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Customer Response to Day-Ahead Market Hourly Pricing: Choices and Performance

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Customer response to day-ahead market hourly pricing: Choices and performance
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ABSTRACT:
Real-time pricing (RTP) has been advocated to address extreme price volatility and market power in electricity markets. This study of Niagara Mohawk Power Corporation's largest customers analyzes their choices and performance in response to day-ahead, default-service RTP. Overall price response is modest: 119 customers are estimated to reduce their peak demand by about 10% at high prices. Manufacturing customers are most responsive with a price elasticity of 0.16, followed by government/education customers (0.11), while commercial/retail, healthcare and public works customers are, at present, relatively unresponsive. Within market segments, individual customer response varies significantly.
KEYWORDS:
real-time pricing, demand response, default service
MAIN TEXT:

1. Introduction

In response to the problems of extreme price volatility and market power observed in some restructured electricity markets, policymakers and analysts are considering the relative roles of pricing and other regulatory and market interventions to improve their performance (Clarke, 2003; Flippen, 2003). Most agree that limited demand response (DR) at the retail level hampers the development of efficient wholesale markets. Relying on conceptual studies and anecdotal evidence, some have pointed to time-varying pricing, particularly real-time-pricing (RTP), as a mechanism to enable demand response (DR) and improve the linkage between wholesale and retail markets (Borenstein, 2002; Flippen, 2003; Horowitz and Woo, 2005; Turvey, 2003).

Unfortunately, there is little publicly available information to help policymakers assess how well RTP actually works to elicit DR or to characterize its actual impacts on wholesale markets. Furthermore, in restructured electric markets, the new choices available to retail customers create a complex set of incentives. A few studies have examined industrial customer experience with RTP and found modest response (Boisvert et al., 2004; Herriges et al., 1993; Schwarz et al., 2002). California regulatory agencies and utilities recently sponsored a statewide pricing pilot for residential and small commercial customers and found load reductions ranging from 5-15% in response to high price signals from a critical peak price tariff (Charles River

Associates, 2005). However, all these studies examined *voluntary* RTP programs implemented in jurisdictions without retail choice.

This research sheds light on how well retail pricing strategies actually promote demand response in restructured electric markets with retail competition. It examines the experience of 149 large customers of Niagara Mohawk Power Corporation (NMPC), an upstate New York utility, that have been exposed to hourly prices indexed to day-ahead, wholesale spot market prices as the default service under retail competition since 1998. Their hourly load and price data over five summers (2000-2004) are supplemented by two phases of detailed customer survey and interview results to estimate demand models and to provide quantitative and qualitative context to model results.[1] Detailed information on data sources, survey administration and response and demand modeling methodology is available in Goldman et al. (2005).

Findings from this study are discussed in terms of customer *choices* in adapting to RTP as the default utility service in a competitive retail market environment, and customer *performance*, the actions customers undertook in response to hourly prices, their degree of price response and the aggregate impact on loads during high-price events.

2. Research Questions

We conceptualized two distinct but interdependent aspects of customer RTP experience in the context of restructuring: *choice* and *performance*. Table 1 lists our specific research questions and the indicators used to assess them.

Customers' choices – of electricity supplier, of hedging products, of participation in NYISO DR programs – determine the magnitude of the incentives they face to respond to RTP signals. For example, choosing a competitive supply contract with a flat rate for all usage effectively removes a customer's incentive to respond to day-ahead hourly pricing signals.[2] Conversely, customers exposed to RTP and also participating in NYISO DR programs face additional incentives to respond at certain times relative to other customers. The choices afforded by retail competition and the

[1] The two rounds of customer surveys and interviews were administered in August-October 2003 and October 2004-January 2005 to individuals responsible for 149 customer accounts. Altogether, 67% of eligible customers answered either the 2003 or the 2004 survey, with broad representation by all five business sectors included in the population.

[2] All hedged competitive supply arrangements reported to us were full-requirements, meaning that they applied to all of the customer's load. However, hedged pricing structures that do not fully insulate customers from price risk, have been offered in other jurisdictions (Barbose et al., 2005).

coexistence of hourly electricity pricing with ISO reliability DR program incentives to adjust usage complicate the analysis of customer price response.

We define customer performance in terms of price response. This is characterized qualitatively, using customers' assessment of their own degree and type of response, and quantitatively, by estimating price elasticities for individual customers and summarizing the results by class, business sector and customer.[3]

3. Tariff and Retail Market Context

NMPC adopted RTP as the default tariff for its largest customers as part of its electricity restructuring plan implemented in the fall of 1998. At the time, promoting DR was not a motivation for RTP. NMPC had agreed to divest most of its generation assets and was interested in passing through wholesale hourly market prices to its largest customers as a way to manage its electricity supply price risk. The company's prior experience with a pilot RTP tariff, along with the generally accepted projection that wholesale market prices would be low in the foreseeable future contributed to initial customer acceptance of RTP. It was not until 2000, when substantial price spikes were first encountered in NYISO markets, that policymakers began to express major concerns about the lack of price-responsive load in New York.

The RTP tariff is the default supply option for the 149 NMPC customers that are served under the "SC-3A" service classification and do not contract with a competitive supplier; a subset of NMPC's customers with monthly peak demand in excess of two megawatts (MW).[4] It was designed to facilitate retail access by unbundling commodity costs from other service elements.[5] Hourly energy commodity prices are indexed to the NYISO day-ahead market's Location Based Marginal Prices corresponding to the customer's geographic location, and include ancillary services and other energy delivery costs. The hourly prices apply to all metered energy usage. NMPC posts the next day's firm SC-3A prices on its website by mid-afternoon each day.

