is defined to be only the MBSSO. For large customers, utilities may choose whether to use the MBSSO rate or the fixed-price rate as the automatic default service but are required to offer the other rate as an optional service. In terms of switching rules, default service customers who take service at the end of the MDP can opt out at any time. POLR service customers can also opt out any time. Customers who do not take default service at the end of the MDP but choose it later are subject to any minimum contract periods, exit fees, or price adjustments that may be required by the serving utility.

The PUCO's rulemaking implies that the MBSSO rate could take the form of a one-part RTP, but the PUC explicitly allowed for a significant degree of flexibility in the specific design of the MBSSO. Similarly, the PUCO has explicitly allowed for utilities to exercise their preferences in other aspects of compliance tariff design, including the source of market prices, the form of bids allowed under CBP for default service, and whether the automatic default for large customers will be fixed or variable-price service (OAC, 2005). The PUCO has yet to promulgate any rules that further define the rate design of default service tariffs.

CG&E's Original Default Service Proposal

Several months before the PUCO issued the default service rules described above, CG&E filed a petition to modify its tariffs in compliance with then undefined post-transition default service mandates in SB3. Under CG&E's proposal, their post-transition standard service offer for customers with demands of 100 kW or more and not taking generation service from a competitive supplier at the end of the MDP would include a choice between five different options for generation service (PUCO, 2003a).

Three of these offerings were designed as fixed-price services – Rider SEP-FPY (fixed annual price option), Rider SEP-FPV (variable term fixed price option), and Rider CB (competitively bid generation option). The two other options for generation service under CG&E's proposal were dynamic-price services – Rider SEP-HP and Rider SEP-HPF. Customers who do not affirmatively choose one of the above generation riders would default to the fixed annual price option, Rider SEP-FPY. The two dynamic-price services are thus optional services by design under CG&E's default service proposal .

Riders SEP-HP rider was proposed as a one-part RTP tariff based on day-ahead hourly prices, and Rider SEP-HPF was proposed a two-part RTP tariff using day-ahead hourly prices and a fixed-price CBL. The level of the CBL would be negotiated bilaterally between CG&E and the customer before generation service under Rider SEP-HPF would begin. Hourly prices for both riders would be derived from the Intercontinental Exchange's published index of day-ahead hourly prices, with customers receiving advance notice of prices by 3pm of the preceding day. The fixed prices applied the CBL would be derived from current wholesale forward prices over the term of the customer contract. Peak- and off-peak forward prices would then be translated into hourly values using statistical modeling and simulation and then weighted and averaged using historical load data or standard load profiles. If demand fell below the negotiated CBL, customers would receive retail credits at the hourly retail price.

Both Rider SEP-HP and Rider SEP-HPF include a program charge of $150 per billing period to cover the additional billing, administrative, and communications costs associated with the provision of hourly-price service. Both riders were also designed to include four separate adders: a 7% loss adjustment factor, a 13.4% operating risk factor, a 1.5% adjustment for uncollectibles, and a 4% adder to cover expected bid-ask differences. Demand charges were not included in any of the generation service proposals described above but are included in the parent distribution service rates (Rates DS, DP, and TS).

Customers that choose to take service under either of the proposed hourly-price generation riders would be required to have interval meters installed and connected to a dedicated phone line to enable remote monitoring of customer loads. CG&E provides intervals meters to customers with demands 500 kW and above at no charge. Customers with demand less than 500 kW that do not have interval meters would be required to pay installation costs. CG&E's proposed Riders SEP-HP and SEP-HPF do not specify minimum contract periods and contract lengths would be negotiated bilaterally on a case-by-case basis.

CG&E's Approved Default Service Rates

CG&E negotiated a stipulation to its rate proposals that was approved by the PUCO with minor modifications in December 2004 and became effective on January 1, 2005 (PUCO, 2004a). Under the terms of the stipulation, default service for large customers who did not affirmatively choose to take generation service from an alternate provider by January 1, 2005 is now a fixed-price service with no other pricing options (PUCO, 2004b). The stipulation also established a market-based variable rate for customers who return to CG&E generation service after January 2, 2005. This market-based variable rate takes the form of a one-part RTP tariff with a price floor equal the generation rates in the fixed-price default service. The source of hourly prices for this market-based variable rate is defined as the "dispatch cost of the highest cost generation unit/purchased power to serve CG&E load" (PUCO, 2005).

PUC's Market-based Standard Service Offer Rules

Applicable Customers	Pricing Structure	Derivation of Prices	Advance Notice	Other Key Provisions
Utilities can designate MBSSO as automatic default service for large customers; under POLR conditions, MBSSO applies to all customer classes	Based on transparent forward, daily, and/or hourly market	Specified by each utility in compliance tariffs	Specified by each utility in compliance tariffs	

CG&E's Original Default RTP Tariff Proposal

Applicable Customers	Pricing Structure	Derivation of Prices	Advance Notice	Other Key Provisions
>100 kW customers taking distribution service at secondary, primary, or transmission level voltage	Rider SEP-HP is a one-part RTP tariff; Rider SEP-HPF is a two-part RTP tariff	Day-ahead hourly prices derived from *ICE* day-ahead hourly price index; fixed prices derived from on- and off-peak forward prices over the contract period, weighted by expected load profile	3pm of preceding day via web-based communication software	CBL and contract length negotiated bilaterally on a case-by-case basis

CG&E's Approved Default RTP Tariff for Returning Customers

Applicable Customers	Pricing Structure	Derivation of Prices	Advance Notice	Other Key Provisions
All customers taking distribution service at secondary, primary, or transmission level voltage	One-part RTP with a price floor equal to the fixed-price default service rate	Dispatch cost of the highest cost generation unit/purchased power to serve CG&E's load	none	

Interval Metering Deployment, CG&E

Deployment of Interval Metering	Estimated Cost of Deployment	Cost Recovery Mechanism of Metering Costs
Utility provides meters for all customers >500 kW; all customers taking hourly-price generation service must have interval meters installed; PUC is considering making metering services competitive	??	Customers smaller than 500 kW pay the meter installation costs

Implementation Process and Issues

In the following section, we briefly summarize the history, stakeholders, and issues that arose during the PUCO's default service rulemaking and the separate but parallel rate case surrounding CG&E's default service proposal.

PUC Default Service Proceeding

The PUCO rulemaking proceeding concerning default service design and implementation was initiated on August 30, 2001 when the PUC directed its staff to convene a stakeholder meeting to discuss the subject, which was consequently held in October of that year. No further stakeholder meetings were held, and in February 2003, the PUCO issued it final default service rules. These rules became effective on May 27, 2004 (PUCO, 2003c).

