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Real Time Pricing as a Default or Optional Service for C&I Customers: A Comparative Analysis of Eight Case Studies

Appendix: Case Studies

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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.[1] 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

[1] 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.[2] 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.[3] 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).[4] Transmission and generation reliability adders are included in the hourly price during conditions

[2] 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.
[3] 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.
[4] The Southern Company system includes the service territories of Georgia Power, Gulf Power, Alabama Power, and Mississippi Power, and Savannah Electric and Power.

when constraints on the transmission network or generation supply are projected.[5] The RTP 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.[6] 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.[7] 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.[8] 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.

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

[6] 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."

[7] 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.

[8] 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).

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 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.[9] This option was made available on a first-come, first-served basis and was fully subscribed of the first day of the offer.[10]

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[9] Customers taking advantage of this offer could reduce their CBL to no less than 80% of their historical load.
[10] 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.

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 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.[11]

Method for deriving hourly prices

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

[11] 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.

interruptible customers were called in response to economic conditions.[12] 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).

Performance

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

[12] 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.

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.[13]

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. 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).

[13] 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).

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.[14] 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

[14] 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.

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.[15] Alternatively, the financial inducement could be provided in the form of an explicit "incentive 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.[16] 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

[15] 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.

[16] 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).

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.[17] 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 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.[18] 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

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[17] 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.

[18] 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.

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).[19] 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

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.[20] 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).[21]

[19] These discussions take place under a confidentiality agreement.

[20] 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.

[21] 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.[22] 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)

[22] 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).

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 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).[23] 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.[24]
- *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,[25] these programs provide substantial incentive payments as well as some technical support services.[26]

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

[23] 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).
[24] Delivery service customers are eligible for "delivery service" incentive payments.
[25] 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.
[26] 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.

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, 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.[27] 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.[28] 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:

[27] 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.

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

- *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 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

<u>Key Findings & Implications</u>

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.

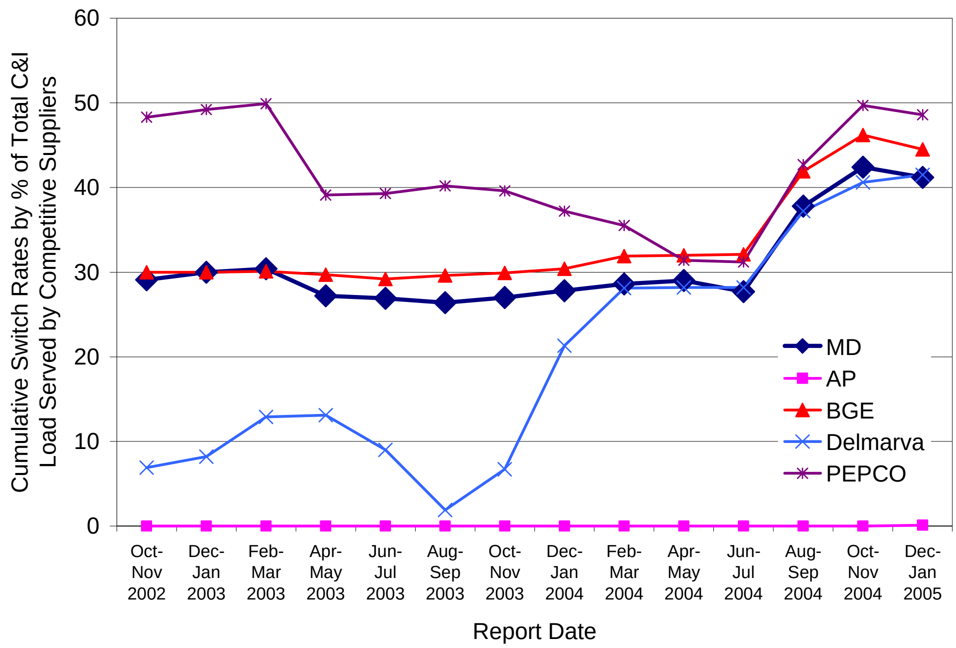
Wholesale Market Structure

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.

Tariff Design and Administration

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).[29]

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

[29] 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.

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 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[30] 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).

[30] 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.

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).

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.[31] 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

[31] One party – Washington Gas Energy Services, Inc. (WGES) opposed the Settlement. However, all stakeholders including the PSC rejected all of WGES's arguments.

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).[32]

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

[32] 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.

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

<u>Performance</u>

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).