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[3] See Goldman et al. (2005) for a detailed discussion of the customer demand models employed.

[4] NMPC has an additional 119 customers with peak demand in excess of 2 MW that are served under the SC-4, SC-11 and SC-12 rates, or have New York Power Authority allocations and take their residual power under SC-3A (see Goldman et al., 2004). We only had access to billing data and customer contact information for the 149 customers with full service under the SC-3A classification; these customers comprise our study population.

[5] Fixed transmission, distribution and other non-energy costs are recovered through monthly per-customer, demand and variable block charges – all SC-3A customers, including those taking supply from competitive retailers, pay these charges.

Figure 1 provides an overview of the choices available to SC-3A customers since RTP became the default service in late 1998. In addition to RTP (termed “Option 1”), NMPC offered a fixed-rate time-of-use (TOU) alternative, called “Option 2”, on a one-time basis, just prior to the introduction of retail access in 1998. The Option 2 tariff was available for up to five years. Subscribing customers nominated a fixed amount of load for peak and off-peak periods (in MW) in each month of the contract. Residual energy requirements could be purchased under Option 1, or from a competitive supplier. A pre-determined rate schedule applied to all nominated load, but the terms of Option 2 were quite restrictive.[6]

SC-3A customers have also had the option of purchasing electric commodity from competitive retailers (referred to as “energy service companies”, or ESCOs, in New York). Contracts may be indexed to SC-3A Option 1 prices or directly to NYISO day-ahead market or some other source of prices, or they may be fixed-rate or TOU arrangements.

In addition to commodity supply options, SC-3A customers have had access to several other products and services that may impact their price responsiveness (see **Figure 1**). They may purchase financial hedges, which are derivatives separate from the supply of electricity that provide protection against price volatility, usually for a specified volume, leaving the customer still exposed to hourly price volatility for marginal usage. SC-3A customers have also been eligible to participate in public benefits funded programs offered by the New York State Research and Development Agency (NYSERDA) that provide incentives for installing demand response enabling technologies.

Finally, SC-3A customers have been eligible to participate in NYISO’s three demand response programs since 2001. Many have enrolled in the two reliability enhancement programs: the Emergency Demand Response Program (EDRP) and the Installed Capacity/Special Case Resource (ICAP/SCR) Program.[7] EDRP is a voluntary program that pays the higher of $500/MWh or the prevailing market price for load curtailments when NYISO declares emergency events. ICAP/SCR participants receive capacity payments for load reduction commitments and, since 2003, energy payments for load curtailed when NYISO declares events, but penalties are levied if they fail to curtail when called upon to do so.

[6] Option 2 was a take-or-pay contract, meaning that customers were responsible for paying for all contracted load regardless of whether they used it or not. A one-time, permanent opt-out provision was available for a premium.

[7] The Day Ahead Demand Response Program (DADRP), an economic program in which customers bid load curtailments directly into the NYISO day-ahead market, has seen low enrollment by SC-3A customers.

4. Customer Choices: Retail Access and Price Risk Mitigation

We evaluated customer choices using tariff history information provided by NMPC augmented by customer survey and interview responses. Here, we discuss three aspects of customer choice: (1) customers' acceptance of and satisfaction with default-service day-ahead RTP, (2) their migration patterns between NMPC default service and competitive retailer alternatives and (3) their hedging decisions. NYISO program participation and enabling technology adoption are discussed along with associated aspects of customer performance in the next section.

4.1. Customer Satisfaction

Most SC-3A customers reported that they were generally satisfied with the default RTP tariff adopted in 1998. On a scale of 1 to 5, with 1 representing "very dissatisfied" and 5 "very satisfied", the average rating was 3.2 among 48 respondents. About 35% indicated that they had no major issues with the tariff design. Among those that provided feedback on the tariff design, the most common complaint was a lack of information. The majority of customers reported that, in retrospect, they had been unprepared for retail access and day-ahead market pricing in 1998.

4.2. Customer Migration

SC-3A customers' migration patterns between NMPC and competitive retailers are shown in Figure 2 for the summers of 2000 through 2004.[8] Each horizontal bar represents an individual customer's supplier history; customers are grouped vertically according to their switching patterns. Switching rates have increased considerably over time. In 2000, only 30% of customers had left NMPC for the competitive market; by 2004, 63% had done so. It appears that once customers make the decision to switch, they tend to stay with competitive retailers – 75% of the customers that switched to an alternative supplier had not returned to NMPC as of summer 2004.

The increase in customers leaving NMPC for the competitive market in 2004 probably reflects three factors: (1) Option 2, NMPC's fixed-rate alternative to RTP, sunset in 2003 and about 15% of SC-3A customers were obligated to enroll in Option 1 or find a competitive alternative, (2) some customers that originally elected Option 1 may have watched the market play out for a few years, gaining a level of comfort in evaluating retail market offers and/or overcoming internal procurement barriers before

[8] Although retail access was introduced in late 1998, customer tariff information was only available from 2000 onward.

deciding to switch,[9] and (3) the number of suppliers and the variety of contract options appears to have taken off in recent years, primarily due to a maturing retail market as several adjacent states have also adopted RTP-type default service (Barbose et al., 2005).