During these rulemaking proceedings, numerous parties filed to intervene. On the customer side, intervenors included the AK Steel Corporation, Cargill Inc., the Office of the Consumers' Counsel, Industrial Energy Users of Ohio, the Kroger Company, the Ohio Hospital Association, and the Ohio Manufacturers Association. On the supplier side, intervenors included MidAmerican Energy, Reliant Resources, the National Energy Marketers Association, Constellation NewEnergy, Dominion Retail, FirstEnergy Solutions, Green Mountain Energy, Strategic Energy, and WPS Energy Services. Ohio's IOUs also intervened in the case – CG&E, Dayton Power & Light, FirstEnergy, and American Electric Power – as well as Ohio's largest municipal aggregator, the Northeast Ohio Public Energy Council.

The PUCO's initial proposed default service rules elicited formal responses from several different intervenors. Below, we briefly summarize the main issues forwarded by these intervenors:

- *PUC jurisdiction in defining MBSSO*. CG&E and other IOUs argued that the PUCO lacked the authority to define rules governing the form and standards for the MBSSO. CG&E argued that because the PUCO defined the MBSSO to be a market-based variable rate, this could have the indirect effect of increasing fixed-price default service rates for CG&E customers (CG&E, 2004). They argued that by requiring utilities to offer only "variable price" service, the rules would effectively drive customers off CG&E's retail service and onto competitively bid fixed-price service. Because CG&E would not win the entire load bid out, the company would be forced to sell supply into less profitable regions and necessarily lose revenue. Since CG&E is the low-price provider in its service territory, some customers would likely end up paying higher prices for fixed-price default service than otherwise.
- *Utility market share*. CG&E argued that utilities should have the right to adjust their retail service offerings according to trends in the competitive market. For example, if market prices fall, CG&E argued that utilities should be able to lower their retail prices so as not to lose market share to competitive retail supplier (PUCO, 2003c). The PUCO countered by arguing that limiting utility offerings to only default and POLR service is necessary to promote the development of competitive retail markets.
- *Availability of fixed-price option*. The PUCO's original proposal defined default service for large customers only as market-based variable rates with no option for competitively bid fixed-rate service. However, competitive suppliers and large industrial customer groups successfully lobbied to amend the proposed rule so that large customers were also eligible choose fixed-price default service.
- *Cost-shifting and/or cross-subsidization issues*. Large customers voiced concern over provisions that allow utilities to recover some the costs of default and POLR service from all distribution service customers, some from default service customers, and some from POLR customers. The PUCO argued in favor of allowing a certain level of flexibility in cost recovery via cross-subsidization and thus implicitly supported some level of cross-subsidization of POLR/default service costs. However, the PUCO also stated their intention

to examine cross-subsidization and cost-shifting impacts associated with default/POLR rates on a case-by-case basis as utilities file compliance tariffs.

During the rulemaking proceedings, the PUCO clearly indicated that one of the main objectives behind using a variable-rate tariff for POLR service customers is to reduce the risk faced by POLR providers. In a broader sense, however, the PUCO's underlying goal of both the fixed-price and variable-price tariff structures was to provide a "plain vanilla" service that would minimize the risk faced by utilities while providing opportunities for the competitive market to offer competitive prices and "value-added" services to customers (PUCO, 2004e). PUCO staff considers such value-added services to include metering, education, and innovative billing, as well as pricing and rates based on customer-specific load profiles and characteristics, i.e. RTP.

CG&E's Default Service Rate Case

In January 2003, CG&E submitted a proposal to modify its non-residential generation rates in compliance with the then-undefined default service tariff mandates in SB3 (PUCO, 2003a). Immediately following CG&E's submission of these compliance tariffs, retailers, power marketers, consumer groups, and other distribution utilities filed intervenor motions with the PUCO. Many of these same parties were also concurrently involved with the separate PUCO hearings that sought to establish rules and structures for these same tariffs. CG&E's main arguments during the rate case hearing were similar to those it offered during the PUCO default service proceedings, namely that the PUCO should not be the entity that determines "market" prices and utilities should be allowed to formulate and adjust its retail service offerings in order to maintain market share (CG&E, 2004).

According to CG&E staff, the utility's goal with its original default service proposal was to continue serving existing customers in the manner that customers want while maintaining reasonable opportunities for company profits. As such, CG&E's original proposal was designed to offer customers the same set of pricing options that a competitive retail provider would offer with the key exception that the price components would be more open and transparent than under competitive offers. CG&E included one-part and two-part RTP rates as optional services to accommodate some customers' stated desire for RTP-based service options, despite the low current enrollment in its voluntary RTP program. CG&E expects that as the market develops in Ohio, more customers will become interested in RTP rates. CG&E staff also considered price response from customers taking RTP service to be a potentially significant benefit to the company, since they are currently short at peak.

CG&E's Approved Default Service Rates

Following the subsequent PUCO order to file a rate stabilization plan, CG&E negotiated a stipulation to its rate proposals that was approved by the PUCO with minor modifications in December 2004 and became effective on January 1, 2005. Under the terms of the stipulation, CG&E will provide fixed-price default service using CG&E's native generation resources (PUCO, 2004b). The stipulation also established a market-based variable rate for customers who return to CG&E generation service after January 2, 2005. This market-based variable rate takes the form of a one-part RTP tariff with a price floor equal the generation rates in the fixed-price default service.

The stipulation represents an exception from the PUCO's default service rules in two ways. First, CG&E necessarily provides the energy commodity for the fixed-price service. Second, the initial fixed-price service rates were established via a confidential market evaluation process by CG&E and stipulation signatories and not via an open, competitive bidding process. Furthermore, future rate adjustments will be made via a series of riders that account for changes in CG&E cost of service.

Stakeholder Perspectives on RTP and DR

In a general sense, CG&E staff strongly believes that demand response is an essential component of well-functioning electricity markets and that RTP is a key mechanism in achieving sufficient levels of demand response (CG&E, 2004). However, CG&E staff does not believe that RTP alone is sufficient and does not think that customers should be forced onto RTP service via default service rules.[145] Rather, CG&E is a strong advocate of offering attractive, two-part RTP as an option within default service. Over the longer term, CG&E staff believes that competitive markets will be able to facilitate adequate levels of demand response, but in the near term, they believe that utilities hold significant efficiencies over competitive suppliers. CG&E staff argues that utilities are often the biggest players in current demand response programs and until wholesale and retail markets are completely mature, competitive suppliers alone may not be able to facilitate sufficient demand response.

For their part, PUCO staff views most aspects of RTP and demand response as services to be offered by the competitive market, and demand response was not a driving factor in its default service rulemakings (PUCO, 2004e). PUCO staff acknowledges, however, that at this point, competitive suppliers in Ohio compete mainly on price and not on the types of value-added services that would enable and encourage demand response.

Default Service Implementation

Statutory Requirements	Implementation Process	Issues Addressed in Implementation Phase	Status
Default service is a "market-based fixed-price service" with "market-based variable-price service" as an option	PUCO rulemaking defined general pricing structure with the goal of providing a "plain vanilla" service that would allow competitive market opportunities to provide value-added services	PUCO jurisdiction over determination of "market prices"; impacts on utility market share; fixed-price service availability for all customer classes; cross-subsidization of default service	PUCO approved final rules in Dec 2003; CG&E filed compliance tariffs but negotiated a stipulation that included some exceptions to PUCO rules; no other utility has filed default service compliance tariffs

[145] CG&E staff notes that making RTP the only default service would tend to distort the market in Ohio, putting the utility at a competitive disadvantage and forcing customers to pay higher average prices (CG&E, 2004). In their specific case, they argue that the vast majority of default service customers would leave RTP service and seek out fixed-price service. If CG&E is not allowed to compete for fixed-price service, customers who are forced to take fixed-price service from competitive suppliers will end up paying higher (i.e. less than competitive) prices because CG&E is currently the low-price provider in its service territory.