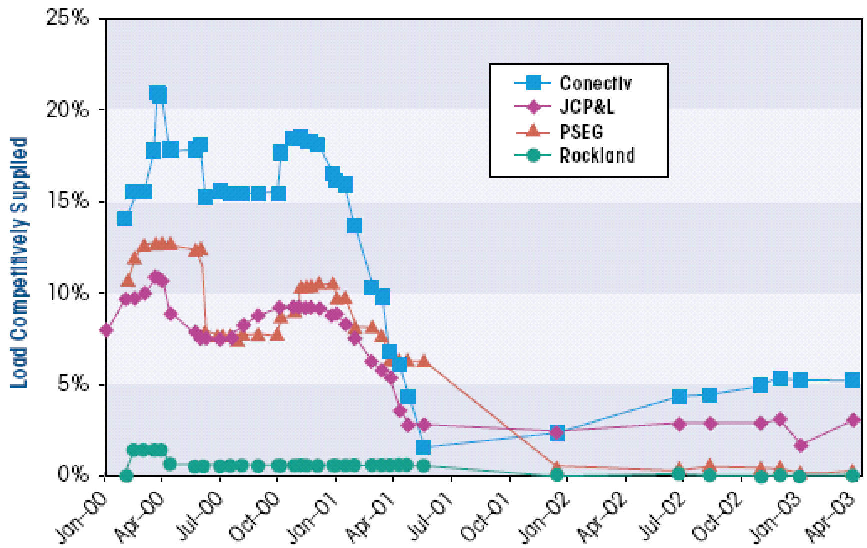
Wholesale Market Structure

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.[33] 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.[34] The BPU also intended to gradually expand the number of

[33]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).

[34]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).

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).

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

<u>Performance</u>

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).[35] 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.[36] 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

[35] The NMPC experience is the subject of another study (Goldman et al. 2004).
[36] 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.[37] 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.

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[37] 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.[38]

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.

[38] 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.

RTP Tariff Design

Applicable Customers	Pricing Structure	Derivation of Prices	Advance Notice	Other Key Provisions
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.[39] 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

[39] Default-service RTP was termed "mandatory" in the proceeding documents.

unacceptable to the customers or switch to an ESCO".[40] 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 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[41], 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).[42]

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[40] In New York, competitive retail electricity suppliers are termed "ESCOs".

[41] 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

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 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[43] and balancing costs.[44] 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).[45] 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).

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).

[42] 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).

[43] 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.

[44] 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.

[45] 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).

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
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.

<u>Performance</u>

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

<u>Tariff Design and Administration</u>

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 proceeding 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.[46] 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.

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[46] 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.

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

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).[47] 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

[47] 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).

Quote Option program event called in February 2003, CG&E estimated a maximum load reduction of ~50 MW due to that program (Rogers 2003).[48]

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 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.

[48] This load curtailment appears to include Quote Option participants in both PSI and CG&E.

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.[49] 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.

[49] 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).

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, 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.[50] 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.

[50] 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.

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.

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.[51]

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

[51] Customers that opt out of the cost-of-service rate but fail to specify which rate they want are placed on the daily option.

each customer's historical usage and is billed at the Schedule 83 cost-of-service rate.[52] 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 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
<u>Market-based options</u>: daily pricing for all non-residential; additional monthly and quarterly options for nonresidential >30 kW <u>RTP</u>: non-residential >1 MW (maximum 6 customers)	<u>Market-based options</u>: unbundled rate with peak and off-peak commodity prices <u>RTP</u>: two-part RTP with CBL	<u>Quarterly/monthly options</u>: PGE forward price curve <u>Daily option</u>: DJ Mid-C index <u>RTP</u>: ICE Mid-C day-ahead index shaped by previous day's actual hourly prices reported by DJ	<u>Quarterly/monthly options</u>: 15 days' notice <u>Daily option</u>: none (prices revealed the next day) <u>RTP</u>: day-ahead	For RTP, the CBL is priced at the default cost-of-service rate.

[52] 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.

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.

<u>Performance</u>

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.[53]
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.

[53] 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.

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.[54]

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

[54] Duquesne Light Company joined PJM on January 1, 2005.

significant with cumulative switch rates of 23% and 18%, respectively, as of October 2004 (POCA 2004).[55] However, cumulative switch rates in the rest of the state remain below 1%.

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).[56] 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

[55] 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.
[56] In Pennsylvania, POLR service includes default service.

estimates, and administration cost estimates and assessed other key logistical tasks associated with establishing economic DR programs in its service territory.

Tariff Design and Administration

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 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.

Implementation Process and Issues

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).[57]

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

[57] 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.

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). 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

<u>Performance</u>

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.