Even though switching is on the increase, 37% of SC-3A customers remain on default-service hourly pricing six years after its introduction. However, not all those that switched are hedged. A large group of customers has switched to competitive suppliers but are served under similar pricing terms, indexed to NYISO day-ahead prices or to the SC-3A rate. This group could represent up to a quarter of the NMPC SC-3A accounts, which means that ~60% of SC-3A customers pay day-ahead wholesale market prices. Relative to other jurisdictions in the U.S. that have implemented default-service RTP and experienced very high switching rates, the number of NMPC customers willing to remain on hourly pricing is high (Barbose et al., 2005). We believe that the major reason for this difference is that NMPC's tariff involves day-ahead prices, while other jurisdictions have indexed their RTP tariffs to real-time markets.

4.3. Hedging Strategies

Combining survey results and tariff history information, we classify customers according to the degree to which they hedged against electricity price volatility in each year (Figure 3). Insufficient information was available to classify more than half the customers and information was particularly scarce in 2004. Of those that could be classified, about 33-39% were fully or partially hedged in each year of the study. The majority hedged with electricity supply arrangements (Option 2 or fixed-rate competitive supply contracts) rather than financial derivatives.[10]

Why have so few customers hedged? Based on two years of surveys and interviews, we propose two explanations. First, some customers told us that, although they would prefer a hedged contract, they have been difficult to find or procure or too expensive relative to the perceived price volatility risk. Second, some customers may be "psychologically hedged", meaning that they have evaluated the market circumstances they face (i.e., perceived high hedge premiums and relatively stable SC-3A prices with declining volatility) and are comfortable managing day-ahead market price risk without a hedge.

[9] About one-third of surveyed customers indicated that they had experienced institutional barriers to switching electric commodity providers.

[10] Based on surveys and interviews, at least half of customers are unfamiliar or uncomfortable with the concept of a financial hedge to protect against electricity price variability.

5. Customer Performance: Price Response

In evaluating the performance of customers faced with default-service day-ahead RTP, we are interested in the extent to which they respond by adjusting their electricity usage patterns. We measure this both at an aggregate level (e.g., average response of all customers and by sector) to provide insight into the larger policy question of the large RTP customers' aggregate DR potential and at a disaggregated level (e.g., the distribution of response among different types of customers and under different operating conditions) to understand the character of response and identify barriers that prevent some customers from being more responsive. We also address how, why and to what signals customers respond, as well as barriers they have encountered, using customer interview and survey results.

Consistent with the economic theory of the firm, we define price response empirically as an *elasticity of substitution*, which measures the propensity of customers to shift electricity usage from peak to off-peak periods in response to changes in relative peak and off-peak prices.[11] It is defined as the percentage change in the *ratio* of peak to off-peak electricity usage in response to a one percent change in the *ratio* of off-peak to peak electricity prices.[12] For example, a substitution elasticity of 0.15 implies that the ratio of a customer's peak to off-peak usage changes by 15% in response to a 100% change in the off-peak to peak price ratio.

We employed an electricity demand model to estimate individual customer elasticities for each summer weekday of the study period (2000-2004), and then subjected the resulting elasticities to secondary regressions to reveal statistical relationships between customer characteristic and circumstances and the level of price response.[13] For theoretical consistency, we only included customers in the model for summers in which we determined that they had faced hourly-varying prices for at least some portion of their load. In all, 119 customers were included in the model for at least one summer of the study period.

5.1. Overall Price Response Results

The load-weighted average elasticity of substitution for the 119 customers that faced hourly prices is 0.11 (Table 2). This means that a doubling of the price ratio,

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[11] We defined the peak and off-peak periods to be 2-5pm (peak) and all other hours (off-peak) based on the results of an exploratory analysis (see Goldman et al, 2005).
[12] Elasticity of substitution values range between zero and infinity. The higher the elasticity, the greater the response.
[13] See Goldman et al (2005) for a detailed discussion of the demand model.

other factors held constant, would result in an 11% reduction in ratio of peak to off-peak electricity use. In terms of aggregate load response, these 119 customers can be expected to reduce their combined summer peak demand by about 50 MW (or 10%) at a peak/off-peak price ratio of 5:1, the highest observed during the study period. This corresponded to a peak price of almost $750/MWh.

Few comprehensive studies of large customer price response have been conducted to which these results can be compared. Nonetheless, they are consistent with portfolio-level substitution elasticity estimates found by Boisvert et al. (2004), Herriges et al. (1993) and Schwarz et al. (2002) for commercial and industrial customers participating in voluntary RTP programs; these studies found average elasticities ranging from 0.12 through 0.15. Wolak and Patrick (2003) found lower elasticities among customers in England and Wales that elected to pay RTP-type prices.

We defined five business sectors based on customers' SIC codes and calculated sector-average elasticities (Table 2). The manufacturing sector has the highest estimated average elasticity (0.16). Government/education customers as a group are also quite responsive – an important finding given a historical bias toward industrial customers as the most likely to exhibit price response. Commercial/retail, healthcare and public works customers are, at present, relatively unresponsive.

5.2. Load Response Strategies

In the 2004 survey, over two-thirds of the 76 respondents claimed to have some load response capability (see Figure 4).[14] They indicated several load response strategies: shifting load from one time period to another (22% of surveyed customers), foregoing electricity use without making it up at another time (45%) and supplying load with onsite generation (16%). Thirteen percent reported more than one response strategy.