Stakeholder Positions on RTP

PUC	Utilities	Competitive Suppliers	Customer Groups
RTP, enabling technologies, and demand response services in general are value-added services that are better provided by the competitive market	Customers should not be forced onto RTP service, but RTP should be offered as an optional service; Offering hedging options is key to getting high RTP participation	??	Most customers do not want RTP service, but some large industrial customers are interested in RTP

Performance

CG&E's newly revised Rates DS, DP, and TS include a one-part default RTP service for customers who return to CG&E generation service after January 2, 2005. Due to its very recent implementation and the dynamic nature of the customer populations eligible for this service, estimates of the number or combined peak load of eligible and participating customers are not yet unavailable. Similarly, estimates of the price response of customers participating customers are also not available.

RTP Participation Statistics

Eligible Customers		Participating Customers	
Number	**Combined Peak Load (MW)**	**Number**	**Combined Peak Load (MW)**
n/a	n/a	n/a	n/a

RTP Load Response Statistics

Maximum Load Reduction (MW)	Price ($/kWh)
n/a	n/a

Some performance data are available for CG&E's PowerShare programs. During summer 2002, customer enrollment in the Call Option program totaled approximately 15 MW of peak load, and enrollment in the Quote Option program totaled approximately 132 MW (Rogers 2002).[146] Since summer 2002, the Call Option program has not been called by CG&E, thus estimates of actual maximum load reductions attributable to this program are not available. However, based on a Quote Option program event called in February 2003, CG&E estimated a maximum load reduction of ~50 MW due to that program (Rogers 2003).[147]

PowerShare Program Participation Statistics

Eligible Customers		Participating Customers	
Number	**Combined Peak Load (MW)**	**Number**	**Combined Peak Load (MW)**
n/a	Call Option = 15 MW Quote Option = 132 MW	n/a	n/a ~50 MW

Key Findings & Implications

CG&E's original default service proposal and the statewide default service rules developed in parallel by the PUCO offer contrasting perspectives on both the nature of default service and the

[146] Enrolled MW for CG&E derived as difference between Cinergy aggregate and PSI (31 – 16 MW for Call Option and 272 -140 MW for Quote Option).
[147] This load curtailment appears to include Quote Option participants in both PSI and CG&E.

development of demand response in restructured markets. The key findings drawn from these contrasting perspectives are summarized below:

- PUCO's underlying goal of both the fixed-price and variable-price tariff structures was to provide a "plain vanilla" service that would minimize the risk faced by utilities while providing opportunities for the market to offer competitive prices and "value-added" services to customers, including metering, education, and innovative billing, as well as pricing and rates based on customer-specific load profiles and characteristics, i.e. RTP.
- CG&E's primary motivation behind the design of its original default service proposal was to offer its customers the same options available from competitive suppliers, including one-part and two-part RTP tariffs. However, CG&E staff does not believe that customers should be forced onto RTP service and does not support RTP-only default service designs.
- PUCO staff views most aspects of demand response as value-added services that are better provided by the competitive market, although they acknowledge that currently most competitive suppliers in Ohio only compete on price and not the type of services that enable or encourage demand response.
- CG&E staff believes that utilities should maintain a direct role in facilitating demand response, not only because utilities hold significant efficiencies over competitive suppliers but also because they believe that Ohio's retail market is not mature enough to facilitate sufficient demand response on its own.

Oregon – Portland General Electric

Background: Market and Regulatory Context

Oregon is taking, as OPUC staff put it, a "cautious approach" to electric industry restructuring (OPUC 2004). The Commission's priorities are to avoid undue cost shifting while fostering a competitive retail market.

Restructuring was initially authorized in Oregon by Senate Bill (SB) 1149, which was primarily designed to open retail markets and did not address rate design issues directly. Oregon's investor-owned utilities (IOUs) were not required to divest generation and wholesale power markets were not established; instead, SB1149 focused on establishing retail access for non-residential customers (OLA 1999). While it became effective October 1, 1999, the first opportunity for customers to switch suppliers did not occur until March 2002 (OPUC 2004, PGE 2004).

Transition Period

House Bill (HB) 3633 was passed by the 2001 Legislature to address concerns stemming from the Western electricity crisis. It ensured that IOUs would continue to offer non-residential consumers a "cost-of-service" option until the PUC finds "...that a market exists in which retail electricity consumers...are able to:

(A) Purchase supplies of electricity adequate to meet the needs of the retail electricity consumers;
(B) Obtain multiple offers for electricity supplies within a reasonable period of time;
(C) Obtain reliable supplies of electricity; and
(D) Purchase electricity at prices that are not unduly volatile and that are just and reasonable." (OLA 2001)

This, in essence, created a transition period of indefinite length.[148] Although the utilities did not divest generation, they were required to undergo a "market valuation" of their assets and perform a transition cost calculation on an ongoing basis (PGE 2004).

Wholesale Market Structure

The wholesale market in Oregon consists of only bilateral transactions. Price indices of transactions at several hubs, Mid-Columbia ("Mid-C") and the California-Oregon border ("COB") are published by a number of entities, e.g., Dow Jones (DJ), Intercontinental Exchange (ICE), and Powerdex.

Default Service

PGE's default service for non-residential customers, Schedule 83, includes four options. The "cost-of-service" option, which customers receive by default, is an unbundled tariff with rates set annually through a Resource Valuation Mechanism (RVM) based on PGE's expected fuel costs,

[148] POLR service has not been an issue in Oregon because the utilities have not been required to divest generation and must continue to offer all direct access eligible customers a standard cost-of-service rate (OPUC 2004).

market purchases and sales, and transmission requirements; capital costs associated with generation plants are set in general rate cases. The other three options are “market-based” rates with TOU prices (peak and off-peak) updated quarterly, monthly, and daily, based on published wholesale market price indices.

Utility Experience with RTP and Demand Response

In the wake of extremely high, volatile prices in 2000-2001, demand response (DR) became a high priority to the Commission and PGE (OPUC 2004, PGE 2004). Several DR programs and strategies have been employed by PGE in the last few years. Non-residential programs have included: (1) a Demand Buyback program in which customers are paid a market-based price for curtailing when called, (2) longer-term demand buybacks, in which a few customers were paid to reduce their electricity usage over several months in 2001, (3) a Blackout Protection program (begun in 2002) in which customers can avoid rotating outages by curtailing 15% of their load when called, and (4) a Dispatchable Standby Generation program, which PGE is currently expanding. PGE also offers time-of-use rates to residential customers and has tested direct load control of residential water and space heating.

In May 2003, OPUC staff issued a white paper on DR, which evaluated the effectiveness of incumbent DR programs and made recommendations about potential future DR options. Among the recommendations was that utilities include DR programs on par with physical generation in their Integrated Resource Plans, and that they file “at least one voluntary real-time hourly or critical-peak pricing tariff” for non-residential customers (OPUC 2003). Moreover, the utilities were advised to consider Georgia Power’s two-part RTP tariff as a model. Overall, the Commission advocated continuing to provide a varied set of DR options to customers, acknowledging the diversity of customer capabilities, needs and motivations.[149] Approved by the Commission in October 2003, RTP was open for enrollment by a maximum of six customers with peak demand in excess of 1 MW in early 2004.

Overview of electric industry structure and organization

Customer choice provisions	Transition period terms and timelines	Utility Participation in Retail Market	Wholesale market structure	Wholesale market organization
Non-residential customers of any size	IOUs must provide a cost-of-service option to all customers until OPUC determines that the retail market is adequately competitive and provides enough options to customers.	Oregon utilities remain vertically integrated (no divestitures). They are required to provide a cost-of-service default rate.	Incremental power needs are met through bilateral trades.	Utilities have not divested their generation, and the wholesale market consists of only bilateral trades.

[149] The report also advised against continuing the long-term buyback program, due to concerns about its cost-effectiveness and staff’s interest in developing rate options based on real-time prices.

Tariff Design and Administration

Schedule 83: Market-based Options

The default electric service for PGE's non-residential customers with peak demand greater than 30 kW is provided through Schedule 83. This schedule is unbundled, and contains the four commodity pricing options introduced above: the default cost-of-service rate and the three market-based options (quarterly, monthly, and daily). Transition cost adjustments are applied on a per-kWh basis to all rates through a separate schedule. Currently, this results in a credit of a few mills.

Every fall, customers can elect to opt out of the default cost-of-service rate for the following year. Customers that do not opt out must commit to the cost-of-service rate for a one-year period to avoid undue cost shifting to other cost-of-service customers. Customers wishing to take service under the market-based rates or from a competitive supplier must opt out of the cost-of-service rate during the open season; they are then committed to taking service for the full year on any combination of the quarterly, monthly, daily or direct access options, with the stipulation that the quarterly and monthly rates require a commitment to each term.[150]

All three of the market-based options are differentiated into on-peak and off-peak prices. The prices for the quarterly and monthly options are based on projected prices at the Mid-C hub. The daily rate is based on the Dow Jones Mid-C Daily On- and Off-peak Electricity Firm Index (DJ-Mid-C Firm Index) for the previous day. Thus, customers on this option have no advance notice of prices applicable each day. Though designed primarily as a stepping block for customers leaving the utility for a competitive supplier, PGE staff noted that some customers do take the daily option indeterminately (PGE 2004).

Real-Time Pricing Pilot

PGE's experimental, voluntary RTP pilot is offered under Schedule 87. Customers with peak demand in excess of 1MW are eligible; the maximum enrollment is six customers. The tariff design is adapted from Georgia Power's two-part RTP tariff design. A CBL is derived based on each customer's historical usage and is billed at the Schedule 83 cost-of-service rate.[151] Hourly deviations from the CBL are debited or credited at the prevailing hourly price. There is no transparent day-ahead market in Oregon. PGE therefore derives the marginal prices for its RTP tariff using prices reported day-ahead by ICE for bilateral deals at the mid-C trading hub for on- and off-peak periods. The utility then shapes these on- and off-peak prices into hourly prices based on hourly prices for the preceding day as reported by DJ, based on the ratio of each hourly price to the average on- and off-peak price for the preceding day (OPUC 2004). Customers receive notification of the next day's prices by 4pm. A 3-mil risk recovery factor is added to this price for consumption above the CBL, and subtracted for consumption below the CBL. T&D-related demand charges, per Schedule 83, and transition cost adjustments are applied only to the CBL (they are fixed at the CBL level of consumption). The tariff also includes an administrative charge of $155 per month to cover billing, administration and communications costs associated

[150] Customers that opt out of the cost-of-service rate but fail to specify which rate they want are placed on the daily option.
[151] There is room to negotiate a slightly lower baseline if the customer's usage changes permanently due to installation of permanent energy-efficiency measures or addition or removal of major equipment.

with the pilot. There are no incremental metering costs for these customers, as all of the eligible customers already have interval meters installed.

PGE staff indicated that a major objective of the program is customer education (PGE 2004). The company has invested in a scenario modeling software tool that shows bill impacts for individual customers. It is used as part of the marketing effort and would be available to participating customers to manage their energy usage on RTP.

PGE actively marketed the RTP pilot for several months in 2004 and some customers have expressed interest in the offering, however, none have yet enrolled. , PGE notes certain differences between RTP and its other customer options (discussed in detail below). The RTP pilot will still be an option for interested customers in 2005 (PGE 2004).

RTP Tariff Design

Applicable Customers	Pricing Structure	Derivation of Prices	Advance Notice	Other Key Provisions
Market-based options: daily pricing for all non-residential; additional monthly and quarterly options for nonresidential >30 kW RTP: non-residential >1 MW (maximum 6 customers)	Market-based options: unbundled rate with peak and off-peak commodity prices RTP: two-part RTP with CBL	Quarterly/monthly options: PGE forward price curve Daily option: DJ Mid-C index RTP: ICE Mid-C day-ahead index shaped by previous day's actual hourly prices reported by DJ	Quarterly/monthly options: 15 days' notice Daily option: none (prices revealed the next day) RTP: day-ahead	For RTP, the CBL is priced at the default cost-of-service rate.

Interval Metering Deployment

Deployment of Interval Metering	Estimated Cost of Deployment	Cost Recovery Mechanism of Metering Costs
Interval meters are installed for large customers.	Individual meters: $320/meter plus $100/installation for large customers, $320/meter plus $30-50/installation for small commercial (OPUC 2003) Network including communications: estimated $25.4 million (OPUC 2003)	

Implementation Process and Issues

Schedule 83: Market-based Options

Overarching goals of the Commission were to approve default service rates based on the utility's cost of service, provide adequate market-based options for customers and facilitate access to alternative retail suppliers (OPUC 2004).

With respect to the market-based options, the Commission's primary goal was to minimize cost shifting from customers leaving the cost-of-service rate. They were designed as a stepping block for customers leaving or returning to PGE service (OPUC 2004). Other goals, shared by PGE, were to provide options to customers as part of the default rate, and to provide information about market-based pricing which, it was hoped, would encourage customers to experiment with managing their loads and energy costs (OPUC 2004, PGE 2004). Nonetheless, OPUC and PGE staff acknowledge that the daily rate does little to promote DR because of the lack of advance notice of prices.