Among business sectors, government/education customers are most likely to respond by foregoing load and not making it up later – almost all (83%) report that they respond in this way. Manufacturing customers report load shifting more often than other sectors, and they display the most variety in their load response strategies.

[14] The survey question was framed in terms of customers' response to any of hourly SC-3A prices, NYISO emergency events or public appeals to reduce electricity consumption.

5.3. The Role of NYISO DR Programs

NYISO's reliability DR programs provided additional incentives for enrolled SC-3A customers to curtail load during several emergency events declared in 2001, 2002 and 2003. Forty-two percent of the 149 study customers were enrolled in at least one of the two programs, EDRP or ICAP/SCR, for at least one summer.

Based on a regression of 55 customers who responded to the 2004 survey, we find a statistically significant correlation between EDRP enrollment and higher customer-average substitution elasticities.[15] The coincidence of these complementary signals makes it impossible to determine statistically how much of the measured "price" response is attributable to RTP and how much to NYISO emergency events.

We asked customers to tell us which conditions – high hourly prices, NYISO emergency events, public appeals to conserve, or major changes in their facility operations – had caused them to respond with load changes. Of the 76 survey respondents, only 5% claimed to have responded to high hourly prices; 80% said they had not and 15% did not know. Self-reported response to NYISO emergency events was much higher: 60% claimed to have responded to NYISO events, 37% said they had not, and 3% didn't know.

Among the 46 customers that attested to responding to NYISO program events, the most common reason cited for doing so was, not surprisingly, to earn incentive payments; 29 customers (63%) gave this reason. But helping to keep the electric system secure appears to be almost as important to customers; 59% indicated that their organization considers it their civic duty to do so. It is also notable that 30% told us that they respond to NYISO program events at least in part because they coincide with high SC-3A prices. This suggests that rather than specifically monitoring and responding to high SC-3A prices, some customers look for external signals that prices are high. Thus, some response appears to be attributable to customers simply being made aware that prices are high through other, coincident events.

5.4. Diversity of Customer Response

There is a great deal of variability in the elasticities estimated for individual customers (Figure 5). About 27% are completely non-responsive – their estimated elasticities are zero, indicating that they use peak and off-peak electricity in fixed proportions, regardless of electricity prices. Another 8% have elasticities that are very

[15] Contrary to expectations, no statistically significant relationship was found for ICAP/SCR. We believe that this is due in part to the limited sample size as well as the extreme coincidence of program events and high SC-3A prices.

small (less than 0.01). Twenty-eight percent of customers exhibit very modest response, with elasticities between 0.01 and 0.05. The remaining 37% have elasticities above 0.05. Nearly half of this group (18%) exhibit average elasticities of substitution above 0.10; this small group of customers provides 75-80% of the overall load response.

Even within business sectors, price response varies substantially (see Figure 6). The government/education sector has almost the same number of price-responsive customers (with elasticities greater than 0.1) as moderately responsive customers (elasticity between 0.05 and 0.1) and non-responsive (< 0.05) customers. Manufacturing customers exhibit a "bimodal" distribution: 64% are non-responsive, 27% are highly responsive, and only 9% are moderately responsive. The sector-level average elasticity results in Table 2 clearly mask considerable variation within sectors.

5.5. Impact of Enabling Technologies

Customers were asked which of three potentially DR-enhancing technology categories they had installed: (1) energy management control systems (EMCS) and/or peak load management (PLM) devices, (2) energy information systems (EIS) that provide near real-time access to facility electricity usage data and (3) onsite generation. Forty-nine percent of survey respondents reported ownership of EMCS/PLM devices, 41% reported EIS systems and 55% told us they had onsite generation capacity.

Despite the potential for these technologies to facilitate price response, their impact on estimated elasticities is not clearly discernable. While the presence of onsite generation does contribute to higher elasticities, customers that had installed EMCS and/or PLM devices actually had lower elasticities than those that didn't and EIS installation did not appear to contribute one way or another to price response.[16] These apparently contradictory results are explained by customers' survey responses regarding how they use these technologies. Only 16% of customers with EMCS systems, 23% with EIS and 7% with onsite generation told us they use the available technologies to respond to high hourly prices. Most customers indicated that at present they use EMCS/PLM and EIS technologies primarily for achieving across-the-board energy savings (permanent load reductions) or managing their peak demand, and that onsite generation is primarily used for emergency backup purposes.

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[16] The negative impact of EMCS systems on price response is statistically significant. The results for EIS and onsite generation are not statistically significant. These results may be in part due to a small sample size – only the 55 customers with complete survey responses could be included in this regression model.

5.6. Barriers to Price Response

Customers were asked about barriers they had encountered in responding to hourly prices. Only 12% of survey respondents claimed not to have encountered any obstacles at all (see Table 3). The remaining 88% reported anywhere from one to five barriers to price response.

Over two-thirds of surveyed customers reported at least one barrier related to their organization's business practices or structure. The most pervasive barrier in this category is insufficient time to monitor hourly prices – over half of survey respondents reported this problem. Asked specifically how often they monitor prices, about 70% of customers indicated that they rarely or never do so. Only 17% told us that they monitor day-ahead hourly prices routinely or weekly. Thirteen percent said they consult day-ahead prices only when other factors, such as hot weather or NYISO emergency program events, suggest that they may be high.