Day-ahead pricing was considered for the standard offer (default) rate but deemed infeasible because the wholesale market in Oregon consists largely of bilateral trades, which presents customer acceptance issues (OPUC 2004). PGE has also discussed internally the possibility of providing day-ahead prices for the daily option, but concluded that due consideration of accuracy, transparency and accessibility of data would be necessary. A goal of the RTP pilot was to test the feasibility of establishing such a day-ahead pricing mechanism (PGE 2004).

According to Commission staff, the process of designing the market-based rate options was relatively un-contentious. The main tariff design issue was a concern that too many market options would begin to replicate potential offers from alternative electricity suppliers and inhibit development of the retail market (OPUC 2004).

Real-Time Pricing Pilot

PGE's goals in initiating the RTP pilot were to: (1) initiate a two-way learning process with customers about price response, (2) promote DR, including intra-day as well as inter-day or seasonal shifting (e.g., PGE hopes customers will shift their load to the spring when hydro runoff reduces power costs), and (3) establish a methodology for developing day-ahead prices (PGE 2004). PGE staff see RTP as a useful tool for educating customers about how costs are derived and to help them realize that they can affect their prices by altering their usage patterns (PGE 2004). PGE does not offer RTP hedging options, and that financial hedges are most appropriately offered by the retail market, not the regulated utility (PGE 2004).

The RTP pilot was proposed by PGE in an advice filing shortly after the Commission issued its white paper requesting the IOUs to implement RTP pilots. After a review process by the Commission staff on certain design details, the pilot was approved without controversy (OPUC 2004).

Commission staff requested changes to three aspects of the tariff design outlined in PGE's proposal, all of which were included in the final tariff design (OPUC 2004). First, PGE's original proposal would have required customers to commit to three years on the pilot; Commission staff suggested revising this to one year to avoid interference with the retail market. Second, PGE originally requested a risk recovery factor of 5 mils per kWh be added to incremental prices. Commission staff felt that it should be lower and that it "should be subtracted rather than added for usage below the CBL so as to cover the utility's risk of undercharging for usage above the baseline and overpaying for load reductions below the baseline" (OPUC 2004). Third, PGE's original proposal for shaping the Mid-C peak and off-peak prices was to use day-ahead load forecasts for the day to which the prices would apply. Commission staff felt it would be more transparent to use the previous day's hourly price and volume data to shape prices. To further address price transparency issues, the Commission instructed PGE to keep full records of its price calculations for future audit by Commission staff (OPUC 2004).

Since introducing the RTP pilot in early 2004, three issues have come to PGE's attention that raise concerns about its appropriateness in the current market context (PGE 2004). First, RTP prices are expected to be higher than the cost-of-service (CBL) prices for 2005. The company is concerned that this creates a situation where "free-riders" – customers that are planning to reduce load regardless of pricing – will be attracted to the tariff. For such customers, PGE notes, "RTP would simply give credits for no real price response". Thus, identifying appropriate candidates is critically important. Second, PGE is emphasizing a commitment to providing stable and predictable electricity prices as part of its current corporate strategy. RTP is potentially at odds with this strategy, since it involves exposing customers to greater levels of price risk. Third, from the beginning, a hurdle for two-part RTP has been sensitivity about offering any product that resembles a derivative. However, without some type of price hedge, RTP is a not an option for many large customers (PGE 2004).

In addition, PGE staff have come to realize that although Georgia Power's objectives and success with two-part RTP were a major inspiration for the pilot (e.g., legitimate, efficient load building – new marginal load at marginal prices), PGE's situation differs from Georgia Power in important ways (OPUC 2004). Georgia Power has historically owned a surplus of generating capacity, and thus a major source of value for RTP was that it enabled customers to build load at marginal-cost based prices. In contrast, PGE utilizes economic market purchases for marginal consumption. Thus, load-building benefits (no demand charges on new marginal load) might only be apparent in targeted areas with excess transmission and distribution system capacity.

In response to these concerns, PGE will continue to offer the RTP pilot for 2005 but will market it selectively. Account managers will offer it to customers that show interest in price responsive rates for unique pricing events (PGE 2004).

Despite the current issues facing the pilot, PGE is still interested in two-part RTP (PGE 2004). Rate design staff believe that the Company can continue introduce customers to day-ahead prices to further customer education around opportunities of time-varying electricity prices. The Company takes a long-term view, noting that:

> *"two-part RTP won't be an overnight sensation; it will take a long time to build. ...It's our belief that a significant amount of load building must occur to build up participation – for this to occur, customers need to see that they can potentially achieve lower average prices...Two-part RTP does not seem to be an attractive program for (non-growth) customers that only have the ability to shed load" (PGE 2004).*

Default Service and Pilot RTP Tariff Implementation

Statutory Requirements	**Implementation Process**	**Issues Addressed in Implementation Phase**	**Status**
Investor-owned utilities are mandated to provide default service; RTP is an optional pilot.	HB 3633 directed utilities to provide a cost-of-service option. Default service rate design was developed in OPUC proceeding. RTP pilot was implemented as an additional, uncontested tariff filing.	Design of default service tariff. Design of RTP pilot.	Default service has been in place since 2002. Marketing of RTP pilot has been scaled back.

Stakeholder Positions on RTP and Market-based Default Service Options

PUC	Utilities	Competitive Suppliers	Customer Groups
Supportive of offering choices to customers and facilitating direct access. Strongly interested in RTP for DR purposes.	Took initiative in developing market-based options and RTP pilot to educate customers about pricing and load response.	Concerned that market-based options replicate potential competitive supply products.	No contentious issues regarding market-based options or RTP pilot.

Performance

Schedule 83: Market-based Options

Relatively few customers have left the default cost-of-service rate option for either a market-based option or a competitive supply arrangement. The first customers to switch to competitive suppliers did so in January 2004; Commission staff feel this is because the retail market has been slow to take off and suppliers simply weren't ready (OPUC 2004). More recent statistics indicate that 4% of PGE's non-residential load is taking service on one of the market-based options (quarterly, monthly or daily) and 7% of its non-residential load has taken service with a competitive supplier (OPUC 2005). Although the daily rate could potentially serve to induce DR, no efforts have been made to measure any price response.

Real-Time Pricing Pilot

No customers have enrolled in the RTP pilot. Commission staff notes that RTP competes with other options, including the Demand Buyback program and direct access (OPUC 2004).

DR Programs

DR in PGE's service territory comes largely from dispatchable programs. The Demand Buyback program previously had 135-170 MW of curtailment capacity (PGE 2003) but has been reduced to ~50 MW because some of the largest participants have left PGE for direct access or self-generation (PGE 2004). PGE is building its Dispatchable Standby Generation program and hopes to have ~30 MW of firm peaking capacity by the end of 2005 (PGE 2004).

RTP Participation Statistics

Eligible Customers		Participating Customers	
Number	**Combined Peak Load (MW)**	**Number**	**Combined Peak Load (MW)**
Daily option: 14,384* RTP: ~150 customers (~250 meters)	Daily option: 1,887 MW* RTP: ~400 MW	Daily option: ~20 RTP: none	Daily option: ~25 MW RTP: none

*These numbers include eligible RTP Pilot Program customer numbers and combined peak load.

RTP Load Response Statistics

Maximum Load Reduction (MW)	Price ($/kWh)
N/A	N/A

Other Utility DR Program Participation Statistics

Eligible Customers		Participating Customers	
Number	**Combined Peak Load (MW)**	**Number**	**Combined Peak Load (MW)**
		1,947**	.6 MW**

**These numbers represent Residential and Small Non-residential TOU customers as of year end 2004.

Other Utility DR Program Load Response Statistics

Maximum Load Reduction (MW)	Price ($/kWh)
Demand Buyback: ~50 MW (PGE 2004) Dispatchable Standby Generation: 9.75 MW (PGE 2003)	Demand Buyback: $129/MWh (average payment) (OPUC 2003)

Key Findings & Implications

In many respects, PGE's experience has direct relevance to California's current context. As part of the Western grid interconnection, Oregon too experienced the high, volatile prices brought on by the crisis of 2000-2001, and PGE now operates in a similar climate of customer mistrust in the wake of rate hikes and price volatility. Oregon, like California's current situation, does not have a transparent day-ahead market to which RTP prices could be indexed, and PGE is short on generation capacity. And Oregon's regulators, like California's, are exploring RTP as part of its efforts to ensure that adequate demand response resources are not only available, but are explicitly included in utilities' resource portfolios.

The following lessons may be taken from PGE's experience:

1) It is important to offer a host of DR programs and price response options. OPUC regulators recognize the savings these programs achieved during the crisis of 2000-2001 and are committed to maintaining and expanding these resources, in addition to exploring RTP.
2) The absence of a transparent, hourly electricity market makes developing price-response challenging. Efforts to integrate day-ahead pricing into PGE's market-based options have been stymied by the lack of a source of prices that would be acceptable to customers. A similar problem exists for RTP. OPUC staff's solution to audit PGE's price calculations addresses the problem in the context of a pilot, but as a full-service tariff may not provide adequate assurance to customers.
3) The Georgia Power model does not work in all contexts. PGE has found that its capacity situation differs substantially from Georgia Power's, making the incentives created by marginal RTP prices *relative to the CBL rate* quite different. Any state or utility considering implementing two-part RTP must carefully evaluate the incentives that relative marginal prices and embedded-cost rates will present to customers and evaluate whether they will meet the goals established for implementing RTP, in the near and long term.[152]

[152] Although marginal prices in California are currently lower than average utility rates (due to expensive power contracts in embedded rates), the incentive this creates is for load building, and not demand response as is the goal for RTP in California. Furthermore, the question of whether to include DWR contract costs and other cost obligations in marginal RTP prices, or just in CBL rates, is unresolved in California. How this issue is eventually resolved will have a strong bearing on the incentives created by a two-part RTP tariff.

4) If market prices are not high enough to trigger market-based DR programs, they are also unlikely to stimulate interest in RTP response. In Oregon, the Demand Buyback program has not been called since 2001 due to low wholesale prices. RTP prices are derived from the same sources and to date there has been little customer interest in participating.

Pennsylvania – Duquesne Light Company

Background: Market and Regulatory Context

Pennsylvania's restructuring legislation, the Electricity Generation Customer Choice and Competition Law (HB 1509), passed in 1996. Utilities were mandated to unbundle generation, transmission, and distribution charges and provide open market access to other generation suppliers (GAP, 1996). Under the customer choice provisions of HB 1509, one third of customers in all classes were granted retail choice on January 1, 1999. Another third of customers gained retail choice on January 1, 2000, and final third gained retail choice on January 1, 2001.

Transition Period

HB 1509 also established a transition period that provided capped rates for customers and stranded cost recovery for utilities via a Competitive Transition Charge (CTC). Caps on total rates and non-generation rates were established for a period of 54 months (ending around June 2001) or until stranded costs are fully recovered, whichever is shorter. Caps on generation rates were established for a much longer period of nine years (ending around January 2006) or until stranded costs are fully recovered.

Wholesale Market Structure

Under HB 1509, utilities were not explicitly required to divest themselves of their generation assets. However, all of Pennsylvania's major IOUs – Duquesne Light Company, PECO, PPL, and Allegheny Power – sold their generation facilities to unregulated affiliates and/or merchant generation companies as part of their PUC-approved restructuring plans. According to the statute, the only requirement related to utility participation in retail markets is that any utility that wants to make sales to customers in other service territories must grant the affected utilities comparable direct access to customers in its own service territory. Since restructuring began in Pennsylvania, none of the regulated utilities have pursued retail markets outside of their respective service territories. In terms of wholesale market exchanges, all service territories in Pennsylvania have become members of the PJM Interconnect and thus have access to all PJM markets, including real-time and day-ahead wholesale energy markets and ancillary services markets.[153]

Retail Market Development & Structure

Since customer choice began, 41 suppliers, aggregators, and brokers have been licensed to operate in the state (PPUC, 2005). However, customer switching to alternative suppliers has not been as strong as anticipated. In the greater Pittsburg and Philadelphia metropolitan areas – the service territories of Duquesne Light and PECO, respectively – customer switching has been significant with cumulative switch rates of 23% and 18%, respectively, as of October 2004 (POCA 2004).[154] However, cumulative switch rates in the rest of the state remain below 1%.

[153] Duquesne Light Company joined PJM on January 1, 2005.
[154] The corresponding amounts of customer load switched to competitive supply are 33% in Duquesne Light's service territory and 15% in PECO's service territory.

In terms of utility obligations in Pennsylvania's restructured electricity market, HB 1509 designates the utilities as the provider of last resort until or unless the Commission designates an alternate provider (GAP, 1996).[155] Since divestment, the IOUs have been buying back POLR generation service from their unregulated affiliates and from merchant generators. In Duquesne's case, the utility has been buying POLR generation service from their unregulated affiliate, Duquesne Light Energy, as well as Reliant (KEMA 2004b, DLC 2004b).

Default Service: Post Transition

HB 1509 charged the Pennsylvania Public Utilities Commission (PPUC) with defining and implementing rules regarding post-transition utility obligations concerning POLR service. The PPUC has yet to issue such rules in a statewide context beyond Duquesne Light Company's recent POLR III proceeding which is the focus of this case study. However, the PPUC convened a series of stakeholder roundtables starting in April 2004 and is likely to issue a straw man proposal sometime in 2005 (PPUC, 2004e).

Overview of market structure and restructuring provisions

Customer choice provisions	Transition period terms and timelines	Utility Participation in Retail Market	Wholesale market structure	Wholesale market organization
All customers have retail choice since Jan 2001 (phased in over two years)	Caps on non-generation rates until June 2001; caps on generation rates until Jan 2006 or until stranded costs are fully recovered	Utilities designated as POLR providers and allowed to participate in retail markets (although none do)	PJM markets (e.g. energy and capacity)	Divestiture not required by law but all IOUs have fully divested; generation now owned by unregulated affiliates and merchant generators

Utility Experience with RTP and Demand Response

Prior to the POLR III rate case, Duquesne Light Company (DLC) had no direct experience with designing or implementing RTP tariffs. However, DLC has administered two different voluntary demand response (DR) programs since 2002 – a voluntary load reduction program called "Energy Exchange" which targets large C&I customers (with customer compensation) and a direct load control pilot program for residential and commercial central AC systems (PPUC, 2004b). It should be noted that both programs have limited enrollment and have had very few events called since their inception.