One third of customers noted inadequate price incentives as a barrier to price response. Twenty-two percent reported that managing electricity use is not a priority and an equal number felt that the cost or inconvenience of responding was greater than the potential savings. In interviews, some customers told us they would only respond if prices stayed high for several hours. These comments are probably shaped by the prices customers have faced. Over the course of the study period, average peak and off-peak prices have been relatively stable, while price volatility has decreased substantially (see **Figure 7**). Very high prices have been infrequent: in 93% of the hours in our study period, prices were below $100/MWh. Prices exceeded $500/MWh in only eighteen hours, all during the summers of 2000 and 2001. These trends may have mitigated customers' perception of the price risk they face.

Finally, 13% of survey respondents indicated that their organization's management views price response as too risky and 12% said they had hedged their electricity costs and did not see price response as necessary.

6. Implications for Policymakers and Market Participants

The results of this study of large customers' adaptation and response to day-ahead market hourly pricing have important implications for RTP's potential as a prescription for improving wholesale and retail electricity market performance.

First, default-service day-ahead market pricing for large customers is consistent with the dual goals of enabling demand-side participation in electricity markets and of encouraging retail market development. In the NMPC case, the retail market provides customers with alternatives to default RTP, and this has been key to customer acceptance. At the same time, for many, managing changes in load in response to high hourly prices is less expensive than paying for a hedge, at least under existing market conditions. Firm, day-ahead hourly prices provide customers the opportunity to plan and execute load adjustments. However, customer choice creates uncertainty for regulators and market participants in predicting price response. If customers sign hedged contracts, they may become price inelastic, even if the structure of the hedge does not eliminate marginal incentives to respond to very high prices.[17] If price response from customers with retail choice is to be relied upon as a resource (e.g., integrated into ISO day-ahead or real-time markets) or expected to mitigate market power, substantial information requirements must be satisfied. Some way of anticipating the amount of price responsive load must be established, at a minimum by collecting aggregate information from retailers on customer subscription to various types of supply contracts. Moreover, other U.S. states that have recently implemented default-service RTP (e.g. New Jersey, Maryland, and Pennsylvania) have established lower customer size thresholds than NMPC's tariff (300-750 kW vs. 2000 kW). Whether these smaller industrial, commercial and institutional customers will respond similarly is a question for further research.

Second, under current conditions, most large customers in the NMPC service territory appear to be somewhat price-responsive, but the overall impact is modest. While over two-thirds of the 80% of SC-3A customers exposed to hourly prices (119 modeled customers) exhibit positive elasticities, their load-weighted average elasticity is 0.11, and their aggregate load response at historical high prices is estimated at about 10% of their combined peak demand.

Third, a number of barriers prevent some customers from being more price-responsive. SC-3A customers have been exposed to default-service RTP for six years, during which time electricity prices and reliability issues have become front-page news and many SC-3A customers have enrolled in NYISO emergency programs and had access to NYSERDA enabling technologies programs. In short, SC-3A customers represent the best available base of RTP experience. Why, then, is the observed price response not higher? Many large customers simply don't see price response as a priority unless there is an actual system emergency, which for some represents an obligation to curtail. Though there has been substantial dissemination of enabling technologies, customers have yet to deploy them to their full price-response potential.

[17] We attempted to incorporate customers' hedging decisions into price response models but were not able to define a variable that described the observed patterns in customer elasticities. The large amount of missing information on hedges (see Figure 3) probably confounded these efforts.

This is apparently due both to a need for assistance developing automated load response strategies as well as a perception that the potential savings from price response, available in only a few hours per year, do not outweigh the costs of using the equipment episodically to shift load. In addition, SC-3A customers have not faced the level and volatility of prices observed in, for example, California's wholesale markets in 2000 and 2001. If such high prices were observed, some NMPC customers would respond by reducing a greater amount of peak load, according to their estimated elasticities. However, sustained higher, more volatile prices could also induce more customers to seek hedged alternatives to RTP, thereby effectively reducing their price response potential. The net effect is hard to predict. Some of these barriers to price response can be overcome, but will require concerted long-term efforts by policymakers to do so. For example, simply disseminating enabling technologies is not enough – technical assistance to develop load response strategies is necessary, at least at the current stage of customer awareness of price response automation strategies. Policymakers should also expect, however, that some customers will probably never be price responsive. RTP alone may not be a sufficient strategy to develop adequate DR.

Fourth, reliability-based DR programs administered by ISOs, Regional Transmission Organizations or regulated utilities appear to complement RTP. Several authors have debated the relative merits of RTP and DR programs (Boisvert and Neenan, 2003; Borenstein, 2002; Ruff, 2002). The NYISO reliability programs clearly enhance the price response of SC-3A customers. Not only do they provide additional financial incentives to curtail, but also notification of coincident high prices and system emergencies. Some customers who are willing to help out in emergencies report that they are not interested in regularly monitoring and responding to high hourly prices. Others may be price responsive but increase their response when events are called, if for no other reason than it makes them aware of the high prices they are paying. The synergies between RTP and DR programs should also be recognized: RTP can serve as a training ground for customers to respond in reliability programs and, conversely, customers may learn to respond to emergency events and subsequently become more price-responsive. Given the observed degree of price response, both strategies for encouraging DR are necessary.