DLC also participated in a working group that was borne out of a PPUC-initiated roundtable on economic demand response programs in November 2000. The working group explored four main issue areas – consumer surveys, technology deployment, cost recovery, and benefits. As part of their participation in the working group, DLC assembled meter inventories, technology cost estimates, and administration cost estimates and assessed other key logistical tasks associated with establishing economic DR programs in its service territory.

<u>Tariff Design and Administration</u>

In August 2004, the PPUC approved DLC's rate application for post-transition POLR service (referred to here as POLR III service), including a default RTP tariff for large customers with a

[155] In Pennsylvania, POLR service includes default service.

fixed-price service option available until May 31, 2007 (PPUC, 2004c). DLC's approved POLR III tariffs went into effect on January 1, 2005.

Commercial and industrial customers with loads of 300 kW and above take distribution service under Rate Schedules GL, GLH, L, and HVPS. For these rate schedules, Standard Contract Riders 8 and 9 (FPS and HPS service, respectively) now represent the customer options for default generation service (DLC, 2004a). These riders are described briefly below:

- *Rider 9 (Hourly Price Service).* Customers who do not take generation service with a competitive supplier or do not affirmatively choose to take generation service under Rider 8 (Fixed Price Service) default to hourly price service under Rider 9. The commodity charges of Rider 9 are structured as a one-part RTP tariff based on a pass-through of real-time PJM locational marginal prices, ancillary service charges, administrative charges, a retail adder, and a daily capacity charge based on the PJM daily capacity market. Customers who wish to return to service under Rider 9 may do so at any time subject to the same administrative switching requirements.
- *Rider 8 (Fixed Price Service).* An optional fixed price service is available to customers via Rider 8 until May 31, 2007. Customers who wish to take service under Rider 8 must notify Duquesne of their affirmative choice. Rider 8 consists of demand charges and commodity charges that were determined through a competitive bidding process. Commodity charges are structured as a Time-of-Use tariff with peak hours defined as 7:00 a.m. to 11:00 p.m. Beginning in February 2005, commodity charges for new customers will be updated on a quarterly basis, according to winning bids, which then remain in effect for the remainder of their Rider 8 service. Customers who wish to leave Rider 8 service are subject to administrative switching rules, a short-term stay-out provision, and a generation rate adjustment payment.

RTP Tariff Design

Applicable Customers	Pricing Structure	Derivation of Prices	Advance Notice	Other Key Provisions
>300 kW	One-part RTP	PJM real-time locational marginal prices	None	Fixed-price option available thru June 2007

In the fall of 2004, DLC notified its distribution service customers by mail of the incoming changes to POLR service rates and options (DLC, 2004b). However, DLC staff does not anticipate actively marketing either its default RTP tariff or the optional fixed price service. Likewise, DLC staff does not anticipate pursuing enabling technology programs for large customers. According to an enabling technology inventory conducted in 2003 and 2004 as part of DLC's participation in the PPUC's Demand Side Response Working Group, all large C&I customers have interval meters installed, but none have direct load control devices installed. DLC's investment costs are being recovered via distribution rates.

<u>Implementation Process and Issues</u>

DLC initiated the POLR III rate case in December 2003. The rate case was initiated primarily because Duquesne's contracts for POLR generation service were due to expire at the end of 2004 (DLC, 2004b; PPUC, 2004c). However, DLC was also the first of Pennsylvania's IOUs to fully recover their stranded costs and thus exit the mandated transitional period and associated generation rate caps. Since DLC's POLR III rate filing preceded statewide PPUC rulemaking on post-transition default service, DLC was free to choose any POLR tariff structure that satisfied the legislated criteria of providing "safe and reliable service" at "prevailing market prices", allowing for "recovery of all reasonable costs" (GAP, 1996; PPUC, 2004e).[156]

The PPUC held technical conferences before the rate case proceedings, allowing interested parties to offer comments and questions outside of the litigation setting. Numerous parties petitioned to intervene in the rate case proceedings. On the customer side, intervenors included Duquesne Industrial Intervenors (DII), the Office of the Consumer Advocate (OCA), and the Office of the Small Business Advocate (OSBA). On the supplier side, intervenors included Citizen Power, Constellation NewEnergy, Energy America, Exelon, Dominion Retail, Green Mountain Energy, Reliant Resources, and Strategic Energy. Two other Pennsylvania IOUs also intervened in the case – PECO and Allegheny Power – as did the PJM Interconnection.

Following initial hearings before the PPUC, DLC negotiated stipulations to their rate proposal with DII, OCA, and OSBA in order to address customer concerns (DLC, 2004b). In May 2004, the administrative law judge recommended approval of these negotiated stipulations, after which other intervenors in the case filed exceptions to DLC's revised proposal. At issue in these exceptions and the hearings that followed were four main aspects of DLC's proposed POLR rates, each of which is described below:

- *Switching provisions.* The original stipulation negotiated with DII proposed a fixed-price service (FPS) as the automatic default service with an hourly-priced service (HPS) offered as a customer option. According to DLC staff, this structure addressed a strong customer preference for price stability and the desire to have the option to take on price risk. However, this proposal elicited concerns stemming from the switching rules associated with the FPS, namely a stay-out provision and the required payment of a generation rate adjustment by customers upon leaving fixed-price service. Competitive suppliers argued that these switching rules restricted customer choice and hindered the development of retail markets and proposed that HPS be used as the automatic default service, since HPS had no similar switching restrictions associated with it (PPUC, 2004c).
- *Multiple POLR products*. Suppliers also argued that retail markets would be best supported by a single POLR product, specifically an HPS-only product. They argued that by offering choices within POLR service, customers would be more likely to stay on POLR service rather than migrating to competitive suppliers. Suppliers also noted the high switch rates in DLC's service territory as evidence that large customers who did not want HPS service would be likely to seek out competitive offers for fixed-price supply.
- *Prevailing market prices*. A final argument put forth by suppliers supporting an HPS-only POLR service was that HPS more closely satisfied the statute's call for the use of "prevailing market prices". DLC and DII argued that since the FPS prices would be determined through a competitive bidding process, FPS would, by nature, be an accurate reflection of market prices. DII also argued that exposing large customers to hourly prices could potentially hurt their competitive positions in their respective markets.
- *Scope and size of retail adders*. The DLC -DII stipulation proposed that two retail adders – a risk adder and an administrative cost adder – be applied to all distribution customers, including customers taking generation service from competitive suppliers (PPUC, 2004c).

[156] It should be noted that DLC's approved POLR III rates are subject to compliance with statewide post-transition default service rules that are likely to be promulgated by the PUC in 2005.