Fifth, customer response is extremely diverse. Not only do customers employ a variety of response strategies (shifting, foregoing and self-generation), but the degree of response varies dramatically, even among customers of the same business classification. This underscores the importance of ensuring that hedged alternatives to RTP are available to avoid exposing customers that cannot respond to unacceptable levels of price risk. The diversity of response also merits characterization of drivers to price response so that retailers can target programs to those customers most able to respond.

In conclusion, while default-service day-ahead market pricing is consistent with the goals of enabling demand-side participation in wholesale electricity markets and promoting retail market development, it is unclear whether the current aggregate level of customer response to RTP is sufficient to mitigate the extreme price volatility and potential for market power observed in some electricity markets. Default-service RTP at its current stage of development should be seen as part of the solution, alongside other means of eliciting DR such as ISO reliability-oriented DR programs.

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ILLUSTRATIONS:

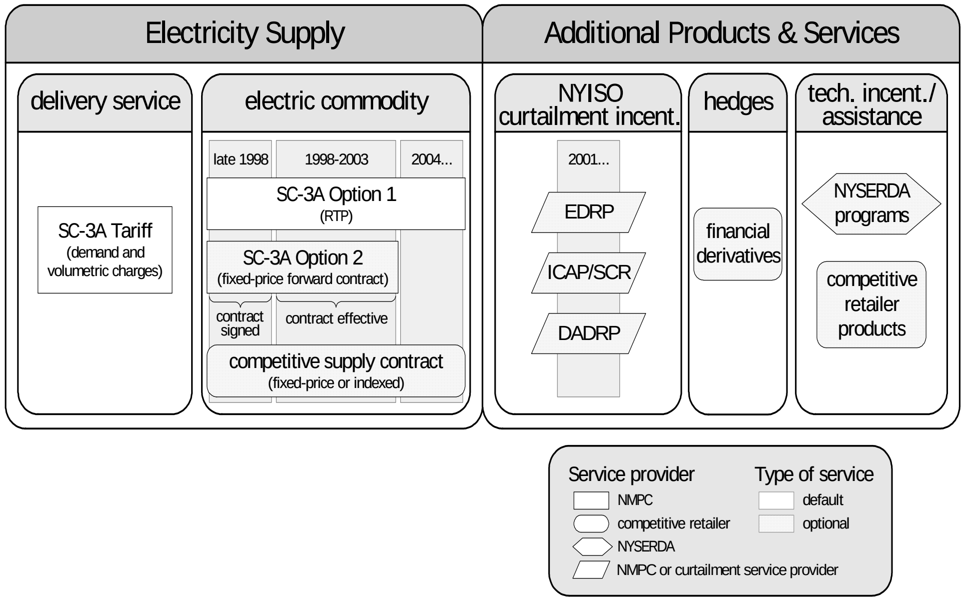

Figure 1. Choices Available to SC-3A Customers

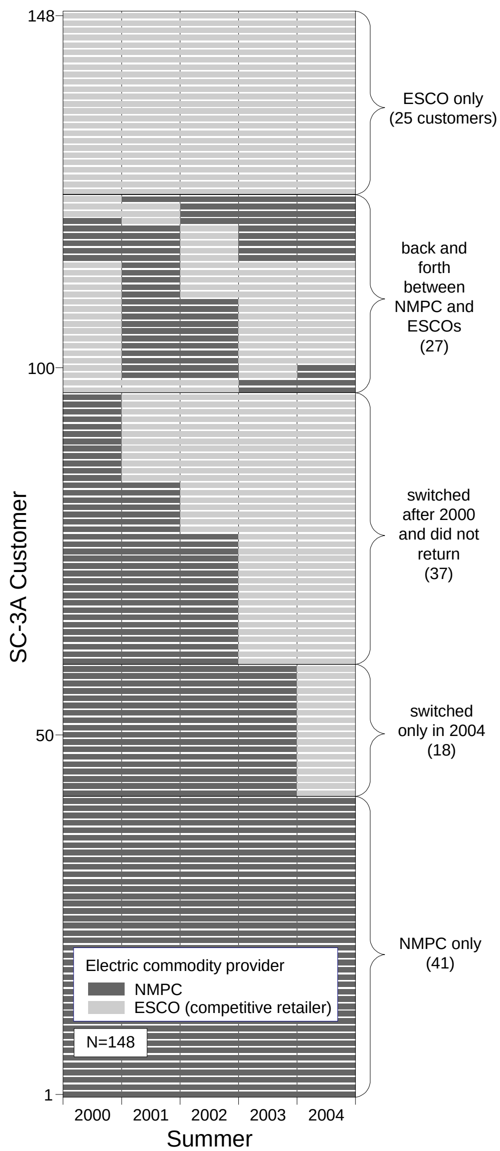

Figure 2. Migration Patterns of SC-3A Customers

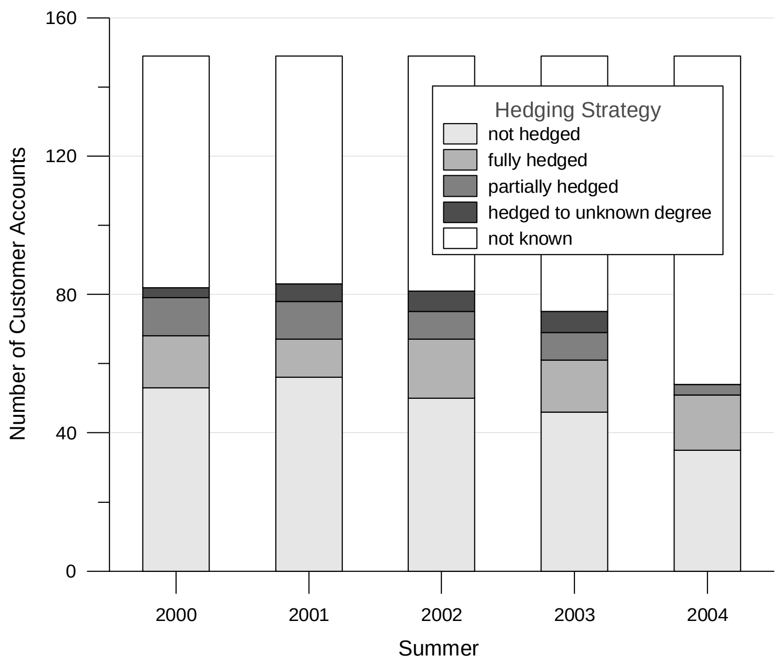

Figure 3. SC-3A Customers' Hedging Trends

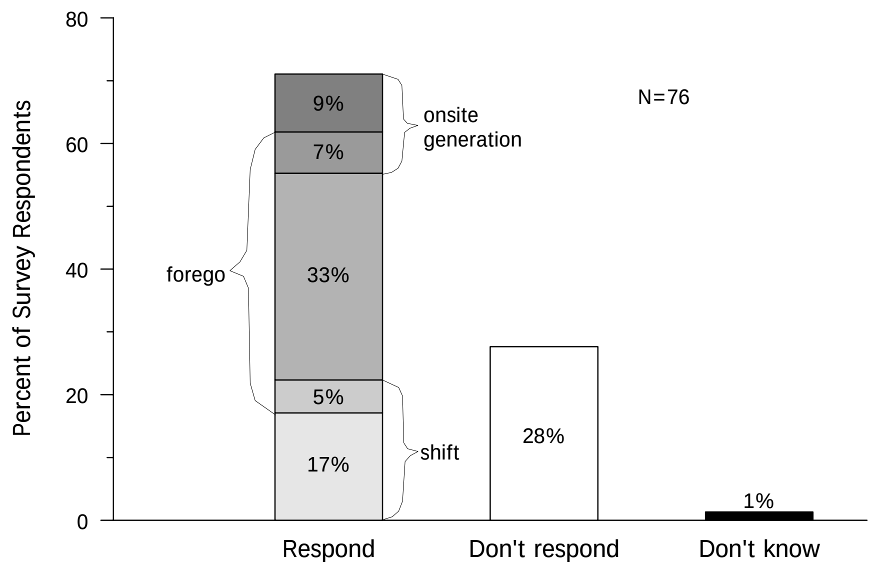

Figure 4. Customers' Self-Reported Load Response Strategies

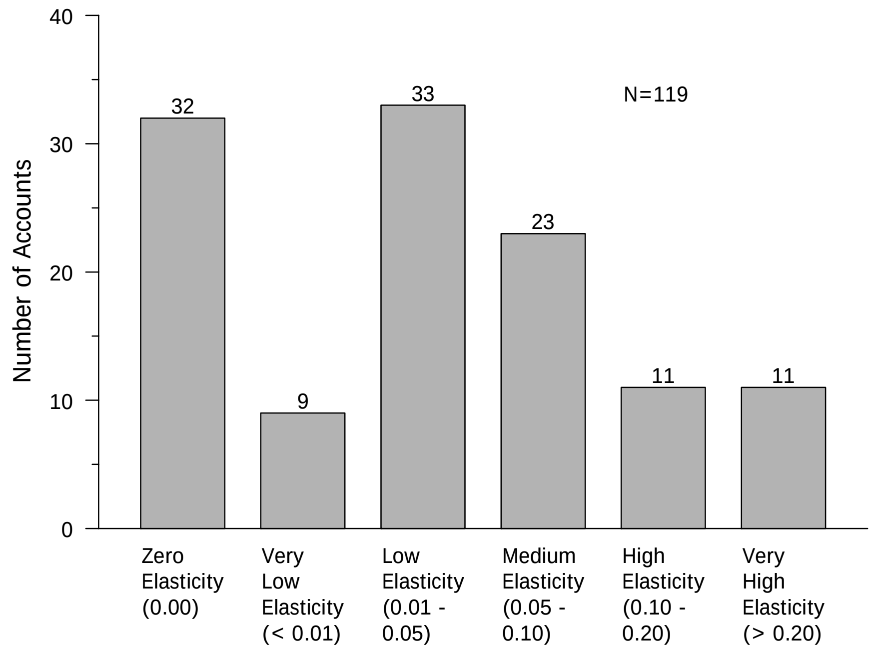

Figure 5. Distribution of Accounts by Elasticity of Substitution

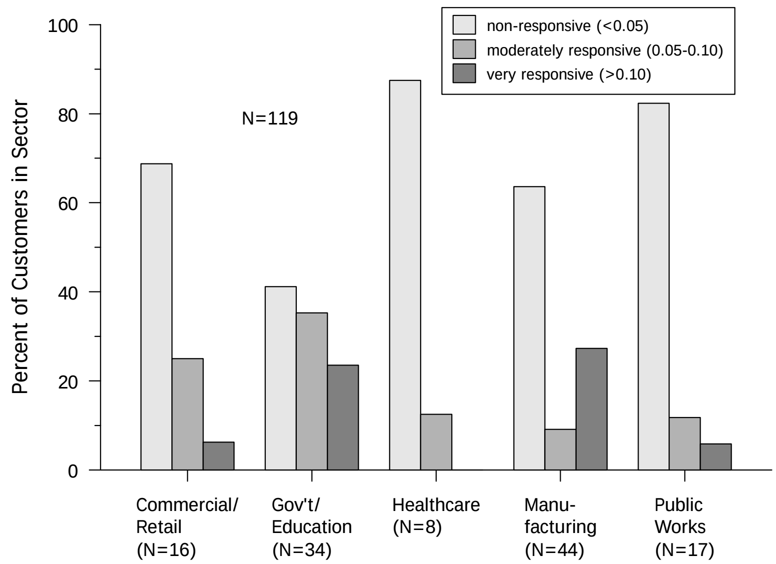

Figure 6. Price Responsiveness by Business Category

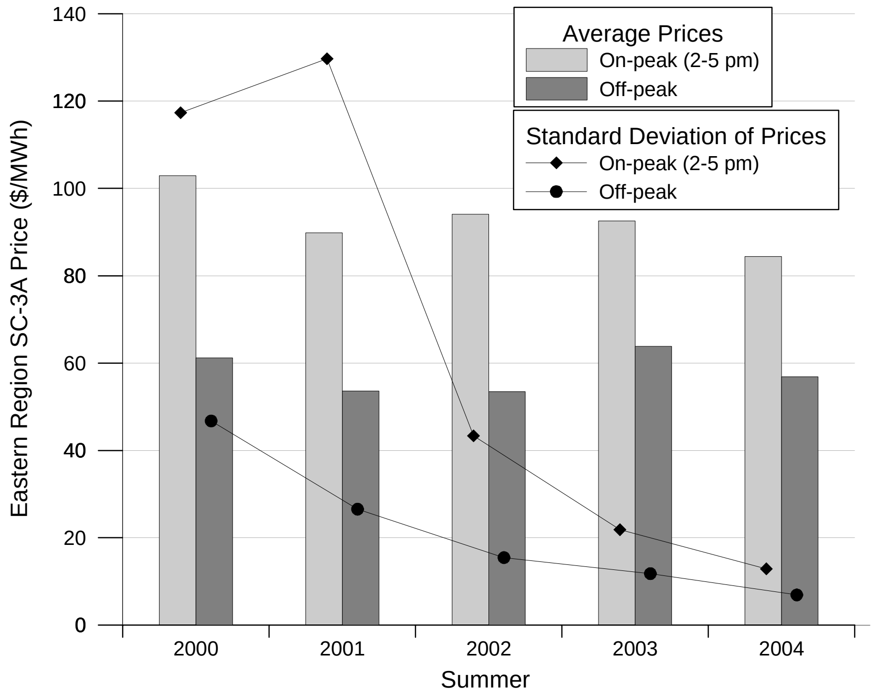

Figure 7. Trends in SC-3A Prices: East Region, Summer Weekdays

TABLES:

Table 1. Research Questions and Indicators

Research Question	**Indicator**
CUSTOMER CHOICES: RETAIL ACCESS AND PRICE RISK MITIGATION	
Are customers satisfied with default RTP?	Customers’ overall satisfaction rating
	Customers’ self-reported access to information
	Individual customers’ comments
Does default RTP encourage customers to switch to competitive suppliers?	Customer choice migration patterns
	Individual customers’ comments
To what extent do customers hedge against price volatility risks?	Percent of customers taking hedged commodity service (NMPC Option 2 or alternative supply contracts)
	Percent of customers taking financial hedges at various times
To what extent do customers on default-service RTP choose to participate in ISO DR programs?	NYISO DR program enrollment
CUSTOMER PERFORMANCE: PRICE RESPONSE	
What is the overall price response by customer class and business sector?	Load-weighted average elasticities of substitution
How do customers respond?	Customers’ self-reported load response strategies
How is price response distributed?	Individual customer elasticities