> This design reflected DLC's concern over recovering costs associated with administering the HPS service in particular. Since DLC has no previous experience with RTP-style tariffs, the up-front costs of establishing the information, communications, billing, and reconciliation systems necessary are perceived to be significant (DLC, 2004b). Suppliers came out against the universal application of the administrative cost adder arguing that this would eliminate opportunities for suppliers to compete on administrative efficiency. Suppliers also argued that the risk adder was too low and did not allow for adequate headroom to promote competition.

In September 2004, the PPUC modified DLC's rate proposal to establish HPS as the automatic default service with FPS available as optional service until June 2007 (PPUC, 2004d). By establishing HPS as the automatic default, the PPUC agreed with suppliers' concerns over the FPS switching restrictions and their argument that HPS was a more accurate reflection of "prevailing market prices" as required by the statute. However, in allowing FPS to be available as an optional service for a limited time, the PPUC acknowledged its desire to balance the promotion of retail markets with the provision of POLR service on reasonable terms, i.e. allowing customers enough time to understand and adapt to operations in an hourly price regime (PPUC, 2004d; PPUC, 2004e).

Enabling and/or promoting demand response (DR) was not a driving factor for either DLC or the PPUC during the POLR III proceedings. The PPUC's primary objective in establishing a default RTP tariff was satisfying the requirements of the statute (PPUC, 2004e). Similarly, DLC's original default service proposal was designed to address customer preference for multiple POLR products (DLC, 2004b).

Stakeholder Perspectives on RTP and DR

Both DLC and the PPUC consider DR to be a critical component of well-functioning electricity markets and both consider RTP to be an important tool in achieving DR, but neither believe that RTP alone is sufficient.

For its part, PPUC staff is "aggressively pursuing demand response via any of the tools it has at its disposal" (PPUC, 2004e) and has already convened a stakeholder working group and a series of roundtable meetings. The PPUC also actively supports PJM-sponsored DR programs. In terms of promoting customer adoption of RTP, however, the PPUC staff believes that the competitive market is better able to provide attractive RTP rates than the PPUC and the utilities are able to do via default service.

From DLC staff's perspective, default RTP does not support any internal objectives of a wires-only distribution company or a "default-service company" (DLC, 2004b). Similarly, DLC staff believes that it is not the responsibility of utilities to provide incentives to encourage customers to participate in default RTP rates. DLC staff does believe, however, that utilities have an important role to play as "facilitators" of demand response in that utilities should be seen as the primary resource for information and training services after customers make the affirmative choice to learn about or enroll in RTP.

Default service implementation

Statutory Requirements	Implementation Process	Issues Addressed in Implementation Phase	Status
Utilities are the designated POLR providers; "safe and reliable" service at "prevailing market prices", allowing for "recovery of all reasonable costs"	Post-transition POLR rate case initiated by the utility; technical conferences followed by hearings; stipulation negotiated with customer groups	Switching provisions; multiple POLR products vs. single POLR product; "prevailing market prices" mandate; level and scope of retail adders	Commission approved modified rate proposal in August 2004; compliance tariffs approved in December 2004; tariffs went into effect January 2005

Stakeholder Positions Related to RTP

PUC	Utilities	Competitive Suppliers	Customer Groups
RTP most satisfies statutory requirements for default service and mandate to promote retail competition; competitive market better able to provide attractive RTP rates than PPUC and utilities via default service	Default RTP does not support any internal objectives of wires-only utilities; rather, utilities should be seen as important facilitators of demand response and primary resources of information and training services	Default RTP best serves the interest of promoting competitive markets; hedging options should not be a part of default service (e.g. fixed-price options)	Exposure to hourly price volatility could harm competitive positions; Customers need time to understand and adjust to an hourly price regime

Performance

Prior to the implementation of DLC's POLR III tariffs, approximately 530 out of 860 eligible C&I customers were taking generation service from competitive suppliers, representing about 30% or 300 MW of combined peak load from C&I customers (DLC, 2004b). DLC and PPUC staff expects that most remaining default service customers (accounting for about 1050 MW of combined peak load) will opt for fixed price default service. Additionally, neither expects thenew default RTP rate to generate a significant level of price response (DLC, 2004b; PPUC, 2004e).

As of April 2005, four months after the POLR III tariffs were implemented, 59 customers were taking service on the new default RTP rate, accounting for a combined peak load of approximately 35 MW (DLC, 2005). Estimates of the price response exhibited by the customers who have stayed on default RTP service are as of yet unavailable. If enrollment in the default

RTP tariff is larger than expected, DLC will consider explicitly evaluating price response from the tariff (DLC, 2004b).

Participation in DLC's Energy Exchange program has thus far been limited, as customers are required to own back-up generation resources with at least 500 kW of capacity in order to be eligible to receive incentive payments for load reductions during emergency or high price events. During the summer of 2004, a total of 31.5 MW were enrolled in the program (DLC, 2004c). Since the program was established in 2002, however, market conditions have yet to trigger the program, and no estimates of the maximum actual load reductions attributable to this program are currently available.

Default RTP Participation Statistics

Eligible Customers		Participating Customers	
Number	**Combined Peak Load (MW)**	**Number**	**Combined Peak Load (MW)**
860	1050	59	35

Default RTP Load Response Statistics

Maximum Load Reduction (MW)	Price ($/kWh)
n/a	n/a

DLC Energy Exchange Program Participation Statistics

Eligible Customers		Participating Customers	
Number	**Combined Peak Load (MW)**	**Number**	**Combined Peak Load (MW)**
n/a	n/a	n/a	31.5

Key Findings & Implications

The case of DLC's POLR III tariffs presents several interesting perspectives on default service and DR in restructured markets. First, the implementation of default RTP was guided primarily by the statutory requirements of Pennsylvania's restructuring legislation and retail market development goals. Secondly, although both the PPUC and DLC consider DR to be a critical component of electricity markets, neither expects default RTP to create significant levels of DR. and both are pursuing DR programs structured around incentive payments rather than commodity pricing.

Additional findings from this case study are summarized below:

- DLC's primary objective initially in designing their POLR service proposals was to give customers what they want, i.e. multiple POLR products. DLC negotiated directly with customer groups during the rate case and did not make direct concessions to competitive suppliers.
- In their decision to allow a fixed-price service option to be available for 27 months, the PPUC acknowledged that Pennsylvania's retail market is still maturing and paid heed to customer concerns regarding the time needed to realistically adapt to an hourly pricing regime.
- DLC does not believe that it should be the responsibility of utilities to provide incentives or otherwise encourage customers to take service on default RTP rates. DLC does, however, consider utilities to be important "facilitators" of price response in that their existing customer relationships make utilities naturally positioned to serve as the primary

resource for educational and training services for customers taking or interested in taking RTP service (default or competitive).

- The PPUC considers the development of demand response to be critical and actively supports PJM DR programs. In terms of RTP, however, the PPUC believes that the competitive market is better able to provide attractive RTP rates (and high RTP participation) than the PPUC and the utilities are able to do via regulated default service tariffs.