What incentives do customers respond to?	Customers’ survey responses
	Statistical influence of NYISO DR program enrollment on price elasticity
Do enabling technologies enhance price response?	Statistical influence of enabling technologies on elasticity
	Customers self-reported use of enabling technologies
What barriers do customers encounter in responding to prices?	Barriers reported by customers
	Customers’ self-reported frequency of monitoring prices
	Historic SC-3A prices

Table 2. Elasticity of Substitution Results

Business Category	**N**	**Average substitution elasticity**
Government/education	34	0.10
Public Works	17	0.02
Commercial/retail	16	0.06
Healthcare	8	0.04
Manufacturing	44	0.16
Total	**119**	**0.11**

Table 3. Barriers to Price Response

Barrier	**Percent of Respondents[a] (N=76)**
Organization/Business Practices	
Insufficient time or resources to pay attention to hourly prices	*51%*
Institutional barriers in my organization make responding difficult	*30%*
Inflexible labor schedule	*21%*
Inadequate Incentives	
Managing electricity use is not a priority	*22%*
The cost/inconvenience of responding outweighs the savings	*22%*
Risk Aversion/Hedging	
My organization's management views these efforts as too risky	*13%*
Flat-rate or time-of-use contract makes responding unimportant	*12%*
Other barriers	3%
No barriers encountered	12%
Do not know	3%

[a] Customers were asked to check all barriers that applied, so responses do not add up to 100%.